RET Review Analysis

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

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Executive summary

What we have been asked to do

Frontier Economics was asked by the AEMC to investigate the impact of the Renewable Energy Target (RET) on Australia's electricity markets as part of the AEMC's 2014 Residential Electricity Price Trends report. This report details the inputs, methodology and results of the analysis. The RET as currently legislated, and a number of alternative RET scenarios, have been assessed in terms of both economic costs as well as wholesale and retail price impacts.

RET scenarios

The RET comprises a large-scale target (LRET) and a small-scale scheme (SRES). Targets for the scheme were originally set with reference to a percentage of forecast demand (20% by 2020) at a time when demand growth was expected to continue. However, the scheme target was set in fixed TWh terms (41 TWh under the LRET by 2020). In practice, demand has achieved lower than expected growth rates and even fallen in some jurisdictions. As a result, the fixed LRET target, combined with SRES and existing renewable production, corresponds to more than 20% of current demand forecasts in 2020. As such, the Commonwealth Government's RET Review Panel is undertaking a review of the scheme.

Currently, the SRES is predominantly being met by rooftop solar PV systems. The uptake of solar PV, others things being equal, reduces demand for electricity from the grid. Our modelling has focused on outcomes in Australia's wholesale electricity markets, assuming a forecast of demand that accounts for solar PV uptake rates. The scenarios considered in the modelling focus on the large-scale target, which has been and is likely to continue to be met by commercial wind farms.

Reflecting this focus, the scenarios modelled cover the current LRET target, revising the LRET down to with reference to 20% of current demand forecasts, combining the LRET with the SRES production to reference 20% of current demand forecasts and capping the RET at current production levels. The LRET is assumed to end in 2030 in all scenarios.

The scenarios that we have modelled are summarised in Table 1.

Table 1: Scenarios considered in the modelling

Scenario	Description	LRET target in 2020s
No Policy Change	Current legislation	41 TWh
RET 20	Reduction in LRET target to reflect 'true' 20% against Low demand forecasts, SRES unchanged	30 TWh
RET 20 Combined	LRET + SRES target reduced to reflect 'true' 20% against Low demand forecasts, modelled as a fixed SRES and reduced LRET	23 TWh
RET Capped	No further LRET investment occurs	16 TWh

Other key assumptions

In modelling Australia's electricity markets over the long term the following key assumptions are common to all scenarios and drive the outcomes of the modelling.

- **Demand:** The modelling uses the 2013 'Low Demand' forecasts released by the two market operators (AEMO and the IMO). These forecasts are broadly consistent with 2013/14 year to date outcomes and involve little growth in demand into the long term with the exception of Queensland and Western Australia.
- **Fuel costs:** Coal and gas price estimates for all existing power stations and potential new entrants are based on Frontier Economics' current base case forecasts[1]. These estimates reflect long term, international commodity prices, exchange rates, domestic costs of resource extraction, processing and transport and relevant constraints. In most NEM jurisdictions, delivered gas prices start at $5-6/GJ and rise to $8-11/GJ in real 2013/14 dollar terms by 2030. Delivered coal prices for export exposed power stations start at approximately $3/GJ and rise to $3.5-4/GJ in real 2013/14 dollar terms by 2030. Coal prices for mine-mouth power stations are at lower levels and relatively constant in real terms.
- **Capital costs:** Forecasts of capital costs for a range of technologies reflect Frontier Economics' current base case forecasts. The most relevant capital cost is for large scale wind farms, which are estimated to cost $2,300-2,500/kW over the modelling period.

1 Frontier Economics maintains its own set of supply side modelling input assumptions which are discussed in detail in Appendix B of this report.

- **Carbon costs:** The modelling has assumed a permanent repeal of carbon pricing as of 1 July 2014.

Results

The analysis focused on two main results: resource and shortfall costs associated with the RET; and, the RET's impact on residential bills.

The RET, by subsidising investment in renewable generators that are not needed to met demand and/or are more expensive than alternatives, increases the resource costs associated with the operation of Australia's electricity markets. This is the pure economic cost associated with the capital cost of wind farms and other generators built under the scheme net of any avoided fuel costs of existing generators that operate at lower levels due to wind entry. These resource costs are presented in net present value (NPV) terms in Table 2.

Resource costs are lowest in the RET Capped scenario (where no further investment occurs under the LRET) and highest in the No Policy Change scenario (reflecting the highest LRET target across the scenarios). Differences in resource costs are also presented in Table 2 relative to the RET Capped scenario. For example, the incremental resource costs associated with retaining the current policy versus capping further investment under the LRET is $4.284 billion in NPV terms (real $2013/14). This cost is primarily driven by the additional 3 GW of wind built in the No Policy Change scenario to meet the LRET.

Apart from the RET Capped case, we forecast that there will be shortfalls under the scheme, even when the target is reduced. Shortfalls against the target can occur if a liable entity (a retailer) chooses to pay the penalty price rather than source LRET certificates.

This outcome is driven by a number of key assumptions – low demand growth into the long term, the permanent removal of the carbon price (which acts to lower wholesale prices and increase the subsidy needed for a renewable generator to recover its costs) and modelling an end to the scheme from 2030. To the extent that gas prices rise above the assumed levels of $8-11/GJ in the long term, this may act to reduce shortfalls under the RET (via higher wholesale prices).

Shortfalls do not represent a pure economic cost (a resource cost) but are rather a transfer from consumers to the Government. If significant shortfalls eventuated under the scheme, the penalty price could be raised and/or other changes made to the RET, which would change outcomes under the scheme. The NPV impact of shortfalls is shown in Table 2.

Table 2: Summary of resource cost and shortfall cost results ($m NPV, real $2013/14)

Scenario	NPV resouce costs	Difference in NPV resource costs (from RET Capped case)	NPV shortfall costs
RET Capped	$59,949		$0
RET 20 Combined	$61,676	$1,727	$561
RET 20	$63,186	$3,237	$1,480
No Policy Change	$64,232	$4,284	$3,529

The economic cost of the RET is borne by different stakeholders across the economy depending on how investment under the RET impacts on wholesale, and ultimately retail, electricity prices. Retailers are liable to surrender LRET and SRES certificates, and direct costs of sourcing these certificates are passed onto consumers.

Offsetting this to some extent, low variable cost generators (such as RET-eligible plant) suppress wholesale electricity prices via the so called 'merit order effect'. To the extent that these reductions in wholesale costs are reflected in retail electricity prices, electricity consumers may achieve lower bills. However, reductions in wholesale prices also impact non-RET generators (via lower revenues). As such, the economic cost of the RET is borne by electricity consumers and existing, non-RET generators, although how these costs are allocated depend on pricing outcomes over the long term.

The results of our analysis indicate that in net terms, consumers are likely to pay more for electricity due to the RET over the next decade. Representative customer bills in most jurisdictions will be $25-75 per annum higher in the No Policy Change case compared to the RET Capped case. Post-2025, outcomes are less certain. To the extent that market prices in each scenario remain subdued (near the short-run marginal cost levels relevant to the scenario) the RET will continue to impose a net cost on consumers. If market prices in each scenario rise to higher levels (higher than the short-run marginal cost levels relevant to the scenario) then the RET may lead to lower consumer bills in some cases (i.e. the direct cost to consumers from the RET is more than offset by lower wholesale prices).

2 Introduction

This section describes the analysis undertaken and outlines the structure of this report.

2.1 What we have been asked to do

Frontier Economics was asked by the AEMC to investigate the impact of the RET on Australia's wholesale electricity markets the NEM and the SWIS. The analysis focuses on the outcomes in these markets in terms of investment, retirements, dispatch, emissions and pricing for the currently legislated scheme and a number of alternative RET target scenarios. Using these results, the impact of the RET in terms of economic costs has been estimated as well as wholesale and retail price impacts.

2.2 About this report

This report is structured as follows:

- Section 3 provides background on how the RET works.
- Section 4 presents the approach we have used to assess the impact of the RET.
- Section 5 details the assumptions used in the analysis and scenarios modelled.
- Section 6 outlines the results of our analysis.
- Section 7 discusses the conclusions of our analysis.
- Appendix A provides more detail on the economics of green schemes.
- Appendix B presents Frontier's detailed supply-side input assumption estimates.

3 Economic assessment of the RET

This section provides a brief overview of the RET scheme and sets out the economic principles relevant to an assessment of the implications of the scheme for economic costs and for prices.

3.1 What the RET does

The Renewable Energy Target (RET) is a "green certificate scheme" comprising a Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES). The objective of the scheme is to encourage additional generation from renewable sources and reduce emissions of greenhouse gases from the electricity sector.

For both the large-scale and small-scale schemes, eligible renewable generators can create certificates (large-scale generation certificates (LGCs) and small-scale technology certificates (STCs)) for output. These tradeable certificates can be sold to liable parties (retailers) and are ultimately paid for by electricity consumers via retailer cost pass-through in retail tariffs. The scheme certificates provide a subsidy to renewable generation which, on top of the wholesale pool price or other sources of revenue, aims to ensure renewable generators costs are recovered. This subsidy encourages increased output from renewable generation, which is less concerned with the wholesale pool price than the bundled price (the combination of pool prices and certificate revenue). The operation of the scheme, costs and transfers are discussed below.

3.2 Costs, prices and the RET

The RET has a number of general impacts on Australia's electricity markets and the wider economy, in terms of economic costs to society and transfers between different participants via an impact on wholesale and retail electricity prices[2].

To the extent that the RET acts to subsidise investment in and production from renewable generators that would not have occurred absent the scheme, the scheme imposes incremental economic costs on the economy. These economic costs reflect the net increase in *resource costs* that arise from meeting the demand for electricity with investment in higher total cost renewable generators compared to running existing, or investing in lower cost, generation technologies. This cost may be offset to some extent by a reduction in variable costs of existing thermal power stations to the extent that renewables displace such plant.

2 Appendix A presents a detailed description of these effects.

Whilst the magnitude of this economic cost depends on a number of factors - the scheme target, supply-demand conditions, relative generation costs, interaction with other policies (such as carbon pricing), etc - it is clear that while renewables remain above grid parity cost levels, the RET will increase resource costs in Australia's electricity markets.

Who bears this cost is far less certain. This is because the RET creates a number of direct and indirect transfers in the economy via wholesale and retail pricing impacts. The two most important pricing impacts are:

- **A direct effect via increases in retail electricity prices to reflect the cost of retailers complying with the RET.** This represents a transfer from consumers of electricity to renewable generators via electricity retailers as the liable entity under the scheme and is facilitated by the market for LGC and STC certificates. This is mostly consistent with the increase in resource cost of the scheme, as certificate revenue should largely reflect the higher resource cost of generating from renewable as opposed to non-renewable plant.
- **An indirect 'merit order effect' on wholesale and retail electricity prices.** Investment in renewables, other things being equal, adds additional low variable cost supply to the NEM and SWIS. This supply will tend to displace existing, higher variable cost, thermal generators and act to suppress wholesale pool prices. To the extent that lower wholesale prices eventuate then it is likely that they will be passed into lower retail prices via retail competition. This 'merit order effect' on retail electricity prices will offset the direct RET compliance effect to some extent and may overwhelm it. The merit order effect is a transfer from generators (who earn lower wholesale pool prices) to electricity consumers (who pay lower wholesale energy prices). To the extent that the RET promotes the retirement of existing generators, then the merit order effect will be weakened. This merit order effect reflects increased supply of capacity and is not unique to renewables: a subsidy to new gas/coal capacity would have similar effects and would involve far less resource costs.

The merit order effect of the RET complicates analysis of the impact of the scheme. When comparing different models, modelling results, or modelling approaches, there is generally consistency regarding estimates of the resource costs. These resource costs are always higher for a higher RET. There is more variability across different models/approaches regarding the indirect impacts (the size of the merit order effect on prices and hence on consumers). This reflects the distribution of the resource cost, or the extent of transfers from existing generators to consumers. If analysis suggests that the merit order effect outweighs the resource cost of the scheme (i.e. that consumers are better off for a stronger RET) then this implies that non-renewable generators effectively fund the RET in the form of lower prices.

Whilst the impact of the direct RET compliance cost on the retail prices can be estimated in a relatively straightforward manner (depending only on a forecast of certificate prices and the scheme target relative to demand) the merit order effect is much harder to forecast, particularly over long timescales. Wholesale pricing outcomes are influenced by a range of factors - demand, fuel costs, carbon costs, generation retirements, market structure - all of which interact with the RET in a complex fashion. As such, the magnitude of the merit order effect will be different over time and across different jurisdiction. The key questions are:

- Does the scheme reduce the profitability of existing generators to the point where large scale retirements occur?
- Does the merit order effect offset or overwhelm the direct impact of the scheme, i.e. do consumers face higher or lower retail electricity prices in net terms?

The analysis presented in this report seeks to answer these questions.

3.3 Risk sharing under the RET

Currently the LRET is expressed as a fixed TWh target (41TWh from 2020-2030), though this is subject to bi-annual reviews in the interim. This does not expressly vary with changes in demand, unless accounted for during a review.

When the initial 41TWh target was set, the target was based on projected demand of around 300TWh by 2020. The combined LRET and SRES target of 45 TWh reflected approximately 15% of the 300TWh expected demand. When added to output from pre-existing hydro (~15TWh, which is renewable but ineligible to create LGCs) this resulted in a renewable target of 20% (i.e. total renewable output of 60 TWh against expected total demand of 300 TWh). Recent energy demand projections are now substantially lower by 2020 (NEM and SWIS) due to a number of factors. With the LRET and SRES unchanged at current levels, this implies a total renewables share would likely be closer to around 27% (new and pre-existing renewables)[3]. In the previous and current RET reviews, some parties (existing generators) have proposed a reduction in the target to reflect a "true" 20% by 2020 based on more recent (lower) demand projections.

Currently, renewable generators (or their contractual offtakers) face minimal risk: if pool prices fall, LGC prices are likely to rise to offset this. If overall energy demand falls, the LRET target is generally unchanged (unless explicitly varied as

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3 In calendar year 2020, national demand on a native, Sent Out basis, reflecting AEMO and the IMO's 2013 Low Scenario forecasts, plus 7.5 TWh of Rooftop PV production, plus 17 TWh of off-grid production, equates to approximately 240 TWh. Renewable production is the 41.85 TWh under the LRET, 7.5 TWh of Rooftop Solar under SRES and 15 TWh of existing production for a total of 64.3 TWh equating to 26.8% of demand. Note, 2 TWh of voluntary Greenpower is in addition to this 26.8% renewable production.

part of a RET review process). In contrast, non-renewable generators face the risk of falling demand (and increased entry from new renewables) via falling wholesale prices and revenues. This can arguably undermine the operation of the NEM to the extent that a large volume of supply/new entrant generation is largely unresponsive to energy demand and pool prices (the market signal). This issue becomes particularly acute when the level of renewable investment required to meet the target exceeds growth in demand such that new entrant renewables significantly displace existing generators, reducing both their volume of dispatch and the price received on that volume. This is the current situation in the NEM, where a wedge is opening between wholesale prices (which are suppressed by the RET) and retail prices (which reflect reduced wholesale prices due to the merit order effect and increases to recover retailers LGC purchases).

Existing non-RET eligible generators are facing an uncertain future around investments made in good faith. Similarly, RET eligible generators have invested under the current RET arrangements where they are not exposed to downside system demand risk. In an over supplied market, with a policy that will lead to significant further over supply, ensuring investor certainty for both RET and non-RET generators will likely involve increased costs on electricity consumers.

4 Modelling methodology

This section provides a brief overview of our electricity market models and how we use these models to investigate the effects on the electricity market of the RET.

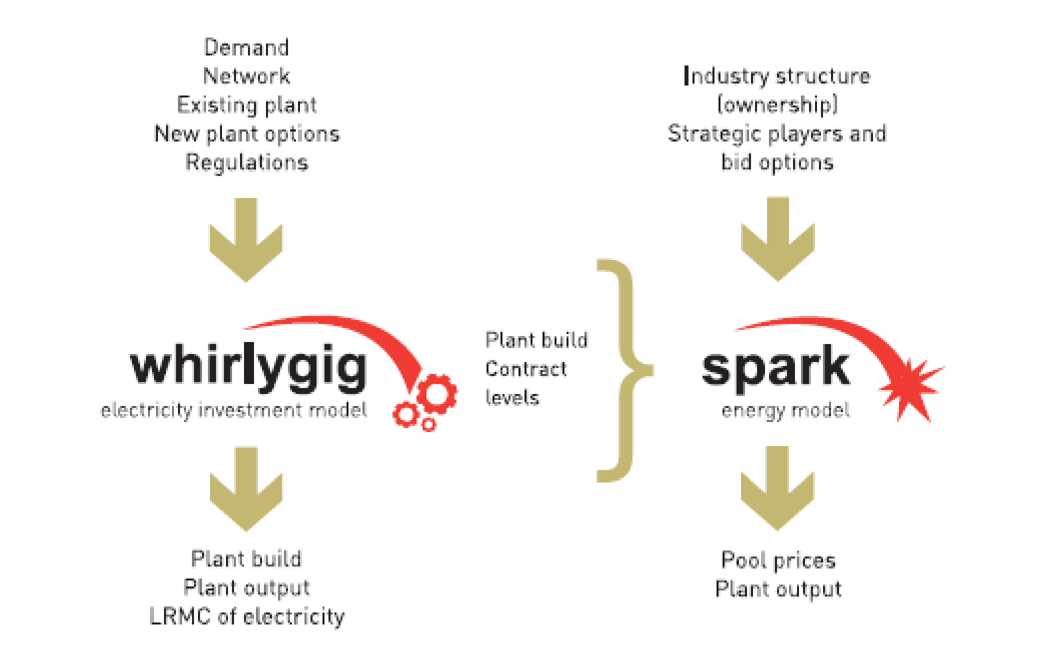
4.1 Frontier Economics' modelling framework

For the purposes of modelling the effects of the RET, we adopt a two-staged modelling approach, which makes use of two inter-related electricity market models: *WHIRLYGIG* and *SPARK*. 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 modelled regulatory obligations. *WHIRLYGIG* can be configured to perform a stand-alone LRMC estimate of wholesale energy costs or to model the NEM in order to provide estimates of the cost of meeting the LRET target and an investment pattern that can be used as an input to *SPARK*.
- *SPARK* uses game-theoretic techniques to identify mutually-compatible and hence stable patterns of bidding behaviour by generators in the electricity market. *SPARK* determines Nash Equilibrium sets of generator bidding strategies by having regard to the incentives for generators to alter their behaviour in response to the bids of other generators. The model determines profit outcomes from all possible combinations of bidding strategies (taking into account assumed contract positions) and finds Nash Equilibrium sets of bidding strategies in which no generator has an incentive to deviate from its chosen strategy. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.

