# 2015 Residential Electricity Price Trends Report

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION (AEMC)

November 2015

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# 1 Introduction

The Australian Energy Market Commission (AEMC) is currently undertaking the 2015 Residential Electricity Price Trends report. This report is the sixth annual residential electricity price trends report prepared by the AEMC at the request of the COAG Energy Council (formally the Standing Council on Energy and Resources).

The AEMC's report sets out, in broad terms, the drivers of price movements and trends in residential electricity prices for each state and territory of Australia over the four years from 2014/15 to 2017/18. These drivers and trends are also consolidated to provide a national summary.

## 1.1 Frontier Economics' engagement

Frontier Economics has been engaged by the AEMC to advise on future trends in residential electricity prices, and the drivers behind them. Specifically, Frontier Economics has been retained to advise on future trends in the wholesale energy cost component of residential electricity prices in the National Electricity Market (NEM) and the South West Interconnected System (SWIS). The specific cost components for which we are to provide cost forecasts are:

- wholesale electricity costs, estimated using a market based approach for NEM jurisdictions and a stand-alone Long Run Marginal Cost (LRMC) approach in the SWIS
- network losses
- market fees for both the NEM and the SWIS
- the cost impact of any relevant jurisdictional environmental policies or programs (or other relevant policies or programs)
- the cost impact related to the national Renewable Energy Target (including both the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES)).

Our advice on wholesale energy costs is to cover the four-year period from 2014/15 to 2017/18. We have been asked to investigate a number of scenarios with regard to demand forecasts, fuel input costs and generator retirements.

## 1.2 Frontier Economics' previous work

Frontier Economics has advised the AEMC on future trends in residential electricity prices as part of the AEMC's previous price trends reports, including the AEMC's 2014 Residential Electricity Price Trends report.

The methodology that we have adopted for this report is very similar to the methodology that we have adopted previously. Key differences between our work for this year's report and last year's report are:

- We have slightly modified our approach to modelling investment and retirement in the NEM, as discussed in Section 2.2.3.
- We have modified our approach to forecasting market-based energy purchase costs by separately estimating the cost to supply standard load and controlled load, as discussed in Section 3.1.2.
- We have updated all of our modelling assumptions as part of our annual updating process, although we have generally adopted the same approach to sourcing this modelling assumptions.

## 1.3 About this report

This report is structured as follows:

- Section 2 presents the approach we use to determine wholesale energy costs for residential customers.
- Section 3 details the assumptions used in the analysis and the scenarios modelled.
- Section 4 presents our wholesale energy cost estimates.
- Section 5 covers our non-energy cost estimates.

Appendix A presents Frontier's detailed supply-side input assumptions.

# 2 Modelling methodology

This section presents an overview of Frontier Economics' electricity market models and their application to the NEM and SWIS to determine estimates of wholesale energy costs for residential customers.

## 2.1 Frontier Economics' modelling framework

In forecasting wholesale energy costs in the NEM and SWIS, we make use of a number of related energy market models.

Forecasting long term gas prices for both eastern Australia and Western Australia is undertaken in our gas market model – *WHIRLYGAS*. Coal prices are forecast using our detailed mining cost and netback price models.

The market and cost based approaches to modelling wholesale energy costs in the NEM and SWIS respectively are implemented using our three electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*.

The key features of these models are as follows:

- *WHIRLYGAS* seeks to minimise the total cost of supplying forecast gas demand for Australia's major demand regions. This optimisation is carried out subject to a number of constraints that reflect the physical structure and the market structure of the relevant gas markets. *WHIRLYGAS* has been structured to incorporate the effect on domestic markets of LNG exports and, where relevant, to produce domestic price forecasts that reflect the opportunity costs of exporting gas as LNG.
- Our proprietary coal mine cost models, developed with Metalytics[1], estimate cost based and netback price based estimates for each mine in Australia. These estimates are combined with forecasts of demand for coal to produce delivered coal price estimates for each power station in the NEM and the SWIS.
- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* provides an estimate of LRMC, including the cost of any plant required to meet any regulatory obligation, as required under the scope of work for this consultancy.
- *SPARK* identifies optimal and sustainable bidding strategies for generators in the electricity market using game theoretic techniques. This is a very important difference between Frontier's approach and that of other analysts.

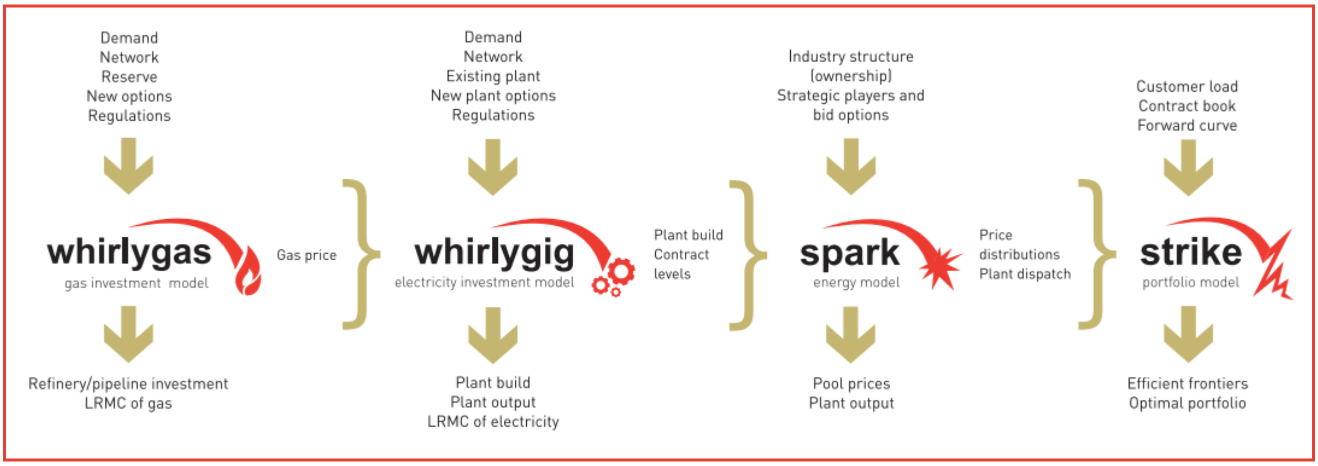
1 Metalytics is a resource economics consultancy that works closely with Frontier Economics.

Instead of making arbitrary and dubious assumptions about possible patterns of bidding for the purposes of calculating a price, our approach has bidding behaviour as a model *output* rather than an *input*. The model determines the optimal pattern of bidding by having regard to the reaction by competitors to a discrete change in bidding behaviour by each generator to increase profit (either by attempting to increase price or expand market share). Once the profit outcomes form all possible actions and reactions to these actions are determined the model finds the equilibrium outcome based on standard game theoretic techniques. An equilibrium is a point from which no generator has any incentive to deviate because they will get pushed back to this point by competitor responses.

- *STRIKE* uses portfolio theory to find the best mix (portfolio) of available electricity purchasing options (spot purchases, derivatives and physical products). This model can be used to determine the additional costs to a retailer of meeting a new load. *STRIKE* uses the output of *SPARK* to provide a distribution of spot (and contract) prices to be used in the optimisation of the suite of purchasing options. *STRIKE* provides a range of efficient purchasing outcomes for all levels of risk.

The relationship between these models is illustrated in Figure 1.

Figure 1: Model inputs and outputs




## 2.2 Methodology for forecasting wholesale energy costs

Regulators use a number of different approaches to estimating wholesale energy costs, including a stand-alone LRMC approach and a market-based approach.

Retail markets are deregulated in NSW, Victoria and South Australia, making a market-based approach to estimating wholesale costs most appropriate in those regions. Queensland is set to move to a deregulated market as of 1 July 2016 and the Queensland Competition Authority (QCA) has previously used a market-based approach to set regulated wholesale costs for residential customers. In Tasmania, the state government uses an approach that is broadly based on market costs of wholesale energy. For these reasons, on balance, the market based approach is the best approach for estimating wholesale costs in the NEM regions.

In contrast, in the SWIS, we consider that the stand-alone LRMC approach is the best approach to estimating wholesale energy costs. There are a number of reasons for this:

- The design of the Wholesale Energy Market (WEM) in the SWIS was intended to continue to support the long-term bilateral contracts that were a feature of the market when the WEM was designed. For instance, the WEM is a net pool market, which market participants principally use to balance their bilateral contract position. Far greater volumes are traded bilaterally than through the energy market. In our view, a stand-alone LRMC approach to estimating retail costs is appropriate for a market design like the WEM.
- There are bidding restrictions in the WEM that prevent any large generators bidding in excess of the Short Run Marginal Cost (SRMC) in the energy market. In our view, a stand-alone LRMC approach to estimating retail costs is consistent with these bidding restrictions.
- There is no formal public market for the exchange of electricity forward contracts in the SWIS. This means that there is no external benchmark that can be used to assess the market's view of future market prices.
- Both the state government and the Economic Regulation Authority (ERA) have made use of a stand-alone LRMC based approach to forecast wholesale costs for the residential market.

These approaches are discussed in more detail in the sections that follow.

### 2.2.1 Stand-alone LRMC of energy

The stand-alone LRMC approach reflects the costs that a retailer would face if it were to build and operate a hypothetical least-cost generation system to serve only its retail load (or a relevant subset of its retail load, such as the retail load of regulated customers). Typically, the stand-alone LRMC approach is implemented by assuming that there is no existing generation plant to meet the relevant load: each year, a new hypothetical least-cost generation system is built and operated, and the costs of investment (annualised over the assumed life of the investment) and operation are calculated.

The intuition behind the stand-alone LRMC approach is that the costs that a retailer faces to serve its retail load can be thought of in two ways: either the costs of purchasing electricity to serve the relevant retail load from a market such as the NEM (accounting for the financial hedging contracts that are typically used by retailers to manage risk) or the cost of building and operating generation plant to directly supply the electricity to serve the relevant retail load. The market-based energy purchase cost considers the first, the stand-alone LRMC considers the second.

Because regulators typically calculate a stand-alone LRMC each year of a determination period (assuming, in each year, that the investment slate is wiped clean and the retailer will need to invest in a mix of entirely new plant) the stand-alone LRMC will, by design, always incorporate both capital and operating costs. In this sense, the stand-alone LRMC is indeed a **long-run** marginal cost: the stand-alone LRMC treats all factors of production as variable and reflects the costs of all factors of production. The same is not true for all approaches to estimating the LRMC of energy for regulatory purposes.

A major appeal of the stand-alone LRMC approach is that it is a simple and easily reproduced approach that relies on a minimum of assumptions. A significant drawback is that the approach considers a highly theoretical system (a residential load shape with no existing generators) which can be seen by some stakeholders to hold little relevance to actual electricity markets. On balance, however, the stand-alone LRMC is a useful approach for informing regulatory decisions and has been widely adopted in Australia.

### Implementation

We model the stand-alone LRMC using *WHIRLYGIG*, assuming that there is no existing generation plant in the system, and a mix of entirely new generation plant must be built in each jurisdiction to meet the load of residential customers in that jurisdiction (including an assumed reserve margin of 15 per cent).

In practice, in both the NEM and the SWIS, reserve margins are set as a fixed MW margin that accounts for likely variations in the system load shapes, operational issues and, in the case of the NEM, the diversity of peak demand between different regions of the NEM. Such numbers cannot easily be used as a reserve margin for a residential load shape within the stand-alone LRMC framework. For example, AEMO's reserve margin for NSW is currently -1,564 MW (i.e. NSW has a *negative* reserve margin, reflecting its ability to import from other regions at times of peak NSW demand).

In the context of a stand-alone LRMC estimate, a single residential load shape is being benchmarked using an entirely new stock of capacity each year in a single region. The choice of a 15 per cent reserve margin acts as a proxy for the more detailed considerations of reserve that are required in actual markets with pre-existing investments and a greater range of load types. A 15 per cent reserve margin has been chosen as it reflects an acceptable margin against a peakier residential customer. Frontier have historically used a 15 per cent reserve margin in our work for the AEMC, the Independent Pricing and Regulatory Tribunal

(IPART), the Essential Services Commission of South Australia (ESCOSA), the Economic Regulation Authority (ERA) and the Office of the Tasmanian Economic Regulator (OTTER), and this approach has been subject to extensive consultation from the industry over a number of years.

### 2.2.2 Market-based approach

The market-based approach to determining the wholesale energy cost of a representative residential customer requires two steps:

- First, a forecast of market prices, which would be required to have regard to strategic bidding behaviour of market participants and actual supply and demand conditions in the market. These prices need to be correlated to residential load shapes to properly capture the risks faced by retailers.
- Second, a forecast of the cost of purchasing electricity (including the cost of purchasing hedging contracts for the purposes of risk management) to meet the load of a representative residential customer. This can be based on a forecast of contract prices (typically tied to forecast spot prices) or publicly available spot prices (such as those on ASX Energy).

In order to properly estimate the wholesale energy cost faced by a prudent retailer, it is important to ensure that the risk of serving a given customer is accurately captured in the modelling approach. Key to this is ensuring that the assumed customer load shape is correctly correlated to an accurate distribution of possible pool price outcomes. Given these inputs – accurately correlated spot prices and customer loads – a framework for quantifying the trade off between risk and reward, and ultimately determining an optimal hedging position and associated wholesale supply costs, is required. We use our models *SPARK* and *STRIKE* to achieve these objectives.

#### *Implementation*

The market-based approach is implemented by using *WHIRLYGIG* to forecast investment and (potentially) retirement outcomes and then modelling market price outcomes using *SPARK*. *STRIKE* uses the forecast spot prices from *SPARK* and assumes that financials hedges – swap and cap products – are available at an assumed 5 per cent premium to forecast prices (as explained below). *STRIKE* is then used to determine optimal conservative hedging outcomes for residential load shapes.

The correlation between residential load shapes and wholesale pool prices is a key driver of the risk associated with hedging a residential customer's load. The residential load shapes are based on AEMO's Net System Load Profile (NSLP), Controlled Load Profile (CLP) and Victorian Manually Read Interval Meter (MRIM) data. This residential load shape data is developed in parallel with the system demand profile shapes used in the *WHIRLYGIG* and *SPARK* stages.

This ensures that the pool prices forecast using *SPARK* (based on system demand shapes) are accurately correlated to the residential load shapes[2] used in *STRIKE,* such that risks are properly captured in the modelling.

### Implementation in Tasmania

For the mainland NEM regions, *STRIKE* is used to determine an optimal mix of spot purchases and financial hedges to serve a residential load shape where both the purchases and hedges are at the relevant regional reference node. For Tasmania, where there is no public financial hedge market, OTTER uses an approach based on the market cost of contracts in Victoria adjusted for losses on Basslink:

> The methodology uses published Victorian forward contract prices as the starting variable and makes a number of transparent adjustments to translate these values into Tasmanian contract prices – taking into account expected net energy exports between Tasmania and Victoria.[3]

We have altered our standard approach to more closely mimic this approach by:

- assuming that a Tasmanian residential load shape is hedged *at the Victorian spot price and using Victorian hedge products* to determine an energy purchase cost at the Victorian node, and
- adjusting this energy purchase cost to the Tasmanian node as per forecast losses on Basslink from the relevant *SPARK* model run.

We believe this approach embodies the most accurate market-based approach for Tasmania.

### Contract premiums under the market-based approach

While *SPARK* provides a forecast of spot prices that can be used as an input to *STRIKE*, there is a requirement to make some assumptions regarding financial contract prices. ASX Energy market prices for such contracts do not trade at sufficient levels of liquidity to establish a meaningful price estimate for all jurisdictions over all years of the modelling. Our approach is to assume that financial hedges trade at a 5 per cent premium to our *SPARK* forecasts of spot prices.

This contract premium value – 5 per cent above forecast pool prices – was established based on initial analysis of spot and contract price data over 2006-2007 as part of Frontier Economics' advice to IPART's 2007 retail price

2 Table 1 presents load factors for the residential load shapes and pool correlation coefficients.

3 See http://www.energyregulator.tas.gov.au/domino/otter.nsf/8f46477f11c891c7ca256c4b001b41f2/0de2f2a45e46402aca257c4a00079a4a?OpenDocument, accessed 29 June 2015.

determination. The 5 per cent premium has been used in all our work for IPART (the 2007, 2010 and 2013 determinations and annual reviews), in our advice to ESCOSA, and elsewhere. Over this period, no stakeholder has raised concerns or provided alternative data that would suggest this 5 per cent value is significantly wrong.

In practice, there is no single percentage or dollar contract premium that applies to contracts for all retailers in all markets at all times. Expectations around both the level and volatility of spot and contract prices evolve over time and differ by region, participant, counterparty and transaction. Prices of traded financial contracts reflect many factors, including:

- expectations about future spot prices
- expectations about the volatility of spot prices, for example due to wind output uncertainty
- participants' risk preferences
- participants' risk policies and hedging limits
- participants' assessment of counterparty risk
- the timing of the transaction relative to maturity dates for the traded contracts
- the range of alternative trading strategies used by participants
- uncertainty around market externalities such as demand, wind output, and generation and transmission outages.

We believe there are strong theoretical arguments and empirical evidence to suggest that different participants seek different premiums on different products at different times. For example, whilst two generators may have differing risk preferences that lead them to seek different contractual premiums, either participant in isolation is also likely to have a wide spread of expected premiums across its book of hedges as a result of the factors listed above.

However, observing prevailing hedge premiums across a market is essentially impossible. The hedge contract premium is ex ante unobservable and ex post can only be crudely measured or approximated. The reason for this is that the hedge contract premium reflects an aggregate consensus of spot market expectations and risk tolerances on a forward-looking basis at a point in time. Over time, with the revelation of new information and possible shifts in risk preferences, the ex ante hedge contract premium can, ex post, reflect a very different value.

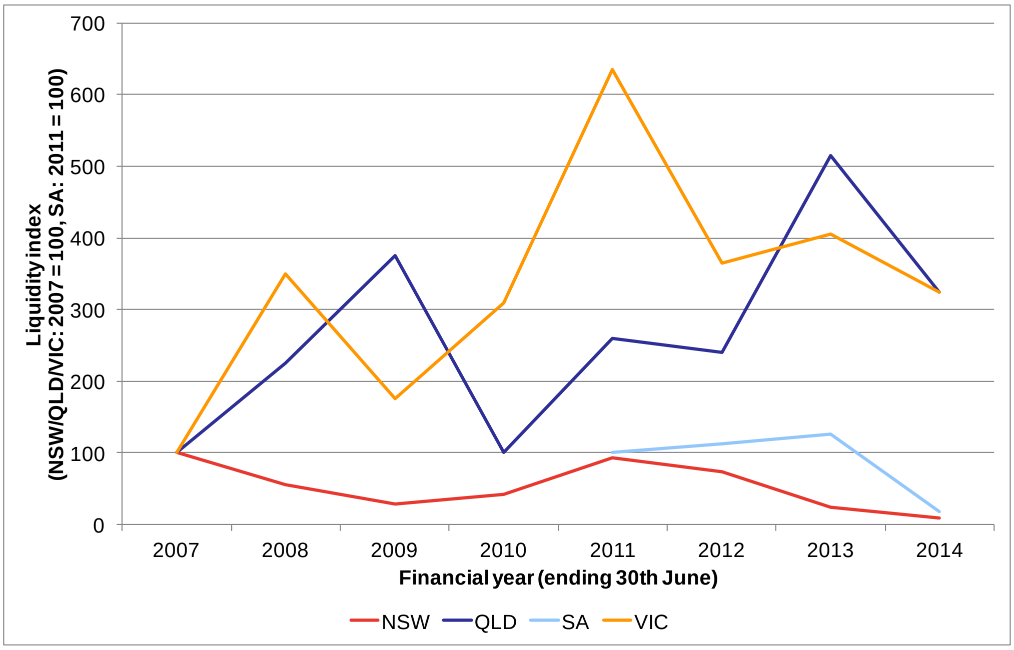
The simplest example of this is a situation where the market expects spot prices to rise strongly for the coming year. In such a situation, all else being equal, the forward price of contracts would reflect this expectation. To the extent an unexpected factor results in prices being lower than the market's initial consensus (e.g. a mild summer), the ex post realised hedge contract premium will appear higher than the ex ante premium. The reverse is true of unanticipated factors which cause spot prices to increase.

The above suggests that measuring the ex ante hedge contract premium is essentially impossible, since there is no way of determining the market's true expectation of forward spot prices at the time a given contract is struck. Likewise, while estimating the ex post hedge contract premium is possible, any estimate will be biased by factors which became evident at a point in time after a given contract is struck. Finally, the ex post hedge contract premium is likely to be highly variable and fluctuate over time with the revelation of new information.

We believe there to be little evidence of systematic differences in contract premiums between NEM jurisdictions. That is, there is no evidence of a causal link between levels of observed contract market liquidity and expected contract premiums. This view is informed by the large observable swings in the contract market that are not correlated with stakeholder distress around contract pricing levels. This is shown in Figure 2, which depicts an index of liquidity for exchange traded financial year flat swap contracts. For NSW, Queensland and Victoria, the index is set such that the volume traded in 2007 equals 100. In South Australia the index is set such that 2011 equals 100.

Figure 2 clearly shows that liquidity within all the NEM regions regularly fluctuates significantly from year to year. Our experience is that participants observe no material change in the implied premium of hedges when these significant swings in liquidity occur. Even if a robust historical relationship between jurisdictional liquidity and hedge premiums existed, it is difficult to imagine how this could be used in a forward looking analysis due to the difficulty of forecasting liquidity by region over the forecast period.

Figure 2: ASX Energy historical liquidity




*Source: Frontier Economics analysis of ASX Energy data*

Frontier Economics is of the view that assuming a contract premium of 5 per cent above pool prices is a reasonable first order estimate of actual contract premiums paid in the market.

### 2.2.3 Forecasting plant retirements

This section discusses the increasing relevance, under conditions of weak demand growth and oversupply in the market, of forecasting retirements.

#### *Importance of retirements*

In recent years, the NEM and the SWIS have experienced an unprecedented period of low or, in some cases, negative demand growth. For instance, in NSW and Victoria, annual energy has reduced by approximately 12 per cent from the 2008/09 peak. These reductions have been driven by a number of factors, including:

- energy efficiency schemes
- structural changes to the economy (for example closures of industrial facilities like the Point Henry smelter)
- residential Solar PV installations driven by state and Commonwealth subsidies and falling costs
- price elasticity of demand effects in response to rapid increases in retail tariffs (driven mostly by increased network tariffs).

These factors and others have acted to reduce the demand for electricity met by large thermal and renewable generators, which has resulted in wholesale prices close to SRMC, and low profitability for a number of generators. In some cases generation plant have been removed from the market temporarily (this is often referred to as mothballing or standby outages); for instance, Northern, Tarong and other units have been mothballed. In other cases, older generation plant have been retired permanently; for instance, the Munmorah coal-fired power station, Swanbank B and E, Collinsville, Playford, Wallerawang units 7 and 8, Torrens Island A and most recently Northern have permanently closed or announced intentions to close.

This is a significant quantity of capacity that has already exited the NEM. However, over the forecast period of this study, demand is not assumed to grow in all scenarios. Also, to the extent that the confirmed RET of 33,000 GWh in 2020 brings on low variable cost renewable generation, this will further loosen the supply demand balance and put downward pressure on prices and generator profitability. As such, it is possible that further retirements may occur over the modelling period. Ideally, a robust economic framework for forecasting retirements would be developed and used to predict such outcomes.

### *Difficulty in modelling power station retirements*

Many factors impact on a particular participant's decision to retire a power station, including:

- for generation plant that is operating at a loss, the need to weigh up relatively certain short term losses against less certain long term profits when deciding whether to remain in the market
- decommissioning and site remediation costs that would be incurred on retirement
- dry storage costs (i.e. costs associated with temporarily closing a plant such that it can be easily returned to service)
- portfolio considerations:
  - stand-alone generators with single assets need to assess stand-alone profitability of the asset
  - stakeholders with a portfolio of assets face a more complex decision and may have stronger incentives to both retire plant (due to ability to capture any uplift in revenue via other assets) and to persist with struggling assets (as they can better support short term losses on one asset with profits on other assets).

The most complex aspect of forecasting retirement is that the decision to retire represents an economic game between participants in an electricity market involving a strong first-mover **disadvantage**. That is, to the extent that loose supply-demand conditions would justify the retirement of a significant amount of capacity, each player wants retirements to occur (so that profitability is restored to the remaining suppliers in the market) but wants its competitors to retire plant, rather than retiring their own assets (and foregoing any gains in profitability from those assets). In the case where multiple large power stations are experiencing marginal profitability, this is likely to lead to an outcome where no plant retires and all make minimal profits or even some losses.

### Modelling approach

There are a number of approaches to modelling power station retirements. These fall into three broad categories:

- **By assumption**. Specific plant are assumed to retire. This is obviously quite subjective but cuts through the complexity noted above. Capacity can also be retired generically, as opposed to specific units, via an addition to demand.
- **On the basis of cost**. In the same way that least cost investment schedules can be determined, retirement can also be considered as part of any cost optimisation model. This was the approach implemented for the analysis we undertook which supported the AEMC's RET Review submission in 2014. Because this approach is focused on costs only, it does not account for strategic element of retirement decisions.
- **On the basis of expected profit**. This involves forecasting the profitability of various portfolios with and without specific combinations of retirements. This allows considerations of the strategic game between major NEM participants. We adopted this approach in our advice to the Commonwealth as part of the Contracts for Closure program which focused on a limited number of eligible plant. Robust analysis across a large number of plant using this approach rapidly becomes intractable due to the combinatorial explosion of retirement scenarios that must be considered.

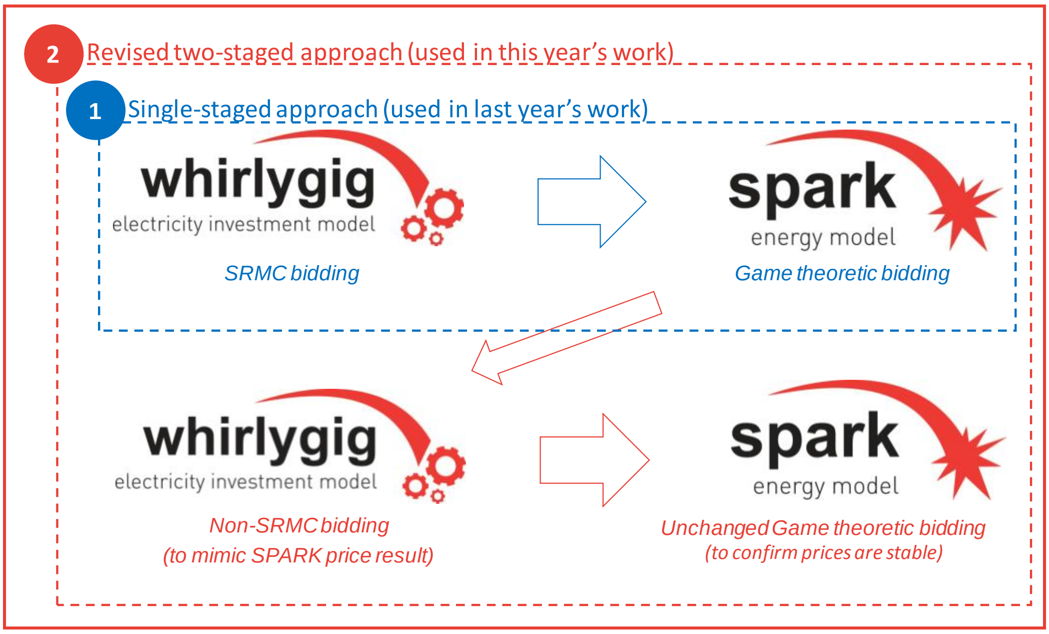
In our previous modelling work we have modelled cost-based retirements in *WHIRLYGIG*, our least-cost investment model. We do this because retirements are long-term decisions that are affected by other long-term decisions such as investments in power stations; to capture this relationship, retirements and investment should be modelling together. The issue with our previous approach to modelling retirements is that our *WHIRLYGIG* modelling does not account for strategic bidding; this means that retirement decisions are based on *WHIRLYGIG* prices that are lower than the *SPARK* prices that include strategic bidding, and that retirement will be more attractive. In order that retirement decisions are based on what we consider are a more realistic set of prices (that reflect strategic bidding) we have revised our approach so that we run a version of WHIRLYGIG that incorporates our view of expected future strategic bidding. This approach combines the least-cost, centralised optimisation approach used in

*WHIRLYGIG* and the equilibrium bidding patterns forecast in *SPARK* in a two-step iterative process.

1. First, we forecast outcomes in *WHIRLYGIG*, assuming perfectively competitive, SRMC bidding. This is used to model both retirement and investment. We then model market outcomes in *SPARK* to determine bidding and pricing forecasts. This is our usual approach to modelling with *WHIRLYGIG* and *SPARK*, and our approach for last year's Price Trends Review.
2. Second we relax the assumption of perfect competition in *WHIRLYGIG* by adopting profiled quantity offers for all strategic generators. These profiled offers are consistent with the bidding outcomes forecast in *SPARK* in our first step. Under our review approach, we use this second *WHIRLYGIG* run to model both retirement and investment. Finally, we model market outcomes in *SPARK*, using these revised investment and retirement outcomes, to confirm that bidding and pricing forecasts are stable, thereby confirming that the iterative loop converges.

