Energy costs – annual review for 2012/13

A FINAL REPORT PREPARED FOR IPART

June 2012

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Figures

Tables

1 Introduction

The Independent Pricing and Regulatory Tribunal (IPART) has determined regulated electricity tariffs to apply for the period between 1 July 2010 and 30 June 2013 for customers of the Standard Retailers operating in NSW who are supplied on standard contracts (**2010 Determination**). Frontier Economics advised IPART on the total energy cost allowance for 2010/11 to 2012/13 to be incorporated by IPART in its 2010 Determination.[1]

IPART's 2010 Determination provided for annual reviews of the total energy cost allowance for 2011/12 and 2012/13 for each Standard Retailer.

1.1 Frontier Economics' engagement

Frontier Economics has been engaged by IPART to provide advice on the annual reviews of the total energy cost allowance. Our advice to IPART for the annual review of the total energy purchase cost allowance is to consist of estimates of:

- the long run marginal cost (LRMC) of generation to meet the regulated load of each of the Standard Retailers
- the market-based energy purchase costs to meet the regulated load of each of the Standard Retailers (using the conservative point on an efficient frontier curve)
- the volatility allowance associated with the market-based energy purchase cost for each Standard Retailer (using the conservative point on an efficient frontier)
- the cost allowances for complying with obligations under the LRET, the SRES and the ESS.

Last year we advised IPART on the total energy purchase cost allowance for their 2011 annual review,[2] which covered both 2011/12 and 2012/13. For IPART's

1 Frontier Economics, *Energy purchase costs*, A Final Report prepared for IPART, March 2010. Available at:

http://www.ipart.nsw.gov.au/files/Consultant%20Report%20-%20Frontier%20Economics%20-%20Final%20Report%20-%20Energy%20Purchase%20Costs%20-%20March%202010%20-%20WEBSITE%20DOCUMENT.PDF

2 Frontier Economics, *Energy costs – annual review for 2011/12 and 2012/13*, A Final Report prepared for IPART, June 2011.

http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews_All/Retail_Pricing/Changes_in_regulated_electricity_retail_prices_from_1_July_2011/14_Jun_2011_-_Frontier_Economics_Report_on_Energy_Costs_Annual_Review/Consultant_Report_-_Energy_Costs_Annual_Review_for_2011-12_and_2012-13_-_Frontier_Economics_-_June_2011

2012 annual review, we are advising IPART on the total energy purchase cost allowance for 2012/13.

1.2 This final report

This final report sets out Frontier Economics' advice to IPART on the total energy cost allowance for 2012/13, for the purposes of IPART's 2012 annual review.

The modelling results set out in this final report are based on the modelling methodology and assumptions adopted by Frontier Economics for its modelling during the 2010 Determination, as set out in Frontier Economics' final report for the 2010 Determination (**Frontier Final Report for 2010**)[3] and Frontier Economics' modelling methodology and assumptions report for the 2010 Determination (**Frontier Assumptions Report for 2010**).[4] For this reason, for a detailed understanding of the modelling methodology and the modelling assumptions underpinning the results set out in this report, this report should be read in conjunction with the Frontier Final Report for 2010 and the Frontier Assumptions Report for 2010.

In keeping with the intention of the annual review, a number of modelling assumptions have been updated since the 2010 Determination and since the 2011 annual review in order to take account of the availability of better information over this period. Where input assumptions have been updated, the updated assumptions are set out in this report.

1.2.1 What has changed since the draft report?

Prior to the release of this final report, we provided a draft report to IPART.[5] This draft report was released by IPART for public consultation.

This final report updates Frontier Economics' advice to IPART on the total energy cost allowance for 2012/13. Since the release of Frontier Economics' draft report, IPART have updated the following key input assumptions:

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3 Frontier Economics, *Energy purchase costs*, A Final Report prepared for IPART, March 2010.

4 Frontier Economics, *Modelling methodology and assumptions*, A Report for IPART, August 2009. Available at:

http://www.ipart.nsw.gov.au/files/Review%20of%20regulated%20electricity%20retail%20tariffs%20and%20charges%202010%20to%202013%20-%20Frontier%20Economics%20%20-%20electricity%20purchase%20cost%20allowance%20%20-%20methodology%20and%20assumptions%20report%20

Note that this modelling and assumptions report was updated by addenda also available on IPART's website.

5 Frontier Economics, *Energy costs – annual review for 2012/13*, A Draft Report prepared for IPART, April 2012 (**Frontier Annual Review Draft Report**).

- the weighted average cost of capital (WACC) for generation, which has been revised from 6.5% to 7.1%
- the rate of inflation from 2010/11 to 2011/12 and 2011/12 to 2012/13, which has been revised from 3.1% to 1.6%
- the rate of escalation of coal costs of production, which has been revised from 4.1% to 4.3%
- the transmission and distribution loss factors applicable to each Standard Retailer (which are used for the purposes of our analysis only to calculate the cost of complying with the LRET and the SRES, but are also used by IPART for other purposes)
- the non-binding estimate of the STP, which has been updated from 7.87 per cent to 7.94 per cent.

These updated input assumptions have resulted in us updating our estimates of the following:

- **The long run marginal cost (LRMC) of generation to meet the regulated load of each of the Standard Retailers**. The LRMC is updated to reflect the revised WACC for generation and the revised inflation and coal escalation. Our updated advice on the LRMC of generation to meet the regulated load is set out in Section 4.
- **The market-based energy purchase costs to meet the regulated load of each of the Standard Retailers**. The market-based energy purchase cost is updated to reflect the revised inflation. Our updated advice on the market-based energy purchase costs is set out in Section 5.
- **The volatility premium**. The volatility premium is updated to reflect the updated market-based energy purchase cost and the revised WACC for generation. Our updated advice on the volatility allowance is set out in Section 5.5.
- **The cost allowances for complying with obligations under the LRET and SRES**. These LRMC of meeting the LRET is updated to reflect the revised WACC for generation and the revised inflation and coal escalation (just as the LRMC of generation to meet the regulated load is updated to account for these changes). The real STC cost is also updated to reflect the revised inflation. The cost of complying with the LRET and the SRES (measured at the regional reference node) is updated to reflect updated transmission loss factors. Our updated advice on these cost allowances for the LRET and SRES is set out in Section 7.

1.3 Structure of this report

This report is structured as follows:

- Section 2 provides a brief overview of the two approaches used by Frontier Economics to estimate the energy purchase cost allowance, and the modelling methodologies used under these two approaches
- Section 3 sets out the input assumptions that have been updated for use in the modelling for this 2012 annual review
- Section 4 sets out the results of Frontier Economics' modelling of the LRMC of supplying the Standard Retailers' regulated load
- Section 5 sets out the results of Frontier Economics' modelling of the market-based energy purchase cost of supplying the Standard Retailer's regulated load
- Section 6 summarises the impact of carbon pricing in the stand-alone LRMC, wholesale pool price and energy purchase cost results
- Section 7 sets out Frontier Economics' advice on the allowance for the costs of complying with the LRET, the SRES and the ESS
- Section 8 provides a summary of Frontier Economics' advice.

More detail on input assumptions used by Frontier Economics is provided in a spreadsheet released with this report.

2 Overview of modelling approach

As discussed in Section 1.1, Frontier Economics' advice to IPART for this annual review is to consider two approaches to the energy purchase cost allowance:

- the LRMC of generating plant to supply the Standard Retailers' regulated load
- the market-based energy purchase cost to supply the Standard Retailers' regulated load.

This section provides a brief overview of the modelling approach used by Frontier Economics to estimate the LRMC to supply the Standard Retailers' regulated load and the market-based energy purchase cost to supply the Standard Retailers' regulated load.

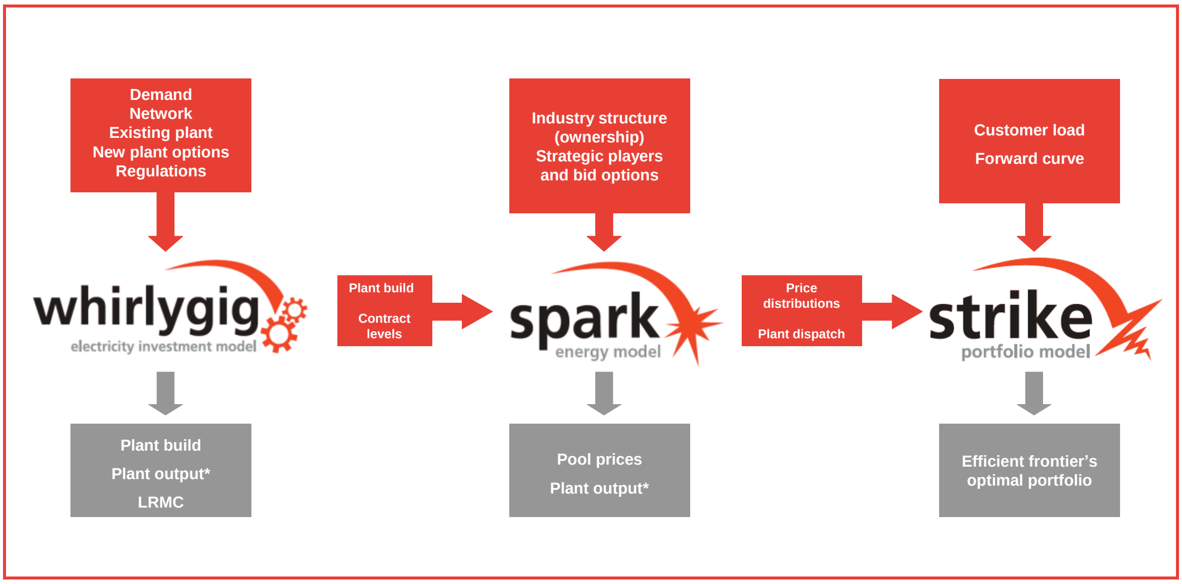
2.1 Frontier Economics' energy market models

For the purposes of estimating energy costs, Frontier Economics adopts a three-staged modelling approach, which makes use of three inter-related electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*. These models were used in Frontier Economics' advice for the 2010 Determination and for the 2011 annual review. The key features of these models are as follows:

- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* provides an estimate of LRMC, including the cost of any plant required to meet modelled regulatory obligations.
- *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 levels of variation of 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.*

As discussed, there are essentially two aspects to Frontier Economics' analysis for this annual review: an estimate of LRMC and an estimate of market-based energy purchase costs.

To estimate LRMC, Frontier Economics uses *WHIRLYGIG*, which identifies the least cost mix of existing plant and new plant options to meet electricity demand. Frontier Economics uses *WHIRLYGIG* in two different ways:

- Frontier Economics estimates the LRMC of serving the Standard Retailers' regulated load using a stand-alone LRMC approach (which assumes that there is no existing plant to meet the regulated load). Under this approach, the load used to estimate LRMC is the Standard Retailers' regulated load, and the LRMC is the cost of serving an incremental increase to this load shape with a hypothetical new least-cost generation system.
- Frontier Economics estimates the LRMC of meeting the LRET using the incremental LRMC approach (which assumes that the existing mix of generation plant, regions and interconnectors in the NEM is in place). Under this approach, the load used to estimate the LRMC is the system load in each region, and the LRMC of meeting the LRET is the marginal cost of an incremental increase in the relevant target.

