Possible future retail electricity price movements

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION

December 2012

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1 Introduction

In December 2011 the Australian Energy Market Commission (AEMC) received a request from the Ministerial Council on Energy (which is now the Standing Council of Energy and Resources) to report on possible future trends in electricity prices in the states and territories of Australia for the years 2012/13 to 2014/15.

The AEMC's report is to analyse potential trends for representative residential retail electricity prices, with the focus on the movements in prices and the drivers of prices. The AEMC's report is to disaggregate pricing into its component parts and to provide commentary on both a jurisdictional basis and a national basis.

1.1 Frontier Economics' engagement

Frontier Economics has been retained by the AEMC to advise on future trends in residential electricity prices, and the drivers behind them. Specifically, Frontier Economics has been retained to advise on future trends in the wholesale energy cost component of residential electricity prices. The specific cost components for which we are to provide cost forecasts are:

- wholesale electricity costs, including costs associated with the carbon price
- network losses
- National Electricity Market (NEM) fees
- the cost impact of any relevant jurisdictional environmental policies or programmes (or other relevant policies or programmes)
- the cost impact related to the national Renewable Energy Target (including both the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES)).

Our advice on wholesale energy costs is to cover the three-year period from 2012/13 to 2014/15.

1.2 This final report

This report is structured as follows:

- Section 2 provides a brief overview of the two approaches used by Frontier Economics to estimate the wholesale electricity costs, and the modelling methodologies used under these two approaches
- Section 3 sets out the input assumptions that have been used to forecast wholesale electricity costs for this task

- Section 4 sets out the results of Frontier Economics' modelling of the stand-alone LRMC for each distribution area
- Section 5 sets out the results of Frontier Economics' modelling of the market-based energy purchase cost for each distribution area
- Section 6 summarises carbon pass-through under Frontier Economics' modelling
- Section 7 sets out Frontier Economics' advice on the allowance for the costs of complying with the LRET, the SRES and the Queensland Gas Scheme
- Section 8 sets out Frontier Economics' advice on the allowance for the costs of complying with the energy savings schemes
- Section 9 sets out Frontier Economics' advice on the allowance for the NEM fees and ancillary services costs.

2 Overview of modelling methodology

A number of aspects of our advice to the AEMC will be based on energy market modelling. In particular, energy market modelling will be used to forecast the following cost components:

- wholesale electricity costs, including costs associated with the carbon price
- the cost impact related to the LRET
- the cost impact related to the Queensland Gas Scheme.

This section provides a brief overview of the energy market modelling methodology that we have used to forecast these cost components as well as the two approaches we have adopted to forecast wholesale electricity costs.

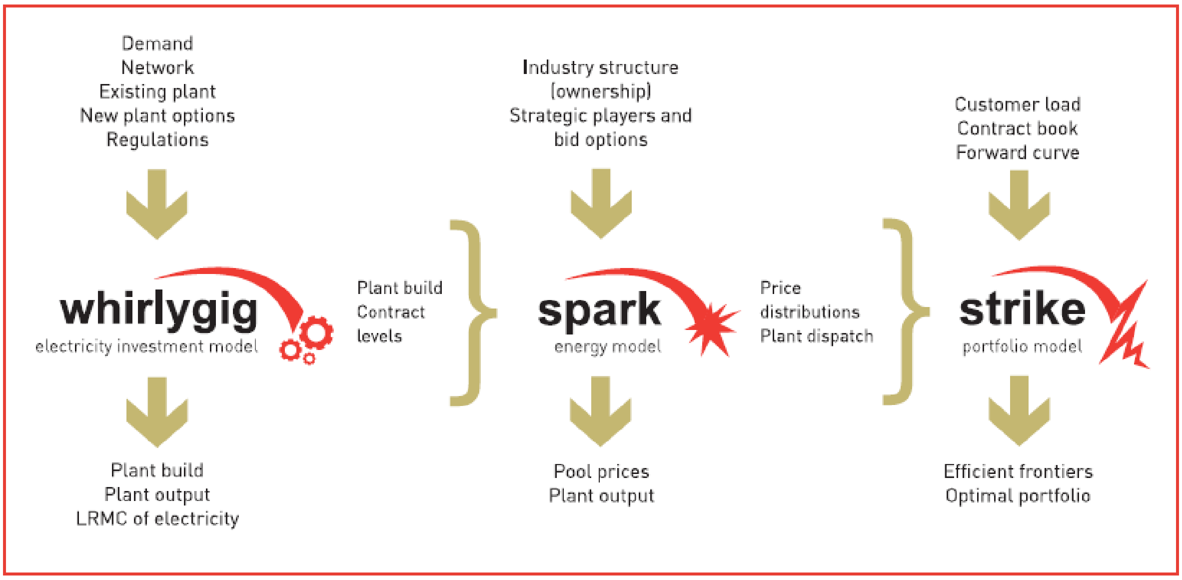
2.1 Frontier Economics' energy market models

For the purposes of estimating energy costs, Frontier Economics adopts a three-staged modelling methodology, which makes use of three inter-related electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*. These models are used in our work advising regulators and regulated businesses around Australia. The key features of these models are as follows:

- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* provides an estimate of LRMC, including the cost of any plant required to meet any regulatory obligations incorporated in the modelling.
- *SPARK* uses game theoretic techniques to identify optimal and sustainable bidding behaviour by generators in the electricity market. *SPARK* determines the optimal pattern of bidding by having regard to the reactions by generators to discrete changes in bidding behaviour by other generators. The model determines profit outcomes from all possible actions (and reactions to these actions) and finds equilibrium bidding outcomes based on game theoretic techniques. An equilibrium is a point at which no generator has any incentive to deviate. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.
- *STRIKE* uses portfolio theory to identify the optimal portfolio of available electricity purchasing options (spot purchases, derivatives and physical products) to meet a given load. *STRIKE* provides a range of efficient purchasing outcomes for different levels of risk, where risk relates to the level of variation in expected purchase costs.

The relationship between Frontier Economics' three electricity market models is summarised in Figure 1.

Figure 1: Frontier's energy modelling framework



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

2.2 Estimating wholesale electricity costs

Our assignment requires us to estimate wholesale electricity costs using two approaches.

Market-based energy purchases costs

The first is a market-based energy purchase costs approach. Market-based energy purchase costs are the costs that retailers face in buying energy from the wholesale market, including the hedging contracts that retailers enter into to manage their risk. This approach is only appropriate where there is a reasonable basis for forecasting spot prices and contract prices.

To estimate market-based energy purchase costs, we use *STRIKE*, which identifies the least cost portfolio of electricity purchasing options for each level of risk. The load used in *STRIKE* is the residential load (rather than, for instance, the total system load in each region). *STRIKE* makes use of inputs from *WHIRLYGIG* and *SPARK*:

- An important input into the estimation of energy purchase costs is a forecast of future spot prices. In order to forecast spot prices, we use *SPARK*, which applies game theoretic techniques to forecast spot price outcomes.

- An important input into the forecast of future spot prices is investment in generation plant. In order to forecast patterns of investment in generation plant, we use *WHIRLYGIG*, which determines least-cost patterns of investment in the NEM. Given that we are interested in modelling market outcomes, patterns of investment are determined using an incremental LRMC approach, which incorporates all existing plant in the NEM.

Stand-alone LRMC

The second is a stand-alone LRMC approach. Under this approach, we estimate the LRMC of serving the residential load in each jurisdiction assuming that there is no existing plant to meet the regulated load. In effect, this provides an LRMC that is the cost of serving an incremental increase to the residential load shape with a hypothetical new least-cost generation system. This approach was used by the jurisdictions in their most recent estimates of wholesale energy costs.

To estimate the stand-alone LRMC of the residential load, we use *WHIRLYGIG*. The load used to estimate the stand-alone LRMC is the residential load (rather than, for instance, the total system load in each region) and all existing generation plant is excluded from the modelling. This provides an LRMC estimate that is the cost of serving an incremental increase to the residential load shape with a hypothetical new least-cost generation system.

Approach adopted in each jurisdiction

The approaches that we have adopted in each jurisdiction are set out in Table 1.

Table 1: Wholesale energy cost – approaches in each jurisdiction

Jurisdiction	Market-based	Stand-alone LRMC
QLD	✓	
NSW	✓	✓
ACT	✓	
Tas		✓
VIC	✓	✓
SA	✓	✓
WA		✓

Within each jurisdiction, at a minimum, we have adopted the approach that most closely reflects the approach of the regulator within that jurisdiction. Where possible we have used both approaches. Exceptions to this are:

- **Queensland and the ACT:** In these jurisdictions, only the market-based approach has been modelled. This is consistent with the approach adopted by the Queensland Competition Authority (QCA) and the Independent Competition and Regulation Commission (ICRC) in these jurisdictions.
- **Western Australia:** Only the stand-alone LRMC approach has been adopted. This is consistent with the approach of the Economic Regulation Authority (ERA) and reflects the market structure in the WEM, which is not well-suited to a market-based approach.

2.3 Estimating the cost impact related to the LRET and the Queensland Gas Scheme

We estimate the cost impact related to the LRET and the Queensland Gas Scheme on the basis of the LRMC of meeting these regulatory obligations. One of the advantages of adopting an LRMC approach is that it is possible to model investment and dispatch decisions for renewable plant over the long term. This is important given the design of the LRET, which allows for banking and borrowing of certificates and, therefore, important relationships between the costs of certificates over time.

To determine the LRMC of meeting these regulatory obligations, we use *WHIRLYGIG*. Because there are important interactions between these schemes and the broader energy market, we use an incremental LRMC approach when determining the LRMC of meeting these regulatory obligations. This incremental LRMC approach assumes that the existing mix of generation plant in the NEM and WEM is in place to meet system demand in each region. The LRMC of meeting the LRET and the Queensland Gas Scheme is then calculated as the marginal cost of generation resulting from an incremental increase in the relevant target.

3 Input assumptions

This section sets out the key input assumptions that we have used in our energy market modelling for this project.

3.1 Key sources of input assumptions

The AEMC's report on future trends in residential electricity prices covers each of Australia's states and territories. Residential electricity prices remain regulated in most of these states and territories, with jurisdictional regulators playing a role in determining regulated tariffs.

Ideally, the input assumptions used in our modelling of wholesale energy costs for the AEMC would be the same as those used by the jurisdictional regulators. In practice, of course, this is not possible: in many case regulators have, at least to an extent, developed their own input assumptions. This creates two difficulties for the AEMC. First, beyond the current regulatory period it is unclear what input assumptions will be adopted in each jurisdiction. Second, because jurisdictional regulators adopt different input assumptions it is impossible to adopt a single set of input assumptions that is consistent with the approach in all jurisdictions.

Given these issues, our advice to the AEMC is to rely, where possible, on input assumptions developed by the Australian Energy Market Operator (AEMO) and the Independent Market Operator (IMO). Specifically, our advice to the AEMC is to rely on the following key sources for input assumptions:

- AEMO, *2012 National Electricity Forecasting Report* (**AEMO 2012 NEFR**). This is the source for system demand forecasts for the National Electricity Market (NEM) to be used in our modelling. In previous years, AEMO provided system demand forecasts in their annual *Electricity Statement of Opportunities* reports. These reports have commonly been used as the source for system demand forecasts by jurisdictional regulators. From 2012, however, system demand forecasts will be provided by AEMO in their annual *National Electricity Forecasting Report* and reproduced in their annual *Electricity Statement of Opportunities*.
- IMO, *Statement of Opportunities*, July 2012 (**IMO 2012 SOO**). This is the source for system demand forecasts for the South West Interconnected System (SWIS) that are used in our modelling.
- AEMO, *2012 National Transmission Network Development Plan* (**AEMO 2012 NTNDP**) consultation documents. This is the source for most generation assumptions.
- AEMO, *2011 National Transmission Network Development Plan* (**AEMO 2011 NTNDP**) consultation documents.

- Bureau of Resources and Energy Economics (BREE), *2012 Australian Energy Technology Assessment*, July 2012 (**BREE 2012 AETA**).

As part of the development of the AEMO 2012 NTNDP, AEMO has consulted on a range of input assumptions and released reports dealing with the costs and the technical characteristics of new and existing generators. At the time of conducting this modelling task, the consultation process for the AEMO 2012 NTNDP was ongoing and a number of documents had not been released. As a result, where required information had not been released, the AEMO 2011 NTNDP and the BREE 2012 AETA assumptions were adopted.

These sources tend to be adopted, or at least considered, by jurisdictional regulators. These sources of input assumptions also have the advantage of being something of an industry standard.

3.2 Scenarios

In our report we provide results for two scenarios. These two scenarios are based on two sets of input assumptions:

- **Planning Scenario** – reflecting Scenario 3 from the AEMO 2012 NTNDP and the Expected growth scenario from the IMO 2012 SOO
- **Slow Rate of Change Scenario** – reflecting Scenario 5 from the AEMO 2012 NTNDP and the Low growth scenario from the IMO 2012 SOO

Some of the key differences between the Planning Scenario and the Slow Rate of Change Scenario from the AEMO 2012 NTNDP are summarised in Table 2. Further detail on the implications of these differences for key input assumptions is set out in remainder of this section.

Table 2: Summary of scenario drivers

	Planning Scenario	Slow Rate of Change Scenario
Name	Planning	Slow Rate of Change
Economic Growth	Predicted	Lower
Commodity prices	Medium	Low
Productivity growth	Medium	Low
Population growth	Medium	Low
Greenhouse reduction target	5% reduction by 2020	Zero reduction by 2020
Carbon price assumption	Treasury core scenario	$0/t$CO_2$ after fixed price
Renewable Energy Target	Remains	Remains
GreenPower	Flat	Flat
International coal price	Medium	Low
LNG east cost production	Medium	Low

Source: AEMO, 2012 Scenarios Descriptions, January 2012.

3.3 Overview of input assumptions

This section provides an overview of the key modelling assumptions that we propose to adopt for our energy market modelling.

3.3.1 Inflation

All costs in this report are in real 2012/13 dollars. All our modelling is undertaken in real 2012/13 dollars.

3.3.2 Discount rate

Under both the incremental LRMC approach and the stand-alone LRMC approach, *WHIRLYGIG* optimises the total system costs of meeting demand over the entire modelling period. Total system costs are calculated as a net present cost in a specified base year using an assumed discount rate. The objective to be minimised by the model is the net present cost.

We have adopted a pre-tax, real discount rate of 7.1% to discount future values for the optimisation process. This is consistent with the discount rate used in the

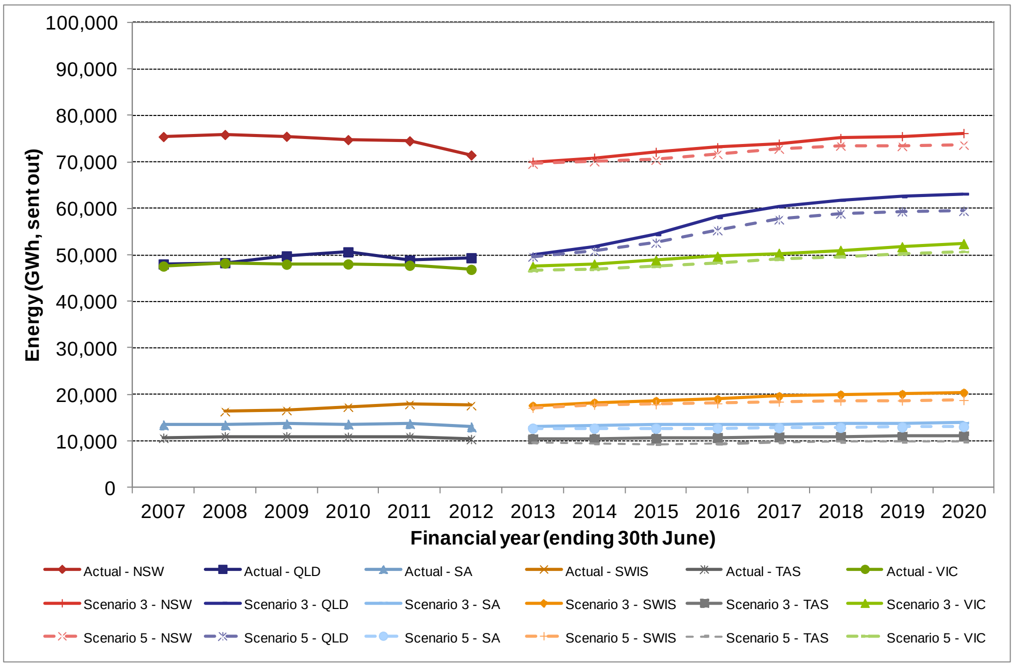
Independent Pricing and Regulatory Tribunal's (IPART's) most recent annual review.

3.3.3 System demand forecasts

System demand forecasts are used as an input to *WHIRLYGIG* under the incremental LRMC approach and are used as an input to *SPARK*.

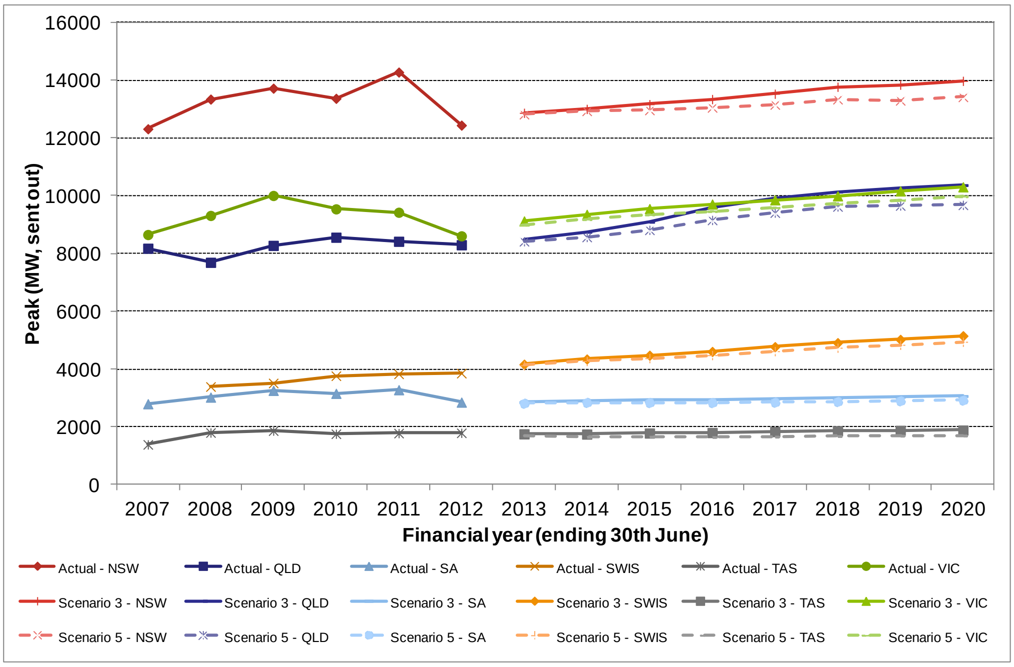
For the NEM jurisdictions, we have adopted the Planning Scenario and the Slow Rate of Change Scenario, which are also referred to as the Medium and Low growth forecasts in the AEMO 2012 NEFR (and the 2012 ESOO). For the SWIS, we have adopted the Expected growth demand forecast for the Planning Scenario and the Low growth demand forecast for the Slow Rate of Change Scenario from the IMO 2012 SOO. With respect to peak demand, we have modelled the corresponding 50% POE peak demand forecasts. These energy and peak demand forecasts are set out in Figure 2 and Figure 3 respectively.

Figure 2: Energy forecasts



Source: AEMO 2012 NEFR, IMO 2012 SOO

Figure 3: Peak demand forecasts



Source: AEMO 2012 NEFR, IMO 2012 SOO

For each scenario, we have also used the corresponding 10% POE projections for summer and winter for the purpose of modelling reserve constraints in *WHIRLYGIG*. In the NEM, these 10% POE projections are assumed to be 100% co-incident, implying that maximum demand occurs in each NEM region at the same time. This assumption of co-incidence is made to ensure consistency with AEMO's reported regional reserve margins in the reserve constraints which are reported on the same basis.

3.3.4 Residential customer demand forecasts

Demand forecasts for residential customers are used as an input to *WHIRLYGIG* under the stand-alone LRMC approach, and are used as an input to *STRIKE* under the market-based approach. In both cases the relevant factor is the half-hourly shape of residential demand (and its correlation to system demand and system prices), rather than the absolute level of residential demand.

Half-hourly demand forecasts for residential customers have been based on half-hourly data published by AEMO for the net system load profile (NSLP) and controlled load profile (CLP). For those distribution areas with a CLP, the two half-hourly shapes have been combined to provide a half-hourly shape of a representative 'residential' load that includes a proportion of controlled load.[1] Combining the NSLP and CLP data requires an assumption regarding the energy ratio between the two profiles, we have used:

- **NSW:** ratios were adopted such that the final load factor modelled was broadly consistent with our understanding of the load factors in each of the distribution areas.
- **Queensland:** the ratio was inferred using data from an Energex report.[2]
- **South Australia:** the ratio was provided by the Essential Serves Commission of South Australia (ESCOSA).
- **Other jurisdictions:** not applicable as CLP is not measured separately

For some distribution areas we were unable to get half-hourly load data. For these distribution areas, we have used the half-hourly data from another distribution area that we considered likely to be the most reasonable proxy: the 'residential' load shape in the SWIS has been assumed to match the 'residential' load shape in South Australia and the 'residential' load shape in Tasmania has

1 The NSLP is published by AEMO as total energy for each half-hour (in kWh). However, the CLP is published as total energy for each half-hour (in kWh) for a sample of customers with interval metered controlled load. As such the data cannot be combined directly, a proportion of NSLP to CLP must be assumed.

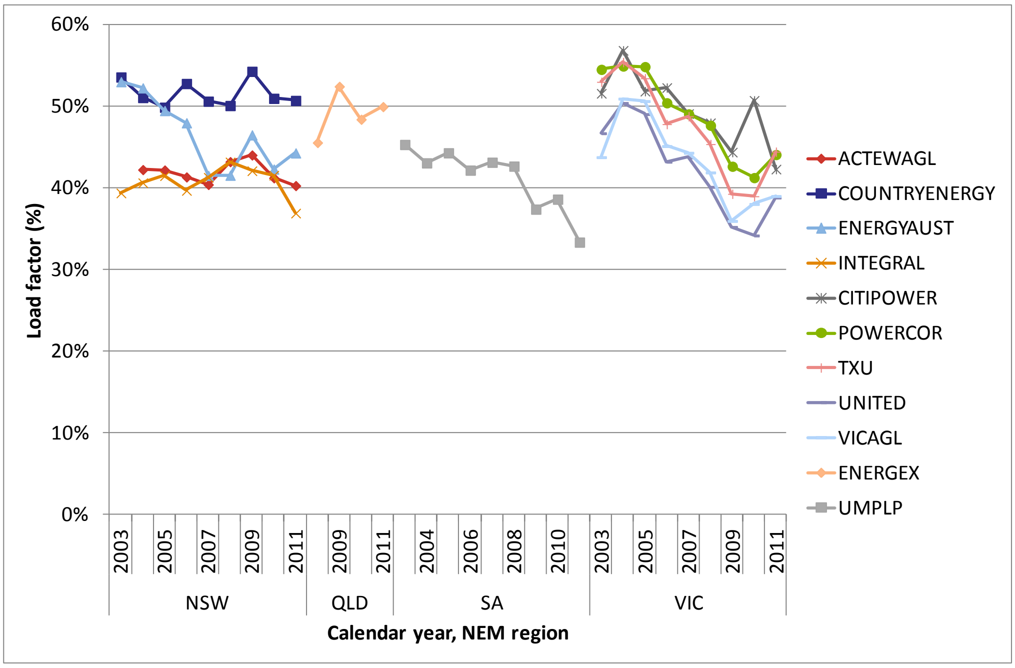
2 Energex, *Regulatory Proposal July 2010 – June 2015*, July 2009

been assumed to match the 'residential' load shape for the Powercor distribution area in Victoria.

While these load profiles will in fact include customers who are not residential customers (including small business customers) we consider that this data is likely to provide a reasonable representation of the load shape for residential customers in each jurisdiction. It is only the load shape that is relevant to our estimate of wholesale energy costs under both the stand-alone LRMC approach and the market-based approach, as under both approaches we are reporting units costs independent of the total energy being considered.

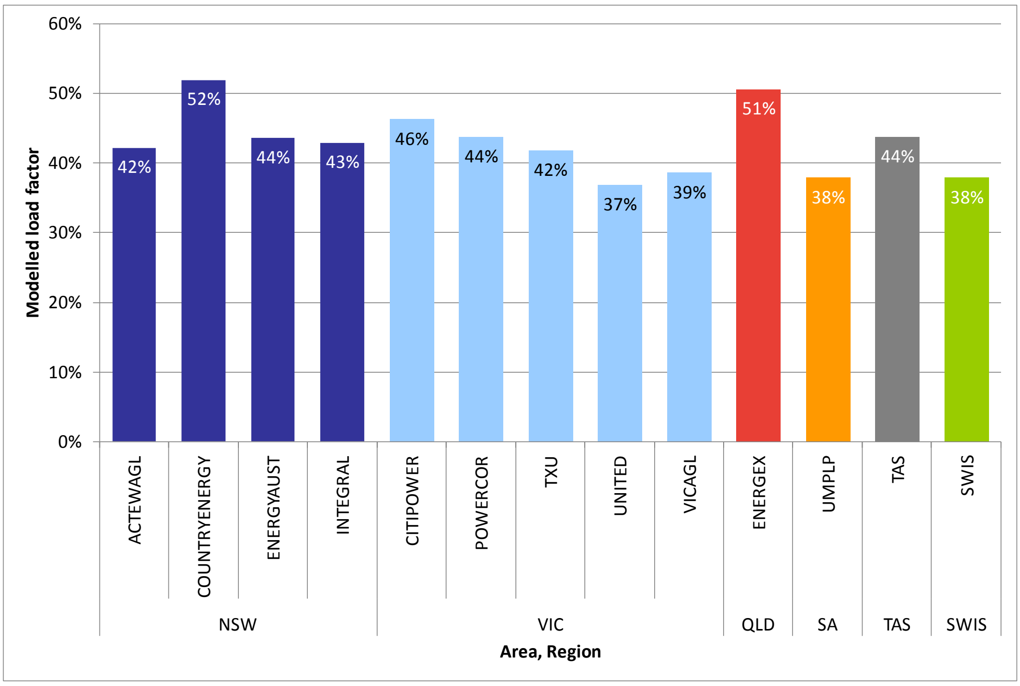
The historical 'residential' load factors created by combining the NSLP and CLP are shown in Figure 4. For each distribution area we have used the last 4 years data to generate a representative 'residential' half-hourly load shape. The load factors associated with these load shapes are shown in Figure 5.

Figure 4: Historical load factors for 'residential' demand



Source: Frontier Economics analysis, AEMO NSLP and CLP.
Note: NSLP and CLP used a proxy for residential load shape

Figure 5: Load factors for modelled 'residential' demand



Source: Frontier Economics
Note: NSLP and CLP used a proxy for residential load shape

3.3.5 Existing generation plant in the NEM and the SWIS

We have used the latest information available from AEMO's website[3] on existing and committed scheduled and semi scheduled generation plant in each region of the NEM. This provides both the identity of existing and committed generation plant and the summer and winter capacity of these generation plant. We have used the latest information available from the IMO's website[4] on capacity credits assigned to existing and committed generation plant in the SWIS.

Frontier Economics' market modelling (using *SPARK*) also requires information on ownership of existing generation plant. Frontier Economics has used up-to-date publicly available information on plant ownership in its modelling.

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3 AEMO, Tables of Existing and Committed Scheduled and Semi Scheduled Generation – by Region. Available from:

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

Announcements around temporary capacity withdrawals from Playford, Northern, Tarong and Yallourn were made after the analysis was underway and have not been included.