This approach is illustrated in Figure 3.

Figure 3: Overview of approach to modelling retirements




We believe that this approach has a number of benefits:

- Retirements occur based on outcomes in the market that reflect strategic bidding, which we think is a more realistic treatment of retirement that assuming SRMC bidding.

- The approach maintains a centralised optimisation framework such that *all* combinations of retirements are investigated simultaneously, just as all combinations of new investment are captured in the approach.

While representing an improvement, the approach is still limited in some regards. Portfolio effects (first mover disadvantage and strategic considerations for large portfolios) are explicitly *not* considered in the approach. The optimisation also occurs with 'perfect foresight' on all model inputs. For example, for a given scenario the model 'knows' that carbon will not return and that demand growth will be strong in some regions and weak in others, with implications for forecast retirements.

On balance, we believe this revised approach to be a material improvement on our previous pure cost-based approach and far more practically applicable than open ended expected profit analysis. The effect of this approach, relative to our previous work, is that retirement decisions are delayed. This reflects the logic that with strategic bidding and higher prices, power station operators will be more inclined to continue to run their power stations. The results of the modelling demonstrate credible retirement forecasts (see Section 4.1.2).

The new approach also has implications for our modelled LGC cost estimates and LRET outcomes. Just as the *relative* fixed costs of existing plant alter if market prices are higher, the same effect also makes incremental renewable investments economic. This makes sense, as a new entrant renewable generator must be able to recover its LRMC in order to justify entry, either directly through a power purchase agreement (PPA) or through LGC and energy sales. To the extent that energy is more valuable (i.e. market prices are higher) then, other things equal, LGC prices will be lower and/or higher cost renewable generators will be able to recover their long run costs. In our modelling, this has the effect of lowering our forecast cost estimate of LGCs and, in some cases, reducing the extent to which shortfalls against the LRET are forecast to occur. We believe these revised outcomes represent an improvement to our previous approach.

## 2.3 Methodology for forecasting cost of the RET

In addition to advising on wholesale energy costs for the period 2014/15 to 2017/18, this assignment also requires us to estimate a range of other energy-related costs. This section considers the costs associated with complying with the RET, including both:

- the Large-scale Renewable Energy Target (LRET)
- the Small-scale Renewable Energy Scheme (SRES).

In June 2015 the Commonwealth Government changed the RET[4] by reducing the LRET to 33,000 GWh, by altering eligibility of supply to include native forest wood waste, and by altering liability of load to exempt all emissions-intensive trade-exposed industry. Our modelling incorporated these changes in all scenarios.

### 2.3.1 LRET

The LRET places a legal obligation on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP), which is set by the Clean Energy Regulator (CER).

LGCs are created by eligible generation from large scale, renewable energy power stations. Small-scale installations such as solar water heaters, air sourced heat pumps and small generation units, are not eligible to create LGCs under the LRET. Instead, these small-scale installations are eligible to create certificates under the SRES.

#### *Approach to estimating costs of complying with the LRET*

In order to calculate the cost of complying with the LRET, it is necessary to determine the Renewable Power Percentage (RRP) for a representative retailer (which determines the number of LGCs that must be purchased) and the cost of obtaining each LGC.

#### *Renewable Power Percentage*

The RPP establishes the rate of liability under the LRET. It is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year.

The RPP is calculated as the quotient of the scheme target over the quantity of liable demand. It is set to achieve the renewable energy targets specified in the legislation. The CER is responsible for setting the RPP for each year. The recent amendments to the legislation have resulted in both a reduction in the target *and* a reduction in the volume of liable demand as Energy Intensive Trade Exposed (EITE) industries are now fully exempt from the scheme. The reduction in the target (the numerator) reduces the RPP whilst the reduction in the quantity of

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4 See http://www.cleanenergyregulator.gov.au/About/Pages/News%20and%20updates/NewsItem.aspx?ListId=19b4efbb-6f5d-4637-94c4-121c1f96fcfe&ItemId=146.

liable demand (the denominator) increases the RPP, partially offsetting the cost reduction of a lower target for consumers. Whilst the revised targets have been made public[5] the impact on the quantity of liable demand has not yet been published to our knowledge. Our approach has been to use data on LGCs surrendered by EITEs to establish a baseline of pre-amendment liability. The pre-amendment RPPs have then been adjusted assuming that EITE are now completely exempt. This adjustment equates to an approximate increase in the RPP of 0.2 per cent.

The *Renewable Energy (Electricity) Act 2000* states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh's of renewable energy for the current year divided by the required GWh's of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not decrease the RPP to account for any growth in demand. This assumption is likely to be somewhat inconsistent with AEMO's 2015 NEFR demand forecasts (which include growth in the Medium and High cases and declines in demand in the Low case), the 2014 Medium demand forecast is reasonably consistent as growth in demand is approximately flat under that forecast.

### Cost of obtaining LGCs

The cost to a retailer of obtaining LGCs can be determined either based on the resource costs associated with creating LGCs or the price at which LGCs are traded.

We use resource costs to estimate the cost of obtaining LGCs. Specifically, the estimated cost of LGCs is estimated as the LRMC of meeting the LRET. The LRMC of meeting the LRET is calculated as an output from Frontier Economics' least-economic cost modelling of the power system, using *WHIRLYGIG*. The LRMC of meeting the LRET in any year is effectively the marginal cost of an incremental increase in the LRET target in that year, where the incremental increase in the LRET target can be met by incremental generation by eligible (large scale) generators at any point in the modelling period (subject to the ability to bank and borrow under the scheme). Modelling the LRMC of the LRET in this way accounts for the interaction between the energy market and the market for LGCs. This includes the impact that a change in underlying wholesale costs, due to fuel prices movements or other factors, will have on the incremental cost of creating an LGC.

As discussed above in section 2.2.3, we have revised our approach to incorporate strategic bidding in *WHIRLYGIG*, based on forecast bidding outcomes in

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5 See https://www.comlaw.gov.au/Details/C2015B00071.

*SPARK*. In brief, this means that the LRMC of meeting the LRET is relative to market prices that are consistent with strategic bidding as forecast by *SPARK*. This acts to decrease our LGC cost estimates because a higher forecast wholesale spot price means that the 'subsidy' required to make renewable generation competitive is reduced.

### 2.3.2 SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP), which is set each year by the CER. STCs are created by eligible small-scale installations based on the amount of renewable electricity produced or non-renewable energy displaced by the installation.

Owners of STCs can sell STCs either through the open market (with a price determined by supply and demand) or through the STC Clearing House (with a fixed price of $40 per STC). The STC Clearing House works on a surplus/deficit system so that sellers of STCs will have their trade cleared (and receive their fixed price of $40 per STC) on a first-come first-served basis. The STC Clearing House effectively provides a cap to the STC price: as long as a seller of STCs can access the fixed price of $40, the seller would only rationally sell on the open market at a price below $40 to the extent that doing so would reduce the expected holding cost of the STC.

#### *Approach to estimating costs of complying with the SRES*

In order to calculate the cost of complying with the SRES, it is necessary to determine the Small-scale Technology Percentage (STP) for a representative retailer (which determines the number of STCs that must be purchased) and the cost of obtaining each STC.

#### *Small-scale Technology Percentage*

The STP establishes the rate of liability under the SRES and is used by liable entities to determine how many STCs they need to surrender to discharge their liability each year.

The STP is determined by the CER and is calculated as the percentage required to remove all STCs from the STC Market for the current year. The STP is calculated in advance based on:

- the estimated number of STCs that will be created for the year
- the estimated amount of electricity that will be acquired for the year
- the estimated number of exemptions expected to be claimed for the year.

The STP is to be published for each compliance year by 31 March of that year. The CER must also publish a non-binding estimate of the STP for the two subsequent compliance years by 31 March.

In exactly the same way that increased exemptions under the revised RET increase the RPP, the STP is also increased. We have used the same approach to adjust both the RPP and the STP.

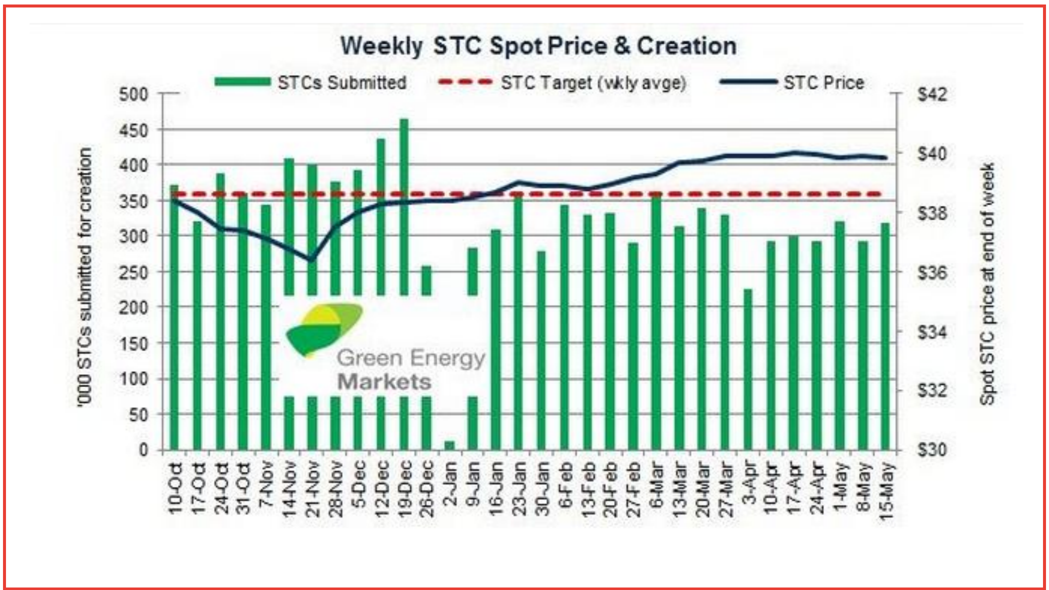
## Cost of STCs

The cost of STCs exchanged through the STC Clearing House is fixed at $40 (in nominal terms). While retailers may be able to purchase STCs on the open market at a discount to this $40, any discount would reflect the benefit to the seller of receiving payment for the STC at an earlier date. In effect, the retailer would achieve the discount by taking on this holding cost itself (that is, by acquiring the STC at an earlier date).

We would also note that STC prices are currently trading at close to the clearing price as shown in Figure 4.

For these reasons, in estimating the cost to retailers of the SRES, Frontier Economics proposes to adopt the STC penalty price of $40/STC fixed in nominal terms.

Figure 4: Current STC market prices




*Source: Green Energy Markets (http://greenmarkets.com.au/resources/stc-market-prices)*

## 2.4 Methodology for forecast cost of energy efficiency schemes

In addition to advising on wholesale energy costs for the period 2014/15 to 2017/18, this assignment also requires us to estimate a range of other energy-related costs, such as the costs associated with complying with market-based energy efficiency schemes that impose obligations in a number of jurisdictions:

- the NSW Energy Savings Scheme (ESS)
- the Victorian Energy Saver Initiative (VEET)[6]
- the South Australian Residential Energy Efficiency Scheme (REES)
- the ACT Energy Efficiency Improvement Scheme (EEIS).[7]

The NSW and Victorian schemes are both certificate based schemes, whereas the South Australian and ACT schemes are obligations on retailers that impose costs which are recovered from all customers.

### *Approach to estimating energy efficiency costs*

Where possible, costs are estimated with reference to retailer obligations and penalty prices under the scheme. Where this approach is not feasible, we use jurisdictional data on the cost of the schemes. We believe this will be sufficient to determine trends in the costs of these schemes.

## 2.5 Other costs

In addition to advising on wholesale energy costs for the period 2014/15 to 2017/18, this assignment also requires us to estimate a range of other energy-related costs.

### 2.5.1 Market fees

Market fees are charged to market participants in order to recover the cost of operating the market.

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6 With the change in Government in Victoria, the intention to close the VEET at the end of 2015 has been overturned. The Minister for Energy and Resources has announced that the VEET will continue. http://www.energyandresources.vic.gov.au/energy/about/legislation-and-regulation/energy-saver-incentive-scheme-management/esi-review

7 The EEIS has been extended to 2020 http://www.environment.act.gov.au/energy/energy_efficiency_improvement_scheme_eeis#Extension

The market fees charged to participants are based on the revenue requirements of market operators. In the NEM, the revenue requirements are based on the operational expenditures of AEMO and are divided into the following categories:

- general fees
- FRC fees
- National Transmission Planner fees
- National Smart Metering fees
- Electricity Consumer Advocacy Panel fees.

#### *Estimating market operator fees*

To estimate future market fees for NEM regions, we use AEMO's budgeted revenue requirements. AEMO publishes its budget requirements and the resulting market fees and we rely on these estimates, and hold the final year estimate constant in real terms where necessary.

To estimate future market fees for the SWIS, due to the difficulty of predicting how market fees vary in future years, we have assumed that the IMO market fee rate stays constant in real terms.

### 2.5.2 Ancillary services costs

Ancillary services are those services used by the market operator to manage the power system safely, securely and reliably. Ancillary services can be grouped under the following categories:

- Frequency Control Ancillary Services (FCAS) are used to maintain the frequency of the electrical system.
- Network Control Ancillary Services (NCAS) are used to control the voltage of the electrical network and control the power flow on the electricity network.
- System Restart Ancillary Services (SRAS) are used when there has been a whole or partial system blackout and the electrical system needs to be restarted.

AEMO operates a number of separate markets for the delivery of FCAS and purchases NCAS and SRAS under agreements with service providers. AEMO publishes historic data on ancillary services costs on its web site.

#### *Estimating ancillary services costs*

To estimate the future cost of ancillary services for NEM regions, we extrapolate based on the past 10 years of ancillary service cost data published by AEMO for each region of the NEM.

For the SWIS, a similar approach is based on the IMO's ancillary services report[8]. Estimates are held constant in real terms.

### 2.5.3 Losses

We base loss estimates on information on transmission and distribution losses published by the relevant market operators - AEMO[9] and the IMO[10].

8 See http://www.imowa.com.au/publications-and-reporting/ancillary-services/annual-ancillary-services-report

9 See http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/List-of-Regional-Boundaries-and-Marginal-Loss-Factors-for-the-2015-16-Financial-Year for transmission loss factors and http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/Distribution-Loss-Factors-for-the-2015_16-Financial-Year for distribution loss factors.

10 See http://www.imowa.com.au/market-reports/loss-factors.

# 3 Modelling assumptions

This section provides an overview of the input assumptions that we use in our modelling. Frontier has used a range of public sources and, for supply side costs and operating parameters, our own in-house estimates. Our approach to generating these estimates is discussed in more detail in Appendix A.

This section is intended to provide an overview of our approach to developing these input assumptions, and a high-level summary of the input assumptions that we have used.

The key input assumptions in terms of impact on modelling wholesale outcomes are:

- demand
- RET assumptions
- fuel costs
- capital costs.

Each of these key assumptions is discussed below.

## 3.1 Demand

Our modelling approach requires demand data for both the system load in the NEM and the SWIS and for residential load shapes for the different distribution areas across the jurisdictions. It is important that the shapes for system demand and residential load are correctly correlated so that market-based energy purchase cost estimates reflect the correct correlation between wholesale prices (that reflect the system load shape) and residential load.

This is achieved by using historical data for both the system and residential load shape from 2013/14.

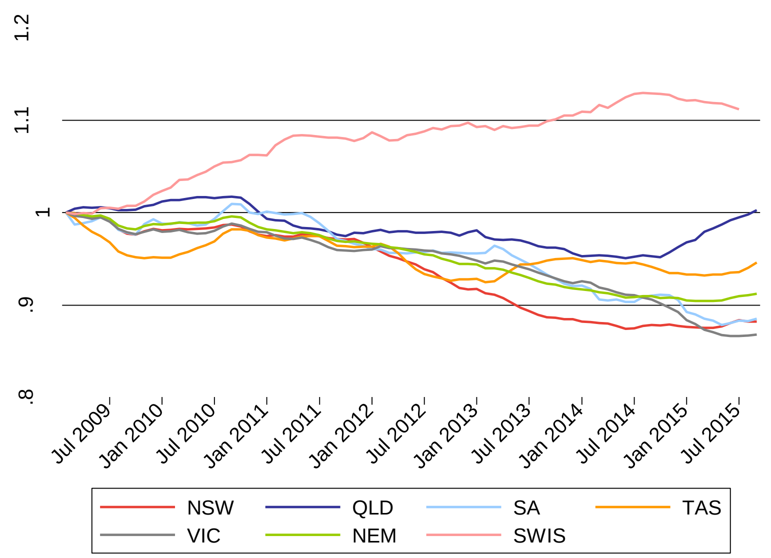
### 3.1.1 System load

The system load shapes are based on historical data from 2013/14. This is only relevant in the NEM regions (as the stand-alone LRMC approach used in the SWIS relies only on a residential load shape). Depending on the scenario, this profile shape has been scaled to forecast energy and peak taken from AEMO's 2015 National Electricity Forecast Report (NEFR) or from AEMO's 2014 NEFR.

Actual demand outcomes indicate little evidence of demand growth over 2014/15, with the exception of the SWIS, where demand is primarily driven by large scale mining projects, relatively higher population growth rates and the associated multiplier effect on the rest of the economy. Queensland has also seen significant growth in energy consumption since late 2014 with the commissioning of the first LNG trains in Gladstone; this is expected to continue as further trains come online. This recent trend is summarised in Figure 5, which shows Frontier's rolling annual demand index values since the approximate NEM market peak in 2008/09.

In the previous 12 months, Victoria has experienced steep reductions in demand while Queensland has seen demand growth primarily due to the commissioning of the first LNG trains.

Figure 5: Rolling-monthly annual energy demand since approx. peak level (12-month period Mar 08 to Feb 09)




*Source: Frontier Economics*

Figure 6 and Figure 7 present the AEMO demand forecasts used in the modelling. As can be seen, this year's Medium forecast predicts far more growth in demand than the 2014 Medium case; demand is expected to be higher in both the short and longer term in NSW, Victoria and Queensland. In Queensland there is rapid growth in demand over the period 2014/15 to 2017/18 as the LNG trains come online; this is equivalent to a 20% rise in energy terms. In the Low case, there are significant reductions in demand in all regions.

Figure 6: AEMO demand forecasts (NSW, Victoria and Queensland)

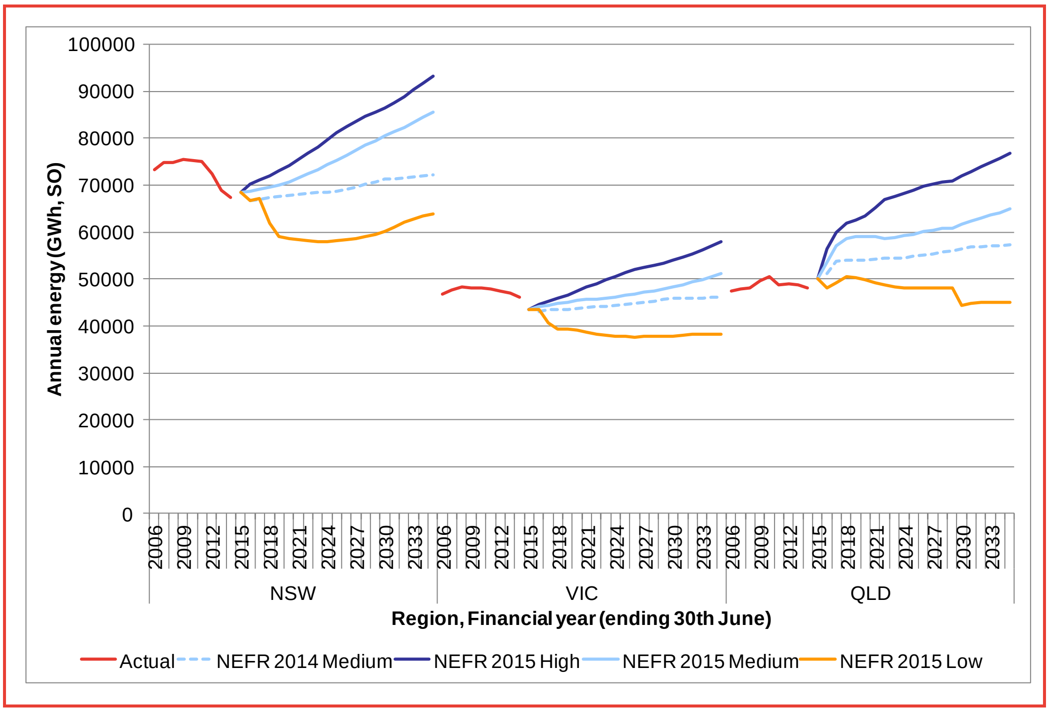
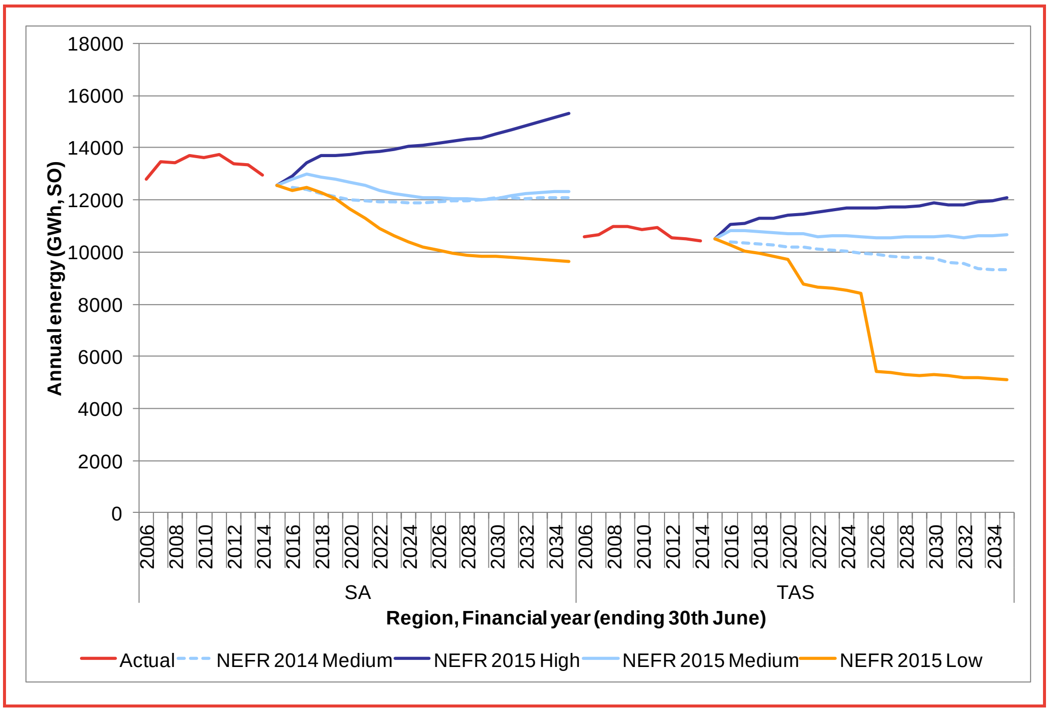



Figure 7: AEMO demand forecasts (South Australia and Tasmania)




While most of the scenarios that we model make use of demand forecasts from AEMO's 2015 NEFR, we also model the medium case from AEMO's 2014

NEFR. There are material differences between the medium case from AEMO's 2014 NEFR and the medium case from AEMO's 2015 NEFR: the more recent forecasts have significantly higher demand growth. We have investigated the drivers of the change between AEMO's 2014 NEFR and AEMO's 2015 NEFR and our analysis suggests that the differences in the demand forecasts are driven by two factors:

- Revised estimates of the price elasticity and income elasticity of electricity demand based on an additional year of data. For the most part, these revised estimates indicate that electricity demand will change more as a result of an increase in income or a decrease in prices.
- Revised forecasts of electricity prices. In particular, in NSW, the revised estimates take into account reductions in electricity prices as a result of the AER's recent electricity network determinations.

As our modelling shows, the significantly higher demand forecasts in AEMO's 2015 NEFR result in higher pool prices.

### 3.1.2 Residential load shapes

The residential load shapes are obtained by using AEMO's half-hourly NSLP, CLP and Victorian MRIM load for each distributor in 2013/14. For Western Australia, where residential load shape data is not publicly available, we have used data provided by the jurisdiction. In areas where controlled load exists, it will be modelled separately. This is a change in approach relative to Frontier's advice for the 2014 Residential Electricity Price Trends Report, where a combined NSLP plus CLP shape was modelled.

This change in approach has been motivated by a requirement to model the representative customer's controlled load under the relevant controlled load network tariff, increasing the accuracy of network cost estimates. For the wholesale modelling, this change in approach introduces a slight systematic overestimation in wholesale energy costs estimates.

This overestimation arises due to the fact that a customer's controlled load is typically anti-correlated to general consumption (controlled load is highest around midnight when general consumption is low). As such, there is a portfolio benefit associated with the combined shape and it is cheaper to hedge with standard products. This is illustrated in Figure 8, Figure 9 and Figure 10 which show illustrative hedging positions against a controlled load, net system load and combined load shape respectively. As shown, there are portfolio benefits under the combined shape and this results in less 'overhedging' and a lower wholesale energy cost estimate. This effect is not material and will not influence trend outcomes in the modelled results.

Figure 8: Hedging a controlled load shape (illustrative)

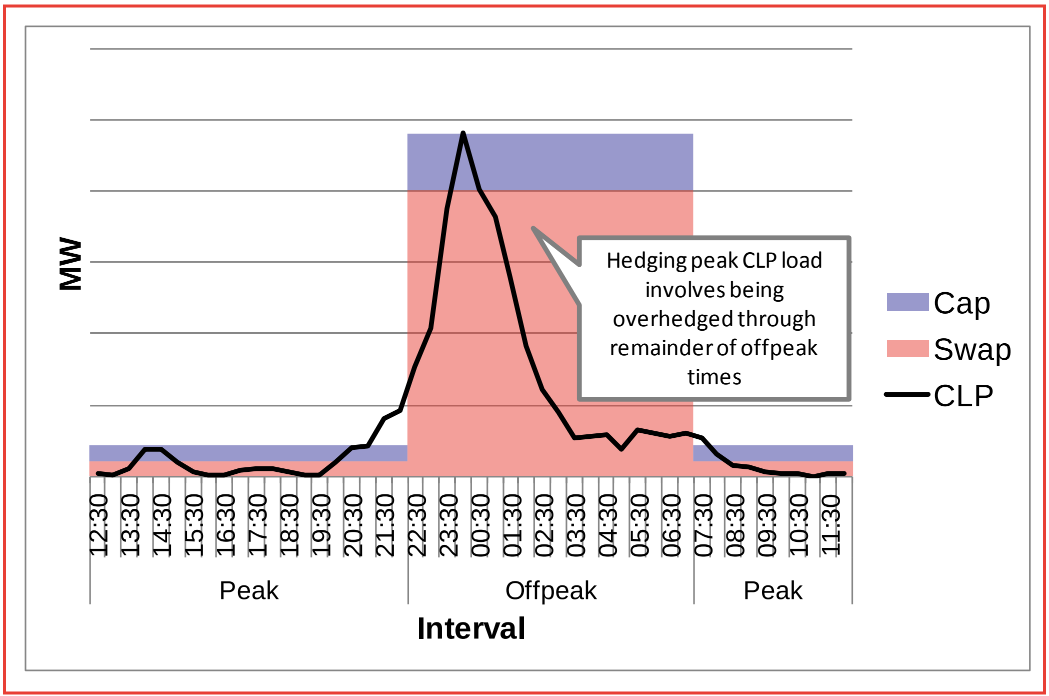



Figure 9: Hedging a net system load shape (illustrative)

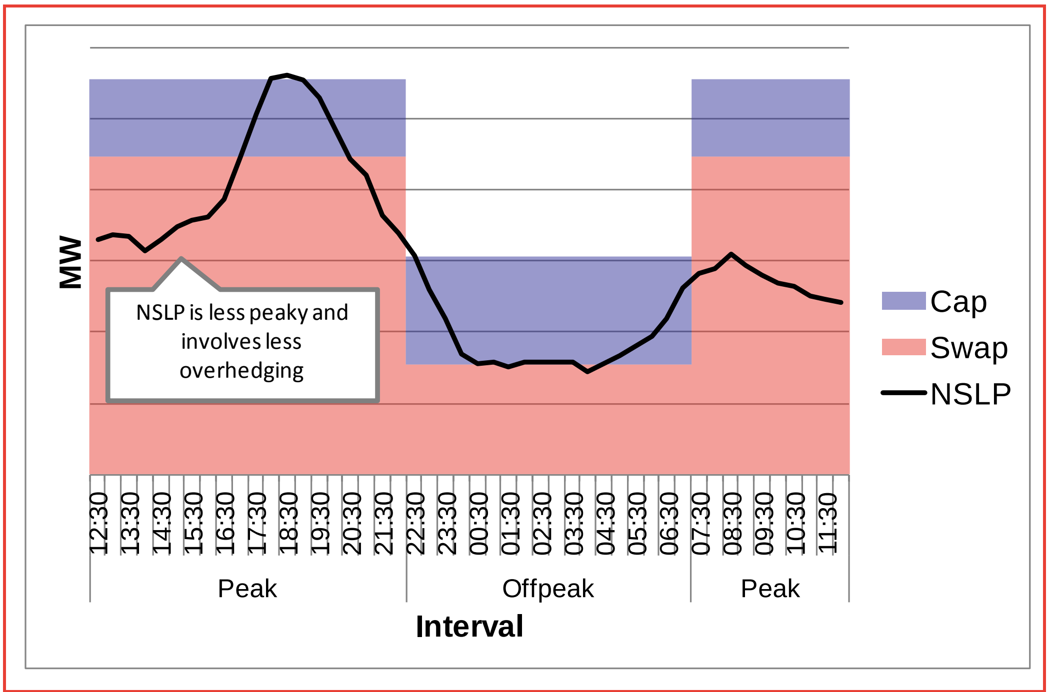
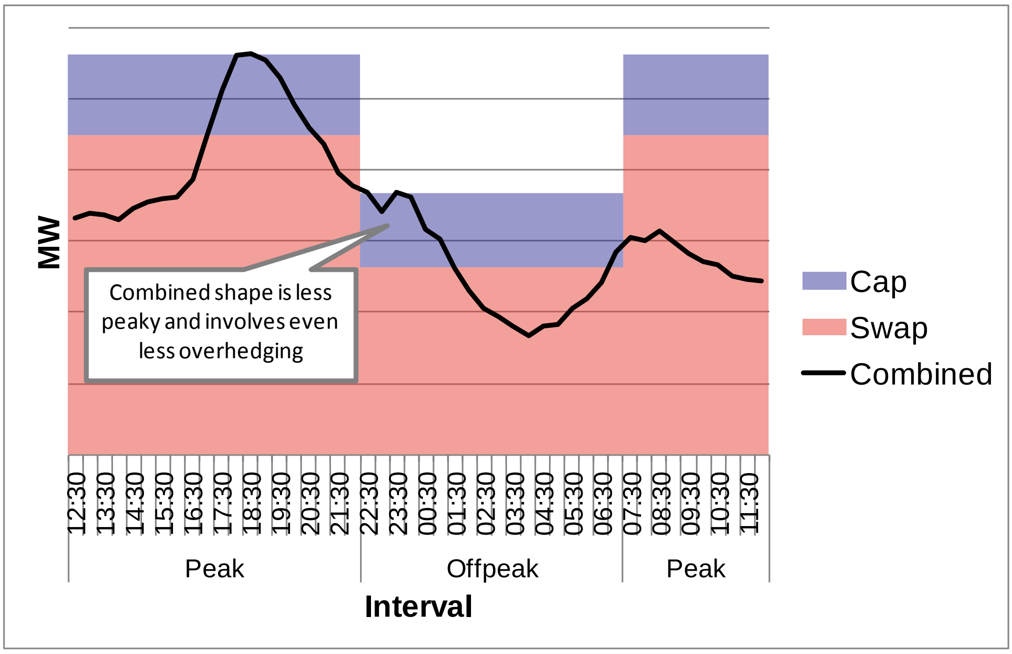


Figure 10: Hedging a combined load shape (illustrative)




For each distribution area, we have normalised the residential load so that the annual energy is 1GWh.[11] The cost of serving the load will be higher if the load and pool prices are positively correlated, such that both prices and volumes are high simultaneously.