To estimate the market-based energy purchase costs, Frontier Economics uses *STRIKE*, which identifies the least cost portfolio of electricity purchasing options for each level of risk. An important input into the estimation of energy purchase costs is a forecast of future spot prices. In order to forecast spot prices, Frontier Economics uses *SPARK*, which applies game theoretic techniques to forecast spot price outcomes.

3 Input assumptions

IPART's 2010 Determination outlines those input assumptions that IPART will review as part of its annual review process. Since IPART completed the 2010 Determination, and since the completion of the 2011 annual review, a number of sources of new information regarding key modelling assumptions have become available.

In considering the appropriateness of these sources of modelling assumptions, Frontier Economics' advice to IPART has been guided by the same objectives as were adopted for the 2010 Determination:

- To the extent possible, we have adopted input assumptions that are publicly available. This increases the transparency of our modelling results
- To the extent possible, we have adopted input assumptions that are more likely to be used reasonably broadly across the industry. Adopting input assumptions from these sources is likely to better facilitate the comparison of our modelling results with forecasts or modelling from other sources
- To the extent possible, we have used the most recent input assumptions available at the time the modelling is undertaken (within the constraint of using publicly available and industry standard assumptions)

As noted in the Frontier Annual Review Draft Report, one possible source of input assumptions for this annual review is the information released by AEMO as part of the 2011 National Transmission Network Development Plan (NTNDP). As part of the NTNDP, AEMO has released consultant reports on cost and technical information relevant to the NEM. These reports on cost and technical information are intended to replace the similar reports on cost and technical information that were prepared for the Inter-Regional Planning Committee (IRPC). Given that ACIL Tasman's 2009 report to the IRPC[6] was relied on as a source of input assumptions for the 2010 Determination, it might be expected that the equivalent report for the NTNDP would provide a useful source of updated input assumptions. However, as noted in our reports for the 2011 annual review, the 2010 and 2011 NTNDPs both considered the development of the NEM over the next 20 years by considering a set of five scenarios, each of which reflect "different combinations of the principal energy sector and national transmission network development drivers".[7] AEMO makes clear that none of these five scenarios is a base case but neither does each

6 ACIL Tasman, *Fuel resource, new entrant and generation costs in the NEM*, Final Report, Prepared for the Inter-Regional Planning Committee, April 2009 (**ACIL 2009 Report**).

7 AEMO, *National Transmission Network Development Plan*, 2010, page 22.

scenario have an equal probability of occurring.[8] What this means is that no single scenario from the 2010 or 2011 NTNDP – and therefore no single set of input assumptions – can be considered an effort to best reflect likely future outcomes in the market. Yet, for the purposes of this annual review, the input assumptions adopted should reflect a view of the most likely future outcomes.

Since the release of the draft report, stakeholders have commented that the 2012 NTNDP now includes six scenarios, one of which is identified as the "planning scenario". AEMO note that the planning scenario "represents our best estimate of how the future will develop given the currently known and well advanced and anticipated changes."[9] This raises the prospect that the 2012 NTNDP might ultimately be an appropriate source of input assumptions. However, IPART considers that there are some issues with relying on the 2012 NTNDP for this annual review. These issues, and the expected results of relying on the 2012 NTNDP, are discussed in Section 4.7.

Based on its view that the input assumptions from the 2010 and 2011 NTNTP were not appropriate for use in the determination of regulated retail tariffs, for the 2011 annual review IPART decided to update input assumptions for cost and technical information relevant to the NEM by relying, to a large extent, on an ACIL Tasman report to the QCA.[10] For the purpose of this 2012 annual review, IPART have decided to again rely on the ACIL Report for the QCA. As a result, for this 2012 annual review IPART have decided to rely on the following sources:

- AEMO, *Electricity Statement of Opportunities for the National Electricity Market*, 2011 (**AEMO 2011 ESOO**). This is the source for system demand forecasts used in Frontier Economics' modelling. This updates the 2009 ESOO, which was relied on for the 2010 Determination, and the 2010 ESOO, which was relied on for the 2011 Determination.
- ACIL Tasman, *Calculation of energy costs for 2011-12 BRCI*, Draft Report, Prepared for the Queensland Competition Authority, December 2010 (**ACIL Report for the QCA**).[11] ACIL Tasman note in this report that, to a large extent, the input assumptions from the ACIL 2009 Report continue to be relevant and, for this reason, have been adopted in the ACIL Report for the QCA.

8 AEMO, *National Transmission Network Development Plan*, 2010, page 23.

9 AEMO, *2012 Scenarios Descriptions*, 23 January 2012.

10 ACIL Tasman, *Calculation of energy costs for 2011-12 BRCI*, Draft Report, Prepared for the Queensland Competition Authority, December 2010.

11 At the time of writing, ACIL Tasman's final report to the QCA is not publicly available.

As well as relying on the report itself, Frontier Economics has, in some cases, used input assumptions from spreadsheets accompanying the ACIL Report for the QCA that were provided to IPART by ACIL Tasman.

- Australian Government, *Securing a clear energy future*, 2011 and Commonwealth Government, *Strong Growth, Low Pollution*. These are the sources for the fixed carbon price during the initial three years of the carbon price and the forecasts carbon price thereafter.

This section sets out the updated modelling assumptions that Frontier Economics has used in its modelling for this 2012 annual review. Modelling assumptions that are not explicitly discussed in this section have not been updated since the 2010 Determination.

A detailed set of input assumptions is set out in the assumptions spreadsheets released with this final report.

3.1 Inflation rate

Frontier Economics' advice to IPART in this final report is provided in 2011/12 dollars. Where it has been necessary to convert costs or prices into 2011/12 dollars, Frontier Economics has used the following inflation rates, as advised by IPART:

- 1.6% from 2010/11 to 2011/12 and 2011/12 to 2012/13
- 2.8% for each year thereafter.

The exception to this has been where converting input assumptions from the ACIL Report for the QCA into 2010/11 dollars. In this case, the inflation rate of 2.5% adopted by ACIL Tasman in that report has been used. These inflation assumptions will be updated prior to the release of the final report.

3.2 Discount rate

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.

Frontier has assumed a pre-tax, real discount rate of 7.1% to discount future values for the optimisation process. This is consistent with IPART's advice for this annual review on the appropriate discount rate for the purposes of electricity generation assets.

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*.

Frontier Economics has used energy and maximum demand projections for each NEM region based on the AEMO 2011 ESOO. For this final report, Frontier Economics has used the low growth, 50% POE projections from the AEMO 2011 ESOO for the purposes of determining the energy and maximum demand projections. However, Frontier Economics has also used the medium and low growth, 10% POE projections for summer and winter for the purpose of modelling reserve constraints. 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.

3.4 Existing NEM generation plant

Frontier Economics has used the latest information available from AEMO's website[12] 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.

In addition, Frontier Economics' 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 – Frontier Economics has used the same information on outage rates as was used for the 2010 Determination (sourced from NEMMCo)
- Heat rate – Frontier Economics has used the information on the heat rate for existing generators that is set out in the ACIL Report for the QCA
- Emissions intensity – Frontier Economics has used the information on emissions intensity for existing generators that is set out in the spreadsheets accompanying the ACIL Report for the QCA that were provided to IPART by ACIL Tasman

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

http://www.aemo.com.au/data/gendata.shtml

- Auxiliary power – Frontier Economics has used the information on use of auxiliary power for existing generators that is set out in the ACIL Report for the QCA

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

- Variable operating and maintenance costs – Frontier Economics has used the information on variable operating and maintenance costs for existing generators that is set out in the ACIL Report for the QCA. Frontier Economics has assumed that variable operating and maintenance costs remain flat in real terms at these levels over time (which is consistent with the spreadsheet provided to IPART by ACIL Tasman)
- Fuel costs – Frontier Economics has used the information on fuel costs for existing generators that is set out in the ACIL Report for the QCA. Where the fuel costs for existing generators are not stated in the ACIL Report for the QCA, Frontier has used the information on fuel costs for existing generators that is set out in the more detailed accompanying spreadsheet that was provided to IPART by ACIL Tasman

In addition to these assumptions on cost and technical information, Frontier Economics' modelling also requires information on ownership of existing generation plant. Since the 2010 Determination, the following changes have occurred, or have been announced by government:

- The NSW Energy Reform Strategy, which has resulted in the transfer of bidding control of Eraring and Shoalhaven power stations to Origin Energy and of Mt Piper and Wallerawang power stations to TRUenergy
- The Queensland Government has restructured the three Government-owned generators in Queensland (CS Energy, Stanwell and Tarong Energy) into two Government-owned generators.[13] This restructure took effect from 1 July 2011.

3.5 New generation plant

Frontier Economics has used the ACIL Report for the QCA as the basis for input assumptions for new entrant generation plant.

The technologies that will be available as options over the modelling period are, therefore, black coal, brown coal, CCGT, OCGT, wind, hydro and biomass. Frontier Economics has not included geothermal as an option over the modelling period because Frontier Economics considers it unrealistic that geothermal will be available to any significant degree over the modelling period at the capital cost

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13 Office of Government Owner Corporations, *Successful Reorganisation of the Queensland Government Owned Corporation Generators*, 1 July 2011.

in the ACIL Report for the QCA (which is around $5,000/kW). At this capital cost, and taking account of the other geothermal assumptions in the ACIL Report for the QCA (particularly availability), geothermal will be lower cost than any other generation technology in the NEM once a carbon price is introduced, and will be built in preference to coal-fired generation, gas-fired generation and all other renewable technologies. It is Frontier Economics' opinion that the cost and availability of geothermal over the modelling period make it unlikely that investment in geothermal over this period will dominate investment in all other generation technologies.

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

The required technical information for new entrant generation plant includes the following:

- Expected outage rates – Frontier Economics has used the same information on outage rates as was used for the 2010 Determination (sourced from NEMMCo)
- Heat rate – Frontier Economics has used the information on the heat rate for new entrant generators that is set out in the ACIL Report for the QCA
- Emissions intensity – information on emissions intensity for new entrant generators is not set out in the ACIL Report for the QCA. Therefore, Frontier Economics has assumed that the emissions intensity for a new plant will be the same as the emissions intensity of the most recently built plant of the same technology
- Auxiliary power – Frontier Economics has used the information on use of auxiliary power for new entrant generators that is set out in the ACIL Report for the QCA.