4 IMO, Capacity Credits assigned since Energy Market Commencement. Available from:

http://www.imowa.com.au/cap-credit-info

In addition to the identity and capacity of existing and committed generation plant, our models require key technical and cost information for existing generation plant. The required technical information for existing generation plant includes the following:

- **Expected outage rates** – we have sourced expected outages rates for each existing and committed generation plant from the AEMO 2012 NTNDP.
- **Heat rate** – we have sourced heat rates for each existing and committed generation plant from the AEMO 2012 NTNDP.
- **Emissions intensity** – we have sourced emissions intensity (including both combustion emissions and fugitive emissions) for each existing and committed generation plant from the AEMO 2012 NTNDP.
- **Auxiliary power** – we have sourced auxiliary power rates for each existing and committed generation plant from the AEMO 2012 NTNDP.

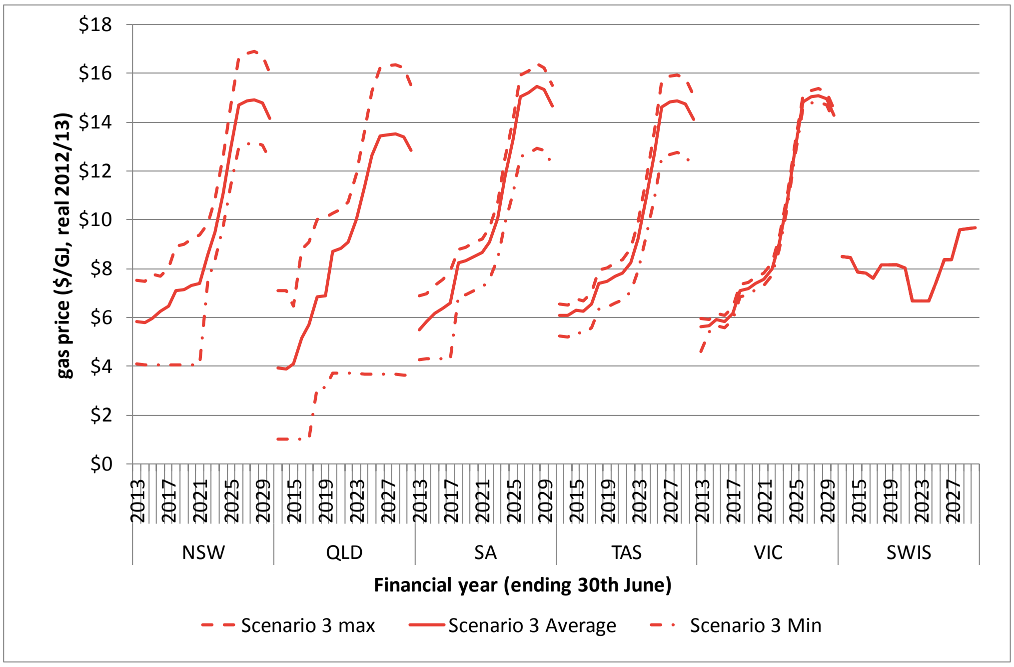
The required cost information for existing generation plant is the following:

- **Variable operating and maintenance (VOM) costs** – we have sourced VOM costs for each existing and committed generation plant from the AEMO 2012 NTNDP.
- **Fuel costs** – we have sourced fuel costs for each existing and committed generation plant from a combination of the AEMO 2011 NTNDP and the AEMO 2012 NTNDP.

  At the time of this modelling task, fuel cost forecasts for SWIS generators had not been released as part of the AEMO 2012 NTNDP, so we have relied on the AEMO 2011 NTNDP for that information.

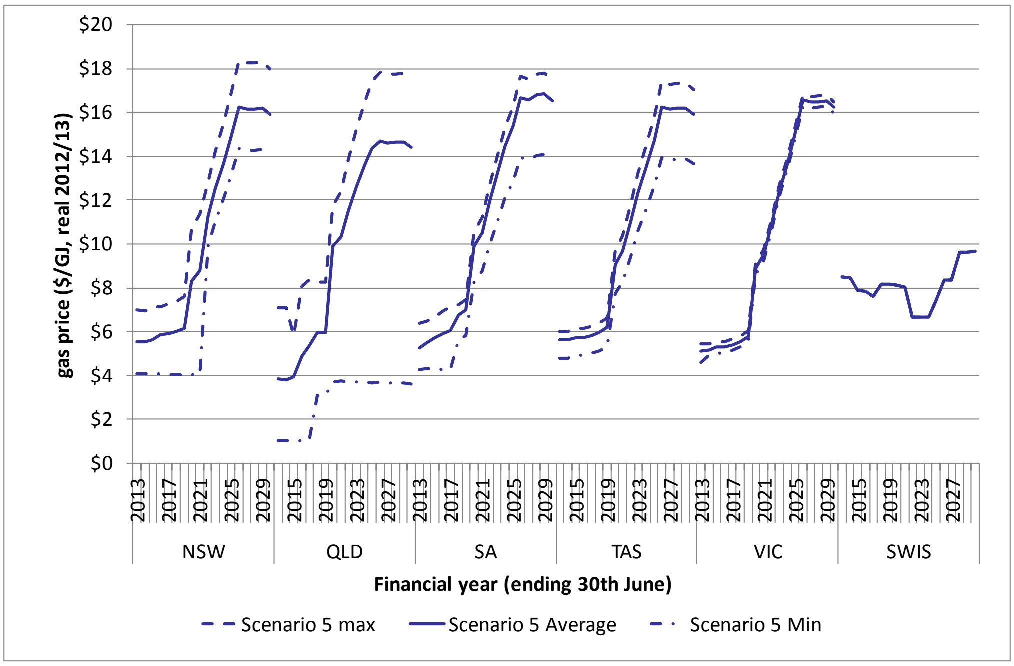
  Using this approach, fuel price forecasts for existing and committed coal-fired and gas-fired generators in each NEM region and in the SWIS are set out in Figure 6 through Figure 8. While the AEMO 2012 NTNDP assumes different gas price trajectories across Scenarios 3 and 5 over the modelling period, it assumes that the coal price trajectories are the same for existing and committed coal-fired generators (coal prices for new entrants do change), as illustrated in Figure 8.

Figure 6: Gas prices for existing and committed generators – Scenario 3 ($2012/13)



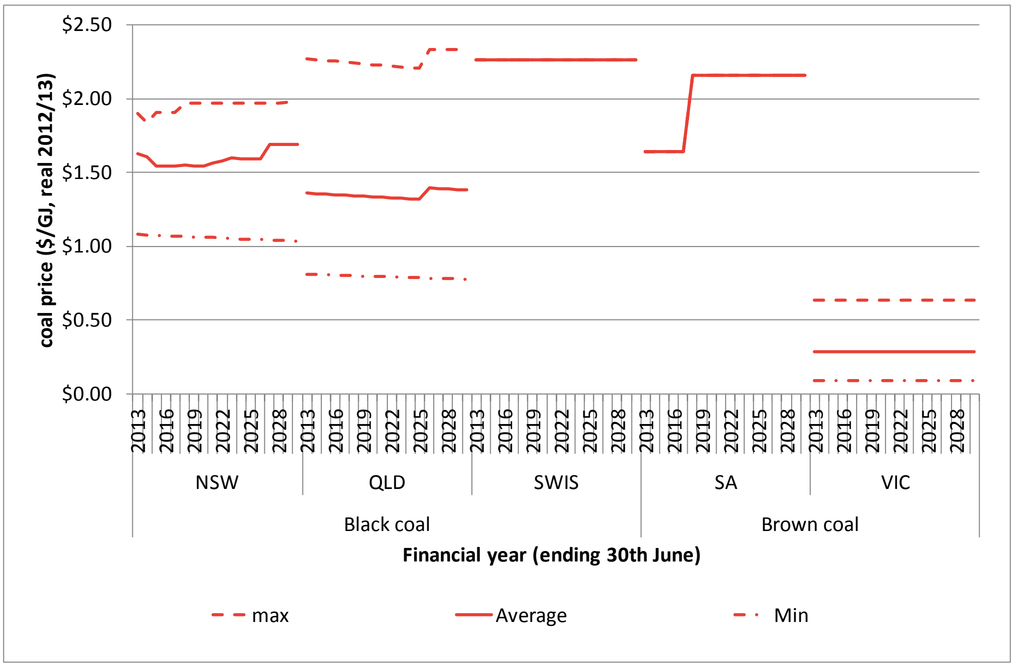
Source: AEMO 2011 NTNDP and AEMO 2012 NTNDP

Figure 7: Gas prices for existing and committed generators – Scenario 5 ($2012/13)



Source: AEMO 2011 NTNDP and AEMO 2012 NTNDP

Figure 8: Coal prices for existing and committed generators – Scenario 3 and 5 ($2012/13)



Source: AEMO 2011 NTNDP and AEMO 2012 NTNDP

3.3.6 New generation plant

We have used the AEMO 2012 NTNDP as the basis for input assumptions for new entrant generation plant.

The generation technologies that will be available as options for new generation over the modelling period are:

- Supercritical pulverised coal – black coal without CCS, both brown and black coal with CCS, black coal oxy-combustion with CCS
- Integrated gasification combined cycle (IGCC) – both brown coal and black coal with CCS
- Combined cycle gas turbine (CCGT) – both with and without CCS, also with an integrated solar combined cycle (ISCS)
- Open cycle gas turbine (OCGT)
- Solar thermal – parabolic trough and central receiver with storage. Compact linear Fresnel reflector without storage.
- Solar PV – fixed flat plate
- Wind

- Geothermal
- Biomass

In some instances, these generation options are not available in certain regions, or are available only up to a total capacity limit in each region. Assumptions on the availability of these new generation technologies in each region are informed by the AEMO 2011 NTNDP. This information has not yet been made available as part of the AEMO 2012 NTNDP.

As with the existing generation technologies, for each of the new entrant generation technologies our models require key technical and cost information for existing generation plant.

The required technical information for existing generation plant includes the following:

- **Expected outage rates** – we have sourced expected outages rates for new generation plant from the AEMO 2012 NTNDP.
- **Heat rate** – we have sourced heat rates for new generation plant from the AEMO 2012 NTNDP.
- **Emissions intensity** – we have sourced emissions intensity (including both combustion emissions and fugitive emissions) for new generation plant from the AEMO 2012 NTNDP.
- **Auxiliary power** – we have sourced auxiliary power rates for new generation plant from the AEMO 2012 NTNDP.

The required cost information for existing generation plant includes the following:

- **Capital costs** – we have sourced capital costs for new generation plant from the AEMO 2012 NTNDP.

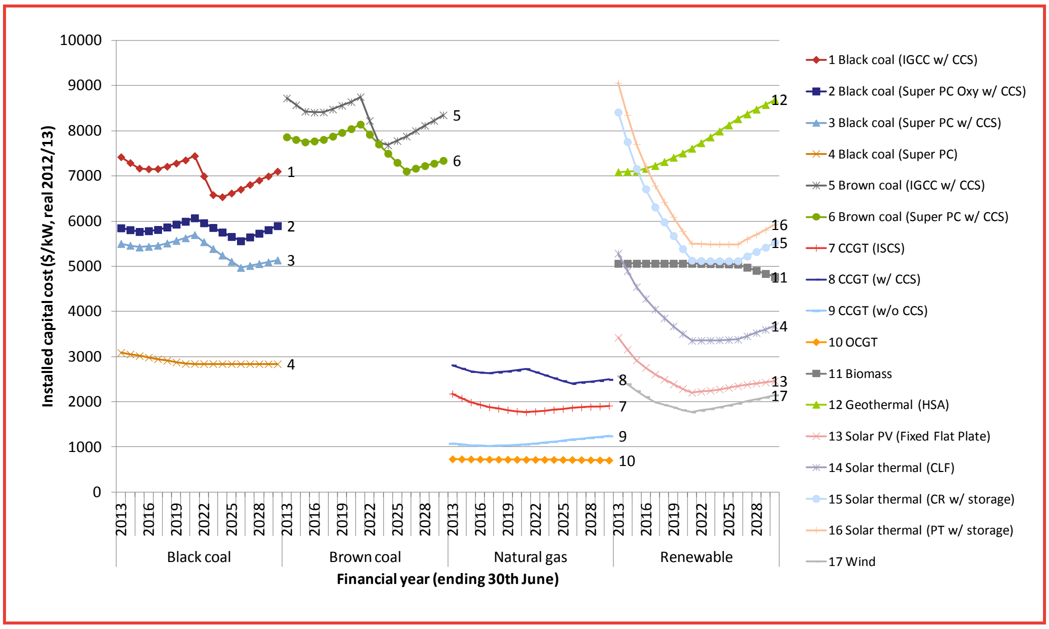
  At the time of this modelling task, capital cost forecasts for SWIS generators had not been released as part of the AEMO 2012 NTNDP. We have relied on the AEMO 2011 NTNDP to estimate that information.

  A summary of capital costs for coal and gas plant is shown in Figure 9 (for the Planning Scenario) and Figure 10 (for the Slow Rate of Change Scenario).
- **Variable operating and maintenance (VOM) costs** – we have sourced VOM costs for new generation plant from the AEMO 2012 NTNDP.
- **Fixed operating and maintenance (FOM) costs** – we have sourced FOM costs for new generation plant from the AEMO 2012 NTNDP.

  At the time of this modelling task, capital, VOM and FOM cost forecasts for supercritical pulverized black coal without CCS had not been released as part of the AEMO 2012 NTNDP. We have relied on the BREE 2012 AETA and the AEMO 2011 NTNDP to estimate that information.

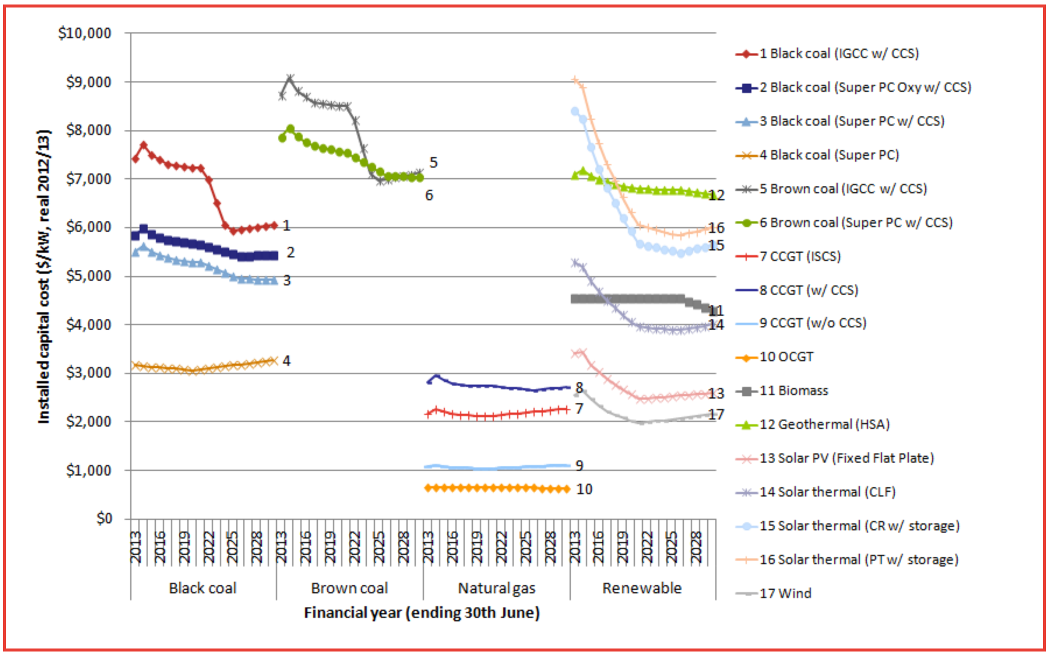
- **Fuel costs** – we have sourced fuel costs for new generation plant in the NEM from the AEMO 2012 NTNDP. We have source fuel costs for new generation plant in the SWIS from the AEMO 2011 NTNDP as this information had not been made available as part of the AEMO 2012 NTNDP. Gas price forecasts for new entrant CCGT plant in each region are shown in Figure 11 (for the Planning Scenario) and Figure 12 (for the Slow Rate of Change Scenario) and coal price forecasts for new entrant coal plant in each region are shown in Figure 13 (for the Planning Scenario) and Figure 14 (for the Slow Rate of Change Scenario).

Figure 9: New entrant capital costs – Scenario 3 ($2012/13)



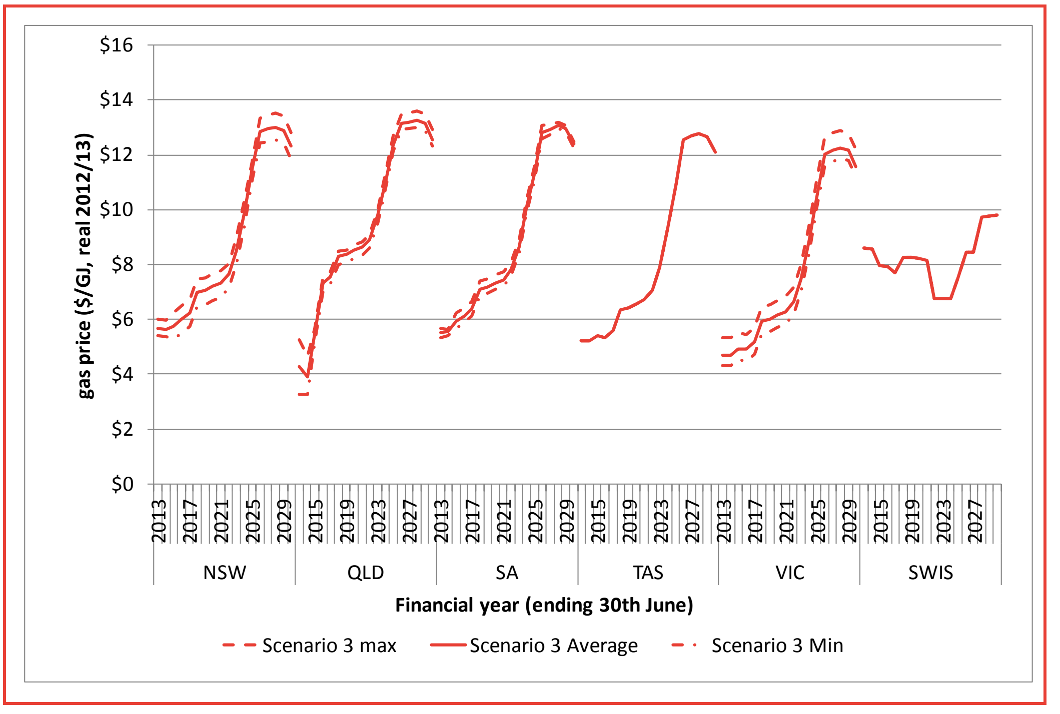
Source: AEMO 2011 NTNDP, AEMO 2012 NTNDP and BREE 2012 AETA

Figure 10: New entrant capital costs – Scenario 5 ($2012/13)



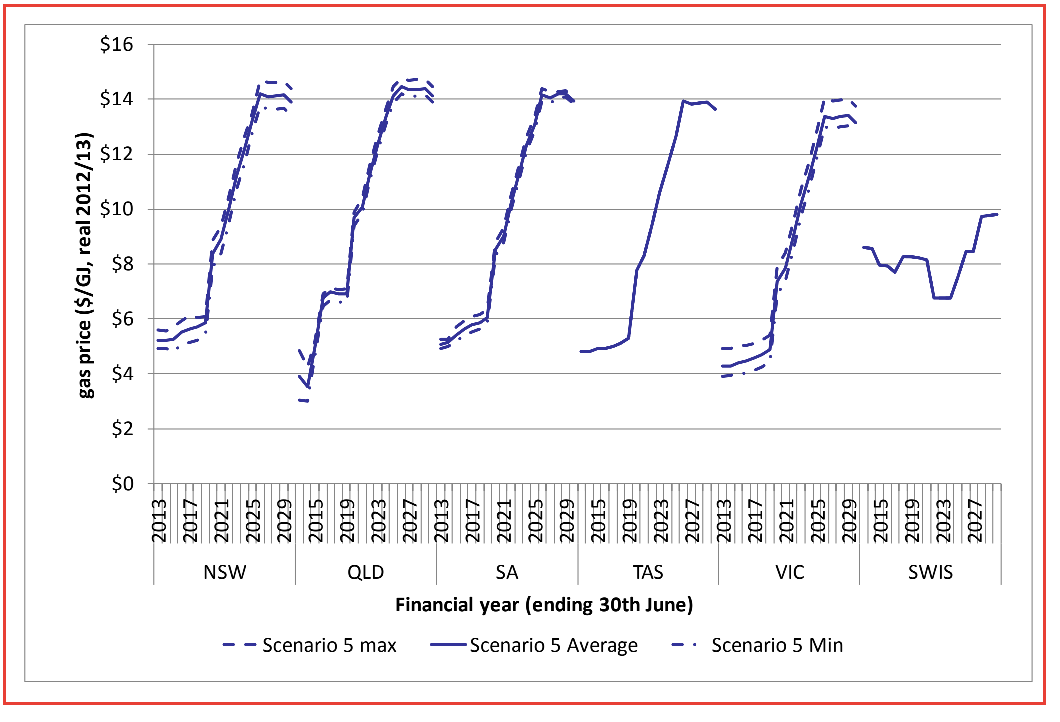
Source: AEMO 2011 NTNDP, AEMO 2012 NTNDP and BREE 2012 AETA

Figure 11: Gas prices for new entrant CCGT plant – Scenario 3 ($2012/13)



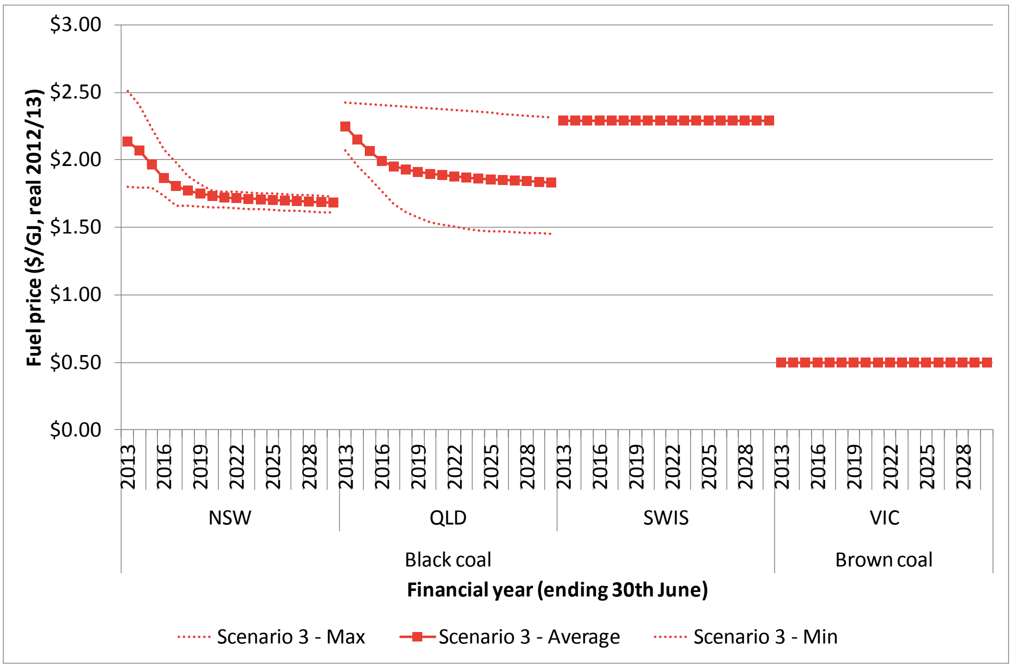
Source: AEMO 2011 NTNDP, AEMO 2012 NTNDP and BREE 2012 AETA

Figure 12: Gas prices for new entrant CCGT plant – Scenario 5 ($2012/13)



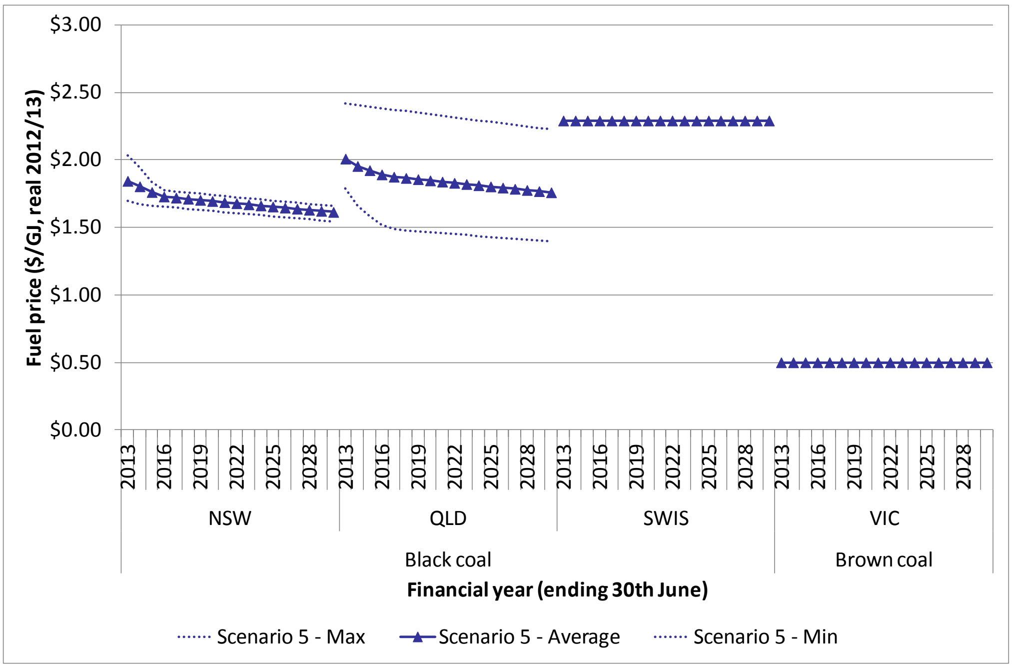
Source: AEMO 2011 NTNDP, AEMO 2012 NTNDP and BREE 2012 AETA

Figure 13: Coal prices for new generators – Scenario 3 ($2012/13)



Source: AEMO 2011 NTNDP, AEMO 2012 NTNDP and BREE 2012 AETA

Figure 14: Coal prices new generators – Scenario 5 ($2012/13)



Source: AEMO 2011 NTNDP, AEMO 2012 NTNDP and BREE 2012 AETA

3.3.7 Carbon price

The carbon price is incorporated in all of our modelling – our LRMC modelling under both the incremental approach and stand-alone approach and our *SPARK* modelling.

With the passage of the Clean Energy Act there is now certainty about the level of the carbon price for the fixed price period (2012/13, 2013/14 and 2014/15). Beyond the fixed price period of the current legislation, there is uncertainty associated with the level of the carbon price.

Scenario 3 of the NTNDP (the Planning Scenario) assumes that, following the fixed price period, the carbon price will follow Commonwealth Treasury's Core Policy scenario.[5] Scenario 5 of the NTNDP (the Slow Rate of Change Scenario) assumes that, following the fixed price period, the carbon price will fall to $0/t$CO_2$. These two carbon price paths are shown in Figure 15 and have been adopted in the two scenarios that we have modelled.

For the sake of comparison, Figure 15 also shows a forecast of the forward price of carbon in the EU sourced from publically available data from the Intercontinental Exchange (ICE). With the announcement of the scrapping of the carbon price floor that was to have applied following the fixed price period, and given that carbon permits can be imported from the EU, the EU carbon price is likely to set the carbon price in Australia.