Table 1 shows the load factor and correlation coefficient between the normalised residential load and the relevant regional pool price for 2013/14.

11 The energy purchase cost and stand-alone LRMC, both expressed in $/MWh, are independent of the volume of energy modelled. The normalisation process ensures that the *shape* of the load remains unchanged.

Table 1: Load factor and Correlation coefficient with pool price based on 2013/14 data

| Region | Distributor | Profile | Load factor | Correlation coefficient with pool price |
|---|---|---|---|---|
| NSW | ACTEWAGL | NSLP | 0.38 | 0.06 |
| | Ausgrid | CLP EA | 0.18 | -0.02 |
| | | NSLP | 0.34 | 0.07 |
| | Endeavour | CLP IE | 0.17 | -0.02 |
| | | NSLP | 0.33 | 0.10 |
| | Essential | CLP CE | 0.20 | -0.02 |
| | | NSLP | 0.48 | 0.07 |
| QLD | Energex | CLP 31 | 0.10 | -0.02 |
| | | CLP 33 | 0.13 | 0.01 |
| | | NSLP | 0.33 | 0.16 |
| | Ergon | CLP CE | 0.20 | -0.04 |
| | | NSLP | 0.51 | 0.13 |
| SA | SA Power Networks | CLP | 0.14 | -0.03 |
| | | NSLP | 0.24 | 0.22 |
| TAS | Aurora | NSLP | 0.42 | 0.05 |
| VIC | Citipower | MRIM | 0.42 | 0.21 |
| | Jemena | MRIM | 0.30 | 0.21 |
| | Powercor | MRIM | 0.38 | 0.21 |
| | SP Ausnet | MRIM | 0.30 | 0.23 |
| | United | MRIM | 0.29 | 0.21 |

*Source: AEMO and Frontier Economics Analysis*

For the stand-alone LRMC, the load factor of the residential load shapes are a key driver of the final cost estimate. This is because peakier load shapes require a great proportion of high LRMC peaking capacity compared to flatter load shapes. For the stand-alone LRMC, the correlation to pool prices is irrelevant as it is a cost-based approach.

For the market-based approach, both the load factor and the correlation to pool prices drive the estimate of wholesale costs. There is a combined impact where residential consumers demand more electricity when pool prices are high (during the morning, evening peaks and across the day in summer), and less when prices are low (overnight). That is, the peaky, high demand times under the residential load shape are correlated to higher pool price events.

Financial year 2013/14 was the most recent, complete financial year for which data was available and was deemed suitable for the purpose of this analysis. Data is available over the historical period of the NEM, although Frontier is aware of issues in the data for the 2006 to 2008 period.

The NSLP, MRIM and, to a lesser extent, CLP load profiles do change over time. However, absent a detailed statistical analysis of the data, it is difficult to forecast how this will change in the future. Not only does this involve forecasting the impact of weather and other factors on peak residential demand but the task is made harder in recent years by increased energy efficiency and rooftop PV penetration in the residential segment. In the absence of such analysis, using the most recent data is an appropriate assumption for the current analysis.

## 3.2 Carbon

All modelling cases assume zero carbon prices throughout the modelling period, consistent with the Commonwealth Government's repeal of the Clean Energy Act in July 2014. Note that this means that the 2014/15 modelling results will not assume a carbon price for the first few weeks of July 2014 as was the case in practice.

## 3.3 RET

The revised LRET target of 33,000 GWh, including the revised trajectory of the target to 2020, will be modelled across all cases. This target drives the level of investment in large-scale renewable technology over the modelling period and impacts on pool price forecasts.

Our approach for estimating retail costs associated with the RET was discussed in Section 2.3. As discussed in Section 2.3, the estimate for LGC prices is obtained from the marginal cost of meeting the LRET, as calculated in the *WHIRLYGIG* stage of our modelling.

SRES will be modelled consistent with current legislation.

## 3.4 Frontier Economics' supply side inputs

In recent years, Frontier Economics has developed its own framework for estimating key supply side inputs – capital costs, fuel prices, O&M costs and new generation entrant operating parameters. This work has been motivated by issues around the extent, timeliness and internal consistency of publically available alternatives.

This section briefly discusses the sources of data available for modelling Australia's electricity markets, Frontier's motivations for developing our own estimates and the extent to which our estimates have been subject to review by stakeholders.

### 3.4.1 Sources for modelling assumptions

There are other public documents that also provide estimates of key input assumptions. In particular, various reports released by AEMO provide a detailed set of cost and technical data and input assumptions that can be used in energy market modelling:

- AEMO publish information on the capacity of existing and committed generation plant in the NEM over the next two years.[12]
- AEMO publish the National Transmission Network Development Plan (NTNDP), and supporting documents, which include a range of technical and cost input assumptions.[13]
- AEMO publish information on marginal loss factors for generation plant.[14]

These various reports released by AEMO could be used in our energy market modelling. However, there are a number of reasons that we consider the input assumptions that we have developed are preferable:

- It appears that the most recent input assumptions developed for the NTNDP are not, in all cases, based on the same macroeconomic forecasts. For instance, it appears that the fuel cost forecasts and the capital cost forecasts are based on different assumptions about forecast exchange rates (which are an important determinant of both fuel prices and capital costs).
- The NTNDP does not provide input assumptions for the SWIS. In order to ensure that we develop a set of input assumptions that are entirely consistent (in the sense that they are based on the same methodology and the same underlying assumptions) we have had to develop input assumptions for both the SWIS and the NEM.

Nevertheless, we continue to adopt some input assumptions from various reports released by AEMO. In particular, we adopt input assumptions from

12 http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information

13 http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan

14 http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries

various reports released by AEMO where the input assumptions relate to market data collected or generated by AEMO as part of their function as market operator (such as capacities of existing generation plant), where the data is NEM-specific in nature (such as capacity factors for wind plant in various regions of the NEM) or where there is less uncertainty about the input assumptions (including when they relate to technical characteristics of existing generation plant or are not sensitive to changing market conditions). These are discussed in more detail in the remainder of this report.

### 3.4.2 Peer review of Frontier's input assumption estimates

Our input assumption estimates are based on a range of proprietary databases, upstream fuel market modelling and in-house analysis. IPART retained Frontier Economics to develop the key modelling inputs for its 2013 NSW retail electricity price determination.

As part of IPART's determination, our approach to developing estimates and the estimates themselves were documented publically and subject to stakeholder scrutiny through public consultations and stakeholder submission processes[15]. Stakeholders did not raise any material objections to either our approach or estimates.

Similarly, our assumptions were used in the AEMC's 2014 Retail Price Trends review and a range of other projects we have undertaken recently, and were subject to further scrutiny through these processes.

The input assumptions presented below use the same approach as previous years and have been only been updated for more recent information.

### 3.4.3 Fuel

Frontier's fuel prices are based on modelling and analysis of the Australian gas and coal markets. We maintain a Base Case that reflects current estimates of key inputs such as the number of LNG trains and long term export coal and LNG prices. Given the rapid move to internationalised prices in both coal and gas, we have also developed a high case to provide a set of inputs that can be used to investigate the impact of higher than expected input fuel costs. This high case reflects increased export fuel prices and more east coast LNG trains.

A detailed description of our approach to estimating fuel prices can be found in Appendix A.

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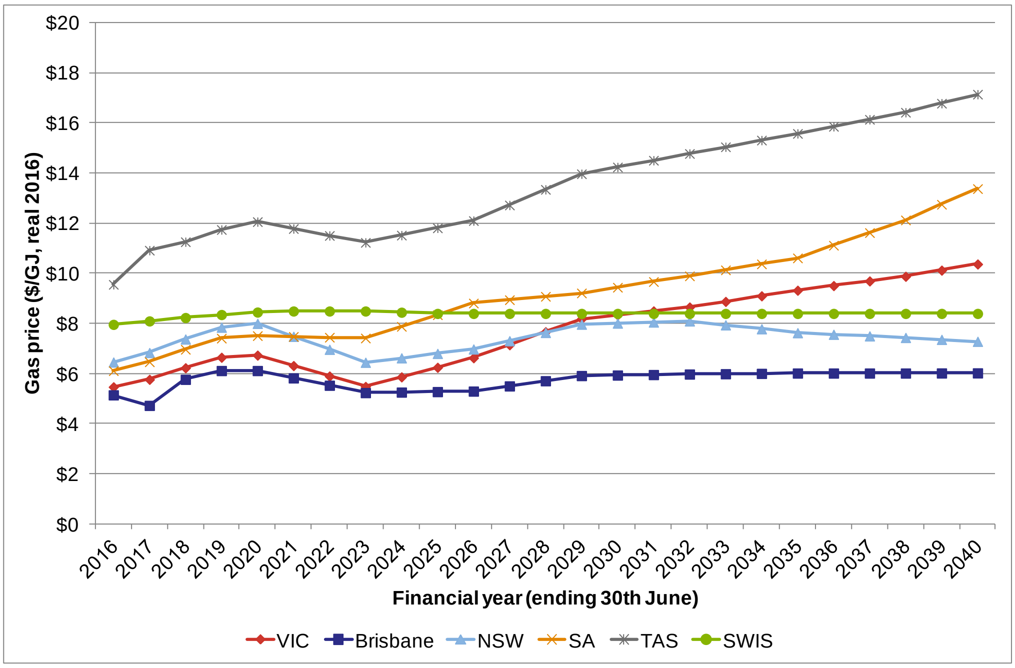
15 See, for example, Frontier Economics' report for IPART:

http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Review_of_regulated_electricity_retail_prices_2013_to_2016/17_Jun_2013_-_Consultant_Report_-_Frontier_Economics_-_June_2013/Consultant_Report_-_Frontier_Economics_-_Input_assumptions_for_modelling_wholesale_electricity_costs_-_June_2013

### Gas prices

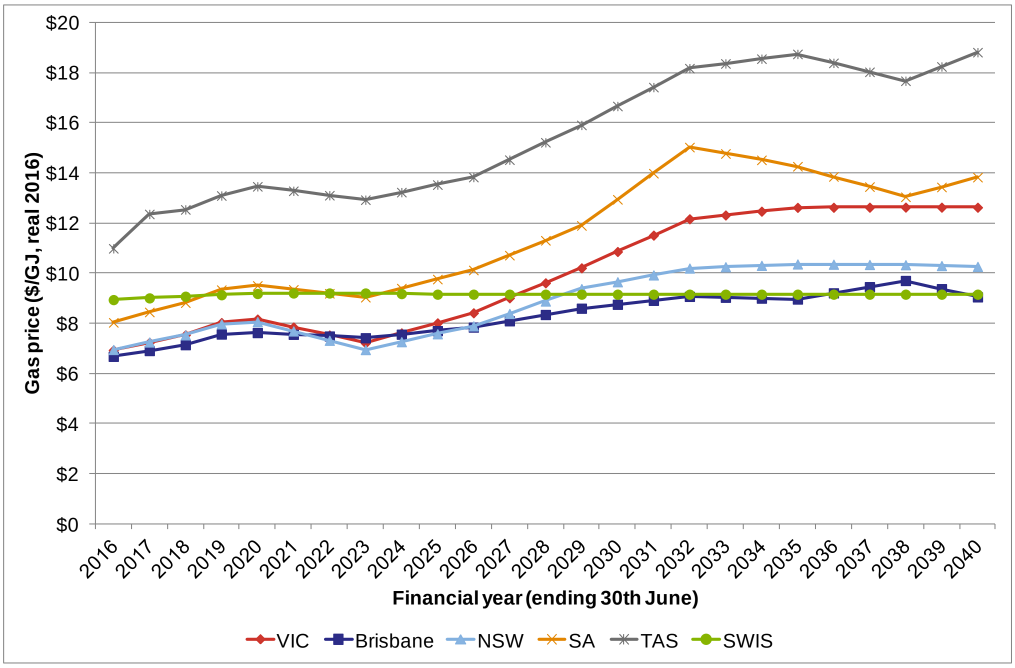
Gas prices are driven by demand for gas, international LNG prices, foreign exchange rates and underlying resource costs associated with gas extraction and transport. Frontier's Base Case and High Case forecasts are shown in Figure 11 and Figure 12 for a selection of pricing zones across Australia.

Figure 11: LRMC of gas by region ($/GJ, real 2016) – Base Case




*Source: Frontier Economics*

Figure 12: LRMC of gas by region ($/GJ, real 2016) – High Case




*Source: Frontier Economics*

Our forecasts of gas prices reflect changing dynamics in the east coast gas markets.

While the first LNG trains in Gladstone commenced operation in early 2015, these facilities are at the top of the cost curve internationally and selling into a falling market. Contrary to recent expectations, it appears that no further LNG trains beyond the 6 which have been committed in Gladstone will be commissioned in the short or medium term. This is our Base Case assumption, and is consistent with base case assumptions adopted by AEMO.[16] Based on public information on gas reserves, including from the Queensland Department of Natural Resources and Mines[17] and AEMO,[18] this makes it likely not only that there is enough gas to meet demand from the LNG trains, but that there are surplus reserves in Queensland that can be used to meet domestic demand into

16 See, for example, Jacobs' LNG Report for AEMO:

http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report/NGFR-Supplementary-Information

17 https://www.business.qld.gov.au/invest/investing-queenslands-industries/mining/resources-potential/petroleum-gas-resources

18 See, for example, Core Energy Group's Reserves and Resources report for AEMO:

http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2015-GSOO-Supporting-Information the longer term. This results in low forecast prices for gas in Brisbane, where there is ample local gas to supply demand.

In the southern states, gas supply from conventional sources - offshore Victoria and the Cooper-Eromanga basin - continues to be a major source of low cost supply. In the longer term, the development of further gas resources in these basins, combined with the eventual development of coal seam gas in New South Wales, are sufficient to meet demand. However, these new developments involve higher production costs than existing sources of supply and, in the case of NSW involve transport costs from northern NSW to the southern states. An important driver of this outcome is AEMO's demand forecasts, which are for material reductions in gas demand in all regions (with only LNG exports driving growth). Finally, the shape of gas demand across the year is peakier in the southern states, which also acts to increase costs.

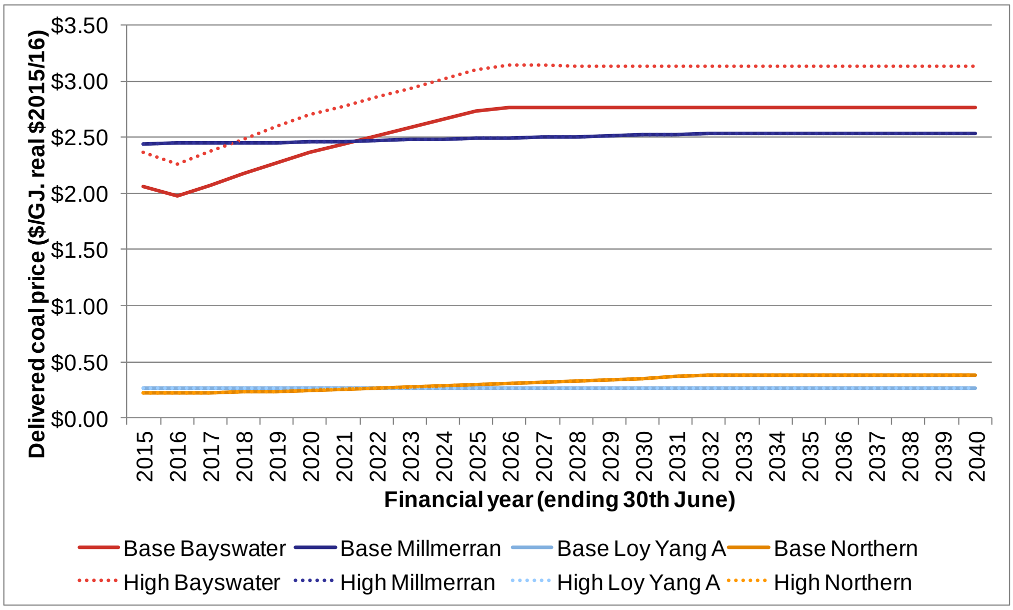
Due to these factors – higher cost marginal production, the cost of delivering gas to the southern states and peakier consumption profiles – gas prices are higher in the southern states relative to Queensland.

### *Coal prices*

Coal prices are driven by demand for coal, international export coal prices (for export exposed power stations), foreign exchange rates and underlying resource costs associated with coal mining. Frontier's Base Case (solid line) and High Case (dashed line) forecasts are shown in Figure 13 for representative power stations both export exposed and mine-mouth stations. Note, Bayswater is the only export exposed plant shown and is therefore the only one with a higher price in the High Fuel case.

Relative to last year, the coal prices have reduced. This is primarily driven by falls in international coal export prices which have not been completely offset by the falling currency.

Figure 13: Coal prices for representative generators ($2015/16) – Base Case (solid) and High Case (dashed)




*Source: Frontier Economics*

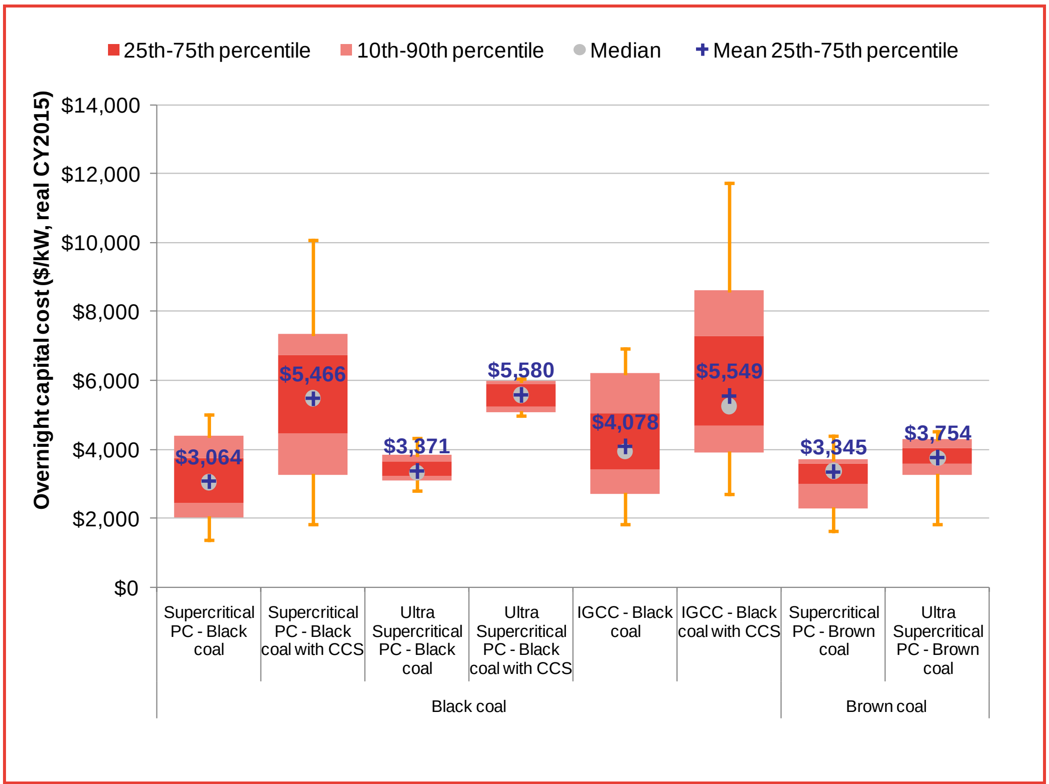
### 3.4.4 Capital

Frontier's capital cost estimates are based on a detailed database of actual project costs, international estimates and manufacturer list prices. A detailed description of our approach to estimating capital costs can be found in Appendix A.

Our approach relies on estimates from a range of sources – actual domestic and international projects, global estimates (for example, from EPRI [19]) and manufacturer list prices. These estimates are converted to current, Australian dollars. Our estimate is then taken as the mean over the middle two quartiles of the data (the 25th to 75th percentiles). The range of estimates and the final number used in the modelling are shown in Figure 14 and Figure 15 for thermal and renewable technologies respectively. The movements of capital cost over time are driven by factors such as real cost escalation, exchange rate movements and technological improvements. More details on factors that change capital costs over the modelling period can be found in Appendix A.

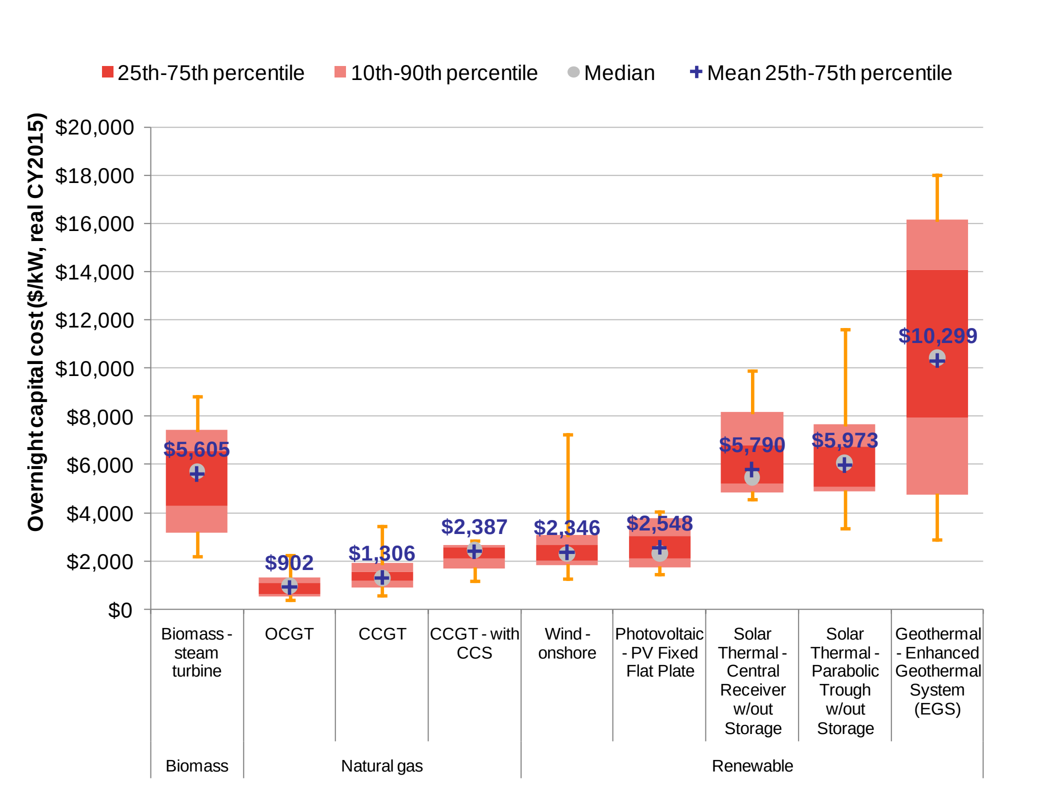
19 See http://www.epri.com.

Figure 14: Current capital costs for coal generation plant




*Source: Frontier Economics*

Figure 15: Current capital costs for gas and renewable generation plant




*Source: Frontier Economics*

### Large scale solar PV capital costs

Frontier Economics' current estimates for large scale solar PV are based on the same approach as for all other technologies. Our approach relies on estimates from a range of sources – actual domestic and international projects, global estimates (for example, from EPRI[20]) and manufacturer list prices. International estimates of costs, including solar, are dominated by European and US data.

Large scale solar PV, as a technology currently experiencing rapid cost reductions, is subject to additional uncertainty. Successful projects under the recent ACT Solar auction process[21] are estimated at a cost of approximately $2,400/kW, substantially less than our 2014 estimate of $4,001/kW. Some stakeholders questioned this.

In 2015, based on more recent estimates and commissioned solar farms in Australia and abroad, and focusing our analysis on these more recent sources, our estimate has fallen to $2,548/kW. However, we would continue to note that even at a capital cost $2,400/kW for solar PV, on an LRMC basis wind is cheaper (at $90-120/MWh) than solar (at $178/MWh for the ACT projects[22]) and would be the cost-optimal choice for meeting the LRET. If solar PV costs fell by a further 20 per cent from $2,400/KW, the implied LRMC is around $140/MWh, which is still considerably higher than current wind costs.

On these starting cost estimates, and accounting for changes in capital costs over the modelling period[23], wind is by far the lowest cost renewable technology out to 2030. As all investment required to meet the LRET needs to occur before this period we see wind as the only forecast technology to meet the LRET. To the extent that additional sources of funding enabled utility scale solar PV to be commissioned (such as ARENA funding or the ACT reverse auction process) it may be the case that some incremental investment occurs in solar PV despite wind being a lower cost technology. Similarly, if the cost learning rate for solar PV was relatively higher than assumed when compared to wind then solar PV may become cost competitive with wind prior to 2030, however we consider this unlikely.

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20 See http://www.epri.com.

21 See http://www.cmd.act.gov.au/open_government/inform/act_government_media_releases/corbell/2013/canberras-renewable-energy-future-new-solar-farms-announced.

22 See http://reneweconomy.com.au/2013/act-solar-auction-won-by-elementus-zhenfa-solar-67633, which states Zhenfa won the ACT auction with a FiT of $178/MWh.

23 Our capital cost estimates vary over time to account for cost learning, escalation of domestic labour costs construction and to account for movements in the exchange rate. In net terms over the period to 2030, Solar PV is assumed to fall by 1.73% per annum while wind is assumed to fall by 0.27% per annum.

## 3.5 Scenarios considered in the modelling

Our modelling considers a Base Case and multiple scenarios as listed in Table 2. Scenarios consider a range of demand inputs, fuel costs and whether or not the modelling allows existing plant to retire as a modelled outcome.

All cases assume a number of announced retirements as follows:

- Northern exits as announced.[24] We have assumed an exit date of 1 July 2016 consistent with Alinta's announcement and the financial year basis of our modelling.
- TIPS A exits prior to the 2017/17 summer as registered with AEMO.[25]
- In light of the decision to retire Northern, Pelican Point returns all units to service (contrary to the current mothballing of one unit).
- In addition, in the Retirement case, our modelling finds that Eraring power station and Vales Point B power station will retire with low demand.