The relationship between these electricity market models is summarised in Figure 1.

Figure 1: Frontier Economic' electricity market modelling framework



** Plant output from WHIRLYGIG and SPARK differs due to different assumptions about bidding behaviour*

4.2 Modelling the RET

The **first step** of our modelling of the RET is to model the effect of the RET on least cost investment and dispatch in the electricity market. We do this by including a constraint in *WHIRLYGIG* to ensure that the amount of renewable generation required by the RET is generated. The constraint that we include allows banking and borrowing over the life of the RET consistent with the scheme rules. This means that *WHIRLYGIG* will invest in and operate renewable generation plant to meet the RET in the years that it is least cost to do so (subject to the limits on borrowing under the scheme rules). The constraint is also subject to the penalty price under the scheme rules. This means that *WHIRLYGIG* will only invest in and operate renewable generation plant to meet the RET if it is cheaper to do so than it is to pay the penalty price under the scheme rules. This optimisation is performed concurrently with investment in, and dispatch of, the wider markets (the NEM and the SWIS) so that trade-offs between renewable and thermal investment are determined in an internally consistent manner.

There are two key outputs from our modelling that are used in our assessment of the effects of the RET:

- **Investment in generation plant** - the least cost investment path from *WHIRLYGIG*, for both renewable and thermal plant, is used as an input into our *SPARK* modelling and the costs of this investment in generation plant is used in estimating total resource costs. So, for instance, as wind plant is built in *WHIRLYGIG* to meet the RET target, that wind plant is incorporated in our *SPARK* modelling. *WHIRLYGIG* also provides an estimate of plant retirements which is discussed further below.

- **The LRMC of meeting the RET** - 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. An incremental increase in the LRET target can be met by additional generation by eligible renewable generators at any point in the modelling period (subject to the ability to bank and borrow under the scheme) or can be met by paying the penalty price for the additional generation. Modelling the LRMC of the LRET in this way accounts for the interaction between the energy market and the market for LGCs, and also accounts for the temporal dimension of the RET scheme.

The **second step** of our modelling of the RET is to model the market-based effects of RET. We do this by incorporating the investment outcomes from *WHIRLYGIG* into our *SPARK* modelling and modelling market dispatch with these investment outcomes. So, for instance, where the RET results in investment in additional wind generation in *WHIRLYGIG*, this additional wind capacity is incorporated in our market modelling. Since wind generation has very low marginal cost, this additional wind capacity will occur at the bottom of the dispatch merit order. In this way, our modelling framework is able to capture the effect on the merit order of investment in renewable plant that is driven by the RET.

4.2.1 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
- 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 discussed in Section 3.2. 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 consumers. 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.

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 marginal, 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 decision 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 to include 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) and allowing *WHIRLYGIG* to retire existing plant to avoid these costs. 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 revenue adequacy on a unit profitability level.
- We do not consider decommissioning costs or plant scrap value in the decision to retire. In practice, it is uncertain when these costs will 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.

Forecast retirement outcomes are presented in Section 6.

4.2.2 Estimating resource cost effects

As discussed in Section 3.2, the RET imposes economic costs (via fostering higher cost generators to be built that are not necessary to meet demand or maintain reliability). These resource costs are distinct from transfer effects, such as the impact of the RET on wholesale and retail prices.

Resource cost outcomes are a direct output of the modelling and can be presented by type (fixed versus variable), by year and various other segmentations. Resource costs reflect total/average system costs and are relatively easier to forecast when compared to pricing impacts that occur on the margin.

Forecast resource cost impacts of the RET are presented in Section 6.

4.2.3 Estimating price effects

The RET impacts on retail tariffs in two ways:

- Via the merit order effect on wholesale prices. This effect is captured in our modelling of both market-based and SRMC prices.
- Via a direct cost to consumers arising from retailer RET liabilities under the scheme. This effect is captured using estimates of LGC marginal costs from the *WHIRLYGIG* modelling stage.

We have constructed a simple retail tariff model to combine these effects into a net impact on retail tariffs and annual bills. This model:

- Uses forecast load weighted, wholesale pool prices as a proxy for residential energy purchase costs and LGC marginal cost estimates from our modelling.
- Assumes values of the other cost components of a retail tariff (network, market fees, losses, retail OPEX and margin, etc) based on current 2013/14 values.
- Varies the energy and RET component of the tariff over time in line with modelled outcomes and fixes the other components in constant real 2013/14 dollar terms.

This approach provides a consistent starting point across the scenarios modelled and focuses on changes over time that are only driven by different wholesale price and RET outcomes based on the modelling.

Forecast transfer (pricing) impacts of the RET are presented in Section 6.

5 Modelling assumptions

This section provides an overview of the input assumptions that we have used in our modelling of the RET. 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 B.

The key input assumptions are:

- Demand
- Carbon costs
- Fuel costs
- Capital costs

Each of these key assumptions are discussed below. Finally, the scenarios presented in this report are defined in terms of assumptions around the LRET, and are also discussed below.

5.1 Demand

Our modelling approach requires demand data for the system load in the NEM and the SWIS. 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 2013 National Electricity Forecast Report (NEFR)[4]. The Low Scenario has been used. AEMO released an update of the supply-demand balance in March 2014[5] that stated that actual demand was trending lower than the Medium forecast.
- For the SWIS, the IMO's demand forecasts from the 2013 ESOO[6], Low scenario, consistent with assumptions used in the NEM.

Energy forecasts for these cases are shown in Figure 2 below.

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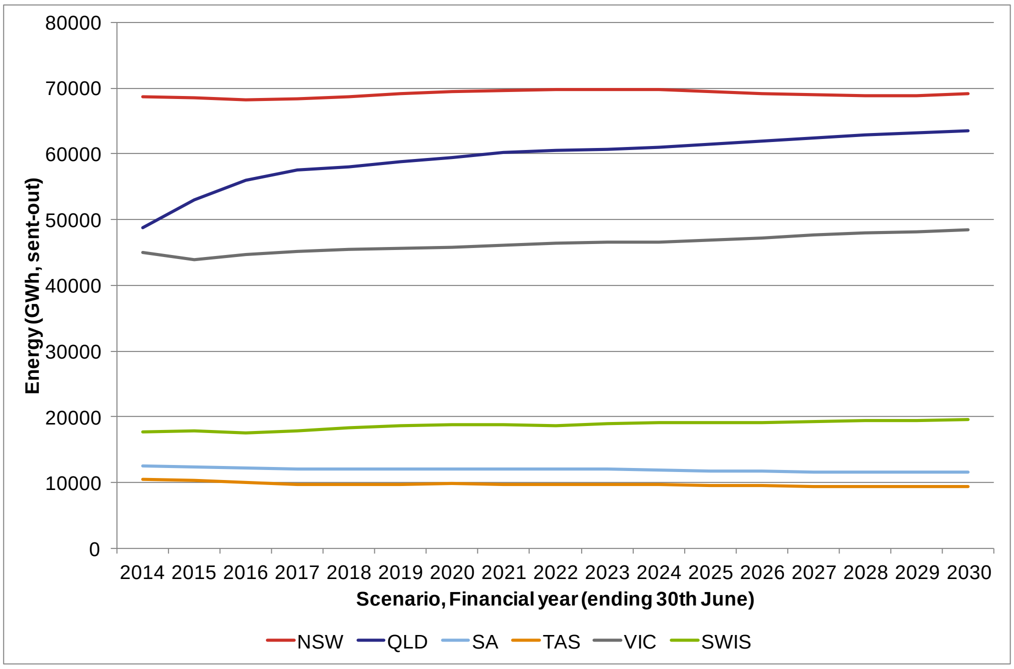
4 http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013

5 http://www.aemo.com.au/News-and-Events/News/News/Supply-Demand-Snapshot-February-2014

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

Figure 2: Demand



Source: AEMO and IMO

5.2 Carbon

All scenarios assume that the carbon price will be repealed from 1 July 2014 onwards.

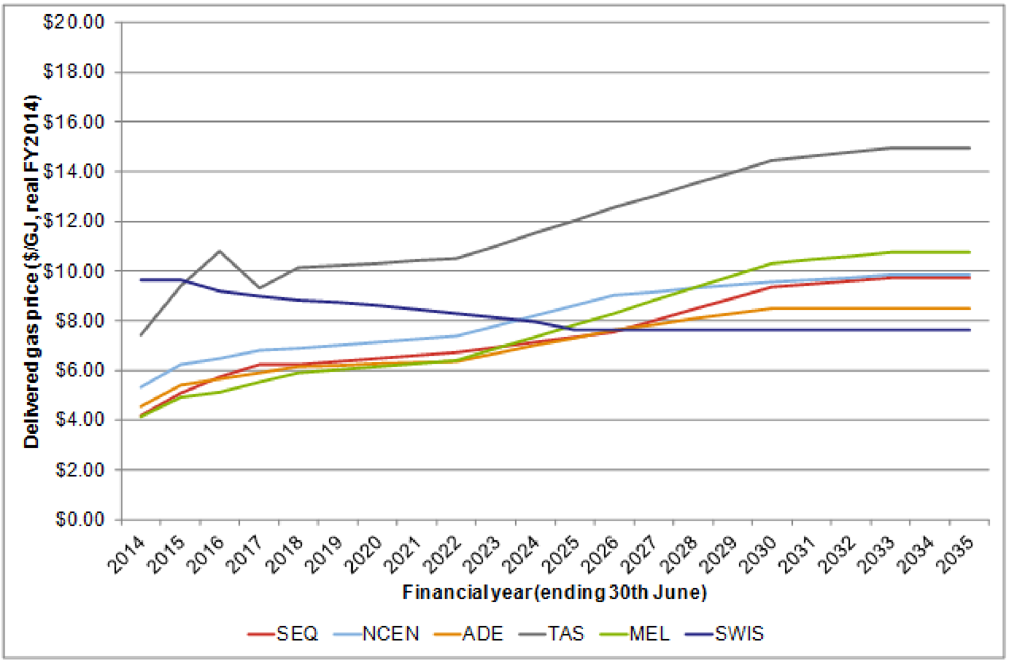
5.3 Fuel

Frontier's fuel prices are based on modelling and analysis of the Australian gas and coal markets. A detailed description on our approach to estimating fuel prices can be found in Appendix B.

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 forecasts are shown in Figure 3.

Figure 3: LRMC of gas by State capital cities ($2013/14)

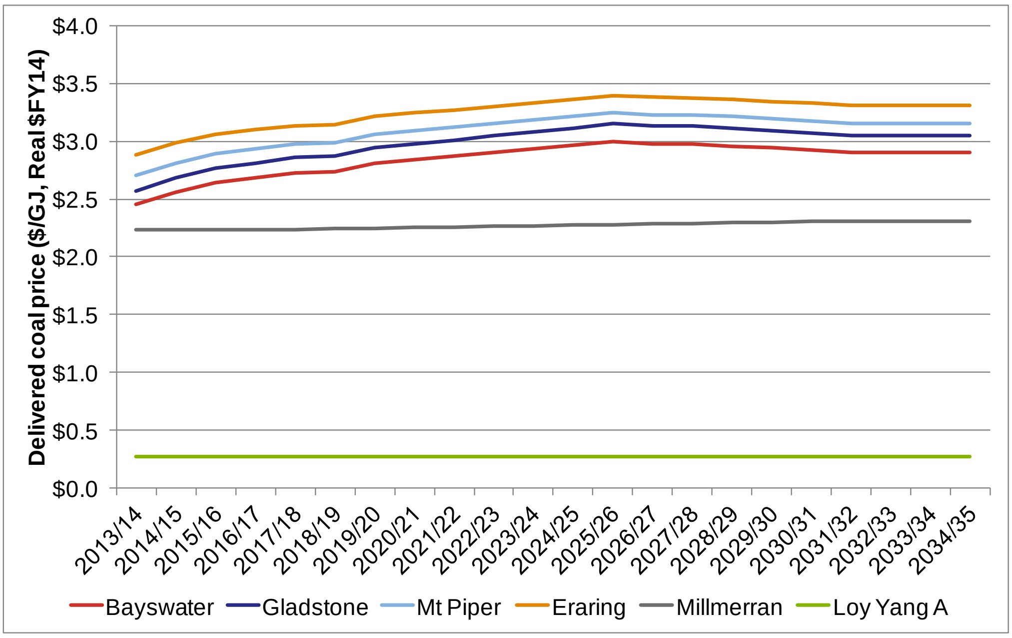


Source: Frontier Economics

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. A sample of Frontier's base case forecasts are shown in Figure 4 for representative power stations (both export exposed and mine-mouth stations).

Figure 4: Coal prices for representative generators ($2013/14)



Source: Frontier Economics

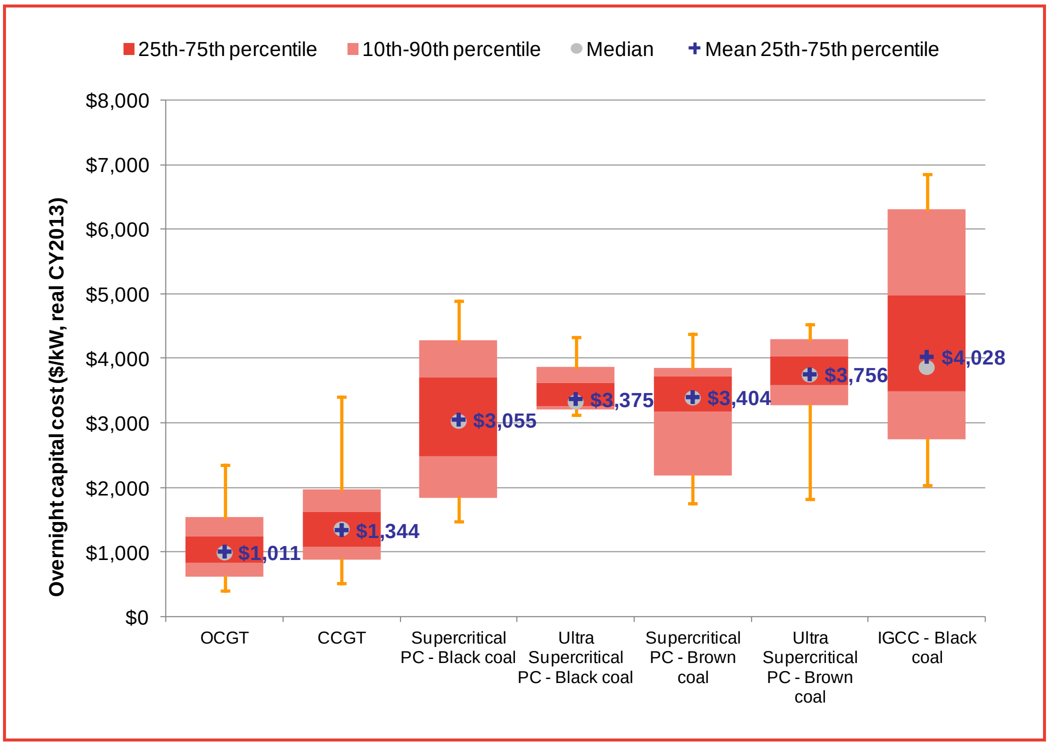
Note: Bayswater, Gladstone, Mt Piper & Eraring are export exposed, Millmerran and Loy Yang A are mine mouth stations

5.4 Capital

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

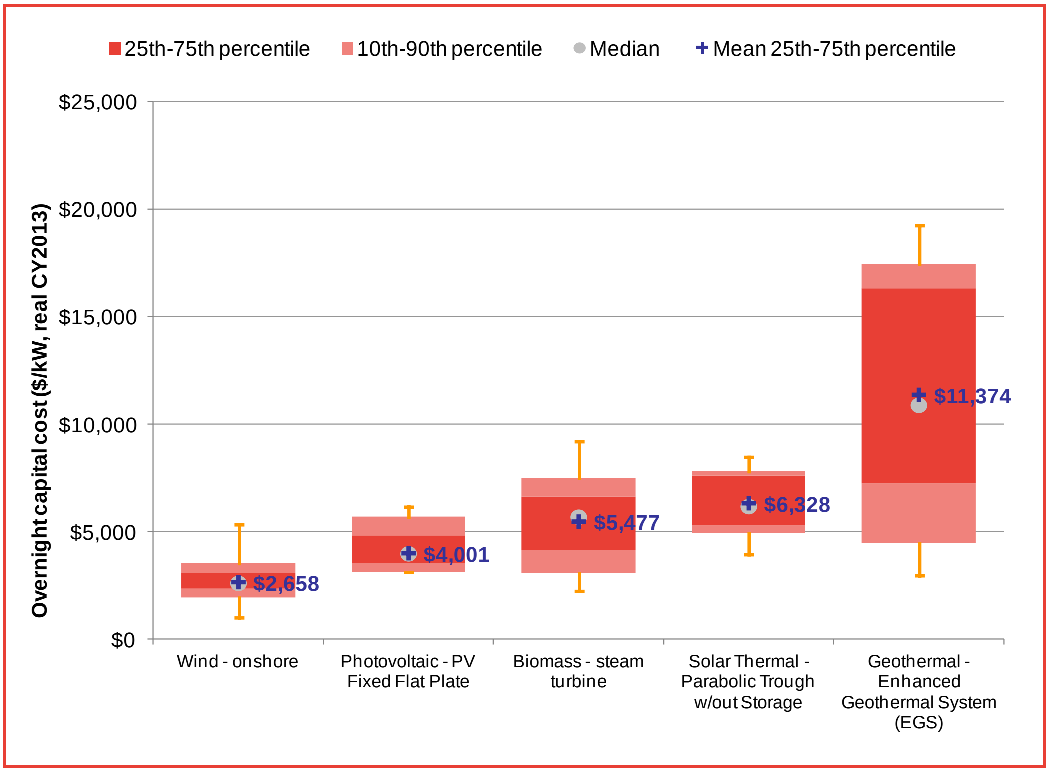
Capital costs estimates for thermal generation technologies are presented in Figure 5, renewable technologies are presented in Figure 6.