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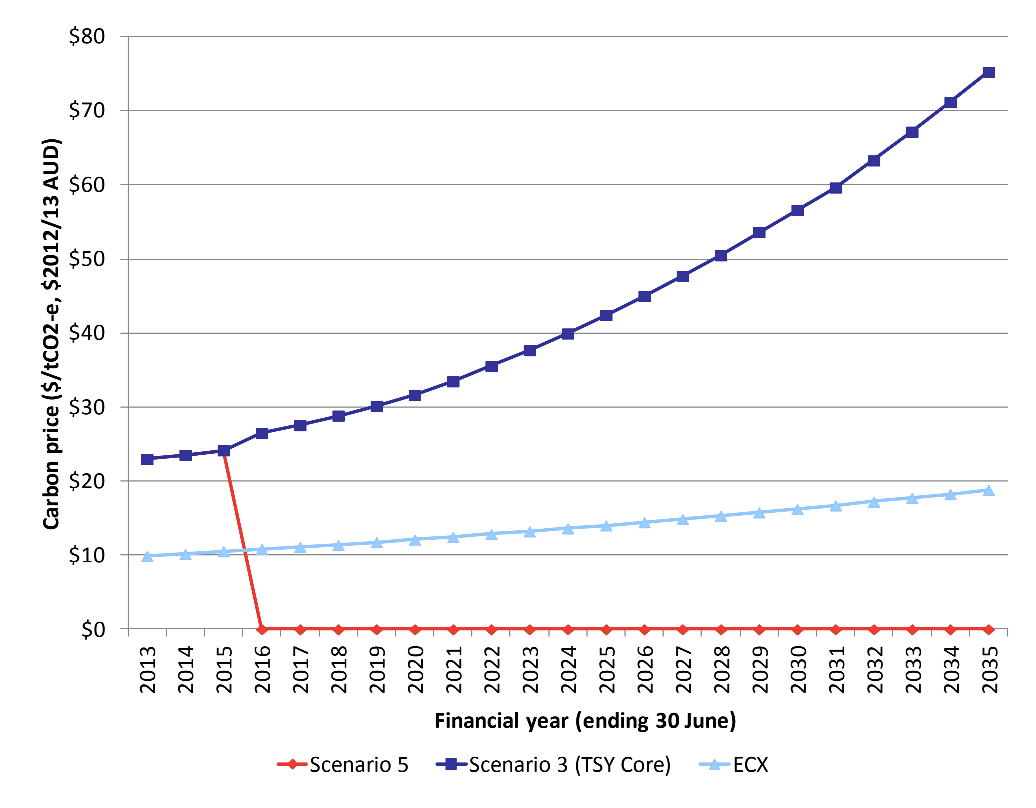
5 Commonwealth Department of Treasury, *Strong Growth, Low Pollution*, July 2011 (see: Chart 5.1, http://treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp). The Core Policy scenario assumes a world with a 550 ppm stabilisation target and an Australian emission target of a 5 per cent reduction on 2000 levels by 2020 and a 20 per cent reduction by 2050.

Figure 15: Assumed carbon prices ($2012/13)



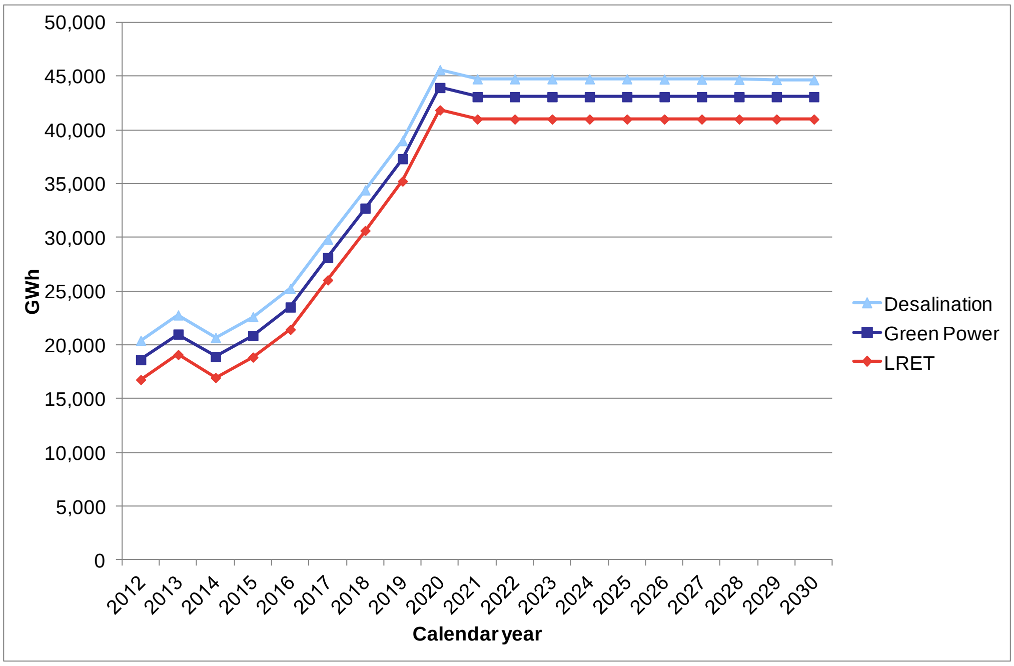
Source: Clean Energy Bill 2011, Commonwealth Treasury modelling, Intercontinental Exchange 2012

3.3.8 LRET target

Our *WHIRLYGIG* modelling incorporates the LRET target to ensure that sufficient renewable energy is generated to meet the target. Consistent with the approach in the AEMO 2012 NTNDP, the renewable energy target we propose to include in our modelling incorporates the LRET target as well as estimates of the additional renewable energy required to meet GreenPower obligations and obligations to supply renewable energy to desalination plants. The target is shown in Figure 16.

Our modelling also takes account of the existing surplus of LGCs.

Figure 16: Renewable energy target



Source: AEMO 2012 NTNDP

4 Stand-alone LRMC results

This section sets out the results of the stand-alone LRMC of meeting the 'residential' load shape in each distribution area. This section is set out as follows:

- a brief re-statement of Frontier Economics' approach to estimating the LRMC of the 'residential' load in each distribution area
- the results of the LRMC modelling
- an overview of investment and dispatch outcomes from the LRMC modelling.

4.1 Approach to estimating the stand-alone LRMC

As discussed in Section 2, to estimate the stand-alone LRMC of the 'residential' load in each distribution area, we use *WHIRLYGIG*. In this stand-alone LRMC case, the load used to estimate LRMC is the 'residential' load (rather than, for instance, the total system load in each region). All existing generation plant and the regional structure of the NEM is excluded from the modelling. This provides an LRMC estimate that is the cost of serving an incremental increase to the residential load shape with a hypothetical new least-cost generation system.

4.2 Stand-alone LRMC results

Results for the stand-alone LRMC approach for each distribution area are shown in Figure 17 (for the Planning Scenario) and Figure 18 (for the Slow Rate of Change Scenario) and set out in Table 3. A few patterns are evident from these results.

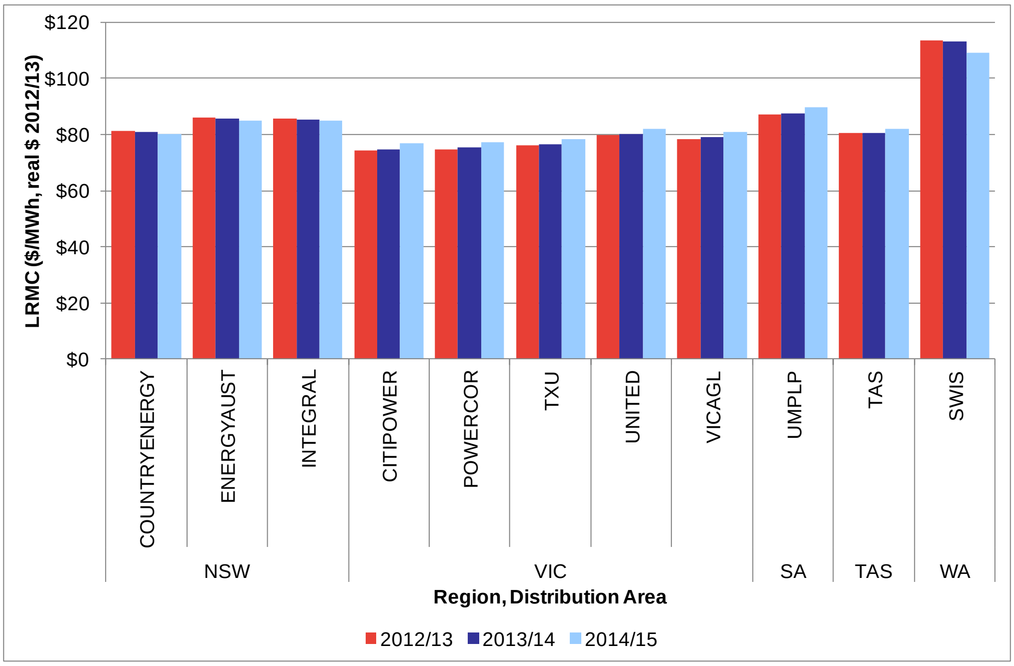
First, the 'residential' load shape within each distribution area affects the stand-alone LRMC: the peakier the 'residential' load shape the higher the stand-alone LRMC. This reflects the fact that a peakier load shape will require more peaking plant to reliably serve that load, resulting in higher costs. This is most evident within NSW, where the stand-alone LRMC for the Country Energy distribution area (which has the flattest load shape in NSW) is lowest and the stand-alone LRMC for the Integral Energy distribution area (which has the peakiest load shape in NSW) is highest.

Second, the relative costs of generation within each distribution area affects the stand-alone LRMC: in particular, where fuel costs are higher the stand-alone LRMC will be higher. This reflects the fact that generating electricity to meet a given load shape will be more expensive where fuel costs (or other costs of generation) are higher. This is most evident when comparing the stand-alone LRMC in NSW and Victoria. The stand-alone LRMC in Victoria tends to be lower than the stand-alone LRMC in NSW (despite 'residential' load shapes tending to be peakier in Victoria) because assumed gas prices in Victoria are lower than assumed gas prices in NSW. Similarly the stand-alone LRMC in Western Australia is higher than in other regions both because of higher assumed capital costs for generation and higher assumed fuel prices.

Third, the changes in the stand-alone LRMC over time are relatively moderate. These changes over time are driven entirely by changes in the underlying input costs as the 'residential' load shapes have been assumed to have constant load factors. In most distribution areas there are moderate increases in the stand-alone LRMC over time. This reflects small increases in the carbon price over this period, as well as small increases in assumed gas prices. In NSW and Western Australia, however, the stand-alone LRMC tends to decrease slightly over time, with small decreases in assumed gas prices having a larger effect than small increases in the carbon price.

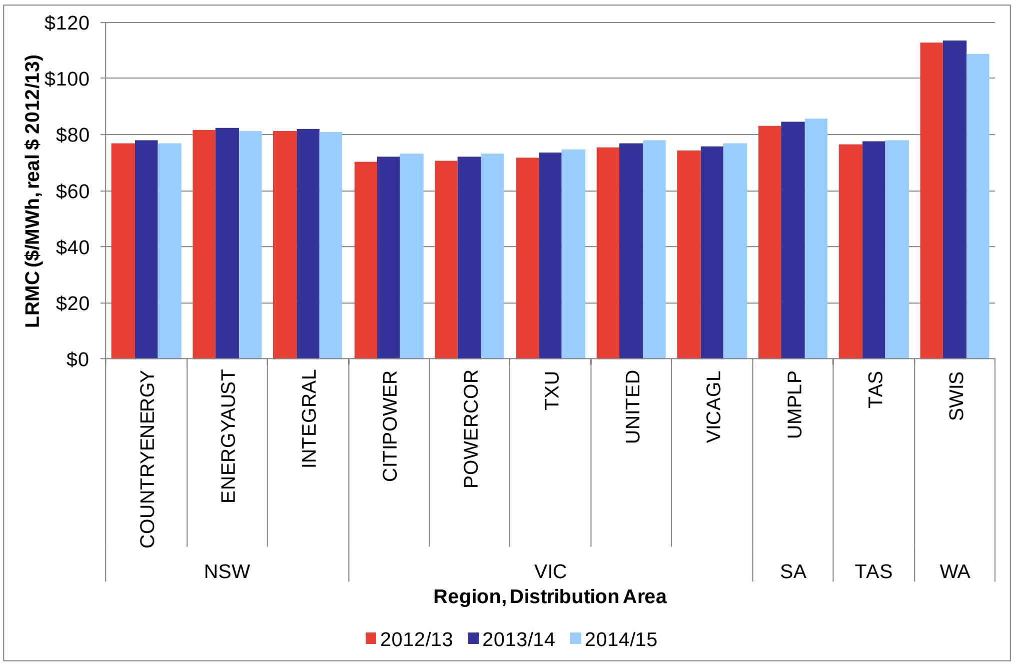
Finally, the stand-alone LRMC is lower in the Slow Rate of Change Scenario than it is in the Planning Scenario. This is entirely due to the difference in underlying input costs between the Slow Rate of Change Scenario and the Planning Scenario: the lower capital costs and fuel costs in the Slow Rate of Change Scenario result in a lower stand-alone LRMC.

Figure 17: Scenario 3 stand-alone LRMC results ($2012/13)



Source: Frontier Economics

Figure 18: Scenario 5 stand-alone LRMC results ($2012/13)



Source: Frontier Economics

Table 3: Stand-alone LRMC results ($2012/13)

Financial Year	State	Distribution Area	Planning Scenario – LRMC ($/MWh)	Slow Rate of Change Scenario – LRMC ($/MWh)
2013	NSW	Country Energy	$81.15	$77.00
2013	NSW	EnergyAustralia	$85.96	$81.57
2013	NSW	Integral Energy	$85.68	$81.24
2013	VIC	Citipower	$74.33	$70.41
2013	VIC	Powercor	$74.80	$70.71
2013	VIC	TXU	$76.09	$71.90
2013	VIC	United	$79.65	$75.23
2013	VIC	VicAGL	$78.47	$74.16
2013	TAS	Aurora	$80.66	$76.61
2013	SA	ETSA	$87.21	$82.93
2013	WA	SWIS	$113.57	$112.86
2014	NSW	Country Energy	$80.86	$77.90
2014	NSW	EnergyAustralia	$85.64	$82.52
2014	NSW	Integral Energy	$85.37	$82.16
2014	VIC	Citipower	$74.78	$72.04
2014	VIC	Powercor	$75.27	$72.29
2014	VIC	TXU	$76.56	$73.48
2014	VIC	United	$80.11	$76.83
2014	VIC	VicAGL	$78.92	$75.76
2014	TAS	Aurora	$80.41	$77.45
2014	SA	ETSA	$87.51	$84.41
2014	WA	SWIS	$113.34	$113.64
2015	NSW	Country Energy	$80.35	$76.73
2015	NSW	EnergyAustralia	$85.09	$81.30
2015	NSW	Integral Energy	$84.84	$80.96
2015	VIC	Citipower	$76.72	$73.04
2015	VIC	Powercor	$77.22	$73.31
2015	VIC	TXU	$78.52	$74.51
2015	VIC	United	$82.06	$77.85
2015	VIC	VicAGL	$80.87	$76.78
2015	TAS	Aurora	$81.88	$77.96
2015	SA	ETSA	$89.84	$85.80
2015	WA	SWIS	$109.07	$108.94

Source: Frontier Economics

4.3 Investment and dispatch under stand-alone LRMC

This section provides the investment and dispatch outcomes associated with the stand-alone LRMC modelling for each distribution area. The focus of this section is the investment and dispatch outcomes that occur in 2012/13 – outcomes in the other financial years are not significantly different to those that occur in 2012/13.

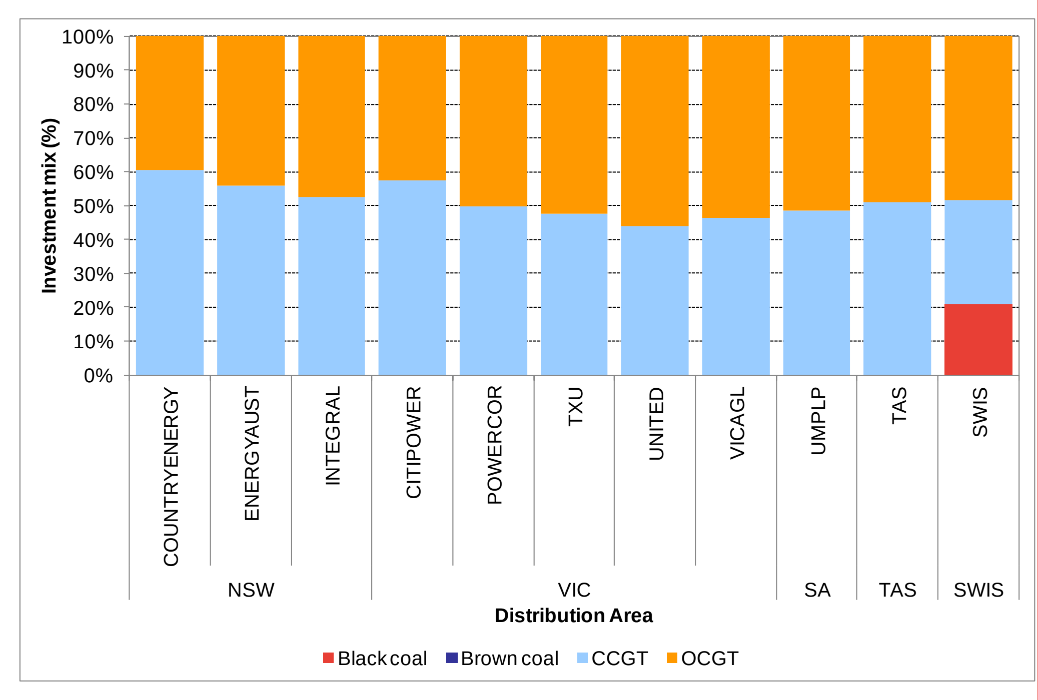
In considering the investment and dispatch outcomes associated with the stand-alone LRMC modelling, it is important to note that, under this approach, no existing plant are incorporated in the modelling. This means that the mix of generation built by the model to serve the residential load will not necessarily reflect the mix of generation that has been built in reality to serve the system load. Furthermore, under this approach, the mix of generation built by the model to serve the residential load in each distribution area is optimised each year. Because the system is optimised each year, changes in patterns of investment and dispatch from year to year can be more pronounced than would be expected in the actual system (where investments require long lead times and, once committed, plant will remain in the system until it is retired). These investment constraints are reflected in Frontier Economics' modelling under the market-based approach.

Investment outcomes for each distribution area in 2012/13 under the Planning Scenario are shown in Figure 19. The investment mix across the distribution areas in 2012/13 is roughly 45-60% CCGT plant, with OCGT plant accounting for the rest of required capacity. The exception is the SWIS, where the relative prices of coal and gas mean that black coal plant remains part of the optimal investment mix in the Planning Scenario. Dispatch outcomes for each distribution area in 2012/13 under the Planning Scenario are shown in Figure 20. The dispatch results reflect the investment outcomes, with dispatch accounted for by CCGT plant and OCGT plant (with coal plant also part of the dispatch mix in the SWIS). Given that CCGT plant have much lower operating costs than OCGT plant, CCGT plant accounts for the majority of dispatch with OCGT run infrequently to meet peak demand. The varying patterns of investment and dispatch across the distribution areas reflect the load shape of the retailers. Peakier regulated loads, such as those in Victoria and South Australia, result in greater investment in OCGT plant. Flatter loads, such as those in NSW, result in relatively less investment in OCGT plant.

Investment outcomes and dispatch outcomes for each distribution area in 2012/13 under the Slow Rate of Change Scenario are shown in Figure 21 and Figure 22. The only material difference between investment outcomes and dispatch outcomes in the Planning Scenario and the Slow Rate of Change

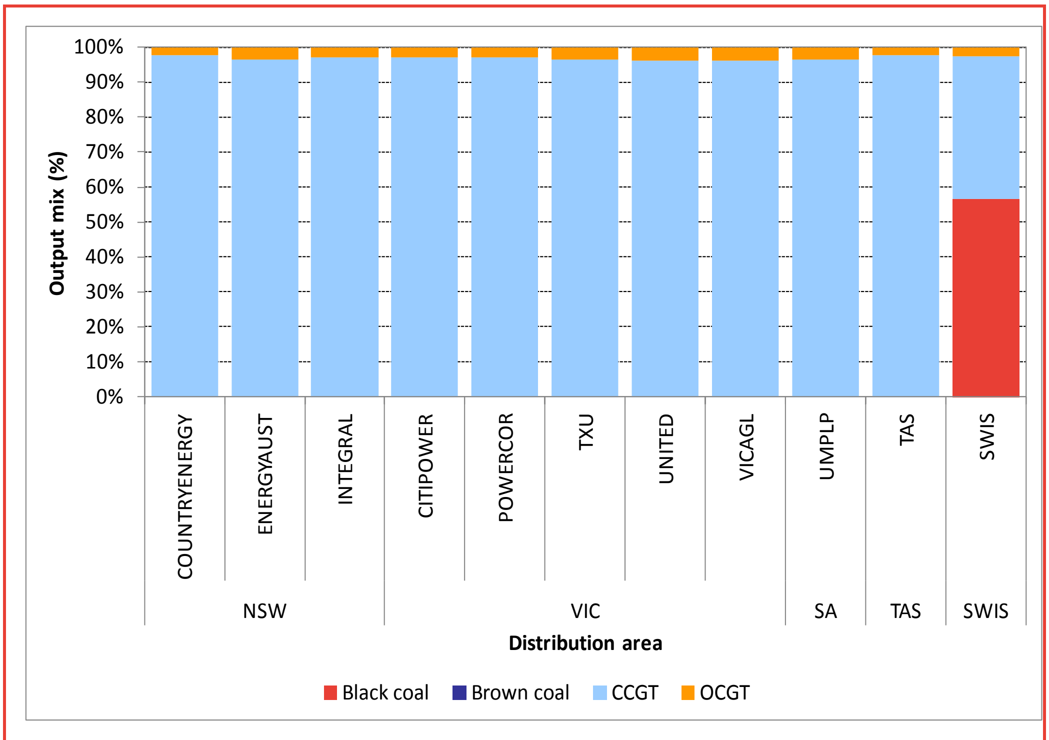
Scenario is that black coal plant does not form part of the least cost investment mix in the SWIS in the Slow Rate of Change Scenario.

Figure 19: Scenario 3 investment outcomes – stand-alone LRMC (2012/13)



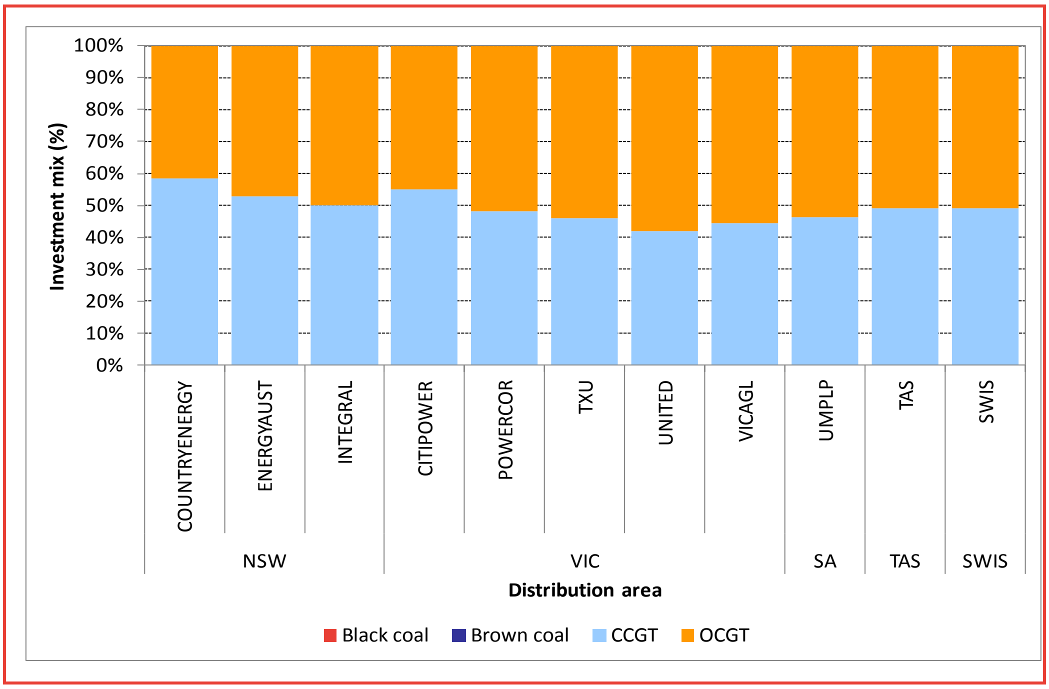
Source: Frontier Economics

Figure 20: Scenario 3 dispatch outcomes – stand-alone LRMC (2012/13)



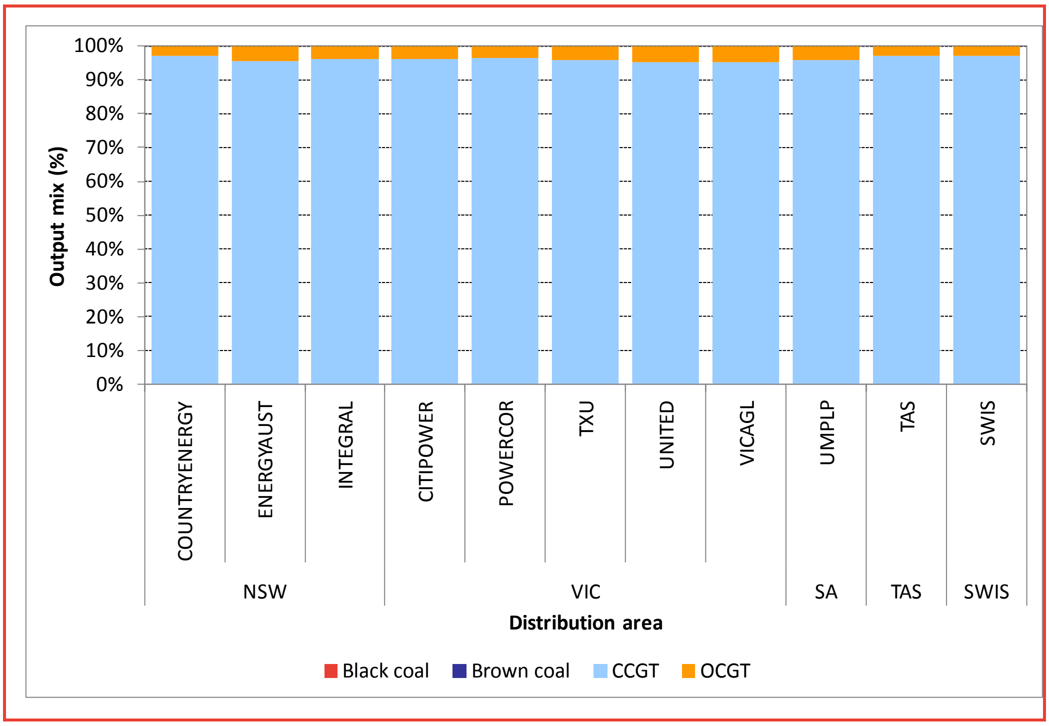
Source: Frontier Economics

Figure 21: Scenario 5 investment outcomes – stand-alone LRMC (2012/13)



Source: Frontier Economics

Figure 22: Scenario 5 dispatch outcomes – stand-alone LRMC (2012/13)



Source: Frontier Economics

5 Market-based energy purchase cost results

This section sets out the results of the market-based energy purchase costs of meeting the 'residential' load shape in each distribution area. This section is set out as follows:

- a brief re-statement of our approach to estimating market-based energy purchase costs
- the results of our modelling of spot prices
- the results of our modelling of market-based energy purchase costs.

5.1 Determining the market-based energy purchase cost

Market-based energy purchase costs are the costs that retailers face in buying energy from the wholesale market, including the hedging contracts that retailers enter into to manage their risk. The estimation of market-based energy purchase costs can be separated into two broad steps:

- forecasting spot and contract prices
- based on these forecast prices and the 'residential' load shape in each distribution area, determining an efficient hedging strategy and the cost and risk associated with that hedging strategy.