Table 2: Summary of scenarios

| Scenario | | LRET (SRES policy unchanged) | Demand scenario | Fuel | Modelled retirements |
|---|---|---|---|---|---|
| 1 | Base Case | 33,000 GWh by 2020 | NEFR 2015 Medium | Mid-range | No |
| 2 | Low Demand | 33,000 GWh by 2020 | **NEFR 2015 Low** | Mid-range | No |
| 3 | High Demand | 33,000 GWh by 2020 | **NEFR 2015 High** | Mid-range | No |
| 4 | High Fuel | 33,000 GWh by 2020 | NEFR 2015 Medium | **High estimate** | No |
| 5 | Retirement | 33,000 GWh by 2020 | NEFR 2015 Low | Mid-range | **Yes** |
| 6 | NEFR 2014 | 33,000 GWh by 2020 | **NEFR 2014 Medium** | Mid-range | No |

*Source: Frontier Economics*

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24 See https://alintaenergy.com.au/about-us/news/flinders-operations-announcement.

25 See http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Electricity/Planning/Related%20Information/Generation%20Information/2015/Generation_Information_SA_20150515.ashx.

# 4 Wholesale energy cost estimates

This section presents Frontier Economics' estimate of wholesale energy costs under the two approaches discussed in Section 2.2:

- **Market-based** energy purchase cost (EPC) where dispatch modelling of the NEM is used to forecast pricing outcomes and the residential load shapes are served with a mix of financial hedges and residual pool exposure.
- **Stand-alone LRMC** where a 'greenfields' mix of generation capacity is built to meet the residential load shape.

## 4.1 Market-based energy purchase cost

This section presents the results of our modelling of the market-based energy purchase cost in each of the NEM jurisdictions. Section 4.1.1 provides a summary of our results and discusses key trends. Section 4.1.2 presents more detailed results.

### 4.1.1 Summary results and key trends

A summary of the results of our Base Case modelling of market-based energy purchase costs, for each distribution area and load shape, is presented in Figure 16. A summary of the results of our modelling of market-based energy purchase costs for each of the other cases we have modelled is presented later in this section.

Trends in the market-based energy purchase costs are primarily driven by pool price forecasts. Key drivers of trends in pool price forecasts in the Base Case are:

- **Demand growth**. Strong demand growth in NSW, Victoria and Queensland over the period to 2017/18 leads to a tightening supply-demand balance. This is particularly the case in Queensland, where demand growth of 20 per cent over the four year period results in the most significant increases in pool prices (and, therefore, energy purchase costs).
- **Rising gas prices**. All NEM regions experience rising gas prices over the period to 2017/18, which creates rising costs for generators and contributes to rising pool prices. A temporary dip in gas prices in Queensland in 2016/17 (due to additional investment in gas production infrastructure) contributes to a slower rate of increase in pool prices in Queensland in 2016/17, followed by a return to stronger growth in pool prices with a return to increasing gas prices in 2017/18.
- **Investment in wind**. There is significant wind investment over the period to 2017/18, which leads to lower price growth than would have otherwise been forecast. This is particularly the case in southern states, where we forecast for

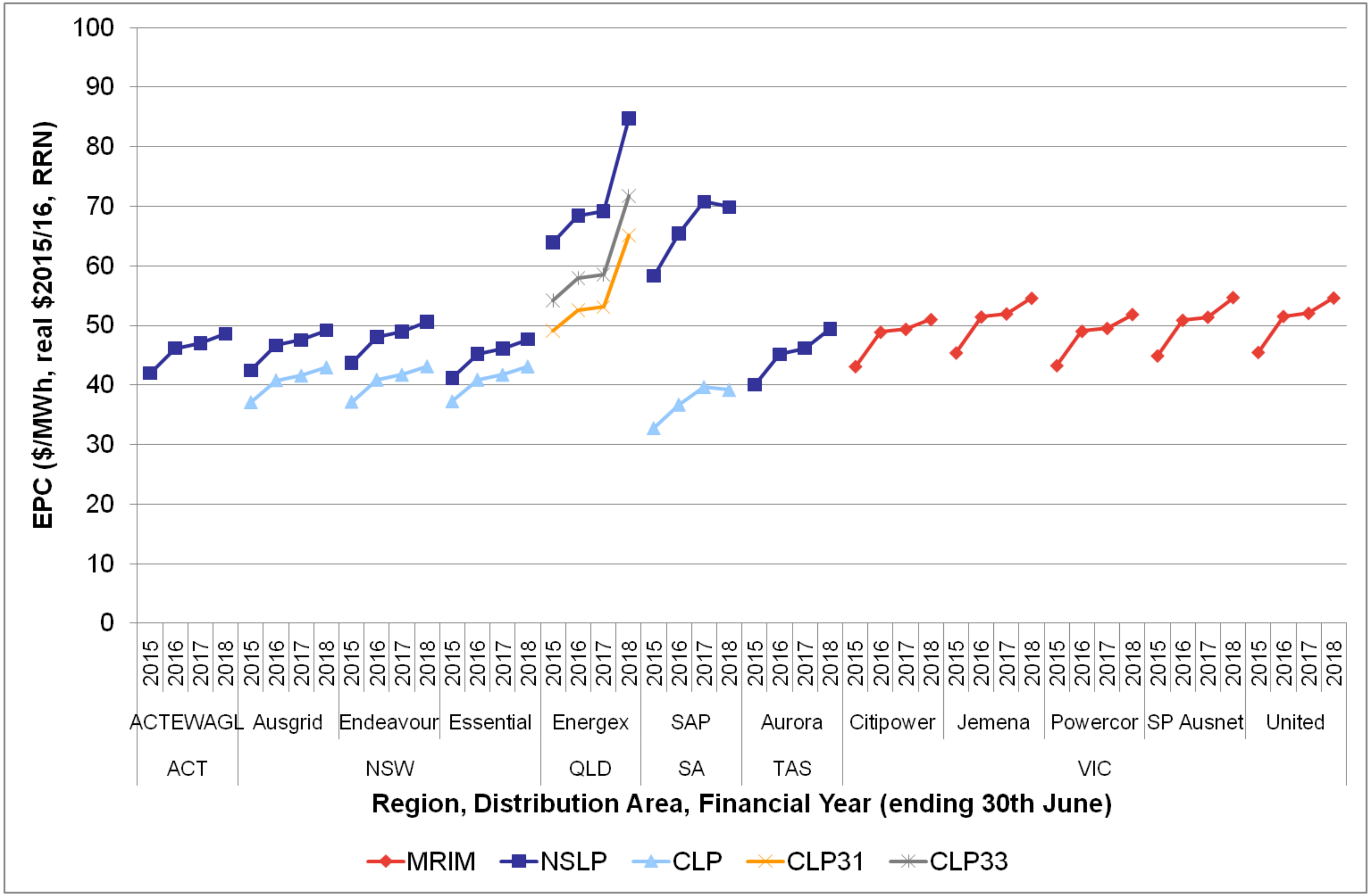
both South Australia and Victoria around 500MW of wind investment in 2016/17 and around 700MW of wind investment in 2017/18, and where we forecast around 400MW of wind investment in Tasmania in both 2016/17 and 2017/18. The effect of this investment in pool prices is most notable in South Australia, which experiences slight reductions in pool prices in 2017/18 as a result of this wind investment. Our modelling suggests that there will be no investment in new OCGT or CCGT plant until beyond 2020.

- **Retirements**. Planned retirements of generation plant contribute to the tightening supply-demand balance. The most significant retirement is the announced closure of Northern Power Station, which leads to increased prices in South Australia as well as other regions.

The other key input into market-based energy purchase costs - residential load shapes - affects the relative level of the energy purchase cost between distribution areas and for different load shapes. However, since these load shapes are assumed to be constant over the forecast period (and between scenarios), the residential load shapes do not drive trends over time in the energy purchase cost. The residential load shapes have the following effects on market-based energy purchase costs:

- **Differences between distribution areas**. The different market-based energy purchase costs in different distribution areas within a single NEM region are driver by differences in the residential load shape in these distribution areas: the peakier the load shape in a distribution area, and the more closely correlated it is to high prices, the higher the energy purchase costs. This is apparent in New South Wales, for instance, where the load shape of residential customers in the Essential Energy network area is cheaper to serve than the load shape of residential customers in other network areas.
- **Differences between standard and controlled loads**. The different market-based energy purchase costs for different loads within a distribution area is also driven by differences in the shapes of these different loads, and the correlation of these loads with prices. In each distribution area, the controlled load has a cheaper energy purchase cost than the standard load, reflecting the fact that controlled load occurs overnight when prices tend to be lower.

Figure 16: Energy purchase cost results – Base Case




Wholesale energy cost estimates

Table 3 summarises the key trends that drive outcomes in the Base Case and in each of the scenarios we have modelled.

Demand is the key driver of NEM price trends across the modelling period. In both the Base and High scenarios, strong assumed demand growth leads to rising price trends across the NEM. In the Low, Retirement and NEFR 2014 scenarios, lower levels of assumed demand growth lead to flat or falling price trends.

Rising input fuel costs are the second most important driver of increasing price trends. Fuel costs are assumed to rise towards international netback levels. Rising gas prices in response to the commencement of LNG shipping at Gladstone drives rising gas prices. This exacerbates the impact of demand growth and reinforces the rising price trend seen in the modelled results.

The timing of investment and retirements impact on the trends in prices on a region by region basis and with regard to each scenario. In some regions, wind investment acts to dampen or reverse price rises caused by demand growth and rising fuel costs. In other regions, retirements rebalance supply and demand and lead to price rises despite falling demand levels.

In the SWIS, the stand-alone LRMC approach leads to fairly stable wholesale energy cost estimates over the modelling period under both of the modelled scenarios.

Table 3: High level trends in the market-based energy purchase cost, by scenario

| Scenario | Key trends in wholesale pool prices |
|---|---|
| Base Case | General trend of price rises due to NEM demand growth and rising gas prices, only partially mitigated by wind investment.<br>There is also demand growth in all regions (although demand in South Australia and Tasmania falls slightly in 2017/18). This tends to increase prices. Queensland shows most significant increase in prices due to highest demand growth.<br>There is wind investment in all states except NSW. Southern wind farms have access to better sites (with better capacity factors) than are available in NSW, wind farms in Queensland can earn the higher Queensland pool prices than are available in NSW. Wind investment in South Australia depresses the price in South Australia 2017/18.<br>Announced retirements in South Australia and Victoria (Anglesea/ Northern/ TIPS A) exacerbate demand growth effect, leading to higher prices.<br>Moderate gas price growth in price trends period to 2017/18 reinforces impact of demand growth and leads to a rising price trend.<br>Recent high Queensland prices in practice are due to market structure and 5min bidding events, and are not fully captured in our annual modelling. |
| High Demand | Higher demand levels from 2015/16 in this scenario.<br>This results in pool prices that are materially higher than the Base Case pool prices in all regions.<br>Queensland 2016/17 price drops in High Demand case due to wind investment in Queensland in that year and the effect of a temporary reduction in gas price in that year: with higher demand, gas plant in Queensland sets the electricity price more often so that the effect of the temporary reduction in the gas price is stronger than in the Base Case. |
| High Fuel | The same demand levels and investment patterns as the Base Case.<br>Pool prices are materially higher than the Base Case pool prices in all regions, reflecting higher input gas prices. |
| Low Demand | Lower demand levels from 2015/16 in this scenario.<br>This results in pool prices that are materially lower than the Base Case pool prices in all regions. Pool prices are at the SRMC of coal-fired generation plant, since with low demand coal-fired plant sets the electricity price almost all the time.<br>Generation assets operating at a loss with these low prices, but are not allowed to retire. |

| Scenario | Key trends in wholesale pool prices |
|---|---|
| Retirement | The same lower demand levels as the Low Demand case, but retirements are allowed.<br>Our modelling shows that both Vales Point B and Eraring retire (at least partially) during the modelling period. This is a result of their relatively high fuel costs compared to other baseload power stations. This, in turn, is a result of Vales Point B and Eraring having to purchase coal at the international net-back price, which is not the case for mine mouth power stations in Victoria and Queensland.<br>With modelled retirements, there is a relatively tighter supply/demand balance, and prices are higher than in the Low Demand case. However, prices are still close to SRMC. |
| NEFR 2014 Medium | Significantly lower long term demand growth as compared to NEFR 2015 medium forecast in all regions.<br>With no modelled retirements allowed, lower demand levels lead to lower market price outcomes to 2017/18 compared to the Base Case. |

### 4.1.2 Detailed results

Market-based results are presented for all scenarios. Investment, retirement, dispatch and LRET results are presented as well as pool price and energy purchase cost results.

#### *New investment*

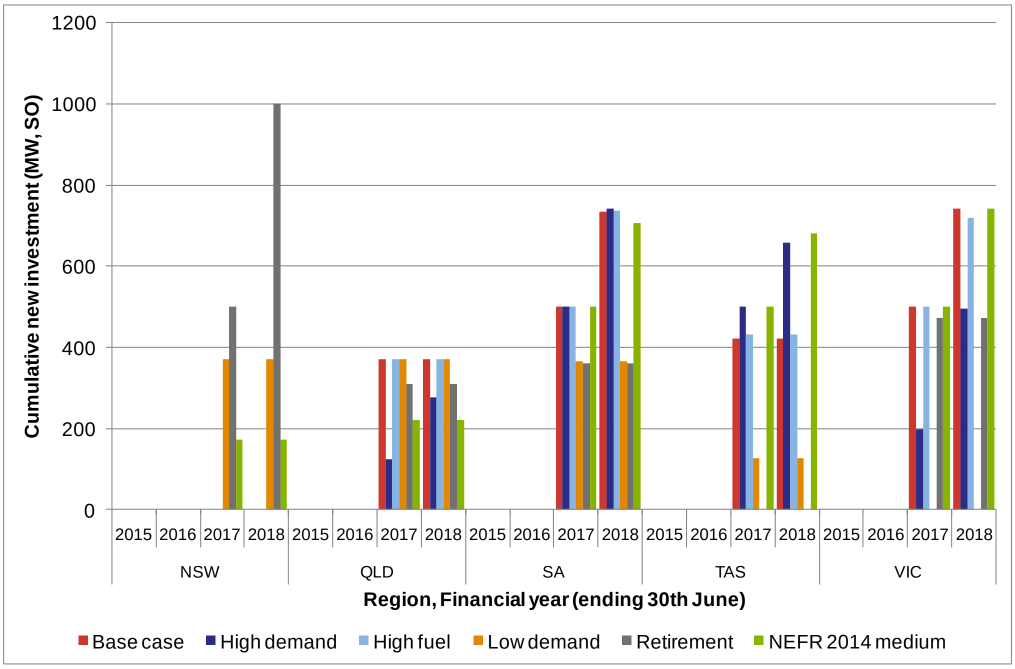
Short term investment is predominantly wind farms, constructed to meet the LRET. Figure 17 shows cumulative new investment by region in each case. Investment in this period is exclusively wind in all cases except the High scenario.

Wind investment is highest in the High Demand and High Fuel cases (where wind can earn higher pool prices) and also the Retirement case, where wind is built in NSW to partially replace the black coal generation that retires. As would be expected, investment in wind is lowest in the Low Demand scenario (where new wind entry earns the lowest pool prices). This wind investment, other things being equal, adds to supply and reduces forecast wholesale pool prices.

Outcomes in both the Retirement and NEFR 2014 scenarios, where the supply demand balance is loose but not as low as the Low Demand case, sit between these other cases in terms of wind investment.

We are forecasting shortfalls against the LRET in some cases. This is discussed further below.

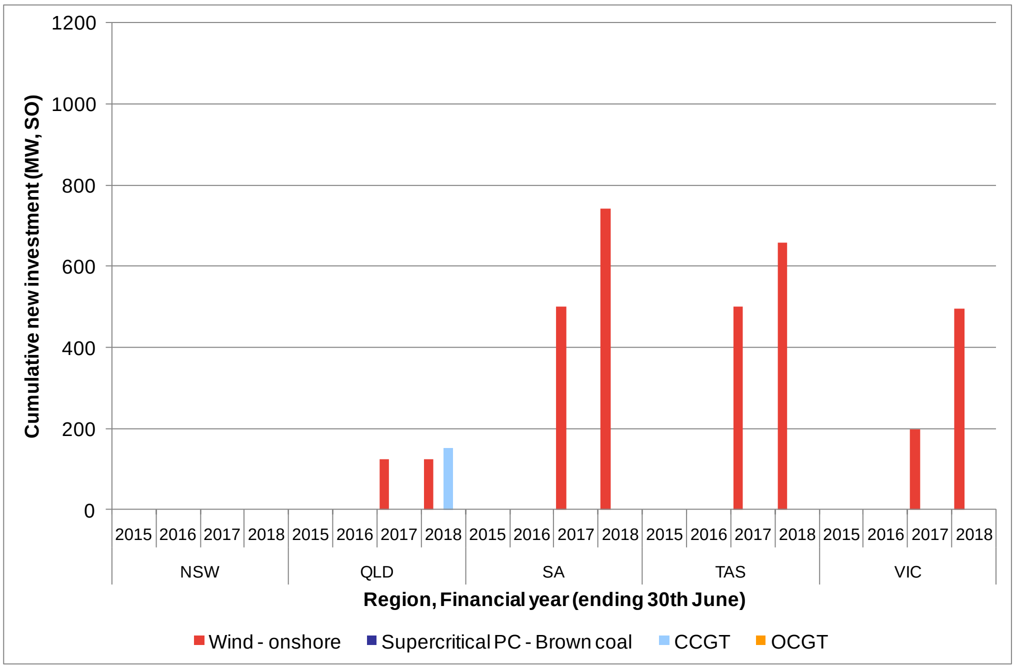
Figure 17: Cumulative new investment by case




*Source: Frontier Economics*

Strong demand growth in Queensland under the High Demand scenario leads to a small level of investment in CCGT, as shown in Figure 17. This investment is in response to the rapid growth in demand in Queensland and continues beyond 2017/18.

Figure 18: Cumulative new investment in High Demand case




*Source: Frontier Economics*

## Plant retirements

All cases are modelled with the same announced retirement assumptions. The retirement profiles in Figure 19 are based on AEMO's latest generation information data, with one adjustment. Due to the announced closure of Northern Power Station it seems unlikely that both Pelican Point and Torrens Island A will also retire in South Australia. It has been assumed that Pelican Point remains in operation as its operating profile is a better replacement for Northern as a lower cost CCGT plant.

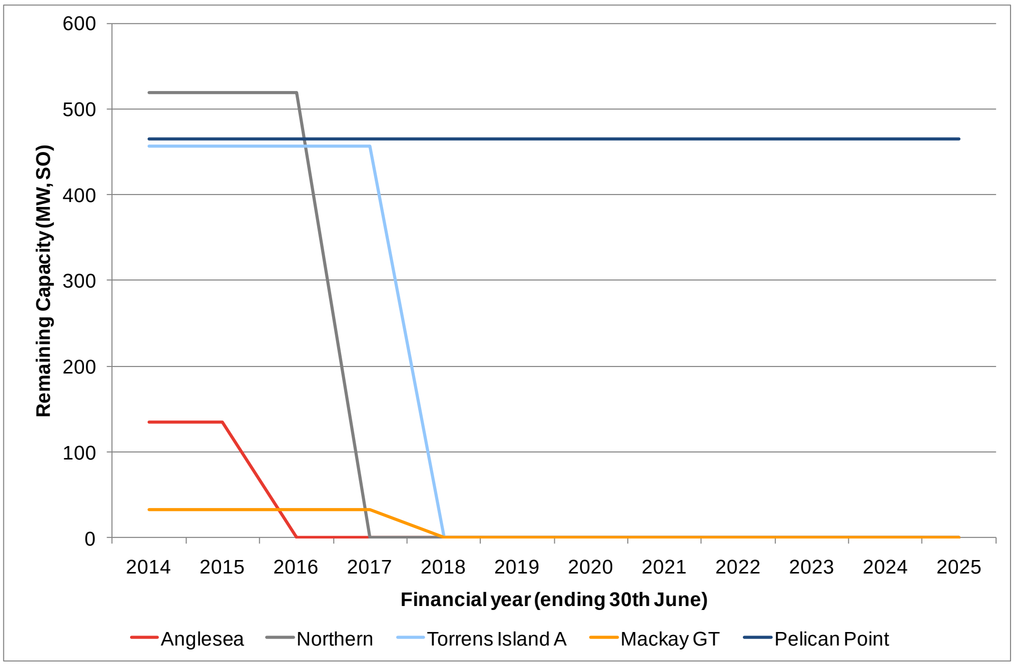
As discussed in section 2.2.3, we have revised our approach relative to the 2014 Residential Electricity Price Trends report to more accurately forecast retirements in *WHIRLYGIG* on the basis of forecast bidding outcomes form *SPARK*.

Using this new methodology, we have confirmed that incremental retirements over those announced are only forecast to occur against the 2015 NEFR Low demand forecast and the 2014 NEFR Medium demand forecast. There is no requirement for retirements in the Base Case.

The only case where results contain modelled retirements is the Retirement case, the Low Demand and 2014 NEFR Medium cases demonstrate the impact of low demand without market exit.

In the Retirement case, which assumes the 2015 NEFR Low demand forecast, all units at Eraring and Vales Point B are retired by 2020/21. These retirements occur sooner when modelling *WHIRLYGIG* with an SRMC bidding assumption[26]. Eraring and Vales Point B retire in our modelling because they have higher fuel costs compared to most other baseload power stations and they are located in NSW where there is an abundance of baseload capacity. The high fuel costs for Vales Point B and Eraring is a result of them having to purchase coal at the international net-back price, which is not the case for mine mouth power stations in Victoria and Queensland.

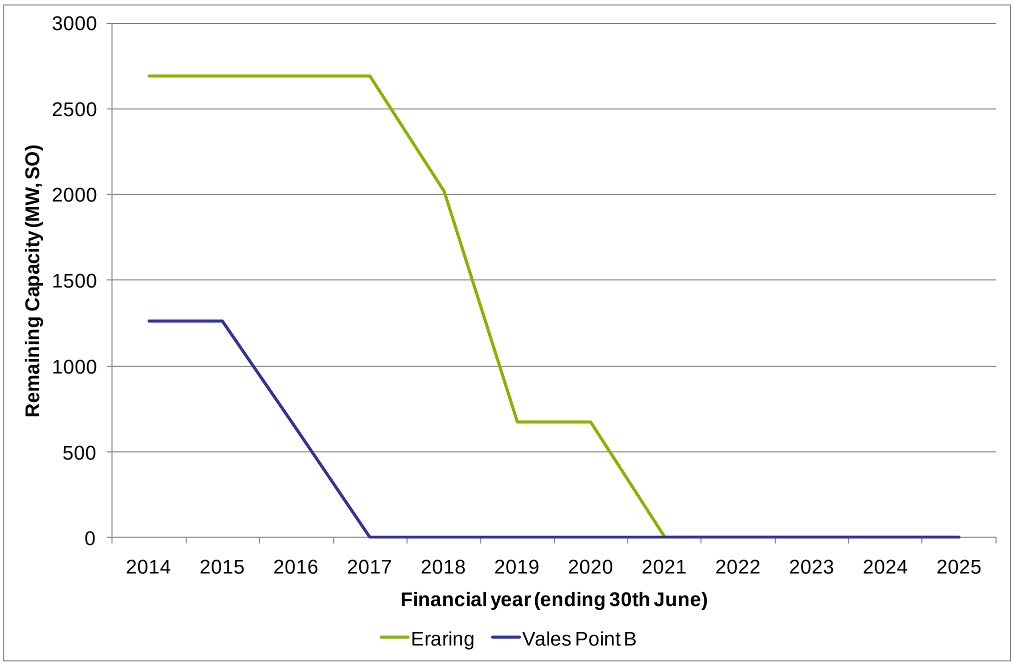
Figure 19: Assumed retirements in all cases (announced)




*Source: Frontier Economics*

[26] Equivalent to step one in Figure 3.

Figure 20: Forecast retirements – Retirement case




*Source: Frontier Economics*

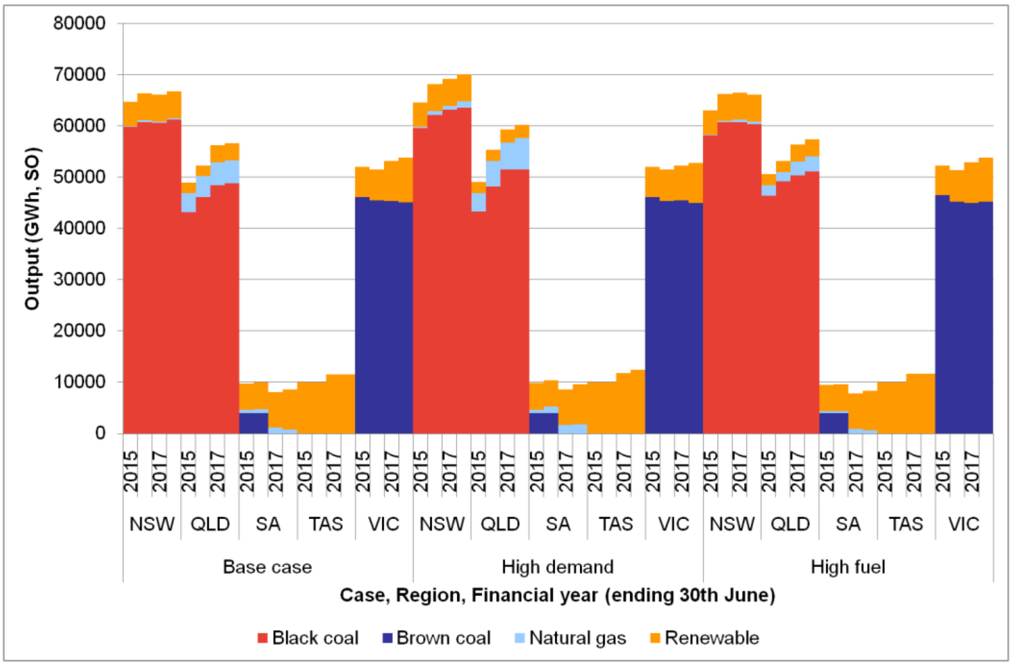
In the Retirement scenario, the retirement of both units of Vales and one unit of Eraring over the period to 2017/18 acts to partially offset reductions in demand under the assumed Low demand forecast. This leads to generally flat, rather than falling, pool prices in this case.

## Dispatch

Demand growth in the Base Case is met partially by new investment in wind and partially by increased output from existing thermal generators. Thermal dispatch increases most significantly in Queensland, which experiences the largest demand growth.

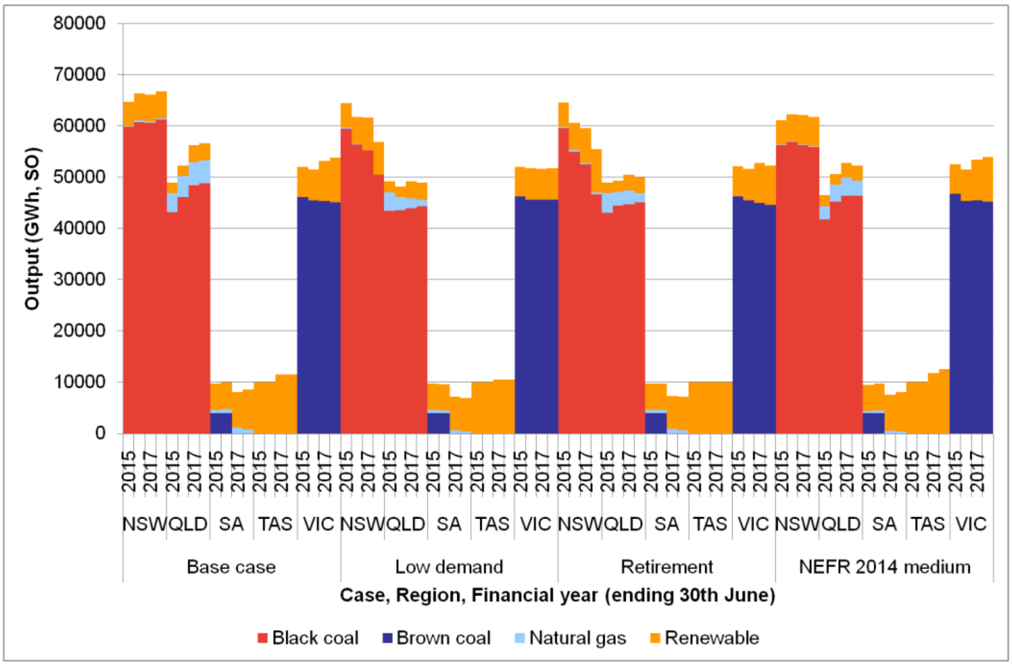
Higher gas prices in the High Fuel scenario leads to reduced output from natural gas generation and higher output from black coal. This is most evident in Queensland where generation from natural gas was higher in the Base Case, consistent with the higher price outcomes.

