2014 Residential Electricity Price Trends – Final Report

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

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1 Introduction

The AEMC is currently undertaking the 2014 Residential Electricity Price Trends report. This report is the fifth 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 2013/14 to 2016/17. These drivers and trends are also consolidated to provide a national summary.

1.1 Frontier Economics' engagement

Frontier Economics has been retained 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 South West Interconnected System (SWIS). The specific cost components for which we are to provide cost forecasts are:

- wholesale electricity costs, on both stand-alone Long Run Marginal Cost (LRMC) and market based and under any jurisdictional approaches for which determinations have not made over the modelling period
- network losses
- Market fees for both NEM and SWIS
- the cost impact of any relevant jurisdictional environmental policies or programmes (or other relevant policies or programmes)
- 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 2013/14 to 2016/17. We have been asked to investigate a number of scenarios to reflect current policy uncertainties about the timing of the repeal of carbon price and other key input assumptions. These scenarios are set out in details in Section 3.7.

1.2 About this report

This report is structured as follows:

- Section 2 presents the approach to determine wholesale energy costs for residential customers.

- Section 3 details the assumptions used in the analysis and 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 assumption estimates.

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.

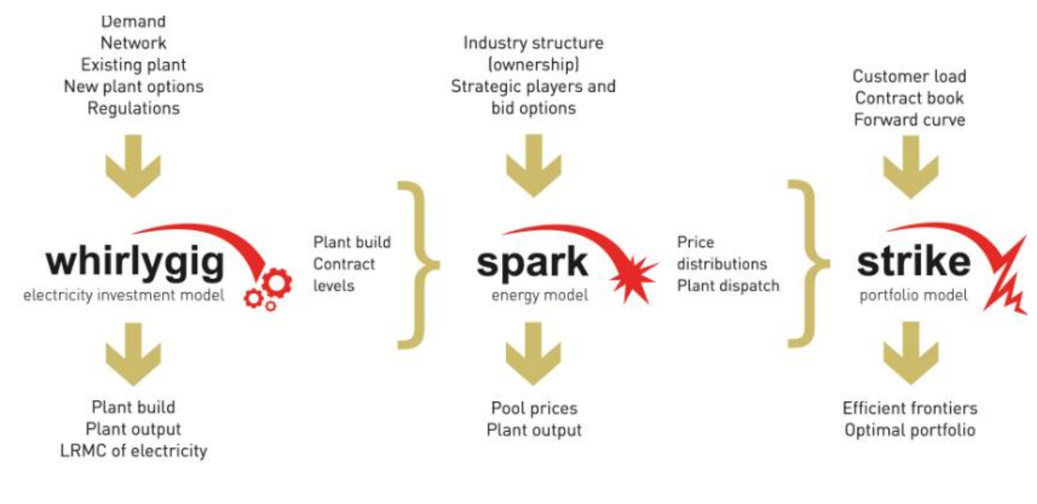
2.1 Frontier Economics' modelling framework

The various approaches to modelling the NEM/SWIS and estimating wholesale energy costs are implemented using our three electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*. The key features of these models are as follows:

- *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 behaviour strategy for generators in the electricity market using game theoretic techniques. This is a very important difference between Frontier's approach and other analysts. 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 at which no generator has any incentive to deviate from because they will get pushed back to this point by competitor responses.
- *STRIKE* is a model that 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 of meeting a new load having to the portfolio effects of a standard retailer and other energy assets (e.g. existing customer base, hedges, power stations, gas contracts, etc). *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 models, and their inter-relationships, are illustrated in Figure 1.

Figure 1: Model inputs and outputs



2.1.1 Forecasting plant 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. In NSW, annual energy has reduced by approximately 12% 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 network increases)

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 plant have been removed from the market temporarily (often referred to as mothballing or standby outages) such as Northern, Tarong, Swanbank E, Wallerwang unit 8 and other units to some extent. In other cases, older plant have been retired such as the Munmorah coal-fired power station, Swanbank B, Collinsville, Playford and most recently Wallerawang unit 7.

Over the forecast period of this study, demand is not expected to return to long term average growth rates. Also, to the extent that the RET 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 likely that further retirements may occur over the modelling period.

In fact, these retirements play a role in determining what impact the RET will have on generators and, ultimately, retail tariffs. Other things being equal, retirements will act to reduce supply in the market, offsetting to some extent the additional renewable supply brought on by the RET and influencing the net effect of the RET on retail tariffs. This means that forecasting retirements is an important part of analysing the impact of the RET on retail tariffs.

Difficulty in modelling retirements

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

- Relatively certain short term losses versus less certain long term profits.
- Decommissioning and site remediation costs.
- 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 outcomes relates to the decision to retire representing 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, then 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 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. This appears to be occurring to some extent in the NEM at present.

Modelling approach

Capturing all the factors that influence participant decisions to retire plant is beyond the scope of this study. However, as discussed, it is important to identify any further retirements that may occur. In order to determine a set of possible retirements across the NEM we have used *WHIRLYGIG*.

WHIRLYGIG uses a least cost optimisation framework to determine the cost minimising pattern of investment and dispatch across the NEM and SWIS subject to supply meeting demand, reliability constraints and greenhouse policy (such as the RET) under the assumption of a perfectly competitive market.

The cost minimising solution is the one that minimises the net present value of the variable costs of existing generators (whose fixed costs are sunk) and the fixed and variable costs of potential new entrants. This framework can be extended by allowing *WHIRLYGIG* to retire existing plant to avoid fixed operating and maintenance (FOM) costs for existing plant (which are annual costs that could be partially or completely avoided if the plant was mothballed or retired). This is consistent with the framework used to determine the pattern of new investment in *WHIRLYGIG*.

This approach involves a number of key assumptions:

- Retirements are a one-off process. That is, retirements can occur unit by unit at a station but units cannot be brought back to market. The focus is on forecasting permanent retirements, not temporary mothballing of plant.
- The decision to retire a unit reflects outcomes across the entire generation fleet and modelling period, retirements occur to reduce the net present value of total system costs. This is distinct from a time sequential treatment where plant are retired from a given year once some threshold has been breached. In considering the entire modelling period, *WHIRLYGIG* has perfect foresight with respect to model inputs (such as demand, fuel prices, carbon prices, the RET, etc). This approach goes some way to capturing the inter-related nature of incentives for individual participants to retire units.
- Plant are retired on the basis of system cost-minimisation, not on unit profitability requirements.
- We do not consider decommissioning costs or plant scrap value in the decision to retire. In practice, it is uncertain when these costs will be incurred. For example, the Munmorah coal-fired power station, Playford and Wallerwang unit 7 power sites have not yet been remediated.

The benefits of this approach are that we determine a schedule of possible retirements using a systematic and repeatable approach consistent with the framework used to determine investment in *WHIRLYGIG*. The approach does have some limitations, primarily related to the assumption of a perfectively competitive market (which is relaxed in *SPARK*) and issues related to perfect foresight.

In conducting this analysis, initial modelling indicated that some recently constructed, baseload gas assets would be candidates for retirement in the near future. This outcome is consistent with the assumed inputs of low demand growth, rising gas prices and the permanent removal of the carbon price. Given these assumptions, the model is identifying these plant as stranded assets.

In practice, given that these plant are less than five years old and provide a hedge against future regulatory uncertainty around carbon pricing, it was decided to exclude these plant as possible retirements. It was assumed that only coal-fired plant older than 20 years would be able to be retired in the modelling.

2.2 Methodologies commonly used for forecasting wholesale energy costs

Regulators use a number of different approaches to estimating wholesale energy costs. Wholesale energy costs are estimated under the following approaches:

- a stand-alone LRMC approach
- a market-based approach
- the relevant jurisdictional approaches.

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

2.2.1 Stand-alone LRMC of energy

There are a number of different LRMC methodologies that can be applied to estimate retail electricity prices. The stand-alone LRMC approach is one that has been used frequently in the Australian context and it is this approach that has been used to develop cost-based estimates of wholesale costs.

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 the NEM (accounting for the financial hedging contracts that are typically used by retailers to manage risk in the NEM) 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 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 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

The stand-alone LRMC is modelled 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 issue and, in the case of the NEM, the diversity of peak demand between different regions of the NEM. Such numbers cannot easily be compared to a 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 time of peak.

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. 15 per cent has be chosen as it reflects a trade off between prudence and efficiency. Frontier have historically used 15 per cent in our work for the AEMC, IPART, ESCOSA, the ERA and 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 price (typically tied to forecast spot prices) or publicly available spot prices (such as those on ASX Energy).

In the second step, 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 the all years of the modelling. Our approach is to assume that financial hedges trade at a 5% premium to our *SPARK* forecasts of spot prices.

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

In practice, there is no single percentage or absolute contract premium value that applies exactly to 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. 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
- retailer risk preferences
- retailer's risk policies and hedging limits
- the range of alternative trading strategies used by participants, and
- uncertainty around market externalities such as demand, wind output and generation and transmission outages.

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

Implementation

This approach is implemented by using *WHIRLYGIG* to forecast investment outcomes and then modelling market price outcomes using *SPARK*. *STRIKE* is then configured to use these input spot prices forecasted using *SPARK* and assumes that financials hedges – swap and cap products – are available at a premium to forecast prices. *STRIKE* is then used to determine optimal conservative hedging outcomes for residential load shapes.

The correlation between residential load shapes and wholesale 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) and Controlled Load Profile (CLP) 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 forecasted using *SPARK* (based on system demand shapes) are accurately correlated to the residential load shapes[1] used in *STRIKE* such that risks are properly captured in the modelling.

Tasmania has no liquid contract market (due primarily to market structure in the state), neither does Western Australia (due to its alternative market design). In these jurisdictions the market-based approach is less relevant.

2.3 Jurisdictional approaches

Jurisdictional regulators use a variety of different approaches to estimating the wholesale energy cost of supplying a regulated customer. Ultimately, however, most regulators adopt either a cost based (usually stand-alone LRMC) approach, or a market based approach, or a combination of both.

Frontier has been asked to replicate these jurisdictional approaches where current determinations do not extend to 2016/17. In light of decisions to deregulate retail electricity prices in NSW and Queensland, this is only relevant in the case of Tasmania. Western Australia and the ACT have determinations/estimates on foot to 2016/17 and other regions are already deregulated.

Queensland

The Queensland Competition Authority (QCA) determines the wholesale energy cost of supplying a regulated customer using a market-based approach. The QCA had previously (under the Benchmark Retail Cost Index) based the wholesale energy cost on an average of LRMC and a market-based approach. However, under its new methodology, the wholesale energy cost is based entirely on a

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

market-based approach that is broadly consistent with Frontier Economics' approach. The QCA separates the impact of carbon on wholesale prices as part of its determination.

Queensland is on track to deregulate electricity prices in the South East of the state (the Energex distribution zone) as of 1 July 2015. This means that the current jurisdictional approach is only likely to apply for the 2014/15 year, for which there is a final determination[2].

For 2015/16 and 2016/17 we escalated the QCA's 2014/15 jurisdictional wholesale energy cost in line with the trend from Frontier Economics' market based energy purchase cost modelling for Energex.

New South Wales

The Independent Pricing and Regulatory Tribunal (IPART) determines the wholesale energy cost of supplying a regulated customer in NSW. IPART's Terms of Reference required IPART to base tariffs on an average of results from an cost-based approach and a market-based approach (with the LRMC given a 75 per cent weighting and the market-based approach given a 25 per cent weighting). IPART chooses to use a stand-alone LRMC as its cost-based approach. IPART's also allows for an additional allowance for Customer Acquisition and Retention Costs (CARC) over and above the cost- and market-based estimates.

From 1 July 2014 the NSW Government has decided to deregulate electricity prices. Customers currently on a regulated tariff will be automatically placed on to a transitional tariff from this date. The transitional tariff is set at a 1.5% (nominal) reduction on the 2013/14 regulated rate and a increase of CPI or less in 2015/16. Customers who have already switched off the regulated tariff will not have access to this transitional tariff. It is assumed that in the event that the carbon tax is repealed, that this would be reflected in the transitional tariff over and above the 1.5% discount, as would any changes in network costs.

Whilst IPART determined regulated tariff rates for 2014/15 and 2015/16 as part of its 2013 Determination, these will not be used in light of the decision to deregulate. For 2014/15 and onwards, we escalated IPART's 2013/14 wholesale energy cost for each distribution area by the relevant trend from Frontier Economics' market based energy purchase cost modelling.

Australian Capital Territory

The Independent Competition and Regulatory Commission (ICRC) has developed its own model to determine market-based energy costs. The wholesale

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2 See http://www.qca.org.au/Media-Centre/News-and-Events/News/2014/May/Regulated-Retail-Electricity-Prices-2014-15

energy cost is based on the results of this model, without regard to LRMC. The ICRC's current draft determination[3] estimates regulated prices out to 2016/17.

Tasmania

The Office of the Tasmanian Economic Regulator (OTTER) previously determined the wholesale energy cost of supplying a regulated customer as the higher of the cost of importing electricity from Victoria and the LRMC of electricity to supply regulated customers.

The Tasmanian Government has implemented retail contestability as of 1 January 2014. The decision to introduce contestability has been accompanied by the implementation of a mechanism whereby Hydro Tasmania provides hedges to Aurora at an efficient price. This has lead to OTTER altering the approach used in the past[4], Ernst & Young have produced a building block model[5] where the wholesale energy cost component is sourced from the Tasmanian Government and Aurora as an input as opposed to being determined by OTTER or its advisors. The current determination covers the period to 2015/16.

The approach adopted in OTTER's determination and Aurora's pricing proposal is based on OTTER's Notional Maximum Revenue (NMR) cap and associated tariffs. This approach sets tariffs to recover required revenue on average across all customers, as opposed to directly recovering costs for a given customer. OTTER has published Aurora's approved retail pricing proposal for 2013/14[6] and 2014/15[7], which supersedes OTTER's original determination[8]. We have

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3 See http://www.icrc.act.gov.au/energy/electricity/#price-direction-for-the-supply-of-electricity-to-small-customers-in-the-act-from-1-july-2014

4 See http://www.energyregulator.tas.gov.au/domino/otter.nsf/8f46477f11c891c7ca256c4b001b41f2/1d8b676f4eea9102ca257b8d001948ba?OpenDocument

5 See http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/132014_Ernst_and_Young_revised_Retail_Price_Submission_18_June_2013.PDF/$file/132014_Ernst_and_Young_revised_Retail_Price_Submission_18_June_2013.PDF

6 See http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/132717%20Retail%20Pricing%20Proposal%20for%20Period%201%20of%20the%202013%20Interim%20Price-Regulated%20Retail%20Service%20Price%20Determination.PDF/$file/132717%20Retail%20Pricing%20Proposal%20for%20Period%201%20of%20the%202013%20Interim%20Price-Regulated%20Retail%20Service%20Price%20Determination.PDF and http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/134475_20131217_Aurora_Energy_Retail_Pricing_Proposal_2013_Standing_Offer_Determination_from%201_January_2014_to_30_June_2014.PDF/$file/134475_20131217_Aurora_Energy_Retail_Pricing_Proposal_2013_Standing_Offer_Determination_from%201_January_2014_to_30_June_2014.PDF

7 See http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/14-1742_Email_from_Aurora_enclosing_revised_2014-15_pricing_proposal_140619.pdf/$file/14-1742_Email_from_Aurora_enclosing_revised_2014-15_pricing_proposal_140619.pdf

escalated the 2014/15 wholesale energy cost by the Victorian average trend[9] from Frontier's market based energy purchase cost modelling.

Western Australia

The Economic Regulation Authority (ERA) does not determine electricity tariffs in Western Australia, but does make recommendations to the Government as to the appropriate level of tariffs. The Government then sets tariffs. In its most recent review, the ERA modelled the actual energy costs faced by Synergy, based on a detailed review of Synergy's contract book and load shape.

In the absence of further information, we have not been able to replicate the jurisdictional approach for Western Australia. Only stand-alone LRMC estimates of wholesale energy costs are presented.

2.4 Approach to carbon pass through

Frontier Economics' modelling framework uses the same approach to model the impact of the carbon pricing for both the stand-alone LRMC and market-based modelling.

2.4.1 Pass through defined

Carbon pass through is a measure of the extent to which a given carbon price (in \$/tCO2e), as an input cost to generating electricity, is reflected in output prices (in \$/MWh). The pass through rate is expressed in tCO2e/MWh and is given by:

$$PT = \frac{price_{with\ carbon} - price_{without\ carbon}}{carbon\ price}$$

This formula can be applied in a number of ways, key degrees of freedom are:

- Which prices? Pass through can be measured against wholesale pool prices, contract prices, wholesale energy costs for specific customer classes (e.g. residential), retail prices, etc.
- What time period? Over a day, week, year?

The two most relevant measures of carbon pass through for Australia's electricity markets and the analysis presented in this report are:

- **Annual pass through into pool prices:** This is the most commonly reported pass through rate and reflects the increase in wholesale pool

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8 See http://www.energyregulator.tas.gov.au/domino/otter.nsf/LookupFiles/134360_134037_2013_Standing_Offer_Determination_Aurora_Energy_6_December_2013.PDF/$file/134360_134037_2013_Standing_Offer_Determination_Aurora_Energy_6_December_2013.PDF

9 Weighted by the customer numbers in each jurisdiction.

prices over a year. In the NEM, as a common clearing price market, this level of pass through will reflect the emissions intensity of marginal price setting generators across the year with and without carbon. In practice, this cannot be measured definitively. Many analyses, for example AEMO[10] and our own[11], have compared pool price outcomes from periods with carbon pricing to periods without carbon pricing as an imperfect measure of the level of pass through. Modelling can also be used to determine a pool price pass through estimate by comparing scenarios with and without a carbon price (as is done in this report). Pass through into pool prices is driven by the underlying cost structure of the market in question (i.e. supply side dynamics) and also reflects the load shape of system demand (i.e. demand side dynamics) as both factors act to drive marginal prices. In the NEM, pool price carbon pass through has been estimated to be around 1.00-1.20 tCO2e/MWh although estimates vary by region (as discussed below).

- **Annual pass through in wholesale energy costs:** Wholesale energy costs (WEC) are an estimate of the costs of sourcing energy for a specific customer load shape. These costs account for underlying pool prices and *additionally* account for differences in the load shape of the given customer class relative to system load. In the case of residential customers, which are peakier than system load, this represents an increase in cost. Wholesale energy costs may also reflect hedging costs, another increase. As pass through is measured as a difference in prices over the static carbon price as a denominator, this means that if the difference in wholesale energy costs is greater than the difference in pool prices for a given carbon price then WEC pass through will be higher than pool price pass through. In our market based modelling we have consistently estimated WEC pass through rates[12] higher than pool price pass through rates at around 1.2-1.45 tCO2e/MWh. The rate of carbon pass through into wholesale energy costs ultimately drives increases in retail prices.

2.4.2 Pass through by jurisdiction

Levels of pass through vary by jurisdiction due to different underlying supply structures and different system and customer load shapes. In the NEM, things are further complicated by the multi-regional structure of the market as this

10 See http://www.aemo.com.au/Electricity/Planning/~/media/Files/Other/planning/NEM_Historical_Information_Report_2012_13.ashx

11 See http://www.frontier-economics.com.au/documents/2014/06/carbon-pricing-in-the-nem-day-one.pdf

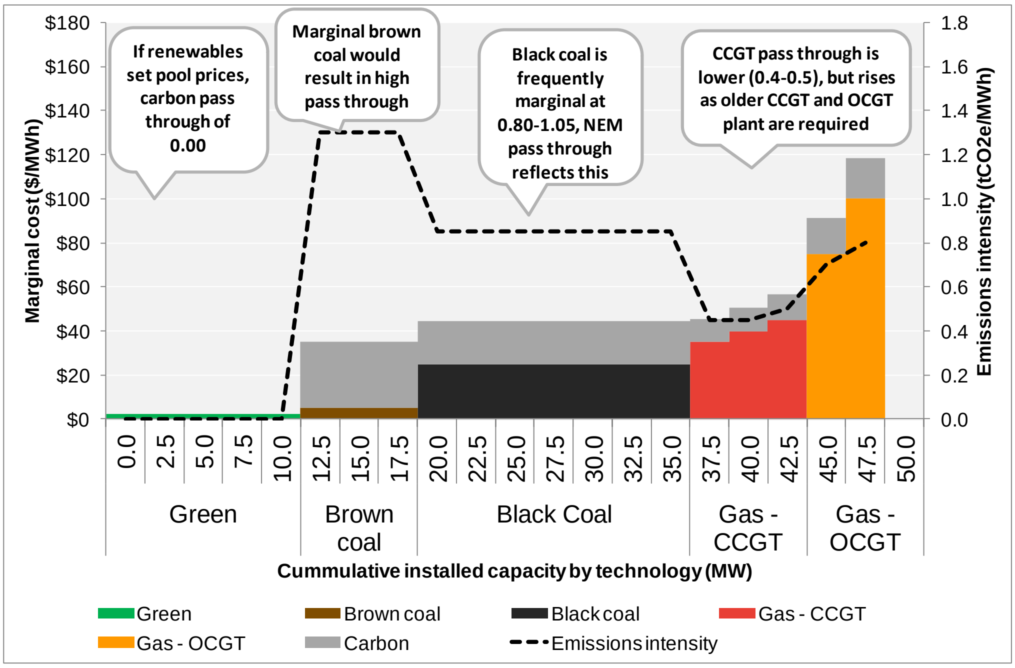
12 See http://www.aemc.gov.au/getattachment/20d9f0b8-f2bc-4165-91a6-d088dc3b8612/Frontier-Economics-Possible-future-retail-electric.aspx, section 6.3, p 56.

means carbon pass through is a given region is influenced by price settings outcomes across the NEM.