The required cost information for new entrant generation plant is the following:

- Capital costs – Frontier Economics has used the information on capital costs for new entrant generations that is set out in the ACIL Report for the QCA. However, rather than using the learning curve for capital costs implied by the ACIL Report for the QCA, Frontier Economics has applied the same information on learning curves as was used for the 2010 Determination, and applied these learning curves to the capital cost for 2011/12 from the ACIL Report for the QCA
- Fixed operating and maintenance costs – Frontier Economics has used the information on fixed operating and maintenance costs for new entrant generators that is set out in the ACIL Report for the QCA. Frontier Economics has assumed that fixed operating and maintenance costs remain

flat in real terms at these levels over time (which is consistent with the spreadsheet provided to IPART by ACIL Tasman)

- Variable operating and maintenance costs – Frontier Economics has used the information on variable operating and maintenance costs for new entrant generators that is set out in the ACIL Report for the QCA. Frontier Economics has assumed that variable operating and maintenance costs remain flat in real terms at these levels over time (which is consistent with the spreadsheet provided to IPART by ACIL Tasman)
- Gas costs – Frontier Economics has used the information on new entrant gas costs that is set out in the ACIL Report for the QCA
- Biomass costs – Frontier Economics has used the information on new entrant biomass costs that is set out in the ACIL Report for the QCA.
- Coal costs – neither the ACIL Report for the QCA nor the spreadsheet provided to IPART by ACIL Tasman provide new entrant coal costs. The ACIL Report for the QCA does contain a set of coal prices that ACIL uses in its LRMC modelling. However, these coal prices are simply an average of the coal prices to the existing coal-fired generators in the relevant region.

  Adopting the coal prices used by ACIL Tasman in its LRMC modelling would represent a significantly different approach to that adopted for the 2010 Determination. For the 2010 Determination, new entrant coal prices were taken from the ACIL 2009 Report, which provides, for each relevant NTNDP Zone in the NEM, forecasts of future coal prices that are based on an assessment of coal supplies and costs in those individual NTNDP Zones. These are not simply the average coal prices faced by existing generators in those NTNDP Zones.

  Similarly, adopting the coal prices used by ACIL Tasman in its LRMC modelling would represent a significantly different approach to that adopted for new entrant gas prices. For this annual review, new entrant gas prices are taken from the ACIL Report for the QCA which provides forecasts of future gas prices in each State in the NEM that are derived from modelling of gas supply and gas demand in these States, not the average gas prices faced by existing generators.

  ACIL Tasman's rationale for basing its LRMC modelling on coal prices that are an average of coal prices into existing coal-fired generators is that existing coal sources will be available to new build coal-fired generators. However, even if new entrant coal-fired generators source coal from the same mines as existing coal-fired generators, it is unclear why the coal price for new entrant generators would be the same as the coal price for existing generators.

  Having considered these issues, IPART have decided that the coal prices used by ACIL Tasman in their LRMC modelling for the QCA are inappropriate for the purposes of this annual review. For this reason, and in the absence of other appropriate sources for new entrant coal prices, IPART have decided that, for the purpose of this annual review, the new entrant coal price should be determined by escalating the new entrant coal prices from the ACIL 2009 Report in line with average increases in mining cost indices over the previous ten years.[14] This implies an annual increase in coal prices of 4.1% in nominal terms.

- Maximum capacity factors – Frontier Economics has used the information on maximum capacity factors that is set out in the ACIL Report for the QCA.

3.6 Carbon price

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). The stand-alone LRMC and market modelling assumes the legislated[15] carbon price of $23/tCO2e (nominal[16]) for 2012/13.

The incremental LRMC modelling extends to 2019/20, beyond the fixed price period of the current legislation. There is uncertainty associated with the level of the carbon price in the market period (post 2014/15). Commonwealth Treasury has performed the most comprehensive forecast of carbon prices to date. However, in undertaking this forecasting, Commonwealth Treasury assumes a higher level of global action on carbon than currently seems likely to eventuate. This is supported by the current carbon price in the European scheme sitting below EUR9/tCO2e, which is significantly lower than the legislated fixed carbon price or the Commonwealth Treasury forecast in the market period.

To assess the impact of the level of the carbon price on medium to longer term investment and marginal LGC costs Frontier has modelled the carbon price path for the 2015/16 to 2019/20 based on the Commonwealth Treasury Core Policy scenario.[17]

This carbon price path is shown in Figure 2.

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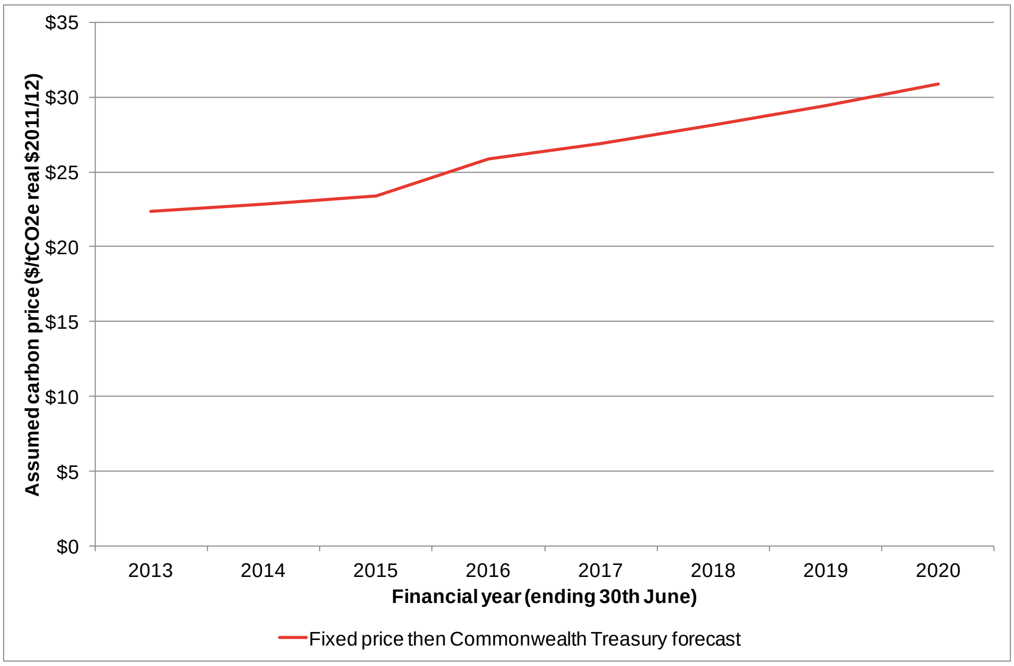
14 The index for open cut mining and the index for underground mining, both from the ABS' Producer Price Index, have been used to determine an average increase in mining costs over the previous ten years. The two indices have been given an equal weight.

15 Clean Energy Bill 2011 (see: http://www.comlaw.gov.au/Details/C2011B00166/)

16 Equivalent to $22.64/tCO2e in real $2011/12 assuming escalation of 1.6%.

17 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)

Figure 2: Assumed carbon prices



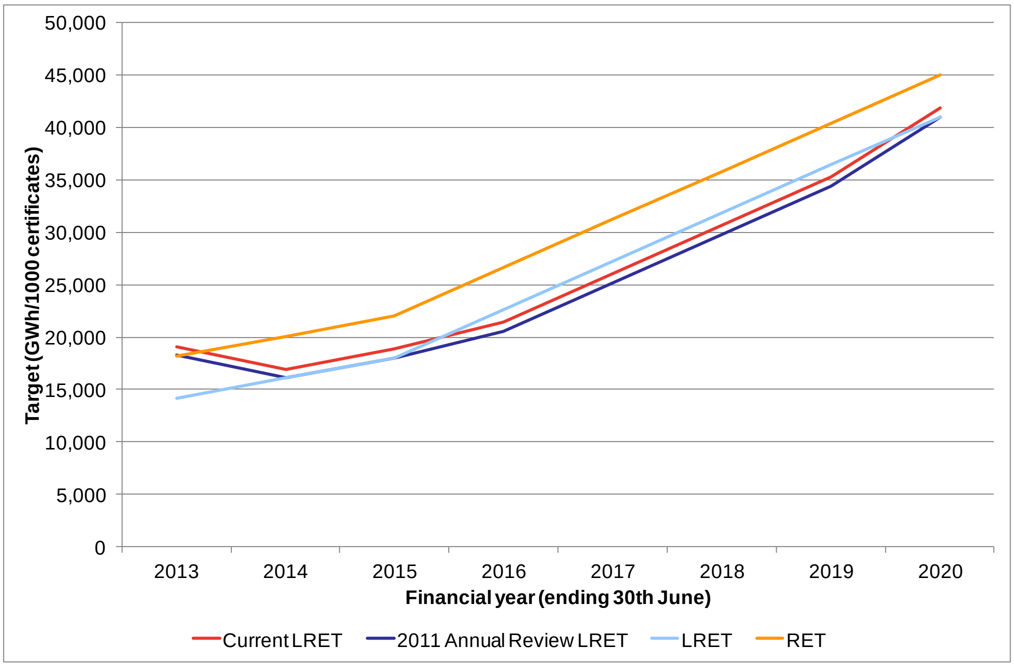
Source: Clean Energy Bill 2011, Commonwealth Treasury modelling

3.7 LRET target

Since the 2010 Determination, the RET scheme has been split into the Large-scale Renewable Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). As part of this process the RET target has been amended to come up with the LRET target and the adjusted LRET target (which accounts for the surplus of RECs available at the end of 2010). In 2012, further adjustment to the LRET target has occurred to account for changes to the treatment of waste coal mine gas under the scheme.

Figure 3 shows the RET target, the initial LRET target, the adjusted LRET target used in the 2011 annual review, as well as the current LRET target. The current LRET target has been used in our modelling for this annual review.

Figure 3: LRET target



Source: ORER, Frontier Economics.

3.8 Response to submissions

In submissions to IPART's draft report a number of stakeholders commented on specific input assumptions used in our modelling. Other than comments on the WACC (which we understand will be addressed by IPART), the main issues raised by stakeholders were in regard to the assumed coal price and the assumed gas price.

3.8.1 Coal price assumption

AGL, Origin and TRUenergy each commented on the coal price assumptions adopted by IPART. In particular, they commented that they consider the coal price assumption used for new entrant black coal plant in NSW is too low and does not reflect market realities.

The main argument used to support the view that the coal price assumption is too low is that current export prices are high – around $3/GJ – and that coal generators in NSW are exposed to these export prices.

However, the price that is used as an input assumption in modelling the stand-alone LRMC is an estimate of the cost that a new entrant coal generator would face (as opposed to an existing generator). The lowest coal price that a new entrant coal generator would be able to achieve has typically been assumed to occur in south-west NSW, where coal export prices at current levels are not likely to have a large influence on the coal price to a new entrant generator.

Nevertheless, it might be argued that the input assumption for the cost of production of coal that have been used for this annual review are too low. We note that the input assumptions for the 2012 NTNDP include a higher cost of production of coal. We have run a scenario in which we have adopted this higher coal price assumption (as well as other input assumptions from the 2012 NTNDP). This is discussed in Section 4.7.

3.8.2 Gas price assumption

Origin and TRUenergy both commented on the gas price assumptions adopted by IPART. In particular, they commented that they consider the gas price assumption used for gas plant in NSW is too low.