Figure 21: Annual dispatch in high cases




*Source: Frontier Economics*

Figure 22: Annual dispatch in low cases



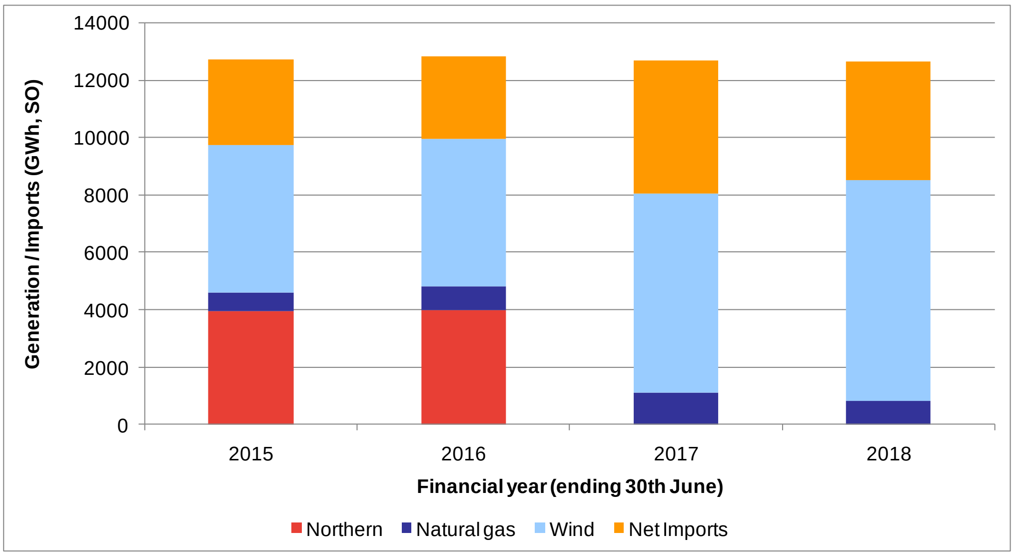

*Source: Frontier Economics*

Falling demand in the Low Demand and Retirement cases leads to significantly reduced output from black coal in NSW. In the Low Demand case, generators near the top of the merit order experience very low output levels. When retirements are allowed, these generators (Vales Point and Eraring) retire as opposed to operating at a loss.

### South Australia

The announced retirement of Northern radically changes the dispatch mix in South Australia. With Northern operating in 2014/15 and 2015/16, the station is forecast to meet over 30 per cent of South Australian demand (at a capacity factor of 80%), wind is roughly 40 per cent and imports on Heywood and Murraylink contribute 22 per cent with the balance coming from gas fired plant. In 2016/17 and 2017/18, with Northern's exit imports rise to almost 40 per cent of state demand in 2016/17, with wind forecast to rise to 60 per cent of state demand by 2017/18. This is shown in Figure 23.

Figure 23: Generation and imports in South Australia – Base Case




*Source: Frontier Economics*

We would note that actual dispatch of Northern for 2014/15 was at a capacity factor of 57%, substantially lower than our modelling forecast of 80%. This can be explained by the fact that in our modelling Northern is the lowest cost supply in South Australia and is dispatched to a high level whereas in practice Northern has been attempting to manage financial hardship by operating less at times of low prices and has begun to experienced increased outages as a result of reduced maintenance spend at the plant, both factors which are beyond the level of resolution of the analysis presented in this report. Other things being equal, modelling Northern at a lower capacity factor would raise forecast prices in South Australia, however given that much of the reduction in dispatch would likely have occurred at times of low prices (for example overnight periods) we do not think that this would have a material impact on forecast prices or trends. We would also note that Northern has been observed to behave consistently with our forecast in the past, for example in 2010/11 it ran at a capacity factor of 84.9%.

More generally, these trends in dispatch are likely to have a large impact on system security in South Australia, which will be relying heavily on Heywood. Our forecast of net imports on Heywood meeting 40% of South Australian demand post Northern's exit are highly consistent with AEMO's recent work on the subject.[27] It remains to be seen what operational issues may arise during times of Heywood outages or otherwise.

### LRET outcomes

As discussed in above, there are differing levels of wind investment arising primarily due to the different market conditions under the various demand forecasts. In general, scenarios with lower levels of demand, looser supply demand balances and weaker prices see less wind investment and in some cases significant shortfalls against the revised RET target. This is shown in Figure 24.

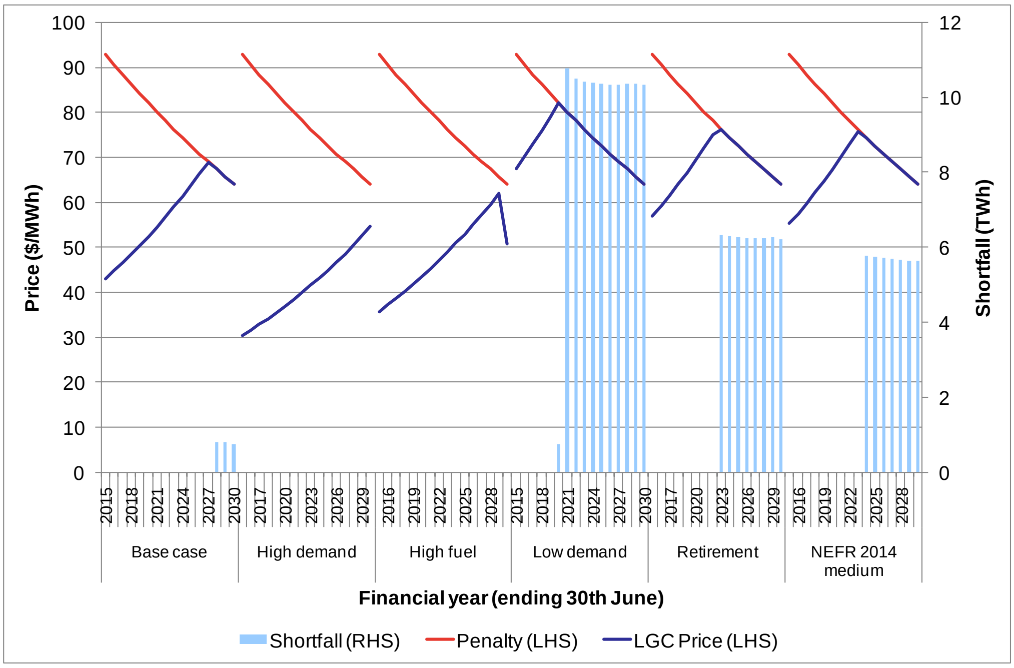
There is a slight shortfall towards the end of the modelling period in the Base Case. This reflects the models ability to perfectly optimise banking and borrowing against the national target. Given the small magnitude of the shortfall in this case, and the fact that it occurs so late in the modelling period, the model is essentially indicating that the LRET would be met in the Base Case. LGC cost estimates are around $44/LGC (real 2015/16) in 2015/16.

The target is explicitly met in both the High Demand and High Fuel scenarios as underlying supply-demand conditions are tighter leading to higher pool prices which in turn make greater quantities of wind economic. LGC cost estimates are correspondingly lower.

Under the Low Demand scenario, where no incremental retirements are allowed to offset falling demand, significant shortfalls occur and certificate prices hit the scheme penalty price in 2019/20. This is consistent with the low level of pool prices in this scenario leaving all but the highest capacity factor wind farms uneconomic. When incremental retirements are allows in the Retirement scenario this offsets roughly half of the shortfall and delays when the scheme penalty is hit, but significant shortfalls remain. Outcomes in this case are similar to the NEFR 2014 scenario, reflecting a broadly similar level of supply-demand balance across the NEM in the two scenarios.

27 AEMO, *South Australian Electricity Report*, August 2015.

Figure 24: LRET outcomes by scenario




*Source: Frontier Economics*

## Pool prices

Figure 25 shows the modelled pool prices on a time-weighted, annual average basis and includes actual and ASX Energy flat swap prices as a comparator (RRN basis, real $2015/16). ASX prices for 2013/14 have been adjusted to remove the impact of the carbon price.

In all regions except South Australia, current ASX traded prices tend to be lower than forecast spot prices in the Base Case. Our view is that this is the result of the assumption of AEMO's relatively high growth 2015 NEFR Medium demand forecast in the Base Case, while the market's view is that growth in demand will be more moderate (and more consistent with what has been observed in recent years). In South Australia, current ASX traded prices are higher than forecast spot prices in the Base Case. In our view, the forward price in South Australia may be high due to participants being unwilling to sell contracts in the region due to uncertainty surrounding Northern's closure. The market price in SA increased significantly as a result of the Northern announcement on low trading volumes, where our modelling suggests that Northern's output will be at least partially replaced by low cost coal generation from Victoria, imported across the upgraded Heywood interconnector.

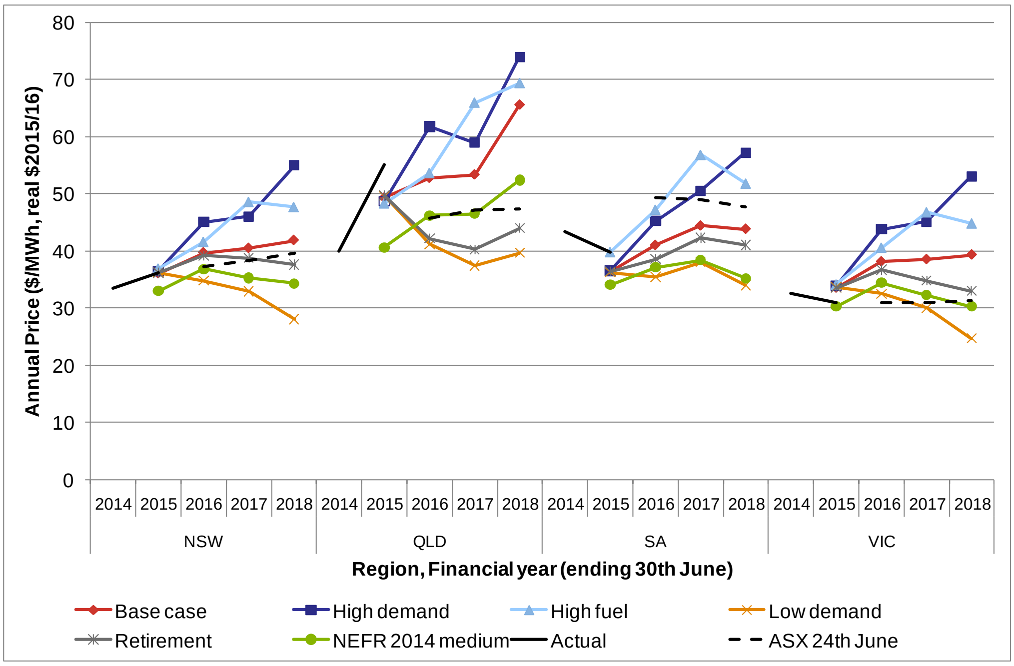
Actual prices for 2014/15 in Queensland are roughly $55/MWh (real 2015/16). This is higher than modelled outcomes and reflects a number of high price events in Queensland, particularly in January 2015 when the LNG trains came online. In our view this is caused at least in part by structural issues in

Queensland and manifest in highly specific bidding behaviour at the 5 minute dispatch interval level.[28] Whilst *SPARK* is custom designed to investigate strategic incentives in electricity markets, our analysis has focused on annual level modelling and, in this study, does not have the resolution to capture the kind of 5 minute bidding behaviour that has been observed on occasion in Queensland.

In the Base Case, prices rise modestly in NSW, South Australia and Victoria due to demand growth in the assumed NEFR 2015 Medium demand forecast. Prices in Queensland have both a higher starting point and higher forecast growth. The tighter supply demand balance in this region is creating higher spot prices than other regions. Aggressive demand growth and a jump in forecast gas prices in 2017/18, coupled with a strategic response, leads to significant price rise over the price trends period.

Pool price increases are more significant in the High Demand and High Fuel cases. In the High Demand case, there is a small drop in Queensland electricity prices from financial year 2015/16 to financial year 2016/17. This is due investment in wind generation plant and a temporary drop in gas prices in 2016/17. Forecast prices are higher in the High Fuel scenario reflecting increased input costs for thermal generators.

Figure 25: Pool price forecasts and ASX futures prices – All scenarios ($/MWh annual average prices, real $2015/16)




[28] See for example http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Pricing-Event-Reports/January-2015.

*Source: Frontier Economics*

## Energy Purchase Cost

Figure 26 to Figure 29 show the energy purchase costs under each scenario for each region (RRN basis, real $2015/16).

Energy purchase costs are driven by the peakiness of the residential load shapes and the assumed 5% contracting premium for hedges. Trends over the modelling period are driven solely by changes in forecast pool prices as load factors are assumed to be constant.

Figure 26: Energy purchase cost results for NSW and the ACT

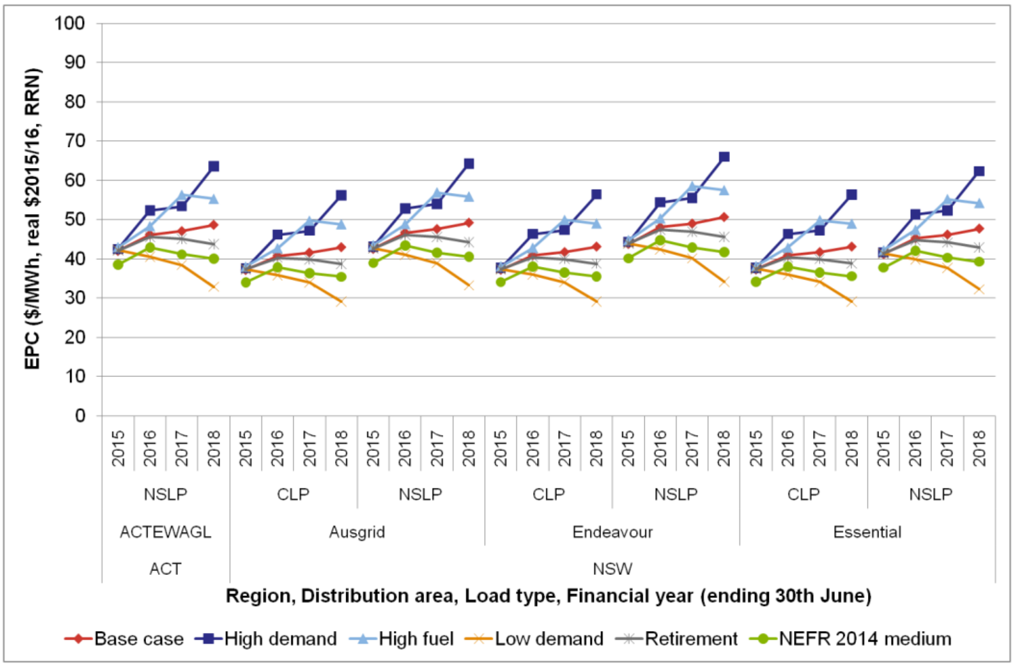


Figure 27: Energy purchase cost results for Queensland

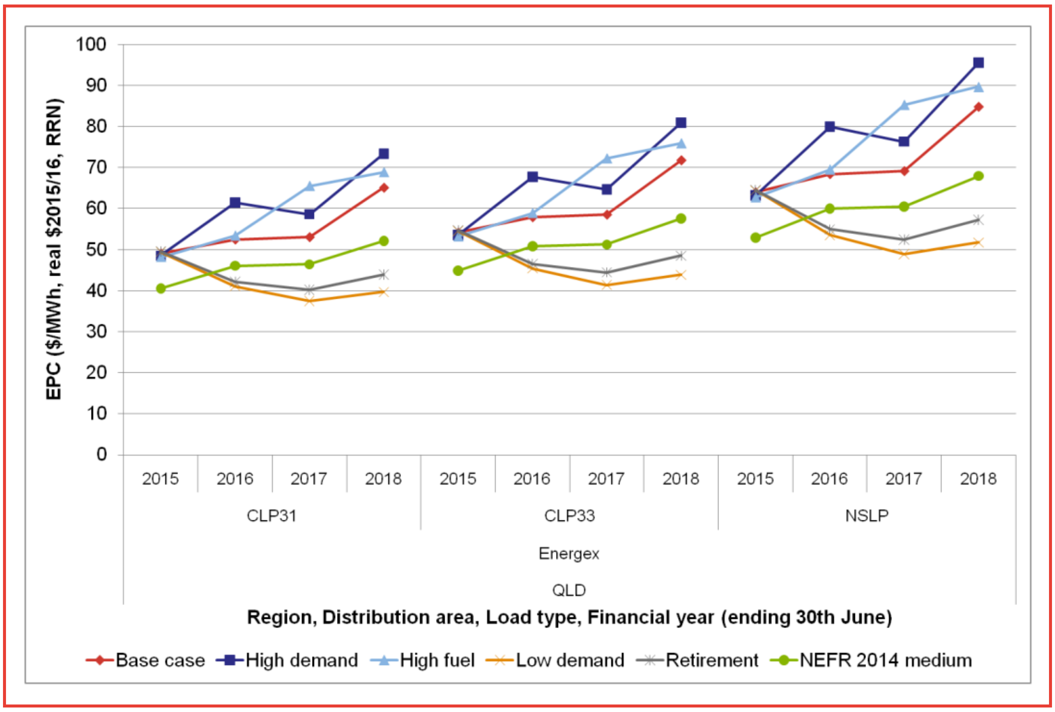



Figure 28: Energy purchase cost results for South Australia and Tasmania

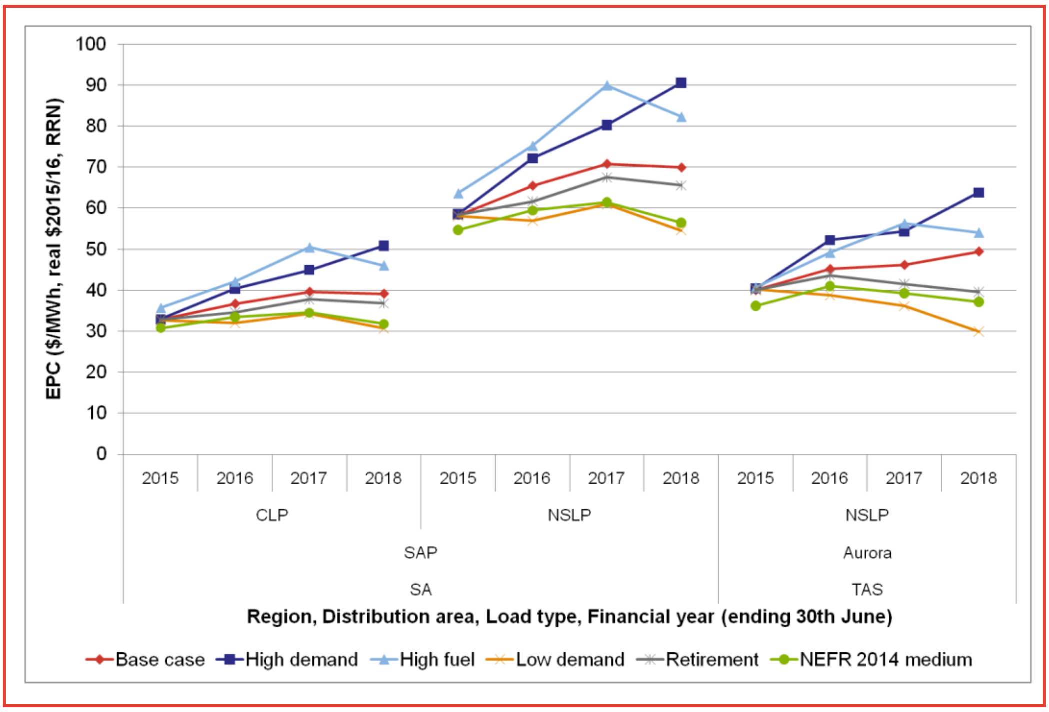
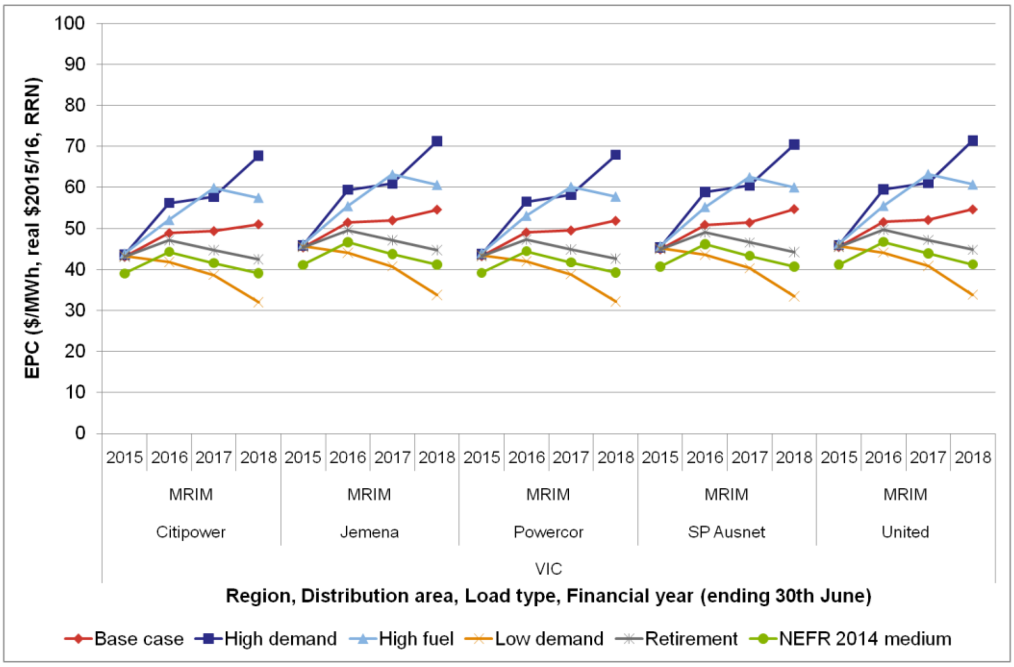


Figure 29: Energy purchase cost results for Victoria




## 4.2 Stand-alone LRMC of energy

Stand-alone LRMC results are presented for the Base and High Fuel scenarios. The various demand scenarios and the Retirement scenario, being sensitivities on NEM demand levels and the approach to NEM generation retirements, are not relevant under the stand-alone LRMC approach where the system is not modelled and only the SWIS is considered.

### 4.2.1 Trends in the stand-alone LRMC results

For the stand-alone LRMC estimates, estimated costs are driven by fixed and variable costs of generation technologies and by the peakiness of residential load shapes. Changes over time can only be driven by changes in input costs – fuel, capital, VOM and FOM costs. Load shapes are held constant over the modelling period.

The trend is for costs that are flat in real terms. Key drivers this trend is:

- **Constant load factors.** This leads to a similar investment mix year to year over the modelling period.
- **Close to constant capital costs.** Over the four years modelled there are no substantial movements in assumed capital costs.
- **Close to constant fuel prices.** As Western Australia is essentially already at an international LNG netback price, there is little assumed growth in SWIS

gas prices over the modelling period. Coal prices are based on a mine mouth power station and remain constant in real terms.

In combination these drivers lead to the modelled outcome of constant wholesale energy costs.

Table 4 summarises the key trends that drive outcomes in the Base Case and in each of the scenarios we have modelled.

Table 4: High level trends in the stand-alone LRMC, by scenario

| Region | Key trends |
|---|---|
| Base Case | A mix of coal, CCGT gas and peaking gas is built to meet the load shape.<br>The mix of investment and input capital and fuel costs are relatively stable in the SWIS, leading to wholesale energy costs that are approximately constant in real terms. |
| High Fuel | LRMC is slightly higher than the Base Case and remains constant over the modelling period. |

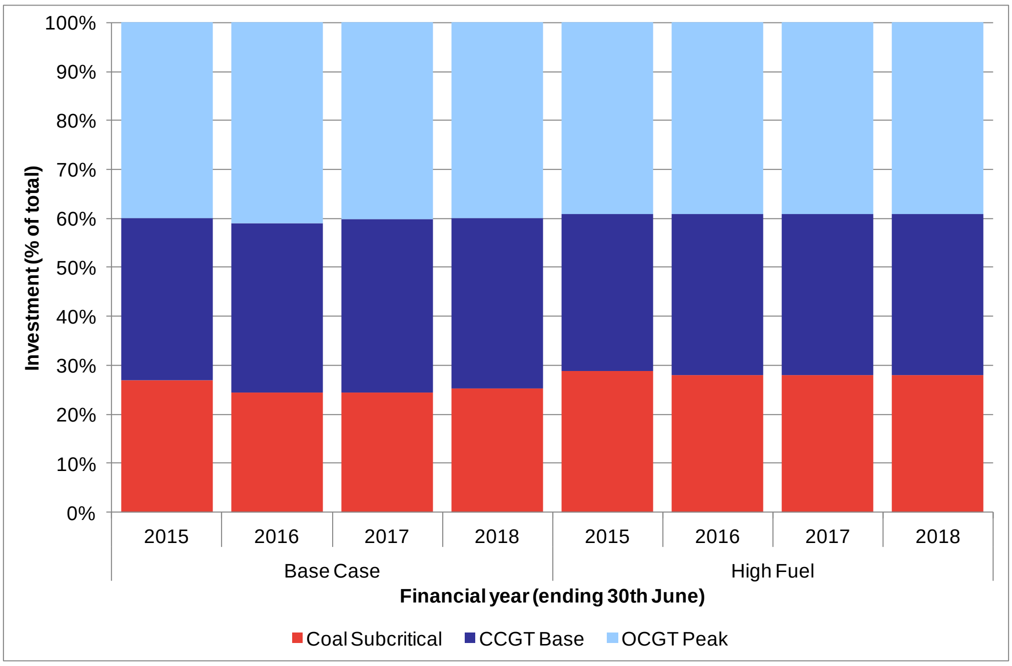
### 4.2.2 Results by scenario

The stand-alone LRMC results are presented in Figure 30 to Figure 32. They are presented on a RRN basis in real 2015/16 dollars.

Underlying optimal investment in all regions is a mixture of coal-fired plant for baseload energy, CCGT plant for mid-merit operation and OCGT for peaking requirements. Coal being part of the investment mix is consistent with the assumption of no carbon price over the modelling and the relative costs of coal and gas fired generation in the SWIS.

Under the High Fuel scenario, in which only gas prices are higher as coal is assumed to be mine-mouth, there is a marginal switch towards coal in the investment mix as it becomes relatively cheaper.

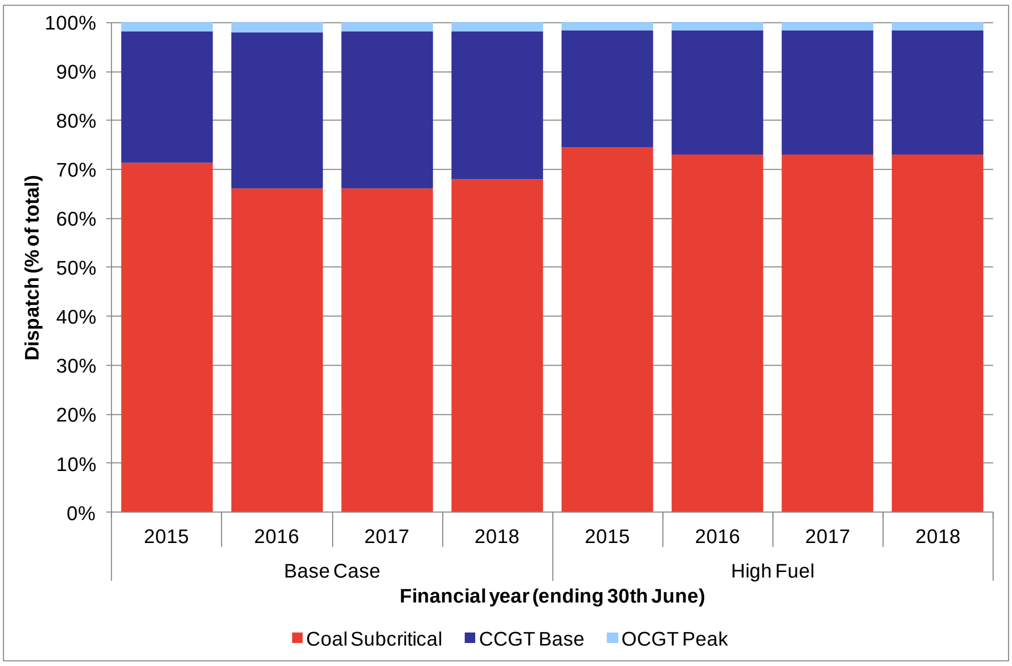
Figure 30: Investment – SWIS Base Case and High Fuel scenarios




*Source: Frontier Economics*

Figure 31 shows forecast dispatch which is consistent with the optimal investment mix. Coal runs baseload and meets the majority of demand with CCGT running mid-merit and OCGT running to meet peak load. Coal dispatch is higher in the High Fuel scenario reflecting a higher proportional investment in coal-plant in that case.