In the case of the NEM, the overall market supply curve drives pass through rates. This is illustrated in Figure 2, which shows an idealised supply curve for NEM by technology type with carbon cost broken out (the stacked areas) and emissions intensity (the line).

Over the course of a typical year, prices in the NEM are mostly set by black coal and gas fired generators, this leads to pool price pass through rates around 1.00 tCO2e/MWh. Renewable and brown coal generators, as the lowest cost supply in the NEM, are rarely marginal and have less impact on carbon pass through rates.

Figure 2: NEM idealised supply curve and emissions intensity

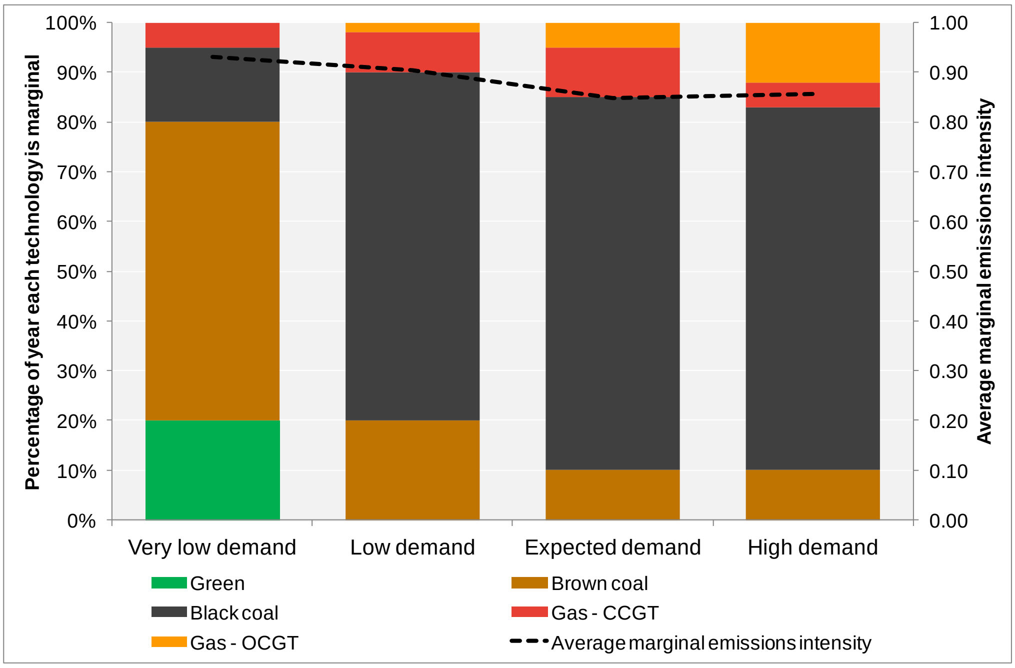


Source: Frontier Economics

To the extent that demand in the NEM varied significantly from expected levels then different pool price pass through outcomes may be expected. In practice, annual pass through outcomes will reflect many factors over the course of a year and vary by region. However, outcomes will be riven by which plant are mrginal over the course of a year. This is illustrated in Figure 3, which shows a range of illustrative demand levels, the associated proportion of the year each technology type is marginal and the average marginal emissions intensity that occurs across the year.

If black coal and gas-fired CCGT are marginal across the year this can lead to pool price pass through rates around 1.00 tCO2e/MWh. To the extent that demand rises, and gas-fired OCGT becomes marginal more often, this may raise pass through rates. Similarly if demand falls significantly, such that brown coal was marginal more frequently, then this may also raise pass through rates.

Figure 3: Example of NEM average marginal emission intensity for varying underlying demand levels



Source: Frontier Economics

Pool price pass through differs by jurisdiction:

- **Queensland, NSW and the ACT:** dominated by black coal and gas-fired supply which are set prices and pool price pass through across the NEM
- **Victoria:** dominated by brown coal which is rarely marginal, pass through is driven by marginal gas (both in state and via imports) and imported prices that reflect marginal NSW and Queensland coal
- **South Australia:** has much more gas and wind supply, pool price pass through may be lower than other regions (depending on imports and transmission constraints)
- **Tasmania:** dominated by hydro supply, pool price pass through is driven by Basslink imports and Hydro Tasmania bidding
- **SWIS:** has a higher proportion of gas supply compared to the NEM regions, the closest analogy is South Australia, and a different market structure which leads to lower pool price pass through

2.4.3 Pass through in the modelling

In both *WHIRLYGIG* and *SPARK*, each generator’s variable costs are assumed to increase due to the policy by the product of the assumed carbon price and the generators emissions intensity. This ensures that carbon costs are reflected in all generator's short run marginal costs and are reflected in the prices forecast by the models. Estimating carbon pass through is achieved by comparison to a counterfactual case where the carbon price is assumed to be zero for both pool price and WEC pass through.

Sources for carbon price assumptions are discussed in section 3.2 and sources for operating parameters, including emission intensity rates, are discussed in section 3.4.

Carbon outcomes in the modelling differ under the stand-alone LRMC and market-based modelling. Under the stand-alone approach, the generation mix can respond to the carbon price signal immediately. This can result in a mix of generation that is dominated by gas, resulting in lower carbon intensities of generation of around 0.4-0.5 t/MWh (consistent with the emission rate of CCGT and OCGT gas-fired generators). Carbon outcomes are driven by the relative economics of different generating technologies with and without the carbon price.

Under the market-based approach, where the existing fleet of generation is included in the models, and system load in the NEM and SWIS are modelled explicitly, emissions intensities are typically higher than under the stand-alone approach reflecting the greater presence of coal in the generation mix. As discussed above, in the NEM pool price pass through outcomes are closer to 1.00 t/MWh consistent with black coal and gas-fired plant frequently setting marginal prices. Pool price pass through is lower in the SWIS reflecting a greater presence of gas in that market. Carbon outcomes are influenced by assumptions around fuel input costs, carbon prices and assumed demand levels as these impact on which plant set marginal prices across the year.

2.5 Estimates of cost under the RET

In addition to advising on wholesale energy costs for the period 2013/14 to 2016/17, 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 in terms of:

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

The Commonwealth Government is currently undertaking a RET Review that may announce changes to the RET during 2014. The remainder of this section refers to current legislation, which has formed the basis of our modelling. We have also modelled some alternative RET policy scenarios due to the current uncertainty about changes to the RET. The results of these alternative RET modelling scenarios are set out in a separate report[13] which has been circulated with this report. The results from these alternative RET scenarios may be used if the Commonwealth Government announces changes to the RET prior to the completion of the AEMC's 2014 Residential Electricity Price Trends Report.

2.5.1 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 less than 100 kW of capacity 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 and is used by liable entities to determine how many LGCs they need to surrender to discharge their liability each year.

The RPP is set to achieve the renewable energy targets specified in the legislation. The CER is responsible for setting the RPP for each year. The RPP for 2014 has been set at 9.87 per cent.

13 Frontier Economics, *RET Review Analysis – Final Report*, June 2014

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 consistent with demand forecasts used in the analysis[14].

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 cost of LGCs is estimated on the basis of 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, including the impact that a price on carbon will have on the incremental cost of creating an LGC.

2.5.2 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

[14] See section 3.1.1.

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 in order to remove 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 all partial exemptions expected to be claimed for the year

The STP is to be published for each compliance year by March 31 of that year. The CER must also publish a non-binding estimate of the STP for the two subsequent compliance years by 31 March. STPs have been published by the CER for 2014, 2015 and 2016. We have assumed that the STP for 2017 remains at the same level as the STP for 2016. These values have then been averaged to arrive at the financial year STPs set out in Table 1.

Table 1: Small-scale Technology Percentages

Year	STP (% of liable acquisitions)
2013/14	15.09%
2014/15	10.29%
2015/16	10.21%
2016/17	10.32%

Source: CER.

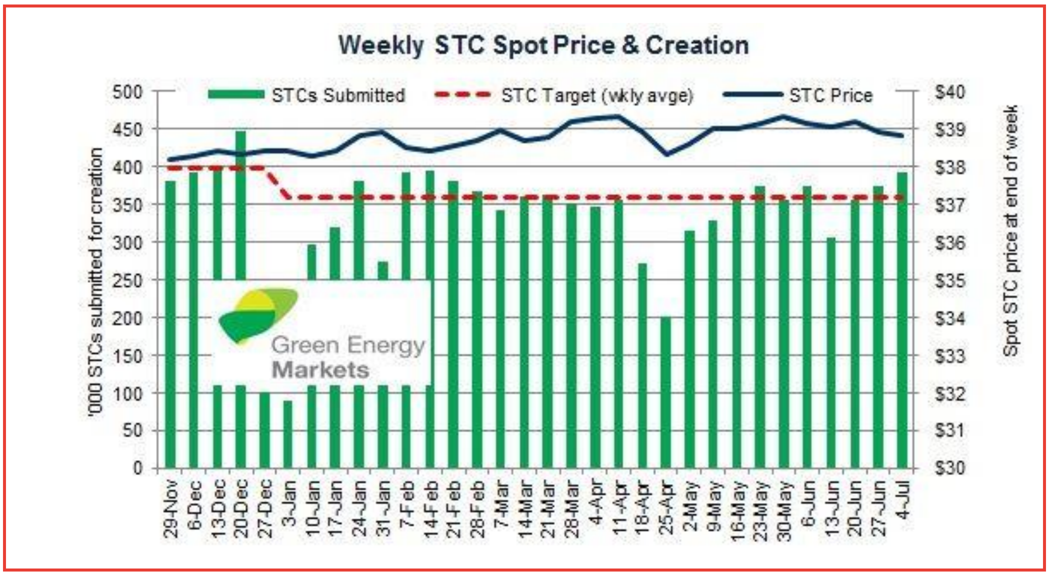
Cost of STCs

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 reason, in estimating the cost to retailers of the SRES, Frontier Economics will adopt an STC cost 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)

2.6 Energy efficiency schemes

In addition to advising on wholesale energy costs for the period 2013/14 to 2016/17, this assignment also requires us to estimate a range of other energy-related costs. 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)[15]
- the South Australian Residential Energy Efficiency Scheme (REES)
- the ACT Energy Efficiency Improvement Scheme (EEIS)[16]

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, we propose to use jurisdictional data on the cost of the schemes. Where jurisdictional data has not been provided, costs will be estimated with reference to retailer obligations and penalty prices under the scheme. We believe this will be sufficient to determine trends in the costs of these schemes.

2.7 NEM fees and ancillary services costs

In addition to advising on wholesale energy costs for the period 2013/14 to 2016/17, this assignment also requires us to estimate a range of other energy-related costs. This section considers the market fees and ancillary services costs.

2.7.1 Market fees

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

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.

15 The Victorian Government has announced the end of the VEET scheme from the end of 2015 (http://www.energyandresources.vic.gov.au/energy/about/legislation-and-regulation/energy-saver-incentive-scheme-management/esi-review).

16 The EEIS runs to the end of 2015 (http://www.environment.act.gov.au/energy/energy_efficiency_improvement_scheme_eeis).

Estimating market operator fees

To estimate future market fees for NEM regions, we have examined AEMO's budgeted revenue requirements. AEMO has published its budget requirements and the resulting market fees and we propose to 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.

2.7.2 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, and
- 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 have investigated the past 10 years of ancillary service cost data published by AEMO for each region of the NEM. AEMO publishes ancillary services costs on a weekly basis. We convert these weekly costs, which are reported on a nominal basis, into real 2013/14 dollars. We then calculate an annual average ancillary services cost for each year and each region. We take a simple average of historical annual average ancillary services costs in each region, and have assumed that ancillary services costs over the forecast period will be equal to that simple average.

We have based estimates of future costs of ancillary services costs for the SWIS on the IMO's ancillary services report[17]. Estimates are held constant in real terms.

2.8 Losses

Losses are based on information on transmission and distribution losses published by the relevant market operators - AEMO[18] and the IMO[19].

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

18 See http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/List-of-Regional-Boundaries-and-Marginal-Loss-Factors-for-the-2013-2014-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-2013_2014-Financial-Year for distribution loss factors.

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

3 Modelling assumptions

This section provides an overview of the input assumptions that we will 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
- Carbon costs
- RET assumptions
- Fuel costs
- Capital costs

Each of these key assumptions are 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 system and residential load profiles shapes are correctly correlated with each other 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 2012/13.

3.1.1 System load

The system load shapes are based on historical data form 2012/13. This profile shape has been scaled to forecast energy and peak taken from:

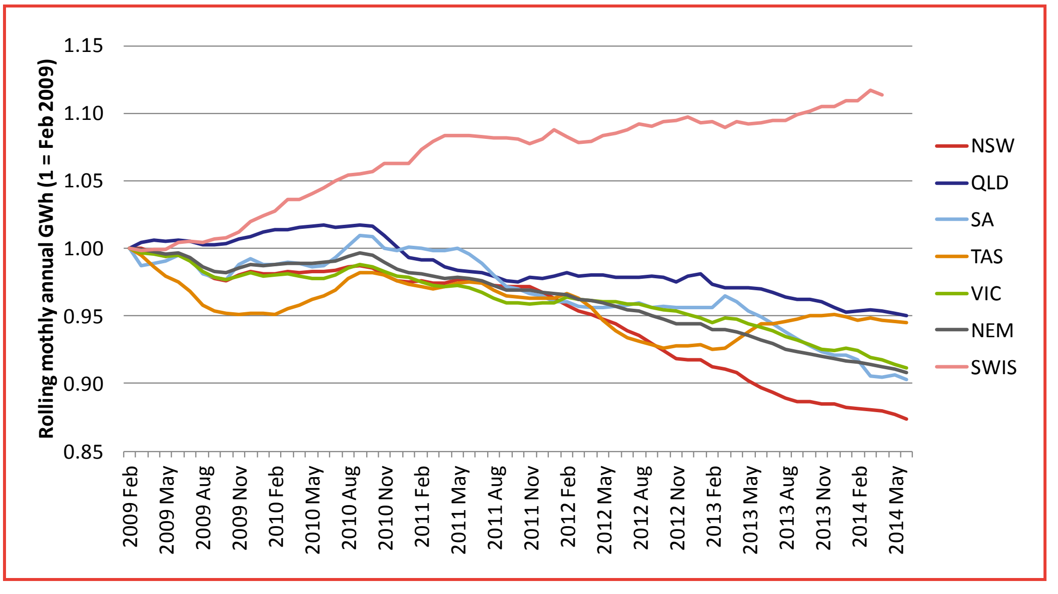
- For the NEM, AEMO's 2014 National Electricity Forecast Report (NEFR)[20]. The Medium and Low scenarios have been used.

[20] http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013

- For the SWIS, the IMO's demand forecasts from the 2013 ESOO[21], Low scenario. This forecast is not scheduled to be updated until 2015.

Actual outcomes indicate little evidence of demand growth over 2013/14, with the exception of the SWIS, whose demand is primarily driven by large scale mining projects, relatively higher population growth rates and associated multiplier effect on the rest of the economy. This is shown in Figure 5, which shows Frontier's rolling annual demand index values since the approximate NEM market peak in 2008.

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

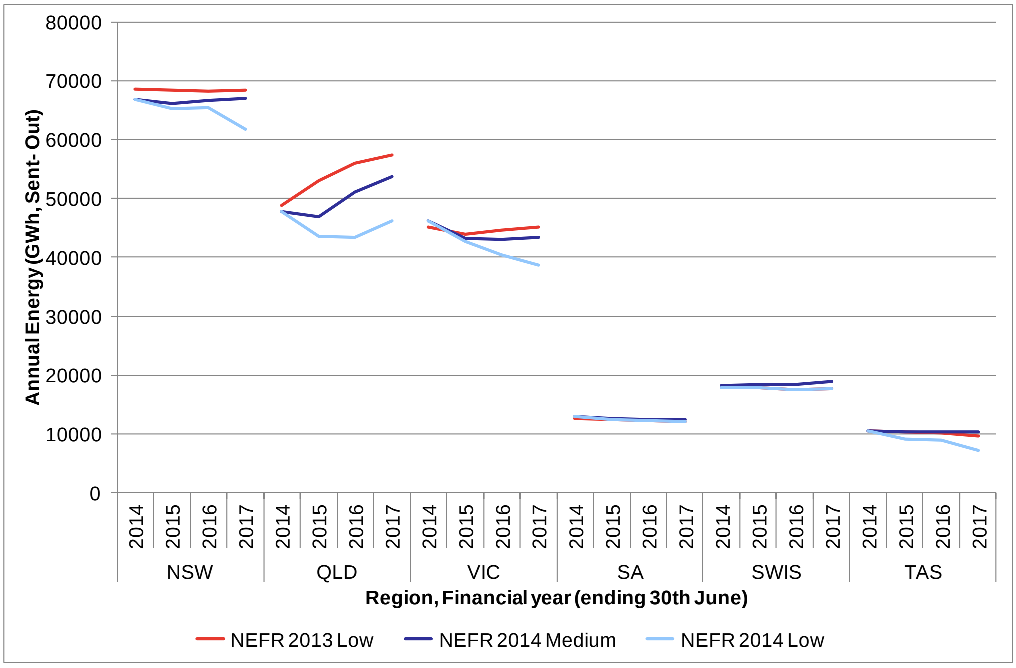


Source: Frontier Economics

Energy forecasts for these cases are shown in Figure 6 below.

21 http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-(esoo)

Figure 6: Demand forecasts (AEMO and IMO forecast energy, GWh Sent Out)



Source: AEMO and IMO

In the major jurisdictions – NSW, Queensland and Victoria – AEMO's 2014 Medium forecast is lower than the 2013 Low forecast for most years. AEMO's 2014 Low forecast is then significantly lower again, particularly in Queensland and Victoria in the longer term.

This is due to a number of factors:

- lower forecast per capita residential consumptions
- higher forecast rates of energy efficiency and rooftop PV uptake
- assuming major industrial closures in the Low scenario

These updated AEMO forecasts impact on the market-based energy purchase costs over the modelling period and the estimates of costs associated with the LRET.

Lower system demand, other things being equal, results in lower forecast pool prices which in turn drives lower market-based energy purchase costs. This is partially offset by higher LRET costs. As pool prices are lower, LGC prices need to rise to ensure incremental renewable projects can recover their costs. In this way lower system demand forecasts drive higher LGC cost estimates.

3.1.2 Residential load shapes

The residential load shapes are obtained by using both the half-hourly Net system Load Profile (NSLP) and Controlled Load Profile (CLP) load for each distributor in 2012/13. In areas where controlled load exists, we have combined the load shapes using proportions based on jurisdictional data to arrive at a combined residential load shape.

The cost of serving the load will be higher if the load and pool prices are positively correlated. For each distribution area, we have normalised the residential load so that the annual energy is 1GWh.[22]

Since 2010/11, distribution areas in Victorian have seen a decline in the total NSLP energy, presumably due to large numbers of customers adopting smart meters (and therefore being excluded from the NSLP). The issue is particularly pronounced for Citipower and Powercor, where the residential load shape in 2012/13 is dominated by the rate of customer fall off over the year rather than seasonal variation. For those two regions, we needed to correct the load shape to remove this roll off effect. This was done by first scaling the 2012/13 proportion of energy in each month consistent to monthly energy in 2009/10, which is the last financial year before the persistent decline in NSLP energy. We then normalise the rescaled residential load so that annual energy is 1GWh.

Table 2 shows the load factor and correlation coefficient between the normalised residential load and the relevant regional pool price for 2012/13. It can be seen that the correlation between residential load and pool price is high in NSW.

Table 2: Load factor and Correlation coefficient with pool price based on 2012/13 data

Region	Distributor	Load factor	Correlation coefficient with pool price
NSW	ACTEWAGL	0.40	0.42
	Ausgrid	0.38	0.44
	Endeavour	0.35	0.45
	Essential	0.60	0.36
QLD	Energex	0.46	0.19
SA	SA	0.34	0.15
TAS	TAS	0.43	0.06

22 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.

Region	Distributor	Load factor	Correlation coefficient with pool price
VIC	Citipower	0.46	0.13
	Jemena	0.45	0.14
	Powercor	0.47	0.14
	SP Ausnet	0.40	0.14
	United	0.43	0.15

Source: AEMO and Frontier Economics Analysis

For the stand-alone LRMC, the load factor of the residential load shapes is 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. This occurs as a combined effect, 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 2012/13 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 – 2008 period.