Figure 5: Current capital costs for gas and coal generation plant



Source: Frontier Economics

Figure 6: Current capital costs for renewable generation plant



Source: Frontier Economics

5.5 RET assumptions and modelling scenarios

The modelling is presented for four scenarios that differ only with regards to assumptions about the LRET.

All scenarios assume that the RET extends to 2030 and not beyond. This means that plant installed from 2020 (or 2025) will have a shorter period of certificate creation, and hence will require a higher LGC price over that period. This increases the risk of a permit shortfall than the alternative assumption that the scheme target is continued beyond 2030 (allowing renewable generators to earn LGC revenue over a longer period).

All scenarios assume that the RET penalty remains unchanged at $65 nominal, and we assume that in practice this equates to a tax-effective penalty limit of around $93 nominal (given that certificate purchases would be a tax deductible expense but penalties would not be). This implicitly assumes that companies face an effective marginal tax rate of 30% - in practice this may be lower. We assume that this nominal penalty declines in real terms over time.

The modelled targets are:

- **No Policy Change:** Current RET legislation - LRET target in 2020's of 41TWh p.a.
- **RET 20:** LRET reduced to a 'true' 20% relative to forecast demand - LRET target in 2020's of 30TWh p.a.
- **RET 20 Combined:** LRET plus SRES reduced to a 'true' 20% relative to forecast demand - LRET target in 2020's of 23TWh p.a.
- **RET Capped:** LRET target capped at current and committed investment production levels of 16TWh p.a.

For the No Policy Change scenario, the RET 20 scenario and the RET Capped scenario, the changes to our modelling are relatively straightforward: the differences between these scenarios is simply the TWh target of the LRET. For each of these scenarios, the SRES remains a separate scheme, and all we need to do is account for the fact that solar PV generation will reduce the amount of energy that is required from large-scale generation to meet total energy demand.

We do this by adopting long-term forecasts of solar PV generation from AEMO and the IMO (so that these forecasts of long-term solar PV generation are consistent with our long-term demand forecasts). We do not use the short-term forecasts of solar PV adoption and STC creation used by the Clean Energy Regulator to set the small-scale technology percentage because in this instance we are interested in forecasts of energy from solar PV generation, not the creation of STCs by solar PV generation, and because our long-term modelling requires a long-term forecast of solar PV generation.

For the RET 20 Combined scenario, there is the additional complication of combining the existing LRET and SRES schemes. In doing so, we have assumed that solar PV will contribute to the combined RET target according to the same forecasts of solar PV generation from AEMO and the IMO. The implication is that large-scale generation needs to meet the remainder of the combined target. Again, we adopt forecasts from AEMO and the IMO for solar PV generation because these are consistent with the demand forecasts that we adopt and because they provide the long-term forecasts required for our modelling.

In the forecasts of solar PV generation that we use in this scenario we do not account for deeming of the certificates created by small-scale solar PV (according to which STCs can be created on installation of a solar PV system, with the number of STCs deemed to be created coinciding to 15 years of operation of the system). We do not account for deeming of certificates for solar PV generation because we consider that, in the long-term, this would result in different treatment of large-scale and small-scale renewable generation, despite the fact that under this scenario they operate under the same scheme.

To understand this, consider what would happen under a combined scheme with deeming in 2025: a large-scale renewable generator would be able to create certificates for 5 years (until the assumed end of the scheme in 2030) while a small-scale renewable generator would be able to create certificates for the 15 year deeming period. We consider that this different treatment would be an unusual outcome under a combined scheme, and so we have assumed that under a combined scheme deeming would not occur.

6 Modelling results

This section sets out the results of our least-cost investment and market modelling for each of the RET scenarios. Results are organised into the following categories:

- Investment, retirements and dispatch
- Wholesale prices and LGC costs
- Resource costs
- Retail prices

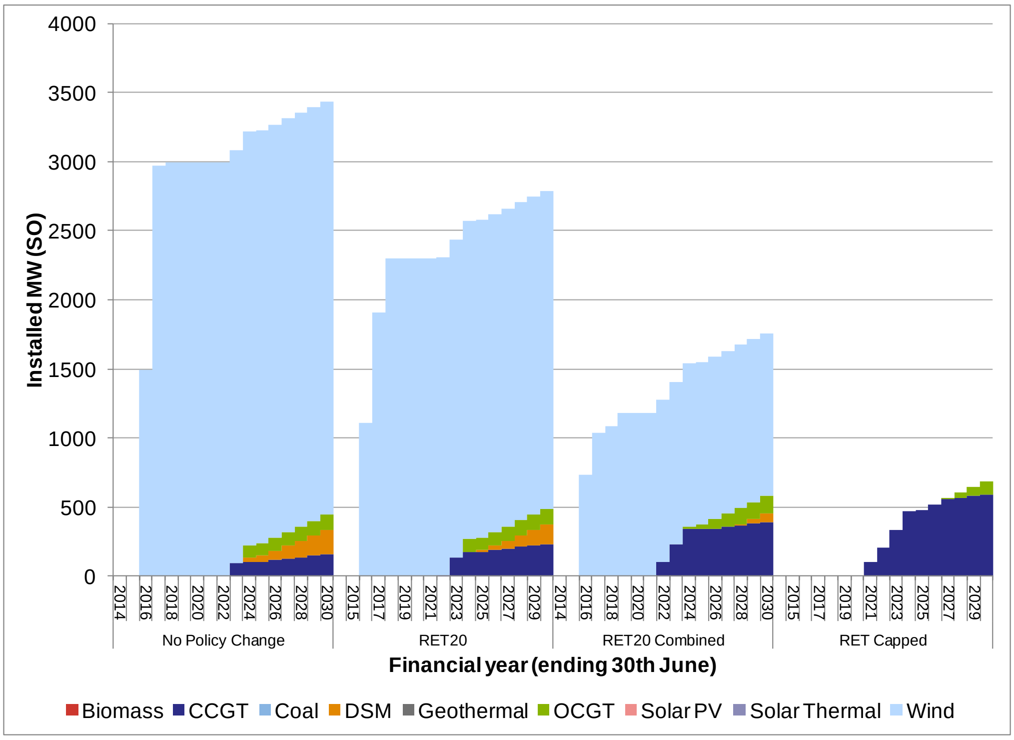
6.1 Investment, retirements and dispatch

Figure 7 provides investment outcomes at the national level for each RET scenario. These scenarios are ordered by the combined size of the RET in each case, with the largest target on the left. From an investment perspective, reductions in the RET result in:

- a decrease in overall investment, and
- a decrease in investment in renewables, which is partly substituted with investment in thermal plant.

In the cases with a RET (i.e. No Policy Change, RET20, RET20 Combined), Figure 7 shows significant investment in wind plant to meet the target. In the absence of any increases to the target from current levels in the RET Capped scenario, the model chooses not to invest in any renewable plant. This is consistent with the current oversupply in the NEM and SWIS and high relative cost of renewable versus thermal plant.

Figure 7: National investment by technology

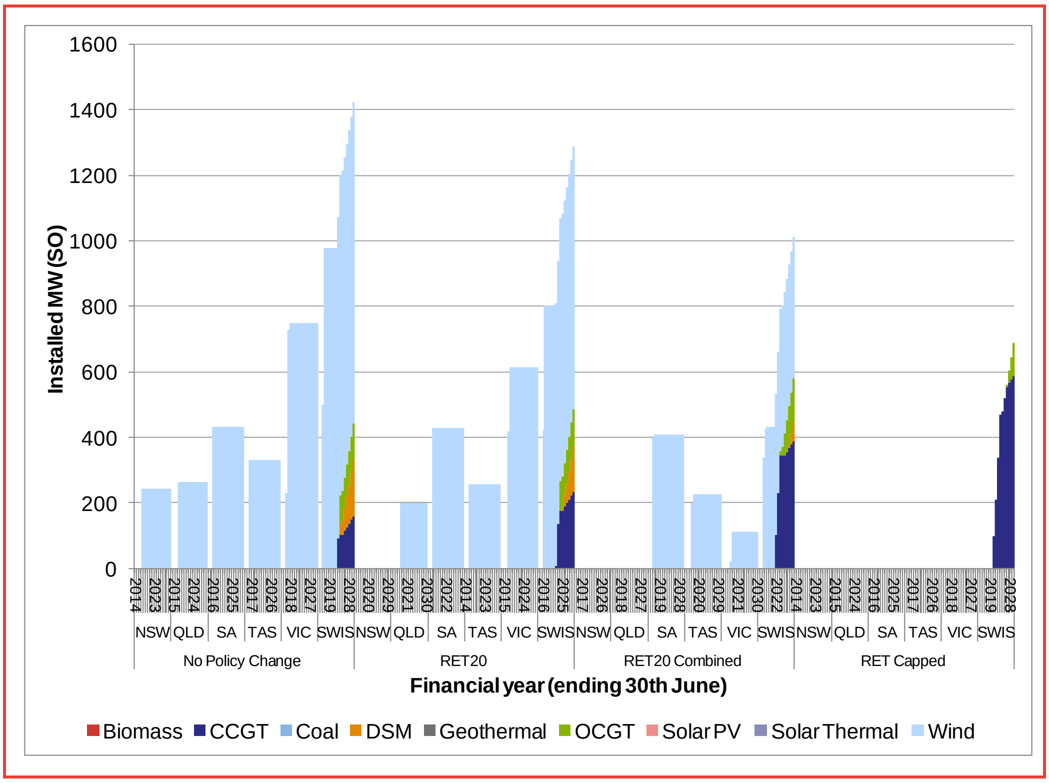


Source: Frontier Economics

Figure 8 provides investment outcomes at the region level for each RET scenario. Thermal investment occurs only in the SWIS, where there is significant demand growth, across all scenarios. In the NEM regions where demand growth is mild, the only investment in capacity is driven by the RET.

In the No Policy Change scenario, where the modelled RET target is highest, there is wind investment in all states. As the target is reduced (reading the chart from left to right), wind investment decreases in the lower quality, higher cost sites first (i.e. NSW and QLD) reflecting the wind tranche assumptions discussed in Appendix B. As incentives for wind investment decrease in the SWIS, CCGT, OCGT and DSM are substituted as necessary to meet demand growth and reserve capacity requirements.

Figure 8: Region level investment by technology



Source: Frontier Economics

Figure 9 outlines plant retirements within the modelling period, both due to announced retirements and retirements determined endogenously as discussed in Section 4.2.1. The starting value of each series represents the total amount in sent out MW that will be retired in the modelling period. The decreases of these series convey the timings of the retirements.

The generators Vales Point B and Wallerawang unit 8 (over and above the announced retirement of unit 7) are retired by the model immediately, in financial year 2013/14. This is consistent with current and forecast low demand and prices in NSW, but different to actual outcomes with respect to financial year 2013/14 to date. Both Wallerawang units were non-operational for the majority of 2013/14 to date but Vales Point B has been operating.

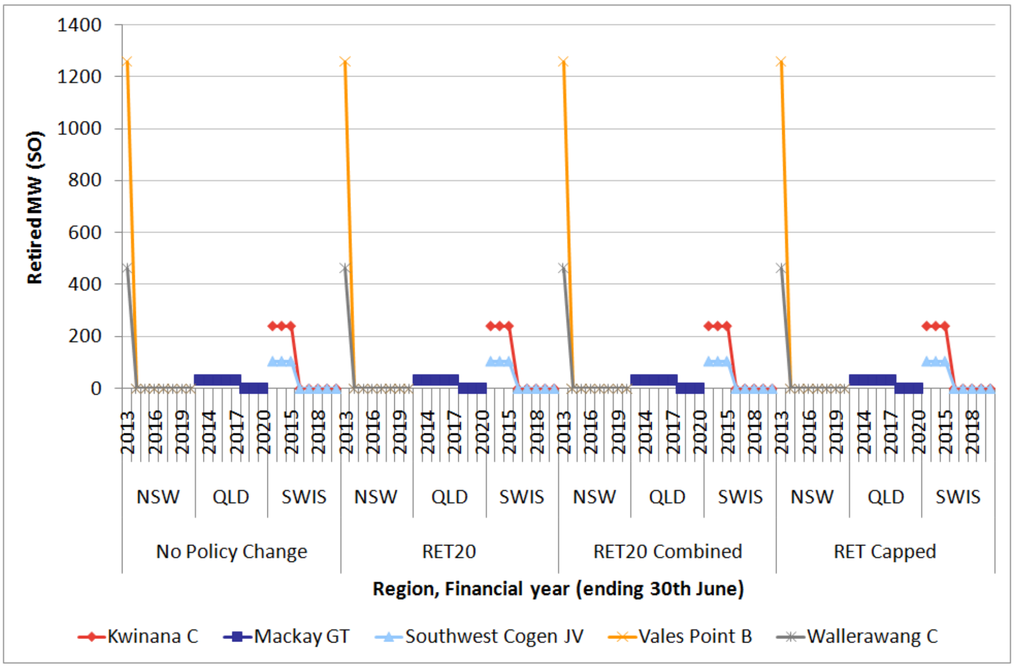
For the purpose of market modelling in *SPARK*, and dispatch and pricing outcomes presented in this report, these retirements have been delayed until the start of financial year 2017/18. This reflects the uncertainties around retirement decisions.

Generators Kwinana C, Mackay GT, and Southwest Cogen JV have announced retirement dates and are hence retired on these occasions.

Retirements across each of the RET scenarios are the same, reflecting the current oversupply of capacity in the NEM and the lack of future demand growth.

Changes to the RET assumptions in the forward period are not altering forecast retirements between the scenarios.

Figure 9: Unit retirements



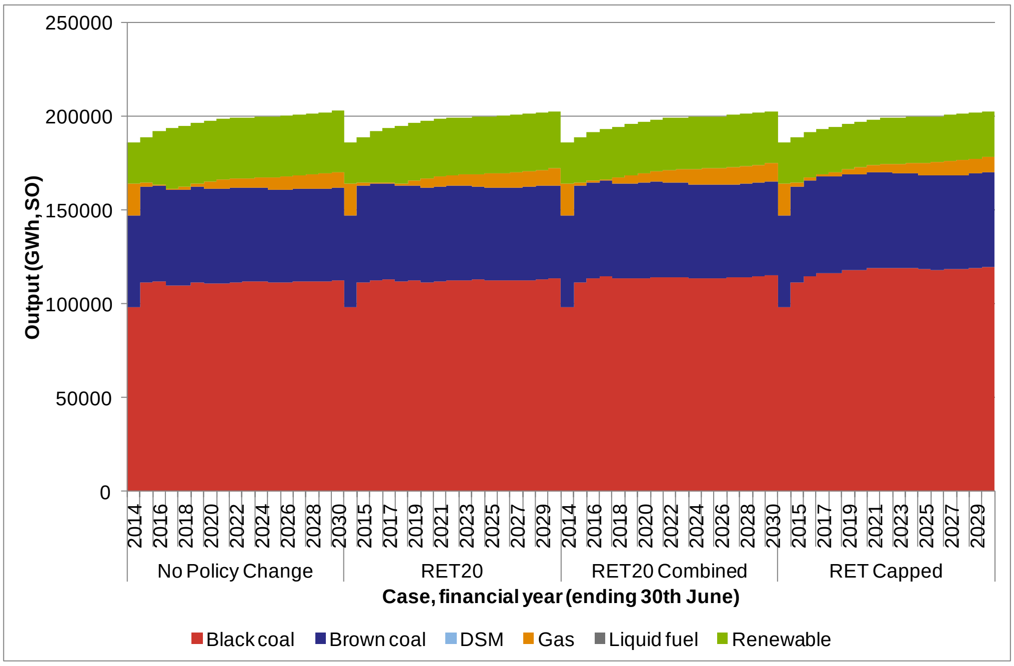
Source: Frontier Economics

Figure 10 outlines national dispatch outcomes by fuel type for each scenario. Coal dispatch increases sharply after the first year due to the assumed removal of the carbon price, and mostly displaces gas generation.