The main argument used to support the view that the gas price assumption is too low is that LNG exports from Gladstone will drive up the price of gas in eastern Australia. While this may well be the case, it is unclear why gas prices would be higher in 2012/13, when LNG exports from Gladstone will not commence until 2014. Indeed, if anything, the production of gas prior to the commencement of LNG exports ('ramp gas') would be expected to result in lower prices during 2012/13. Certainly, recently observed prices on the Short Term Trading Market have not shown signs of significant increases in gas prices.

We also note that the input assumptions for the 2012 NTNDP include a lower gas price. We have run a scenario in which we have adopted this lower gas price assumption (as well as other input assumptions from the 2012 NTNDP). This is discussed in Section 4.7.

4 Long run marginal cost

The LRMC of generating plant is typically determined on the basis of the least economic cost mix of plant to meet the required load to a particular security standard.

This section sets out the results of the LRMC modelling of generating plant to serve the regulated load of the Standard Retailers, including:

- a brief re-statement of Frontier Economics' approach to estimating the LRMC of the Standard Retailers' regulated load
- the results of the LRMC modelling
- a comparison between the LRMC estimated for this final report and the LRMC estimated for the 2010 Determination
- an overview of investment and dispatch outcomes from the LRMC modelling
- consideration of the expected results for the stand-alone LRMC in the event that input assumptions were derived (to the extent possible) from the 2012 NTNDP.

4.1 Approach to estimating the LRMC

As discussed in the Frontier Final Report for 2010, there are two broad approaches to estimating the LRMC:

- Stand-alone LRMC – this approach assumes that there is currently no plant available to serve the required load. This approach effectively builds, and prices, a whole new least-cost generation system to meet the required load. This approach has the effect of re-pricing all existing capacity at efficient levels.
- Incremental LRMC – this approach assumes that the existing mix of generation plant in the system is in place and that the required load can be served using both existing generation plant and new generation plant. Under this approach, new generation plant is only built if it is required as part of a least-cost generation system to meet the required load. This approach prices load on the basis of the least cost way of adding to the existing stock of plant

Frontier Economics estimates the LRMC of serving the Standard Retailers' regulated load using the stand-alone LRMC approach. Under this approach, the load used to estimate LRMC is the Standard Retailers' regulated load, and the

LRMC is the cost of serving an incremental increase to this load shape with a hypothetical new least-cost generation system.[18]

4.2 LRMC results

Results for the stand-alone LRMC approach are set out in Table 1.

Table 1: Stand-alone LRMC results ($2011/12)

Financial Year	Draft Report LRMC ($/MWh)	Final Report LRMC ($/MWh)
	Country Energy	
2012/13	$78.06	$82.05
	EnergyAustralia	
2012/13	$81.12	$85.37
	Integral Energy	
2012/13	$84.59	$89.02

Source: Frontier Economics

For 2012/13 the LRMC for the three businesses is in the range of $82/MWh to $89/MWh. The LRMC determined for the businesses is highest for Integral Energy and lowest for Country Energy. This is consistent with the 2010 Determination and 2011 annual review, and reflective of the load shapes of the businesses. Integral Energy's regulated load is relatively peaky due to it containing the majority of western Sydney's temperature-sensitive load. Conversely, Country Energy's regulated load is more geographically diverse leading to an overall flatter load. EnergyAustralia's regulated load lies in the middle of these two businesses.

The increase in the LRMC between the draft report and the final report is a result of the higher WACC for generation adopted by IPART for the final report.

18 In effect, the LRMC is calculated by adding to the regulated load an increment that is the same shape as the regulated load. This ensures that the LRMC reflects the fixed and variable costs associated with the mix of plant that is efficient, given the shape of the regulated load.

4.3 Differences relative to the 2010 Determination

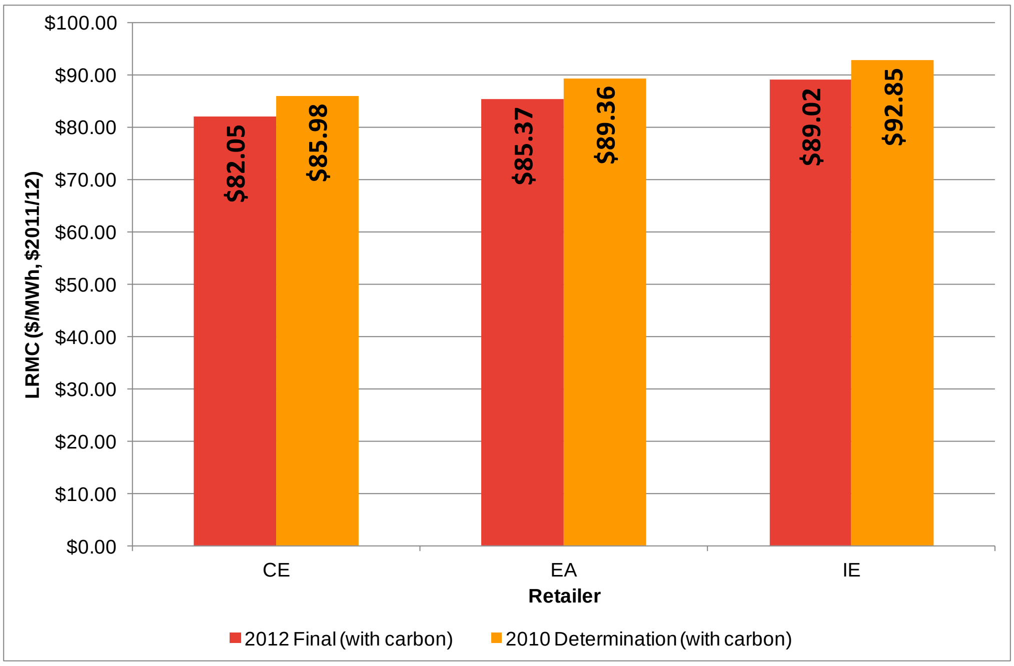
Results for the stand-alone LRMC approach from this final report are compared with the equivalent results (from the scenario with a carbon price) from the 2010 Determination in Figure 4. In the 2011 annual review there was no estimate of the stand-alone LRMC for 2012/13 inclusive of carbon so no direct comparison can be made.

As can be seen, the stand-alone LRMC for this annual review is lower than the 2010 determination. There are two major sources of difference:

- The assumed carbon price is now lower – $22.37/tCO2e versus $28.01/tCO2e (real $2011/12)
- The assumed WACC is now lower – 7.1% versus 7.8% pre-tax real

These factors account for the reduction in the stand-alone LRMC. This reduction is further analysed in the next section.

Figure 4: Stand-alone LRMC results compared to 2010 Determination ($2011/12)



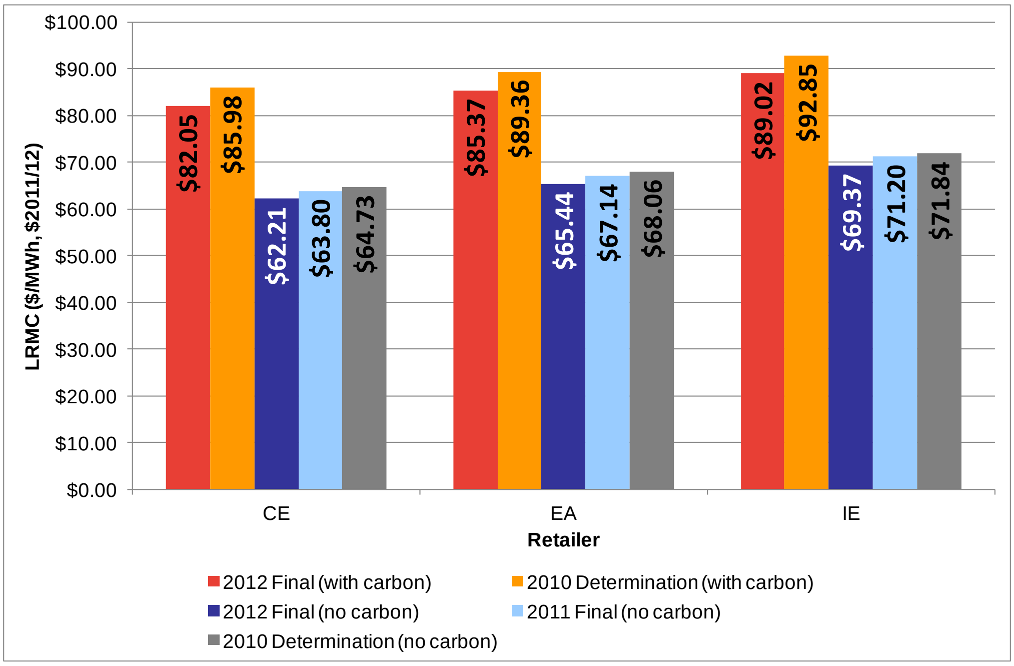
Source: Frontier Economics

4.4 Differences relative to the 2010 Determination and the 2011 annual review, with and without carbon

Results for the stand-alone LRMC approach from this final report are compared to both the 2010 Determination with and without carbon and the 2011 annual review without carbon in Figure 5.

Focusing on the without carbon results, the current analysis is lower than both the 2010 Determination and the 2011 annual review. This is driven by the reduction in assumed WACC and the resulting lower capital costs in the current analysis. In the results with carbon, as discussed in Section 4.3, the current analysis is lower than the 2010 Determination. This is due to reduced capital costs due to a lower assumed WACC and a lower assumed carbon price.

Figure 5: Stand-alone LRMC results compared to the 2010 Determination and 2011 annual review, with and without carbon ($2011/12)



Source: Frontier Economics

4.5 Investment and dispatch outcomes

This section provides the investment and dispatch outcomes associated with the stand-alone LRMC modelling, for each Standard Retailer.