We use *SPARK* to forecast spot electricity prices. Like all electricity market models, *SPARK* reflects the dispatch operations and price-setting process that occur in the NEM. Unlike other models, however, generator bidding behaviour is a modelling output from *SPARK* rather than an input assumption. That is, *SPARK* calculates a set of optimal (i.e. sustainable) generator bids for all representative market conditions. As the market conditions change, so does the optimal set of bids. *SPARK* finds the optimal set using standard game theoretic techniques.

We infer contract prices from our forecast spot prices. In doing so, we assume that contract prices trade at a 5 per cent premium to spot prices.

We use *STRIKE* to determine the efficient mix of hedging products that retailers would enter into over the period of the determination, and the energy costs and risks associated with each of these efficient mixes.

Ultimately, retailers hedge to reduce the volatility of the energy purchase cost of their customers. This volatility arises from:

- load volatility;
- price volatility; and

- the correlation of load and price.

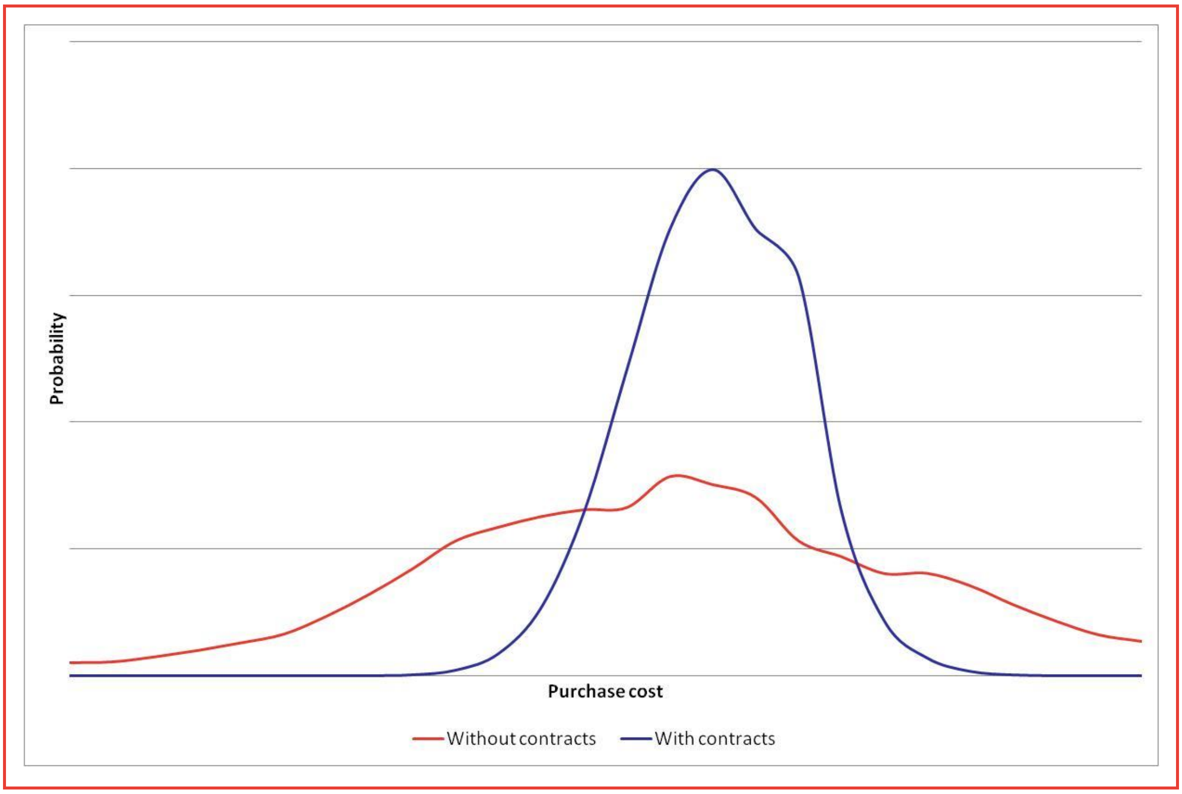
We have ensured that the important correlation between residential load and pool prices are captured via the modelled system load profile. That is, when determining the residential load profile, we have also constructed a system load profile that is correlated to the residential load. The pool prices forecasted in *SPARK* under the assumption of this system profile are therefore able to be correlated to the residential load profiles.

Using these inputs, *STRIKE* sees a distribution of likely pool purchase costs for a given year. An example is shown diagrammatically in Figure 23 (which is not based on any actual data). If the entire load is priced at the pool price (no contracts are entered into) then the distribution of purchase costs will be very wide, representing a high level of volatility associated with the expected purchase cost. Adding contracts to the portfolio:

- increases expected purchase cost (to the extent that contracts sell at a premium), and
- changes the volatility (risk) associated with the expected purchase cost

In Figure 23 we see these effects in the series with contracts. The expected purchase cost is higher and its distribution is narrower. The trade off between cost and risk is exactly what *STRIKE* quantifies when it constructs an efficient frontier of contracting options.

Figure 23: Distribution of purchase cost – with and without contracts (illustrative only)



Each point on the efficient frontier calculated by *STRIKE* represents an optimal bundle of contracts for a given risk profile. At the high risk end of the efficient frontier, very little weight is placed on risk in the portfolio and *STRIKE* tries to find the set of contracts that minimise the expected purchase cost regardless of how risky this is (indicated by how wide the distribution of purchase costs gets). In the extreme this may involve the entire load being purchased at spot prices. Conversely, at the conservative end of the efficient frontier, a high weight is put on risk. In this case, *STRIKE* seeks to minimise risk with little regard to cost, which is equivalent to finding a set of contracts that minimises the spread in the distribution of expected purchase costs notwithstanding that this will increase expected purchase costs.

5.2 Spot price forecasts

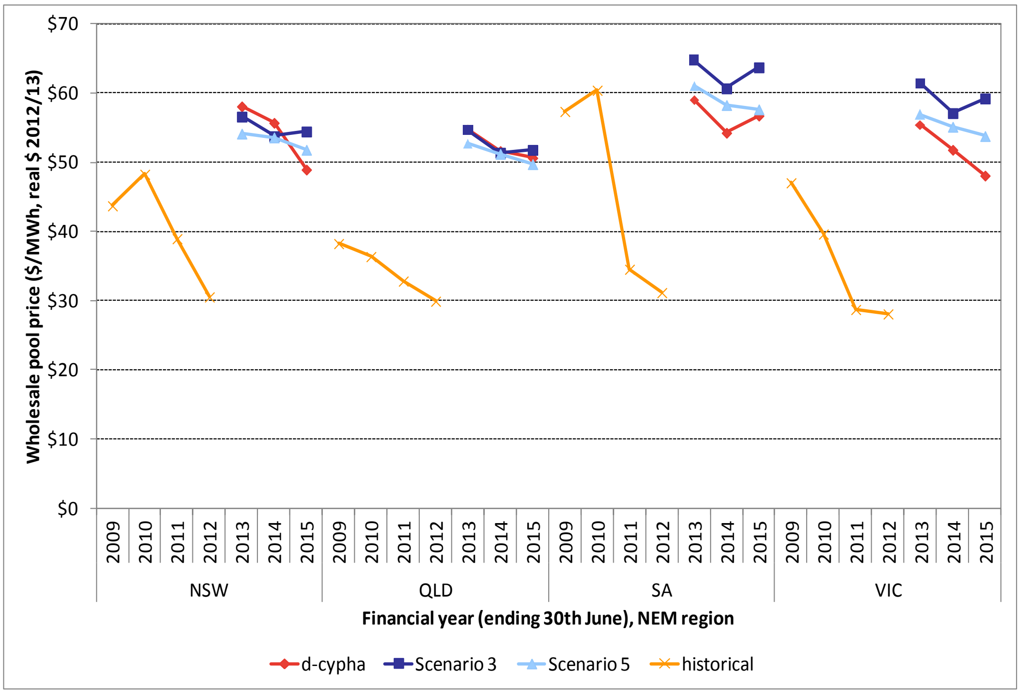
Spot price forecasts for each NEM region (other than Tasmania) are shown in Figure 24. This figure shows the annual average spot price forecast for the Planning Scenario and the Slow Rate of Change Scenario. For the purpose of comparison, this figure also shows historical annual average spot prices for 2008/09 to 2011/12 (during which time there was no carbon price in place) and forward prices implied by the strike prices of d-cyphaTrade financial year base-load swap contracts.[6] The d-cyphaTrade prices provide an indication of the market view on future contract prices and, by association, pool prices. For easier comparison, Figure 25 shows the same data on a different scale and without the historical annual average spot prices.

In our modelling, the general trend in each region (and in both Scenarios) is towards lower spot prices. This is most evident in the Slow Rate of Change Scenario, and is a result of the fact that over the forecast period there is ongoing investment in generation plant (largely investment in renewable plant to meet the RET) while system demand is forecast to remain relatively flat. As a result, the supply-demand conditions that have resulted in the decreases in spot prices that have been observed in recent years are forecast to persist. Furthermore, the effect of ongoing investment with little demand growth has a larger impact on prices than the small increases in input costs (fuel costs and carbon prices) over this period. In the Planning Scenario, with higher demand forecasts, spot prices recover somewhat in 2014/15 in each region as a result of a slightly tighter supply-demand balance (and small increases in input costs).

Comparing the results from our modelling with the d-cyphaTrade prices shows that the trends are broadly consistent: in most NEM regions the trend is towards lower d-cyphaTrade prices (although traded volumes are very low for all but the first forecast year). The levels of prices are also quite comparable, particularly in NSW and Queensland.

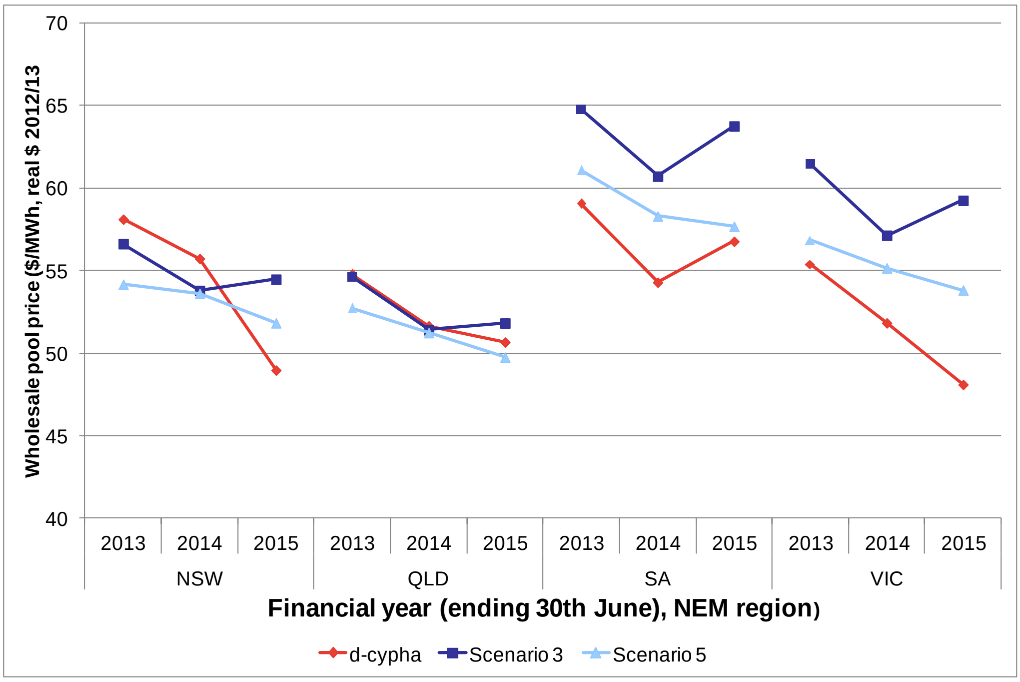
6 Prices are as of 21st August 2012. The strike prices of d-cyphaTrade financial year base-load swap contracts are reduced by 5 per cent to account for an estimate of the contract premium.

Figure 24: Spot price forecasts ($2012/13)



Source: Frontier Economics

Figure 25: Spot price forecasts ($2012/13)



Source: Frontier Economics

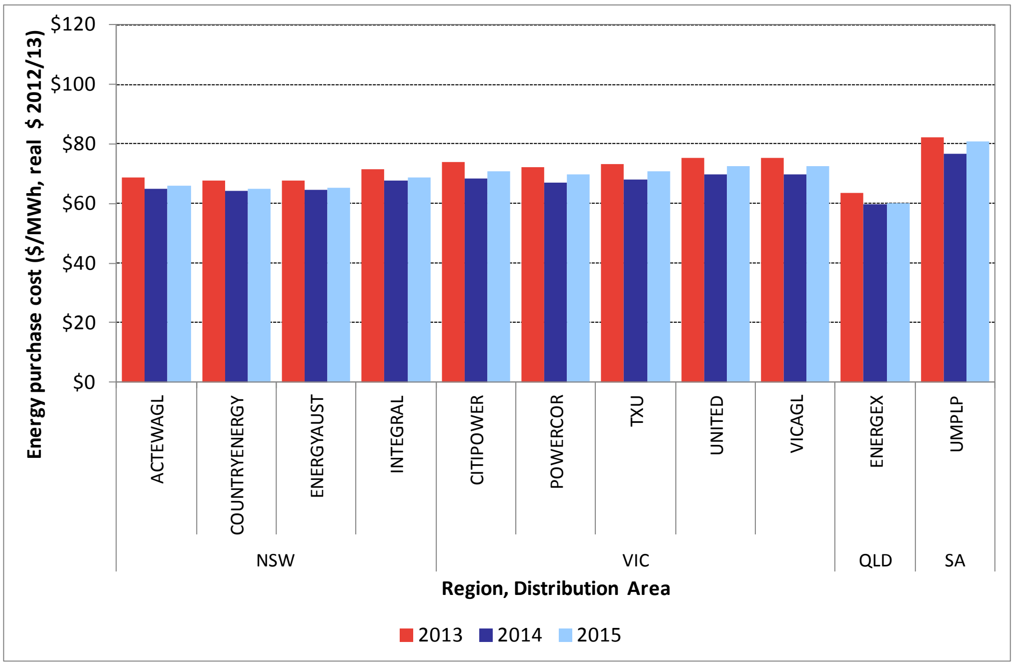
5.3 Market-based energy purchase cost results

Based on the spot price forecasts set out above, the 'residential' load shape generated by combining the NSLP and CLP, and contract prices inferred from the spot price forecasts set out above, *STRIKE* determines the full set of possible efficient contracting positions. There is a cost and a risk associated with each of these contracting positions. Consistent with the approach adopted in other jurisdictions, we have based the market-based energy purchase cost on the most conservative (least risky) efficient contracting position. The resulting market-based energy purchase costs are shown in Figure 26 (for the Planning Scenario) and Figure 27 (for the Slow Rate of Change Scenario) and set out in Table 4. A few patterns are evident from these results.

First, as with the stand-alone LRMC results, the 'residential' load shape within each distribution area affects the market-based energy purchase cost: the peakier the 'residential' load shape the higher the market-based energy purchase cost. This reflects the fact that a peakier load shape will generally require more contract cover to manage the risk associated with supplying that load, resulting in higher costs. This is most evident within NSW, where the market-based energy purchase cost for the Country Energy distribution area (which has the flattest load shape in NSW) is lowest and the market-based energy purchase cost for the Integral Energy distribution area (which has the peakiest load shape in NSW) is highest.

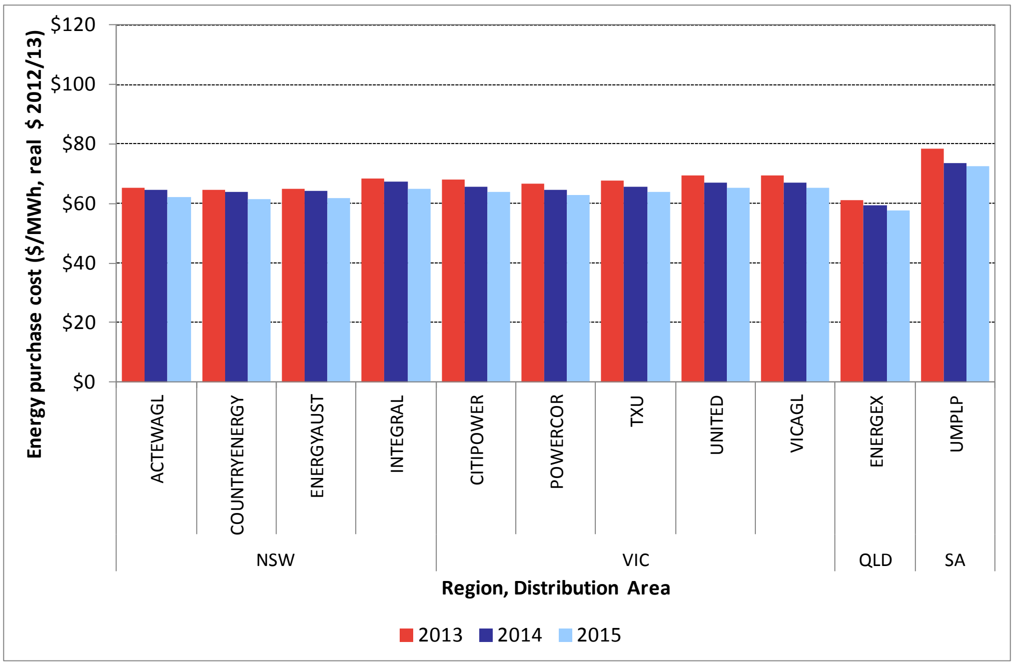
Second, forecast spot prices (and, by extension, the forecast contract prices) are an important determinant of market-based energy purchase costs. This stands to reason: where spot prices and contract prices are higher, the cost of serving a given load will also be higher. This can be observed both across jurisdictions and over time. Those jurisdictions for which spot price forecasts are higher – Victoria and South Australia – tend to have higher estimates of market-based energy purchase costs. And the trend in market-based energy purchase costs over time reflects the trend in forecast spot prices over time.

Figure 26: Scenario 3 market-based energy purchase cost results ($2012/13)



Source: Frontier Economics

Figure 27: Scenario 5 market-based energy purchase cost results ($2012/13)



Source: Frontier Economics

Table 4: Market-based energy purchase cost results ($2012/13)

Financial Year	State	Distribution Area	Planning Scenario – Energy purchase cost ($/MWh)	Slow Rate of Change Scenario – Energy purchase cost ($/MWh)
2013	QLD	Energex	$63.56	$61.25
2013	NSW	Country Energy	$67.78	$64.68
2013	NSW	EnergyAustralia	$67.85	$64.84
2013	NSW	Integral Energy	$71.48	$68.25
2013	ACT	ActewAGL	$68.57	$65.28
2013	VIC	Citipower	$73.90	$68.06
2013	VIC	Powercor	$72.20	$66.77
2013	VIC	TXU	$73.34	$67.77
2013	VIC	United	$75.27	$69.44
2013	VIC	VicAGL	$75.44	$69.57
2013	SA	ETSA	$82.18	$78.28
2014	QLD	Energex	$59.59	$59.35
2014	NSW	Country Energy	$64.13	$63.78
2014	NSW	EnergyAustralia	$64.43	$64.15
2014	NSW	Integral Energy	$67.62	$67.21
2014	ACT	ActewAGL	$64.92	$64.63
2014	VIC	Citipower	$68.21	$65.66
2014	VIC	Powercor	$67.03	$64.54
2014	VIC	TXU	$68.01	$65.54
2014	VIC	United	$69.60	$67.00
2014	VIC	VicAGL	$69.73	$67.14
2014	SA	ETSA	$76.59	$73.43
2015	QLD	Energex	$60.03	$57.63
2015	NSW	Country Energy	$65.09	$61.54
2015	NSW	EnergyAustralia	$65.37	$61.97
2015	NSW	Integral Energy	$68.69	$64.92
2015	ACT	ActewAGL	$65.94	$62.19
2015	VIC	Citipower	$70.95	$63.72
2015	VIC	Powercor	$69.70	$62.91
2015	VIC	TXU	$70.69	$63.80
2015	VIC	United	$72.40	$65.11
2015	VIC	VicAGL	$72.52	$65.22
2015	SA	ETSA	$80.70	$72.57

Source: Frontier Economics

6 Carbon pass-through

This section summarises the impact of carbon pricing in the results presented in previous sections. Quantification of the impact of carbon in a particular case requires modelling an equivalent case where all assumptions are fixed except that carbon is assumed to be absent. We have remodelled Scenarios 3 and 5 under the stand-alone and market-based approaches where we have assumed that the price of carbon is zero in all years. Comparing these 'no carbon' cases to the original cases allows the impact of carbon to be quantified in a manner that captures changes in wholesale energy costs due to:

- the direct impact of increased variable costs for thermal generators
- indirect impacts due to changes in the underlying investment and dispatch decision that are altered by the presence/absence of carbon pricing

Carbon pass-through measures the impact of the carbon price on electricity prices. Carbon pass-through can be measured in a number of ways. This section reports the effect of carbon pricing on pool prices and energy costs measured in two ways: in $/MWh terms and as a percentage of the assumed $/tCO2e carbon price that is passed through to energy costs.[7]

These measures are presented for three sets of modelling results (that is, three sets of electricity 'prices'):

- the stand-alone LRMC results
- time-weighted, annual average pool prices calculated in *SPARK* and used as part of the market-based approach
- the market-based energy purchase costs.

The impact of carbon is different for each of these results.

Carbon pass-through under the stand-alone LRMC approach measures the extent to which the stand-alone LRMC increases as a result of the introduction of a carbon price. In the stand-alone LRMC approach, investment can respond immediately to the introduction of a carbon price, which helps to mitigate some of the impact of the carbon price (because immediate investment in generation plant with lower emissions is assumed to be possible under this approach). As a result the carbon pass-through is lowest under the stand-alone LRMC approach.

Carbon pass-through into pool prices measures the extent to which time-weighted average pool prices increase as a result of the introduction of a carbon price. In existing generation systems, of course, investment cannot respond

[7] That is, the $/MWh difference in pool prices or energy costs with and without carbon divided by the assumed carbon price in $/tCO2e. Measured in this way, a carbon pass-through of 100% implies that the increase in electricity prices (in $/MWh) is equal to the carbon price (in $/tCO2e).

immediately to the introduction of a carbon price. This is reflected in our market-modelling. When modelling pool prices, there is no investment response in the short term, only a change of patterns of dispatch of the existing generation plant. As a result, the impact of carbon is greater than under the stand-alone LRMC approach. It is this carbon pass-through – the impact of the carbon price on time-weighted average pool prices – that is the most common measure of carbon pass-through.

Carbon pass-through can also be reported for market-based energy purchase costs. In this case, carbon pass-through measures the extent to which the cost of suppling residential customers increases as a result of the introduction of a carbon price. These market-based energy purchase costs reflect the cost of hedging to meet the relatively peaky residential load shape. Because the market-based energy purchase cost reflects the peakiness of the residential load shape relative to system demand, and also the additional costs of hedging (at an assumed contract premium of 5 per cent), the impact of the carbon price is higher than the impact of the carbon price on pool prices.

6.1 Stand-alone LRMC

Outcomes for the stand-alone LRMC approach are presented in this section in terms of changes in investment (which drive altered dispatch outcomes) and the resulting estimates of LRMC.

6.1.1 Change in underlying investment

Figure 28 through Figure 30 show changes to the optimal mix of investment with and without carbon pricing for each scenario and distribution region for 2012/13 only. As discussed, in the stand-alone LRMC approach, investment can respond immediately to the introduction of a carbon price

In all regions except Western Australia, the mix with carbon involved only CCGT and OCGT gas plant and no coal (as shown in Section 4.3). Removing carbon does not alter this technology mix, however there is a slight increase in the quantity of investment in OCGT relative to CCGT in the without carbon cases (reflecting the higher emissions intensity of OCGT relative to CCGT plant).

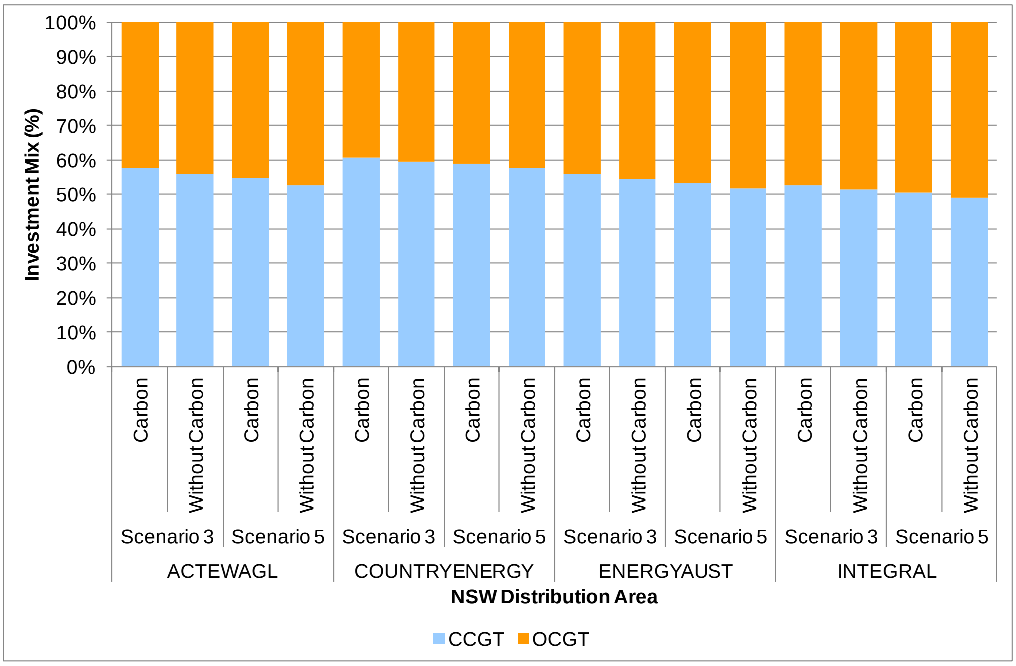
In Western Australia, removing carbon leads to an increase in coal-fired generation investment in the Planning Scenario and the inclusion of coal-fired generation in the Slow Rate of Change Scenario.

These investment outcomes have important implications for the level of carbon pass-through.

In the eastern states, because the investment mix does not alter to any great degree, the only real change as a result of the introduction of a price on carbon is that the existing generators face higher costs (driven by the carbon price and the generators' emissions intensities). This results in carbon pass-through rates that primarily reflect the emission intensity of CCGT gas plant, because the major impact of carbon is to increase the variable cost of CCGT (and OCGT) generators in line with their emission intensity.

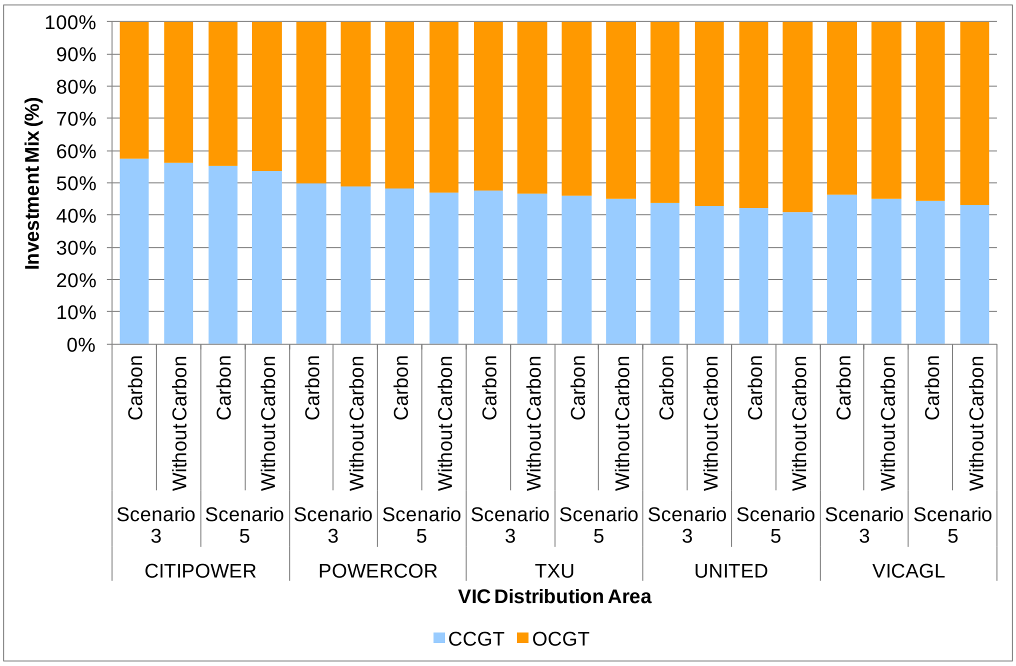
In Western Australia, introducing carbon shifts the investment mix away from high emissions coal plant towards more low emission gas plant. The result is a higher pass-through rate in Western Australia because the pass-through rate reflects not only the change in variable costs due to carbon but also the costs associated with a change in investment and dispatch from coal plant to gas plant.