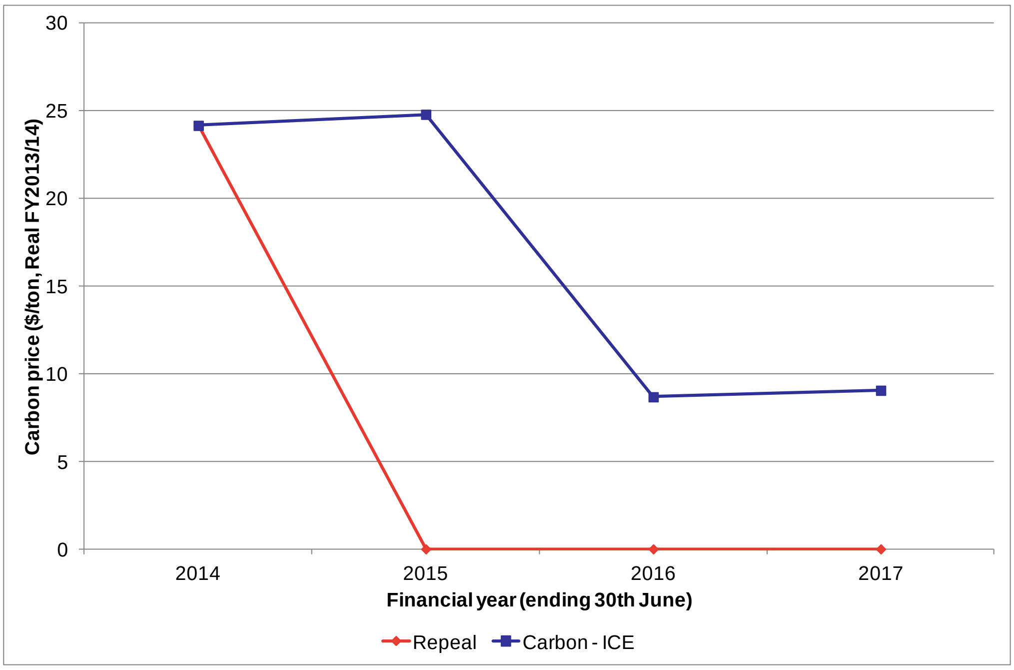
The NSLP and, to a lesser extent, CLP load profiles do change over time. However, absent a detailed statistical analysis of the data, it is difficult to forecast how this will change in the future. Not only does this involve forecasting the impact of weather and other factors on peak residential demand 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

The base case assumes that the carbon price will be repealed from 2014/15 onwards. This is consistent with the Commonwealth Government's repeal of the Clean Energy Act in July 2014.

Frontier has also been asked to model a Carbon case under the legislation Clean Energy Act for the entire modelling period. This was to reflect uncertainty about the timing of the repeal of the this legislation (as the study commenced prior to the repeal). In the Carbon case, from 2015/16, the carbon price will be linked to the Europe market. Frontier used forward prices on the European intercontinental exchange[23] (as of 16th Apr 2014) for carbon prices from 2015/16 and converted to Australian dollars using exchange rate assumptions consistent with other input assumptions and shown in Figure 25.

Figure 7: Carbon price



Source: FE/AEMC and Intercontinental exchange data

3.3 RET

The current LRET target, reaching 41,000 GWh over the 2020s, has been 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 2.4. As discussed in this section, the estimate for LGC prices is obtained from the marginal cost of meeting the LRET in the *WHIRLYGIG* stage of our modelling.

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23 See https://www.theice.com/marketdata/reports/ReportCenter.shtml?reportId=31#report/31.

This target is currently under review by the Commonwealth Government's RET Review Expert Panel. As noted in section 2.4, Frontier has modelled several alternative RET scenarios with different targets. The results of these alternative RET modelling scenarios are set out in a separate report[24] which has been published separately to this report.

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 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 these 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.[25]
- AEMO publish the National Transmission Network Development Plan (NTNDP), and supporting documents, which include a range of technical and cost input assumptions.[26]
- AEMO publish information on marginal loss factors for generation plant.[27]

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:

- Much of the work for the development of the input assumptions used in the latest NTNDP is increasingly out-of-date. For instance, the fuel prices used

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24 Frontier Economics, *RET Review Analysis – Final Report*, June 2014

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

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

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

in the latest NTNDP are based on a report released in the middle of 2012. Similarly, the capital costs used in the latest NTNDP are based on a report released in the middle of 2012. There have been substantial developments in energy markets since then that would be expected to affect these forecasts, including in regard to forecast exchange rates, technology development and forecast LNG prices.

- 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 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 because 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 via public consultations and stakeholder submission processes[28]. Stakeholders did not raise any material objections to either our approach or estimates. The numbers used in our final report were only updated for more recent information and not in response to stakeholder submissions.

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28 See here and here.

3.5 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.

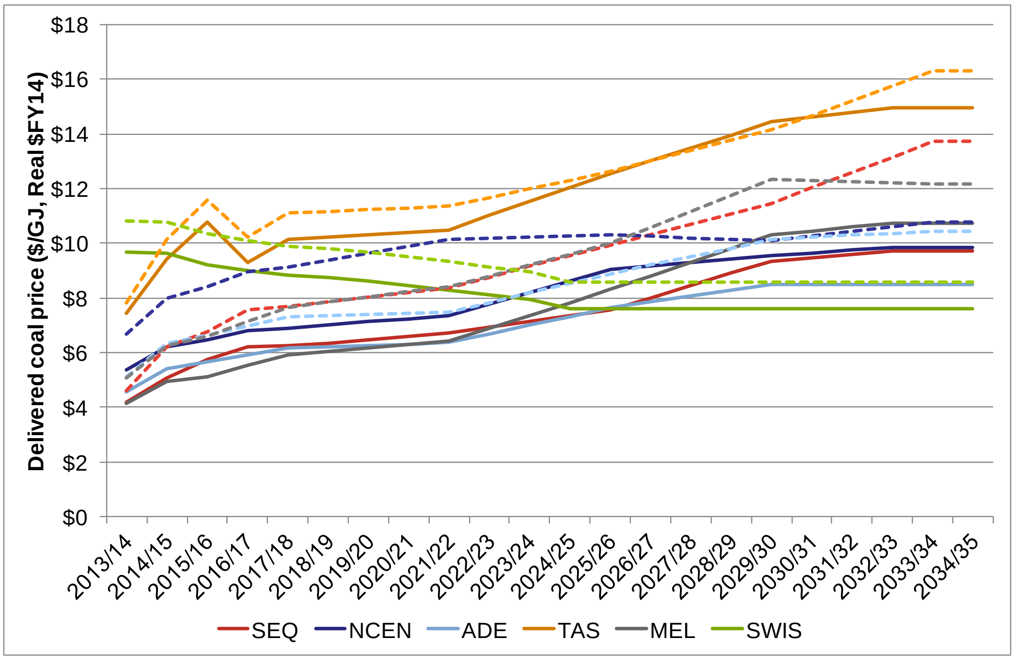
A detailed description on our approach to estimating fuel prices can be found in Appendix A.

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 (solid line) and high case (dashed line) forecasts are shown in Figure 8 for a selection of pricing zones across Australia.

High case prices are on the order of $1-2/GJ higher, representing an approximate 30% increase over the base case.

Figure 8: LRMC of gas by State capital cities ($2013/14) – Base (solid) and High (dashed) cases



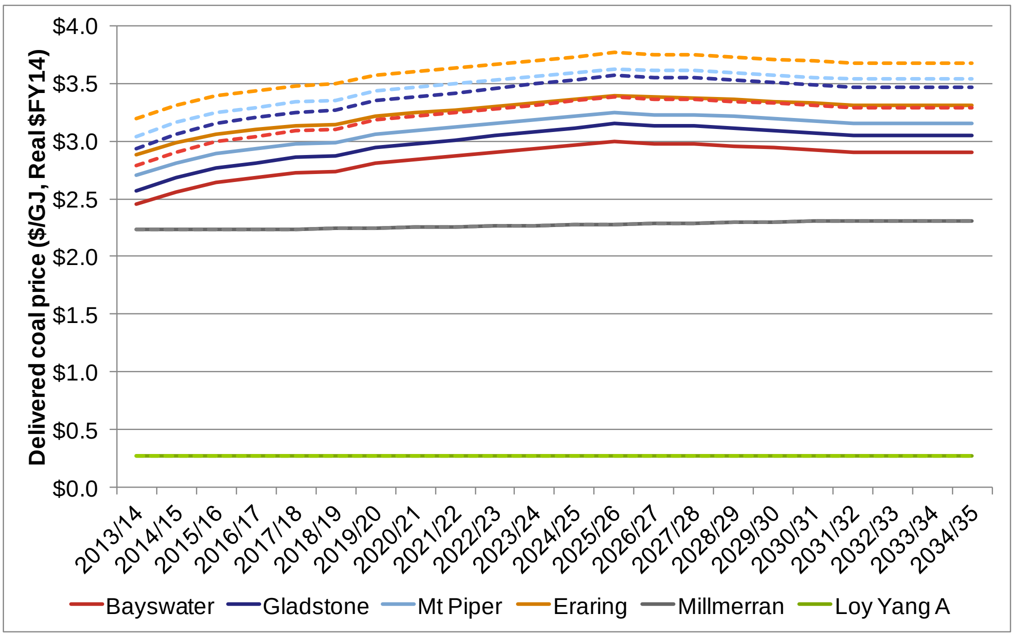
Source: Frontier Economics

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 9 for representative power stations (both export exposed and mine-mouth stations).

High case prices are on the order of $0.5/GJ higher, representing an approximate 20% increase over the base case.

Figure 9: Coal prices for representative generators ($2013/14) – Base (solid) and High (dashed) cases



Source: Frontier Economics

Note: Bayswater, Gladstone, Mt Piper & Eraring are export exposed, Millmerran and Loy Yang A are mine mouth stations

3.6 Capital

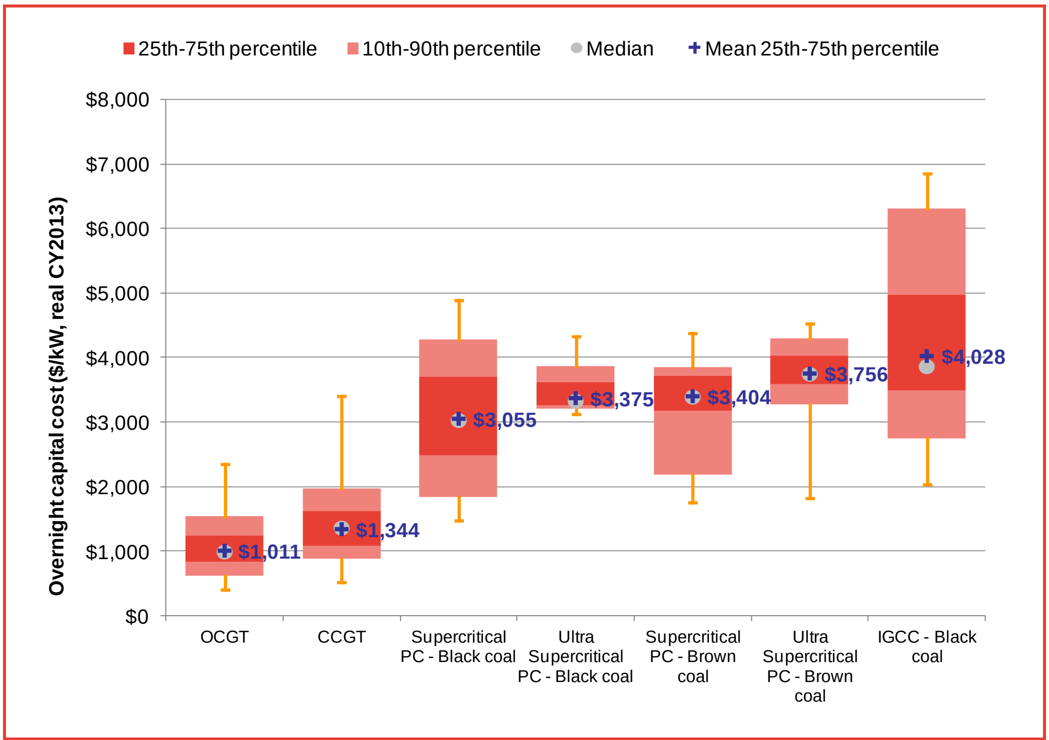
Frontier's capital cost estimates are based on a detailed database of actual project costs, international estimates and manufacturer list prices. A detailed description on our approach to estimating capital costs can be found in Appendix A.

Our approach involves relies on estimates from a range of sources – actual domestic and international projects, global estimates (for example, from EPRI[29])

[29] See http://www.epri.com.

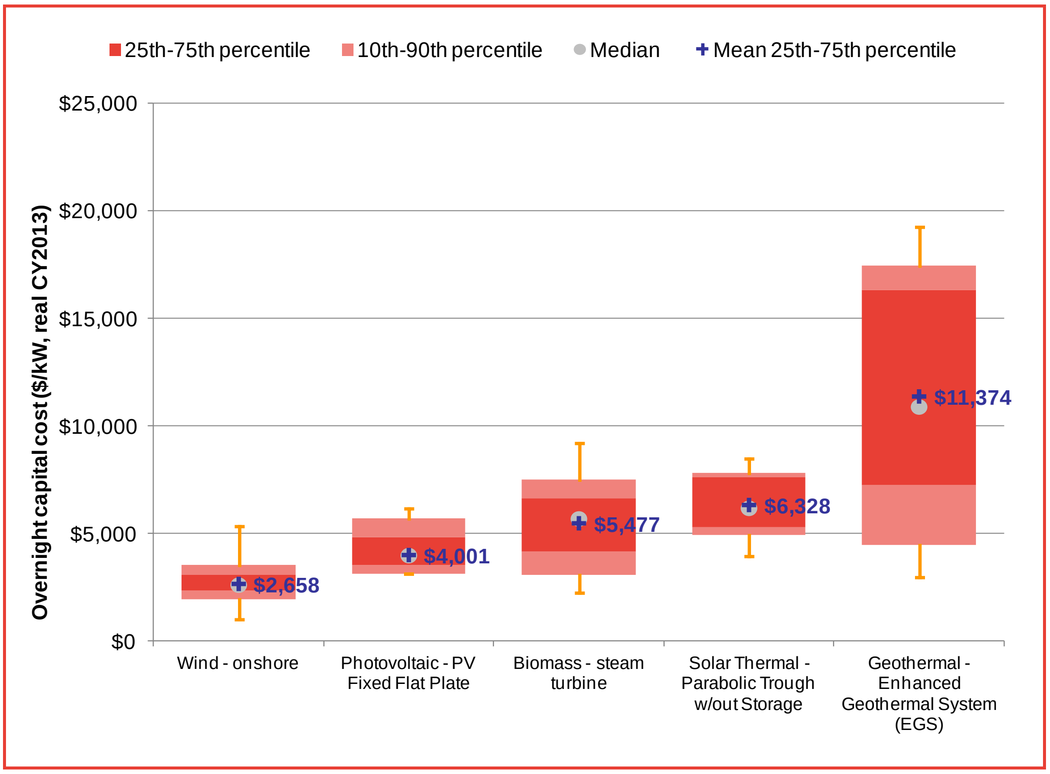
and manufacturer list prices. These estimates are converted to current, Australian dollars. Our estimate is then taken as the mean over the middle two quartiles of the data (the 25th to 75th percentiles). The range of estimates and the final number used in the modelling are shown in Figure 10 and Figure 11 for thermal and renewable technologies respectively. The movement of capital cost over time are driven by factors such as real cost escalation of domestic costs (essentially labour), exchange rates and technological improvement. More details on factors that change capital costs over the modelling period can be found in Table 15, Figure 10 and Figure 11 in Appendix A.

Figure 10: Current capital costs for gas and coal generation plant



Source: Frontier Economics

Figure 11: Current capital costs for renewable generation plant



Source: Frontier Economics

Large scale solar PV capital costs

Frontier Economics' current estimates for large scale solar PV use 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[30]) 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[31] are estimated at a cost of approximately $2,400/kW, substantially less than our estimate of $4,001/kW.

We would note that:

- Even at $2400/kW, on an LRMC basis wind is cheaper (at $90-120/MWh) than solar (at $178/MWh for the ACT projects[32]) and would be the cost-optimal choice for meeting the LRET. If solar PV costs fell by a further 20% from $2400/KW, the implied LRMC is around $140/MWh, considerably higher than current wind costs.
- There is strong suspicion that these recent extraordinarily low reported costs are influenced by Chinese Government subsidisation of its Solar PV manufacturing sector. In this respect, we note that the US Government has recently moved[33] to impose anti-subsidy tariffs of 18-35% to address this concern. Europe has also imposed similar tariffs. Our estimates are dominated by European and US data which reflects these anti-tariff subsidies to some extent. Whilst subsidised Solar PV is likely to be a net benefit to Australian consumers (as a minor PV manufacturer), there is a question as to how global Solar PV prices will react to the impact of enduring anti-subsidy tariffs in major markets for Chinese producers and the extent to which further Solar PV cost reductions are able to repeat recent reductions.
- These costs would represent outliers under our current methodology (they would be outside the 25th to 75th percentile). If more low projects are developed then this will ultimately affect the interquartile range and hence the mean cost estimate that we use. In the interim, if we consider

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

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

32 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.

33 See http://www.nytimes.com/2014/06/04/business/energy-environment/us-imposing-duties-on-some-chinese-solar-panels.html?_r=0.

that the weight we place on these cost outliers are likely to influence the modelling conclusions then we will review the approach of placing greatest weight on the mid range results.

3.7 Scenarios considered in the modelling

The modelling considers a Base Case and multiple scenarios as listed in Table 3.

Table 3: Modelling scenarios

Scenario	Demand	Carbon	RET	Fuel	Capital
Base Case	NTNDP 2014 Medium	Repeal from 1 July 2014	Current legislation	FE Base	FE Base
Carbon	NTNDP 2014 Medium	**Current legislation**	Current legislation	FE Base	FE Base
Low Demand	**NTNDP 2014 Low**	Repeal from 1 July 2014	Current legislation	FE Base	FE Base
High Fuel	NTNDP 2014 Medium	Repeal from 1 July 2014	Current legislation	**FE High**	FE Base

Source: Frontier Economics

4 Wholesale energy cost estimates

This section presents Frontier Economics' estimate of wholesale energy costs under the three approaches discussed in section 2.2 and 2.3:

- **Stand-alone LRMC** where a 'greenfields' mix of generation capacity is built to meet the residential load shape.
- **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.
- **Jurisdictional** approaches as set by each jurisdictional regulator.

4.1 Summary of key modelling trends

This subsection presents a summary of the key trends in the modelling results, firstly by modelling approach and then by jurisdiction.

4.1.1 Overarching trends

Overarching trends relate to assumed carbon prices, input fuel costs and system demand forecasts and depend on the modelling approach used. In general, the modelled scenarios differ in the *level* of prices and costs but have similar *trends* across the modelling period. For example, trends are essentially the same between the base and High Fuel scenarios under both modelling approaches however the level of prices in higher in the High Fuel scenario consistent with the higher input costs in that case.

Trends in both the stand-alone LRMC and market-based approaches are strongly influenced by the assumed carbon prices in the modelling. In the Base, High Fuel and Demand scenarios carbon is assumed to be repealed from 2014/15 and in the Carbon scenario prices fall to an international, market-based carbon price from 2015/16. This results in a downward step change in all scenarios and under both modelling approaches due to the assumed removal of reduction of carbon prices.

Input fuel costs are assumed to be at, or to rise to, international netback levels. This is particularly relevant for gas prices given the assumption that LNG exports will begin in Queensland over the modelling period, vastly increasing demand for gas and resulting in a ramp up in gas prices over the modelling period, leading to a trend of rising wholesale energy costs. The impact of rising gas prices is most clearly seen in the stand-alone LRMC results, where the optimal plant mix is dominated by gas-fired generation. Effects are lessened in the market-based approach, where gas-fired generation is smaller share of supply and where rising gas prices in Queensland are more than offset by loose supply-demand conditions across the wider NEM. This is supported by the higher WEC estimates in the High Fuel scenario under both approaches.

In the market-based approach, the assumption of AEMO's 2014 NEFR demand forecasts, which forecast low to no demand growth in NEM, in conjunction with continued investment to met the currently legislated LRET, puts downward pressure on wholesale energy costs. This leads to downward trends as wind investment occurs over the modelling period in all regions depending on scenario and particularly in South Australia and Victoria.

Pool prices in the Low Demand scenario do not decrease significantly relative to the Base scenario. This is consistent with the market being close to SRMC pricing levels across the NEM even in the base scenario such that further falls in demand have only a minimal impact on prices. In some sense this can be thought of as a an 'SRMC floor' to market prices.

This outcome varies by region. In NSW and Queensland, this floor is set at around $35/MWh by black coal generators being marginal for most of the year. In South Australia, the SRMC floor is set by gas-fired plant at around $40/MWh but is further suppressed by additional wind investment. In Victoria, the SRMC price floor is driven by imports from other regions combined with the large supply of brown coal supply to set an SRMC floor around $30/MWh.