The main differences between the scenarios occur in the amount of thermal generation substituted for renewable energy. Scenarios with a higher RET have more available renewable capacity, which displaces the higher variable cost incumbent thermal plant. As the target is reduced (reading from left to right on the chart), the amount of renewable capacity available for dispatch declines, and coal and gas plant are dispatched in their place.

In all scenarios, dispatch of black coal and gas generally increases over time, and dispatch of brown coal remains approximately constant. However, in the RET scenarios, a higher target means more renewable generation is substituted for primarily black coal, and to a lesser extent brown coal and gas.

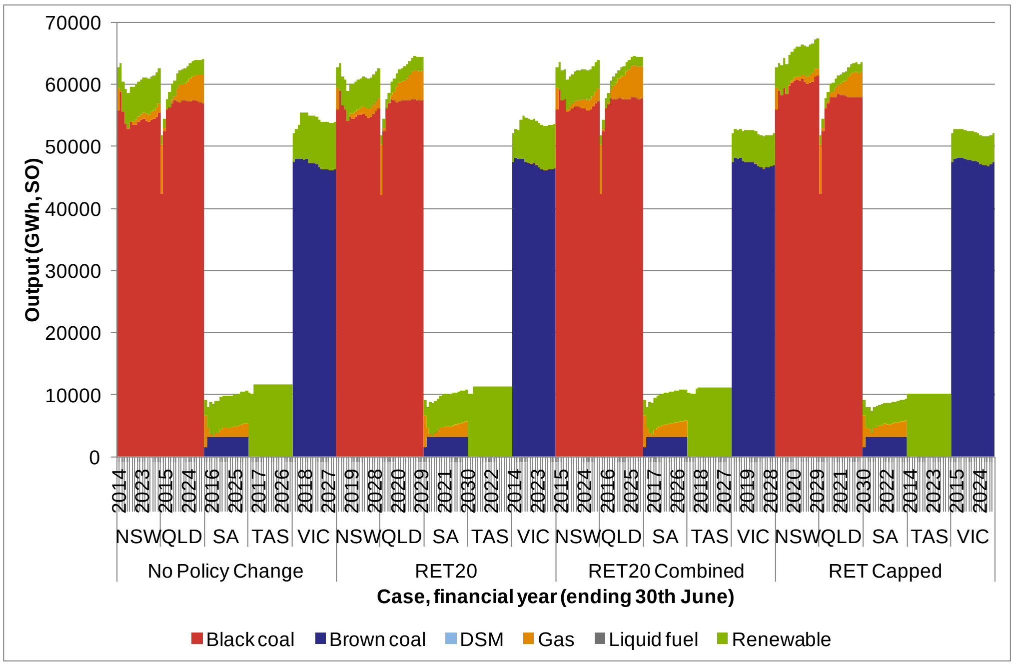
Figure 10: National dispatch outcomes



Source: Frontier Economics

Figure 11 presents dispatch outcomes by region for each of the RET scenarios. The general trends outlined above are apparent at the region level, although the different technology mix in each region suggests a reason for the imbalance in fuels displaced by renewable investments. Black coal is the dominant fuel in each of NSW, QLD and the SWIS, where brown coal is dominant in VIC and apparent in SA. NSW black coal, being mostly export price exposed, is displaced by wind generation across the NEM. This reflects these plant currently being marginal at specific times of the year and getting increasingly displaced by new entrant wind in the scenarios with a higher RET.

Figure 11: Regional dispatch outcomes



Source: Frontier Economics

6.2 Wholesale prices and LGC costs

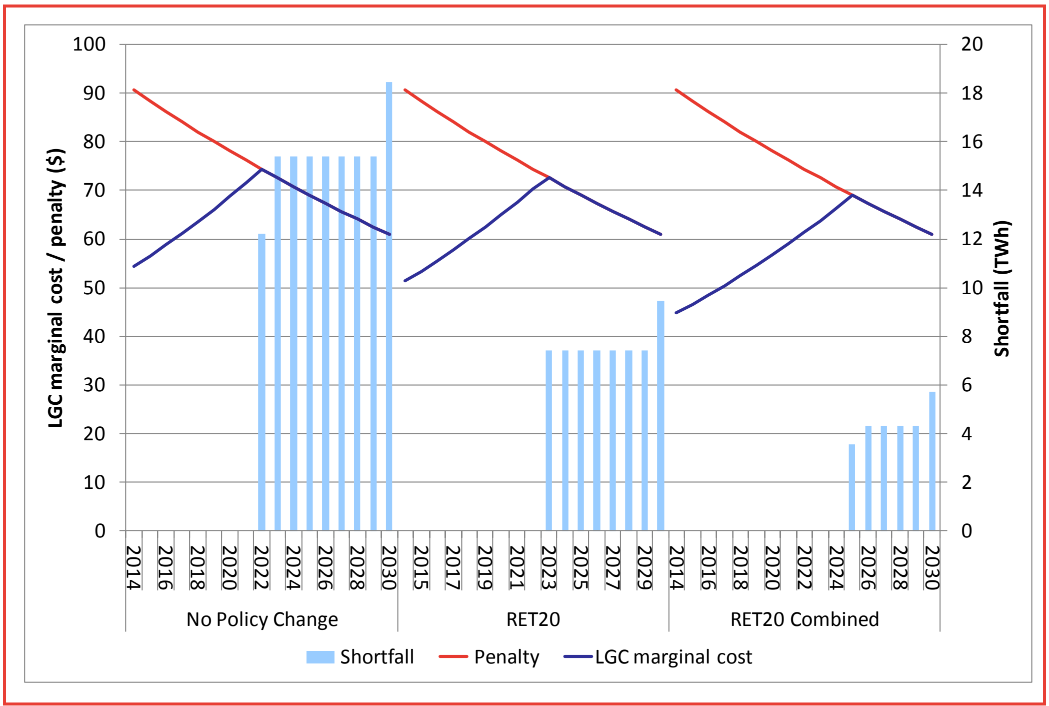
Figure 12 outlines RET outcomes from *WHIRLYGIG* for each of the scenarios with an increasingly RET (i.e. excludes the RET Capped case). The vertical bars denote the shortfall in GWh, which is incurred after the LGC marginal cost (blue line) meets or exceeds the penalty cost (red line). Note the penalty is set constant in nominal terms and is therefore declining in real terms (numbers in Figure 12 are presented on a real $2013/14 basis). Our assumption that the scheme ends in 2030 requires a higher LGC price than if we assumed continuation beyond 2030, as revenue must be recovered over a shorter period.

In all three cases - No Policy Change, RET 20 and RET 20 Combined - the LRET target is not met and material shortfalls are forecast to occur. There are three key outcomes in reducing the LRET, all else remaining equal, as demonstrated in Figure 12:

1. The magnitude of the shortfall is reduced
2. The timing of the shortfall, or the first instance at which the marginal LGC cost meets or exceeds the penalty price, is delayed
3. The current marginal LGC cost is lower (reflecting more years of discounting from the first year a shortfall occurs and the penalty price binds)

These outcomes are all related. A higher target means the cheaper wind options are built earlier, and higher LRMC wind options are needed to meet the target. As a result, the point at which the LRMC of the marginal new entrant wind farm exceeds the penalty occurs sooner. From this point on, no further renewable investment occurs. Instead, it is cheaper to incur the penalty price and shortfalls against the LRET accrue.

Figure 12: LRET outcomes – marginal certificate costs and scheme penalty ($/LGC, $2013/14), shortfalls (TWh)



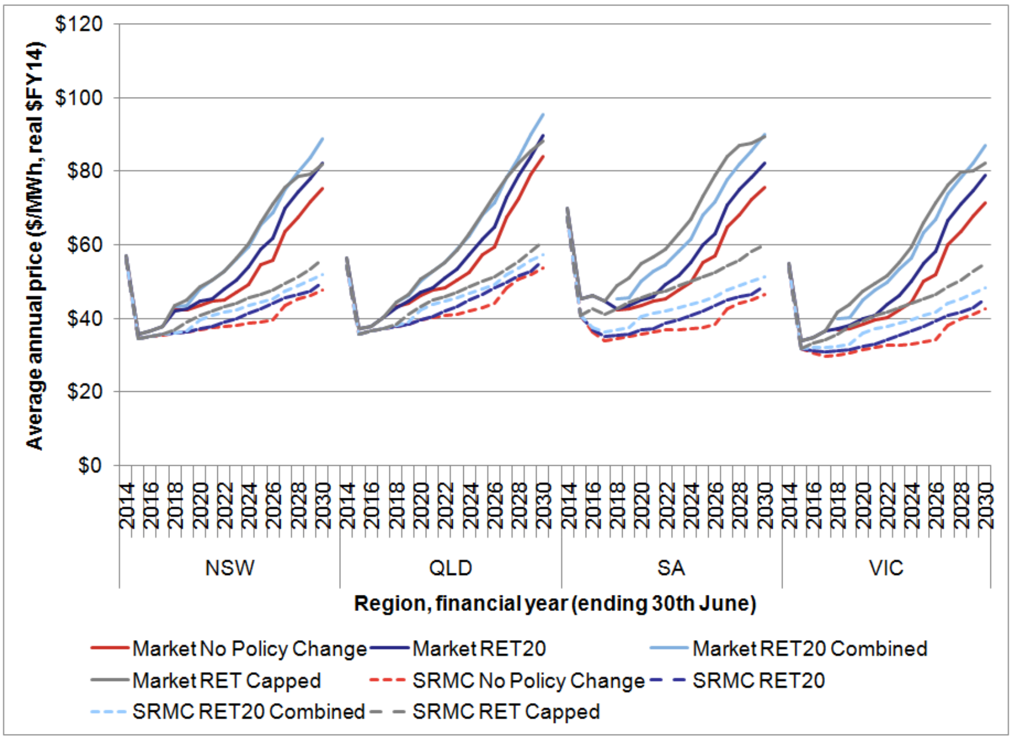
Source: Frontier Economics

Figure 13 presents annual average SRMC and market prices for each region and RET scenario. The SRMC prices are obtained from *WHIRLYGIG* and represent the SRMC of the marginal source of energy in each region. The market prices are obtained from *SPARK*, modelling strategic dispatch and withholding by generators.

The sharp drop of around $22 between 2014 and 2015 in all scenarios reflects the common assumption that carbon pricing is repealed. SRMC prices increase over time, driven primarily by increasing fuel price assumptions as described in Appendix B. In the early modelling periods, market prices and SRMC are close reflecting a loose supply and demand balance. The divergence in later periods is due to a tighter demand and supply balance and the strategic response by generators across the NEM.

In each region, SRMC and market prices are generally higher as the RET target is lower. This result demonstrates the merit order effect as discussed in Section 3, where the wind investment due to the RET acts to suppress wholesale prices. Relativities between the scenarios in the market pricing approach are complicated by the timing of investment and the fact that wind investment occurs across the NEM, while retirements are concentrated in NSW.

Figure 13: SRMC and market prices by region, $FY2013/14



Source: Frontier Economics

6.3 Resource costs

The resource/economic costs are the direct costs referred to in Section 2.2. This reflects the higher economic of generating from renewables than from non-renewable generation. Estimates of resource costs are typically more consistent across different modelling approaches, reflecting consistency regarding estimates of wind capital costs (the main driver of RET resource costs).

Figure 14 presents the NPV differences in total costs from the RET Capped case for each scenario over the period 2013/14 to 2034/35. The costs are broken into two categories, comprising

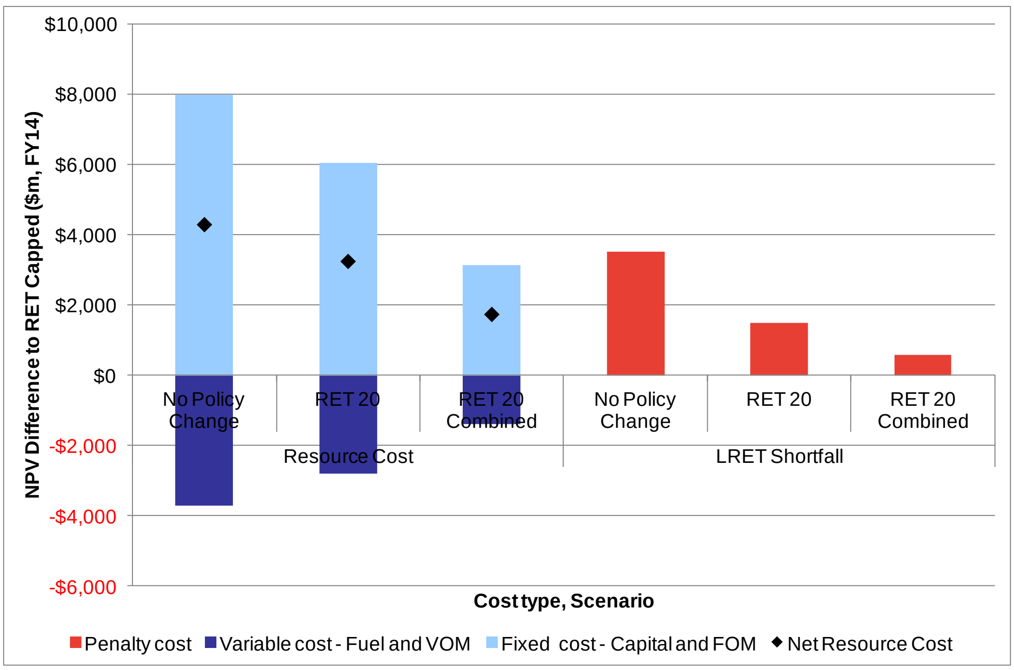
- resource costs, reflecting real economic costs, including fuel, VOM, FOM; and capital costs; and
- RET penalty costs, which are a transfer from electricity consumers to government and are calculated as the penalty cost multiplied by the shortfall incurred in the scenario. Although this is a transfer rather than a resource

cost, this is because of the LRET shortfall in our results. Under different assumptions (such that the target was met, via a higher penalty, and the shortfall did not arise) then shortfalls would be reduced but resource costs would be correspondingly higher.

In each of the scenarios, increases in capital and FOM resource costs due to renewable investment will be offset by a decrease in fuel costs at the stations that this investment displaces. This is primarily a reduction in the fuel cost of displaced NSW black coal generators.

The No Policy Change scenario, with the highest RET target, incurs both the highest penalty cost and the highest net resource costs. Negative resource costs in the No Policy Change scenario relative to the RET Capped scenario (i.e. savings) arise in NSW, due to the reduction in fuel and VOM costs from coal displaced by wind investment outweighing the capital and FOM cost incurred to build the renewable plant. Generally, in the other states, these costs are not offset and there is a net positive NPV cost difference between the cases. Overall, the net NPV resource cost for all scenarios is higher than the RET Capped case, however declining in line with the RET.

Figure 14: NPV difference in resource and shortfall costs to RET Capped scenario by region ($m, $2013/14)



Source: Frontier Economics

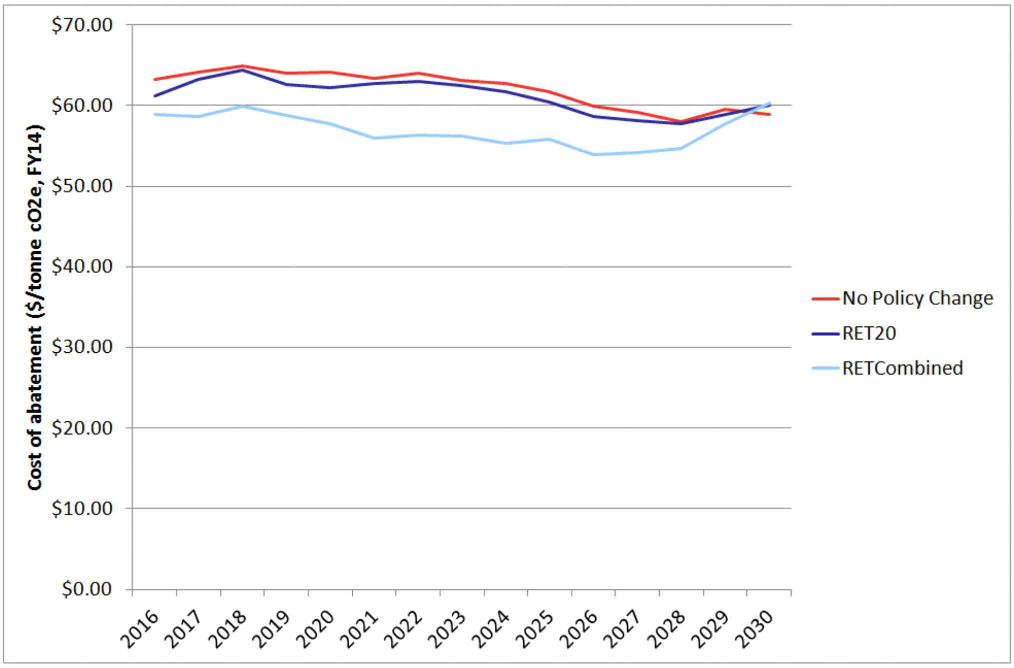
Figure 15 presents the incremental increase in resource costs (excluding costs associated with shortfalls) relative to the RET Capped case divided by the incremental reduction in emissions, i.e. the resource cost per tonne of abatement achieved under the RET targets.