Figure 28: Investment outcome with and without carbon (2012-2013, NSW)



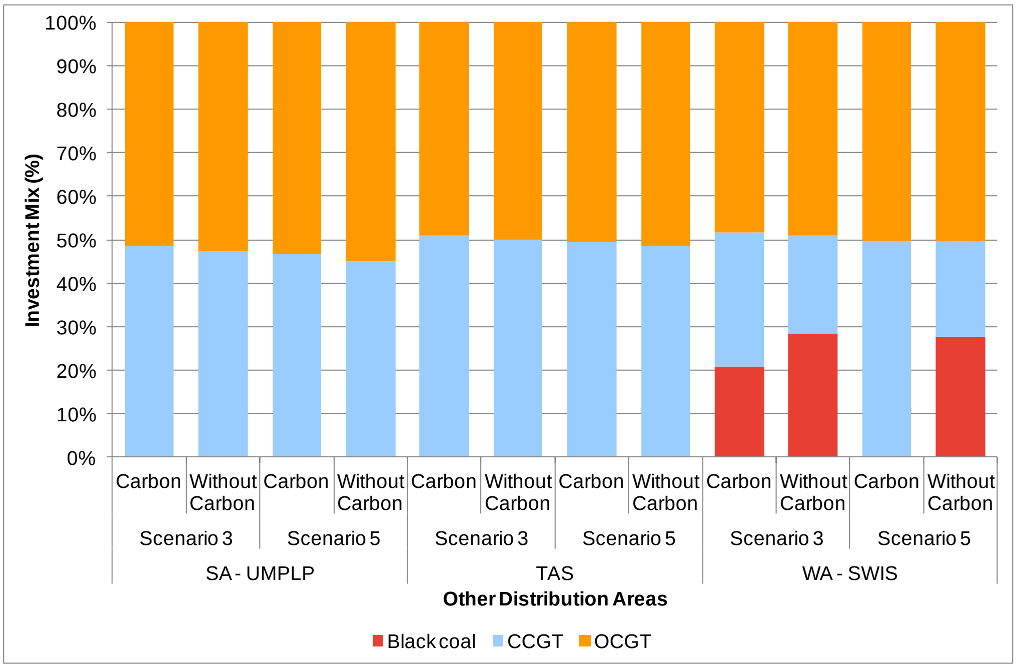
Source: Frontier Economics

Figure 29: Investment outcome with and without carbon (2012-2013, VIC)



Source: Frontier Economics

Figure 30: Investment outcome with and without carbon (2012-2013, other regions)



Source: Frontier Economics

6.1.2 LRMC outcomes and pass-through

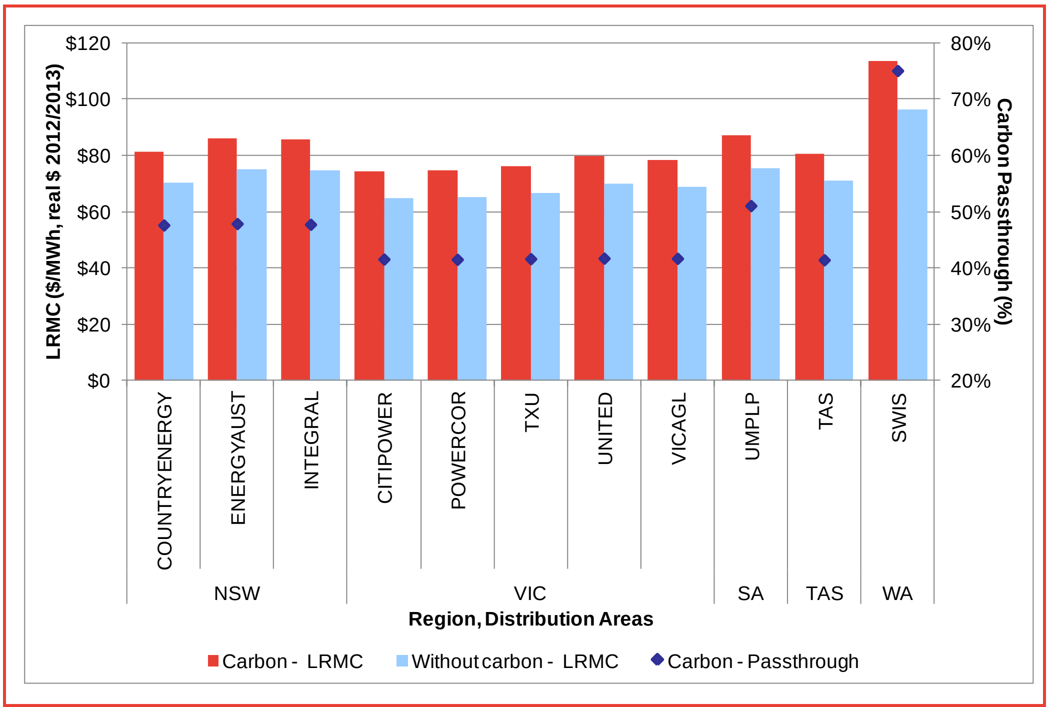
Figure 31 through Figure 36 show the LRMC estimates under the stand-alone approach with and without carbon for both scenarios and all years. Carbon inclusive LRMC estimates (red bars) are shown for the purpose of comparison to carbon exclusive estimates (blue bars); the pass-through percentage[8] is shown as a point on the chart.

Pass-through is forecast to be around $10/MWh and at a pass-through rate of roughly 50% depending on scenario, year and distribution region. The exception to this is Western Australia where pass-through is higher at around 75% due to a reduction in coal-fired generation in the with carbon case (as discussed in the previous section).

Pass-through levels in NSW under the stand-alone approach (approximately 47%) are lower than those reported by IPART (approximately 88%) as part of its 2012 annual review using the same approach. This difference reflects the different input cost assumptions in the two analyses. In the IPART work, the introduction of a carbon price led to a switch away from coal-fired generation in NSW. As observed for Western Australia in this analysis, this change in investment means that the carbon pass-through reflects both the costs of the change in investment and the change in variable costs due to carbon.

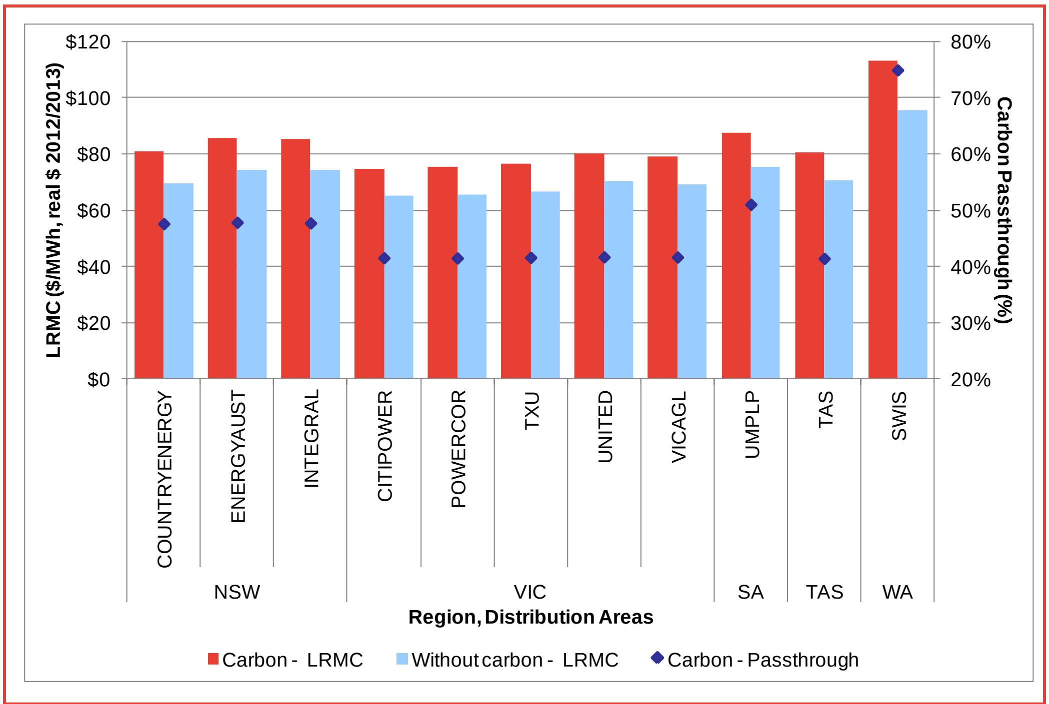
8 The passthrough percentage is the difference in the carbon inclusive and exclusive estimate in $/MWh divided by the assumed carbon price for the relevant year in $/tCO2e.

Figure 31: Scenario 3 stand-alone LRMC with and without carbon cost (2012/2013)



Source: Frontier Economics

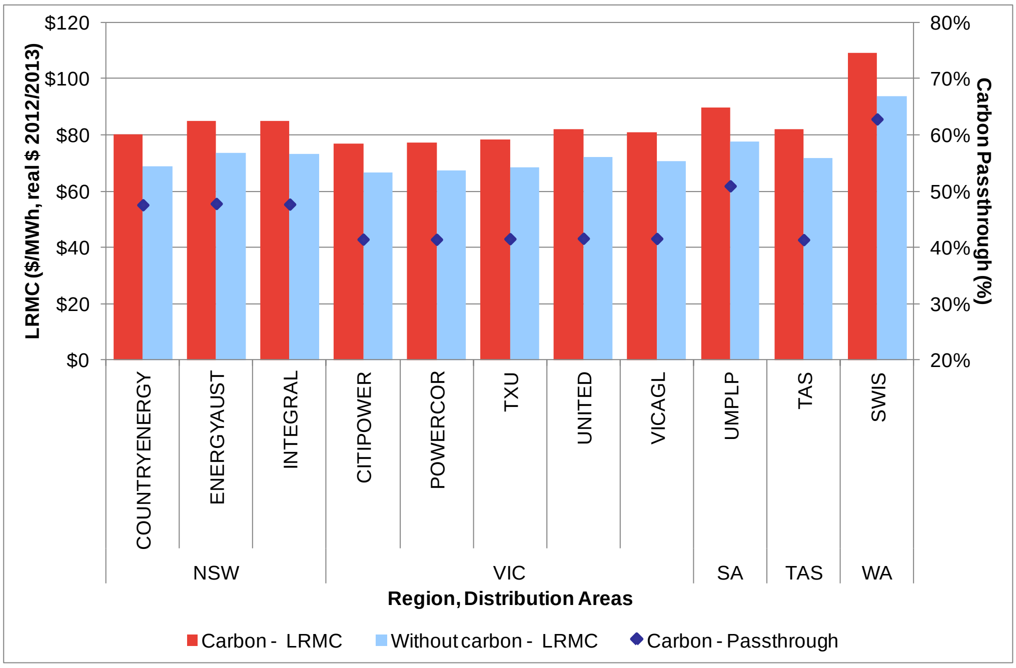
Figure 32: Scenario 3 stand-alone LRMC with and without carbon cost (2013/2014)



Source: Frontier Economics

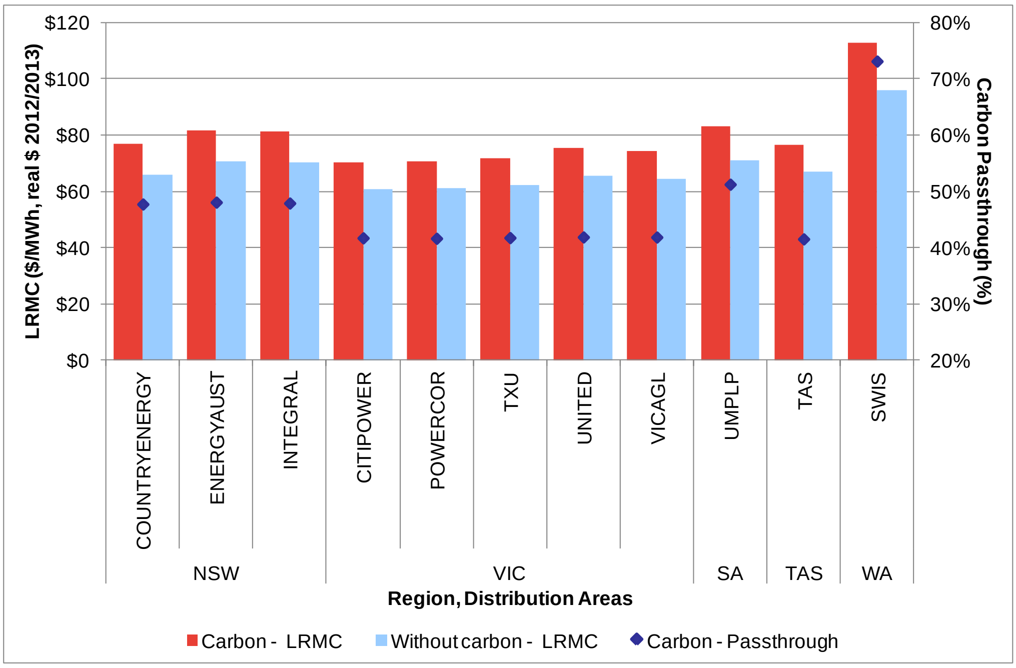
Carbon pass-through

Figure 33: Scenario 3 stand-alone LRMC with and without carbon cost (2014/2015)



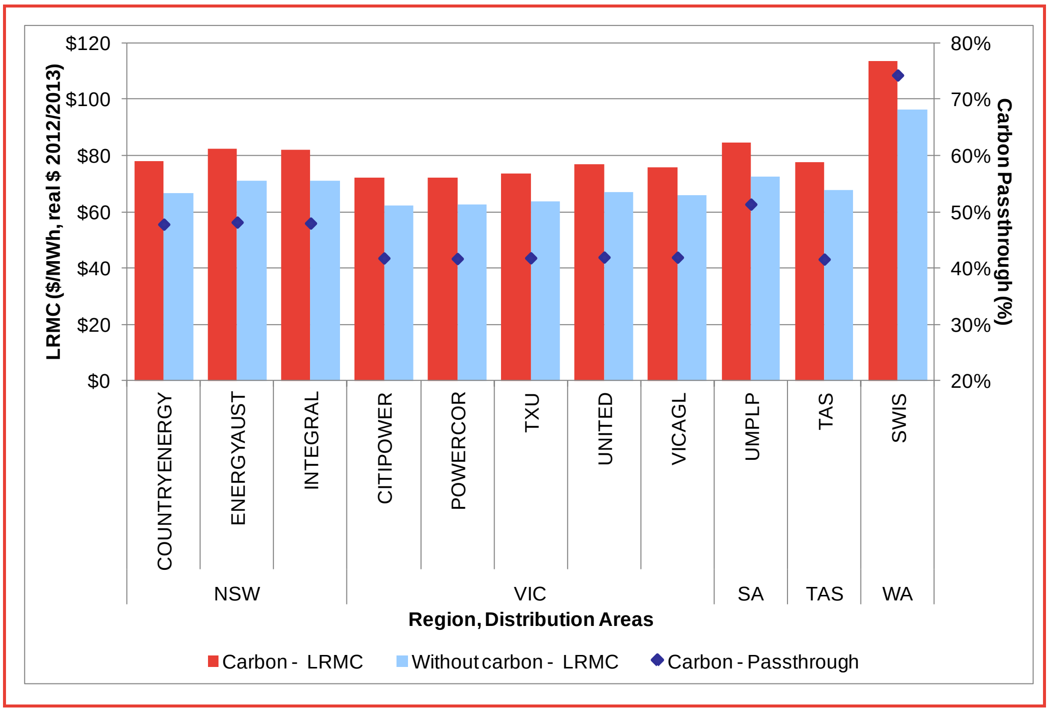
Source: Frontier Economics

Figure 34: Scenario 5 stand-alone LRMC with and without carbon cost (2012/2013)



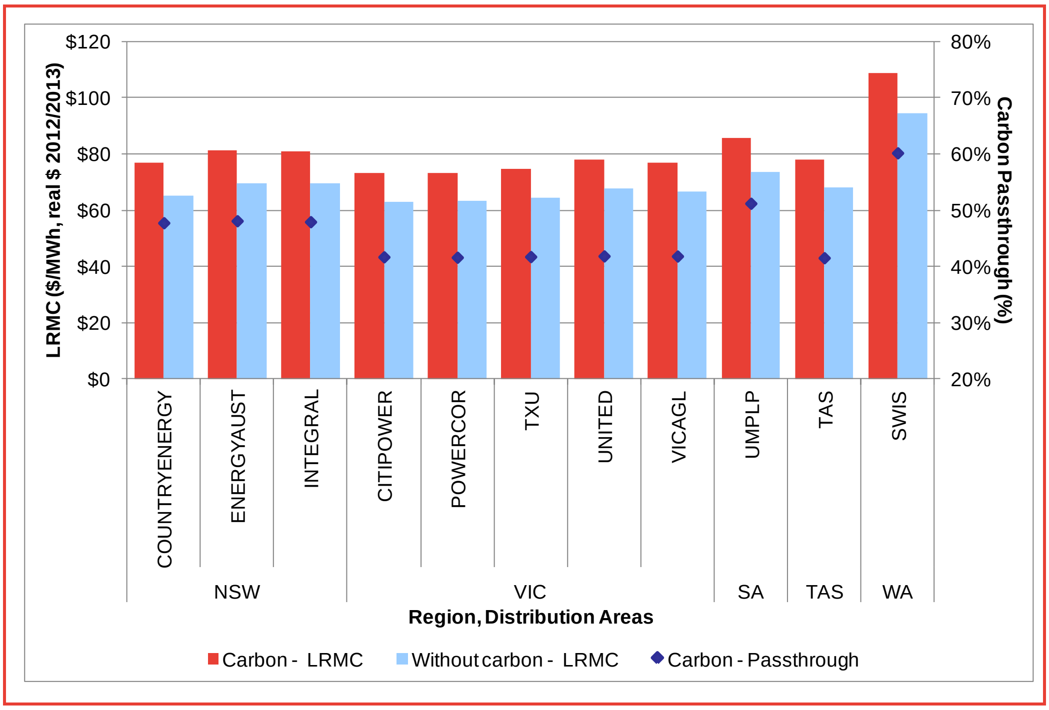
Source: Frontier Economics

Figure 35 : Scenario 5 stand-alone LRMC with and without carbon cost (2013/2014)



Source: Frontier Economics

Figure 36: Scenario 5 stand-alone LRMC with and without carbon cost (2014/2015)



Source: Frontier Economics

6.2 Wholesale pool prices

Changes to wholesale pool prices and pass-through levels are presented in this section. Wholesale prices feed into the market-based estimates of wholesale energy costs and wholesale pass-through rates are often used as a general measure of the level of carbon pass-through. Figure 37 through

Figure 39 show the wholesale pool price by NEM region with and without carbon for both scenarios and all years. Carbon inclusive pool prices (red bars) are shown for the purpose of comparison to carbon exclusive prices (blue bars); the pass through percentage[9] is shown as a point on the chart.

Pass-through levels are broadly between 110% to 120% in all regions and years. Pass-through is typically higher in the Slow Rate of Change Scenario, reflecting more subdued pool prices both with and without carbon in that scenario relative to the Planning Scenario. This outcome, that, for a given carbon price, pass-through levels will be higher when wholesale price levels are lower, makes intuitive sense. Lower wholesale prices reflect a looser supply demand balance in the NEM (as is the case in the Slow Rate of Change Scenario where demand is assumed to be lower). Under such conditions, cheaper coal fired-generation would be expected to be marginal for a greater time across the year. This means that, other things being equal, coal generators will be able to set marginal prices inclusive of carbon at their high emission rates for a greater proportion of the year leading to higher pass-through levels. We would note that this outcome is being driven in part by our forecasts *not* incorporating mothballing of generation at Northern, Playford, Tarong and Yallourn (announcements of the mothballing of units at these generators were made after our modelling was completed). Mothballing of these power stations, other things being equal, may decrease the level of carbon passthrough in the market under conditions of loose supply demand balance in the NEM.

Passthrough rates are highest in 2013/14, approximately 120% across the regions and scenarios. This outcome reflects the very low level of wholesale pricing in both the with and without carbon cases. Without carbon, we are forecasting annual average pool prices less than $30/MWh in NSW, Queensland and Victoria. It is unlikely that all generators would be able to recover fixed costs if such low pool price levels persisted, which is borne out by recent announcements of unit mothballing across the NEM. The low levels of pool prices in our forecasts are driven by a number of factors:

- Low levels of assumed demand, especially in the Slow Rate of Change Scenario. However, we would note that actual demand outcomes in Q3 2012

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9 The passthrough percentage is the difference in the carbon inclusive and exclusive price in $/MWh divided by the assumed carbon price for the relevant year in $/tCO2e.

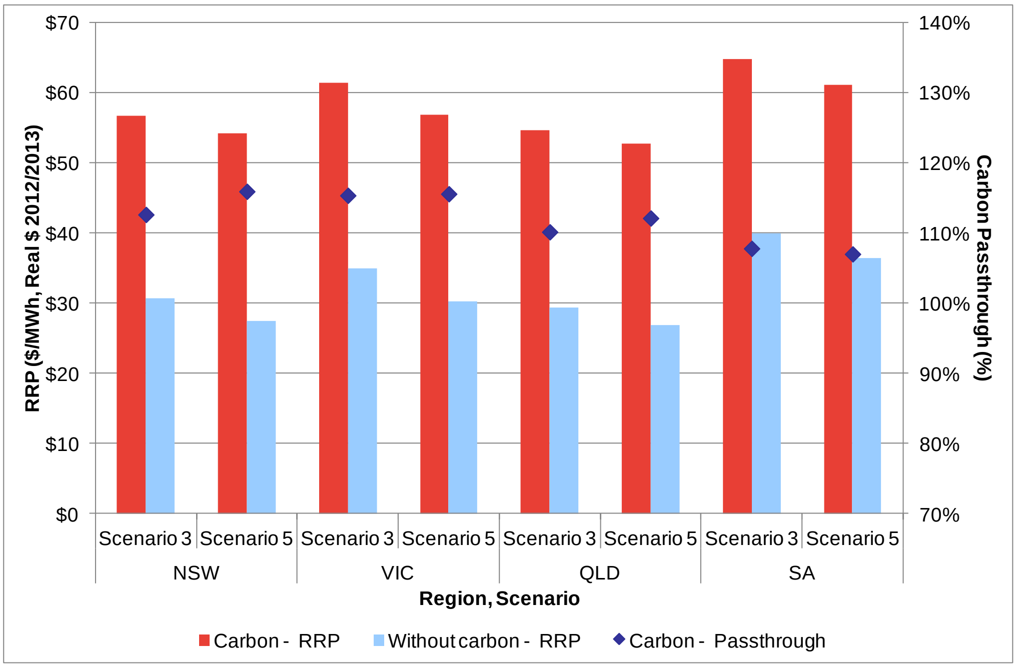
are coming out lower than even the Slow Rate of Change Scenario forecast (ESOO/NEFR 2012 Low case) in both NSW and Victoria.

- Investment in renewable generation to meet the LRET, which puts further downward pressure on pool prices.
- Our analysis does not assume that any mothballing of units at Northern, Playford, Tarong or Yallourn occurs as our analysis was conducted prior to these announcements being made. Incorporating these mothballings in the analysis would most likely counteract other factors that are leading to low pool price outcomes.

The years and regions for which we are reporting higher levels of wholesale pool price passthrough of carbon are a result of loose supply demand balance leading to large proportions of the year where emissions intensive coal-fired generators are marginal. In practice, this may be mitigated to some extent by decisions to mothball generation, although it is difficult to make definitive statements about how such decisions will ultimately impact on carbon passthrough outcomes.

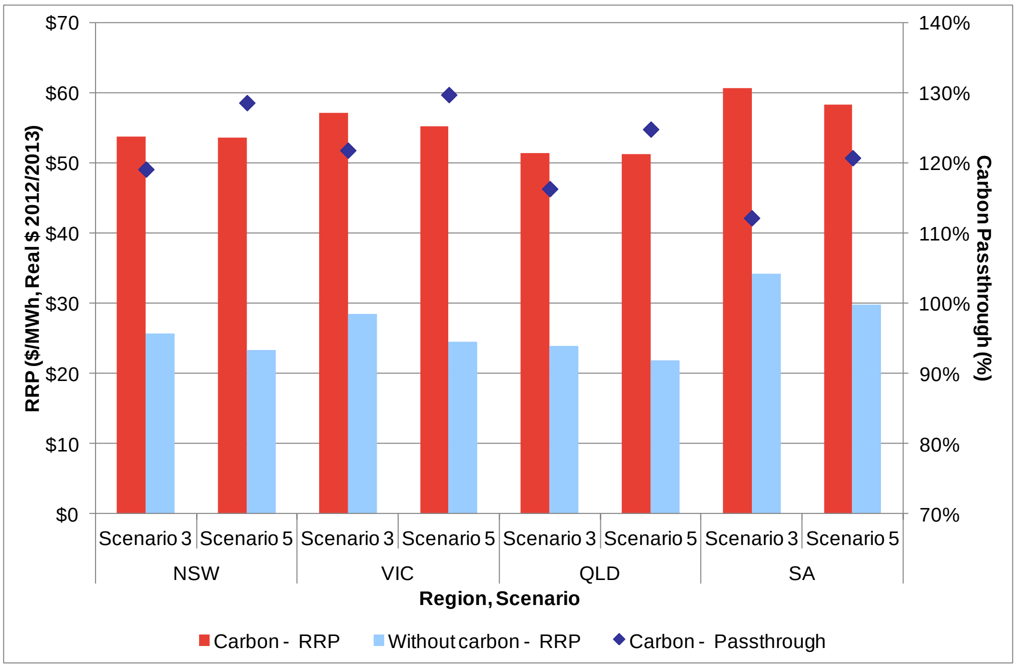
Pass-through levels of approximately 110% are within the range of previous estimates of wholesale pass-through that Frontier Economics' has conducted as part of short-term studies for the AEMC, IPART, ESCOSA, DRET and other entities and with initial outcomes in the NEM post July 2012 (although it is difficult to isolate the carbon component from actual pricing outcomes in the NEM). This highlights a key conclusion from the experiences in the EU ETS where it is difficult, even after the introduction of carbon, to estimate pass-through rates as there is no longer a counterfactual carbon-free market to compare against. It is not possible with certainty to entirely separate the effects of carbon against other factors such as fuel prices, demand, plant outages, or renewables entry for example. In the longer term, particularly in an environment of strong growth in demand, new investment in lower emission intensity generation will tend to result in lower passthrough rates.