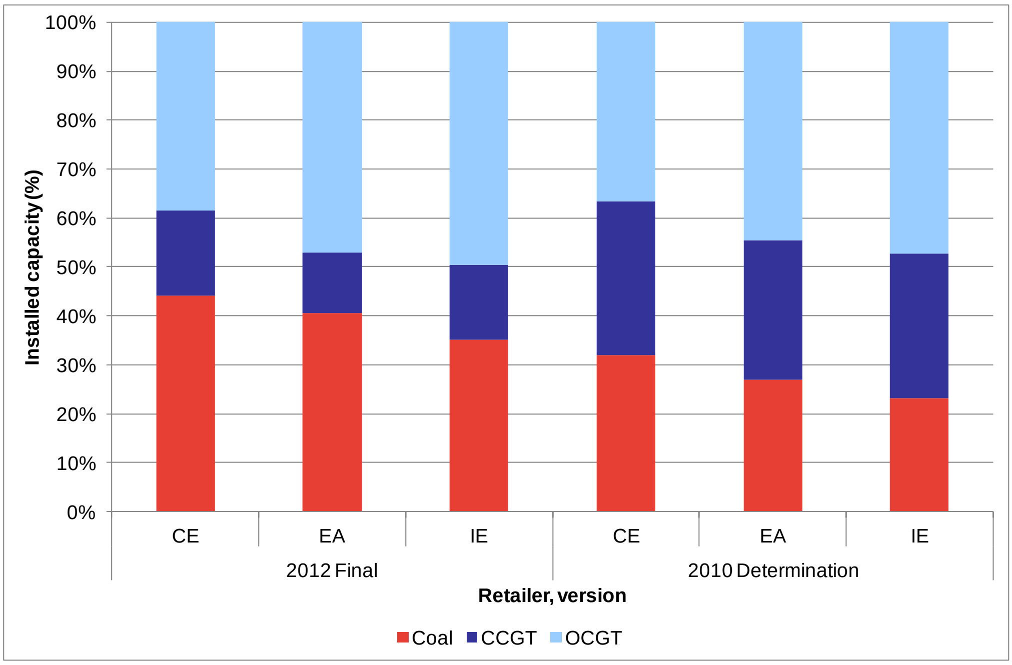
As discussed in the Frontier Final Report for 2010, in considering the investment and dispatch outcomes associated with the stand-alone LRMC modelling, it is important to note that under this approach the system that is built to serve the Standard Retailers' regulated load is optimised each year. Optimising the system each year is important because in cases where the regulated load is falling over time, if the system is not optimised each year the resulting LRMC would reflect excess capacity in the later years of the Determination, and may not include a capital cost component. Because the system is optimised each year, changes in patterns of investment and dispatch from year to year are 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.

Figure 6 provides investment outcomes for each Standard Retailer in 2012/13. In the current analysis, the investment mix across the Standard Retailers in 2012/13 is roughly 34-45% coal, 10-15% CCGT and the residual capacity is OCGT. The optimal mix in the current analysis includes more coal than the results for the 2010 Determination. The reason for the difference between the current analysis and the 2010 Determination is that the lower assumed carbon price in the current analysis does not shift the relative economics of CCGT gas as favourably as for the 2010 Determination, resulting in more coal fired generation in the optimal generation mix. Levels of OCGT investment are similar in the current and 2010 work.

Figure 7 provides dispatch outcomes for each Standard Retailer in 2012/13. The dispatch results reflect the investment outcomes. The major change relative to the 2010 Determination is the increase in output from coal fired generation in the current analysis which is consistent with the greater levels of investment in coal due to it being relatively cheaper with the lower assumed carbon price.

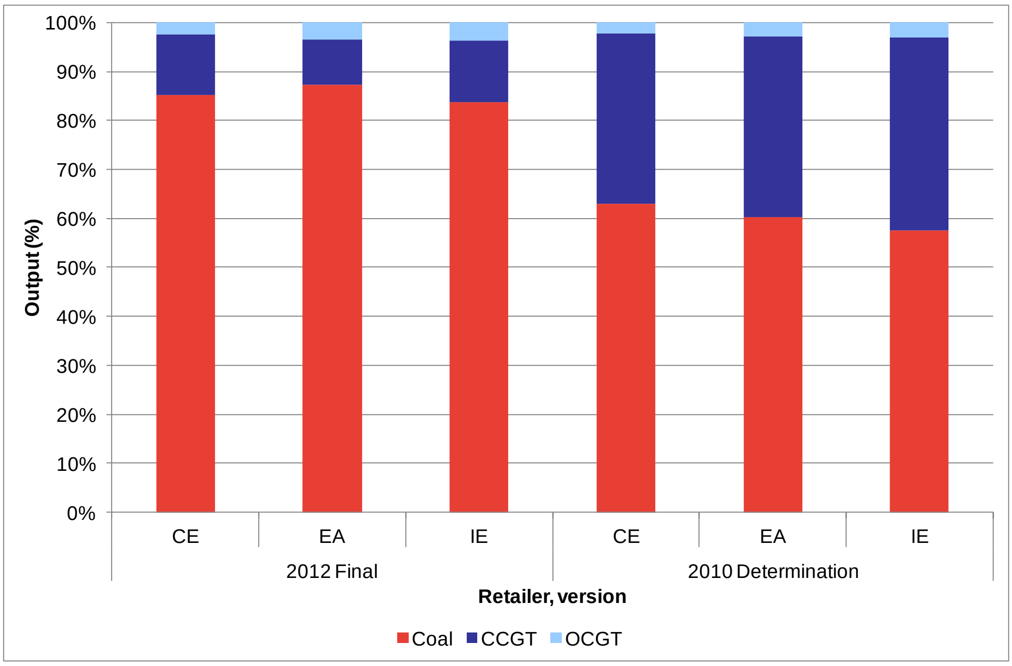
The patterns of investment and dispatch across the Standard Retailers reflect the load shape of the retailers. Peakier regulated loads, such as those of Integral Energy and EnergyAustralia, result in greater investment in OCGT plant. Flatter loads, such as Country Energy's, result in relatively less investment in OCGT plant.

Figure 6: Investment outcomes – stand-alone LRMC



Source: Frontier Economics

Figure 7: Dispatch outcomes – stand-alone LRMC



Source: Frontier Economics

4.6 Carbon pass-through in the stand-alone LRMC approach

Carbon pass-through can be measured in a number of ways. This section considers the effect of carbon pricing on energy costs in $/MWh terms and as a percentage of the assumed $/tCO2e carbon price that is passed through to energy costs.[19]

In the stand-alone LRMC approach the imposition of a carbon price leads to two major effects: firstly, a direct increase in the variable cost of thermal generation; secondly, a change in the relative economics of different thermal options such that the mix of investment and output changes. This secondary effect, whereby the investment mix can immediately respond to the imposition of a carbon price, is stark in the stand-alone LRMC approach as the approach involves determining an entirely new mix of optimal generation investment every year. This is in contrast to an incremental LRMC approach that more closely matches the reality that the existing stock of investment is sunk and will continue to operate for a number of years. This means that, for a given carbon price, the level of pass-through in both $/MWh and percentage terms will be lower in the stand-alone LRMC approach than it would be in an incremental LRMC approach or any other forecasting approach that includes the existing stock of investment. This is even despite the stand-alone LRMC approach assuming residential customer demand profiles that are much peakier than the system load shape (which would be assumed in an incremental LRMC approach). This is borne out by the marketing modelling results presented in Section 5.

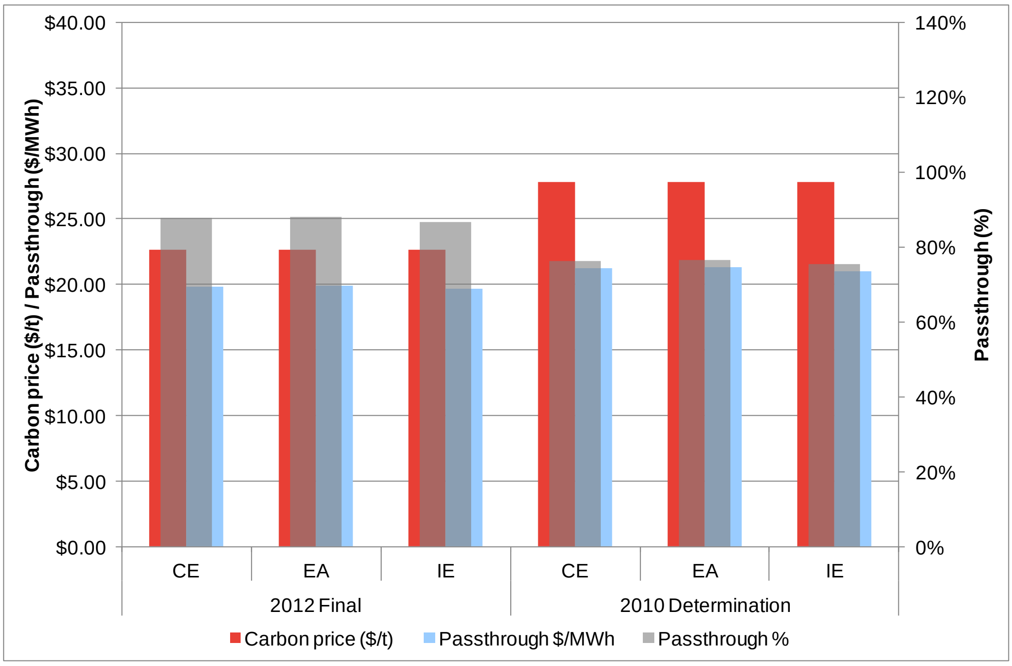
Figure 8 shows the assumed carbon prices (red bars), pass-through in $/MWh (blue bars) and pass-through percentage (grey bars) for both the current analysis and for the 2010 Determination, for the stand-alone LRMC approach. Pass-through is forecast to be around $20/MWh and at a rate of roughly 88% in the current analysis.

Although the assumed carbon price is lower in the current analysis than for the 2010 Determination, the level of pass-through in percentage terms is higher. This is because the lower assumed carbon price means that CCGT plant is relatively less competitive when compared to coal fired generation. As seen in the investment results above, this leads to coal making up a greater proportion of investment in the current analysis and results in a higher percentage pass-through rate. These two effects – lower carbon prices but higher pass-through rates –

19 That is, the $/MWh difference in energy costs with and without carbon divided by the assumed carbon price in $/tCO2e.

offset each other such that pass-through in $/MWh terms is roughly the same in the current analysis and the 2010 Determination at around $20/MWh.

Figure 8: Carbon pass-through in the stand-alone LRMC results compared to the 2010 Determination ($2011/12)



Source: Frontier Economics

4.7 2012 NTNDP

Following the release of the Frontier Annual Review Draft Report, stakeholders have commented that the 2012 NTNDP now includes a planning scenario that represents AEMO's "best estimate of how the future will develop given the currently known and well advanced and anticipated changes."[20]

Given that one of the principal problems with relying on the 2010 and 2011 NTNDP was that these NTNDP's did not have a base case, the fact that the 2012 NTNDP does have a base case raises the prospect that it may be an appropriate source of input assumptions.

However, there are some issues with relying on the 2012 NTNDP for input assumptions for this annual review. The principal issue is that the reports that

20 AEMO, *2012 Scenarios Descriptions*, 23 January 2012.

have been released so far as part of the consultation process for the 2012 NTNDP do not include the complete set of input assumptions that would be required for the modelling for this annual review. So far, as part of the consultation process for the 2012 NTNDP, the following reports have been released on AEMO's website:

- WorleyParsons, *Cost of Construction New Generation Technology*, 10 February 2012 (including an accompanying spreadsheet). This report provides cost and technical information for a number of potential new entrant generation technologies. However, the scope of this report is not as broad as equivalent reports previously released by AEMO. In particular, this report does not have cost and technical information for supercritical black coal without carbon capture and storage or for OCGT plant. Both of these technologies typically form part of the efficient generation mix in our stand-alone LRMC modelling.
- ACIL Tasman, *Fuel cost projections, Natural gas and coal outlooks for AEMO modelling*, Draft Report, December 2011 (including an accompanying spreadsheet). This report provides gas and coal price forecasts for new entrants generators in the NEM.