The cost of abatement ranges from around $55 to around $65, and generally decreases over time due to the RET target peaking in 2020 and then remaining flat to 2030 such that the impact of the RET on investment, associated resource cost impacts and emissions outcome stabilise. These dollar per tonne figures are higher than what could be achieved with a carbon price, owing to the fact that the RET targets renewable investment and not emissions directly.

More specifically, this cost reflects the cost of abatement through renewable plant only, where the carbon price incentivises abatement regardless of technology type. These dollar per tonne figures can also be higher than the marginal cost of an LGC as reported in Figure 12, owing to the fact that these costs reflect the average costs of all new entrant wind farms from the start of the modelling period rather than the (higher) marginal costs of the last block of renewable capacity, and the fact that non-renewable energy sources have varying emissions intensities, meaning the quantity of emissions displaced varies. That is, one MWh of renewable energy does not necessarily displace one tonne of CO2e emissions, rather it depends on the emissions intensity of the plant being displaced[7]. Similarly, a new wind farm built in 2025 will only create LGCs until 2030 (5 years) but will incur resource costs (and deliver emissions abatement) in the years beyond 2030.

7 Both NEM and SWIS average emission intensity is less than 1.00 tCO2e/MWh, and the emissions intensity of the marginal generator (that is displaced by wind) can be considerably less than 1.00 tCO2e/MWh if gas-fired plant is marginal.

Figure 15: Cost of abatement ($/tonne cO2e, $2013/14)



Source: Frontier Economics

6.4 Retail prices

As discussed in Section 2.2, the RET has direct and indirect impacts on retail prices. The direct impact is that consumers must fund the retailer purchases of LGCs. This reflects an increase in retail prices, and is a closer proxy to the higher resource costs of the scheme. The indirect impact is that new renewables entry to meet the RET (irrespective of demand for electricity) can have a dampening effect on wholesale pool prices if it leads to oversupply in the energy market. This is not a reduction in resource costs, but reflects a transfer from existing generators to consumers in the form of lower wholesale prices. The net impact of these countervailing forces on retail prices may be higher or lower.

We find that the net impact of the RET on retail prices on consumers is likely to be:

- negative (a stronger RET leads to higher retail prices) in all scenarios and for most jurisdictions, except Western Australia, to the early 2020s.
- may be positive (a stronger RET leads to lower retail prices) in the post-2025 period in Victoria and South Australia **under the assumption of market bidding**, and remains negative in NSW and Queensland under market bidding in most years/scenarios. Outcomes in Victoria vary by scenario.

- negative (a stronger RET leads to higher retail prices) in the post-2025 period in most jurisdictions, except South Australia, **under the assumption of SRMC bidding.**

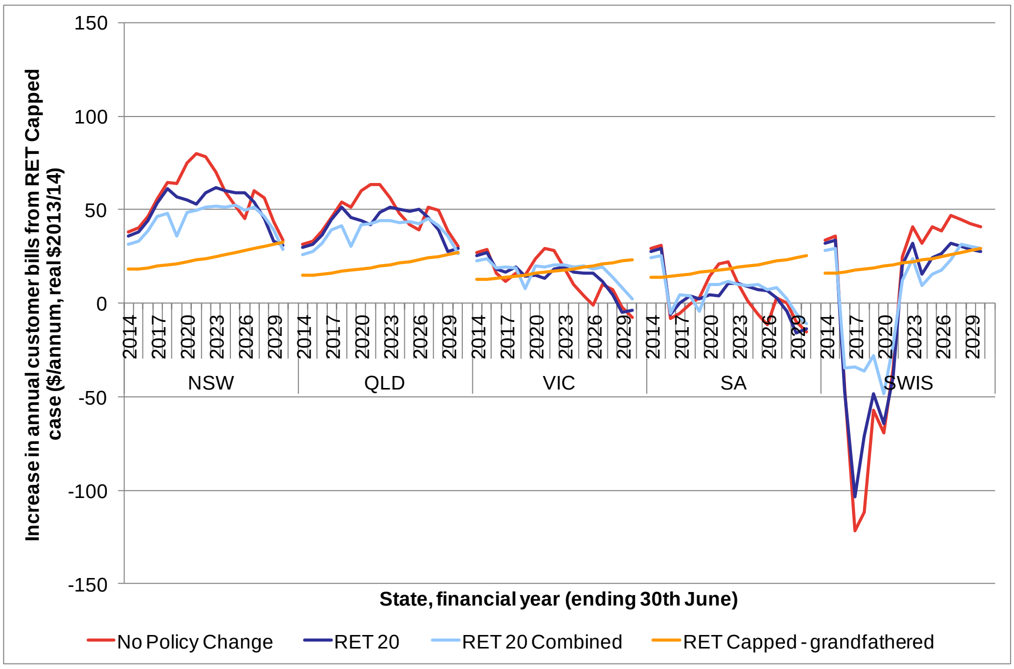
Fundamentally, our finding is that it is likely that a stronger RET will lead to higher retail prices over the next decade but uncertain thereafter.

These findings are illustrated in Figure 16 and Figure 17, which present the differences in typical residential bills relative to the RET Capped scenario by state, for SRMC and market prices respectively. *Positive* values in these figures indicate that the net impact of a higher RET is *higher* annual bills. Conversely, *negative* values in these figures indicate that the net impact of a higher RET is *lower* annual bills. For example, in Figure 16, continuing with the current target (solid red line) will lead to higher annual bills in NSW and lower annual bills in the South Australia (for most years).

The 'RET Capped – grandfathered' line refers to a situation in which the RET is capped at current production, but current LGC prices continue to be enforced with an assumed cost-of-carry of 4% going forward (in order to compensate pre-existing, RET eligible generators). The incremental impact on annual bills for this case is simply the cost of this grandfathering (as pool price outcomes are the same as the RET Capped case).

At SRMC prices (Figure 16), increasing the scheme target generally leads to an increase in annual bills, with the exception of South Australia. In South Australia, large differences in wind investment between the cases in what is a small region result in a large merit order effect when the scheme target is higher. This acts to offset the direct cost of the scheme in some years for South Australian consumers. The No Policy Change case results in largest movements in the typical residential bill. In the SWIS, which experiences significant wind investment in the RET cases and has a higher cost base than the NEM, the merit order effect is stronger and this is reflected in annual bill impacts.

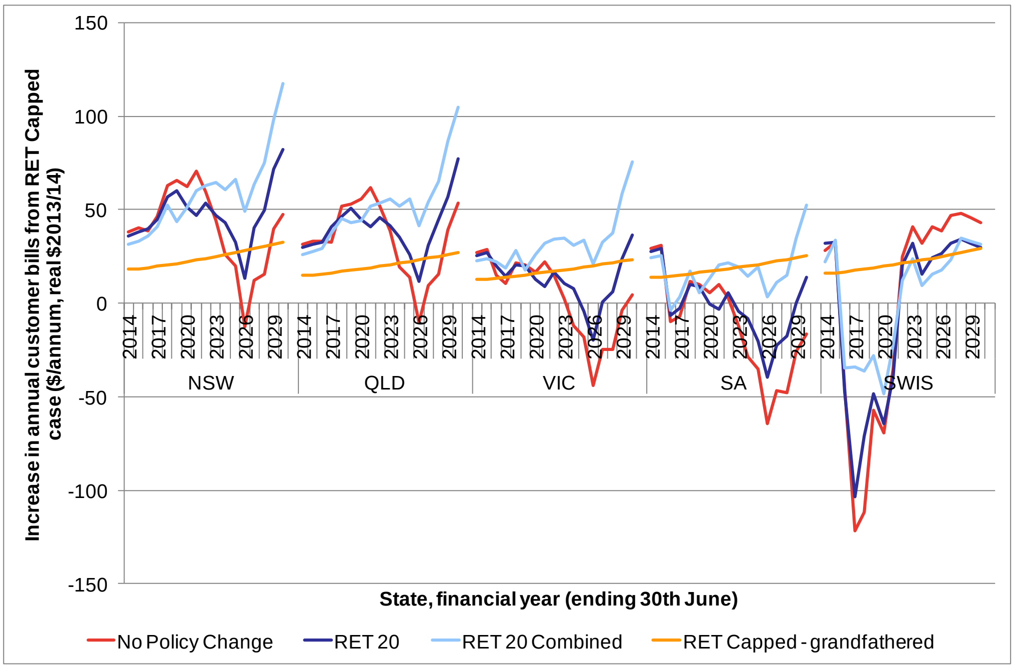
Figure 16: Difference from RET Capped scenario in a typical residential bill ($/annum $2013/14) - SRMC prices



Source: Frontier Economics

Under market-based price forecasts (Figure 17), there is more uncertainty about the impact of the RET on retail bills, particularly in the long term. In NSW, Queensland, South Australia and Victoria, different RET targets may result in different both positive and negative outcomes for annual bills depending on jurisdiction. This reflects the higher level of volatility in wholesale prices under a market based bidding approach, both across jurisdictions and over time.

Figure 17: Difference from RET Capped scenario in a typical residential bill ($/annum $2013/14) - market prices



Source: Frontier Economics

7 Conclusions

From the analysis of the impacts of the RET we draw the following conclusions:

- **The RET has and will likely continue to suppress wholesale pool prices via the merit order effect.** All new entrants affect wholesale prices on the margin. However, investment under the RET is not entering in response to rising wholesale prices signalling a need for new investment. It is entering due to the opportunity for renewable generators to sell LGCs. This has implications for the profitability of non-RET eligible generation and, over the longer term, the viability of wholesale prices in the NEM and SWIS to act as an effective signal to new investment.

  Our analysis has indicated that shortfalls are possible under the assumption of continued low demand growth, the removal of the carbon price, and the scheme ending in 2030. The modelling indicates that the LRET at current, or even reduced, levels is unlikely to be met under these assumptions. To the extent that shortfalls do not eventuate (due to further investment in renewables), merit order impacts may be larger.

- **The net impact of the RET on retail prices is not clear and may change over time.** As the target ramps up to the 2020 peak value, the required investment in renewables exceeds expected growth in energy and will displace existing generation. Over this period, in most jurisdictions, the direct impact of the RET on retail prices (arising from higher permit prices and an increasing percentage of retailer purchases that are liable) will likely exceed any offsetting effects from the merit order, and consumers will likely pay more for electricity as a result of the RET. This is driven by low demand leading to wholesale prices close to SRMC levels. This conclusion holds under market-based price forecasts and SRMC estimates of wholesale pool prices in the NEM[8]. This reflects the fact that the merit-order effect has a limit given that the supply curve is relatively flat beyond a given point. Continued increases in new renewables entry will not have a linear impact on driving down wholesale prices, as coal generation will not operate/bid below SRMC (prices should not fall below this point).

  From the mid-2020s, the impact of the RET on retail prices is uncertain. To the extent that wholesale prices rise (which could be the result of any or all of tighter-supply demand conditions due to demand growth and/or retirements, higher input costs for fuel, a continuation of carbon pricing, etc) then the merit order effect may offset the direct impact of the scheme on retail prices.

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8 In the SWIS, SRMC bidding is a requirement under the market rules.

- **The RET reduces emissions.** The zero-emission generation plant entering under the RET will displace existing or new entrant thermal generation that would otherwise have operated to meet demand. This results in a reduction in carbon emissions in our analysis. Emissions reductions are achieved at an economic cost of approximately $60/tCO2e.

Appendix A - The economics of green schemes

Expanding on the discussion in Section 3.2, this appendix explains the economics behind the costs and transfers of the RET in more detail.

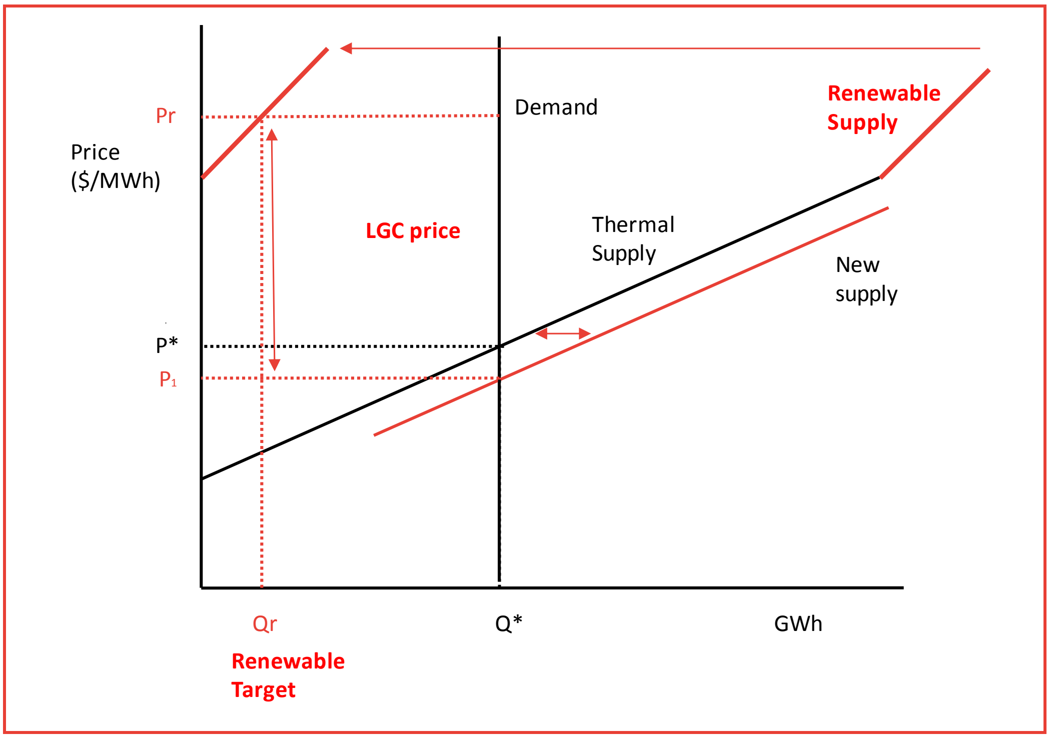
LGC prices and wholesale prices (the merit order effect)

This section explains the costs and transfers of the RET in more detail. An illustrative example of the LRET and interaction with the electricity market is shown in Figure 18. The horizontal axis shows energy (GWh) and the vertical axis shows cost/price ($/MWh). In this simple example, thermal supply is upward sloped (more supply is more costly), demand is inelastic (vertical), and renewables are more expensive than thermal. If this were not the case, renewable support such as the LRET would not be required. Equilibrium without the LRET is P*,Q*. When a renewable target of Qr is imposed, this shifts the residual supply curve (of thermal and existing hydro) to the right by the same amount. For an upward sloped supply curve, this means a fall in the wholesale pool price to P1. **This is called the merit order effect.** This merit order effect may only be short-term, as thermal supply in the longer-run should be more elastic (horizontal), hence additional renewables would generally delay new investment so long as demand was still growing. It is also possible that the entry of renewables may hasten retirements of older and more marginal generators which would offset the effect.

This reduction in wholesale price is a **transfer** as opposed to a reduction in **costs**, as existing thermal generation receives a lower wholesale pool price; overall generation costs have increased because the cost of rewenables is Pr, which is greater than the cost of thermal generation displaced. Because the merit order effect is caused by subsidised entry of excess supply/capacity, this could result from a subsidy to any form of new entrant generation, not just renewables. For example, a subsidy to new entrant gas or coal could create similar levels of excess supply, which might reduce wholesale prices for consumers at the cost of existing generators.

The renewable subsidy/LGC price should be approximately (Pr-P1), and the total subsidy to renewables is worth (Pr-P1) x Qr. The retail levy per MWh to fund this is (Pr-P1) x Qr / Q*. If there is a larger merit order effect, then the net increase in retail prices will be smaller. This means that thermal generators will bear a large share of the burden of the LRET and consumers will bear a smaller share. It does not reduce the cost of meeting the LRET however. If the merit order effect is very small then consumers will bear most of the LRET burden, as wholesale prices won't fall but retail prices will rise by the full cost of meeting the LRET.