Figure 37: Wholesale pool prices with and without carbon (2012/2013)



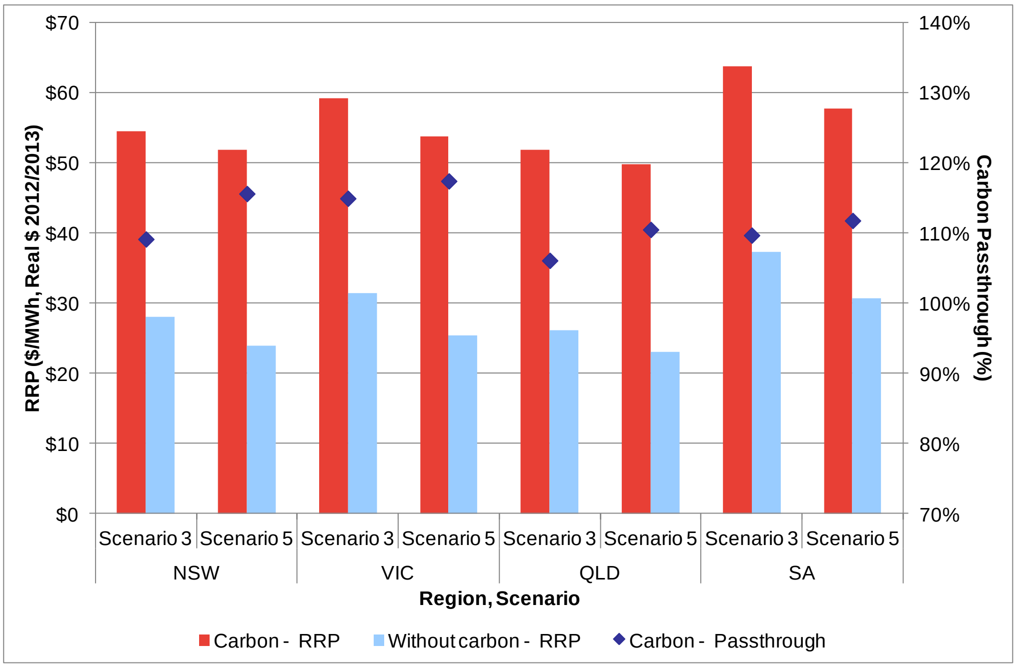
Source: Frontier Economics

Figure 38: Wholesale pool prices with and without carbon (2013/2014)



Source: Frontier Economics

Figure 39: Wholesale pool prices with and without carbon (2014/2015)



Source: Frontier Economics

6.3 Energy purchase cost

Figure 40 through Figure 45 show the wholesale energy cost estimates under the market-based approach with and without carbon for both scenarios and all years. Carbon inclusive wholesale energy cost estimates (red bars) are shown for the purpose of comparison to carbon exclusive estimates (blue bars); the pass through percentage[10] is shown as a point on the chart.

Carbon pass-through is much higher in percentage terms for market-based energy purchase costs (at around 135%) than for the stand-alone LRMC approach (at around 47%). Both approaches use the same demand shapes. The lower carbon pass-through percentage in the stand-alone LRMC approach is a result of investment being able to immediately respond to the imposition of a carbon price.

Carbon pass-through for market-based energy purchase costs is higher than wholesale pool price pass-through. This reflects the peakier residential load shape which is used to calculate market-based energy purchase costs (as opposed to the

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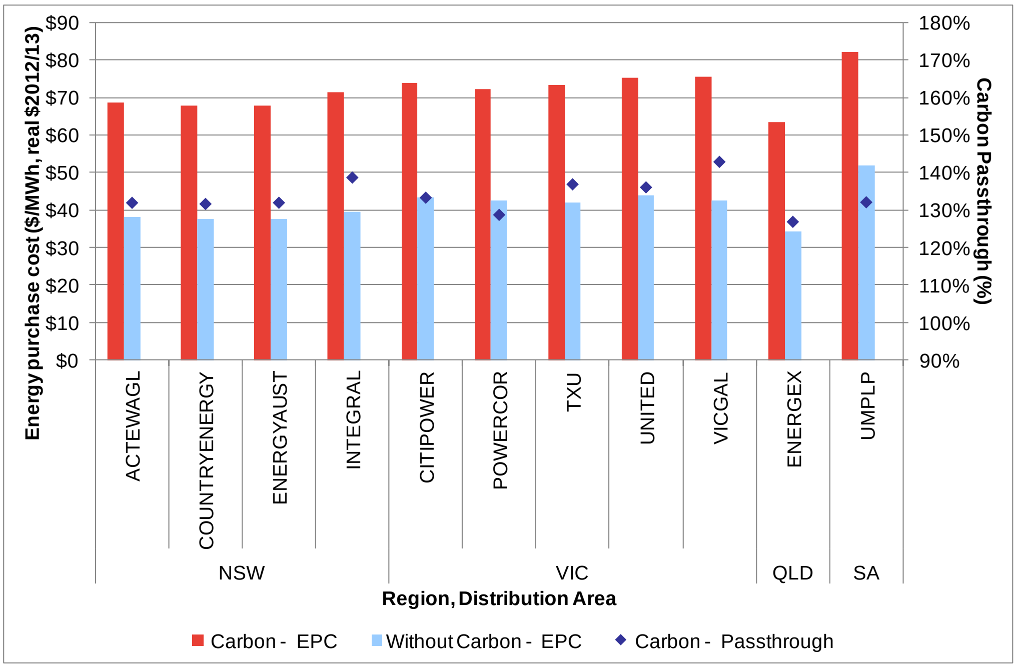
10 The passthrough percentage is the difference in the carbon inclusive and exclusive estimate in $/MWh divided by the assumed carbon price for the relevant year in $/tCO2e.

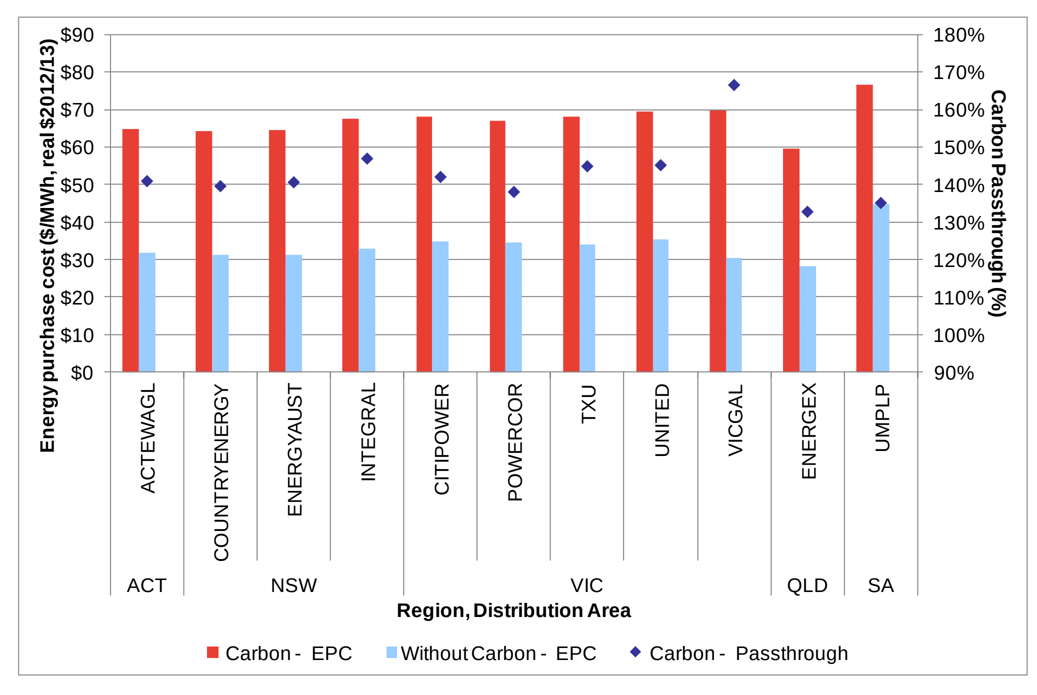
system load shape that drives pool prices) and the inclusion of a contracting premium of 5% above forecast pool prices (which is applied to a higher base in the with carbon case).

Figure 40: Scenario 3 Market-based energy purchase cost with and without carbon (2012/2013)



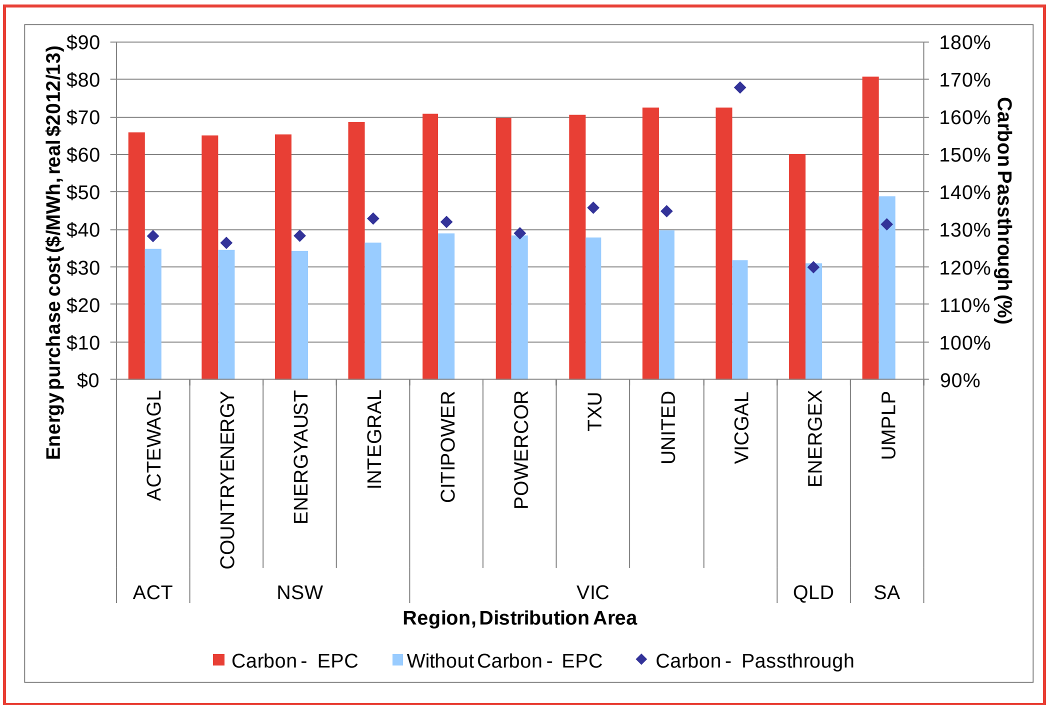
Source: Frontier Economics

Figure 41: Scenario 3 Market-based energy purchase cost with and without carbon (2013/2014)



Source: Frontier Economics

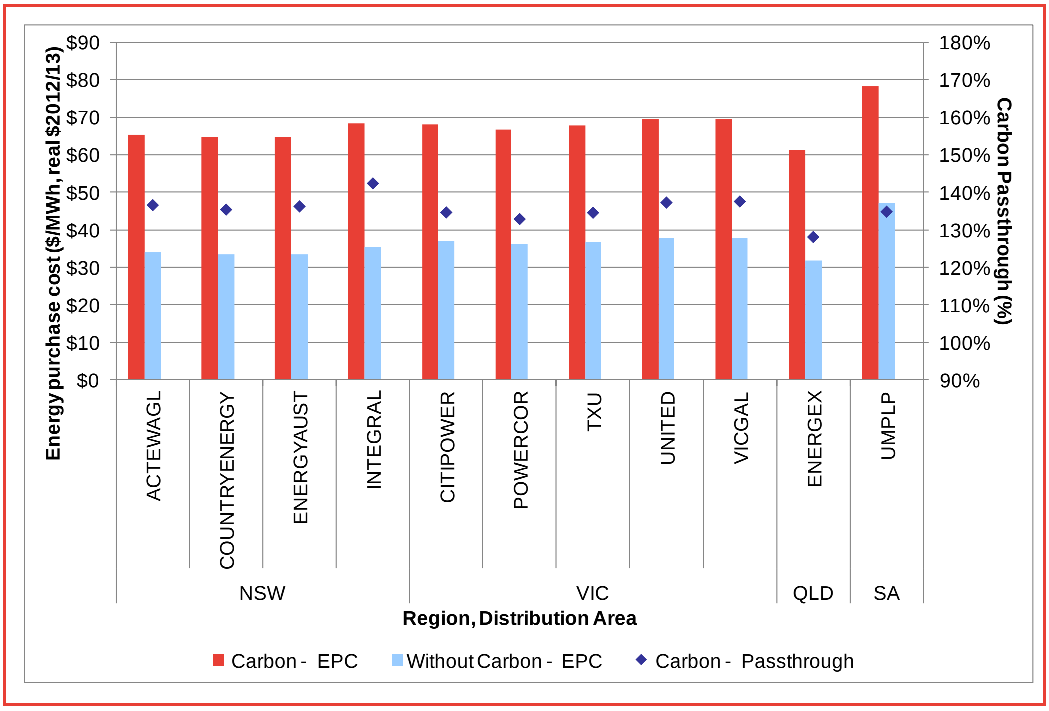
Figure 42: Scenario 3 Market-based energy purchase cost with and without carbon (2014/2015)



Source: Frontier Economics

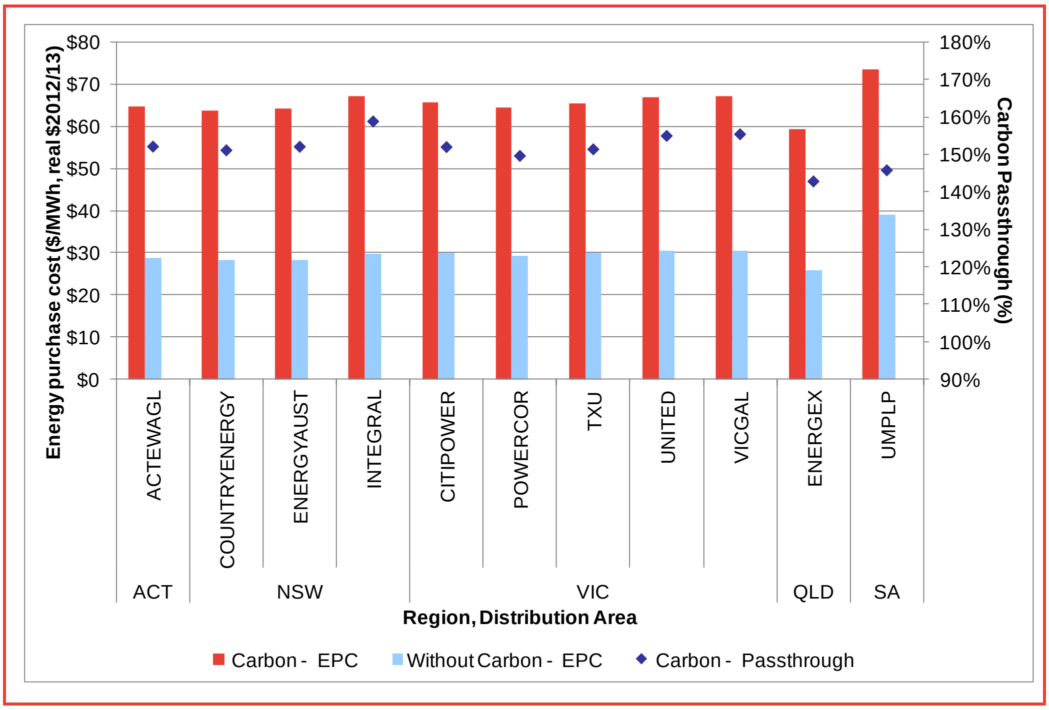
Carbon pass-through

Figure 43: Scenario 5 Market-based energy purchase cost with and without carbon (2012/2013)



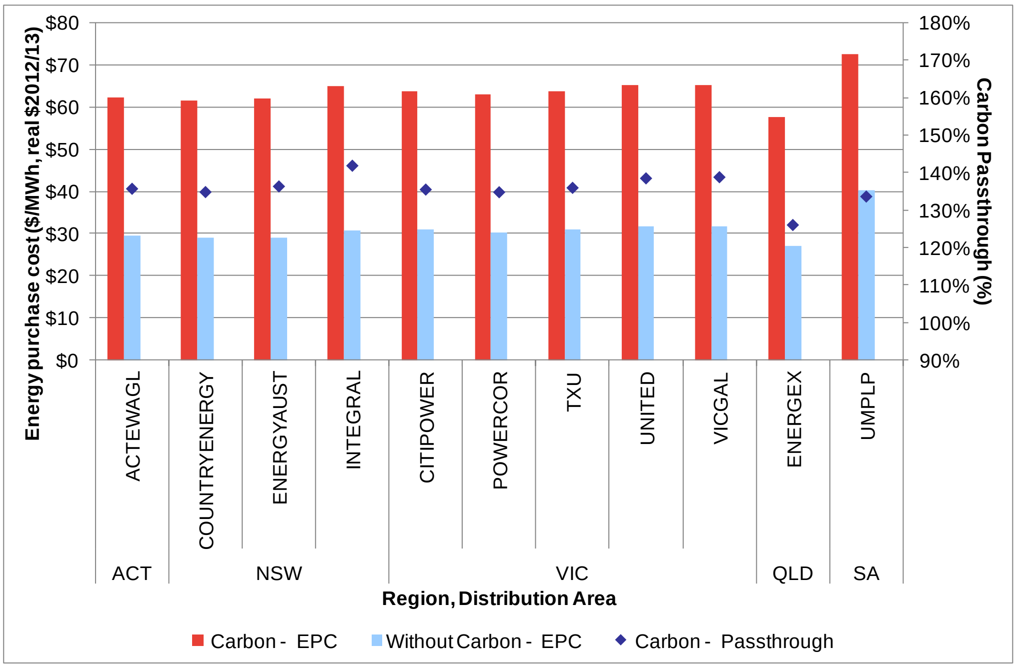
Source: Frontier Economics

Figure 44: Scenario 5 Market-based energy purchase cost with and without carbon (2013/2014)



Source: Frontier Economics

Figure 45: Scenario 5 Market-based energy purchase cost with and without carbon (2014/2015)



Source: Frontier Economics

7 LRET, SRES and the Queensland Gas Scheme

In addition to advising on wholesale energy costs for the period 2012/13 to 2014/15, this assignment also requires us to estimate a range of other energy-related costs. This section considers the costs associated with complying with the following schemes:

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

7.1 LRET

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

The key difference between the RET and the LRET is that small-scale installations such as solar water heaters, air sourced heat pumps and small generation units, which were eligible to create certificates under the RET, are not eligible to create LGCs under the LRET. Instead, these small-scale installations are eligible to create certificates under the SRES.

7.1.1 Approach to estimating costs of complying with the LRET

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

Renewable Power Percentage

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

The RPP is set to achieve the renewable energy targets specified in the legislation. The CER is responsible for setting the RPP for each year. The RPP for 2012 has been set at 9.15 per cent.

The *Renewable Energy (Electricity) Act 2000* states that where the RPP for a year has not been determined it should be calculated as the RPP for the previous year multiplied by the required GWh's of renewable energy for the current year divided by the required GWh's of renewable energy for the previous year. This calculation increases the RPP in line with increases in the renewable energy target but does not decrease the RPP to account for any growth in demand. As a result, this calculation is likely to overestimate the RPP for a given year.

We have used the published RPPs up to 2012 and the renewable energy target for 2012 through to 2015 to calculate the RPPs for 2013 through to 2015. These values have then been averaged to arrive at the financial year RPPs set out in Table 5.

Table 5: Renewable Power Percentages

Year	RPP (% of liable acquisitions)
2012/13	9.78%
2013/14	9.84%
2014/15	9.77%

Source: CER, Frontier Economics.

Cost of obtaining LGCs

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

We have used resource costs to estimate the cost of obtaining LGCs. As discussed in Section 2, we have estimated the cost of LGCs on the basis of the LRMC of meeting the LRET. The LRMC of meeting the LRET is calculated as an output from Frontier Economics' least-economic cost modelling of the power system, using *WHIRLYGIG*. The LRMC of meeting the LRET in any year is effectively the marginal cost of an incremental increase in the LRET target in that year, where the incremental increase in the LRET target can be met by incremental generation by eligible (large scale) generators at any point in the modelling period (subject to the ability to bank and borrow under the scheme). Modelling the LRMC of the LRET in this way accounts for the interaction between the energy market and the market for LGCs, including the impact that a price on carbon will have on the incremental cost of creating an LGC.

Adopting this approach provides the estimated LRMC of an LGC as set out in Table 6. The large difference between the LRMC of an LGC under the Planning Scenario and the Slow Rate of Change Scenario is accounted for by differences in the carbon price. In the Slow Rate of Change Scenario it is assumed that after the fixed price period the carbon price falls to zero $/t$CO_2$ and that fuel prices are lower, lowering the assumed variable costs of generation. Furthermore, the assumption of low demand growth in the Slow Rate of Change Scenario leads to soft supply-demand conditions persisting in the NEM into the longer term. These factors result in lower 'black' energy prices and, as a result, the requirement for a higher LGC price in order to make renewable energy cost-effective.

Table 6: LRMC of an LGC ($2012/13)

Financial Year	Planning Scenario LRMC of LGC ($/certificate)	Slow Rate of Change Scenario LRMC of LGC ($/certificate)
2012/13	$41.11	$71.96
2013/14	$42.75	$74.84
2014/15	$44.46	$77.83

Source: Frontier Economics

7.1.2 Cost of complying with the LRET

Based on the RPPs set out in Table 5 and the LRMC of an LGC set out in Table 6, the cost of complying with the LRET is set out in Table 7.

Table 7: Cost of complying with the LRET ($2012/13)

Financial Year	State	Distribution Area	Planning Scenario – Cost of complying with LRET ($/MWh)	Slow Rate of Change Scenario – Cost of complying with LRET ($/MWh)
2013	QLD	Energex	$3.98	$6.97
2013	NSW	Country Energy	$4.01	$7.02
2013	NSW	EnergyAustralia	$3.98	$6.97
2013	NSW	Integral Energy	$4.03	$7.05
2013	ACT	ActewAGL	$4.06	$7.11
2013	VIC	Citipower	$4.01	$7.02
2013	VIC	Powercor	$4.01	$7.02
2013	VIC	TXU	$4.01	$7.02
2013	VIC	United	$4.01	$7.02
2013	VIC	VicAGL	$4.01	$7.02
2013	TAS	Aurora	$4.01	$7.02
2013	SA	ETSA	$3.95	$6.91
2013	WA	SWIS	$4.01	$7.02
2014	QLD	Energex	$4.16	$7.29
2014	NSW	Country Energy	$4.19	$7.33
2014	NSW	EnergyAustralia	$4.16	$7.29
2014	NSW	Integral Energy	$4.21	$7.37
2014	ACT	ActewAGL	$4.25	$7.44
2014	VIC	Citipower	$4.20	$7.34
2014	VIC	Powercor	$4.20	$7.34
2014	VIC	TXU	$4.20	$7.34
2014	VIC	United	$4.20	$7.34
2014	VIC	VicAGL	$4.20	$7.34
2014	TAS	Aurora	$4.20	$7.34
2014	SA	ETSA	$4.13	$7.22
2014	WA	SWIS	$4.20	$7.34

2015	QLD	Energex	$4.30	$7.53
2015	NSW	Country Energy	$4.33	$7.58
2015	NSW	EnergyAustralia	$4.30	$7.53
2015	NSW	Integral Energy	$4.35	$7.62
2015	ACT	ActewAGL	$4.39	$7.68
2015	VIC	Citipower	$4.33	$7.59
2015	VIC	Powercor	$4.33	$7.59
2015	VIC	TXU	$4.33	$7.59
2015	VIC	United	$4.33	$7.59
2015	VIC	VicAGL	$4.33	$7.59
2015	TAS	Aurora	$4.33	$7.59
2015	SA	ETSA	$4.26	$7.46
2015	WA	SWIS	$4.33	$7.59

Source: Frontier Economics

7.2 SRES

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

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

7.2.1 Approach to estimating costs of complying with the SRES

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

Small-scale Technology Percentage

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

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

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

The STP is to be published for each compliance year by March 31 of that year. The CER must also publish a non-binding estimate of the STP for the two subsequent compliance years by March 31. STPs have been published by the CER for 2012, 2013 and 2014. We have assumed that the STP for 2015 remains at the same level as the STP for 2014. These values have then been averaged to arrive at the financial year STPs set out in Table 8.

Table 8: Small-scale Technology Percentages

Year	STP (% of liable acquisitions)
2012/13	15.95%
2013/14	7.02%
2014/15	6.10%

Source: CER.

Cost of STCs

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

In real terms, and using a forecast inflation rate of 2.5%, this nominal $40 results in the real STC costs set out in Table 9.

Table 9: STC costs ($2012/13)

Calendar Year	STC cost
2012/13	$40.00
2013/14	$39.02
2014/15	$38.07

Source: Frontier Economics

7.2.2 Cost of complying with the SRES

In broad terms, the cost of complying with the SRES is the STP multiplied by the cost of STCs. While this is complicated by the timing of liable entities' obligation to surrender STCs, this complication is only relevant in the event that a liable entities' load changes over time. Since we are implicitly assuming that a representative retailers' load will remain constant over time, we can calculate the cost of complying with the SRES as the STP multiplied by the cost of STCs.

Using this approach, and based on the STPs set out in Table 8 and the cost of STCs set out in Table 9, the cost of complying with the SRES is set out in Table 10.

Table 10: Cost of complying with the SRES ($2012/13)

Financial Year	State	Distribution Area	Planning Scenario – Cost of complying with SRES ($/MWh)	Slow Rate of Change Scenario – Cost of complying with SRES ($/MWh)
2013	QLD	Energex	$6.32	$6.32
2013	NSW	Country Energy	$6.36	$6.36
2013	NSW	EnergyAustralia	$6.32	$6.32
2013	NSW	Integral Energy	$6.39	$6.39
2013	ACT	ActewAGL	$6.45	$6.45
2013	VIC	Citipower	$6.37	$6.37
2013	VIC	Powercor	$6.37	$6.37
2013	VIC	TXU	$6.37	$6.37
2013	VIC	United	$6.37	$6.37
2013	VIC	VicAGL	$6.37	$6.37
2013	TAS	Aurora	$6.37	$6.37
2013	SA	ETSA	$6.26	$6.26
2013	WA	SWIS	$6.37	$6.37
2014	QLD	Energex	$2.71	$2.71
2014	NSW	Country Energy	$2.73	$2.73
2014	NSW	EnergyAustralia	$2.71	$2.71
2014	NSW	Integral Energy	$2.74	$2.74
2014	ACT	ActewAGL	$2.77	$2.77
2014	VIC	Citipower	$2.73	$2.73
2014	VIC	Powercor	$2.73	$2.73
2014	VIC	TXU	$2.73	$2.73
2014	VIC	United	$2.73	$2.73
2014	VIC	VicAGL	$2.73	$2.73
2014	TAS	Aurora	$2.73	$2.73
2014	SA	ETSA	$2.69	$2.69
2014	WA	SWIS	$2.73	$2.73

2015	QLD	Energex	$2.30	$2.30
2015	NSW	Country Energy	$2.31	$2.31
2015	NSW	EnergyAustralia	$2.30	$2.30
2015	NSW	Integral Energy	$2.33	$2.33
2015	ACT	ActewAGL	$2.35	$2.35
2015	VIC	Citipower	$2.32	$2.32
2015	VIC	Powercor	$2.32	$2.32
2015	VIC	TXU	$2.32	$2.32
2015	VIC	United	$2.32	$2.32
2015	VIC	VicAGL	$2.32	$2.32
2015	TAS	Aurora	$2.32	$2.32
2015	SA	ETSA	$2.28	$2.28
2015	WA	SWIS	$2.32	$2.32

Source: Frontier Economics

7.3 Queensland Gas Scheme

The Queensland Gas Scheme places a legal obligation on Queensland electricity retailers to source 15 per cent of their electricity from gas-fired generation. Retailers are required to purchase and surrender Gas Electricity Certificates (GECs). The number of GECs to be purchases each year is determined by the scheme target, which is currently 15 per cent. GECs are created by eligible generation from gas-fired generators.

7.3.1 Approach to estimating costs of complying with the Queensland Gas Scheme

In order to calculate the cost of complying with the Queensland Gas Scheme, it is necessary to determine the scheme target for a representative retailer (which determines the number of GECs that must be purchased) and the cost of obtaining each GEC.

Scheme target

The scheme target establishes the rate of liability under the Queensland Gas Scheme and is used by liable entities to determine how many GECs they need to surrender to discharge their liability each year.