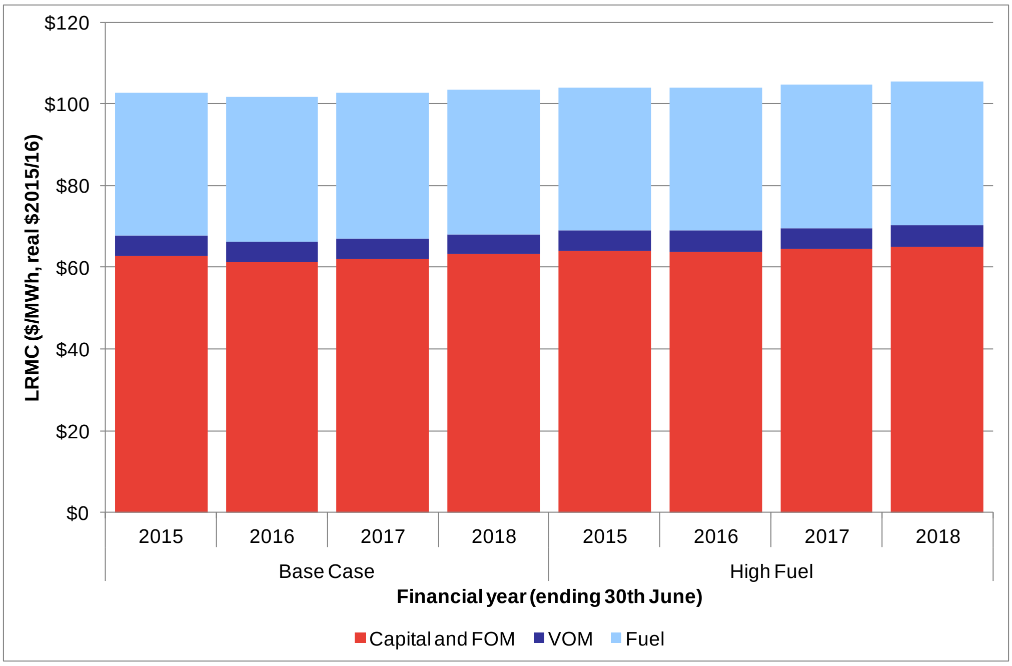
Figure 31: Dispatch – SWIS Base Case and High Fuel scenarios




*Source: Frontier Economics*

Figure 32 presents the forecast stand-alone LRMC for the SWIS under both scenarios. LRMCs are in the $100-105/MWh (real 2015/16 basis) and relatively constant across the modelling period consistent with constant input costs.

Figure 32: Stand-alone LRMC – SWIS Base Case and High Fuel scenarios ($/MWh, real $2015/16)




*Source: Frontier Economics*

Stand-alone LRMC estimates, which range from $100/MWh to $105/MWh, are considerably higher than current observed balancing plus capacity prices in the SWIS. This is consistent with the stand-alone LRMC approach fully reflecting long run marginal costs while the SWIS is currently oversupplied.

# 5 Non-energy cost estimates

In addition to advising on wholesale energy costs for the period 2014/15 to 2017/18, this assignment also requires us to estimate a range of other energy-related costs. These include the Renewable Energy Target, energy efficiency schemes, NEM fees and ancillary services costs.

## 5.1 Estimates of cost under the RET

This section considers the costs associated with complying with the RET, including both:

- the Large-scale Renewable Energy Target (LRET)
- the Small-scale Renewable Energy Scheme (SRES)

The following forecasts for these schemes account for the recent legislative changes to the LRET target and exemptions under both schemes. As discussed in Section 2.3.1, the broader exemptions under the LRET and SRES have the effect of increasing the LRET Renewable Power Percentage (RPP) and SRES Small-scale Technology Percentage (STP); in the case of the LRET, the change in exemptions slightly moderates the effect that the change in the target has in reducing the RPP.

### 5.1.1 LRET

Table 5 presents our forecasts of the RPP. These forecasts account for the effect of the recent legislative changes over the modelling time frame.

Table 5: Renewable power percentages

| Financial Year | RPP (% of liable acquisitions) |
|---|---|
| 2014/15 | 11.34% |
| 2015/16 | 12.90% |
| 2016/17 | 15.67% |
| 2017/18 | 17.23% |

*Source: Clean Energy Regulator with Frontier Economics adjustment.*

Table 6 shows the LRMC of the LGC certificate (RRN basis, real $2015/16) from our modelling. The LRMC based estimates of LGC permit costs reflect the timing and cost of investment to meet the target, as well as the timing and magnitude of the shortfall against the LRET target (which occurs in a number of scenarios). Estimates of the LRMC are lowest in the High Demand and High

Fuel scenarios (where pool prices are high) and highest in the Low Demand scenario (where pool prices are low). This demonstrates the inverse relationship between a renewable generators cost recovery from wholesale and LGC sales.

Table 6: LGC cost estimate ($/MWh, RRN basis, real $2015/16)

| Financial Year | Base Case | Low Demand | High Demand | High Fuel | Retirement | NEFR 2014 Medium |
|---|---|---|---|---|---|---|
| 2014/15 | $43.00 | $67.44 | $30.29 | $35.72 | $56.90 | $55.24 |
| 2015/16 | $44.72 | $70.14 | $31.50 | $37.14 | $59.17 | $57.45 |
| 2016/17 | $46.52 | $72.96 | $32.77 | $38.64 | $61.55 | $59.76 |
| 2017/18 | $48.38 | $75.88 | $34.08 | $40.18 | $64.02 | $62.15 |

*Source: Frontier Economics*

Based on the LRMC of LGC and renewable energy percentage, the LRET costs to residential consumers are presented in Table 7.

Table 7: LRET cost ($/MWh, RRN basis, real $2015/16)

| Financial Year | Base Case | Low Demand | High Demand | High Fuel | Retirement | NEFR 2014 Medium |
|---|---|---|---|---|---|---|
| 2014/15 | $4.61 | $7.22 | $3.24 | $3.83 | $6.09 | $5.92 |
| 2015/16 | $5.42 | $8.50 | $3.82 | $4.50 | $7.17 | $6.96 |
| 2016/17 | $6.64 | $10.42 | $4.68 | $5.52 | $8.79 | $8.54 |
| 2017/18 | $7.96 | $12.48 | $5.61 | $6.61 | $10.53 | $10.22 |

*Source: Frontier Economics*

### 5.1.2 SRES

Table 8 shows our forecasts of the STP percentages. These forecasts account for the effect of the recent legislative changes.

Table 8: STP percentages

| Financial Year | STP percentage |
|---|---|
| 2014/15 | 11.32% |
| 2015/16 | 11.07% |
| 2016/17 | 10.12% |
| 2017/18 | 10.06% |

*Source: Frontier Economics*

Table 9 contains the estimated SRES costs, which are higher in earlier years due to the higher STP percentages.

Table 9: SRES cost ($/MWh, RRN basis, real $2015/16)

| Financial Year | SRES cost |
|---|---|
| 2014/15 | $4.64 |
| 2015/16 | $4.43 |
| 2016/17 | $3.95 |
| 2017/18 | $3.83 |

*Source: Frontier Economics*

## 5.2 Energy efficiency schemes

This section considers the costs associated with complying with market-based energy efficiency schemes that impose obligations in a number of jurisdictions:

- the NSW Energy Savings Scheme (ESS)
- the Victorian Energy Saver Initiative (VEET)[29]

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29 With the change in Government in Victoria, the intention to close the VEET at the end of 2015 has been overturned. The Minister for Energy and Resources has announced that the VEET will continue. http://www.energyandresources.vic.gov.au/energy/about/legislation-and-regulation/energy-saver-incentive-scheme-management/esi-review

- the South Australian Residential Energy Efficiency Scheme (REES)
- the ACT Energy Efficiency Improvement Scheme (EEIS).[30]

The NSW and Victorian schemes are both certificate based schemes, whereas the South Australian and ACT schemes are obligations on retailers that impose costs which are recovered from all customers.

For South Australia and ACT, We have used cost estimates provided by the jurisdictions (in *italic*) for energy efficiency schemes, which are presented in Table 10. Those scheme cost estimated are on end-sale basis and in nominal dollar terms.

30 The EEIS has been extended to 2020 http://www.environment.act.gov.au/energy/energy_efficiency_improvement_scheme_eeis#Extension

Table 10: Energy efficiency scheme cost ($/MWh, end-sale basis, nominal)

| Financial Year | State | Scheme cost |
|---|---|---|
| 2014/15 | NSW | $0.66 |
| 2014/15 | ACT | *$4.91* |
| 2014/15 | VIC | $2.18 |
| 2014/15 | SA | *$2.10* |
| 2015/16 | NSW | $0.95 |
| 2015/16 | ACT | *$4.22* |
| 2015/16 | VIC | $2.11 |
| 2015/16 | SA | *$2.10* |
| 2016/17 | NSW | $0.95 |
| 2016/17 | ACT | *$3.42* |
| 2016/17 | VIC | $2.09 |
| 2016/17 | SA | *$2.10* |
| 2017/18 | NSW | $0.95 |
| 2017/18 | ACT | *$3.42* |
| 2017/18 | VIC | $2.08 |
| 2017/18 | SA | *$2.10* |

*Source: FE analysis and data supplied by jurisdictions*

## 5.3 NEM fees and ancillary services costs

This section considers the market fees and ancillary services costs.

### 5.3.1 Market fees

Table 11 shows our estimated market fees on an RRN basis in real 2015/16 dollars.

Table 11: Market Fees ($/MWh, RRN Basis, real $2015/16)

| Financial Year | Region | Market fees |
|---|---|---|
| 2014/15 | NEM | $0.36 |
| 2014/15 | SWIS | $0.42 |
| 2015/16 | NEM | $0.31 |
| 2015/16 | SWIS | $0.42 |
| 2016/17 | NEM | $0.31 |
| 2016/17 | SWIS | $0.42 |
| 2017/18 | NEM | $0.31 |
| 2017/18 | SWIS | $0.42 |

*Source: Frontier Economics*

### 5.3.2 Ancillary services costs

Table 12 shows our estimated ancillary service cost on an RRN basis and in real 2015/16 dollars.

Table 12: Ancillary service cost ($/MWh, RRN basis, real $2015/16)

| Financial Year | Region | Ancillary service costs |
|---|---|---|
| 2014/15 | QLD | $0.25 |
| 2014/15 | NSW | $0.70 |
| 2014/15 | ACT | $0.70 |
| 2014/15 | VIC | $0.21 |
| 2014/15 | TAS | $0.65 |
| 2014/15 | SA | $0.35 |
| 2014/15 | WA | $2.72 |
| 2015/16 | QLD | $0.25 |
| 2015/16 | NSW | $0.70 |

| Financial Year | Region | Ancillary service costs |
|---|---|---|
| 2015/16 | ACT | $0.70 |
| 2015/16 | VIC | $0.21 |
| 2015/16 | TAS | $0.65 |
| 2015/16 | SA | $0.35 |
| 2015/16 | WA | $2.72 |
| 2016/17 | QLD | $0.25 |
| 2016/17 | NSW | $0.70 |
| 2016/17 | ACT | $0.70 |
| 2016/17 | VIC | $0.21 |
| 2016/17 | TAS | $0.65 |
| 2016/17 | SA | $0.35 |
| 2016/17 | WA | $2.72 |
| 2017/18 | QLD | $0.25 |
| 2017/18 | NSW | $0.70 |
| 2017/18 | ACT | $0.70 |
| 2017/18 | VIC | $0.21 |
| 2017/18 | TAS | $0.65 |
| 2017/18 | SA | $0.35 |
| 2017/18 | WA | $2.72 |

*Source: Frontier Economics*

## 5.4 Loss factors

The loss factors for each distribution area are reported in Table 13.

Table 13: Loss factors

| State | Area | TLF | DLF |
|---|---|---|---|
| ACT | ACTEWAGL | 0.9828 | 1.0456 |
| NSW | Ausgrid | 1.0051 | 1.0637 |
| NSW | Endeavour | 1.0018 | 1.0682 |
| NSW | Essential | 1.0251 | 1.0869 |
| QLD | Energex | 1.0067 | 1.0585 |
| SA | SAP | 1.0115 | 1.0790 |
| TAS | Aurora | 1.0137 | 1.0400 |
| VIC | Citipower | 1.0043 | 1.0403 |
| VIC | Jemena | 1.0053 | 1.0543 |
| VIC | Powercor | 1.0043 | 1.0703 |
| VIC | SP Ausnet | 1.0368 | 1.0605 |
| VIC | United | 0.9919 | 1.0526 |
| WA | WA | 1.0300 | 1.0481 |

*Source: Frontier analysis and AEMO/IMO data*

# Appendix A - Frontier's supply side modelling input assumptions

This section provides an overview of the framework and assumptions used to estimate Frontier Economics' supply side modelling input assumptions. This section is intended to provide an overview of our approach to developing these input assumptions, and a high-level summary of the input assumptions that we have used.

## Key macroeconomic inputs

There are a number of macroeconomic input assumptions that are used in developing the input assumptions set out in this report. For consistency, the same macroeconomic input assumptions have been used throughout this report.

### Exchange rates

As will be discussed in the sections that follow, at various points we make use of both historic and forecast exchange rates and both nominal and real exchange rates. For each of these exchange rates we have relied on data from the IMF's World Economic Outlook.[31] This data includes historic nominal and real exchange rates as well as forecasts of nominal and real exchange rates out to 2020. For nominal exchange rates, for which we require an exchange rate forecast beyond 2020, we have assumed that the exchange rate will remain at the 2020 forecast level for the remainder of the modelling period. Exchange rates for the US dollar are shown in Figure 33 and exchange rates for the Euro are shown in Figure 34.

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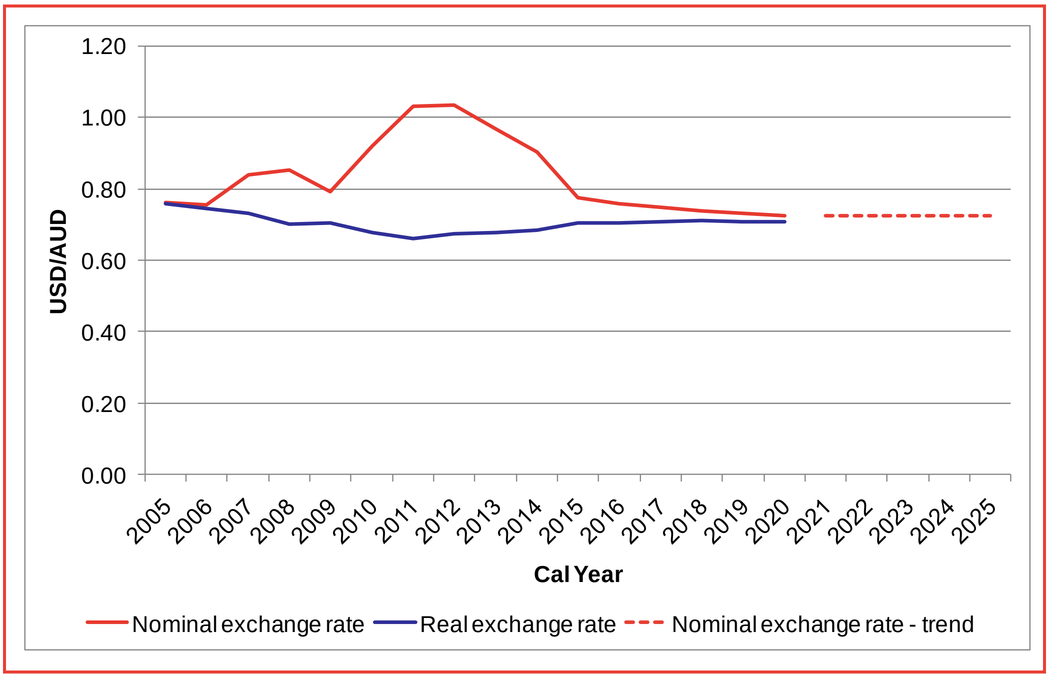
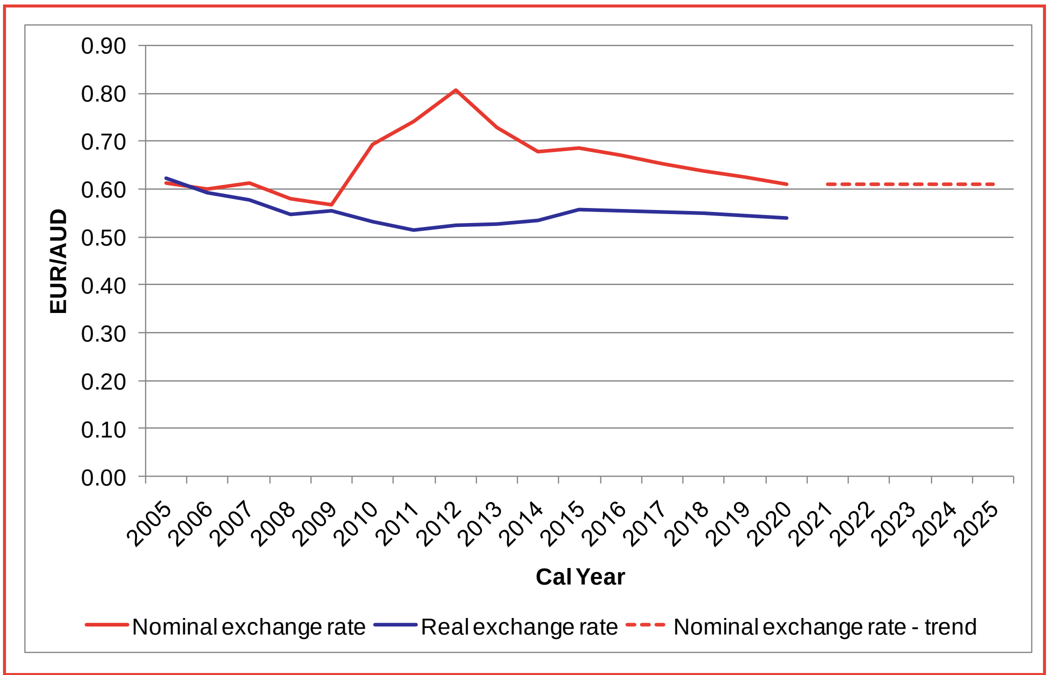
31 http://www.imf.org/external/pubs/ft/weo/2015/01/

Figure 33: Exchange rates (USD/AUD)




*Source: International Monetary Fund, World Economic Outlook Database, April 2015.*

Figure 34: Exchange rates (Euro/AUD)




*Source: International Monetary Fund, World Economic Outlook Database, April 2015.*

## Discount rates

We have used different discount rates for different industries. In each case, the discount rate that we have adopted is based on the discount rate determined by IPART as part of their last review of retail electricity prices in 2013/14. We have updated relevant parameters used in the calculation of these discount rates to account for current market conditions. Based on this approach, the discount rates that we have used in developing our input assumptions are as follows:

- Electricity generation – 8.3 per cent real pre-tax WACC
- Electricity retailing – 9.53 per cent real pre-tax WACC
- Coal mining – 9.23 per cent real pre-tax WACC
- Gas production – 8.82 per cent real pre-tax WACC
- Gas transmission – 6.7 per cent real pre-tax WACC.

## Real cost escalation

When forecasting capital and operating costs we need to take account of real cost escalation. This is particularly the case for power station capital and operating costs. To take account of real cost escalation over the forecast period, we adopt the following approach:

- Capital costs are escalated based on the average real increase in the producer price index for domestic goods over the period from 2000 to 2014 – 0.11 per cent per annum.
- Labour costs are escalated based on the average real increase in the labour price index for workers in the electricity, gas, water and waste services industries over the period from 2000 to 2014 – 1.38 per cent per annum.

By adopting this approach we are effectively assuming that the average real increases that we have seen over this period from 2000 to 2014 will continue into the future.

# Capital costs of power stations

Investors will not commission new generation plant unless they expect to recover the capital costs of building that plant (including an adequate return on their capital). Capital costs of new generation plant are, therefore, relevant to investment decisions in electricity markets, as well as resource costs and electricity prices in the long run.[32]

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32 In contrast, capital costs of existing generation plant are sunk and, therefore, not relevant to economic decisions.

## Our approach to estimating capital costs

Our approach to estimating capital costs is a top-down approach: we estimate the capital costs of new generation plant on the basis of a broad survey of reported cost estimates for generation plant of a particular technology.

We implement the top-down approach by making use of our detailed global database of reported capital costs. This global database is populated by publicly available cost estimates from a wide variety of sources, primarily company reports, reports from the trade press, industry and market analysis, and engineering reports. Additional data is added to our database on an ongoing basis, as data becomes available. However, we tend to only produce updated estimates of capital costs on a bi-annual basis, as new macroeconomic forecasts become available. Our database includes estimates of capital costs of specific generation plant that have been commissioned and are operating, as well as capital costs of specific generation plant that are at some stage of planning or construction. Our database also includes estimates of capital costs for generic new generation plant of a particular technology. Our database contains capital cost estimates for a wide range of existing generation technologies that are widely deployed, as well as newer generation technologies that are in various stages of development.

Our database includes reported costs for the principal power stations that have been built, or proposed, in Australia over the past decade. However, the database also has extensive international coverage. For most of the generation technology options that are covered in this report this international coverage is essential, since there has been little or no development activity in Australia for these technologies. Our global database of reported costs is kept continuously up-to-date, so that as new estimates become available they are incorporated in the database.

In order to ensure that the data that we use to estimate capital costs is relevant to current capital costs in Australia, we filter the data in database in the following ways:

- **Filtering by year**. Our global database includes cost estimates dating back as far as the 1990s and forecasts of future capital costs out to 2050. In order to avoid our cost estimates being affected by changes in technology and learning curves (particularly for the capital costs of some of the newer technologies), we include cost estimates only for projects constructed, or to be constructed, over a narrow range of years. This range varies somewhat from technology to technology; in particular, for technologies for which learning is material we use a narrower range of years.
- **Filtering by country**. Our global database includes cost estimates for a wide range of countries, both developed and developing. In order to avoid cost

estimates being affected by significantly different cost structures, we include cost estimates only for projects in OECD economies.

- **Filtering to remove outliers**. In order to avoid our analysis being affected by cost estimates that reflect a particular project that has substantial project-specific cost advantages (or disadvantages), or by cost estimates that reflect a particularly optimistic (or pessimistic) view, we exclude cost estimates that are material outliers.

## Basis of capital costs

Our estimates of capital costs are intended to reflect the capital costs for a representative generation plant for each of the generation technologies considered in this report.

Our estimates of capital costs include the direct costs of all plant, materials, equipment and buildings inside the power station fence, all labour costs associated with construction, installation and commissioning, as well as owner's costs such as land, development approvals, legal fees, inventories, etc. Our estimates of capital costs do not include the costs of connection to the network, but we have added these connection costs to our capital cost estimates for new generation plant so that the modelled capital cost includes the capital costs 'inside the fence' as well as the cost of connecting to the network. In other words, the capital costs presented in this report exclude connection costs, but the capital costs included in our model include connection costs. These connection costs are based on data from the AEMO 2014 NTNDP, and differ by NTNDP zone.

Our estimates of capital costs are overnight capital costs, expressed in 2015/16 Australian dollars. That is, our estimates do not include interest (or escalation) during construction. These costs are accounted for in the financial model that we use to convert overnight capital costs (in $/kW) into an amortised capital cost (in $/MW/hour) that is used in our energy market models.

Our estimates of capital costs are expressed in $/kW at the generator terminal (or $/kW GT). Power station auxiliaries (and network losses) associated with the operation of power stations are separately accounted for in our modelling.

## Estimates of current capital costs

Our estimates of current capital costs for each of the generation technologies considered in this report are set out in Figure 35 and Figure 36. Figure 35 deals with coal-fired generation technologies and Figure 36 deals with gas-fired and renewable generation technologies.

Our estimates of capital costs for each generation technology include a range of individual cost estimates. Even after filtering our global database for relevant countries and years we have a significant number of unique cost estimates for each generation technology. The full range of cost estimates (from lowest cost to highest cost) for each generation technology is shown by the orange “whiskers” in Figure 35 and Figure 36. The range of cost estimates that covers the $10^{th}$ to $90^{th}$ percentile of cost estimates is shown by the pale red “boxes” in Figure 35 and Figure 36, and the range of cost estimates that covers the $25^{th}$ to $75^{th}$ percentile of cost estimates is shown by the dark red “boxes” in Figure 35 and Figure 36.

Clearly, there are a number of significant outliers in our data – this is seen by the much wider range of costs for the full dataset than for the $10^{th}$ to $90^{th}$ percentile. These outliers might arise either because a particular project has project-specific cost advantages (or disadvantages), because a particular estimate of costs reflects a particularly optimistic (or pessimistic) view, or because there are issues with the reported data (for instance, the reported cost may be net of a received subsidy).

While there are outliers, we note that the rage for the $25^{th}$ to $75^{th}$ percentile is generally reasonably narrow, indicating a reasonable consensus on capital costs for generation plant of that technology. The exception to this is generally for less mature technologies – including IGCC and Geothermal EGS – for which there is a wide range of estimates of capital costs even within the range of the $25^{th}$ to $75^{th}$ percentile.

To avoid our analysis being affected by outliers, we estimate current capital costs for each generation technology as the mean of the cost estimates that fall within the $25^{th}$ to $75^{th}$ percentile of cost estimates for that generation technology. We note that this mean of the cost estimates that fall within the $25^{th}$ to $75^{th}$ percentile is generally very consistent with the median of the full range of data. This suggests to us that using the mean of the cost estimates that fall within the $25^{th}$ to $75^{th}$ percentile is a reasonable approach to dealing with outliers.

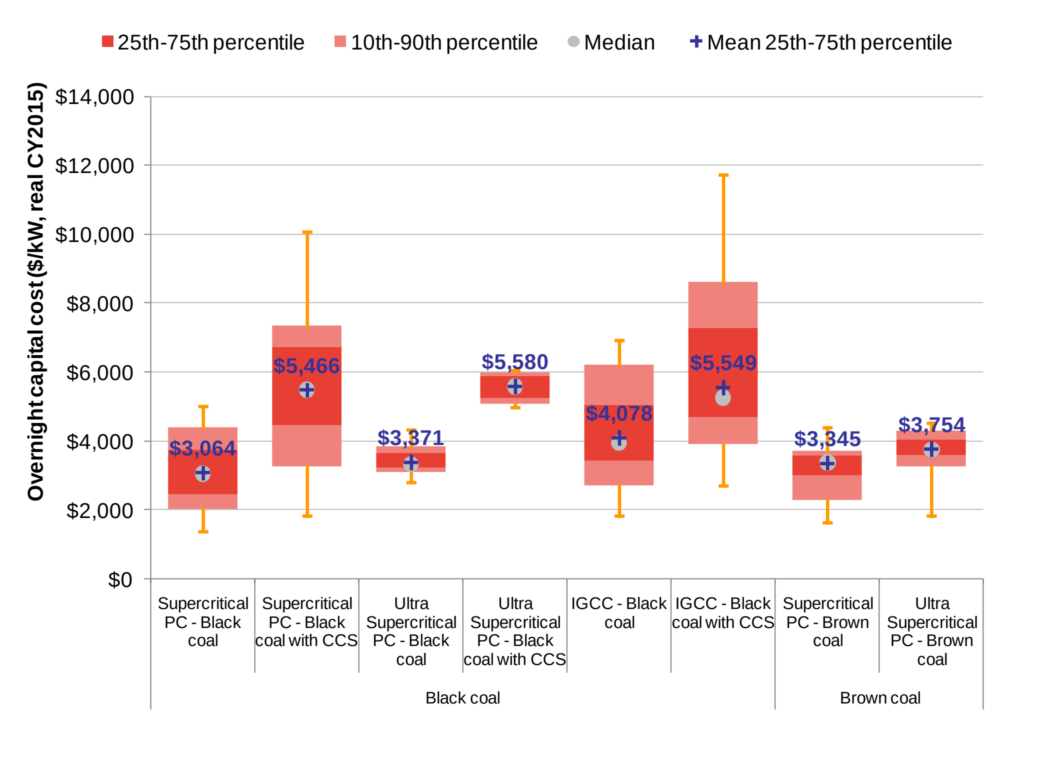
## Estimating capital costs in the SWIS

For all technologies except coal, capital costs in the SWIS are assumed equal to the NEM. However, due to the smaller size of the SWIS market, the optimal unit size for coal technologies is significantly reduced. Specifically, it would not make sense from a system operation perspective to build a 600 MW or larger coal-fired unit in the SWIS, which rules out standard super- and/or ultrasupercritical coal-fired technologies.

To estimate the capital cost of commissioning a new coal-fired power station in WA we have restricted the subset of cost estimates to those with unit sizes approximately half the size of those considered in the NEM. This approach led to a higher capital cost forecast in the SWIS. For example, super-critical coal is forecast at $3,955/kW in the SWIS, compared to $3,265 in the NEM for 2015/16.

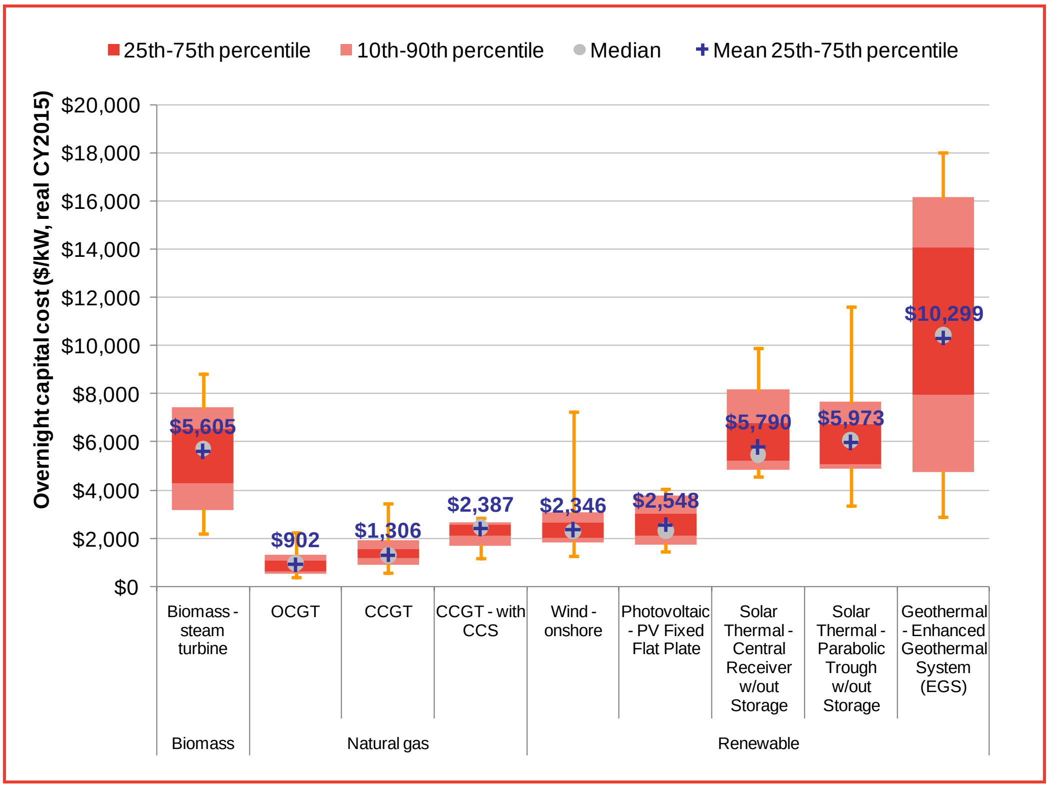
We have excluded ultra super-critical technologies in the SWIS as they require larger unit sizes to achieve the improved efficiencies. It is more likely that less efficient, smaller technologies will be commissioned. We have included a subcritical coal technology in the SWIS with an estimated capital cost of $3,280/kW for 2015/16.