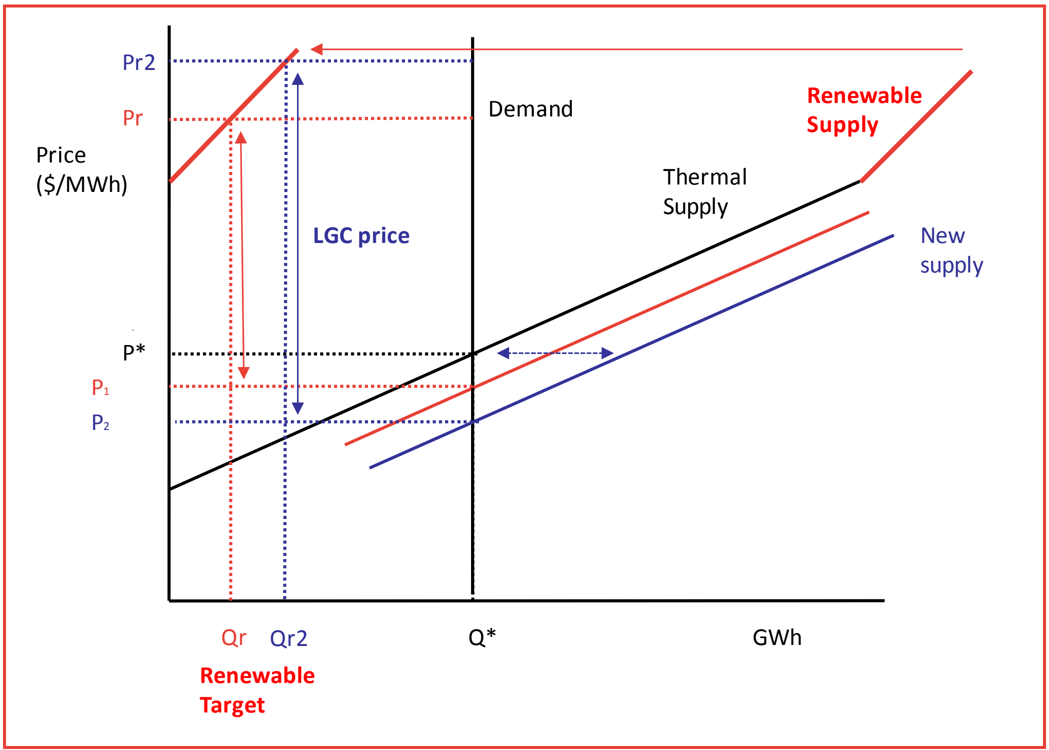
Figure 18: Illustration of the LRET: LGC price setting



Source: Frontier Economics

The impact of an *increase* in the LRET to QR2 is shown in Figure 19. This raises the LGC price, but there are two contributing factors. The first factor is the upward slope of the renewable supply curve (rising from Pr to Pr2). This could reflect the declining quality of wind sites, for example, as lower wind speeds and lower capacity factors contribute to progressively higher cost per MWh generated, though this diagram is illustrative only (larger, efficient turbines in the future might offset this and flatten the renewable supply curve). The second factor is if there is an increase in the merit order effect which contributes to lower wholesale pool prices (P1-P2). The relevance of the distinction is who bears the burden of the LRET. For the first factor (rising renewable costs) it is consumers who bear the burden. For the second factor (declining wholesale pool prices) it is existing thermal generation that bears the burden. Any estimate of the net impact on retail prices in isolation will only reflect the component borne by consumers, and will mask the cost borne by existing generation (and hence the overall cost).

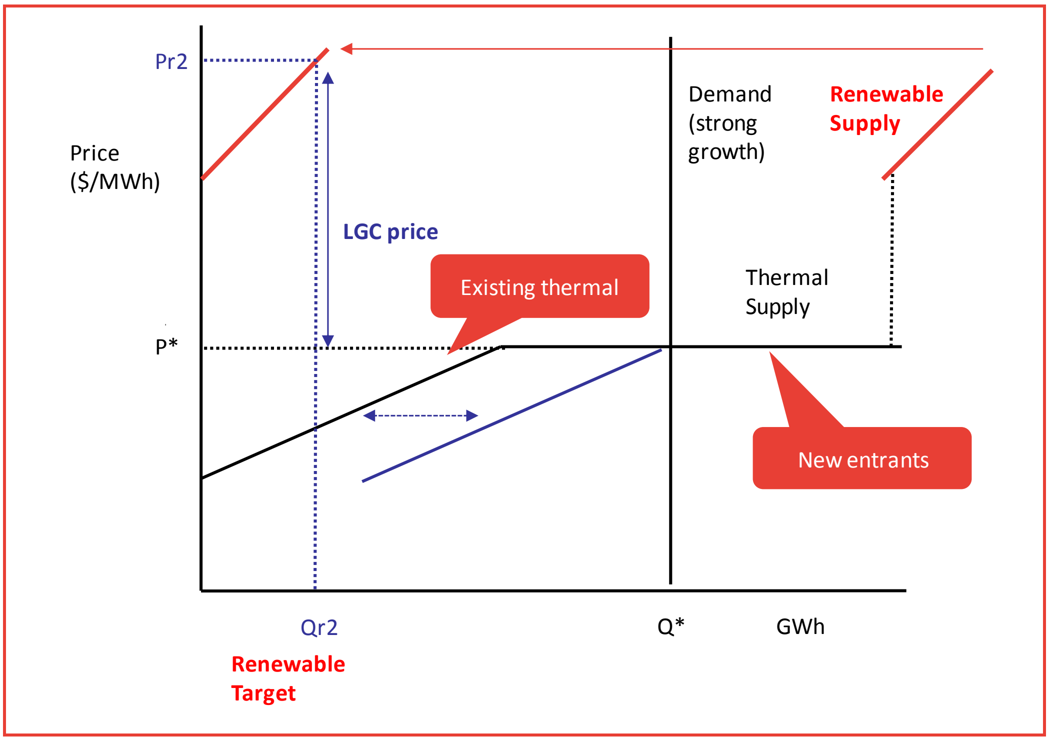
Figure 19: Illustration of the LRET: changes in the target



Source: Frontier Economics

The extent of any merit order effect in the longer-term will depend heavily on the growth in the LRET target relative to growth in energy demand. In the long-run, the thermal supply curve will be upward sloped for existing generation and relatively flat for new investments (at roughly the LRMC of new entrants). Where energy growth is very strong, a smaller increase in the LRET target will displace new entrant thermal plant, but this won't lead to substantially lower wholesale prices (as existing thermal plant is not displaced). This would mean a small or negligible merit order effect and consumers would face most of the incremental cost of the renewable (as wholesale prices would not be much lower than without the LRET). This is illustrated in Figure 20.

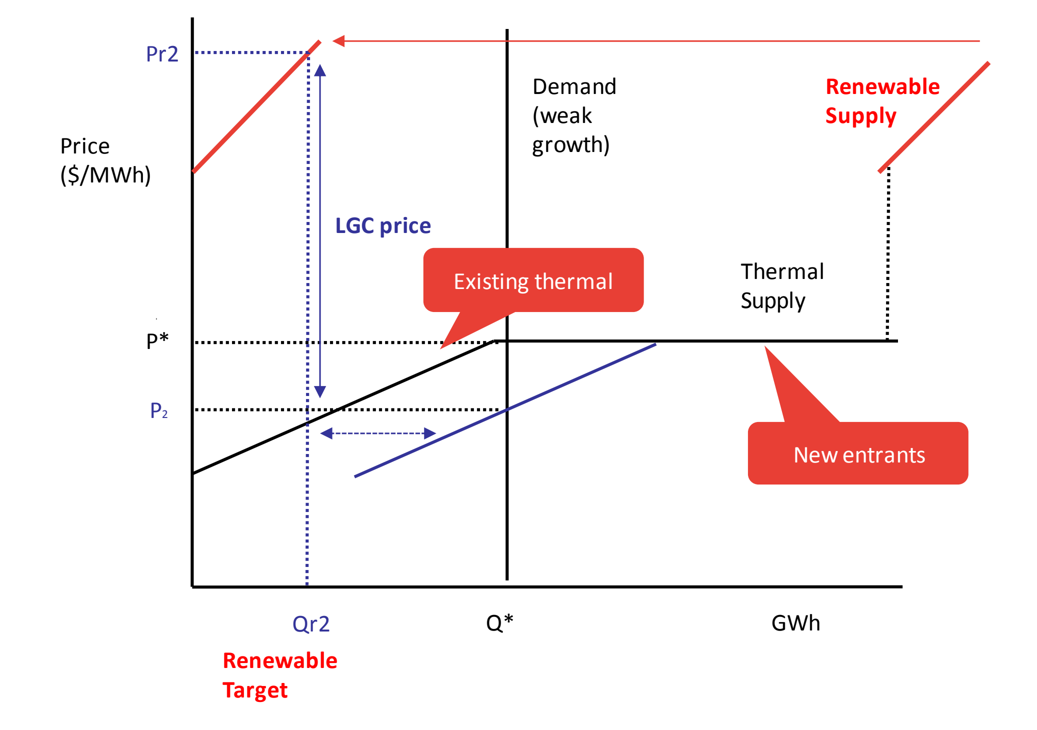
Figure 20: Illustration of the LRET: strong demand growth



Source: Frontier Economics

However, if the growth in the LRET target is large relative to the expected growth in energy demand then the renewables will be displacing existing thermal generation, wholesale prices will be lower than without the LRET, and existing generators will bear the burden of the LRET. This may create substantial investment uncertainty / instability in the thermal market, with prices below cost (LRMC). It may also increase the risk of an LRET shortfall where the RET penalty binds. The other key factor is whether existing generators continue to operate as normal, or whether they bid more aggressively and mothball/retire capacity. If generators do mothball capacity this will offset the merit order effect, reducing the dampening effect of the LRET on wholesale prices and shifting some of the burden back toward consumers.

Figure 21: Illustration of the LRET: weak demand growth



Source: Frontier Economics

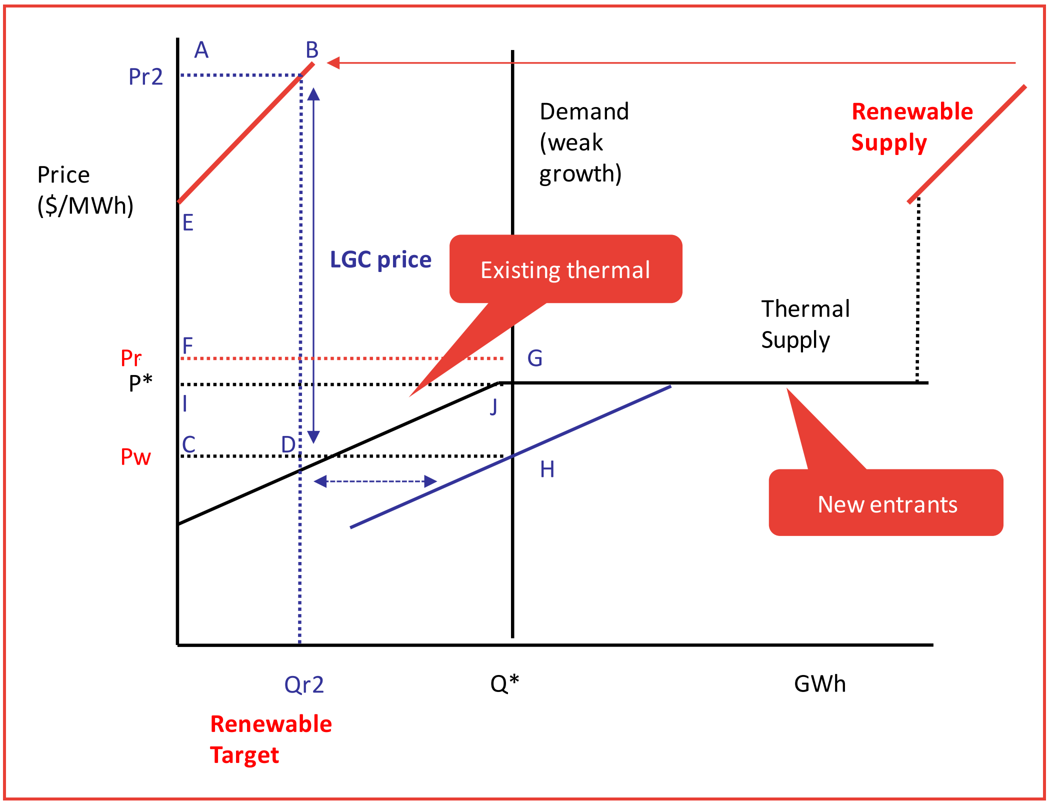
Retail prices and transfers

A stylised description of the operation of the LRET, including price effects, costs and transfers is as follows (Figure 22):

- P* is the wholesale price in the absence of the RET (and Q* is volume)
- QR2 is the renewable target. The remaining thermal supply curve shifts right by the same amount, displacing the more expensive thermal supply.
- The wholesale pool price falls to Pw due to the merit order effect. This is based on the assumption that the renewables displace *existing* thermal generation, as opposed to displacing the need for *new* generation (e.g. demand growth is assumed very weak or even zero).
- The LGC price is the difference between the new wholesale price (on average, Pw) and the marginal cost of the renewable generation (PR2).
- The total LGC subsidy is LGC price multiplied by the RET volume (QR2): ABCD (Figure 23)
- To fund the LGC cost a retail levy is imposed. This is equal to the total LGC cost (ABCD) but spread over energy consumed (Q*) (Figure 24) In this example, this is FGCH (which equals the area ABCD).

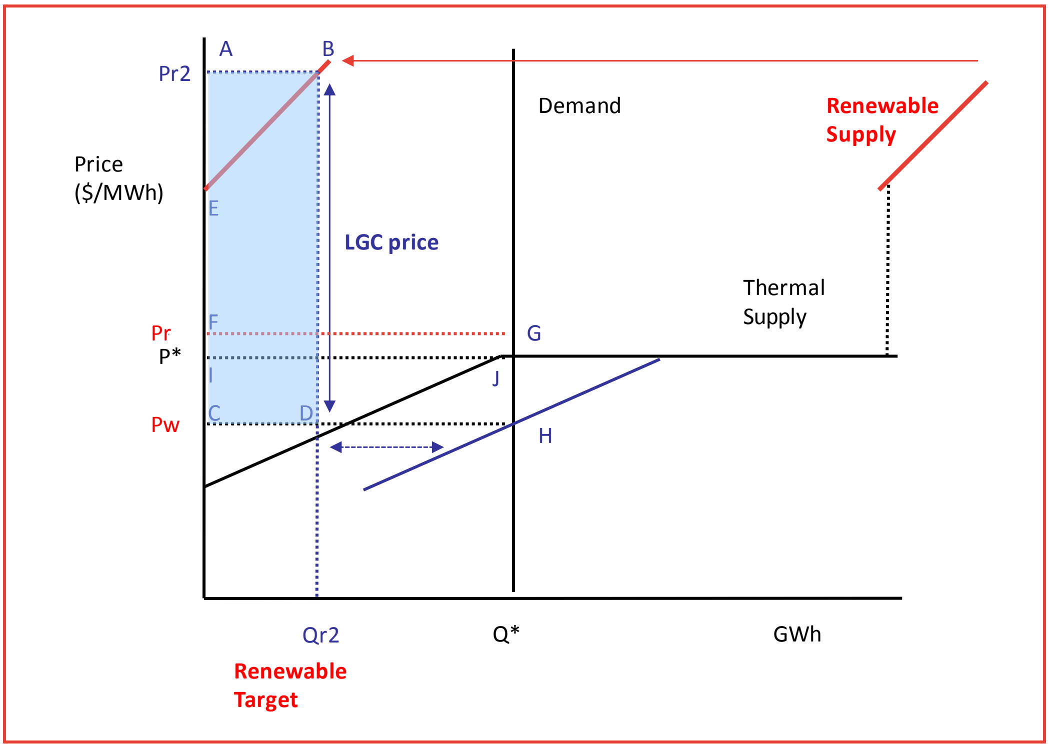
In this example the wholesale price (Pw) is now below P* - this reflects the cost of the LRET borne by existing thermal and hydro generation. The retail price (Pr) is now above P* in this example once the LGC levy is accounted for: this reflects the share of LRET cost borne by consumers (Figure 25). The distribution of burden depends heavily on the extent of the merit order effect.