The scheme target is currently 15 per cent and we have assumed that it remains unchanged at 15 per cent over the forecast period.

Cost of obtaining GECs

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

We have used resource costs to estimate the cost of obtaining GECs. As discussed in Section 2, we have estimated the cost of GECs on the basis of the LRMC of meeting the Queensland Gas Scheme. This is consistent with our approach to estimating the cost of LGCs under the LRET. The LRMC of meeting the Queensland Gas Scheme is calculated as an output from Frontier Economics' least-economic cost modelling of the power system, using *WHIRLYGIG*. The LRMC of meeting the Queensland Gas Scheme in any year is effectively the marginal cost of an incremental increase in the number of GECs to be produced in that year, where the incremental increase can be met by incremental generation by eligible gas generators. Modelling the LRMC of the Queensland Gas Scheme in this way accounts for the interaction between the energy market and the market for GECs, including the impact that a price on carbon will have on the incremental cost of creating a GEC.

Adopting this approach provides the estimated LRMC of a GEC as set out in Table 11. The LRMC of a GEC is zero in 2012/13 as a result of the existing surplus of GECs. From 2013/14 onwards, the existing surplus is insufficient to supply the required number of GECs and, as a result, the LRMC of a GEC becomes positive. The large difference between the LRMC of a GEC under the Planning Scenario and the Slow Rate of Change Scenario is accounted for by changes to assumptions that lead to lower black prices. Primarily this is due to the absence of a carbon price from 2015/16 in the Slow Rate of Change Scenario, however lower fuel costs and weaker demand growth also contribute to lower black prices. As a result, higher GEC prices are required in order to make gas generation cost-effective. Since banking and borrowing of GECs is modelled, the lower 'black' energy prices from 2015/16 onwards result in increased GEC prices in earlier forecast years.

Table 11: LRMC of a GEC ($2012/13)

Financial Year	Planning Scenario LRMC of GEC ($/certificate)	Slow Rate of Change Scenario LRMC of GEC ($/certificate)
2012/13	$0.00	$0.00
2013/14	$8.07	$15.21
2014/15	$8.65	$16.30

Source: Frontier Economics

7.3.2 Cost of complying with the Queensland Gas Scheme

Based on the scheme target of 15 per cent and the LRMC of a GEC set out in Table 11, the cost of complying with the Queensland Gas Scheme is set out in Table 12. Note that the scheme only applies to (and therefore only results in a cost for) retailers in Queensland.

Table 12: Cost of complying with the Queensland Gas Scheme ($2012/13)

Financial Year	State	Distribution Area	Planning Scenario – Cost of complying with Queensland Gas Scheme ($/MWh)	Slow Rate of Change Scenario – Cost of complying with Queensland Gas Scheme ($/MWh)
2013	QLD	Energex	$0.00	$0.00
2014	QLD	Energex	$1.21	$2.28
2015	QLD	Energex	$1.30	$2.45

Source: Frontier Economics

8 Energy savings schemes

In addition to advising on wholesale energy costs for the period 2012/13 to 2014/15, this assignment also requires us to estimate a range of other energy-related costs. This section considers the costs associated with complying with market-based energy savings schemes that impose obligations in a number of jurisdictions:

- the NSW Energy Savings Scheme
- the Victorian Energy Saver Initiative.

We have also considered the costs associated with the ACT Energy Efficiency Improvements Scheme, even though this scheme is not a certificate-based scheme.

8.1 NSW Energy Savings Scheme

The Energy Saving Scheme (ESS) is designed to increase opportunities to improve energy efficiency by rewarding companies that undertake eligible projects that either reduce electricity consumption or improve the efficiency of energy use.

Under the ESS, electricity retailers, and certain other parties, are required to meet individual energy savings targets based on the size of their share of the electricity market. The ESS establishes annual energy savings targets for these scheme participants, which participants are required to meet by obtaining and surrendering Energy Savings Certificates (ESCs). If participants fail to meet their targets through the surrender of ESCs, a penalty is imposed.

8.1.1 Approach to estimating costs of complying with the ESS

In order to calculate the cost of complying with the ESS, it is necessary to determine the energy savings target for a representative retailer (or the number of ESCs that a retailer needs to surrender) and the cost of obtaining ESCs to meet the energy savings target.

Energy savings target

The ESS target is defined as a proportion of total annual NSW electricity sales to be saved through the take-up of energy efficiency projects.

The ESS target is allocated each year to electricity retailers in proportion to their liable electricity sales. Liable electricity sales are defined as total annual NSW electricity sales less sales to exempt emission-intensive trade-exposed activities. Taking this into account, the ESS target, defined as a proportion of total annual NSW electricity sales and as a proportion of total annual liable sales, is set out in

Table 13. These calendar year compliance obligations are averaged to provide financial year compliance obligations.

Table 13: ESS target

Calendar year	Effective scheme target (% of annual NSW electricity sales)	Retailer compliance obligation (% of annual liable electricity sales)
2012	2.8 %	3.5 %
2013	3.6 %	4.5 %
2014 – 2020	4.0 %	5.0 %

Source: ESS web site. Available at: http://www.ess.nsw.gov.au/For_Liable_Entities/Targets

Cost of obtaining ESCs

Frontier Economics has adopted the penalty price of the ESS as a proxy for the cost of obtaining ESCs. The penalty price will act as a cap on the price of ESCs. This approach is consistent with the approach adopted by IPART in determining the cost of complying with the ESS. The penalty price of the scheme for 2012 is $26.45/MWh,[11] which is equivalent to an after-tax price of $37.78/MWh.

8.1.2 Cost of complying with the ESS

Based on the energy savings targets set out in Table 13 and the ESS penalty price of $37.78/MWh, the cost of complying with the ESS is set out in Table 14.

11 The penalty price escalates with CPI.

Table 14: Cost of complying with the ESS ($2012/13)

Financial Year	State	Distribution Area	Cost of complying with ESS ($/MWh)
2013	NSW	Country Energy	$1.51
2013	NSW	EnergyAustralia	$1.51
2013	NSW	Integral Energy	$1.51
2014	NSW	Country Energy	$1.79
2014	NSW	EnergyAustralia	$1.79
2014	NSW	Integral Energy	$1.79
2015	NSW	Country Energy	$1.89
2015	NSW	EnergyAustralia	$1.89
2015	NSW	Integral Energy	$1.89

Source: Frontier Economics

8.2 Victorian Energy Efficiency Target

The Victorian Energy Efficiency Target (VEET) is designed to make energy efficiency improvements more affordable and to contribute to the reduction of greenhouse gases.

Under the VEET, energy retailers face a liability to surrender a specified number of Victorian Energy Efficiency Certificates (VEECs) each year. Accredited entities are able to create VEECs when they help energy consumers make defined energy efficiency improvements.

8.2.1 Approach to estimating costs of complying with the VEET

In order to calculate the cost of complying with the VEET, it is necessary to determine the liability for a representative retailer (or the number of VEECs that a retailer needs to surrender) and the cost of obtaining VEECs to meet that liability.

Liabilities under the VEET

The scheme target for the second three-year phase of the VEET (from calendar year 2012 to calendar year 2014) is 5.4 million VEECs. We have assumed that this scheme target will remain unchanged for 2015.

These scheme targets are translated into greenhouse gas reduction rates for both electricity retailers (known as an RE) and gas retailers (known as an RG). An electricity retailers' obligation to surrender VEETs in a year is calculated by multiplying their liable electricity acquisitions by the RE for the year. The RE for 2012 has been set at 0.12673. Based on the assumption that the scheme target will remain unchanged from 2012 to 2015, but that total electricity sales will increase during this period, we have assumed that the RE will reduce over time, as set out in Table 15. These calendar year compliance obligations are averaged to provide financial year compliance obligations.

Table 15: Liabilities under the VEET

Calendar year	Scheme target (number of VEECs)	RE (% of liable electricity acquisitions)
2012	5,400,000	12.67%
2013	5,400,000	12.52%
2014	5,400,000	12.35%
2015	5,400,000	12.14%

Source: VEET web site. Available at: https://www.veet.vic.gov.au/Public/Public.aspx?id=EnergyRetailers

Cost of obtaining VEECs

Frontier Economics has adopted the shortfall penalty under the VEET as a proxy for the cost of obtaining VEECs. The penalty price will act as a cap on the price of ESCs. This approach is consistent with the approach adopted by IPART in determining the cost of complying with the ESS and with the ICRC in determining the cost of complying with the EEIS. The shortfall penalty of the scheme for 2012 is $42.73 per certificate.

8.2.2 Cost of complying with the VEET

Based on the liabilities set out in Table 15 and the VEET shortfall penalty of $42.73 per certificate, the cost of complying with the VEET is set out in Table 16.

Table 16: Cost of complying with the VEET ($2012/13)

Financial Year	State	Distribution Area	Cost of complying with ESS ($/MWh)
2013	VIC	Citipower	$5.38
2013	VIC	Powercor	$5.38
2013	VIC	TXU	$5.38
2013	VIC	United	$5.38
2013	VIC	VicAGL	$5.38
2014	VIC	Citipower	$5.31
2014	VIC	Powercor	$5.31
2014	VIC	TXU	$5.31
2014	VIC	United	$5.31
2014	VIC	VicAGL	$5.31
2015	VIC	Citipower	$5.23
2015	VIC	Powercor	$5.23
2015	VIC	TXU	$5.23
2015	VIC	United	$5.23
2015	VIC	VicAGL	$5.23

Source: Frontier Economics

8.3 ACT Energy Efficiency Improvements Scheme

The Energy Efficiency Improvements Scheme (EEIS) is designed as a non-certificate based, supplier obligation energy efficiency scheme. The scheme seeks to increase the efficient use of electricity and natural gas in the ACT by incentivising electricity suppliers to install efficient products or undertake activities to improve efficiency.

Under the EEIS, electricity retailers are required to achieve emissions reduction targets as defined by their Supplier Energy Savings Obligation. This obligation is met by undertaking eligible activities that improve energy efficiency or by making an Energy Savings Contribution (ESC).

8.3.1 Approach to estimating costs of complying with the EEIS

In order to calculate the cost of complying with the EEIS, it is necessary to determine the Supplier Energy Savings Obligations for a representative retailer and the cost of undertaking activities to meet that obligation.

Supplier Energy Savings Obligation

The Supplier Energy Savings Obligation is calculated as follows:

$$SESO = EST * (Electricity\ Sales * Emissions\ Factor)$$

Where:

SESO is the Supplier Energy Savings Obligation

EST is the Energy Savings Target, expressed as a percentage of total electricity sales in the ACT

The EST for each calendar year is defined under the scheme. Adopting an emissions factor of 0.89 tCO_2/MWh[12] results in a SESO for each calendar year as set out in Table 17. These calendar year compliance obligations are averaged to provide financial year compliance obligations.

12 ACT Government, *Energy Efficiency Improvement Scheme*, Regulatory Impact Statement, March 2012.

Table 17: Supplier Energy Savings Obligation

Calendar year	EST (% of annual ACT electricity sales)	SESO (tCO_2)
2012	0	0.00
2013	7.2%	0.06
2014	13.1%	0.12
2015	13.6%	0.12

Source: ACT Government, Energy Efficiency Improvement Scheme, *Regulatory Impact Statement, March 2012.*

Cost of obtaining ESCs

Frontier Economics has adopted the ESC as a proxy for the cost of obtaining meeting the SESO. This approach is consistent with the approach adopted by ICRC in determining the cost of complying with the EEIS. The ESC is set at \$37/tCO_2.

8.3.2 Cost of complying with the EEIS

Based on the SESOs set out in Table 17 and the ESC of \$37/ tCO_2, the cost of complying with the EEIS is set out in Table 18.

Table 18: Cost of complying with the EEIS (\$2012/13)

Financial Year	State	Distribution Area	Cost of complying with EEIS (\$/MWh)
2013	ACT	ActewAGL	\$1.19
2014	ACT	ActewAGL	\$3.34
2015	ACT	ActewAGL	\$4.40

Source: Frontier Economics

9 NEM fees and ancillary services costs

In addition to advising on wholesale energy costs for the period 2012/13 to 2014/15, this assignment also requires us to estimate a range of other energy-related costs. This section considers the market fees and ancillary services costs.

9.1 Market fees

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

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

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

9.1.1 Estimating NEM fees

To estimate future market fees for NEM regions, we have examined AEMO's budgeted revenue requirements. AEMO has published its budget requirements and the resulting market fees for 2012/13 through to 2014/15.[13]

To estimate future market fees for the SWIS, due to the difficulty of predicting how market fees vary in future years, we have assumed that the IMO market fee rate stays constant in real terms at the current rate of $0.756/MWh.[14]

Based on this approach, market fees in each distribution area are set out in Table 20.

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13 AEMO, *Electricity Final Budget and Fees 2012/13*, 23 May 2012.

14 IMO website, http://www.imowa.com.au/fees_charges.

Table 19: Market fees ($2012/13)

Financial Year	State	Distribution Area	Ancillary services costs ($/MWh)
2013	QLD	Energex	$0.40
2013	NSW	Country Energy	$0.40
2013	NSW	EnergyAustralia	$0.40
2013	NSW	Integral Energy	$0.40
2013	ACT	ActewAGL	$0.40
2013	VIC	Citipower	$0.40
2013	VIC	Powercor	$0.40
2013	VIC	TXU	$0.40
2013	VIC	United	$0.40
2013	VIC	VicAGL	$0.40
2013	TAS	Aurora	$0.40
2013	SA	ETSA	$0.40
2013	WA	SWIS	$0.76
2014	QLD	Energex	$0.40
2014	NSW	Country Energy	$0.40
2014	NSW	EnergyAustralia	$0.40
2014	NSW	Integral Energy	$0.40
2014	ACT	ActewAGL	$0.40
2014	VIC	Citipower	$0.40
2014	VIC	Powercor	$0.40
2014	VIC	TXU	$0.40
2014	VIC	United	$0.40
2014	VIC	VicAGL	$0.40
2014	TAS	Aurora	$0.40
2014	SA	ETSA	$0.40
2014	WA	SWIS	$0.76

2015	QLD	Energex	$0.39
2015	NSW	Country Energy	$0.39
2015	NSW	EnergyAustralia	$0.39
2015	NSW	Integral Energy	$0.39
2015	ACT	ActewAGL	$0.39
2015	VIC	Citipower	$0.39
2015	VIC	Powercor	$0.39
2015	VIC	TXU	$0.39
2015	VIC	United	$0.39
2015	VIC	VicAGL	$0.39
2015	TAS	Aurora	$0.39
2015	SA	ETSA	$0.39
2015	WA	SWIS	$0.76

Source: Frontier Economics

9.2 Ancillary services costs

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

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

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

9.2.1 Estimating ancillary services costs

To estimate the future cost of ancillary services for NEM regions, we have investigated the past 10 years of ancillary service cost data published by AEMO for each region of the NEM. AEMO publishes ancillary services costs on a weekly basis. We have converted these weekly costs, which are reported on a nominal basis, into real 2012/13 dollars. We have then calculated an annual average ancillary services cost for each year and each region. We have taken a simple average of historic annual average ancillary services costs in each region, and have assumed that ancillary services costs over the forecast period will be equal to that simple average.

We have based estimates of future costs of ancillary services costs for the SWIS on the forecasts reported in the ERA's recent review of Synergy's retailing costs.[15]

Based on this approach, ancillary services costs in each distribution area are set out in Table 20.

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15 Economic Regulation Authority, *Synergy's Costs and Electricity Tariffs*, Final Report, 4 July 2012.

Table 20: Ancillary service costs ($2012/13)

Financial Year	State	Distribution Area	Ancillary services costs ($/MWh)
2013	QLD	Energex	$0.33
2013	NSW	Country Energy	$0.71
2013	NSW	EnergyAustralia	$0.71
2013	NSW	Integral Energy	$0.71
2013	ACT	ActewAGL	$0.71
2013	VIC	Citipower	$0.19
2013	VIC	Powercor	$0.19
2013	VIC	TXU	$0.19
2013	VIC	United	$0.19
2013	VIC	VicAGL	$0.19
2013	TAS	Aurora	$0.61
2013	SA	ETSA	$0.46
2013	WA	SWIS	$1.86
2014	QLD	Energex	$0.33
2014	NSW	Country Energy	$0.71
2014	NSW	EnergyAustralia	$0.71
2014	NSW	Integral Energy	$0.71
2014	ACT	ActewAGL	$0.71
2014	VIC	Citipower	$0.19
2014	VIC	Powercor	$0.19
2014	VIC	TXU	$0.19
2014	VIC	United	$0.19
2014	VIC	VicAGL	$0.19
2014	TAS	Aurora	$0.61
2014	SA	ETSA	$0.46
2014	WA	SWIS	$1.86

2015	QLD	Energex	$0.33
2015	NSW	Country Energy	$0.71
2015	NSW	EnergyAustralia	$0.71
2015	NSW	Integral Energy	$0.71
2015	ACT	ActewAGL	$0.71
2015	VIC	Citipower	$0.19
2015	VIC	Powercor	$0.19
2015	VIC	TXU	$0.19
2015	VIC	United	$0.19
2015	VIC	VicAGL	$0.19
2015	TAS	Aurora	$0.61
2015	SA	ETSA	$0.46
2015	WA	SWIS	$1.86

Source: Frontier Economics

Appendix A – Turvey methodology and results

This section presents the methodology and results for Frontier Economics' estimate of wholesale electricity costs using what is commonly referred to as the Turvey LRMC approach. This section is set out as follows:

- an overview of the Turvey LRMC approach
- our approach to applying the perturbation method to estimate a Turvey LRMC for the NEM
- the results of the modelling.

Overview of the Turvey approach

Motivation for using the Turvey approach

Both the stand-alone and market-based approaches to estimating energy purchase costs involve some drawbacks.

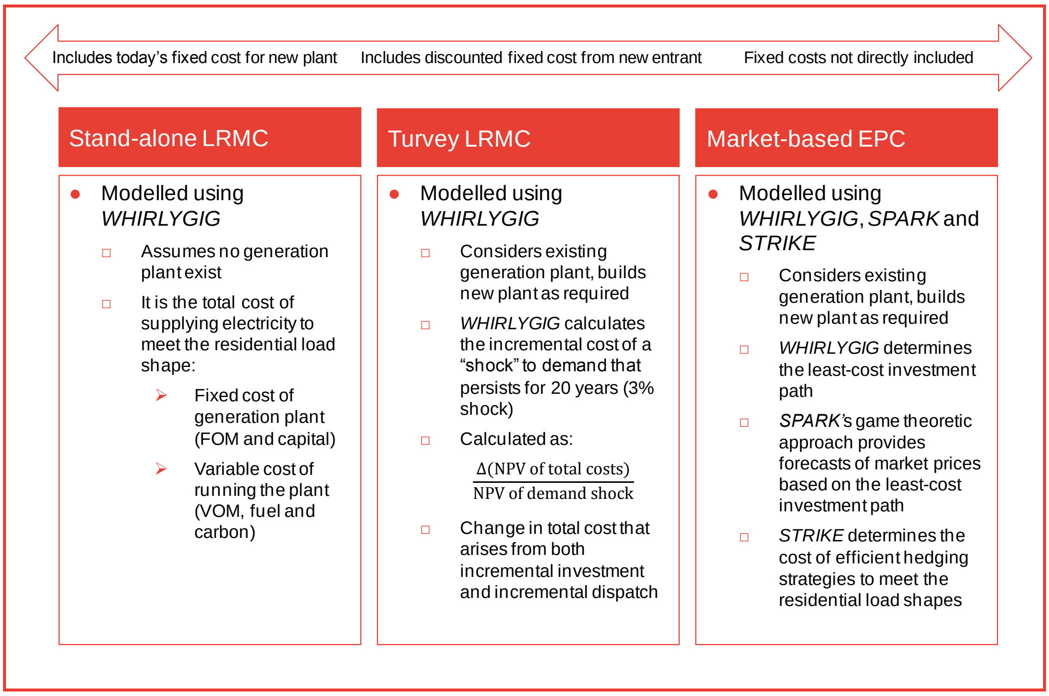
The stand-alone approach requires a degree of abstraction from some of the realities of the NEM. The approach assumes that a hypothetical system of new generation stock is built to meet a single load shape (typically a residential load as opposed to a regional load) in the absence of a multi-regional, interconnected market structure. The stand-alone approach provides a useful benchmark for estimating purchase costs from both a theoretical and practical perspective. The method results in an estimate of LRMC that includes fixed costs of building capital intensive generators, which can be particularly useful as a benchmark of efficient costs of the actual market. From a practical perspective, the approach is simple and relies on a minimum number of assumptions.

Similarly, the market-based approach has some drawbacks. In times of oversupply relative to demand, the method will produce estimates of costs that are significantly below the long-run costs of capital intensive generation assets. Within some contexts, the fact that the approach will not fully reflect capital costs may be a problem. Practically, the method relies on more assumptions than the stand-alone method – information around the existing stock of generators including input costs – however, this is not a major drawback of the approach.

Particularly during times of oversupply, the two approaches are towards opposite ends of the spectrum in regard to how fixed costs of generators flow through to purchase cost estimates. The stand-alone approach includes full fixed costs of the efficient new build system in each year for which an estimate is produced while the market-based approaches will tend towards an SRMC outcome for years where the market is oversupplied.

The Turvey LRMC provides an alternative approach to estimating wholesale energy costs that attempts to steer a middle ground in regard to how fixed costs of generators flow through to purchase cost estimates. By incorporating the discounted fixed costs associated with the next increment of investment into the estimate of LRMC, this approach produces a marginal cost of electricity that reflects the variable costs of an existing 'real-world' system and the costs associated with the next increment of capacity within the same 'real-world' system. Conceptually, this approach is attractive as it avoids the abstraction of the stand-alone approach and the potential for producing energy cost estimates close to the SRMC at times of oversupply symptomatic of the market-based approach. The Turvey LRMC approach instead incorporates the costs associated with an actual system's need for new capacity in the long term. Figure 46 summarises the three approaches and how they are implemented using Frontier Economics' models.

Figure 46: Summary of different approaches



Source: Frontier Economics

Theory behind the Turvey approach

Turvey (and others) have argued that the text-book definition of marginal cost as the first derivative of cost, with respect of output, is too simple to be useful.[16] In

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16 See, for example: Turvey, R. "Marginal Cost", *The Economic Journal*, 1969, Vol. 79, No. 314, pp. 282-299.

particular, both costs and output have time dimensions, and both are subject to uncertainty.

To reflect these complications, Turvey proposed what he considered to be a more relevant approach to defining marginal cost. Starting with a forecast of future output over the long term, it is possible to determine the present value of all future costs to achieve that output. By postulating a permanent increment to forecast future output starting in year *x*, year *x + 1*, and so on, it is possible to determine the present value of all future costs associated with achieving each of these alternative increments to future output. Turvey defined incremental costs for year *x* as the difference in costs between the case in which the permanent increment to forecast output starts in year *x* and the case in which the permanent increment to forecast output starts in year *x + 1*. By dividing these incremental costs by the size of the increment to output, we get marginal cost. According to Turvey then:

> marginal cost for any year is the excess of (a) the present worth in that year of system costs with a unit permanent output increment starting then, over (b) the present worth in that year of system costs with the unit permanent output increment postponed to the following year.[17]

In later works, Turvey considers a number of different techniques for estimating LRMC that relate to these early concepts. For instance, he variously proposes estimating LRMC as:

- Technique 1 – the present value of the difference in costs between a base case and a case with a permanent increment to output, divided by the present value of the difference in output – generally known as the perturbation approach
- Technique 2 – the present value of the cost of bringing forward the next proposed addition of capacity, divided by the present value of the increment to future output that would be possible while maintaining an unchanged quality of service

While Turvey's approach to estimating LRMC can provide useful information about costs in electricity markets, it is important to understand the implications of using these techniques in practice.

First, both techniques are oriented to measuring the incremental cost of the generation system since they use the existing generation system as the base against which the optimal increment to capacity is selected. This makes determining the incremental cost of serving a particular load (such as a residential load) difficult. Theoretically it may be possible to allocate the incremental cost to the regulated load using the perturbation method (Technique 1) by assuming a

17 Turvey, R. "Marginal Cost", *The Economic Journal*, 1969, Vol. 79, No. 314, pp. 282-299; 289.

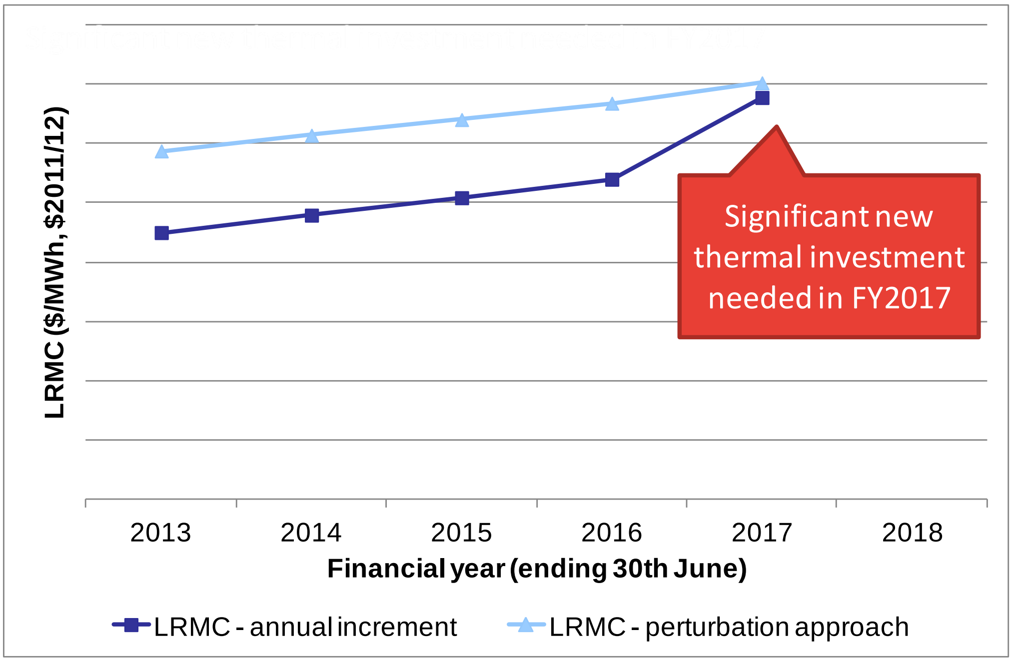
permanent increase is the same 'shape' as the residential load. Or, using Technique 2, it may be possible to allocate a share of the cost of the next increment of capacity to regulated customers based on matching the generation and load profile of residential customers. However this ultimately involves pre-determination of a particular technology mix, which is subjective. Indeed, Technique 2 is more problematic than Technique 1 because it requires the selection of a candidate plant as well as the time at which the plant is required.

Second, by positing a permanent increase in demand, Technique 1 (the perturbation approach) results in an estimate of LRMC that incorporates a capital component in each year's estimate of LRMC; but, where the capital investment is not required for a number of years, the capital component will be discounted.

This can be seen in Figure 47, which provides an illustrative comparison of the LRMC for the NEM under a perturbation approach and under an approach in which the demand increment is only for the year in question (and not permanent). Based on this illustrative modelling, new investment to meet demand is not required in the NEM until 2017. Where the LRMC is based on annual increases in demand, this results in the capital component first appearing in the LRMC in 2017, leading to a significant increase in the LRMC from 2016 to 2017. Using the perturbation approach, however, a capital component is incorporated in the LRMC for all years, despite the fact that new investment is not required until 2017 (the capital component in early years is a discounted capital cost, resulting in a gradual increase in the capital component of costs). While either of these approaches might be valid as an indicator of where market prices (in a competitive and efficient market) might be expected to head in the long term, there are issues with using either as an indicator of short-term market prices. In particular, the LRMC under the perturbation approach is unlikely to adequately capture the effect of excess supply on market prices. Conversely, in years where excess supply exists in the market, the LRMC under the annual incremental approach will not include capital costs associated with the supply of wholesale energy.