4.1.2 Trends by scenario and approach

Table 4 discusses the key trends by scenario and an overview of results in presented in Figure 12. In the market-based approach, outcomes are primarily driven by pool price forecasts which are explained by supply-demand conditions and factors variable cost factors (such as fuel and carbon prices). For the stand-alone LRMC approach, relative costs between different technologies on an LRMC basis drive outcomes as well as the peakiness of the residential load shapes.

Table 4: High level trends by scenario

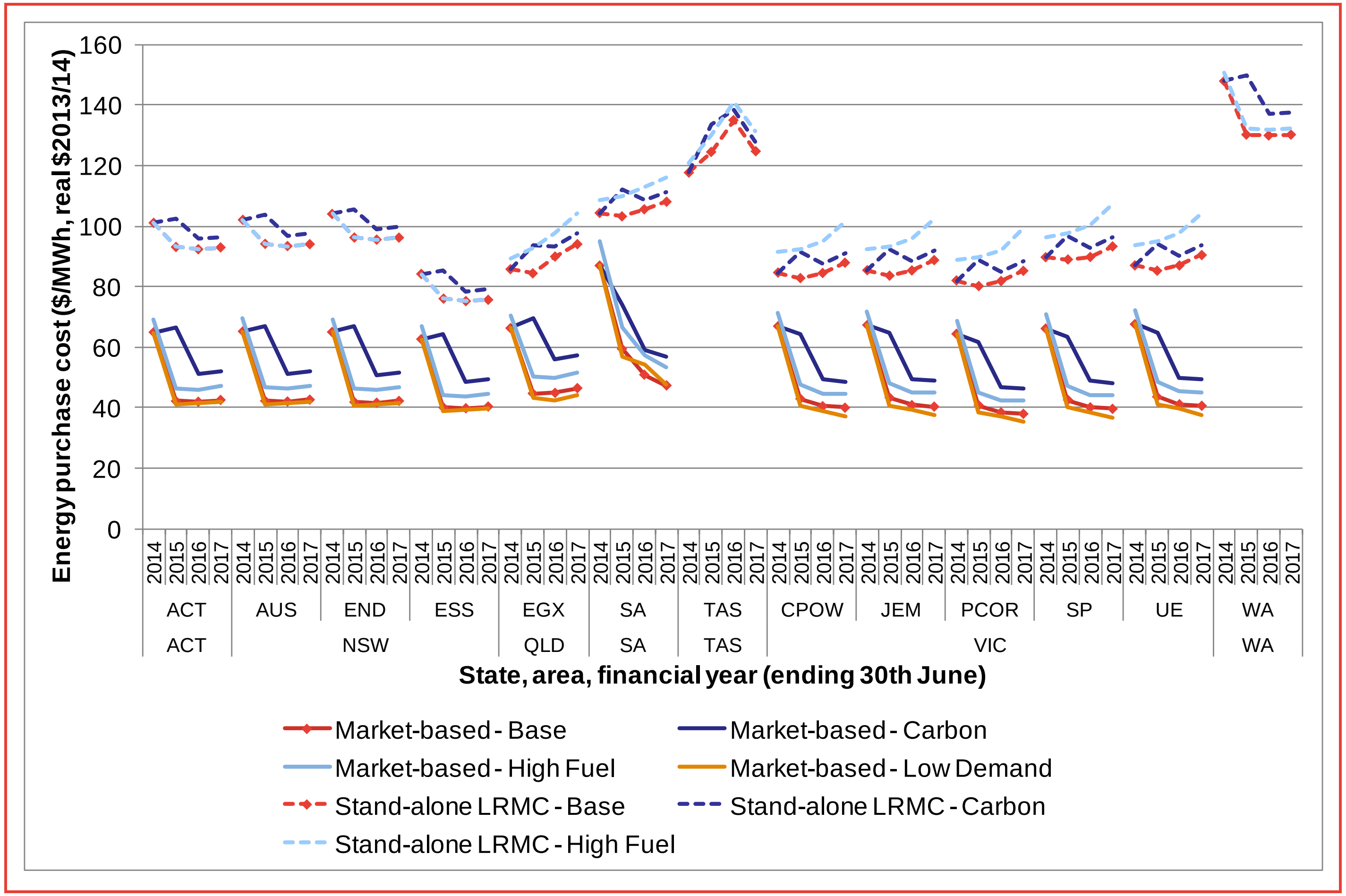
Region	Key trends
Market-based approach (NEM regions only)	
Base case	Pool prices fall from 2013/14 to 2014/15 with the removal of the carbon price. Thereafter prices remain relatively constant in real terms in line with loose supply-demand conditions. Additional investment in wind in the southern states puts downward pressure on pool price in those regions. While gas prices rise over the longer term, increases are muted over the four years of the analysis and there is little impact on pool prices as a result of oversupply.

Region	Key trends
Carbon	The Carbon scenario involves the continuation of a fixed carbon price for 2014/15 and a reduction to a market based carbon price from 2015/16, this increases the level of prices relative to the base scenario. In terms of trends, outcomes are similar to the Base scenario – aside from the impact of carbon prices, pool prices are relatively constant in real terms in NSW and Queensland and fall due in the Southern regions in response to wind investment.
Low Demand	The Low Demand scenario involves reductions in forecast energy which results in reductions in the level of forecast pool prices relative to the Base scenario. Levels are lower by $2-4/MWh, reflecting the fact that prices are already close to an 'SRMC floor' level in each region the Base scenario (as discussed in section 4.1.1). In terms of trends, outcomes in the Low Demand scenario are very similar to the Base scenario - aside from the impact of carbon prices, pool prices are relatively constant in real terms in NSW and Queensland and fall due in the Southern regions in response to wind investment.
High Fuel	The High Fuel scenario involves higher input coal and gas prices (as discussed in section 3.5). These higher input costs lead to higher pool price forecasts across the NEM, with forecast prices $3-5/MWh relative to the Base scenario. In terms of trends, outcomes in the High Fuel scenario are very similar to the Base scenario - aside from the impact of carbon prices, pool prices are relatively constant in real terms in NSW and Queensland and fall due in the Southern regions in response to wind investment.
Stand-alone LRMC approach (all areas)	

Region	Key trends
Base case	Stand-alone LRMC is higher than market-based estimates as it reflects the full capital cost of the mix of generation needed to meet demand. Investment is generally a mix of CCGT and OCGT fired gas plant. This means carbon prices are passed through into stand-alone LRMC estimates at the emissions intensity of these technologies (0.4-0.5 tCO2e/MWh). NSW, the ACT and Western Australia experience similar trends – a reduction with the removal of carbon followed by constant real prices reflecting constant input costs (gas). In NSW and ACT, investment occurs in the NNSW subregion to access low gas prices available from the Gunnedah basin (which is not currently connected to the East Australian gas pipeline network). Gas prices in NNSW do not rise over the modelling period. LRMC estimates are lower in the Essential area reflecting the flatter load shape of regional NSW customers. In WA, prices are assumed to be at netback levels from the start of the modelling period, driving the higher level of LRMC in WA. WA gas prices do not increase over the modelling period, leading to a flat trend post-carbon. In Queensland, Victoria and South Australia LRMC estimates follow a similar trend – a reduction on the removal of carbon followed by increases due to rising gas prices. The level of LRMC is highest in South Australia reflecting the peakier load shape of SA customers. Tasmanian LRMC estimates are the highest level in the NEM, reflecting both the peaky shape of Tasmanian customers and the high cost of gas in the state. The reduction in LRMC on the removal of carbon is more than offset by rising gas prices to 2015/16. In 2016/17, LRMC estimates fall in line with a temporary decline in gas prices.
Carbon	The inclusion of carbon pricing for all four years does not significantly change the underlying investment mix in any region, which continues to be dominated by gas-fired plant. The continuation of carbon prices adds variable costs in line with the assumed carbon price and the emission intensity of gas-fired plant (0.4-0.5 tCO2e/MWh). This acts to increase the level of prices in all regions over the period 2014/15 to 2016/17.
Low Demand	Not applicable as system demand forecasts do not impact on stand-alone LRMC modelling (which is based on residential load shapes)
High Fuel	As with the Carbon scenario, higher gas prices feed directly into the LRMC estimates with little impact on underlying investment. There is no change in NSW and the ACT relative to the Base scenario as gas price estimates for the Gunnedah region do not differ to the Base scenario. In Queensland, South Australia, Tasmania and Western Australia higher input gas prices raises the level of LRMC relative to the Base scenario, however trends remain consistent. Victorian LRMC estimates are also higher in the High Fuel scenario relative to Base. LRMC also rises more quickly in trend terms consistent with faster rises in gas prices compared to the Base scenario.

Source: Frontier Economics

Figure 12: Energy purchase cost results by scenario and approach



Energy purchase cost estimates are tabulated in Table 16.

4.2 Stand-alone LRMC of energy

Sand-alone LRMC results are presented for the Base, Carbon and High Fuel scenarios. The Low Demand scenario, being a sensitivity on NEM and SWIS system demand levels, is not relevant under the stand-alone LRMC approach where the system is not modelled.

4.2.1 Trends in the stand-alone LRMC results

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

Key drivers of trends are:

- **The removal of carbon pricing.** This occurs in 2014/15 in the Base and High Fuel scenarios and involves a reduction in assumed carbon prices in 2015/16 in the Carbon scenario (reflecting a move to market pricing and linkage to European carbon markets). The removal of carbon results in a step change in the stand-alone LRMC results.
- **Rising gas prices.** Gas prices rise in the southern NEM states over the modelling period in all scenarios and this feeds into the stand-alone LRMC results.

Other drivers (changes in capital costs, etc) have a lesser impact on the modelled results.

4.2.2 Results by scenario

The stand-alone LRMC results are presented in Figure 13 to Figure 15. They are presented on RRN basis in real 2013/14 dollars.

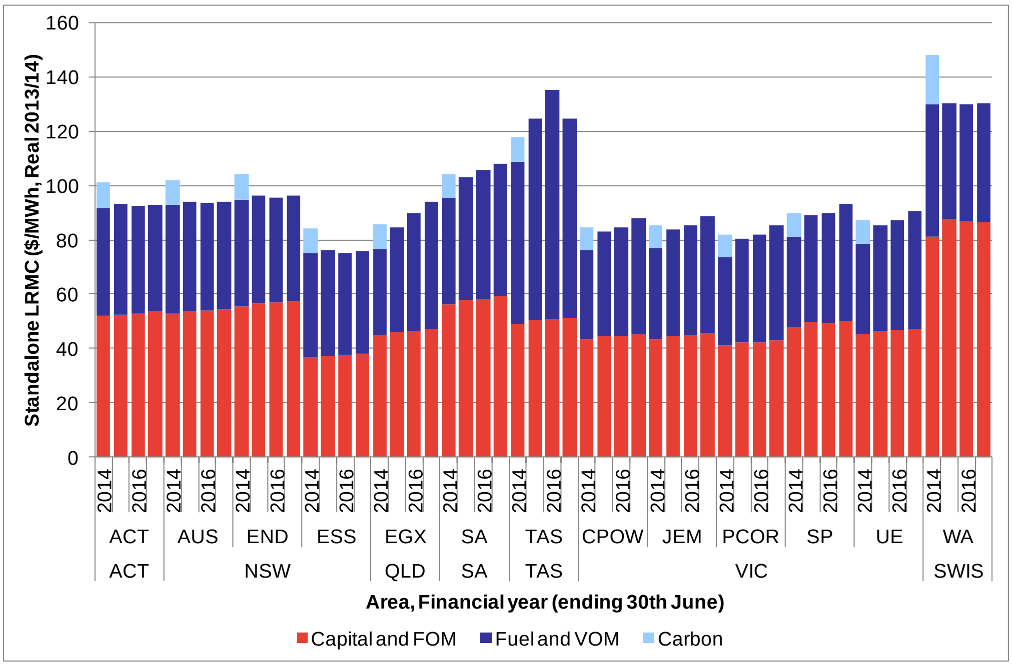
For the Base Case scenario (Figure 13), costs are generally higher in Tasmania and South Australia due to higher gas prices, and significantly higher in the SWIS due to higher fuel and capital costs in general. In NSW and the ACT, results are essentially constant in real terms, ignoring the impact of carbon pricing in 2013/14, reflecting the assumptions that input gas prices and capital costs in NSW are effectively constant in real terms over the four year modelling period. With regard to NSW gas prices, this is due to the stand-alone LRMC investment focusing on the NNSW sub-region of NSW to access low cost gas from the Gunnedah basin. The Gunnedah basin gas, which is currently disconnected from the wider East Australian pipeline network and is less exposed to short term netback pricing pressures, is lower than other areas of the NEM and does not rise over the modelling period in all scenarios.

LRMC results rise in Queensland in line with input gas price rises over the modelling period. Results in Victoria rise in line with gas prices to a lesser extent.

Underlying optimal investment in all regions is dominated by gas-fired plant – CCGT for baseload energy and OCGT for peaking requirements. The only exception is Western Australia where some coal is part of the mix, reflecting different costs relativities between new coal and CCGT plant in the SWIS.

Carbon is passed through into LRMC estimates in the NEM regions at roughly 0.45. This is consistent with the underlying optimal generation mix comprising only gas-fired plant. Carbon pass through is dominated by gas-fired CCGT dispatch which has an emission intensity of roughly 0.40. In the SWIS, higher pass through levels occur (roughly 0.90) in line with investment in coal-fired plant.

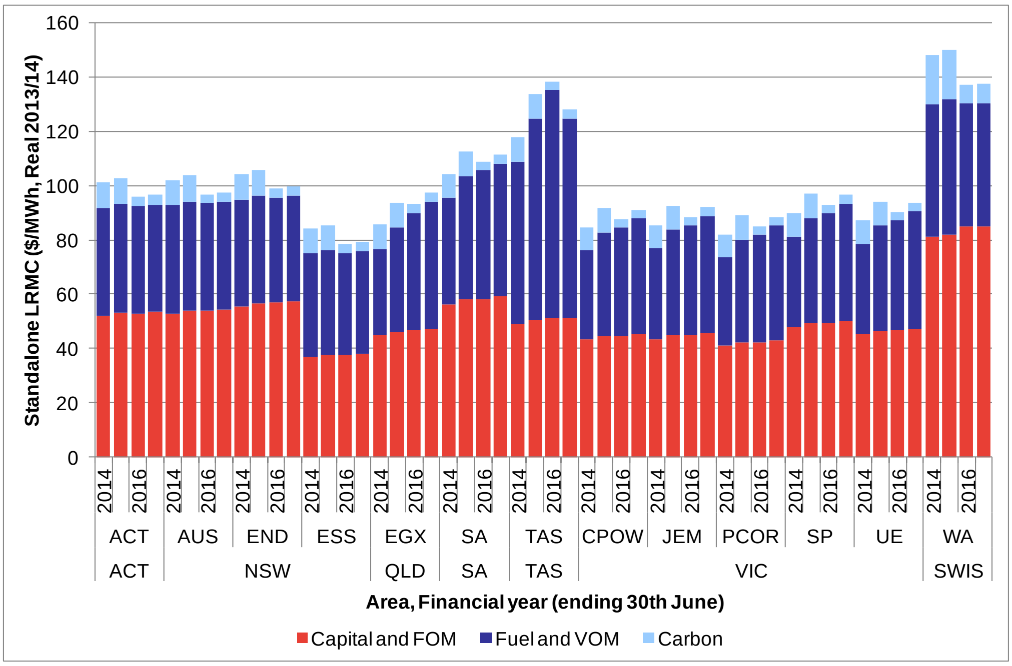
Figure 13: Stand-alone LRMC – Base Case scenario ($/MWh, real $2013/14)



Source: Frontier Economics

In the Carbon scenario (Figure 14), investment is essentially unchanged and carbon costs are passed through into LRMC results for all years of the modelling period. This raises the level of LRMC estimates above the results for the Base scenario. Trend results remain similar to Base scenario trends.

Figure 14: Stand-alone LRMC – Carbon scenario ($/MWh, real $2013/14)

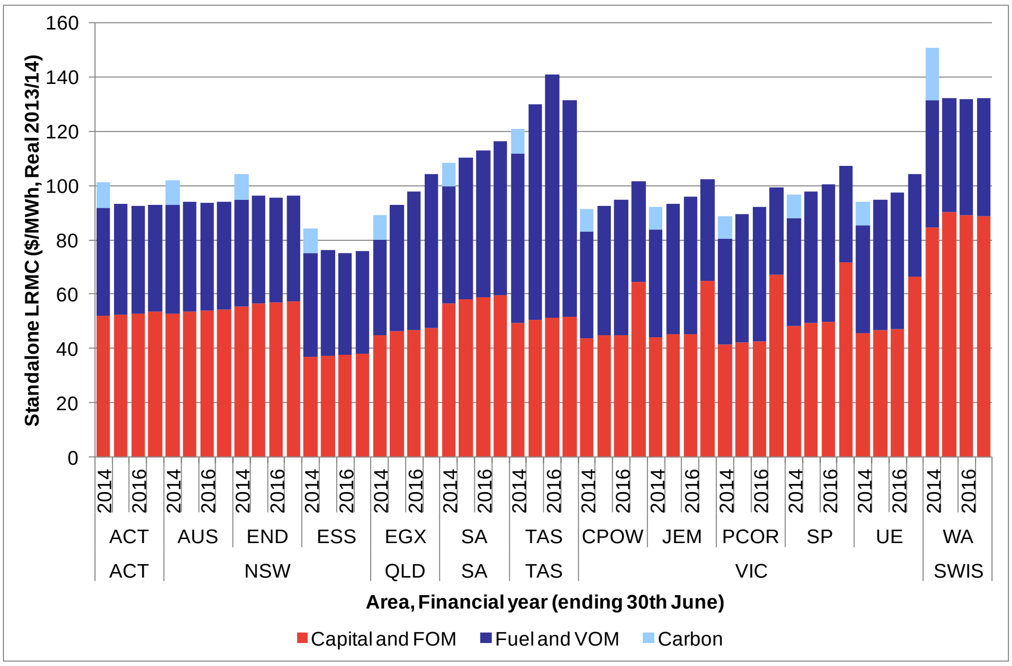


Source: Frontier Economics

In the High Fuel scenario (Figure 15), investment is, again, essentially unchanged. As the supply mix is dominated by gas, this results in higher fuel costs and LRMC estimates in most jurisdictions.

NSW and the ACT distributors' stand-alone LRMC estimates do not vary between the Base and High Fuel scenarios as gas price inputs are the same between these scenarios for the Gunnedah basin gas that is part of the optimal investment mix.

Figure 15: Stand-alone LRMC – High Fuel scenario ($/MWh, real $2013/14)



Source: Frontier Economics

Stand-alone LRMC estimates, which range from $70/MWh to $140/MWh, are considerably higher than current observed pool prices in the NEM and comparable prices in the SWIS. This is consistent with the stand-alone LRMC approach fully reflecting long run marginal costs while both the NEM and the SWIS are currently significantly oversupplied.

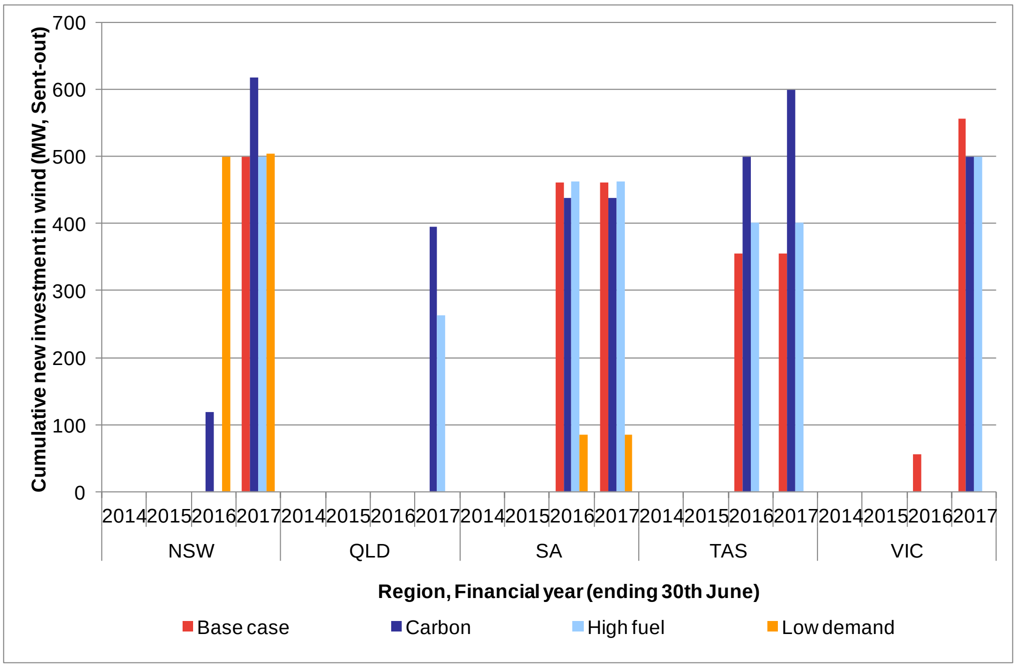
4.3 Market-based approach

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

4.3.1 New investment

Given the current oversupply and low forecast demand levels, the only investment that is forecast to occur is new wind entry to meet the LRET. Figure 16 shows wind investment by region. The total invested amount is highest for the Carbon scenario (where wind can earn higher pool prices) and lowest in the Low Demand scenario (where new wind entry increasingly displaces existing plant).