These reports do not include information on the existing generation plant in the NEM. This would mean that we could not practically rely on these reports to undertake our market modelling (which includes cost and technical information for all the existing generation plant in the NEM). However, these reports do contain most of the information that we would require to undertake our stand-alone LRMC modelling (which includes cost and technical information for potential new generation plant, but not for existing generation plant in the NEM).

Given this, for the purpose of this final report, we have modelled a stand-alone LRMC scenario based on input assumptions from the 2012 NTNDP (to the extent that they are available). Where input assumptions are not available from the 2012 NTNDP (specifically, cost and technical information for supercritical black coal plant and OCGT plant) input assumptions from the 2011 NTNDP are used instead.

The key differences between input assumptions used in the stand-alone LRMC modelling discussed in previous sections of this report and the input assumptions used for the 2012 NTNDP scenario are the following:[21]

- **The capital cost for supercritical black coal plant has increased**.
  - The ACIL Report for the QCA has a capital cost for supercritical black coal plant of $2,248/kW.

[21] All of these costs are reported in 2011/12 dollars, using the escalation rates set out in Section 3.

  - The Worley Parsons report for the 2011 NTNDP has a capital cost for supercritical black coal plant of $2,636/kW.[22]
- **The capital cost for CCGT plant has decreased**.
  - The ACIL Report for the QCA has a capital cost for CCGT plant of $1,296/kW.
  - The Worley Parsons report for the 2012 NTNDP has a capital cost for CCGT plant of $1,030/kW.
- **The capital cost for OCGT plant has decreased**.
  - The ACIL Report for the QCA has a capital cost for OCGT plant of $933/kW.
  - The Worley Parsons report for the 2011 NTNDP has a capital cost for OCGT plant of $864/kW.
- **The coal price for new entrant black coal plant in NSW has increased**.
  - The ACIL 2009 Report has a lowest coal price available for new entrant black coal plant in NSW of $1.19/GJ.
  - The ACIL report for the 2012 NTNDP has a lowest coal price available for new entrant black coal plant in NSW of $1.77/GJ.
- **The gas price for new entrant gas generators in NSW has decreased**.
  - The ACIL Report for the QCA has a lowest gas price available for new entrant CCGT plant in NSW of $5.82/GJ.
  - The ACIL report for the 2012 NTNDP has a lowest gas price available for new entrant CCGT plant in NSW of $5.31/GJ.

Because these reports do not provide a great deal of information about the factors that drive this cost estimates, the reasons for the differences in cost estimates between the reports are not obvious.

There are also differences in the fixed operating costs and variable operating costs in the Worley Parsons report for the 2012 NTNDP, which have been adopted for this stand-alone LRMC scenario. Because these costs are less material than capital costs and fuel costs, these changes have a smaller impact on the stand-alone LRMC.

Results for the stand-alone LRMC approach under the 2012 NTNDP scenario are set out in Table 2 (and compared with the results already presented).

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22 Note that the WorleyParsons reports provide capital costs in "$/kW for net power sent out". These costs have been converted to $/kW installed for the purposes of comparison.

Table 2: Stand-alone LRMC results – 2012 NTNDP scenario ($2011/12)

Financial Year	2012 NTNDP scenario LRMC ($/MWh)	Final Report LRMC ($/MWh)
Country Energy		
2012/13	$77.97	$82.05
EnergyAustralia		
2012/13	$80.81	$85.37
Integral Energy		
2012/13	$83.51	$89.02

Source: Frontier Economics

The results show that adopting input assumptions from the 2012 NTNDP would be expected to result in a lower stand-alone LRMC. The reason is that the decrease in the capital cost of gas plant (particularly CCGT plant) and the decrease in the gas price more than outweigh the increase in the capital cost of coal plant and the increase in the coal price. Indeed, these input assumptions change the relative economics of black coal plant and CCGT plant to such an extent that, in the stand-alone LRMC modelling for the 2012 NTNDP scenario it is no longer efficient to build any black coal plant in order meet the regulated load shape.

Of course, these results may change in the event that any of the data released so far is amended as part of the consultation for the 2012 NTNDP or in the event that more data is released (so that we would not have to rely on input assumptions from the 2011 NTNDP for black coal plant and OCGT plant).

5 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 regulated load that the Standard Retailers supply, determining an efficient hedging strategy and the cost and risk associated with that hedging strategy.

This section sets out the results of Frontier Economics' approach to estimating market-based energy purchase costs for the Standard Retailers, including:

- a brief re-statement of Frontier Economics' approach to estimating market-based energy purchase costs
- the results of Frontier Economics' modelling of spot prices and of the market-based energy purchase cost
- a comparison between the results from this final report and the results from the 2010 Determination
- the results of Frontier Economics' modelling of the volatility allowance.

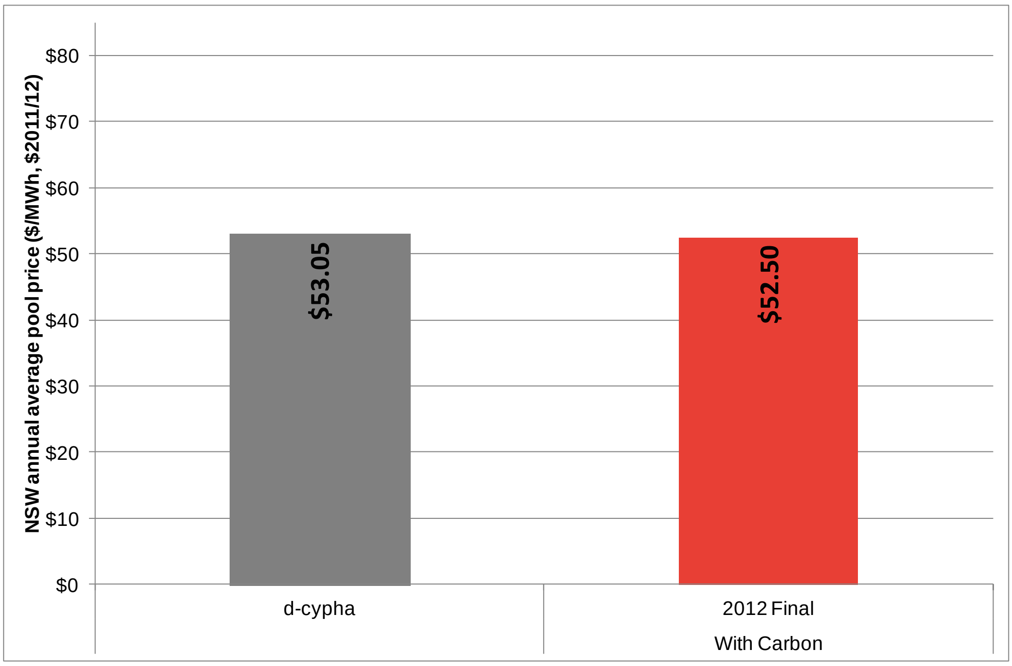
5.1 Spot and contract price forecasts

As discussed in the Frontier Final Report for 2010, Frontier Economics uses *SPARK* to forecast spot electricity prices. Like all electricity market models, *SPARK* reflects the dispatch operations and price-setting process that occurs 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.

Price forecast results for the NSW region from *SPARK* are presented in Figure 9. This shows the annual average, time-weighted NSW pool price from this final report and from the draft report.

For the purpose of comparison, Figure 9 also shows the d-cyphaTrade forward prices for flat annual swaps in NSW as of May 29, de-escalated to $2011/12 at 1.6 per cent and further reduced by 5 per cent to account for the contract premium. The d-cyphaTrade prices provide an indication of the market view on future contract prices (and, by association, pool prices). It is clear from Figure 9 that Frontier Economics' spot price forecasts are highly consistent with the current d-cyphaTrade prices (accounting for implied contract premiums).

Figure 9: NSW annual average price forecast ($2011/12)



Source: Frontier Economics

5.2 Market-based energy purchase costs

As discussed in the Frontier Final Report for 2010, Frontier Economics uses *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.

This section presents the results of Frontier Economics' *STRIKE* modelling. Results are presented as follows:

- efficient frontiers for 2012/13 for each Standard Retailer
- market-based energy purchase costs for 2012/13 for each Standard Retailer.

Consistent with the approach adopted for the 2010 Determination, the efficient frontiers (and therefore the market-based energy purchase costs) for each Standard Retailer have been calculated by using *STRIKE* to optimise over three sets of load-price shapes that capture the volatility of prices and load, and the correlation between the two. That is, *STRIKE* finds an optimal contracting position taking into account the possibility of three alternate versions of the future.

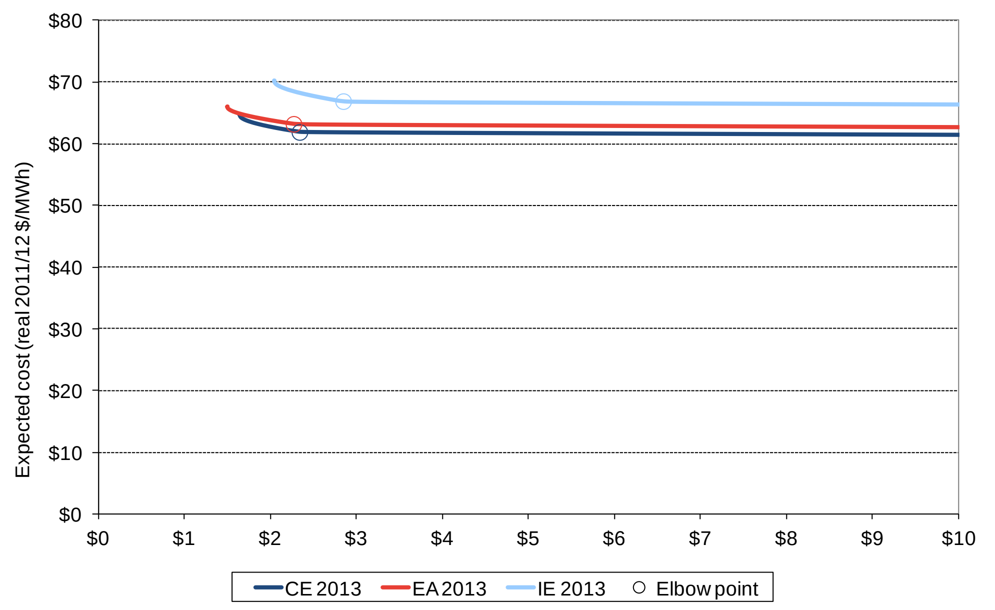
5.2.1 Efficient frontiers

The efficient frontier of contracting options has been calculated for 2012/13 for each Standard Retailer. This frontier is a representation of the expected purchase cost and the associated risk (as measured by standard deviation) of a set of contracts that minimise risk whilst maximising return (minimising purchase cost). Each point on the efficient frontier is associated with a specific mix and quantity of contracts.