Appendix A – Turvey methodology and results

Figure 47: LRMC – annual and permanent increase in output



Source: Frontier Economics

Another issue with the perturbation approach is that the results can be sensitive to the size of the permanent increment to output (in the case of electricity modelling, the size of the permanent increment to system demand). For example, a relatively small perturbation may mean that it is only economic to invest in low capital/high operating cost plant (e.g. peakers), while a larger perturbation may result in the development of mid-merit CCGT plants and peakers and an even larger perturbation may result in the development of base, mid-merit and peaking plant. This sensitivity derives from the scale economies of plant as well as the scope economies that exist between the new investment and the rest of the power system. One way of overcoming this would be to provide the LRMC model the option of picking up very small increments of each plant type for each period. However, this remedy results in the modelling becoming more abstract than is desirable. Other issues arise with regard to the duration of the perturbation and the modelling period and whether the perturbation should be in absolute (MW) or relative (percentage) terms.

A further drawback lies in the practical application of the Turvey LRMC approach to determining wholesale energy costs in the short term (such as part of a regulated price determination). Because the estimate of Turvey LRMC in the short term reflects costs that occur far into the future the result is directly dependent on long term input assumptions, for example fuel costs and carbon price paths. This makes the Turvey LRMC estimate more sensitive to input assumptions as more assumptions over longer timeframes (involving greater uncertainty) are critical to the result. Alternative approaches to calculating wholesale energy costs – such as the stand-alone LRMC and a market based approach – typically only require estimates of input assumption for the year for which wholesale energy costs are being estimated. This is a smaller set of inputs about which far greater levels of certainty are possible (as only short term values are required).

Because of the sensitivity of the Turvey LRMC approach to the size of the perturbation, the difficulties of applying the incremental approaches to determining the LRMC for a regulated load shape and the volatility that the Turvey LRMC approach can produce over time, our primary approaches to estimating wholesale energy costs are the stand-alone LRMC and market-based approaches, as discussed in the main body of this report.

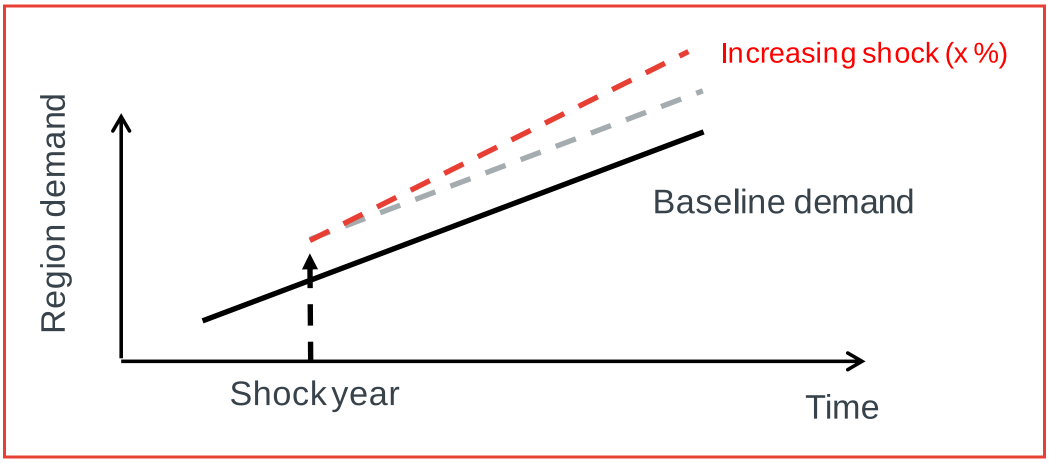
Frontier's implementation of the Turvey LRMC

Frontier Economics' Turvey modelling uses the same underlying *WHIRLYGIG* case (and market assumptions) as the incremental LRMC modelling discussed in Section 2. This case represents the baseline case against which a shock is applied in the Turvey modelling.

We have made the following assumptions regarding the demand shock used to calculate the Turvey LRMC:

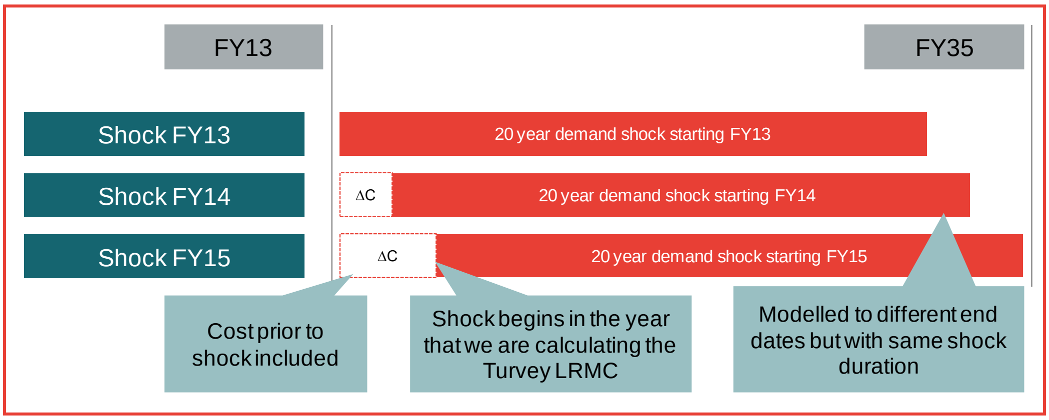
- **Nature:** we have used a relative shock in percentage terms (as opposed to an absolute shock in MW terms, see Figure 48)
- **Magnitude:** the shock was assumed to be 3% of demand within a particular region across the year (not just at peak times), this approach is equivalent to adding an increment of demand to each region that is the same shape as demand in that region
- **Duration:** the shock was assumed to persist for 20 years, this involved calculating the Turvey LRMC for different starting shock years where each shock persisted for 20 years (see Figure 49)

Figure 48: Nature of the demand shock



Source: Frontier Economics

Figure 49: Duration of the demand shock and modelling period



Source: Frontier Economics

We conducted analysis around how the demand shock was applied and determined that the approach outlined above was the most robust in terms of the final Turvey LRMC estimate. We also considered cases where existing plant were allowed to retire, however such an approach added an additional level of complexity to the analysis and was not pursued. The modelling presented here assumes that all existing plant remain in operation for the entire modelling period unless they are registered to retire with AEMO (however uneconomic plant cease to be dispatched in the long-term).

Modelling involved shocking each region separately (as opposed to co-incidentally) starting from each of the three forecast years (2012/13 to 2014/15 inclusive) for which a Turvey LRMC was estimated.

Modelling results

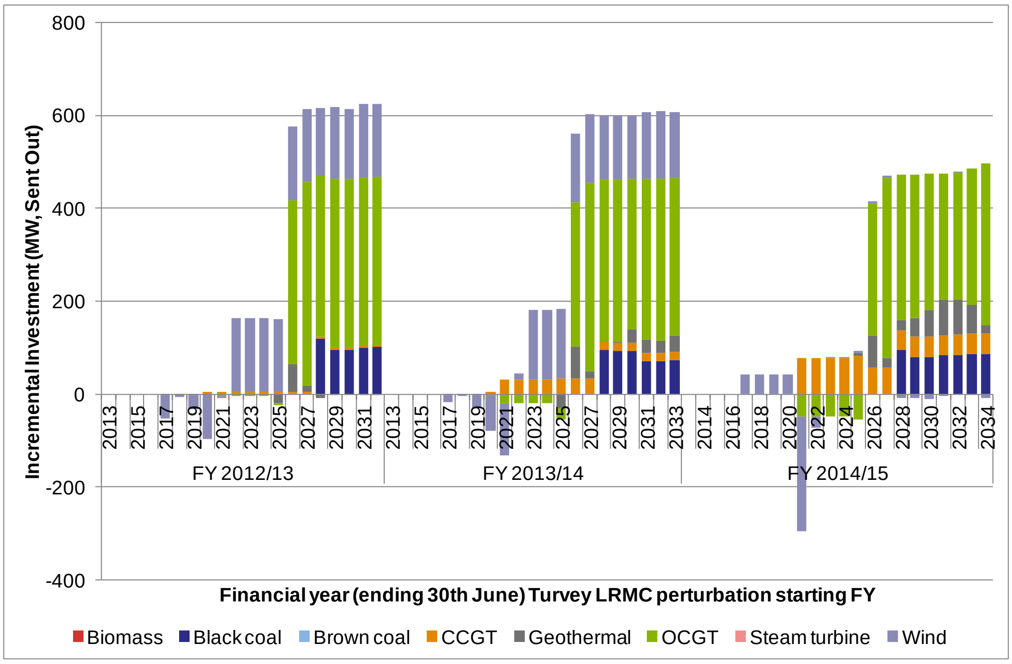
This section presents the results of our Turvey LRMC analysis. Estimates of the Turvey LRMC for all NEM regions are presented. Detailed discussion of outcomes that drive the results are presented with respect to NSW only for simplicity. Results are initially presented for the Planning Scenario.

Planning Scenario

Figure 50 presents the change in investment in the shock case relative to the no shock baseline case. Results are presented for the 20 year period associated with each year for which we have modelled the Turvey LRMC (that is, the 20 year period following a shock starting in 2012/13, the 20 year period following a shock starting in 2013/14 and the 20 year period following a shock starting in 2014/15). Positive values on the chart represent an increase in investment in the shock case.

Figure 50 shows that for all three shock year cases, there is little change in investment upon commencement of the demand shock. However, it is also clear that delaying the start date of the shock defers the point at which investment occurs and/or changes the investment mix. For example, for a shock starting in 2012/13, incremental wind capacity is built in 2021/22 and incremental OCGT in 2025/26. For the shock starting in 2013/14, the wind capacity is deferred to 2022/23 and OCGT still enters in 2025/26. When the shock starts in 2014/15 the investment mix alters significantly with CCGT and Geothermal investment being brought forward. All three cases also involve reductions in investment (shown as negative values on the chart) in some technologies, usually wind capacity, across the modelling period. This reflects the fact that the impact of a demand shock in a single region which is part of a multi-regional market with additional regulatory constraints like the LRET target is not necessarily straightforward.

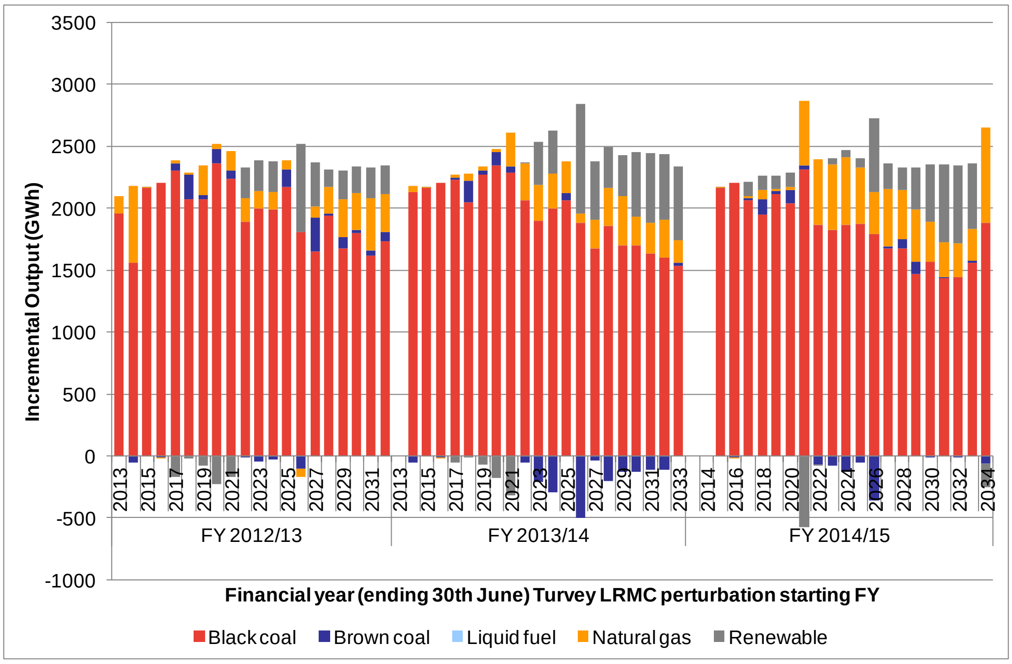
Figure 50: Change in investment relative to no shock case – NSW, Scenario 3



Source: Frontier Economics

Figure 51 presents the change in dispatch in the shock case relative to the no shock baseline case in a manner analogous to Figure 50. Incremental demand from the shock is predominantly met by increased output from existing coal-fired stations in NSW (the cheapest in-state, baseload generation). In the later years of the modelling period incremental demand is met by the new investment shown in Figure 50. This is most clearly seen in the increase in CCGT output for the case where the shock starts in 2014/15.

Figure 51: Change in dispatch relative to no shock case – NSW, Scenario 3



Source: Frontier Economics

Figure 52 shows the change in annual total cost (in terms of fixed and variable costs in *WHIRLYGIG*) broken down by component. It is these costs that are discounted in the numerator of the Turvey LRMC, given by:

$$Turvey\ LRMC = \frac{NPV(cost)}{NPV(demand\ shock)}$$

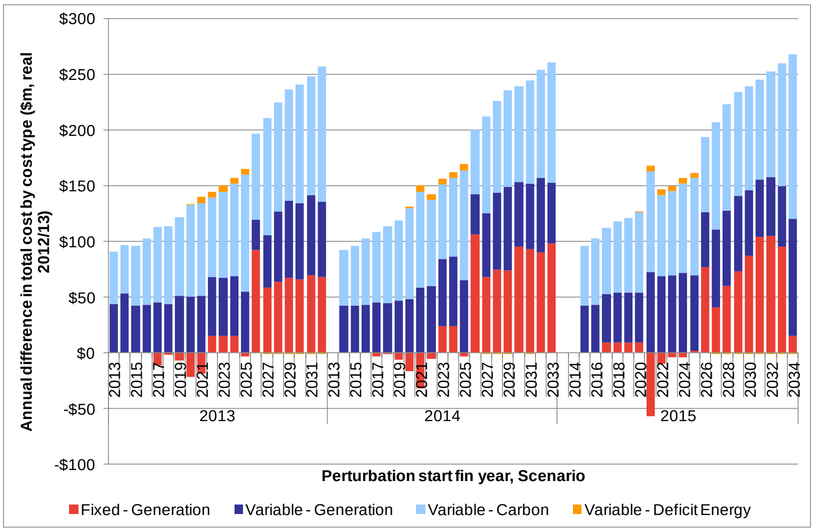
With regard to changes in fixed costs, these only arise from changes in new investment, this reflects our treatment of fixed costs for the existing plant stock as being sunk.

Figure 53 shows the Turvey LRMC for each shock year broken down by component. Turvey LRMC estimates are around $60-65/MWh for the NSW system load shape. Estimates rise as the shock year is delayed reflecting less discounting of the fixed costs of future investment to meet the demand shock. Carbon makes up approximately 50% of this cost. Due to the fact that significant new investment is not needed until the mid-2020s, the Turvey LRMC estimate reflects a small fixed cost component consistent with discounting incremental fixed costs by more than 10 years.

These LRMC estimates are highly consistent with current market prices for forward flat swaps in NSW; the Turvey LRMC estimate, which reflects no need for additional capacity to meet the shock until post-2025, is producing a result similar to the price of hedging contracts currently offered in an oversupplied market.

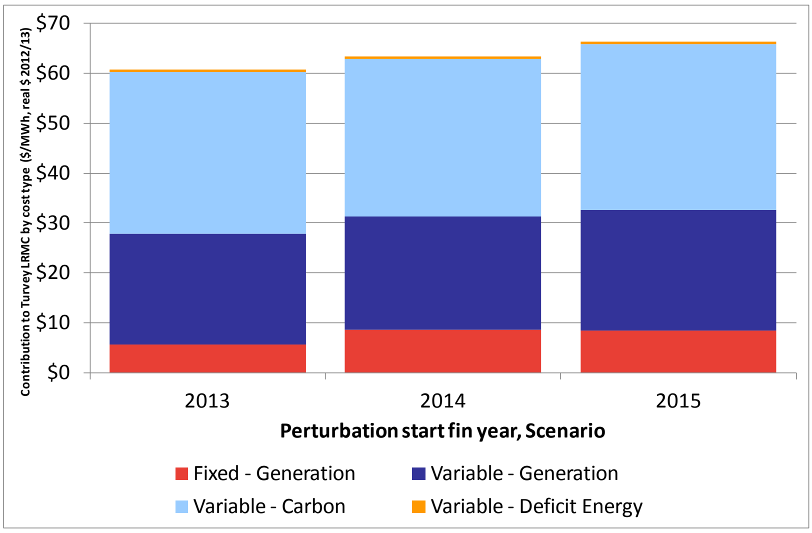
Appendix A – Turvey methodology and results

Figure 52: Change in total cost relative to no shock case – NSW, Scenario 3



Source: Frontier Economics

Figure 53: Turvey LRMC by cost component – NSW, Scenario 3

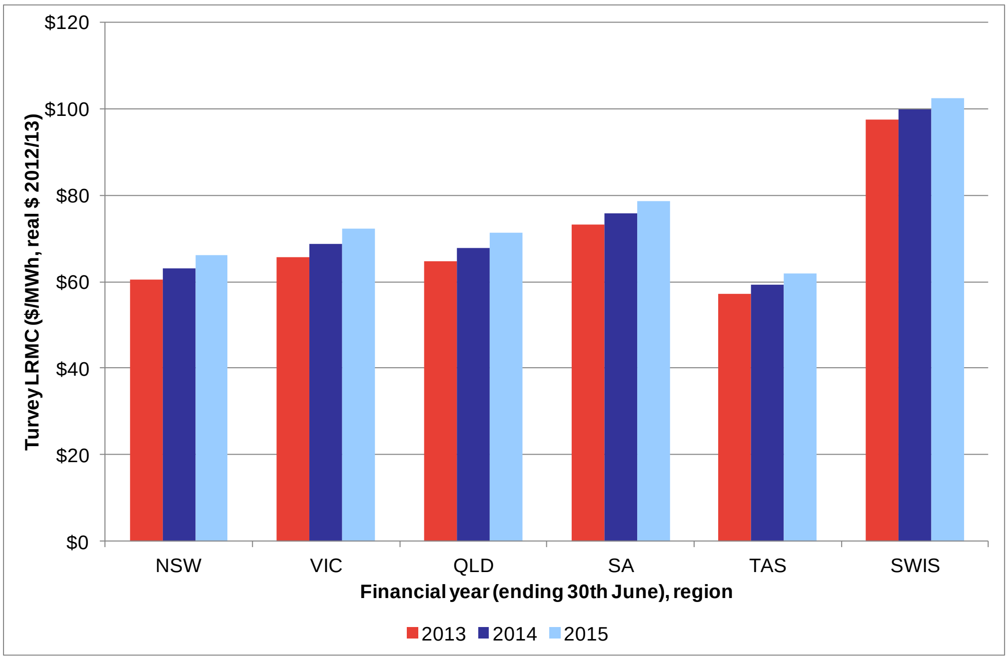


Source: Frontier Economics

Figure 54 presents the Turvey LRMC estimates for each shock year and region for the Planning Scenario. NSW, Victoria and Queensland have similar LRMC levels. Tasmania has a relatively lower Turvey LRMC estimate reflecting lower costs in that region and an absence of the need for new investment over the 20 year shock period. South Australia and Western Australia have higher estimates reflecting the higher cost structures in those regions and higher level of assumed demand growth.

Appendix A – Turvey methodology and results

Figure 54: Turvey LRMC estimates, Scenario 3



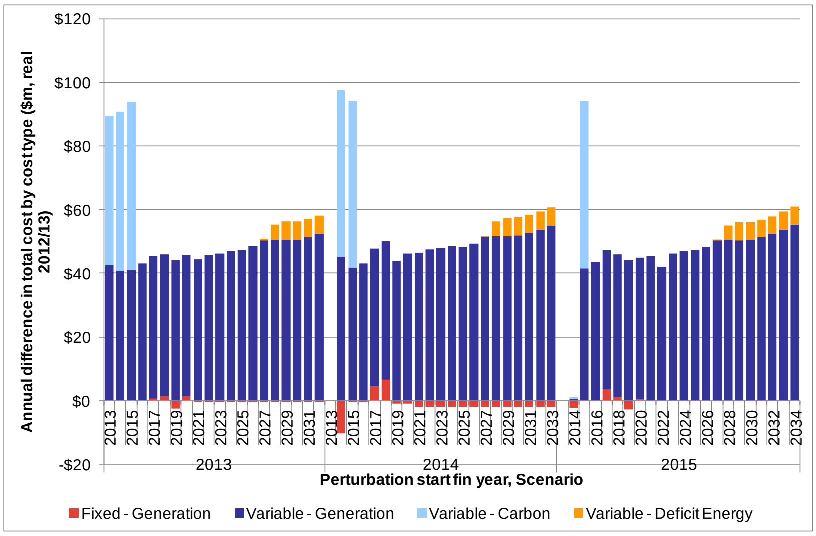
Source: Frontier Economics

Slow Rate of Change Scenario

Figure 55 and Figure 56 present the change in total cost and Turvey LRMC estimates by cost component for NSW in the Slow Rate of Change Scenario. The biggest difference is with regard to the carbon cost component. The Slow Rate of Change Scenario assumes that there will be no carbon price beyond the fixed price period, which can be clearly seen in Figure 55. While carbon is present in the annual result for the 2012/13 to 2014/15 years of the fixed price period, it is absent thereafter. This results in the carbon cost component for the Turvey LRMC being much lower for the Slow Rate of Change Scenario relative to the Planning Scenario (as shown by comparing Figure 56 and Figure 53).

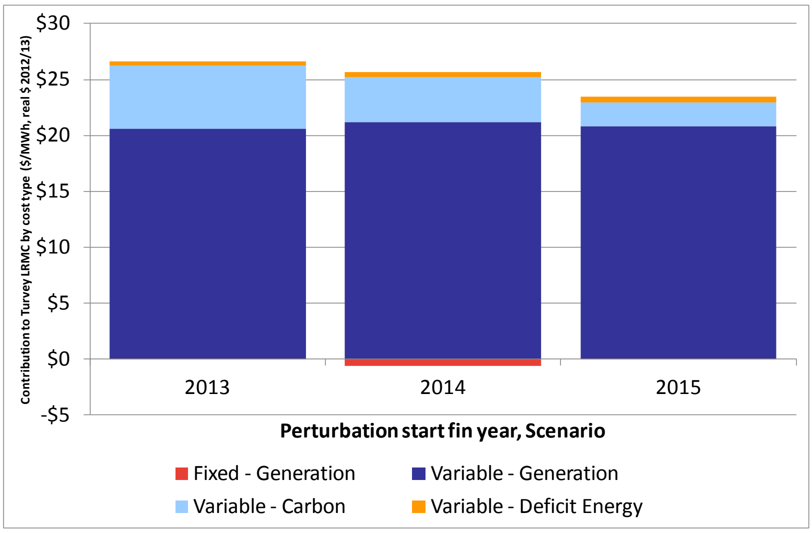
This outcome highlights the dependence of the Turvey LRMC approach on long term estimates of the input assumptions. Because the Turvey LRMC approach measures increases in costs over the full modelling period (because the increment to demand is permanent) the approach reflects costs throughout the modelling period. In the Slow Rate of Change Scenario, the assumption that the carbon price will be zero from 2015/16 onwards, means that for most of the years of the modelling period there is no carbon price and therefore no carbon cost faced by generators. In short, the Turvey LRMC approach will not reflect the impact of this years' carbon price but the impact of average carbon prices over the modelling period. In some situations, such as electricity price regulation, this outcome is likely to be problematic because if will not be reflective of current costs.

Figure 55: Change in total cost relative to no shock case – NSW, Scenario 5



Source: Frontier Economics

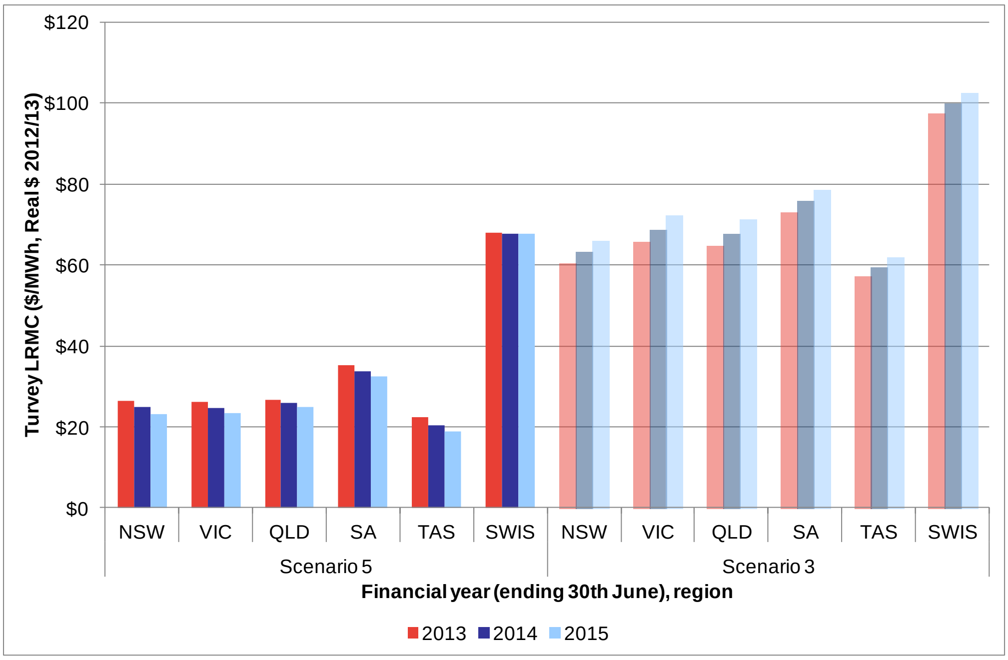
Figure 56: Turvey LRMC by cost component – NSW, Scenario 5



Source: Frontier Economics

Figure 57 presents the Turvey LRMC outcome for both scenarios across all years and regions. LRMC outcomes in the Slow Rate of Change Scenario are significantly lower than in the Planning Scenario. This is primarily driven by assumptions around carbon prices, but also influenced by the relatively lower demand and input cost assumptions in the Slow Rate of Change Scenario.

Figure 57: Turvey LRMC – NSW, Scenario 5 (Scenario 3 included for comparison)



Source: Frontier Economics

Conclusion

The Turvey LRMC provides an alternative approach to estimating wholesale energy costs. By incorporating the discounted fixed costs associated with the next increment of investment into the estimate of LRMC, this approach produces a marginal cost of electricity that reflects the variable costs of an existing 'real-world' system as well as the fixed costs associated with the next increment of capacity within the same 'real-world' system. Conceptually, this approach avoids the abstraction of the stand-alone approach and the potential for the market-based approach to produce energy cost estimates closer to SRMC at times of oversupply. The Turvey LRMC approach instead incorporates the costs associated with an actual system's need for new capacity in the long term.

From a practical perspective, there are a few drawbacks. Theoretically, the approach is more aligned with regulated, centrally planned markets where new investment is subject to greater certainty. There are numerous subjective assumptions required with regard to the method itself – such as the nature (absolute MW or percentage changes), magnitude and duration of the demand shock, all of which can significantly affect the ultimate LRMC estimate. The most problematic aspect within the context of electricity price regulation is the requirement for long term forecasts of all inputs needed to model the market in question. Forecasts of fuel costs and the carbon price path become more uncertain the longer the forecast period. Yet the Turvey LRMC is highly dependent on long term forecast assumptions, as was seen in the impact of carbon in the Slow Rate of Change Scenario modelling. In the Slow Rate of Change Scenario, the assumption that carbon prices will be zero in the future leads to an under-recovery of carbon costs today. This result would not pass the 'sanity test' in many situations, particularly electricity price regulation.

Ultimately, the Turvey approach is an interesting concept and a useful tool for analysing long-term outcomes in electricity markets and the impacts of different policies. Its applicability and practicality as a method for determining wholesale energy costs within the context of electricity price regulation is less certain.

Appendix A – Turvey methodology and results

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