Figure 16: Cumulative new investment by scenario



Source: Frontier Economics

This wind investment, other things being equal, adds to supply and reduces forecast wholesale pool prices.

4.3.2 Plant retirements

Current oversupply, combined with forecasts of low or falling demand growth, results in a number of retirements being required over the modelling period. In the Low Demand scenario, where *WHIRLYGIG* can 'see' long term declines in demand, substantial retirements are forecast.

The retirements forecast by *WHIRLYGIG* reflect the two key assumptions in the modelling framework:

- Cost minimising outcomes in a market that is assumed to be perfectively competitive – this will tend to underestimate the profitability of generators.
- Perfect foresight – this will underestimate the risk (both upside and downside) that generators face in both the short and long term.

For both these reasons, the direct results of the *WHIRLYGIG* modelling will tend to overestimate the extent to which plant will retire. Whilst the model identifies a number of assets as candidates for retirement, in some cases immediate retirement, there are a number of reasons why these plant make delay exit from the market and/or not retire at all.

In light of these outcomes, the retirements assumed in the modelling are presented in Table 5.

Table 5: Forecast retirements

Scenario	Generator	Capacity	Retired from
Base/Carbon/High Fuel	Wallerawang 7	1 x 660 MW	Post-2016/17
	Vales Point	2 x 500 MW	Post-2016/17
	Eraring	2 x 720 MW	Post-2016/17
Low Demand	Wallerawang 7	1 x 660 MW	2016/17
	Vales Point	2 x 500 MW	Post-2016/17
	Eraring	4 x 720 MW	Post-2016/17
	Stanwell	2 x 365 MW	Post-2016/17
	Liddell	3 x 500 MW	Post-2016/17
	Hazelwood	1 x 200 MW	Post-2016/17

Source: Frontier Economics

4.3.3 Key trends in the market-based results

For the market-based estimates, changes over time can be driven by changes in input costs (fuel, VOM and carbon variable costs that directly impact on pool prices) and changes in the supply-demand balance. Load shapes are held constant over the modelling period.

Key drivers of trends are:

- **The removal of carbon pricing.** This occurs in 2014/15 in the Base, High Fuel and Low Demand scenarios and involves a reduction in assumed carbon prices in 2015/16 in the Carbon scenario (reflecting a move to market pricing and linkage to European carbon markets). The removal of carbon results in a step change in the pool price forecasts.
- **Supply-demand balance.** All regions are generally oversupplied, resulting in prices close to SRMC levels. However, the interplay between some demand growth, retirements and the timing and location of wind investment leads to different levels of supply-demand balance by scenario, region and year and influences prices.

Other drivers (changes in fuel costs, etc) have a lesser impact on the modelled results. Specifically, the impact of rising gas prices is greatly reduced in the market-based approach as weak supply-demand balance across the NEM overwhelms the impact of rising gas prices.

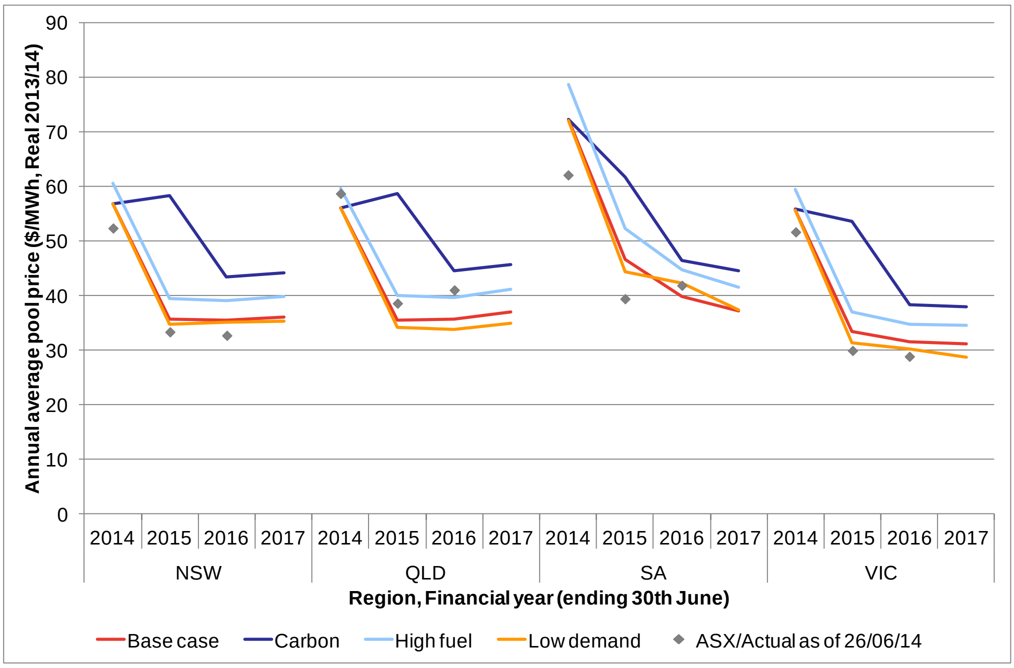
4.3.4 Pool prices

Figure 17 shows the modelled pool prices on a time-weighted, annual average basis and includes ASX Energy flat swap prices as a comparator where possible (RRN basis, real $2013/14). Forecast outcomes are broadly consistent with current ASX traded prices.

In the Base scenario, prices reflect carbon in 2013/14 (at a pass through rate of roughly 1.00). The impact of carbon falls away from 2014/15 onwards, this can be seen most clearly in NSW. Prices in NSW and Queensland are then approximately constant in real terms from 2014/15. In our view prices are effectively at the SRMC floor in these regions due to oversupply, as demonstrated by the minimal difference between the Base and Low Demand scenario price forecasts in these regions. In the Base scenario, South Australian and, to a lesser extent, Victorian prices continue to fall after carbon is removed. This reflects additional investment in wind that acts to lower forecast prices. in the Low Demand scenario, for South Australia in 2015/16 prices are forecast to be higher as less wind investment occurs in this scenario due to the longer term outlook for demand.

Forecast prices are higher in both the High Fuel and Carbon scenarios reflecting increase input costs for thermal generators.

Figure 17: Pool price forecasts and ASX futures prices – All scenarios ($/MWh annual average prices, real $2013/14)



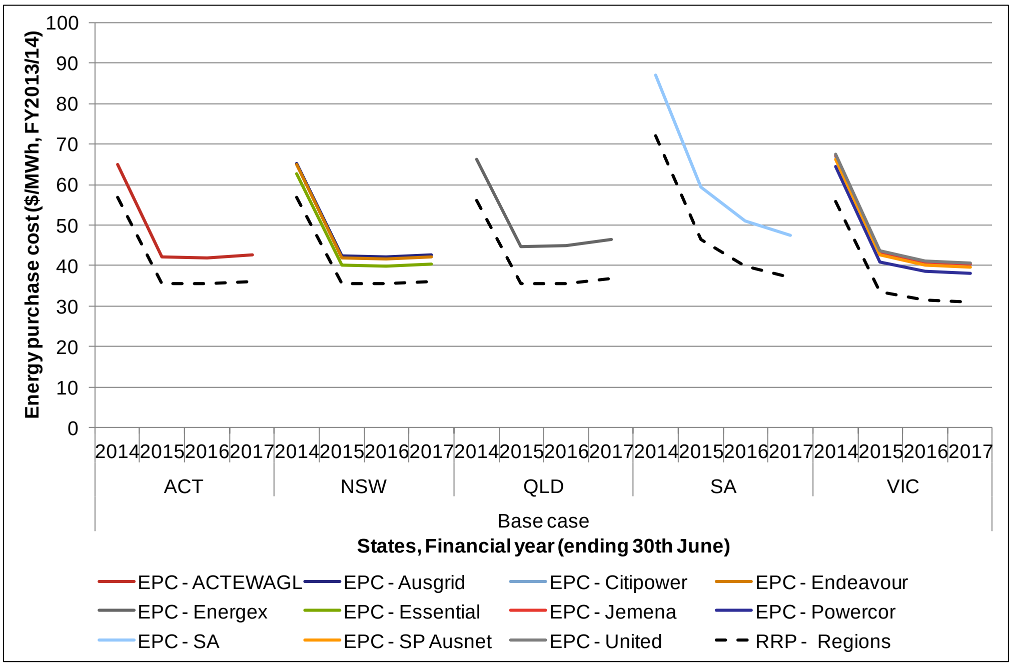
Source: Frontier Economics

4.3.5 Results by scenario

Figure 18 to Figure 21 show the energy purchase costs for each scenario (RRN basis, real $2013/14).

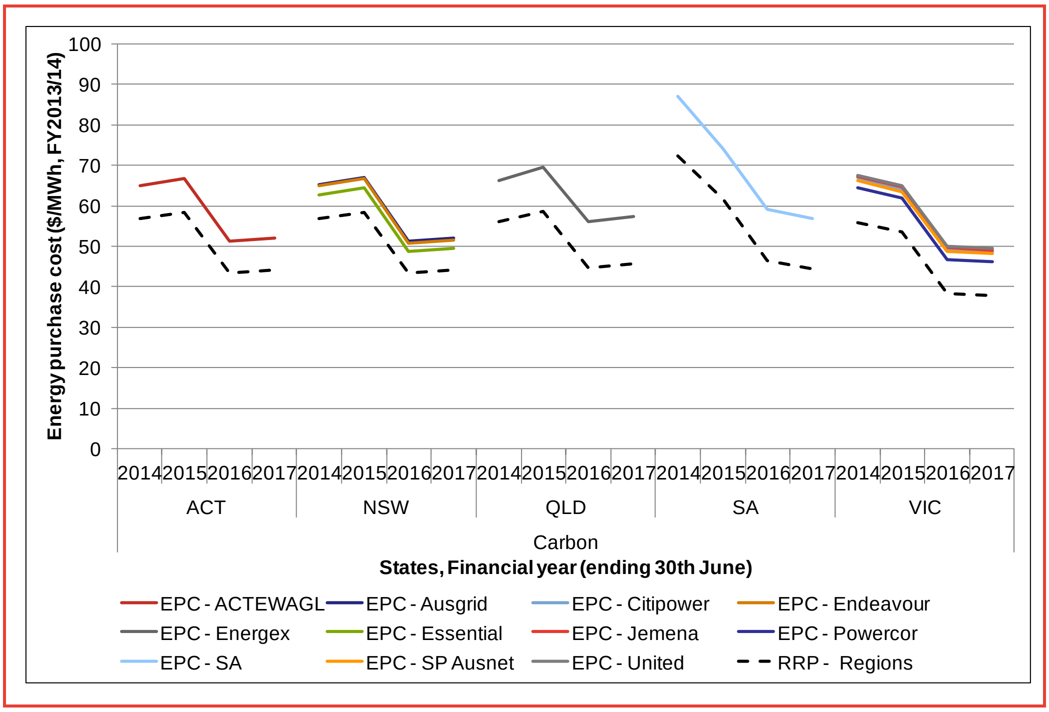
Energy purchase costs are driven by the peakiness of the residential load shapes and the assumed 5% contracting premium for hedges. Trends over the modelling period are driven solely by changes in forecast pool prices as load factors are assumed to be constant. Forecast pool prices are shown on the figures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

Figure 18: Energy Purchase Cost estimates under the market-based approach – Base scenario (RRN basis, $/MWh, real $2013/14)



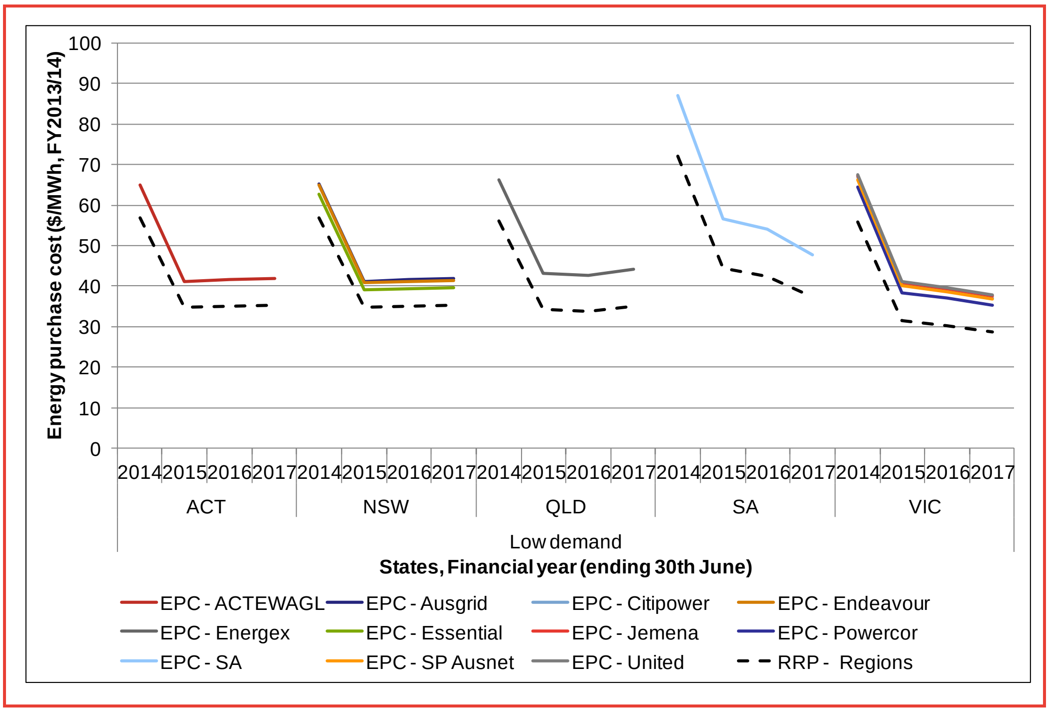
Source: Frontier Economics

Figure 19: Energy Purchase Cost estimates under the market-based approach – Carbon scenario (RRN basis, $/MWh, real $2013/14)



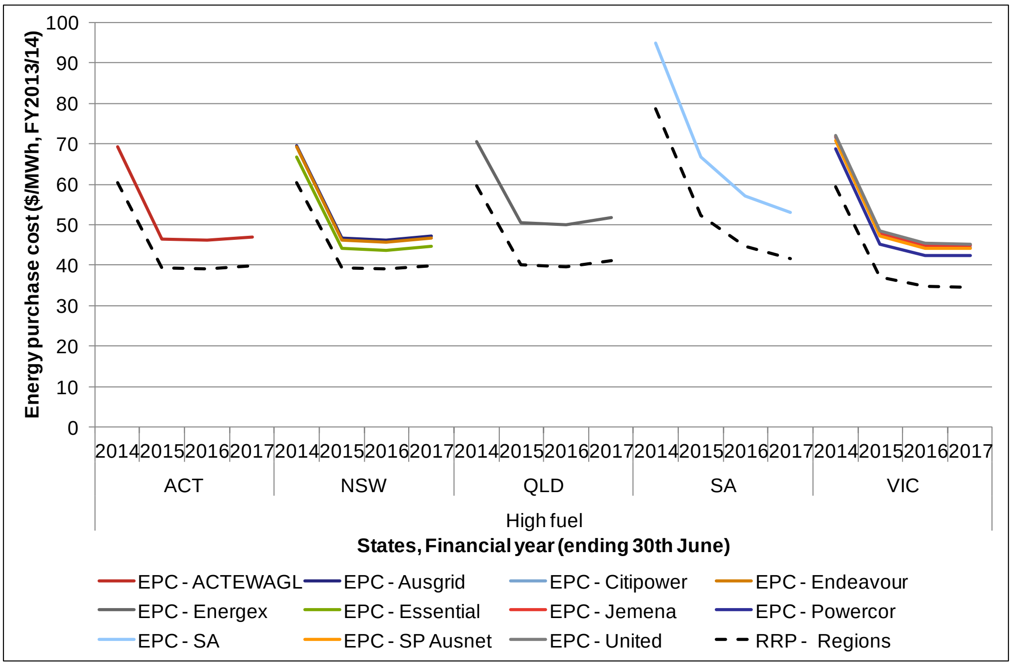
Source: Frontier Economics

Figure 20: Energy Purchase Cost estimates under the market-based approach – Low Demand scenario (RRN basis, $/MWh, real $2013/14)



Source: Frontier Economics

Figure 21: Energy Purchase Cost estimates under the market-based approach – High Fuel scenario (RRN basis, $/MWh, real $2013/14)



Source: Frontier Economics

4.3.6 Relativities between the stand-alone and market based approaches over time.

Frontier Economics has advised the AEMC as part of its annual retail pricing trend reports in 2010, 2012 and 2014. Figure 22 shows the stand-alone and market-based wholesale energy cost estimates for the Citipower distribution area across these three reports. Citipower has been chosen as an illustrative distribution area however the changes in results over time discussed below apply more generally to the NEM and SWIS.

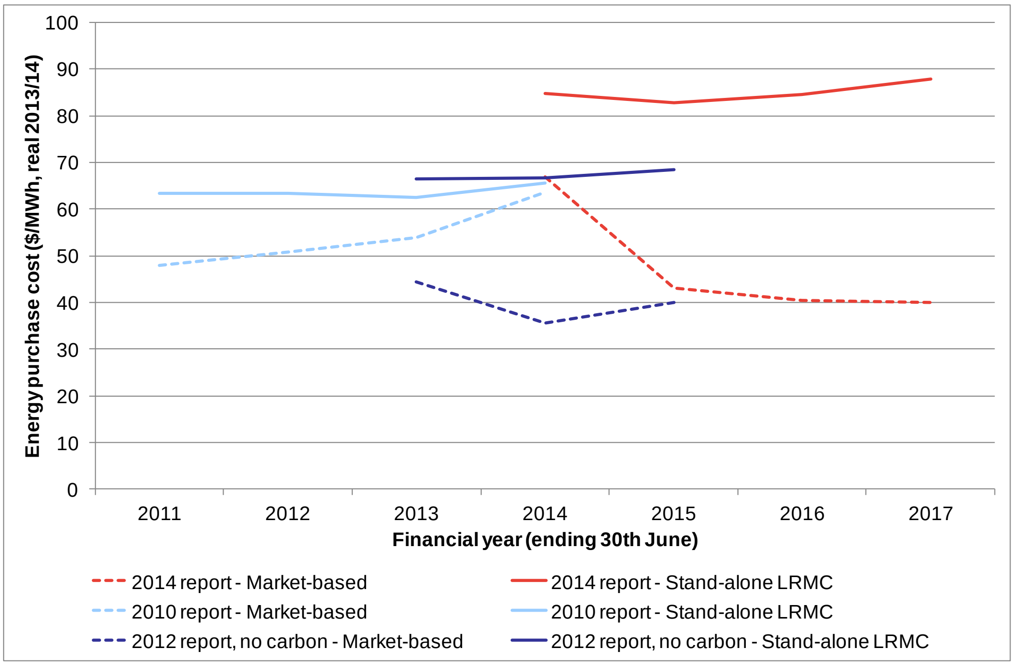
In general, stand-alone LRMC based estimates have been rising over the period due primarily to the internationalisation of upstream fuel markets leading to higher input coal and gas prices. Conversely, in the market-based approach estimates are lower in the current 2014 report compared to 2010. This is primarily due to falling forecasts of system demand combined with continued investment to meet the RET leading to a loosening of the supply-demand balance. This has lead to an increasing 'wedge' between the stand-alone LRMC and market-based approaches.

In 2010, we forecast an initial gap between the approaches and that demand growth in market-based approach would lead to convergence with the stand-alone estimates by 2013/14 as the market moved towards a tighter supply demand balance resulting in near LRMC pricing outcomes.

In 2012, considering the scenario without carbon pricing, the 'wedge' had increased due to higher input cost estimates and weaker forecast demand. Over the modelling period a gap between the approaches was forecast to widen due to wind investment in the market-based approach exceeding assumed demand growth.

In 2014, our forecasts show a strong divergence between the approaches due to low demand forecasts and the currently legislated LRET in market-based approach and high input fuel costs in stand-alone approach. The removal of carbon pricing post-2013/14 in the current modelling also exacerbates this divergence.

Figure 22: Wholesale energy cost by approach over the 2010, 2012 and 2014 reports (RRN basis, $/MWh, real $2013/14, Citipower area)



Source: Frontier Economics

4.4 Jurisdictional approaches

Table 6 presents the jurisdictional wholesale cost estimates for 2013/14 and 2014/15.[34] These costs are presented in nominal dollars and are presented on an RRN basis.