Figure 35: Current capital costs for coal generation plant




*Source: Frontier Economics*

Figure 36: Current capital costs for renewable generation plant




*Source: Frontier Economics*

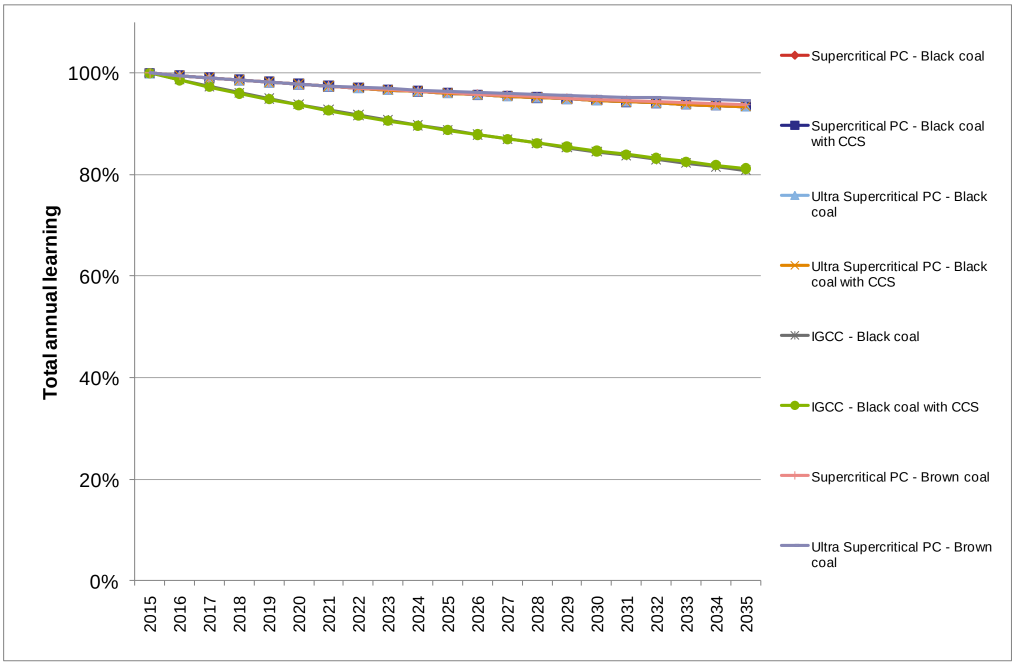
## Estimates of capital costs over the modelling period

Since the RET extends to 2030, our modelling of the RET needs to cover at least this period.

This means that we need to develop estimates of capital costs for generation plant that cover this period. Our approach is to use our current estimates of capital costs as the starting point, and vary these estimates over time to account for cost escalation, exchange rate movements and learning curves.

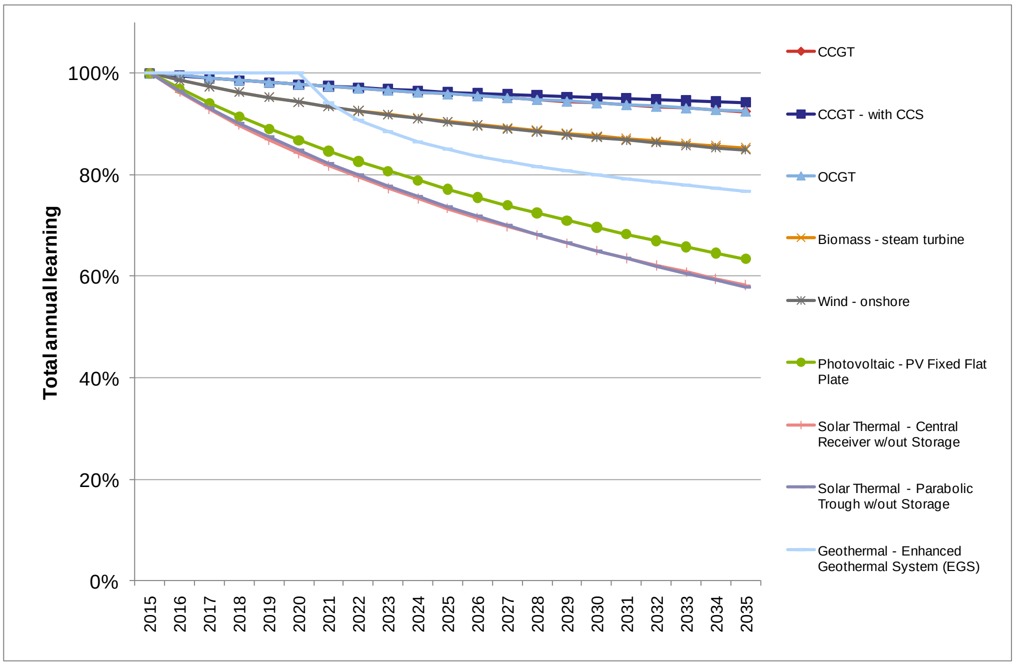
First, we escalate our current estimates of capital costs over the modelling period for a forecast of real increases in the costs of generation plant, using the cost escalation discussed earlier. Second, we adjust our escalated estimates of capital costs to account for movements in exchange rates, using the exchange rates discussed above. Third, we adjust our estimates of capital costs to account for technological improvements and innovation, through the use of 'learning curves', as shown in Figure 37 and Figure 38.

Figure 37: Learning curves for coal generation plant




*Source: Frontier analysis based on various sources*

Figure 38: Learning curves for gas and renewable generation plant



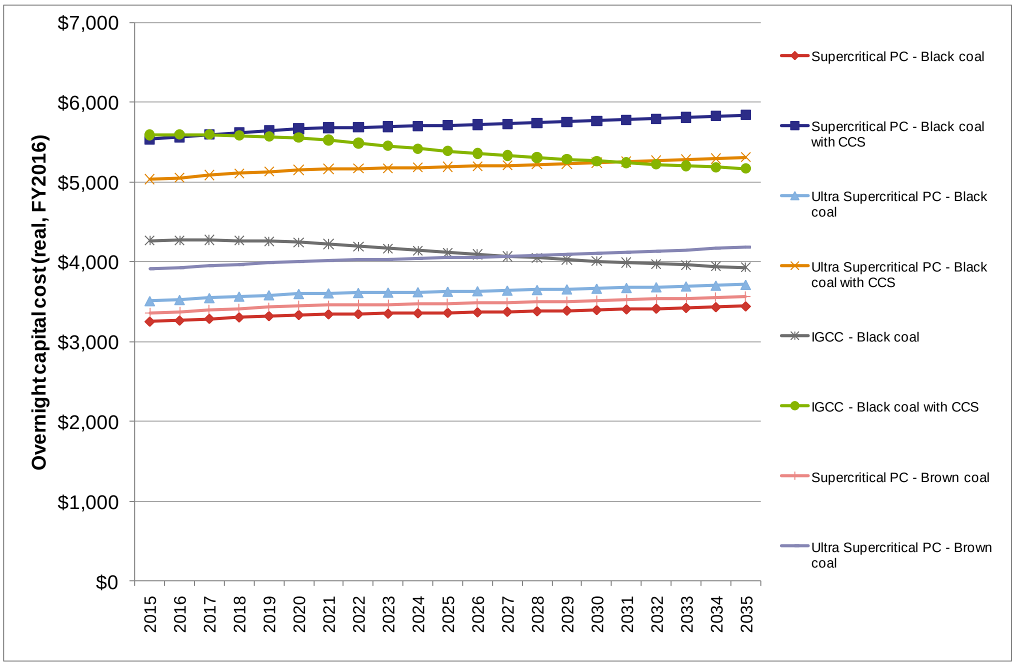

*Source: Frontier analysis based on various sources*

Taking into account these factors, our estimates of capital costs over the modelling period for each of the generation technologies considered in this report are set out in Figure 39 and Figure 40. Figure 39 deals with coal-fired generation technologies and Figure 40 deals with gas-fired and renewable generation technologies.

As seen in Figure 39, the capital costs for coal-fired generation plant tend to increase over the modelling period, with the exception of IGCC technologies. The increasing forecast is the result of: the forecast ongoing real escalation in capital costs and labour costs, and the forecast depreciation of the Australian dollar. Against these factors resulting in increasing costs, these existing coal-fired generation technologies are forecast not to benefit from substantial cost improvements, meaning that, overall, costs increase.

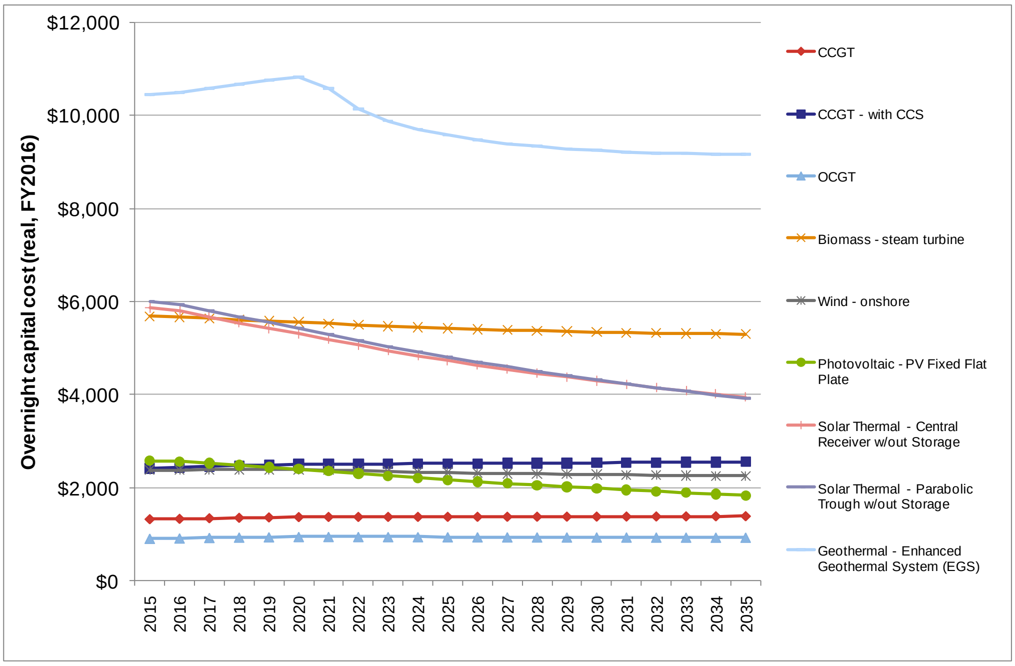
As seen in Figure 40, the capital costs for gas fired and renewable generation plant are more variable over the modelling period. While these generation technologies are subject to increasing costs as a result of real escalation in capital costs and depreciation in the Australia dollar, the cost improvements for newer technologies are forecast to be more significant. In particular, solar thermal capital costs fall significantly as widespread commercialisation is assumed to commence from 2015. Cost reductions for geothermal EGS do not occur until widespread commercialisation is assumed to commence in 2020. In contrast, the expected cost improvements for the established gas fired and renewable technologies – OCGT, CCGT, wind and biomass – are more moderate, resulting in more stable costs for these technologies over the modelling period.

Figure 39: Forecast capital costs for coal generation plant ($2015/16)




*Source: Frontier Economics*

Figure 40: Forecast capital costs for gas and renewable generation plant ($2015/16)




*Source: Frontier Economics*

## Operating costs and characteristics of power stations

There are a range of power station operating costs and characteristics that affect the economics of investment in and operation of power station. These costs and characteristics are required as inputs into our modelling:

- **Fixed operating and maintenance (FOM) costs of new generation plant**. As with capital costs, investors will not commission new generation plant unless they expect to recover the fixed operating and maintenance costs associated with that plant.
- **Variable operating and maintenance (VOM) costs of existing and new generation plant**. The operators of generation plant will not operate their plant unless they expect to recover the variable operating and maintenance costs associated with operating the plant; if they do not recover these costs, they would do better not to operate the plant.
- **Plant capacity**. Measures the capacity (measured in MW at the generator terminal) of the power station.
- **Equivalent Outage Rate (EOR)**. Measures the equivalent outage rate for the power station, calculated as the sum of full outage hours and the conversion of partial outage hours to power station full outage hours. Includes planned, forced and breakdown maintenance outages.
- **Maximum capacity factor**. Measures the maximum capacity factor achievable by the power station in any year. The annual capacity factor is measured as the energy production of the power station in the year compared to the total energy production if the power station operated at full capacity for the full year.
- **Auxiliaries**. Measures the use of energy by the power station. Used to convert plant capacity from a generator terminal (GT) to a sent-out (SO) basis.
- **Heat rate**. Measures the efficiency with which a power station uses heat energy. The heat rate is expressed as the number of GJs of fuel required to produce a MWh of sent-out energy.

### Our approach to estimating operating costs and characteristics

As with our approach to estimating capital costs (discussed above), our approach to estimating operating costs and characteristics is a top-down approach: we estimate the costs and characteristics for new generation plant on the basis of a broad survey of reported estimates for generation plant of a particular technology.

We implement the top-down approach by making use of our detailed global database of reported operating costs and characteristics. This global database is populated by publicly available estimates from a wide variety of sources, including manufacturer specifications, company reports, reports from the trade press, industry and market analysis, and engineering reports. Additional data is added to our database on an ongoing basis, as data becomes available. However, we tend to only produce updated estimates of operating costs on a bi-annual basis, as new macroeconomic forecasts become available. Our database includes estimates for specific generation plant that have been commissioned and are operating, as well as estimates for specific generation plant that are at some stage of planning or construction. Our database also includes estimates of operating costs and characteristics for generic new generation plant of a particular technology. Our database contains estimates for a wide range of existing generation technologies that are widely deployed, as well as newer generation technologies that are in various stages of development.

Our database includes reported estimates for power stations in Australia and also has extensive international coverage. For most of the generation technology options that are covered in this report this international coverage is essential, since there has been little or no development activity in Australia for these technologies. Our global database of reported operating costs and characteristics is kept continuously up-to-date, so that as new estimates become available they are incorporated in the database.

In order to ensure that the data that we use to estimate operating costs and characteristics is relevant to generation plant Australia, we filter the data in database in the following ways:

- **Filtering by year**. Our global database includes cost estimates dating back as far as the 1990s and forecasts of future capital costs out to 2050. In order to avoid our cost estimates being affected by changes in technology and learning curves (particularly for the capital costs of some of the newer technologies), we include cost estimates only for projects constructed, or to be constructed, over a narrow range of years. This range varies somewhat from technology to technology; in particular, for technologies for which learning is material we use a narrower range of years.

- **Filtering by country**. Our global database includes cost estimates for a wide range of countries, both developed and developing. In order to avoid cost estimates being affected by significantly different cost structures, we include cost estimates only for projects in OECD economies.

- **Filtering to remove outliers**. In order to avoid our analysis being affected by estimates that reflect a particular project that has substantial project-specific advantages (or disadvantages), or by estimates that reflect a particularly optimistic (or pessimistic) view, we exclude estimates that are material outliers.

## Basis of FOM and VOM costs

Our estimates of FOM and VOM costs are intended to reflect the costs for a representative generation plant for each of the generation technologies considered in this report.

Our estimates of FOM and VOM costs include all costs associated with the ongoing operation and maintenance of the generation plant over their expected life. These costs include labour costs as well as materials, parts and consumables. Our estimates of FOM and VOM costs do not include fuel costs or carbon costs, but we separately account for these costs when determining the short run marginal cost of generation plant.

In our experience, there is very little agreement as to what costs constitute **fixed** operating and maintenance costs and what costs constitute **variable** operating and maintenance costs. Economists would typically define fixed operating and maintenance costs as those operating and maintenance costs that do not vary with the level of output of the generation plant and variable operating and maintenance costs as those operating and maintenance costs that do vary with the level of output of the generation plant. In practice, of course, for many operating and maintenance costs there is ambiguity about whether or not they should be thought of as varying with output: for instance, where operating and maintenance costs are related to plant breakdowns, should they be considered fixed or variable? This ambiguity can raise issues in estimating FOM costs and VOM costs: in particular, it is important to ensure that estimates of FOM costs and VOM costs do not double count, or fail to count, any costs. To ensure this, our approach to estimating FOM costs and VOM costs involves the following stages:

- Record total operating costs from each source (including FOM costs and VOM costs). These total operating costs are used to develop our estimates of total operating costs for each generation technology considered in this report.
- Record the proportion of total operating costs that are FOM costs and VOM costs from each source. These proportions are used to develop a single estimate of the proportion of FOM costs and VOM costs for each generation technology considered in this report.
- The proportions of FOM costs and VOM costs are applied to our estimates of total operating costs for each generation technology to develop an estimate of FOM costs and VOM costs for each generation technology.

Our estimates of FOM costs and VOM costs are expressed in 2015/16 Australian dollars. Our estimates of FOM costs are expressed in $/MW/hour at the generator terminal (or $/MW/hour, GT). Our estimates of VOM costs are expressed in $/MWh at the generator terminal (or $/MWh, GT). Power station auxiliaries (and network losses) associated with the operation of power stations are separately accounted for in our modelling.

## Estimates of operating costs and characteristics for new entrant generation plant

This section discusses a number of NEM specific inputs to the modelling where we have relied on third party estimates.

# NEM-specific technical characteristics

When modelling new entrant generators in the NEM several additional technical characteristics and constraints are incorporated into the model.

### Wind tranches

In order to capture a realistic 'cost curve' for new entrant wind generators that reflects diminishing marginal quality of new wind sites (i.e. an upward-sloping wind supply curve for a given capital cost) our modelling makes use of 4 tranches of wind capacity in each NTNDP Zone, consistent with AEMO's 2014 NTNDP. Each wind tranche has an assumed maximum available capacity in each NTNDP Zone and an assumed maximum annual capacity factor. Capacity factors decline in each wind tranche, resulting in a higher long-run marginal cost for new wind developments as favourable sites are exhausted. The MW availability and associated annual capacity factors for each wind tranche are taken from AEMO's 2014 NTNDP planning case supply input spreadsheet.[33]

### Solar capacity factors by NEM sub-region

The average annual capacity factors for solar plant in the NEM vary considerably depending on the location of the plant. Accurately capturing the annual average capacity factor of solar plant is important – this is because the annual capacity factor is the primary driver of long-run marginal cost. Our modelling uses annual average capacity factors for solar plant for each NTNDP Zone as outlined in AEMO's 2011 NTNDP planning case supply input spreadsheet.[34] At the time of modelling this was the most up-to-date estimate of the operating capacity factors of solar plant in the NEM on a sub-regional basis that was available.

### Technology-specific build limits

To capture real-world commercial and technical constraints in commissioning generators over a certain timeframe in the NEM, the modelling assumes a variety

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33 http://www.aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/NTNDP/2014/NTNDP%202014%20%20main%20document.ashx

34 http://www.aemo.com.au/Consultations/National-Electricity-Market/Closed/~/media/Files/Other/planning/0418-0013%20zip.ashx

of annual and total build limits. Total build limits for each technology by NTNDP Zone are based on AEMO's 2014 NTNDP planning case supply input spreadsheet.[35] In addition, an annual build limit of 500 MW in each NTNDP Zone in each year has been imposed on wind investment. This assumption is necessary to prevent the model attempting to commission an unrealistically large quantity of wind generation in a concentrated area of the NEM in a single year.

### Technical characteristics of existing generation plant

In addition to technical characteristics for new entrant generation plant, our market modelling also makes use of technical characteristics for existing generation plant.

The technical characteristics of specific existing generation plant can be difficult to accurately assess. The reason is that these characteristics will not just be affected by the generation technology of the plant, but also by a number of factors specific to the plant including its age, how the plant has been operated over its life and continues to operate, and the quality of fuel that the plant has burned and continues to burn.

Without specific knowledge of these factors, anything other than generic estimates of the technical characteristics of existing generators is impractical. Rather than rely on generic estimates of these characteristics for existing generators, we have adopted the data used by AEMO in their NTNDP modelling. Given that AEMO engages in stakeholder consultation in developing these assumptions for their modelling, we consider that these assumptions are more likely to reflect the actual technical characteristics of existing generators than are generic estimates.

## Coal prices for power stations

In order to model outcomes in the electricity market over the period to 2030, we need an estimate of the marginal cost of coal supplied to each existing coal-fired power station, and each potential new coal-fired power station.

This section provides an overview of the methodology that we have adopted for estimating the marginal cost of coal supplied to a power station, and sets out our forecasts of coal prices.

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35 http://www.aemo.com.au/Electricity/Planning/~/media/Files/Electricity/Planning/Reports/NTNDP/2014/NTNDP%202014%20%20main%20document.ashx

## Methodology

Our approach to forecasting coal prices is based on determining the marginal opportunity cost of coal for power stations.

### *Marginal cost of coal*

The marginal cost of coal to each power station is the cost the power station would face for an additional unit of coal. The marginal cost of coal to a power station is likely to differ from the average cost of coal to a power station because the average cost of coal will reflect the price of coal under the various long-term coal supply contracts that power stations typically have in place. For instance, a power station that has in place a number of long-term coal supply contracts at low prices would have an average price of coal that reflects these low contract prices. However, if that power station would face higher market prices in order to purchase an additional unit of coal, then the marginal cost of coal would reflect these higher market prices.

The reason that we forecast coal prices faced by coal-fired generators on the basis of marginal costs, rather than average costs, is that economic decisions about the operation and dispatch of power stations should be based on marginal costs rather than average costs. For instance, a power station with a low average cost but high marginal cost (as considered above) would reduce its profit if it increased dispatch and recovered its average cost but not its marginal cost: the additional dispatch requires the use of additional coal priced at the market price for coal, and if the revenue from that additional dispatch does not cover this marginal cost, the additional dispatch will reduce total profits.

We base the marginal cost of coal faced by a coal-fired generator on the market price for coal available to that generator. To determine this market price, we ultimately need to construct a demand curve and a supply curve for coal supply to coal-fired generators. First, however, we need to consider how to assess the costs of supply to coal-fired generators, which we assess on the basis of the opportunity cost.

### *Opportunity cost of coal*

When economists think about cost, they typically think about opportunity cost. The opportunity cost of an activity is measured by economists as the value of the next best alternative that is foregone as a result of undertaking the activity. For instance, the opportunity cost to a home owner of living in their house could be the rent that is foregone as a result of the decision to live in the house.

Opportunity cost is relevant to assessing the cost to coal producers of supplying coal to coal-fired generators because coal producers may well be foregoing alternative markets for that coal in supplying to a coal-fired generator. For instance, a coal producer that has access to the export market may well be foregoing the export price of coal (less any export-related costs) in supplying to a coal-fired generator. In this case, the export price (less any export-related costs) may be relevant to the opportunity cost of supplying coal to a coal-fired generator.

Clearly then, the markets to which a coal producer has access is important in considering the opportunity cost to that coal producer of supplying to a coal-fired generator. We distinguish between two types of coal mine:

- **Coal mines that do not have access to an export market**. Where coal mines do not have access to an export market it is generally as a result of the absence of the infrastructure necessary to transport coal from the mine to port. In many cases these coal mines are co-located with power stations and supply direct to the power stations through conveyors. These power stations are known as mine-mouth power stations. For these coal mines that do not have access to an export market, the coal producer is not foregoing the export price of coal in supplying to a coal-fired generator and, therefore, the export price is not relevant to the opportunity cost of supplying coal to a coal-fired generator. Indeed, for these coal mines, the coal producers' next best alternative is likely to be simply investing its capital in some other activity, so that the opportunity cost of supplying to a coal-fired generator is simply the resource costs of producing coal, including a competitive return on capital.
- **Coal mines that do have access to an export market**. Where coal mines do have access to an export market, this implies that the coal mine has access to the infrastructure necessary to transport coal from the mine to port. These mines may also supply coal to other users, including coal-fired power stations. For these coal mines, in the absence of any export constraints the coal producer is foregoing the export price of coal (less any export-related costs) in supplying to a coal-fired generator and, therefore, the export price (less any export-related costs) is relevant to the opportunity cost of supplying coal to a coal-fired generator. Importantly, for these coal mines, the opportunity cost of supplying to a coal-fired generator is the **value** of exporting coal, which implies that it is necessary to consider both the revenue from exporting coal and the additional cost of exporting coal. This value is typically known as the net-back price of coal.

It should be noted that simply because a coal mine has access to an export market, this does not mean that the net-back price of coal is the relevant opportunity cost. Indeed, if the net-back price is lower than resource costs, this implies that exporting coal is not the next best alternative (and, indeed, may imply that exporting coal is a loss-making exercise). Rather, the coal producer's next best alternative is likely to be simply investing its capital in some other activity, so that the opportunity cost is the resource costs of producing coal, including a competitive return on capital. In short, for coal mines that do have access to an export market, the opportunity cost of supplying to a coal-fired generator is the higher of resource costs and the net-back price.

### Resource costs

Resource costs are the capital and operating costs associated with coal production. In estimating resource costs, our initial focus is on mine-gate resource costs. These are the direct costs associated with all activities within the mine, including mining, processing and loading coal.

Mine-gate costs do not include royalties or transport costs. We also account for royalties and transport costs when estimating the marginal cost of coal, but because transport costs are different for different power stations (depending on their location) we account for transport costs when estimating the marginal cost of coal to each power station.

We separately estimate the following categories of resource costs:

- Upfront capital costs – upfront capital costs are the costs of establishing a coal mine and include costs of items such as pre-stripping, mining equipment, loading equipment, crushers, screens, washeries, access roads, dams, power and other infrastructure. Capital costs for existing coal mines are sunk, and therefore we do not account for these when considering the marginal cost of coal from these mines. Capital costs for new coal mines are not sunk, and therefore we do account for these when considering the marginal cost of coal from these mines.
- Ongoing capital costs – ongoing capital costs are the costs of ongoing investment in a coal mine to replace major equipment and develop new mining areas. Ongoing capital costs for both existing and new mines are not sunk, and therefore we account for these when considering the marginal cost of coal.
- Operating costs, or mine-gate cash costs – cash costs are the costs associated with producing saleable coal from the mine, and include labour costs and other mining and processing costs. Since cash costs of coal mines are variable, we account for these costs when considering the marginal cost of coal.
- Royalties – are payments to the State Government for the right to make use of the State's coal resources.
- Transport costs – transport costs are the costs associated with delivering coal from the mine-gate to the power station.

These separate elements of resource costs are accounted for, for each coal mine that supplies the domestic market. We have developed a model of resource costs that relate the key characteristics of each coal mine – including strip ratio, overburden and coal quality – to the various categories of resource costs.

### *Net-back price of coal*

In this context, the net-back price of coal refers to the revenue that a coal producer would earn from exporting its coal to the international market, less all of the additional costs that would be incurred by the coal producer as a result of a decision to export the coal rather than sell it domestically, measured at the mine-gate.

As we have seen, the net-back price of coal is relevant to determining the opportunity cost of coal to a coal producer that has access to the export market because the net-back price of coal measures the value that the coal producer would forego if, having produced a unit of coal, it decided to supply that unit of coal to a domestic power station rather than export that unit of coal.

The **first step** for calculating the net-back price of coal is a forecast of the export price of coal. It is this export price that determines the revenue that a coal producer will earn by exporting coal.

The export prices that we have used to calculate the net-back price of coal are from quarterly forecasts released by the World Bank.[36] The World Bank provides forecasts of the export price of thermal coal out to 2025. We have developed consistent forecasts for semi-soft coking coal (SSC) and hard coking coal (HCC) based on relativities between current thermal, semi-soft and hard coking coal prices out of Newcastle.[37] These export prices, which are in USD/tonne, are converted to AUD/tonne based on the forecast nominal exchange rate set out above. This results in the export prices shown in Figure 41.