Figure 22: Illustration of the LRET: retail price impacts



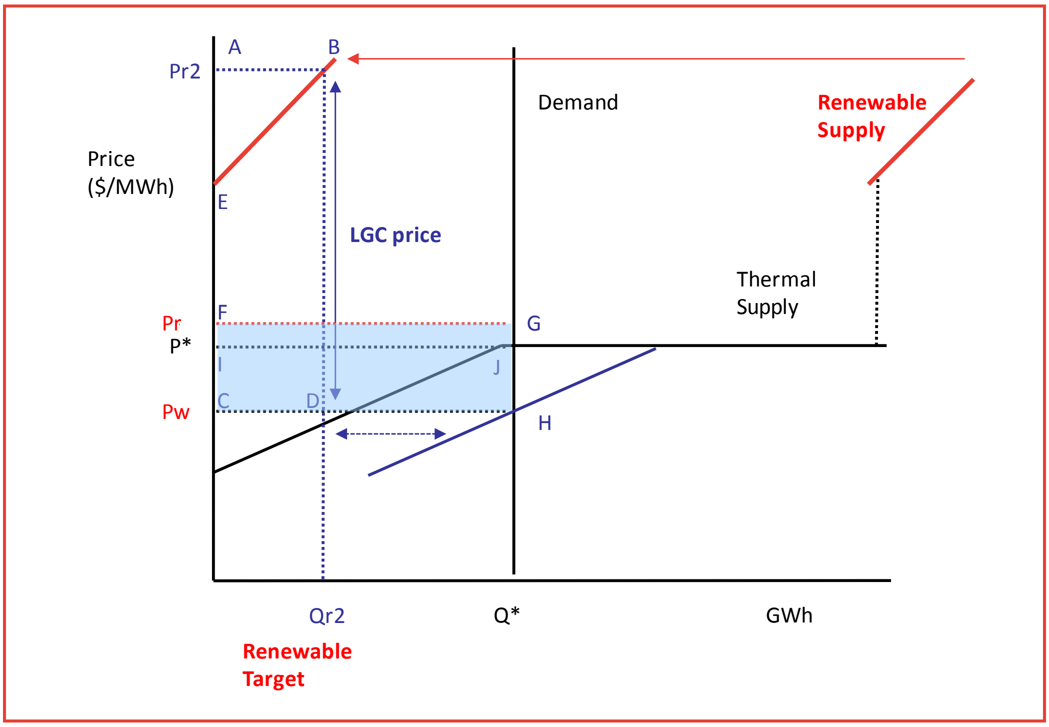
Source: Frontier Economics

Figure 23: Illustration of the LRET: scheme cost



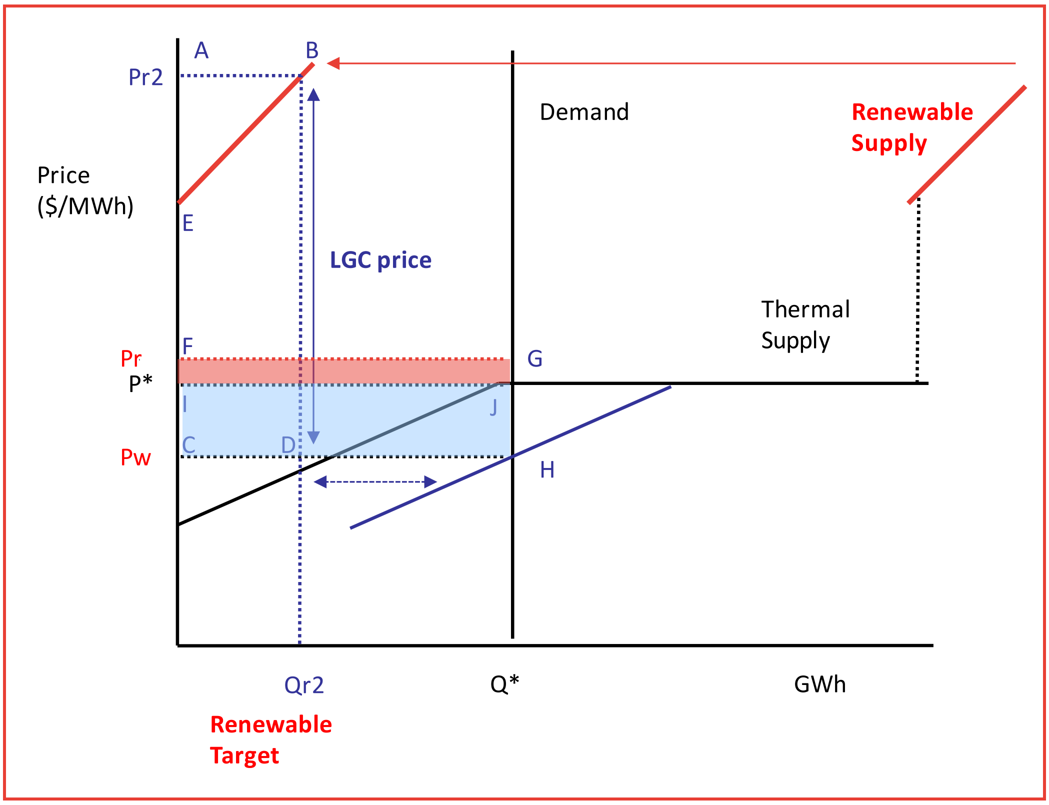
Source: Frontier Economics

Figure 24: Illustration of the LRET: retail levy



Source: Frontier Economics

Figure 25: Illustration of the LRET: distribution of burden



Source: Frontier Economics

Appendix B - Frontier's modelling input assumptions

This section provides an overview of the supply side input assumptions that we have used in our modelling of the RET. 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.[9]
- AEMO publish the National Transmission Network Development Plan (NTNDP), and supporting documents, which include a range of technical and cost input assumptions.[10]
- AEMO publish information on marginal loss factors for generation plant.[11]

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[12]

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

10 http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan and http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions

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

12 http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/ACIL_Tasman_Fuel_Cost_%20Projections_2012.ashx

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 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[13].

Key macroeconomic inputs

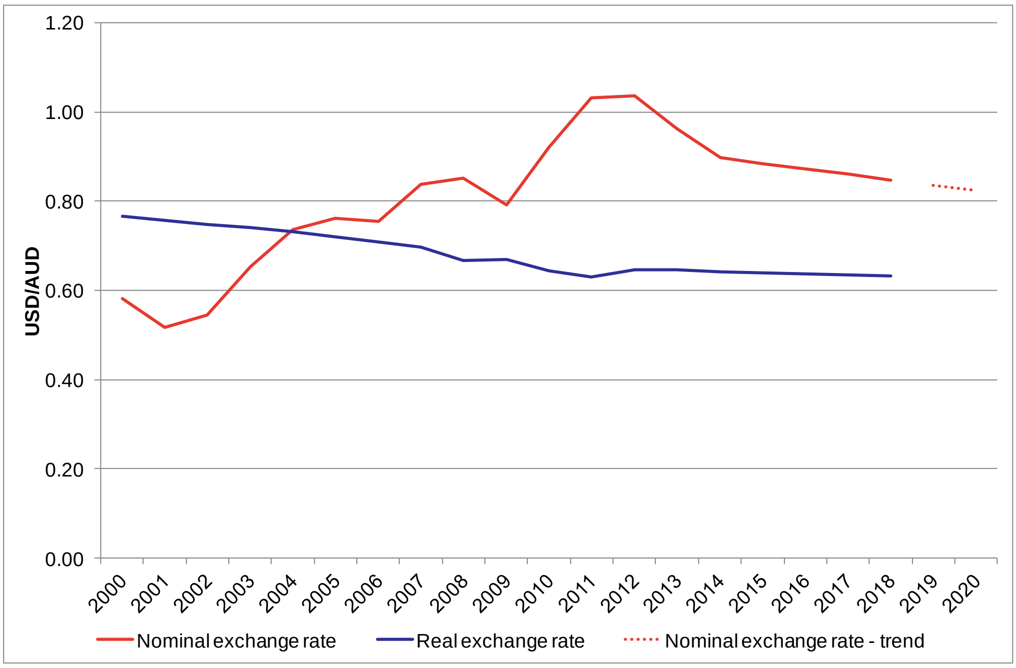
There are a number of macroeconomic input assumptions that are used in developing the input assumptions set out in this report. For consistency, the same macroeconomic input assumptions have been used throughout this report.

13 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.[14] 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 26 and exchange rates for the Euro are shown in Figure 27.

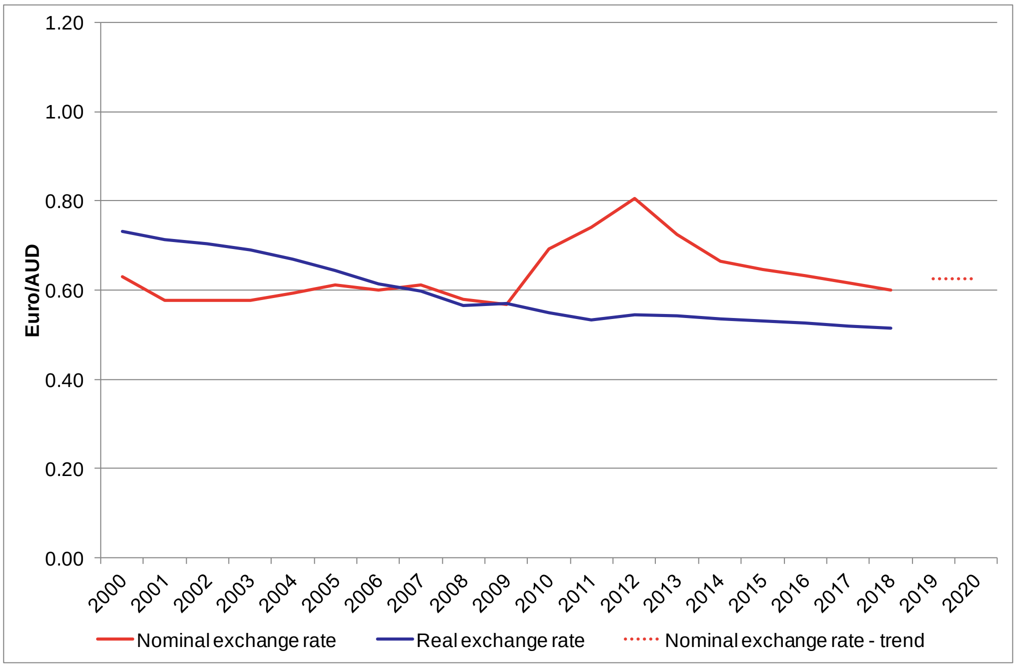
Figure 26: Exchange rates (USD/AUD)



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

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

Figure 27: 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:[15]

- 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

15 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.[16]

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.

16 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 28 and Figure 29. Figure 28 deals with gas-fired and coal-fired generation technologies and Figure 29 deals with renewable generation technologies.

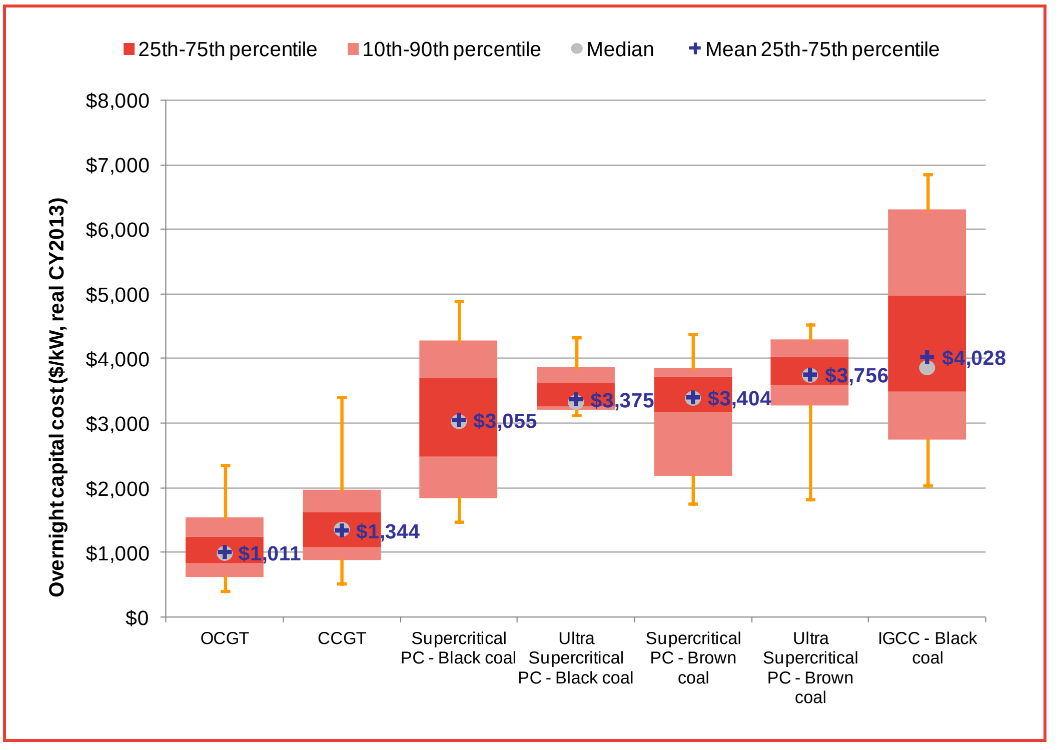
Our estimates of capital costs for each generation technology include a range of individual cost estimates. Even after filtering our global database for relevant countries and years we have a significant number of unique cost estimates for each generation technology. The full range of cost estimates (from lowest cost to highest cost) for each generation technology is shown by the orange "whiskers" in Figure 28 and Figure 29. 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 28 and Figure 29, 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 28 and Figure 29.

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.

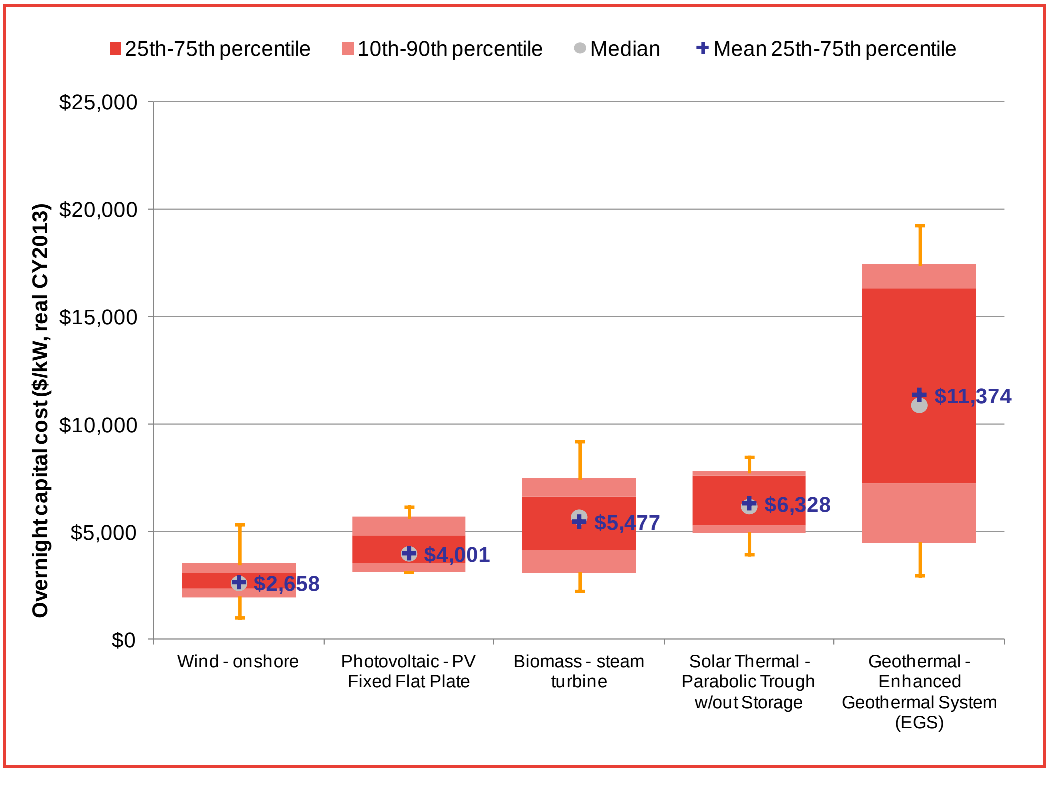
To avoid our analysis being affected by outliers, we estimate current capital costs for each generation technology as the mean of the cost estimates that fall within the 25^{th} to 75^{th} percentile of cost estimates for that generation technology. We note that this mean of the cost estimates that fall 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 28: Current capital costs for gas and coal generation plant



Source: Frontier Economics

Figure 29: 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. We have modelled out to 2035.

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 3.

Table 3: 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%

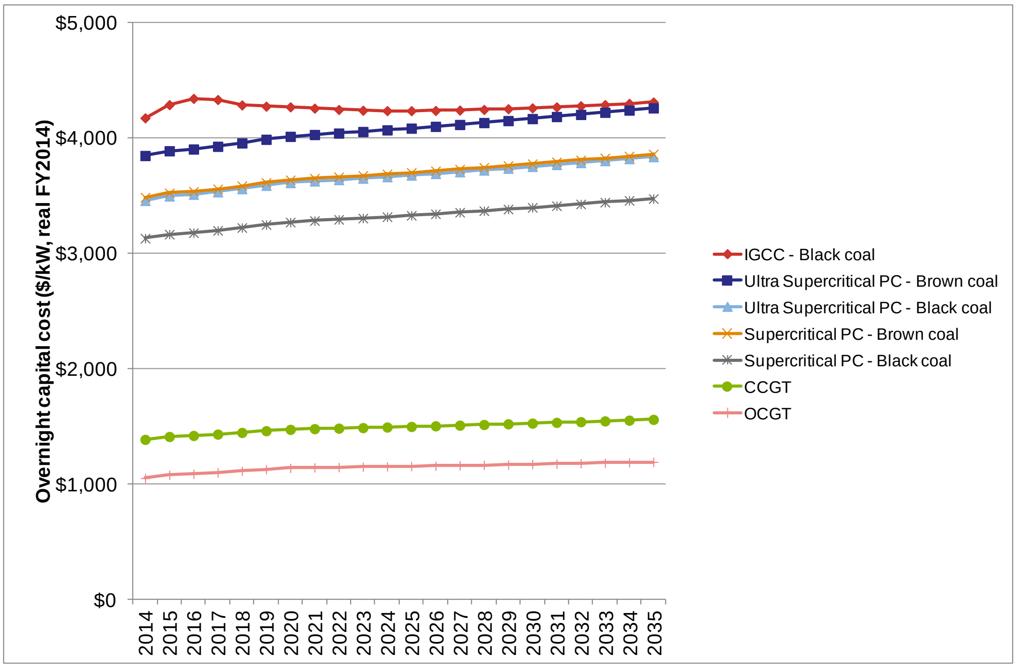
Source: Frontier based on various sources

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 30 and Figure 31. Figure 30 deals with gas-fired and coal-fired generation technologies and Figure 31 deals with renewable generation technologies. These capital costs are also reported in our Modelling Assumptions Spreadsheet, released with this report.

As seen in Figure 30, 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.