Table 6: Jurisdictional wholesale cost estimate ($/MWh, RRN basis, nominal)

Financial year	Jurisdiction	Distributor	Carbon repealed	Carbon
2014	NSW	Ausgrid	NA	81.88
2014	NSW	Endeavour	NA	82.60
2014	NSW	Essential	NA	71.12
2014	QLD	Energex	NA	69.43
2014	ACT	ACTEWAGL	NA	70.28
2014	TAS	TAS	NA	86.10
2014	WA	WA	NA	NA
2015	NSW	Ausgrid	NA	NA
2014	NSW	Endeavour	NA	NA
2014	NSW	Essential	NA	NA
2015	QLD	Energex	62.26	84.38
2015	ACT	ACTEWAGL	49.00	70.99
2015	TAS	TAS	54.45	NA
2015	WA	WA	NA	NA

Source: Jurisdiction pricing review /determinations

4.5 Carbon pass-through

Carbon pass through into both pool prices and wholesale energy costs in our modelling is calculated by re-running each scenario with a carbon price of zero as discussed in Section 2.4.

34 We do not use indicative prices set several years ahead of the actual annual price review as there have been material changes around various cost elements, particularly carbon expectations.

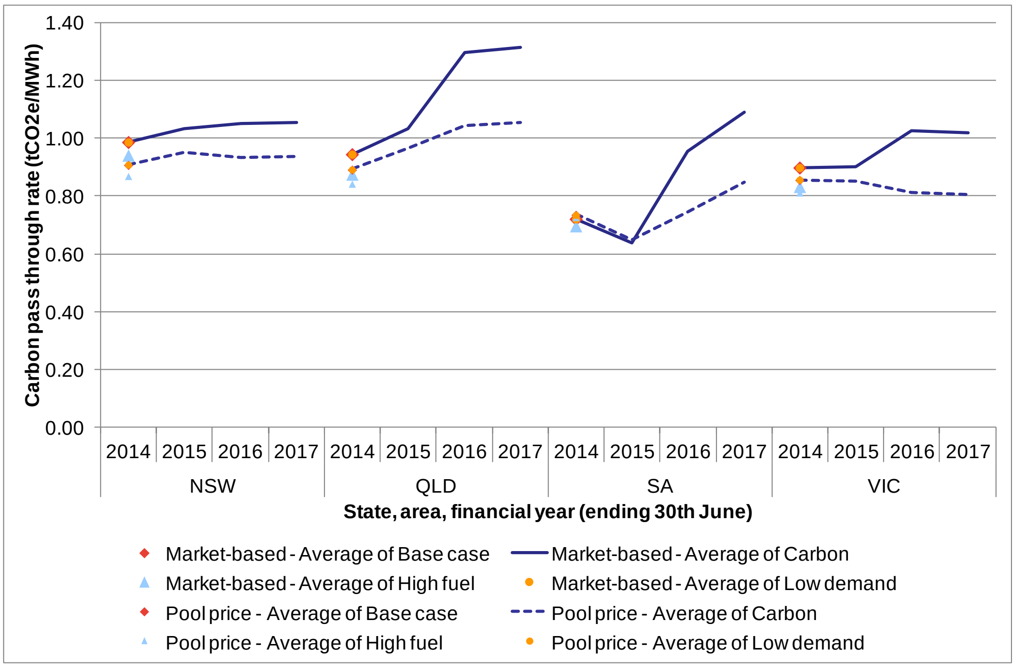
Pass through into both pool prices and market-based wholesale energy costs (on a regional average basis) are presented in Figure 23. Figures are presented for each year of the modelling period in the Carbon scenario and for 2013/14 for the Base, High Fuel and Low Demand scenarios (as the carbon price is assumed to be zero in later years).

In 2013/14, pass through into pool prices is around 0.90 tCO_2e/MWh in NSW, Queensland and Victoria across all scenarios consistent with black coal setting marginal prices in those regions for the majority of the year. Initial pool pass through rates are lower in South Australia owing to the greater presence of wind and gas-fired generation in the region. Initial pass through into market-based wholesale energy costs is higher than pool price pass through in NSW, Queensland and Victoria, reflecting the peakiness of the customer load shapes and positive correlation to high pool prices. In South Australia, 2013/14 pass through rates for both pool prices and wholesale energy costs are similar for all scenarios. The South Australian customer load profile, whilst peaky, is only weakly correlated to pool prices events[35] leading to similar initial pass through rates into pool prices and wholesale energy costs.

In the Carbon scenario, carbon pass through rates increase over time in NSW, Queensland and Victoria. This is consistent with the increasing loose supply demand conditions over the modelling period, which leads to an increase in the proportion of time that high emissions, coal-fired plant is marginal in the NEM. In South Australia, after a temporary fall in 2014/15 due to wind investment leading to greater price setting by in state gas-fired plant, pass through rates also rise in response to conditions in the wider NEM.

35 This can be seen in Table 2. South Australian residential load shapes can peak around midnight when controlled load comes online. This is occurring in the analysis presented in this report and was also an issue in our work for ESCOSA (see http://www.escosa.sa.gov.au/projects/178/electricity-standing-contract-wholesale-electricity-costs.aspx#stage-list=0).

Figure 23: Carbon pass through into **pool prices and market-based wholesale energy costs** by scenario (tCO2e/MWh)



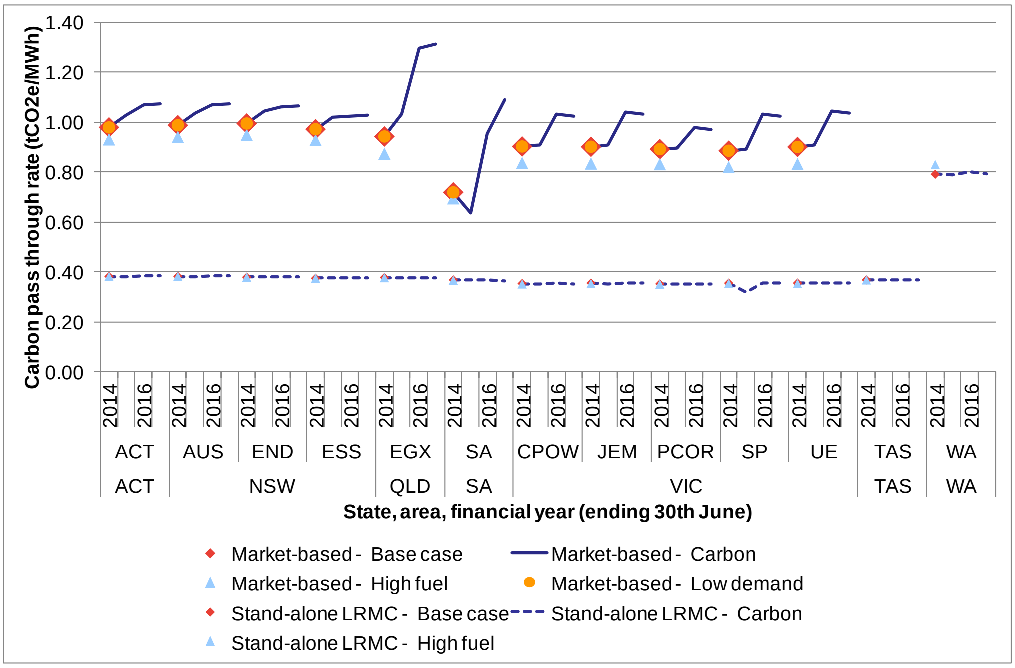
Source: Frontier Economics

Results for pass through into **wholesale energy costs only** are presented in Figure 24 by scenario for both the market-based and stand-alone approaches.

Pass through rates in under the market-based approach are consistently higher than using a stand-alone LRMC approach. Outcomes in the market-based approach reflect the presence of the existing stock of high emissions plant, whereas the stand-alone LRMC approach is indentifying an optimal mix of gas-fired plant in all regions except Western Australia, which leads to lower carbon pass through rates.

The drivers of pass through in the market-based approach have been discussed above. For the stand-alone LRMC approach, pass through rates are dominated by the investment mix being predominantly new CCGT gas-fired plant with an emissions intensity around 0.40 tCO2e/MWh. In Western Australia, where some coal-fired plant is plant of the investment mix, pass through rates are higher, reflecting a mix of both CCGT and coal emissions intensities.

Figure 24: Carbon pass through into **wholesale energy costs only** by scenario and approach (tCO2e/MWh)



Source: Frontier Economics

Carbon pass through under each jurisdiction approach (in $/MWh terms) is presented in Table 7. All data is presented on an RRN basis in real 2013/14 dollars.

The various jurisdictional approaches lead to differing levels of carbon pass through. In Queensland and the ACT, the approach is broadly consistent with the market-based approach presented above, leading to pass through of $21-22/MWh. In NSW, IPART's approach averages across stand-alone and market-based approaches which leads to a lower level of carbon passthrough (which is associated with a higher underlying 'black' price of energy).

Table 7: Carbon pass-through – Jurisdictional approach

Financial year	Jurisdiction	Distributor	Pass-through ($/MWh, nominal)
2013/14	NSW	Ausgrid	11.95
2013/14	NSW	Endeavour	11.95
2013/14	NSW	Essential	12.56
2013/14	QLD	Energex	21.68
2013/14	ACT	ACTEWAGL	21.31

Financial year	Jurisdiction	Distributor	Pass-through ($/MWh, nominal)
2013/14	TAS	TAS	NA
2013/14	WA	WA	NA
2014/15	NSW	Ausgrid	NA
2014/15	NSW	Endeavour	NA
2014/15	NSW	Essential	NA
2014/15	QLD	Energex	22.05
2014/15	ACT	ACTEWAGL	21.00
2014/15	TAS	TAS	NA
2014/15	WA	WA	NA

Source: Jurisdiction pricing review /determinations

5 Non-energy cost estimates

This section present our estimates of non-energy wholesale costs.

5.1 Estimates of cost under the RET

In addition to advising on wholesale energy costs for the period 2013/14 to 2016/17, 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 in terms of:

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

The Commonwealth Government is currently undertaking a RET Review that may announce changes to the RET during 2014. The remainder of this section refers to current legislation, which has formed the basis of our modelling. We have also modelled some alternative RET policy scenarios due to the current uncertainty about changes to the RET. The results of these alternative RET modelling scenarios are set out in a separate report[36] which has been circulated with this report. The results from these alternative RET scenarios may be used if the Commonwealth Government announces changes to the RET prior to the completion of the AEMC's 2014 Residential Electricity Price Trends Report.

5.1.1 LRET

Table 8 presents the renewable power percentage in the modelling time frame. Table 9 shows the LRMC of the LGC certificate (RRN basis, real 2013/14) from our modelling.

Table 8: Renewable power percentages

Financial Year	RPP (% of liable acquisitions)
2013/14	10.26%
2014/15	10.42%
2015/16	11.73%
2016/17	13.82%

Source: Clean Energy Regulator, Frontier Economics.

36 Frontier Economics, *RET Review Analysis – Final Report*, June 2014

The LRMC based estimates of LGC permit costs reflect the timing and magnitude of the shortfall against the LRET target (which occurs in all scenarios). Estimates are lowest in the Carbon scenario (where pool prices are high) and highest in the Low Demand scenario (where pool prices are low). This demonstrate the inverse relationship between a renewable generators cost recovery from wholesale and LGC sales.

Table 9: LRMC of LGC ($/MWh, RRN basis, Real $2013/14)

Financial Year	Base Case	Carbon	Low Demand	High fuel
2013/14	$54.41	$47.22	$61.73	$50.94
2014/15	$56.59	$49.11	$64.19	$52.98
2015/16	$58.85	$51.07	$66.76	$55.10
2016/17	$61.22	$53.13	$69.45	$57.32

Source: Frontier Economics

Based on the LRMC of LGC and renewable energy percentage, the LRET costs to residential consumers are presented in Table 10.

Table 10: LRET cost ($/MWh, RRN basis, Real FY2013/14)

Financial Year	Base case	Carbon	Low demand	High fuel
2013/14	$5.58	$4.84	$6.33	$5.23
2014/15	$5.90	$5.12	$6.69	$5.52
2015/16	$6.90	$5.99	$7.83	$6.46
2016/17	$8.46	$7.34	$9.60	$7.92

Source: Frontier Economics

5.1.2 SRES

Table 11 shows the estimated SRES cost. The cost is higher in earlier years due to the higher STP percentages (see Table 1).

Table 11: SRES cost ($/MWh, RRN basis, Real FY2013/14)

Financial Year	STC cost
2013/14	$6.04
2014/15	$4.02

Financial Year	STC cost
2015/16	$3.89
2016/17	$3.83

Source: Frontier Economics

5.2 Energy efficiency schemes

In addition to advising on wholesale energy costs for the period 2013/14 to 2016/17, this assignment also requires us to estimate a range of other energy-related costs. 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)[37]
- the South Australian Residential Energy Efficiency Scheme (REES)
- the ACT Energy Efficiency Improvement Scheme (EEIS)[38]

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.

We have used cost estimates provided by the jurisdictions for energy efficiency schemes, which are presented in Table 12. Those scheme cost estimated are on end-sale bais and in nominal dollar terms.

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37 The Victorian Government has announced the end of the VEET scheme from the end of 2015 (http://www.energyandresources.vic.gov.au/energy/about/legislation-and-regulation/energy-saver-incentive-scheme-management/esi-review).

38 The EEIS runs to the end of 2015 (http://www.environment.act.gov.au/energy/energy_efficiency_improvement_scheme_eeis).

Table 12: Energy efficiency scheme cost ($/MWh, end-sale basis, nominal)

Financial Year	State	Scheme cost
2013/14	NSW	1.89
2013/14	ACT	3.75
2013/14	VIC	2.60
2013/14	SA	3.00
2014/15	NSW	2.03
2014/15	ACT	4.90
2014/15	VIC	2.60
2014/15	SA	NA
2015/16	NSW	2.08
2015/16	ACT	2.50
2015/16	VIC	1.30
2015/16	SA	NA
2016/17	NSW	NA
2016/17	ACT	0
2016/17	VIC	0
2016/17	SA	3.00

Source: Data supplied by jurisdictions

5.3 NEM fees and ancillary services costs

In addition to advising on wholesale energy costs for the period 2013/14 to 2016/17, this assignment also requires us to estimate a range of other energy-related costs. This section considers the market fees and ancillary services costs.

5.3.1 Market fees

Table 13 shows our estimated market fees on RRN basis in real 2013/14 dollars.

Table 13: Market Fees ($/MWh, RRN Basis, Real 2013/14)

Financial Year	Region	Market fees
2013/14	NEM	$0.25
2013/14	SWIS	$0.46
2014/15	NEM	$0.27
2014/15	SWIS	$0.46
2015/16	NEM	$0.27
2015/16	SWIS	$0.46
2016/17	NEM	$0.27
2016/17	SWIS	$0.46

Source: Frontier Economics

5.3.2 Ancillary services costs

Table 14 shows our estimated ancillary service cost on RRN basis and in real 2013/14 dollars.

Table 14: Ancillary service cost ($/MWh, RRN basis, Real 2013/14)

Financial Year	Region	Ancillary service costs
2013/14	QLD	$0.08
2013/14	NSW	$1.03
2013/14	ACT	$1.03
2013/14	VIC	$0.25
2013/14	TAS	$0.89
2013/14	SA	$0.47
2013/14	WA	$2.59
2014/15	QLD	$0.08
2014/15	NSW	$1.03
2014/15	ACT	$1.03
2014/15	VIC	$0.25

Financial Year	Region	Ancillary service costs
2014/15	TAS	$0.89
2014/15	SA	$0.47
2014/15	WA	$2.59
2015/16	QLD	$0.08
2015/16	NSW	$1.03
2015/16	ACT	$1.03
2015/16	VIC	$0.25
2015/16	TAS	$0.89
2015/16	SA	$0.47
2015/16	WA	$2.59
2016/17	QLD	$0.08
2016/17	NSW	$1.03
2016/17	ACT	$1.03
2016/17	VIC	$0.25
2016/17	TAS	$0.89
2016/17	SA	$0.47
2016/17	WA	$2.59

Source: Frontier Economics

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.

Sources for modelling assumptions

Frontier Economics has developed estimates of all the key cost and technical input assumptions used in our modelling of the electricity markets in Australia. This section discusses the framework used to determine our inputs and presents data for our current base case and relevant sensitivities.

There are other public documents that also provide estimates of these 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.[39]
- AEMO publish the National Transmission Network Development Plan (NTNDP), and supporting documents, which include a range of technical and cost input assumptions.[40]
- AEMO publish information on marginal loss factors for generation plant.[41]

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:

- Much of the work for the development of the input assumptions used in the latest NTNDP is increasingly out-of-date. For instance, the fuel prices used in the latest NTNDP are based on a report released in the middle of 2012. Similarly, the capital costs used in the latest NTNDP are based on a report released in the middle of 2012. There have been substantial developments in energy markets since then that would be expected to affect these forecasts,

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

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

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

including in regard to forecast exchange rates, technology development and forecast LNG prices.

- 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 input 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 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 because 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.

Peer review of Frontier's estimates

Our input assumption estimates are based on a range of proprietary databases, our energy market models 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 that process, our approach to developing estimates and the estimates themselves were documented publically and subject to stakeholder scrutiny via public consultations and stakeholder submission processes[42].

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.

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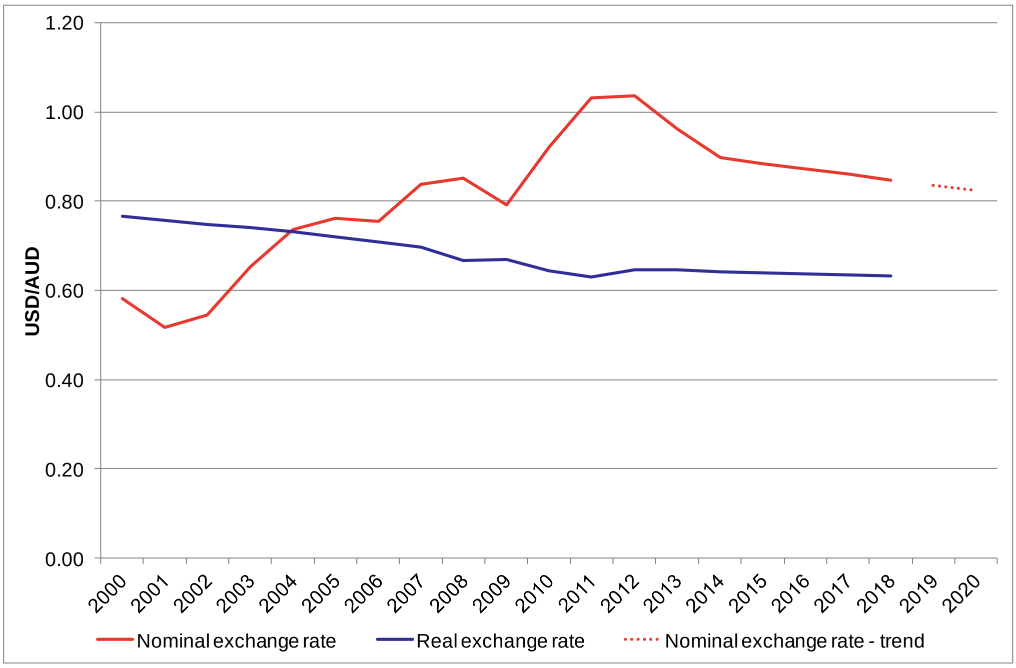
42 See here and here.

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.[43] This data includes historic nominal and real exchange rates as well as forecasts of nominal and real exchange rates out to 2018. For nominal exchange rates, for which we require an exchange rate forecast beyond 2018, we have assumed that exchange rates will continue to follow the trend observed over the last five years of the forecast period to 2018, but will ultimately revert to long-term average exchange rates. Exchange rates for the US dollar are shown in Figure 25 and exchange rates for the Euro are shown in Figure 26.