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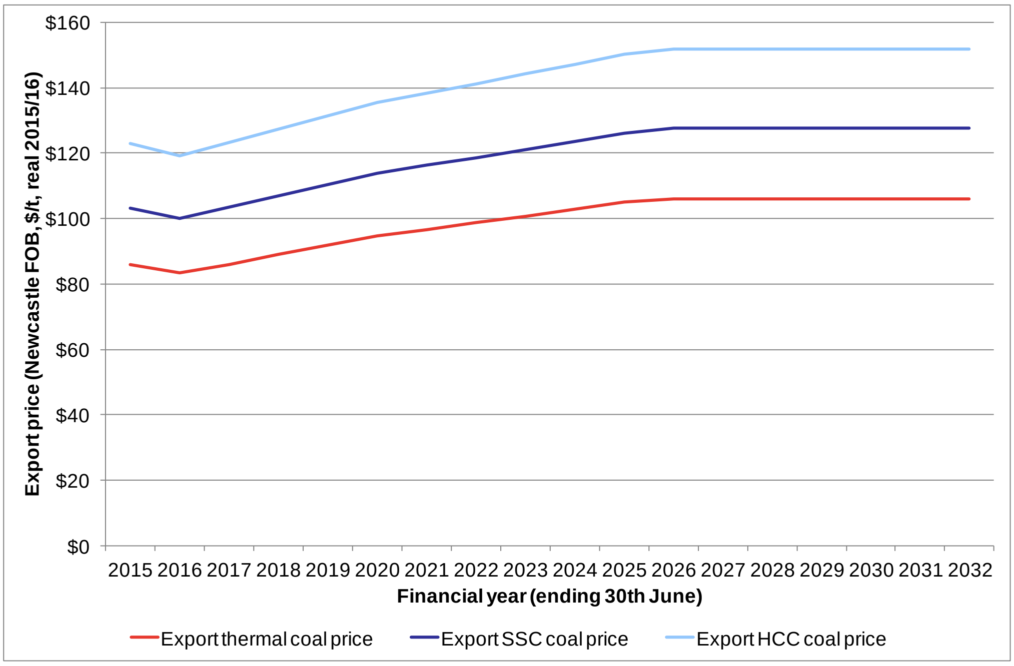
36 See:

http://www.worldbank.org/content/dam/Worldbank/GEP/GEPcommodities/PriceForecast_20150422.pdf

37 See: https://www.platts.com/IM.Platts.Content/ProductsServices/Products/coaltraderintl.pdf

Figure 41: Export coal prices ($2015/16)




*Source: World bank and Metalytics analysis*

The export revenue that a coal producer earns will ultimately depend on the quality of the coal that it produces. The coal prices shown in Figure 41 are for coal of a particular quality. For instance, the export thermal coal price shown in Figure 41 is for coal that meets the benchmark specification of 6,300 cal/kg. For coal that has a different specification, the coal price received by the coal producer will be adjusted according: lower specification coal will receive a lower price and higher specification coal will receive a higher price.

This means that calculating the net-back price of coal requires an estimate of the coal quality for each mine. Coal specifications for export product are generally revealed in company reports or industry publications such as the TEX Report. Many domestic coal calorific values are published in the Register of Australian Mining. In other cases, industry knowledge, the mine's yield and partial pricing signals, provide a reasonable estimate. Our estimates of energy content for domestic thermal coal take into consideration that:

- producers may vary the quality of their product depending on demand from domestic or offshore utilities,
- the quality of the coal being mined may vary through time;
- it may include washery middlings or raw coal which, unprocessed, has little quality consistency.

The **second step** for calculating the net-back price of coal is to estimate the costs that a coal producer will avoid if it does not export coal.

The avoided costs that need to be taken into account in calculating the net-back price of coal are:

- Port fees – we have obtained information on port fees directly from Port Waratah Coal Services and the Newcastle Coal Infrastructure Group. Information on other port charges has come from industry sources and company reports.
- Transport costs – rail costs are calculated using access charges, loading rates and distance travelled.
- Administration and marketing costs – these costs are based on industry estimates.
- The costs of managing exchange rate and counterparty risk – these costs are based on industry estimates.
- Washing costs – these costs are assessed using mine-by-mine information (when available) as well as the mine's yield.

The avoided costs will differ from mine to mine, driven by differences in location, export port and requirements to wash coal. Generally speaking, the avoided costs associated with port fees and transport range from around \$8/t to around \$23/t, the avoided costs associated with administration, marketing and risk management are around \$17/t and the avoided costs associated with washing range from \$0/t (for coal mines that do not need to wash their coal) to around \$9/t.

The **final step** in calculating the net-back price of coal is to adjust for any differences in yield between coal supplied to the export market and coal supplied to the domestic market.

The yield of a coal mine measures the ratio between tonnes of run-of-mine coal and tonnes of saleable coal. Differences between tonnes of run-of-mine coal and tonnes of saleable coal result primarily from washing: washing improves the quality of coal but reduces the tonnage of coal.

Where a coal mine washes export coal but does not wash domestic coal (or washes the coals to different extents) there will be a difference in yield. This means that a decision to export a unit of coal rather than to sell it domestically will result in a reduction in the tonnes of saleable coal – a higher export price will be received for the higher-quality washed coal, but fewer tonnes will be sold as a result of the washing.

We account for any difference in yield between coal supplied to the export market and coal supplied to the domestic market when calculating the net-back price of coal.

# Coal price forecasts

In order to model outcomes in the electricity market, we need an estimate of the marginal cost of coal supplied to each existing coal-fired power station, and each potential new coal-fired power station.

This section provides an overview of the methodology that we have adopted for estimating the marginal cost of coal supplied to a power station, and sets out our forecasts of coal prices.

## *Coal price forecasts for existing mine-mouth power stations*

In the case of mine-mouth coal-fired generators, there is no coal region or coal market as such – the cost of coal to mine-mouth coal-fired generators is based simply on the resource cost of the associated mine (on the basis that the coal supplied by the mine has no realistic alternative use).

We have developed estimates of the resource costs of each mine in NSW and Queensland that supplies thermal coal to power stations in the NEM, including each existing mine supplying mine-mouth power stations. These estimated resource costs include ongoing capital costs, cash costs, carbon costs and royalties.

For some mines that supply mine-mouth power stations, there is a real shortage of data on resource costs. This is particularly the case for brown coal mines in Victoria and for South Australia's Leigh Creek mine. The problem with these mines is that there has been no investment in new coal mines in these regions for many years, and also no investment in equivalent mines in other regions (in particular, brown coal mines), which means that there is very little up-to-date information on the likely resource costs for mines of this type. For this reason, rather than estimating the cost of coal supplied to power stations from Victoria's brown coal mines and South Australia's Leigh Creek mine on the basis of a detailed estimate of resource costs, we have estimated these costs on the basis of the observed bidding of these power stations. By observing the average price bands in which these power stations have historically bid a material proportion of their capacity, and adjusting these electricity prices to account for the efficiency of the power stations and the power stations' VOM costs, we estimate the cost at which these power stations are supplied with coal.

## *Coal price forecasts for existing power stations that are not mine-mouth*

In the case of power stations that are not mine-mouth, the power station is generally supplied from a coal region in which a number of coal mines supply one or more coal-fired power stations through a network of delivery options (including conveyor, truck and rail). There are two coal regions in the NEM that can be characterised in this way:

- The Central Queensland coal region (in the NTNDP zone, CQ), in which Stanwell and Gladstone power stations are able to source coal from a number of coal mines that also have an export option.
- The Central NSW coal region (in the NTNDP zone, NCEN), which consists of a western region in which Bayswater, Liddell, Mt Piper and Wallerawang power stations are located and a coastal region in which Eraring and Vales Point power stations are located. Across this combined region coal can be sourced from a number of coal mines that also have an export option.

Assessing demand and supply in these regions is clearly more complex than doing so for mine-mouth power stations. To determine the cost of coal supplied to coal-fired power stations in these regions, we develop a supply curve and a demand curve for the region.

The supply curve for each coal region is based on the annual capacity of each coal mine to supply thermal coal to domestic power stations and the opportunity cost faced by each coal mine for such supply, where the opportunity cost faced by each coal mine is determined as the higher of the resource cost of supply from the coal mine and (where the mine has an option to export) the net-back price of coal for the coal mine.

The demand curve for each coal region is based on an estimate of the annual coal used by coal-fired generators in each region. The annual coal used by coal-fired generators is calculated based on their annual dispatch, adjusted by the heat-rate for the plant.

The marginal opportunity cost of coal in each region is determined by the point of intersection of the demand curve for coal in the region and the supply curve for coal in the region.

### *Coal price forecasts for new entrant power stations*

In addition to considering options for coal supply to all existing coal-fired power stations, it is also necessary to consider the coal supply options to potential new entrant power stations in those regions in which new entrant coal-fired power stations are a possibility. We have estimated capital costs, ongoing capital costs and cash costs for potential new mines in each region in which there are none coal reserves.

The new mine's cash costs are drawn from estimates for existing mines and adjusted to match the average stripping ratios for the relevant region. Labour costs relate to expected volumes, average productivity and the method of mining.

### *Coal price forecasts for the high case*

In addition to our Base Case forecasts for coal prices (as discussed above) we have also forecast coal prices for a high case. This case assumes that higher export coal prices are 10% higher than the current World Bank forecasts.

# Gas prices for power stations

In order to model outcomes in the electricity market, we need an estimate of the marginal cost of gas supplied to each existing gas-fired power station, and each potential new gas-fired power station.

This section provides an overview of the methodology that we have adopted for estimating the marginal cost of gas supplied to a power station, and sets out our forecasts of gas prices.

## Methodology

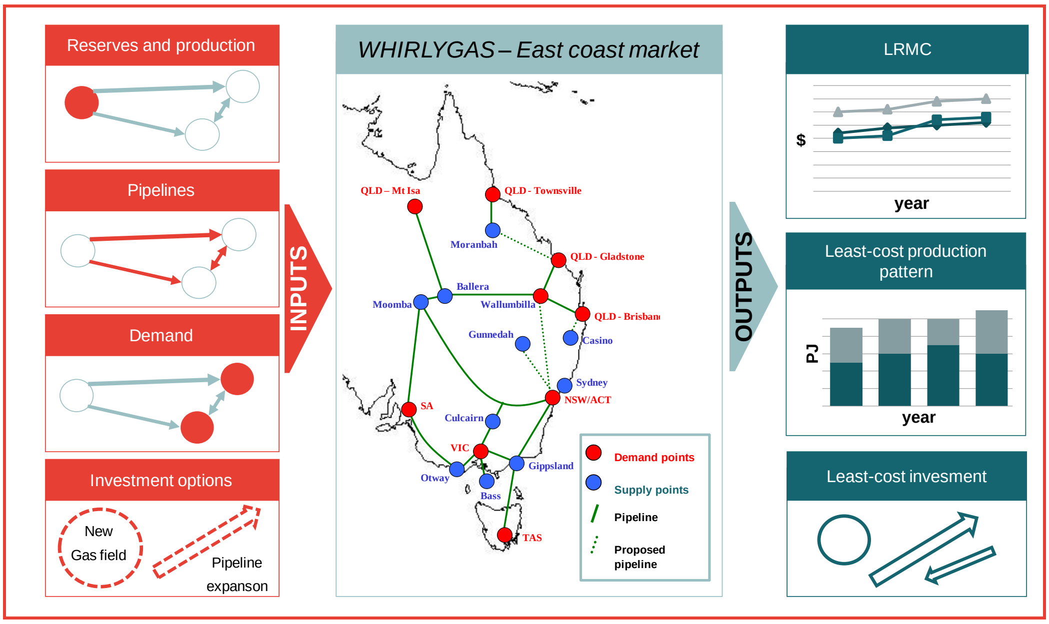
We estimate the cost of gas supplied to gas-fired power stations based on the marginal opportunity cost of gas.

When estimating the marginal opportunity cost of coal, we can do so on a region by region basis, because there is no substantial interconnection between coal supply regions. However, the same is not true of gas: gas regions in eastern Australia are now interconnected through a network of gas transmission pipelines, so that estimating the marginal opportunity cost of gas requires a model that can account for this interconnection. We use our gas market model – *WHIRLYGAS* – for this purpose.

### *Overview of WHIRLYGAS*

*WHIRLYGAS* is a mixed integer linear programming model used to optimise investment and production decisions in gas markets. The model calculates the least cost mix of existing and new infrastructure to meet gas demand. *WHIRLYGAS* also simultaneously optimises total production and transport costs in gas markets and estimates the LRMC of each demand region in the gas market. A visual summary of the model is provided in Figure 42.

Figure 42: *WHIRLYGAS* overview




*Source: Frontier Economics*

*WHIRLYGAS* is configured to represent the physical gas infrastructure in eastern Australia including all existing gas reserves, all existing production plant, all existing transmission pipelines and new plant and pipeline investment options. *WHIRLYGAS* is also provided with the relevant fixed and variable costs associated with each piece of physical infrastructure.

*WHIRLYGAS* seeks to minimise the total cost – both fixed and variable costs – of supplying forecast gas demand for eastern Australia's major demand regions. This optimisation is carried out subject to a number of constraints that reflect the physical structure and the market structure of the east coast gas market. These include constraints that ensure that the physical representation of the gas supply market is maintained in the model, constraints that ensure that supply must meet demand at all times (or a cost equal to the price cap for unserved gas demand is incurred), and constraints that ensure that the modelled plant and pipeline infrastructure must meet the specified reserve capacity margin.

*WHIRLYGAS* essentially chooses from an array of supply options over time, ensuring that the choice of these options is least-cost. In order to satisfy an increase in demand over the forecast period and avoid paying for unserved gas demand, *WHIRLYGAS* may invest in new plant and pipeline options. *WHIRLYGAS* may also shut-down existing gas fields and production plant where gas reserves become exhausted or where they become more expensive than new investment options.

After generating the least cost array of investment options, the model is able to forecast gas production rates and pipeline flow rates, and to provide an estimate of the LRMC of satisfying demand in each demand region in each forecast year. The gas production rates and pipeline flow rates are determined by the least-cost combination of plant and pipeline utilisation that satisfies forecast demand. The LRMC is determined by the levelised cost of the plant and pipelines utilised in meeting a marginal increase in demand at each major demand region. The LRMC is also determined with regard to the scarcity of gas since, for each forecast year, the model considers the trade-offs from consuming gas that is produced from finite gas reserves in that year, as opposed to consuming the gas in other forecast years and in other demand regions (including as LNG exports).

### Opportunity costs in WHIRLYGAS

As with our coal forecasting work, opportunity cost is important to our gas forecasting work. The reason that opportunity cost is relevant to assessing the cost to gas producers of supplying gas to gas-fired generators is because the producers may well be foregoing alternative markets for that gas. For instance, a gas producer that has access to the export market may well be foregoing the export price of gas (less any export-related costs). In this case, the netback price may be relevant to the opportunity cost of supplying coal to a coal-fired generator.

The **first step** in calculating the net-back price of gas is a forecast of the export price of LNG. It is this export price that determines the revenue that an LNG exporter will earn by exporting gas.

The export price that we have used to calculate the net-back price of gas is from quarterly forecasts released by the World Bank.[38] The World Bank provides forecasts of the Japanese LNG price out to 2025. These prices, which are in USD/mmbtu, are converted to AUD/GJ based on forecast nominal exchange rate discussed above. This results in the export prices shown in Figure 43.

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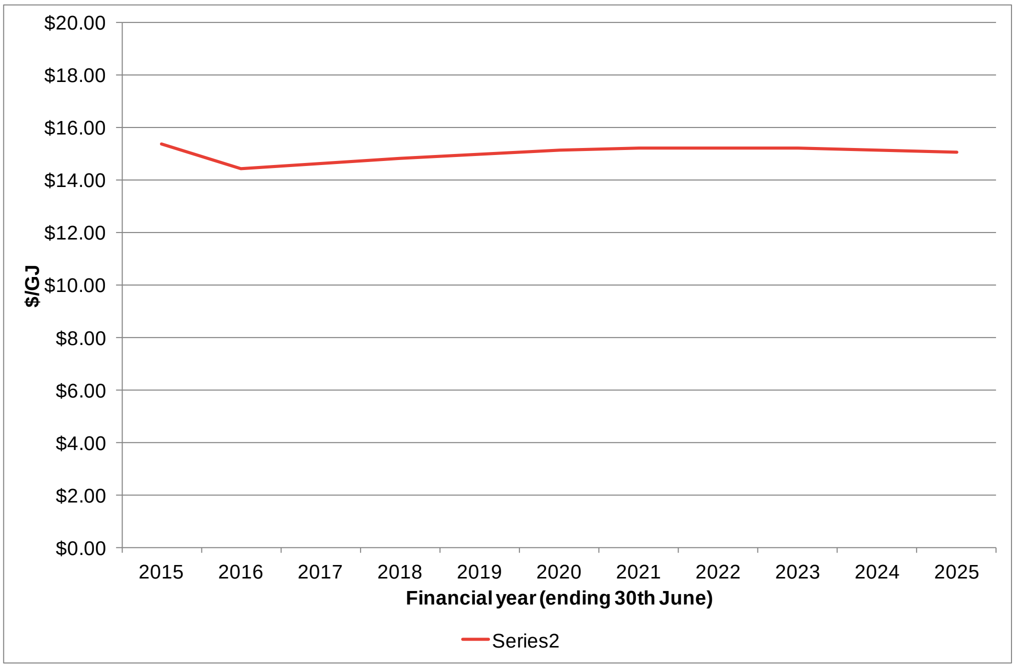
38 See: http://www.worldbank.org/content/dam/Worldbank/GEP/GEPcommodities/PriceForecast_20150422.pdf

Figure 43: Japan LNG prices ($2015/16)




*Source: World Bank, Commodity Price Forecast, April 2015.*

The **second step** for calculating the net-back price of gas is an estimate of the costs that an LNG exporter will avoid if it does not export LNG.

The avoided costs that need to be taken into account in calculating the net-back price of gas are:

- Shipping costs – estimates of the cost of shipping LNG from Gladstone to Japan are based on industry estimates.
- Liquefaction costs – estimates of the capital and operating costs associated with liquefaction of LNG are based on a Frontier Economics database of these costs.
- Pipeline costs – estimates of the capital and operating costs associated with transmission pipelines are based on the same Frontier Economics database of pipeline costs.
- The costs of managing exchange rate risk – these costs are based on industry estimates.

The **third step** in calculating the net-back price of gas is to adjust for the gas used in liquefaction. This use of gas in liquefaction means that there is a difference in the quantity of gas that can be supplied to the export market and the quantity of gas that can be supplied to the domestic market. Specifically, the use of gas in the liquefaction process means that exporting gas as LNG results in a reduction in saleable quantities relative to supplying gas to the domestic market.

The **final step** in calculating the net-back price of gas is to adjust for the effect of the discount rate on any revenues earned as a result of exporting LNG. If it is the case that the opportunity to export gas as LNG does not arise for several years (for instance because an LNG plant is still under construction, a new LNG plant would need to be constructed, or a relevant shortage of gas supplies to an existing LNG plant does not arise for a number of years) then the potential revenue from exporting this gas as LNG needs to be discounted to account for the time value of money. If gas can be supplied to the domestic market sooner, the effect of this discounting can have a material impact on the effective net-back price of gas.

This discounting is accounted for within *WHIRLYGAS*. As discussed, the model can test whether it is indeed the case that there is sufficient capacity in all required export-related infrastructure to export additional gas as LNG. Where it is the case that there is a scarcity of liquefaction capacity (as opposed to a shortage of gas reserves or gas production capacity) the opportunity cost for gas producers need not reflect the net-back price. However, where there is a relevant scarcity of gas reserves or gas production capacity to meet LNG exports, the timing of this scarcity is important for determining the effective net-back price of gas.

### Model inputs

The key modelling inputs for *WHIRLYGAS* under this approach are:

- Gas demand forecasts for each major gas demand region.
- Gas reserves in eastern Australia.
- The relevant costs and technical parameters of existing and new production plant in eastern Australia.
- The relevant costs and technical parameters of existing and new transmission pipelines in eastern Australia.
- The price of LNG in the Asia-Pacific region.

### Model outputs

The key modelling outputs for *WHIRLYGAS* under this approach are:

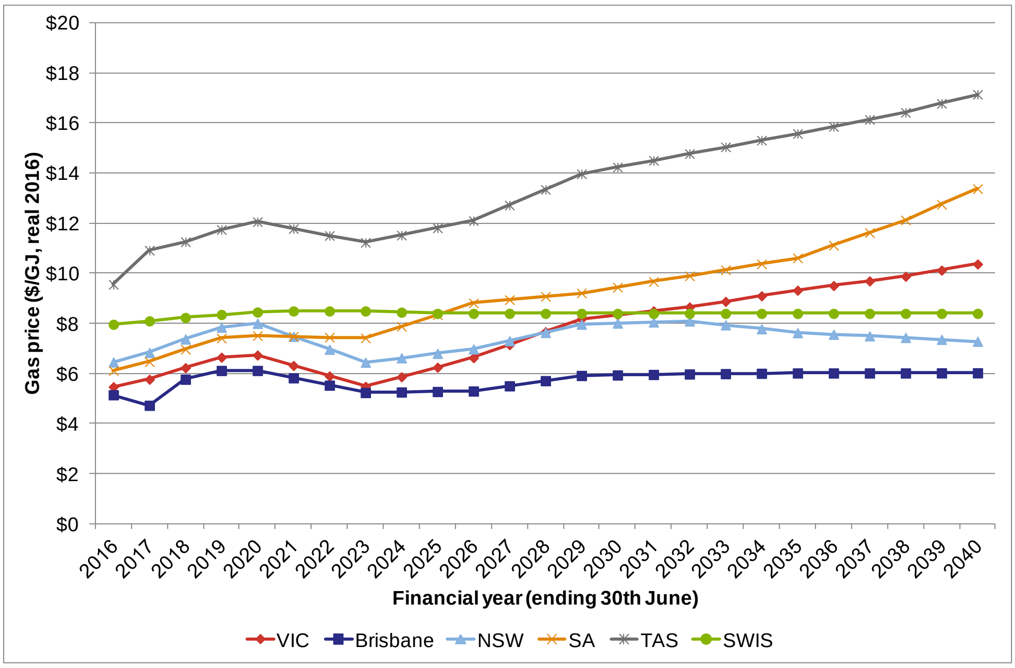
- Forecasts of the LRMC of satisfying demand in each demand region.
- Forecasts of investment in new production plant in eastern Australia.
- Forecasts of investment in new transmission pipelines in eastern Australia.
- Forecasts of production rates for existing and new production plant.

- Forecasts of flow rates for existing and new transmission pipelines.
- Forecasts of remaining gas field reserves in eastern Australia.

## Gas price forecasts

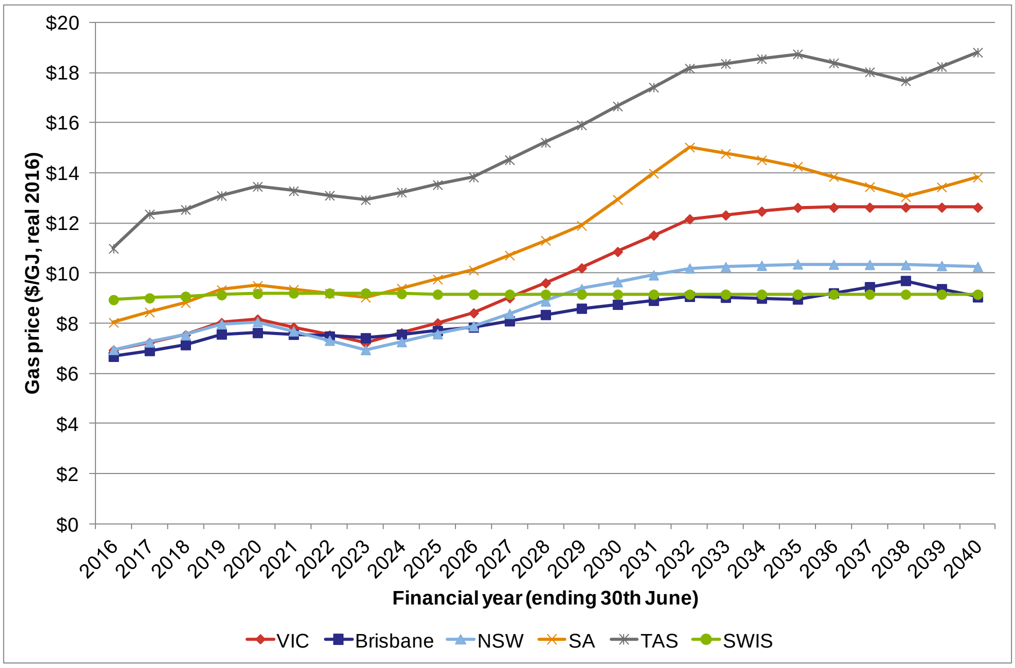
Gas prices are driven by demand for gas, international LNG prices, foreign exchange rates and underlying resource costs associated with gas extraction and transport. Frontier's Base Case and high case forecasts are shown in Figure 44 and Figure 45 for a selection of pricing zones across Australia. The Base Case incorporates the development of 6 LNG trains at Gladstone, the World Bank's most recent LNG price forecast and our central estimate of production costs for new gas projects in Australia. The high case incorporates the development of 7 LNG trains at Gladstone, an LNG price that is higher than the World Bank's most recent LNG price forecast and a high case for the production costs for new gas projects in Australia.

Figure 44: LRMC of gas by State capital cities ($2015/16) – Base Case




*Source: Frontier Economics*

Figure 45: LRMC of gas by State capital cities ($2015/16) –High case




*Source: Frontier Economics*

## Gas price forecasts for gas-fired power stations

The LRMC of gas set out above is used in our electricity market modelling as the cost of gas to CCGT plant, which tend to operate on a mid-merit basis at a reasonable capacity factor. OCGT plant, however, tend to operate as peakers at a much lower capacity factor. The cost of gas to OCGT plant is likely to be higher than the cost of gas to CCGT plant to the extent that OCGT plant consume gas when prices are higher than average. Our analysis suggests that, at the capacity factor that OCGT plant tend to operate at in the NEM, these plant are likely to face gas costs that are 50 per cent higher than the gas costs faced by CCGT plant in the same region. Based on this, the cost of gas OCGT plant that is used in our electricity market modelling is the LRMC of gas in each NTNDP Zone increased by 50 per cent.

## Gas price forecasts for the high case

In addition to our Base Case forecasts for gas prices (as discussed above) we have also forecast gas prices for a high case. This case assumes that the Asia-Pacific LNG price is 10% higher, and the development of 10 LNG exports trains at Gladstone (as opposed to 6 trains in the Base Case).

# Glossary

This section details the acronyms used in the 2015 Residential Electricity Price Trends Scoping Paper.

| | |
|---|---|
| AEMO | Australian Electricity Market Operator |
| ASX | Australian Securities Exchange |
| BREE | Bureau of Resources and Energy Economics (now the Office of the Chief Economist – Department of Industry) |
| CCGT | Combined cycle gas turbine |
| CCS | Carbon capture and storage |
| CER | Clean Energy Regulator |
| CLP | Consumer load profile |
| CLP CE | Consumer load profile (Country Energy) |
| CLP EA | Consumer load profile (Energy Australia) |
| CLP IE | Consumer load profile (Integral Energy) |
| COAG | Council of Australian Governments |
| EEIS | ACT Energy Efficiency Improvement Scheme |
| EFOR | Expected forced outage rate |
| EGS | Enhanced geothermal system |
| EOR | Expected outage rate |
| EPOR | Expected planned outage rate |
| EPRI | Electric Power Research Institute |
| ERA | Energy Resources of Australia |
| ESCOSA | Essential Services Commission of South Australia |
| ESS | NSW Energy Savings Scheme |
| FCAS | Frequency Control Ancillary Services |
| FOM | Fixed operating and maintenance costs |
| GJ | Gigajoule |
| GT | Generator terminal |
| GWh | Gigawatt hours |
| HCC | Hard coking coal |

| | |
|---|---|
| IGCC | Integrated gasification combined cycle |
| IMF | International Monetary Fund |
| IMO | Independent Market Operator of the SWIS |
| IPART | Independent Pricing and Regulatory Tribunal |
| LGC | Large-scale Generation Certificates |
| LNG | Liquid Natural Gas |
| LRET | Large-scale Renewable Energy Target |
| LRMC | Long run marginal cost |
| Mmbtu | Million British thermal units |
| MRIM | Victorian Manually Read Interval Meter |
| MW | Megawatt |
| MWh | Megawatt hour |
| NCAS | Network Control Ancillary Services |
| NEFR | National Electricity Forecast Report |
| NEM | National Electricity Market |
| NSLP | Net System Load Profile |
| NTNDP | National Transmission Network Development Plan |
| O&M | Operating and Maintenance |
| OCGT | Open Cycle Gas Turbine |
| OTTER | Office of the Tasmanian Economic Regulator |
| PV | Photovoltaic |
| REES | South Australian Residential Energy Efficiency Scheme |
| RET | Renewable Energy Target |
| RPP | Renewable Power Percentage |
| RRN | Regional Reference Node |
| SO | Sent-out |
| SRAS | System Restart Ancillary Services |
| SRES | Small-scale Renewable Energy Scheme |
| SRMC | Short run marginal cost |
| STC | Small-scale Technology Certificates |
| STP | Small-scale Technology Percentage |

| | |
|---|---|
| SWIS | South West Interconnected System |
| VEET | Victorian Energy Saver Initiative |
| VOM | Variable operating and maintenance |
| WACC | Weighted average cost of capital |
| WEM | Wholesale Energy Market |

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