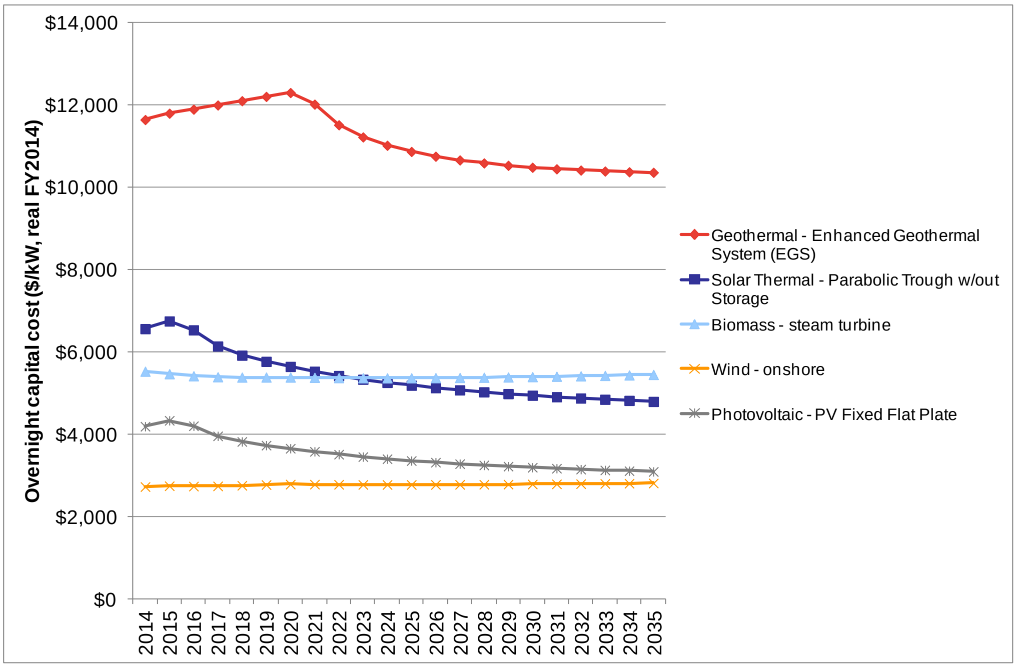
As seen in Figure 31, the capital costs for renewable generation plant are more variable over the modelling period. While these renewable generation plant are subject to increasing costs as a result of real escalation in capital costs and depreciation in the Australia dollar, the cost improvements for 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 30: Forecast capital costs for gas and coal generation plant ($2013/14)



Source: Frontier Economics

Figure 31: 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

Our estimates of operating costs and characteristics for each of the generation technologies considered are reported in our Modelling Assumptions Spreadsheet, released with this report.

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.[17]

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17 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.[18] 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.[19] 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

18 Ibid.

19 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 2035, 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.

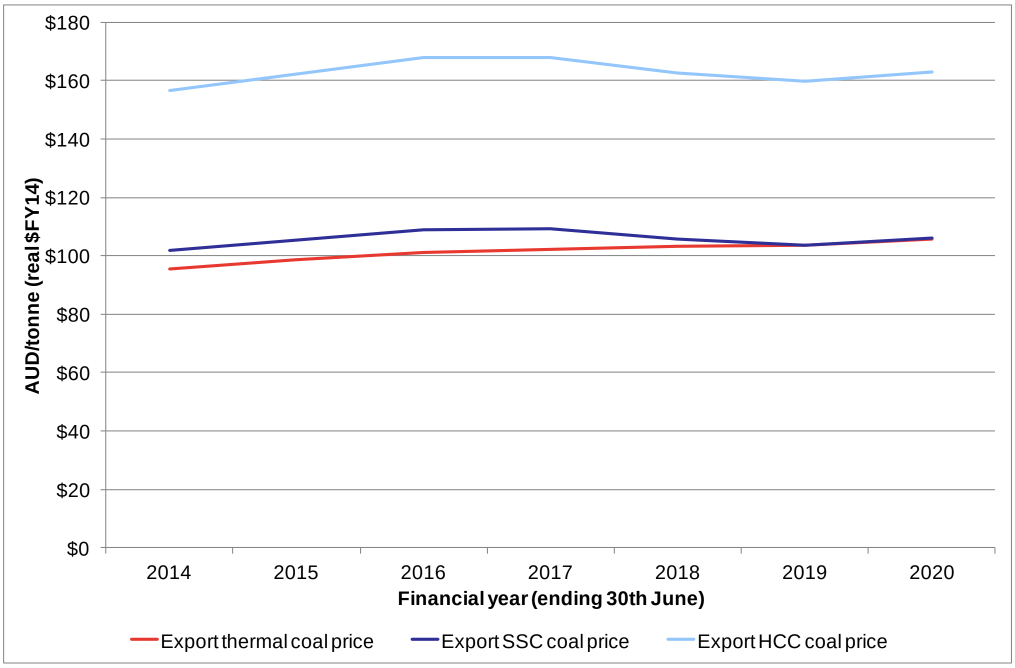
The **first step** for calculating the net-back price of coal is a forecast of the export price of coal. It is this export price that determines the revenue that a coal producer will earn by exporting coal.

The export prices that we have used to calculate the net-back price of coal are from quarterly forecasts released by the World Bank.[20] 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.[21] 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 32.

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

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

Figure 32: 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 32 are for coal of a particular quality. For instance, the export thermal coal price shown in Figure 32 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

Our coal price forecasts are reported in our Modelling Assumptions Spreadsheet, released with this report. This section provides a summary of these results.

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. The resulting coal price forecasts for these power stations in Victoria and South Australia are set out in full in the Draft Input Assumptions Spreadsheet.

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.

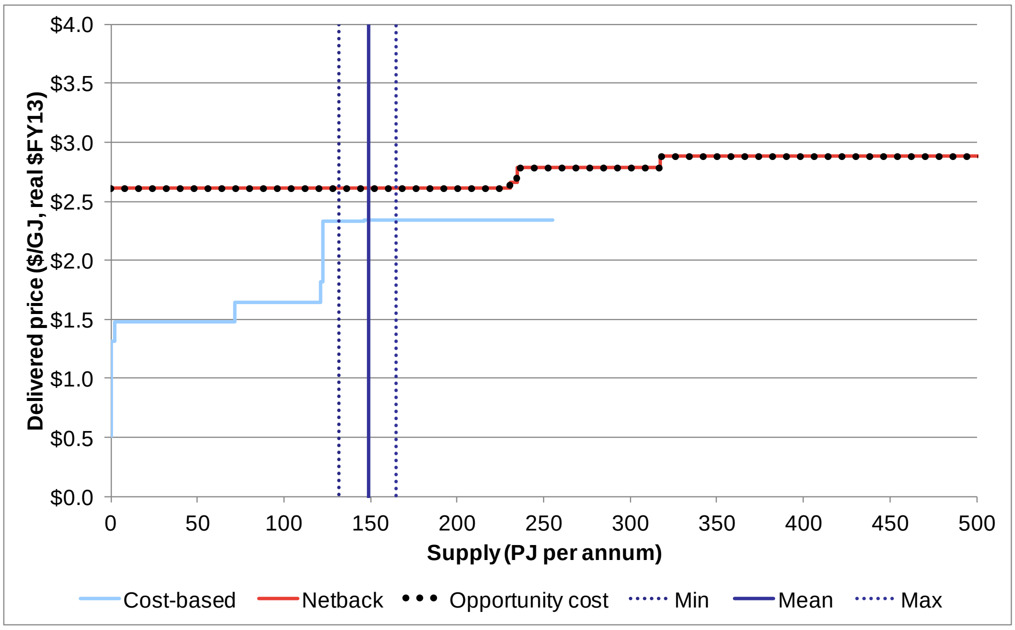
The marginal opportunity cost of coal in each region is determined by the point of intersection of the demand curve for coal in the region and the supply curve for coal in the region.

Demand and supply curves for each coal region are shown in Figure 33 and Figure 34. 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.

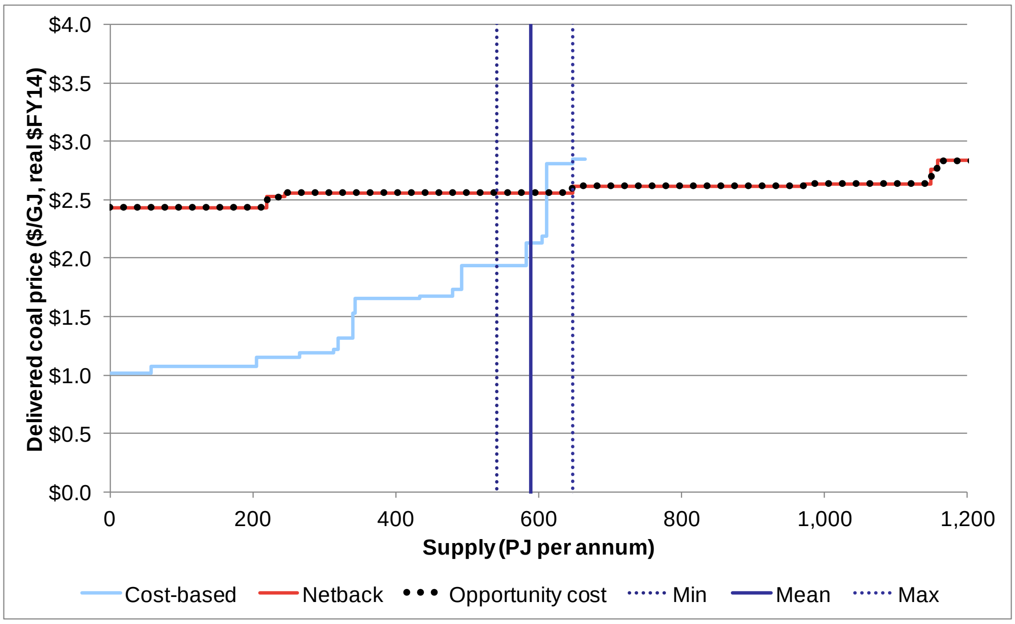
The supply curves for each region that are shown in Figure 33 and Figure 34 are supply curves with reference to the cost of delivery from each coal mine to a particular power station. Even within a single region, however, differences in transport costs result in slight differences in the coal price forecast to power stations that are located in different places.

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



Source: Frontier Economics

Figure 34: 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 a higher export coal prices. Our coal price forecasts for this high case are reported in full in our Modelling Assumptions Spreadsheet, released with this report.

Gas prices for power stations

In order to model outcomes in the electricity market over the period to 2035, we need an estimate of the marginal cost of gas 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 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.

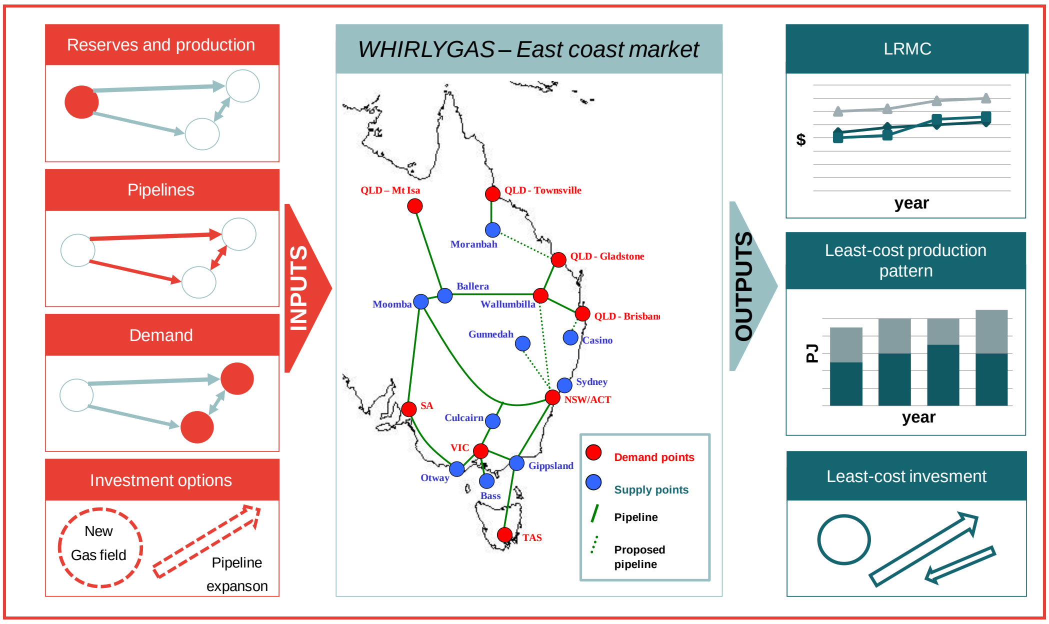
When estimating the marginal opportunity cost of coal, we can do so on a region by region basis, because there is no substantial interconnection between coal supply regions. However, the same is not true of gas: gas regions in eastern Australia are now interconnected through a network of gas transmission 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 35.

Figure 35: *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

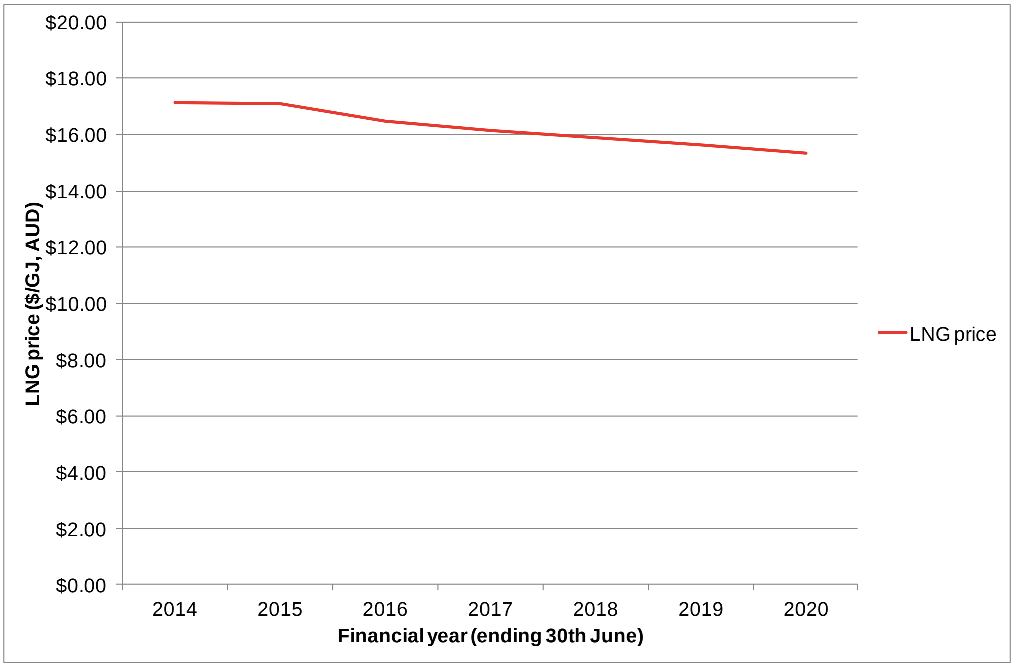
As with our coal forecasting work, opportunity cost is important to our gas forecasting work. The reason that opportunity cost is relevant to assessing the cost to gas producers of supplying gas to gas-fired generators is because the producers may well be foregoing alternative markets for that gas. For 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.[22] 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 36.

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

Figure 36: 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:

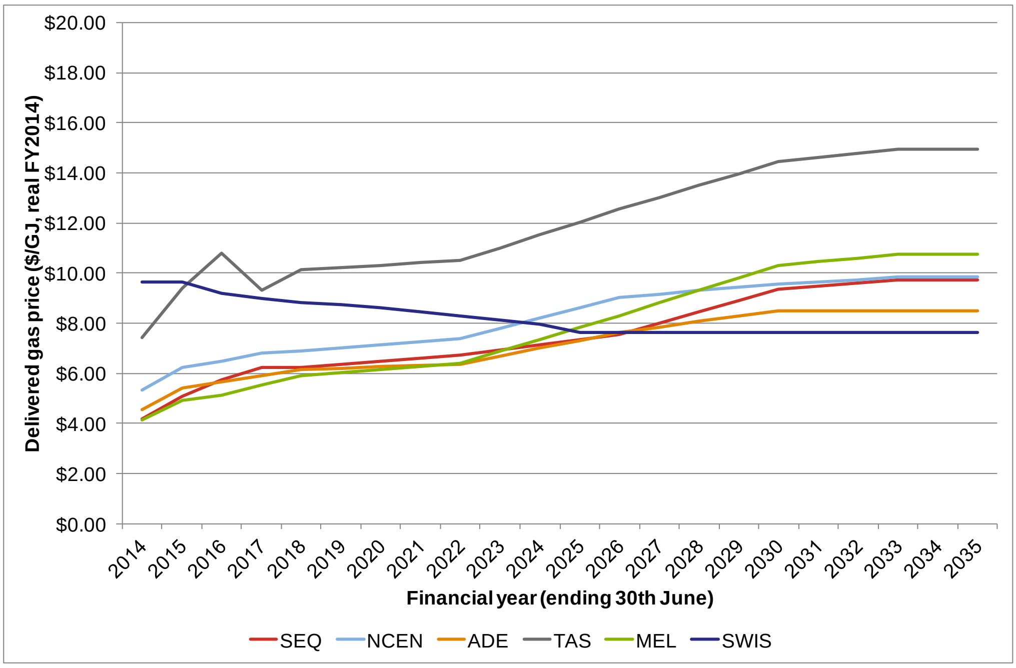
- Forecasts of the LRMC of satisfying demand in each demand region.
- Forecasts of investment in new production plant in eastern Australia.
- Forecasts of investment in new transmission pipelines in eastern Australia.
- Forecasts of production rates for existing and new production plant.

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

Gas price forecasts

Figure 37 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 37: LRMC of gas by State capital cities ($2013/14)



Source: Frontier Economics

Figure 37 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 37 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

Our gas price forecasts are reported in full in our Modelling Assumptions Spreadsheet, released with this report. 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 a higher Asia-Pacific LNG price, and the development of 10 LNG exports trains at Gladstone. Our gas price forecasts for this high case are reported in full in our Modelling Assumptions Spreadsheet, released with this report.

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