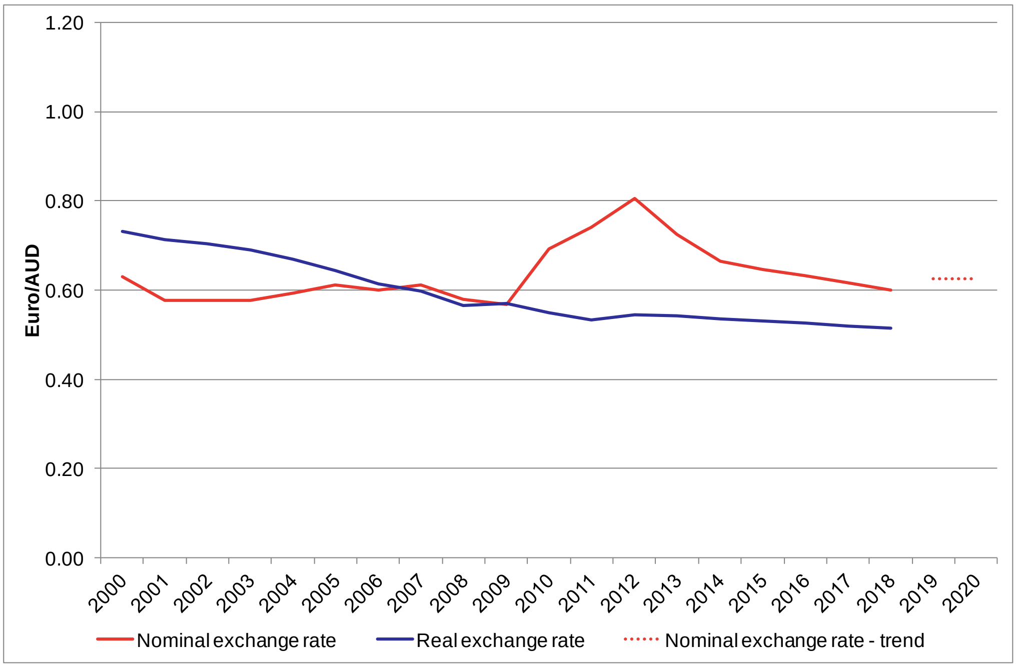
Figure 25: Exchange rates (USD/AUD)



Source: International Monetary Fund, World Economic Outlook Database, October 2013

43 http://www.imf.org/external/pubs/ft/weo/2013/02/

Figure 26: Exchange rates (Euro/AUD)



Source: International Monetary Fund, World Economic Outlook Database, October 2013

Discount rates

We have used different discount rates for different industries. In each case, the discount rate that we have adopted is consistent with IPART's advice on the appropriate WACC for use for that industry. The discount rates that we have used in developing the input assumptions discussed in this report are as follows:[44]

- Electricity generation – 8.60 per cent pre-tax WACC
- Electricity retailing - 10.20 per cent pre-tax WACC
- Coal mining – 9.10 per cent real pre-tax WACC
- Gas production – 9.50 per cent real pre-tax WACC
- Gas transmission – 7.10 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

[44] We also use a discount rate for electricity generation for our electricity market modelling. This is discussed in Frontier's Energy Purchase Cost Draft Report.

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 2012 – 0.38 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 2012 – 0.94 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 2012 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.[45]

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. 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.

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

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, between 2008 and 2015.
- **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 developed economies similar to Australia's. This includes cost estimates from Austria, Belgium, Canada, Denmark, Finland, France, Germany, Ireland, the Netherlands, New Zealand, Norway, Sweden, Switzerland, the United Kingdom and the United States.
- **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.

Our estimates of capital costs are overnight capital costs, expressed in 2013/14 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 27 and Figure 28. Figure 27 deals with gas-fired and coal-fired generation technologies and Figure 28 deals with renewable generation technologies.

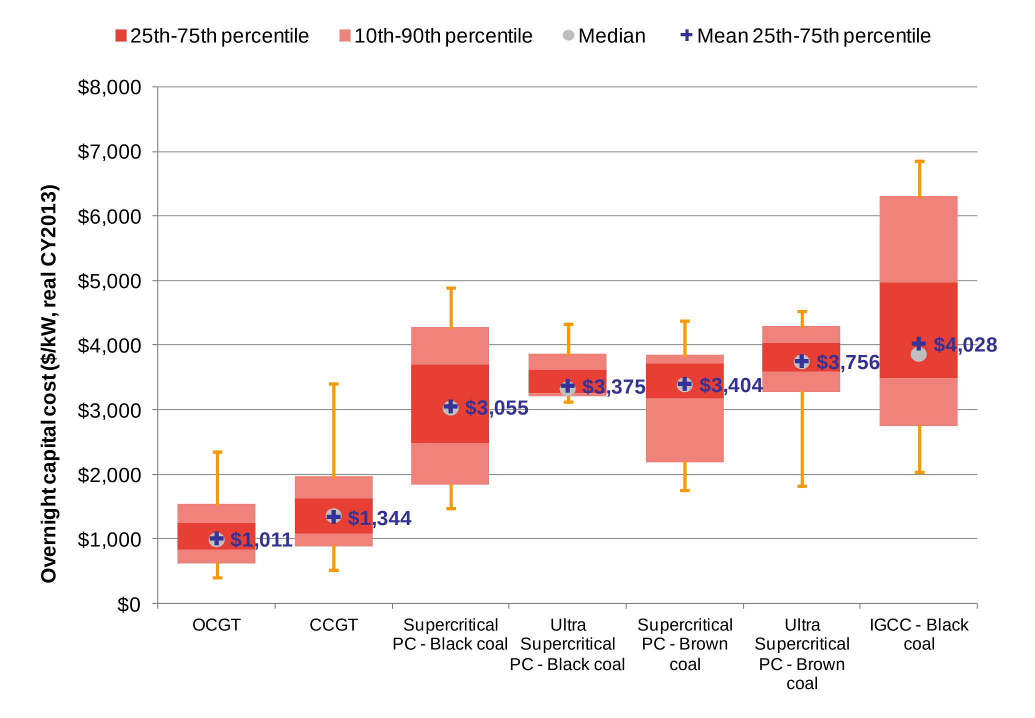
Our estimates of capital costs for each generation technology include a range of individual cost estimates. Even after filtering our global database for relevant countries and years we have a significant number of unique cost estimates for each generation technology. The full range of cost estimates (from lowest cost to highest cost) for each generation technology is shown by the orange "whiskers" in Figure 27 and Figure 28. 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 27 and Figure 28, 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 27 and Figure 28.

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.

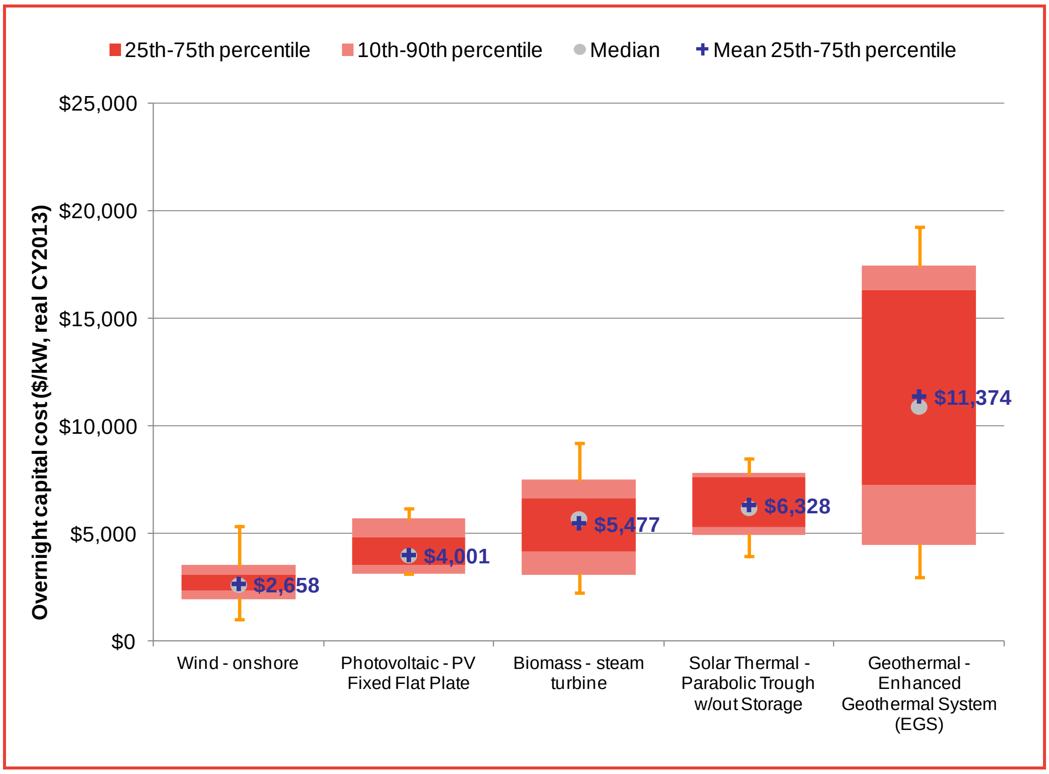
To avoid our analysis being affected by outliers, we estimate current capital costs for each generation technology as the mean of the cost estimates that fall within the 25^{th} to 75^{th} percentile of cost estimates for that generation technology. We note that this mean of the cost estimates that fall within the 25th to 75th 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 25th to 75th percentile is a reasonable approach to dealing with outliers.

Figure 27: Current capital costs for gas and coal generation plant



Source: Frontier Economics

Figure 28: 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 Table 15.

Table 15: Learning curve parameters

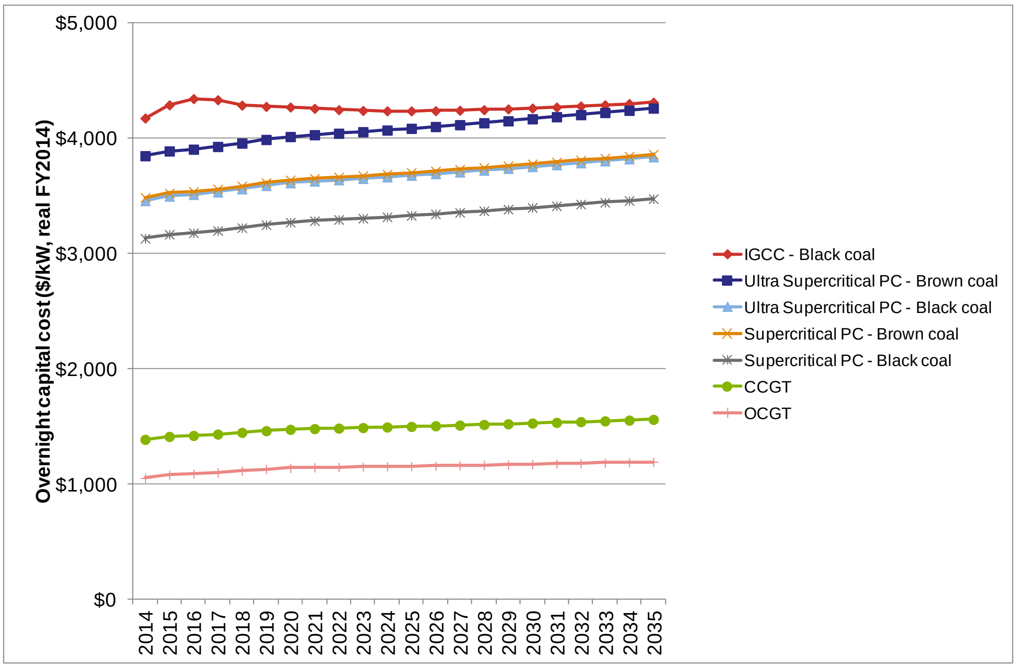
Technology	Cost reduction from (Y_1)	Cost reduction to (Yr_2)	Percent cost reduction over Y_2-Y_1	Implied annual learning rate (2013-Y_2, %)
OCGT	2013	2025	5%	0.41%
CCGT	2013	2025	5%	0.41%
Supercritical PC - Black coal	2013	2025	5%	0.41%
Supercritical PC - Brown coal	2013	2025	5%	0.41%
Ultra Supercritical PC - Black coal	2013	2025	5%	0.41%
Ultra Supercritical PC - Brown coal	2013	2025	5%	0.41%
IGCC - Black coal	2016	2025	10%	1.06%
Biomass - steam turbine	2013	2025	12.5%	0.99%
Wind - onshore	2013	2025	12.5%	0.99%
Geothermal - Enhanced Geothermal System (EGS)	2020	2025	15%	2.83%
Solar Thermal - Parabolic Trough w/out Storage	2015	2030	35%	2.02%
Photovoltaic - Fixed Flat Plate	2015	2030	35%	2.02%

Source: Frontier 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 29 and Figure 30. Figure 29 deals with gas-fired and coal-fired generation technologies and Figure 30 deals with renewable generation technologies. As seen in Figure 29, the capital costs for gas-fired and coal-fired generation plant tend to increase over the modelling period. This is the result of two factors: 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 gas-fired and coal-fired generation technologies are forecast not to benefit from substantial cost improvements, meaning that, overall, costs increase.

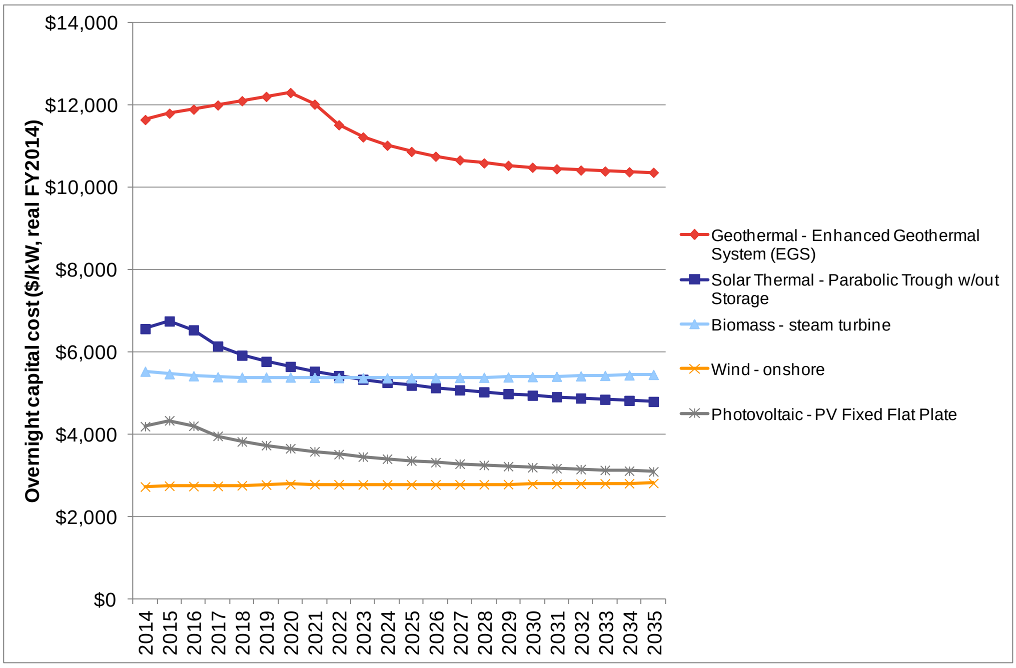
As seen in Figure 30, the capital costs for renewable generation plant are more variable over the modelling period. While these renewable generation plant are subject to increasing costs as a result of real escalation in capital costs and depreciation in the Australia dollar, the cost improvements for these newer technologies are forecast to be more significant. In particular, solar thermal capital costs fall from when widespread commercialisation is assumed to commence in 2015. Cost reductions for geothermal EGS do not occur until widespread commercialisation is assumed to commence from 2020. In contrast, the expected cost improvements for the established renewable technologies – wind and biomass – are more moderate, resulting in more stable costs for these technologies over the modelling period.

Figure 29: Forecast capital costs for gas and coal generation plant ($2013/14)



Source: Frontier Economics

Figure 30: Forecast capital costs for renewable generation plant ($2013/14)



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.
- **Combustion emissions intensity**. Measures the emission rate of the power station relative to the energy produced. For our purposes, the combustion emission intensity is measured as tonnes of CO_2-equivalent emitted through combustion per MWh of sent-out energy. Emissions from coal mining and gas production and transportation are incorporated into forecast fuel cost estimates on a $/GJ basis.

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 these 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. 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 data dating back as far as the 1990s as well as forecasts out to 2050. In order to avoid our estimates being affected by changes in technology and learning curves (particularly for some of the newer technologies), we include data between 2008 and 2015.
- **Filtering by country**. Our global database includes estimates for a wide range of countries, both developed and developing. In order to avoid our estimates being affected by significantly different cost structures or technical requirements, we include estimates only for projects in developed economies similar to Australia's. This includes estimates from Austria, Belgium, Canada, Denmark, Finland, France, Germany, Ireland, the Netherlands, New Zealand, Norway, Sweden, Switzerland, the United Kingdom and the United States.
- **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 2013/14 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.

Basis of technical characteristics

Our assessment of the technical characteristics of new entrant generation technologies is intended to reflect the characteristics for a representative generation plant for each of the generation technologies considered in this report. They are reported on the following basis:

- **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.
- **Combustion emissions intensity**. Measures the emission rate of the power station relative to the energy produced. For our purposes, the combustion emission intensity is measured as tonnes of CO_2-equivalent emitted through combustion per MWh of sent-out energy. Emissions from coal mining and gas production and transportation are incorporated into forecast fuel cost estimates on a $/GJ basis.

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 2011 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 2011 NTNDP planning case supply input spreadsheet.[46]

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

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.[47] 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 of annual and total build limits. Total build limits for each technology by NTNDP Zone are based on AEMO's 2011 NTNDP planning case supply input spreadsheet.[48] 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

47 Ibid.

48 Ibid.

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.

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.[49] 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 BREE's forecast of HCC.[50] 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 31.

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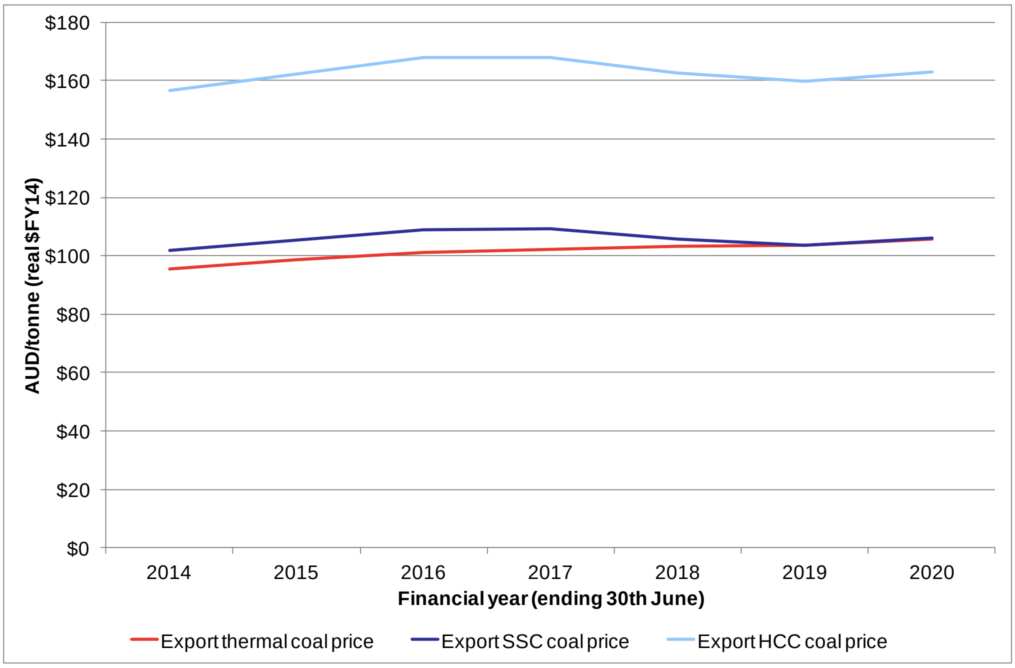
49 See: http://siteresources.worldbank.org/INTPROSPECTS/Resources/334934-1304428586133/Price_Forecast_Jan14.pdf

50 See: http://www.bree.gov.au/publications/resources-and-energy-quarterly

Figure 31: Export coal prices ($2013/14)



Source: Metalytics

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 31 are for coal of a particular quality. For instance, the export thermal coal price shown in Figure 31 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.

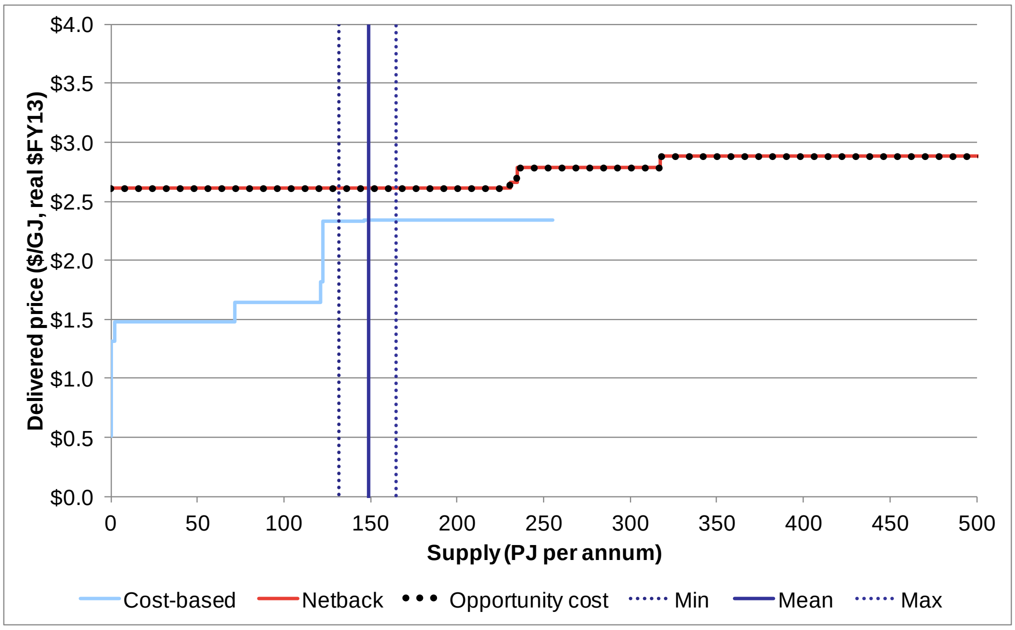
The marginal opportunity cost of coal in each region is determined by the point of intersection of the demand curve for coal in the region and the supply curve for coal in the region.