Figure 10 shows the efficient frontiers for each standard retailer. The vertical axes of these figures represent the expected annual average energy purchase cost (in $/MWh) for the efficient (lowest cost) mix of energy purchasing options at a given level of risk. The horizontal axes of these figures represent risk as the standard deviation of the energy purchase costs (in $/MWh) for each level of efficient costs. These efficient frontiers slope downwards to the right, indicating that the least risky position is also associated with the highest energy cost. This result is intuitively obvious – that is, more price insurance costs more money.

On each frontier an elbow point has been defined. The elbow point denotes the point on the frontier where the rate of change in the slope of the frontier is maximised (i.e. second order derivative of the frontier). This elbow point indicates the position on the frontier where costs are lowest for a given increase in risk. The least risky position (i.e. most conservative) is the point furthest to the left of the efficient frontier.

Figure 10: Efficient frontiers – 2012/13 ($2011/12)



Source: Frontier Economics

5.2.2 Market-based energy purchase costs

Consistent with the approach from the 2010 Determination, market-based energy purchase costs are based on the conservative points on the efficient frontiers.

The market-based energy purchase costs presented are comprised solely of the pool purchase cost of the Standard Retailers' regulated load and the premiums and difference payments made on the optimal set of contracts as determined by *STRIKE*. These are summarised in Table 3. The costs presented correspond to the conservative point on the efficient frontier for each business and are costs at the NSW regional reference node.

Table 3: Market-based energy purchase cost results ($2011/12)

Financial Year	Draft Report EPC ($/MWh)	Final Report EPC ($/MWh)
	Country Energy	
2012/13	$65.03	$64.63
	EnergyAustralia	
2012/13	$66.43	$66.01
	Integral Energy	
2012/13	$70.60	$70.15

Source: Frontier Economics

The market-based energy purchase costs at the conservative point are in the order of $65/MWh to $70/MWh. This is consistent with the spot price forecasts, a 5 per cent contract premium and the effect of the load shape of each business on purchasing cost. The same ranking between the businesses as seen in the LRMC results – Integral Energy most expensive, followed by EnergyAustralia and then Country Energy as the cheapest – is maintained. This reflects the relative peakiness of the load shapes of the three businesses.

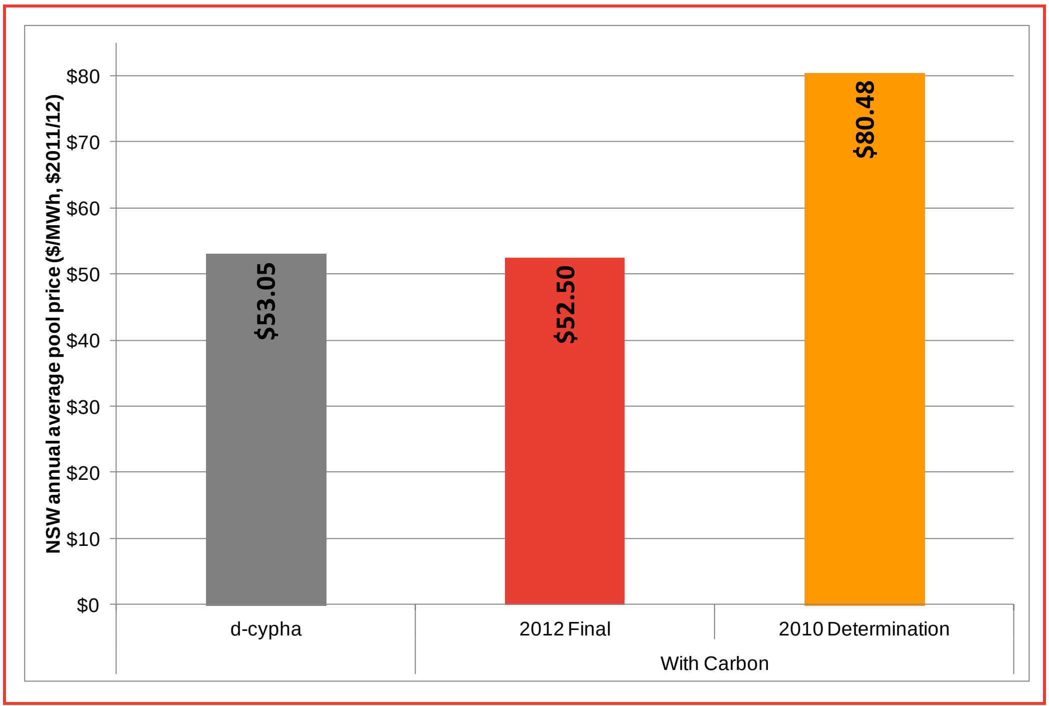
The slight decrease in the market-based energy purchase cost between the draft report and the final report is a result of the updated inflation rates adopted for the final report.

5.3 Differences relative to the 2010 Determination

5.3.1 Differences in price forecasts

Price forecast results from this final report are compared with the equivalent results (from the scenario with a carbon price) from the 2010 Determination in Figure 11. As can be seen in Figure 11, the wholesale price forecasts for this final report are lower than the prices forecast for the no carbon scenario of the 2010 Determination.

Figure 11: NSW annual average price forecast ($2011/12)



Source: Frontier Economics

There are a number of main changes in input assumptions used for this final report that drive this outcome:

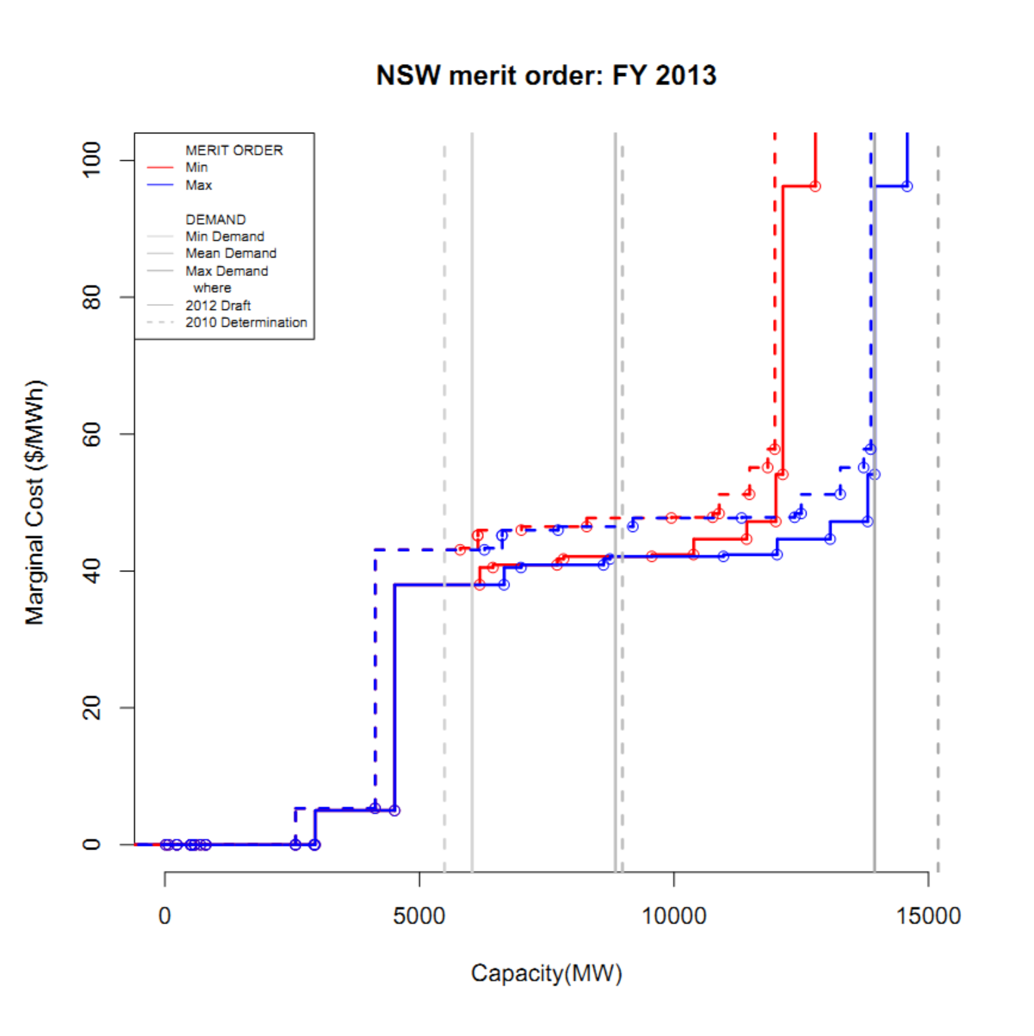
- the assumed carbon price is lower
- the assumed NSW peak demand and energy levels are lower
- there is more capacity in NSW and the wider NEM due to recently committed plant and upgrades
- assumed gas prices for existing gas-fired generators in the southern States are generally lower in the ACIL Report for the QCA than in the ACIL 2009 Report
- the market is arguably more competitive due to Delta Electricity being effectively split following the NSW Energy Reform.

Intuitively, assuming a lower carbon price in the current analysis leads to reduced estimates of the NSW pool price. This effect is exacerbated by the reduction in assumed peak demand levels. In the 2010 Determination, IPART decided that the high growth scenario from the AEMO 2009 ESOO was the most appropriate forecast of system demand. This decision was based on the observation that the forecasts for the AEMO 2009 ESOO were unduly pessimistic regarding the impact of the global financial crisis such that the medium growth scenario from the AEMO 2009 ESOO was likely to understate demand levels. The high growth scenario provided what was considered to be the best forecast of 2010/11 demand levels. However the forecast of demand in later years then grew at a relatively rapid rate. For the purpose of this 2012 annual review, IPART has used the low growth scenario from AEMO 2011 ESOO. This forecast is lower than that used in the 2010 Determination, particularly with regard to peak demand. Peak demand is a greater driver of pricing outcomes than annual energy.

Figure 12 shows the supply demand balance curves from the modelling undertaken for this final report, compared to those for the 2010 Determination (with carbon scenario). Supply is represented by the modelled NSW SRMC merit order supply curve. The current analysis is shown as solid lines and the 2010 Determination as dashed lines. The curves are shown for both the maximum (blue) and minimum (red) capacity offered into the market; *SPARK* models capacity bidding within these ranges. Three levels of assumed demand are also shown as vertical lines – minimum, mean and maximum. The current demand assumptions are shown as solid lines and the 2010 Determination are displayed as dotted lines.

The supply demand balance curves demonstrate the key assumption changes that have led to lower estimates of pool prices in this annual review – lower marginal carbon costs combined with lower NSW peak demand and greater supply. The lower forecast pool prices are entirely consistent with the change in assumptions in the model.