Demand and supply curves for each coal region are shown in Figure 32 and Figure 33. The vertical blue lines represent the demand curve, with the solid blue line representing the mean annual coal use over the last five years and the dotted blue lines representing the minimum and maximum annual coal use over the last five years. The light blue line represents the supply curve based on resource costs and the red line represents the supply curve based on the net-back price of coal. The dashed black line represents the supply curve that is the opportunity cost for each mine (generally the net-back price of coal but, on occasion, the resource cost of coal).

A couple of things are worth noting about these figures. First, as discussed, the net-back price of coal is above resource costs for almost all coal mines. Second, the range of demand generally intersects the supply curve at a flat part of the supply curve: that is, the coal price forecast is not sensitive to variations in coal demand from the mean.

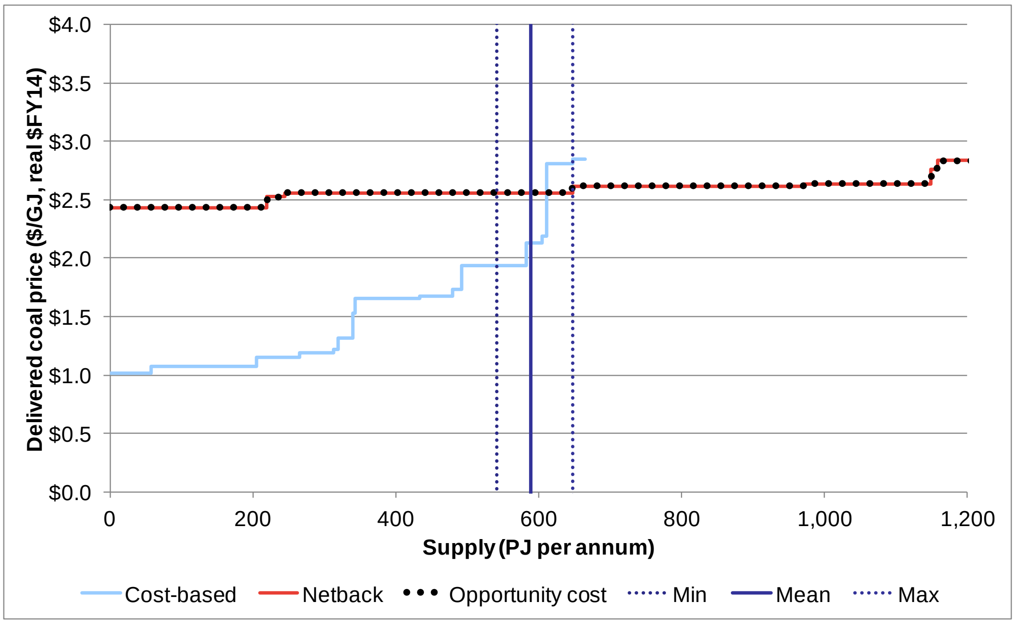
The supply curves for each region that are shown in Figure 32 and Figure 33 are supply curves with reference to the cost of delivery from each coal mine to a particular power station. Even within a single region, however, differences in transport costs result in slight differences in the coal price forecast to power stations that are located in different places.

Figure 32: Central Queensland coal supply and demand ($2013/14)



Source: Frontier Economics

Figure 33: Central NSW coal supply and demand ($2013/14)



Source: Frontier Economics

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

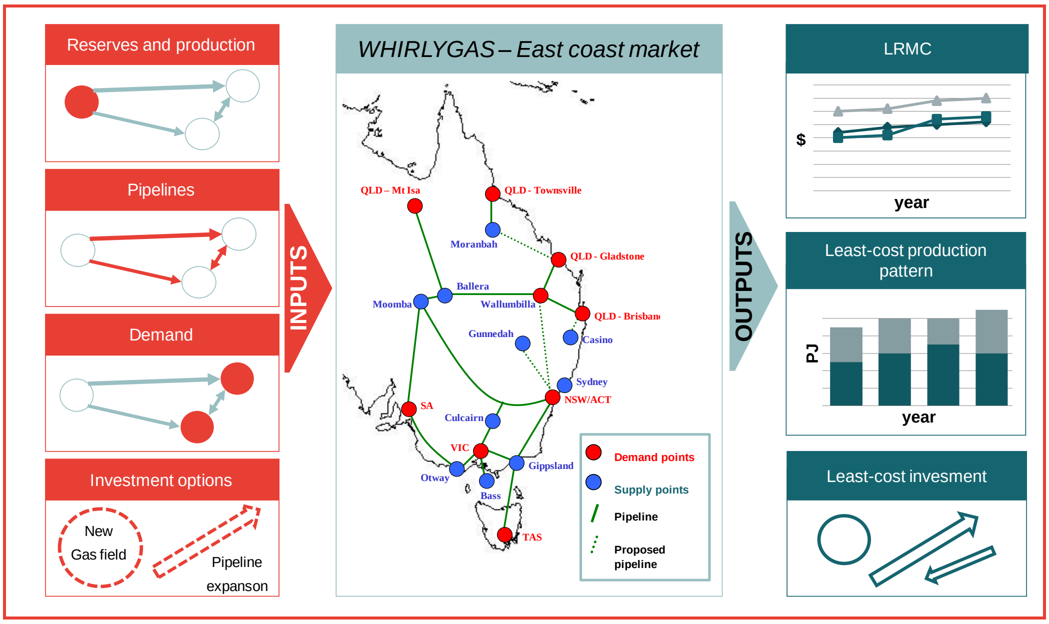
We estimate the cost of gas supplied to gas-fired power stations based on the marginal opportunity cost of gas.

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 34.

Figure 34: *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

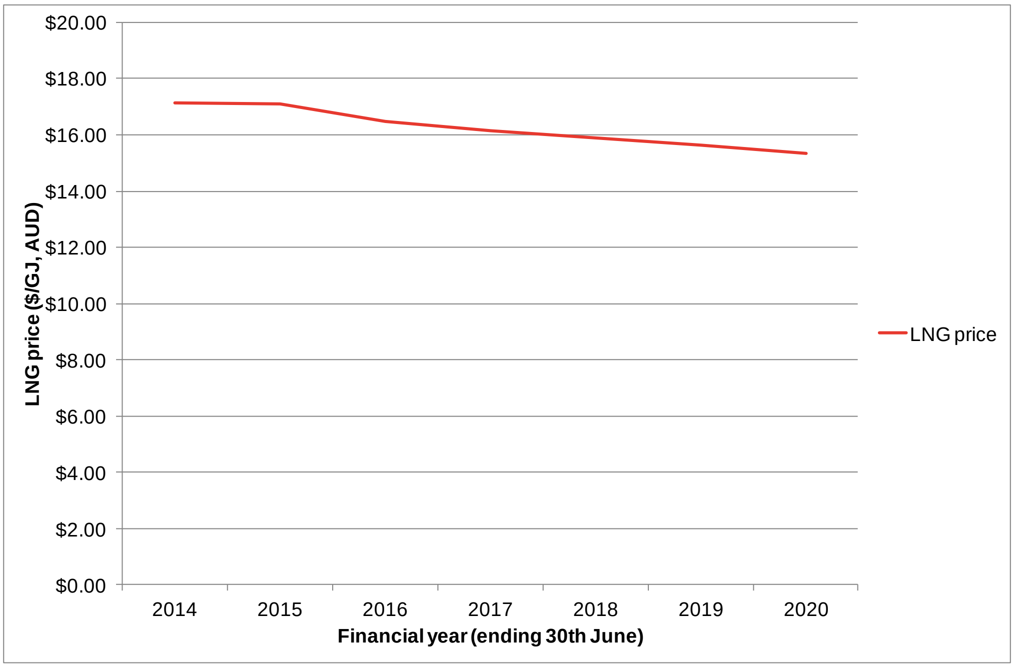
As with our coal forecasting work, opportunity cost is important to our gas forecasting work. The reason that opportunity cost is relevant to assessing the cost to gas producers of supplying gas to gas-fired generators is because the producers may well be foregoing alternative markets for that gas. For 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.[51] 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 35.

51 http://siteresources.worldbank.org/INTPROSPECTS/Resources/334934-1304428586133/Price_Forecast_Jan14.pdf

Figure 35: Japan LNG prices ($2013/14)



Source: World Bank, Commodity Price Forecast, January 2014

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:

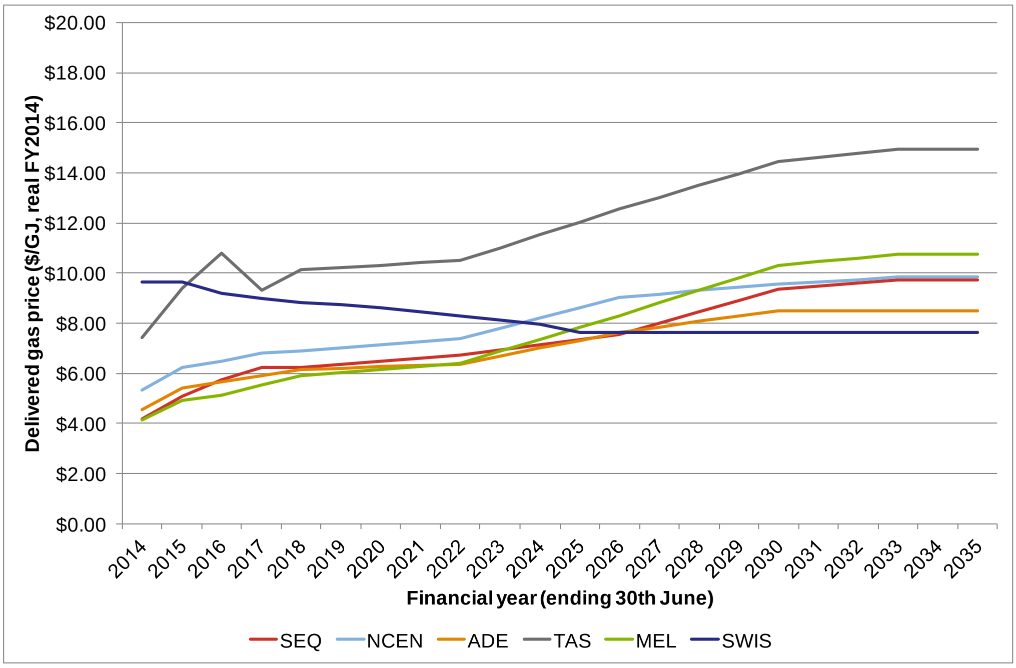
- Forecasts of the LRMC of satisfying demand in each demand region.
- Forecasts of investment in new production plant in eastern Australia.
- Forecasts of investment in new transmission pipelines in eastern Australia.
- Forecasts of production rates for existing and new production plant.

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

Gas price forecasts

Figure 36 presents the forecast LRMC of gas for each of the State capital cities. The LRMC presented is for the base case modelling, which incorporates the development of 6 LNG trains at Gladstone over the modelling period.

Figure 36: LRMC of gas by State capital cities ($2013/14)



Source: Frontier Economics

Figure 36 shows that, with the exception of Tasmania, the LRMC of gas in eastern Australia in 2014/15 is around $5.00/GJ to $6.00/GJ. This result for 2014/15 is reasonably consistent with recent spot prices observed on the STTM.

Figure 36 also shows that there is a general trend towards an increase in the LRMC over the modelling period in eastern Australia:

- In the southern states, including in the ADE, MEL and NCEN NTNDP Zones, the LRMC of gas trends up steadily over time. The LRMC of gas in these regions is linked, with differences in the cost of transporting gas between regions accounting, in large part, for differences in the LRMC of gas between regions. The trend towards higher LRMC that occurs in each of the southern states is driven in large part by the need to source gas from more expensive gas production plant as demand grows over time.

- In Queensland, including in the SEQ NTNDP Zone, the increase in the LRMC of gas is more pronounced. This is a result of the fact that the gas market in Queensland is more exposed to the commencement of LNG exports from Gladstone.
- In Tasmania, prices are substantially higher than in other regions, and are more volatile, particularly over the early years of the modelling period. There are two reasons that prices are so much higher in Tasmania: the additional cost of gas transmission through the TGP are significant; the gas demand forecasts from the AEMO 2013 GSOO forecast very peaky demand for gas in Tasmania, which increases the unit cost of gas.
- In Western Australia, in contrast, the LRMC of gas falls over the modelling period. The reason for this different pattern is that the gas market in Western Australia is already exposed to export markets, so that the price in Western Australia is driven by changes to the net-back price. With the forecast reduction in the Asia-Pacific LNG price, the gas price in Western Australia also falls.

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).

Appendix B – Energy purchase cost results

This section presents all energy purchase cost estimates in Table 16.

Table 16: Energy purchase cost results – $/MWh, real $2013/14

Approach	FYe	Region	Area	Base	Carbon	Low Demand	High Fuel
Market-based	2014	QLD	Energex	$66.31	$66.31	$66.31	$70.59
	2014	NSW	Essential	$62.67	$62.67	$62.67	$66.75
	2014	NSW	Ausgrid	$65.26	$65.26	$65.26	$69.49
	2014	NSW	Endeavour	$65.02	$65.02	$65.02	$69.24
	2014	ACT	ACTEWAGL	$64.97	$64.97	$64.97	$69.17
	2014	VIC	Citipower	$66.96	$66.96	$66.96	$71.50
	2014	VIC	Powercor	$64.41	$64.41	$64.41	$68.77
	2014	VIC	SP Ausnet	$66.18	$66.18	$66.18	$70.70
	2014	VIC	United	$67.61	$67.61	$67.61	$72.16
	2014	VIC	Jemena	$67.34	$67.34	$67.34	$71.88
	2014	TAS	TAS	NA	NA	NA	NA
	2014	SA	SA	$86.99	$86.99	$86.99	$94.84
	2014	WA	WA	NA	NA	NA	NA
	2015	QLD	Energex	$44.75	$69.42	$43.17	$50.38
	2015	NSW	Essential	$40.03	$64.33	$38.96	$44.20
	2015	NSW	Ausgrid	$42.28	$66.97	$41.15	$46.63
	2015	NSW	Endeavour	$41.87	$66.74	$40.75	$46.19
	2015	ACT	ACTEWAGL	$42.19	$66.67	$41.06	$46.55
	2015	VIC	Citipower	$42.96	$64.29	$40.43	$47.65
	2015	VIC	Powercor	$40.78	$61.86	$38.38	$45.23
	2015	VIC	SP Ausnet	$42.58	$63.50	$40.05	$47.26
	2015	VIC	United	$43.63	$64.93	$41.07	$48.37

Approach	FYe	Region	Area	Base	Carbon	Low Demand	High Fuel
	2015	VIC	Jemena	$43.34	$64.66	$40.79	$48.06
	2015	TAS	TAS	NA	NA	NA	NA
	2015	SA	SA	$59.47	$74.14	$56.65	$66.70
	2015	WA	WA	NA	NA	NA	NA
	2016	QLD	Energex	$44.91	$56.04	$42.57	$49.93
	2016	NSW	Essential	$39.83	$48.61	$39.40	$43.72
	2016	NSW	Ausgrid	$42.06	$51.25	$41.61	$46.14
	2016	NSW	Endeavour	$41.65	$50.77	$41.21	$45.70
	2016	ACT	ACTEWAGL	$41.98	$51.17	$41.53	$46.06
	2016	VIC	Citipower	$40.49	$49.19	$38.93	$44.60
	2016	VIC	Powercor	$38.44	$46.69	$36.96	$42.34
	2016	VIC	SP Ausnet	$40.12	$48.81	$38.55	$44.22
	2016	VIC	United	$41.14	$49.94	$39.55	$45.29
	2016	VIC	Jemena	$40.86	$49.62	$39.28	$45.00
	2016	TAS	TAS	NA	NA	NA	NA
	2016	SA	SA	$50.92	$59.23	$54.04	$57.14
	2016	WA	WA	NA	NA	NA	NA
	2017	QLD	Energex	$46.48	$57.30	$44.05	$51.76
	2017	NSW	Essential	$40.39	$49.40	$39.60	$44.69
	2017	NSW	Ausgrid	$42.66	$52.07	$41.82	$47.15
	2017	NSW	Endeavour	$42.24	$51.59	$41.42	$46.70
	2017	ACT	ACTEWAGL	$42.57	$51.99	$41.74	$47.06
	2017	VIC	Citipower	$40.00	$48.67	$37.10	$44.52
	2017	VIC	Powercor	$37.98	$46.19	$35.21	$42.27
	2017	VIC	SP Ausnet	$39.63	$48.28	$36.72	$44.15

Approach	FYe	Region	Area	Base	Carbon	Low Demand	High Fuel
	2017	VIC	United	$40.64	$49.40	$37.69	$45.21
	2017	VIC	Jemena	$40.36	$49.09	$37.43	$44.92
	2017	TAS	TAS	NA	NA	NA	NA
	2017	SA	SA	$47.36	$56.84	$47.78	$53.14
	2017	WA	WA	NA	NA	NA	NA
Stand-alone LRMC	2014	QLD	Energex	$85.79	$85.79	NA	$89.18
	2014	NSW	Essential	$84.23	$84.23	NA	$84.23
	2014	NSW	Ausgrid	$102.12	$102.12	NA	$102.12
	2014	NSW	Endeavour	$104.05	$104.05	NA	$104.05
	2014	ACT	ACTEWAGL	$101.12	$101.12	NA	$101.12
	2014	VIC	Citipower	$84.68	$84.68	NA	$91.41
	2014	VIC	Powercor	$82.08	$82.08	NA	$88.77
	2014	VIC	SP Ausnet	$89.76	$89.76	NA	$96.56
	2014	VIC	United	$87.05	$87.05	NA	$93.84
	2014	VIC	Jemena	$85.47	$85.47	NA	$92.24
	2014	TAS	TAS	$117.74	$117.74	NA	$120.77
	2014	SA	SA	$104.40	$104.40	NA	$108.54
	2014	WA	WA	$147.98	$147.98	NA	$150.74
	2015	QLD	Energex	$84.43	$93.76	NA	$93.02
	2015	NSW	Essential	$76.06	$85.35	NA	$76.06
	2015	NSW	Ausgrid	$94.17	$103.66	NA	$94.17
	2015	NSW	Endeavour	$96.25	$105.65	NA	$96.25
	2015	ACT	ACTEWAGL	$93.13	$102.61	NA	$93.13
	2015	VIC	Citipower	$82.85	$91.58	NA	$92.33
	2015	VIC	Powercor	$80.21	$88.93	NA	$89.65

Approach	FYe	Region	Area	Base	Carbon	Low Demand	High Fuel
	2015	VIC	SP Ausnet	$89.01	$96.87	NA	$97.67
	2015	VIC	United	$85.29	$94.07	NA	$94.86
	2015	VIC	Jemena	$83.66	$92.43	NA	$93.21
	2015	TAS	TAS	$124.56	$133.65	NA	$130.04
	2015	SA	SA	$103.26	$112.36	NA	$110.15
	2015	WA	WA	$130.28	$149.81	NA	$132.11
	2016	QLD	Energex	$89.97	$93.23	NA	$97.86
	2016	NSW	Essential	$75.24	$78.50	NA	$75.24
	2016	NSW	Ausgrid	$93.44	$96.77	NA	$93.44
	2016	NSW	Endeavour	$95.58	$98.87	NA	$95.58
	2016	ACT	ACTEWAGL	$92.39	$95.72	NA	$92.39
	2016	VIC	Citipower	$84.55	$87.62	NA	$94.89
	2016	VIC	Powercor	$81.89	$84.95	NA	$92.18
	2016	VIC	SP Ausnet	$89.84	$92.93	NA	$100.30
	2016	VIC	United	$87.03	$90.11	NA	$97.45
	2016	VIC	Jemena	$85.38	$88.47	NA	$95.79
	2016	TAS	TAS	$135.07	$138.24	NA	$141.03
	2016	SA	SA	$105.60	$108.78	NA	$113.07
	2016	WA	WA	$130.01	$136.97	NA	$131.93
	2017	QLD	Energex	$94.07	$97.46	NA	$104.36
	2017	NSW	Essential	$75.69	$79.08	NA	$75.69
	2017	NSW	Ausgrid	$94.07	$97.53	NA	$94.07
	2017	NSW	Endeavour	$96.23	$99.66	NA	$96.23
	2017	ACT	ACTEWAGL	$93.00	$96.47	NA	$93.00
	2017	VIC	Citipower	$87.94	$91.14	NA	$101.47

Approach	FYe	Region	Area	Base	Carbon	Low Demand	High Fuel
	2017	VIC	Powercor	$85.25	$88.44	NA	$99.30
	2017	VIC	SP Ausnet	$93.33	$96.54	NA	$107.23
	2017	VIC	United	$90.47	$93.69	NA	$104.07
	2017	VIC	Jemena	$88.80	$92.01	NA	$102.38
	2017	TAS	TAS	$124.78	$128.11	NA	$131.47
	2017	SA	SA	$108.10	$111.41	NA	$116.15
	2017	WA	WA	$130.28	$137.45	NA	$132.27

Source: Frontier Economics

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