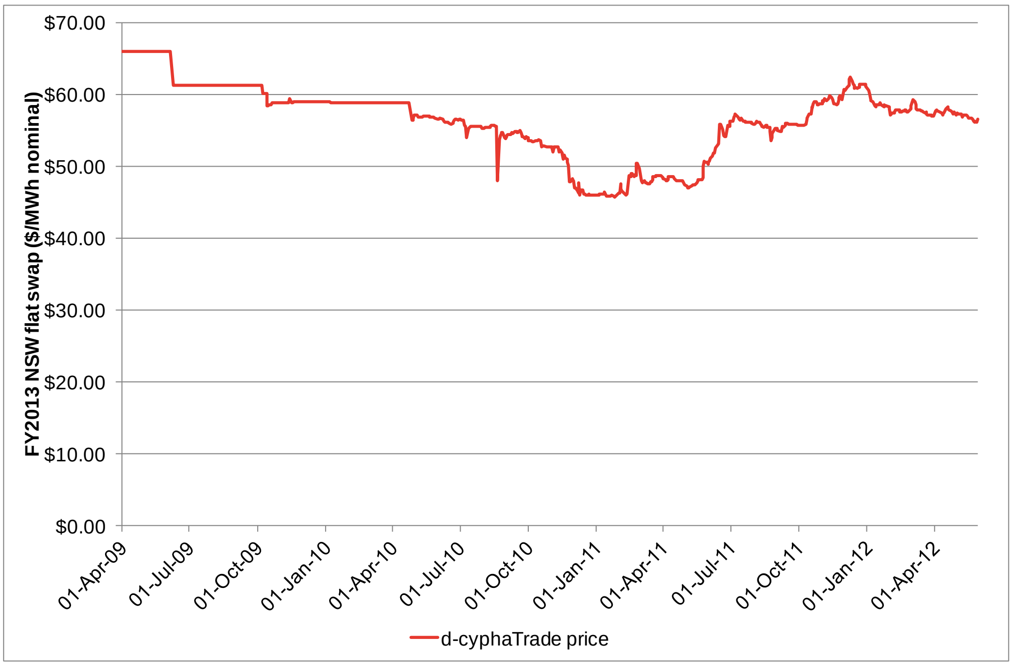
Figure 12: NSW supply demand balance 2012/13



Source: Frontier Economics

Just as Frontier Economics' wholesale spot price forecasts for 2012/13 have fallen since the 2010 Determination, d-cyphaTrade NSW flat swap forward prices for 2012/13 have also come down over the same period, even accounting for the change in carbon pricing. Figure 13 shows a time series for d-cyphaTrade NSW flat swap forward prices for 2012/13, over the period from April 2009 to 29 May 2012. During the period when the 2010 Determination was being carried out (late 2009 and early 2010), d-cyphaTrade prices were above $60/MWh (on very low traded volumes). Prices then fell, bottoming at $46/MWh in early 2011 before rising to a peak of $66/MWh in late 2011 with a significant jump in July 2011 when the Clean Energy Package was announced. As of 29 May 2012, the d-cyphaTrade price for 2012/13 is $56.59. While it is difficult to draw firm conclusions about what is driving changes in d-cyphaTrade prices, Frontier Economics expects that, among other things, these prices have been responding to the same factors discussed above: changing expectations about carbon, demand, changes in generation plant and costs, and changes in industry structure.

Figure 13: d-cyphaTrade NSW flat swap forward prices for 2012/13 (nominal)



Source: d-cyphaTrade

5.3.2 Differences in market-based energy purchase costs

Results for the market-based energy purchase costs from this report are compared with the equivalent results (from the scenario with a carbon price) from the 2010 Determination in Figure 14. Energy purchase costs are lower in the current analysis when compared to the 2010 Determination. The purchase cost is now around $30/MWh to $40/MWh lower. These changes are a direct result of the reduction in the spot price forecasts discussed above, which are in turn driven by changes in assumed carbon and peak demand in combination with other second order factors.

Figure 14: Market-based energy purchase cost results compared to 2010 Determination ($2011/12)

Source: Frontier Economics

5.4 Carbon pass-through in market based forecasts

As discussed in Section 4.6, carbon pass-through can be measured in a number of ways. This section considers the effect of carbon pricing on both the wholesale pool prices and the energy purchase costs. This effect is expressed in $/MWh terms and as a percentage of the assumed $/tCO2e carbon price that is passed through to wholesale pool prices.[23]

5.4.1 Wholesale pool price effect

The impact of carbon in our pool price forecasts is a result of the change in the supply curve of the NEM due to carbon costs increasing the marginal cost of all thermal generators. This leads to changes in dispatch and pricing outcomes relative to a case without a carbon price.

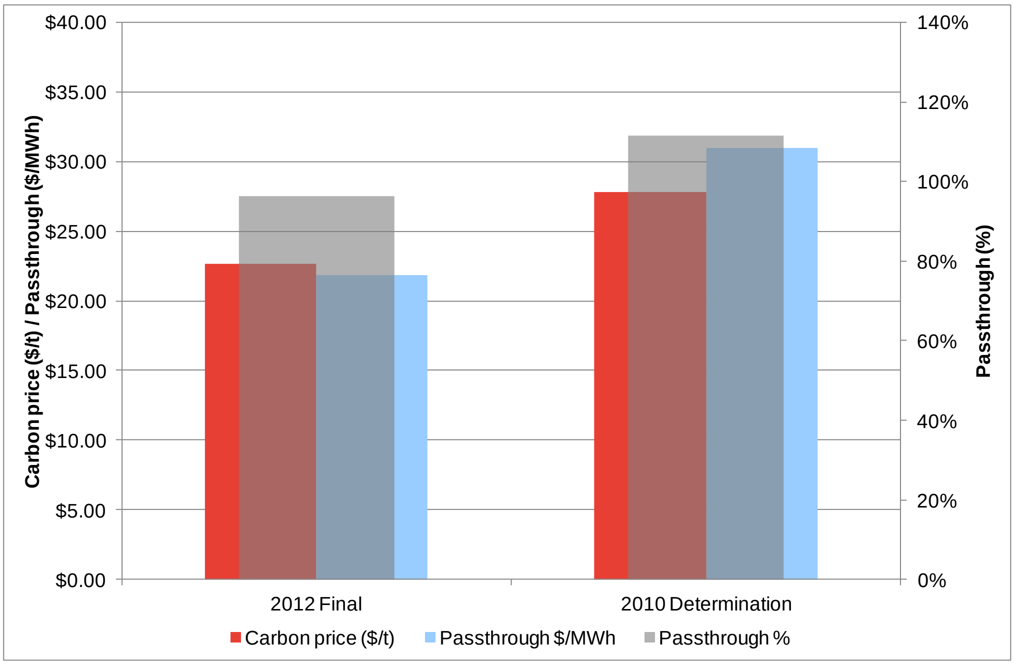
Figure 15 shows the assumed carbon prices (red bars), wholesale price pass-through in $/MWh (blue bars) and wholesale price pass-through percentage (grey

23 That is, the $/MWh difference in forecast wholesale pool prices/energy purchase costs with and without carbon divided by the assumed carbon price in $/tCO2e.

bars) for both the current analysis and for the 2010 Determination. Pass-through is forecast to be around $23/MWh and at a rate of close to 100 per cent in the current analysis.

The impact of the carbon price in the current analysis is lower than in the analysis for the 2010 Determination. To some extent this is the result of a lower pass-through rate. Primarily, however, it is due to the lower carbon price.

Figure 15: Carbon pass-through in NSW wholesale pool price forecasts compared to the 2010 Determination ($2011/12)



Source: Frontier Economics

Carbon pass-through in wholesale pool prices can arise from two sources:

- Increases in the marginal costs of all thermal generators. For a given level of demand and set of generator bids, the marginal generator will have higher marginal cost if a price on carbon is included and this will set a higher market clearing price. Of course, the identity of the marginal generator (specifically, its emissions intensity) determines the extent of this effect. Where more generation plant with a higher emissions intensity are marginal this will result in a higher carbon pass-through. This might be expected to occur with lower demand, in which case higher emissions intensity brown coal plant and black coal plant are likely to be the marginal generator more often.

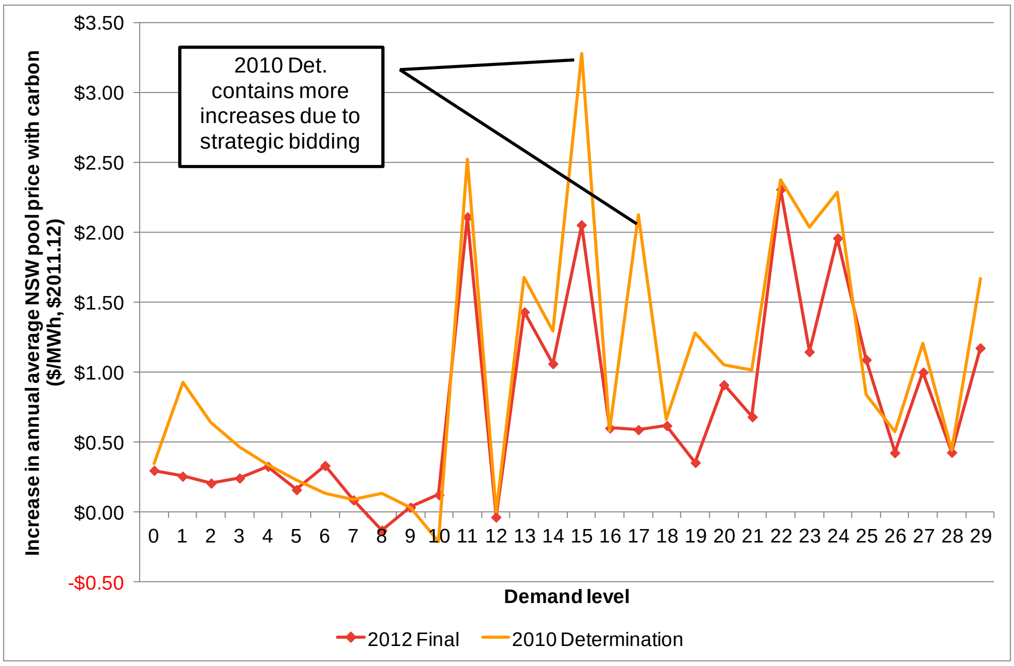
- Changes in bidding incentives. Adding carbon costs to the supply curve of the market will change the incentives for generators to engage in strategic behaviour. This may lead to outcomes where more aggressive bidding strategies are profitable in a world with carbon pricing when compared to a world without. The converse may also be true: the imposition may at times lead to a reduction in strategic bidding incentives.

The overall level of carbon pass-through in wholesale prices is a function of these two drivers.

Figure 16 shows the increase in annual average NSW pool prices due to carbon for the current analysis and the 2010 Determination for each of the 20 demand levels included in the analysis. For each demand level, the chart shows the $/MWh contribution to annual average prices due to the price on carbon.

In the 2010 Determination – which had a higher assumed carbon price, higher peak demand and less supply – there were more instances where strategic bidding lead to additional increases in pool prices over and above the direct impact of increasing the marginal cost of thermal generators. This is manifest in the increases present at demand levels 15, 17 and, to a lesser extent, 29 and 1. The medium case in the current analysis still contains one instance where bidding results in a large uplift in pool prices (demand level 24). In the modelling for this annual review there are not the same profitable opportunities for strategic behaviour to lead to oversize increases in pool prices.

Figure 16: Increase in the forecast annual average NSW price due to carbon ($2011/12)



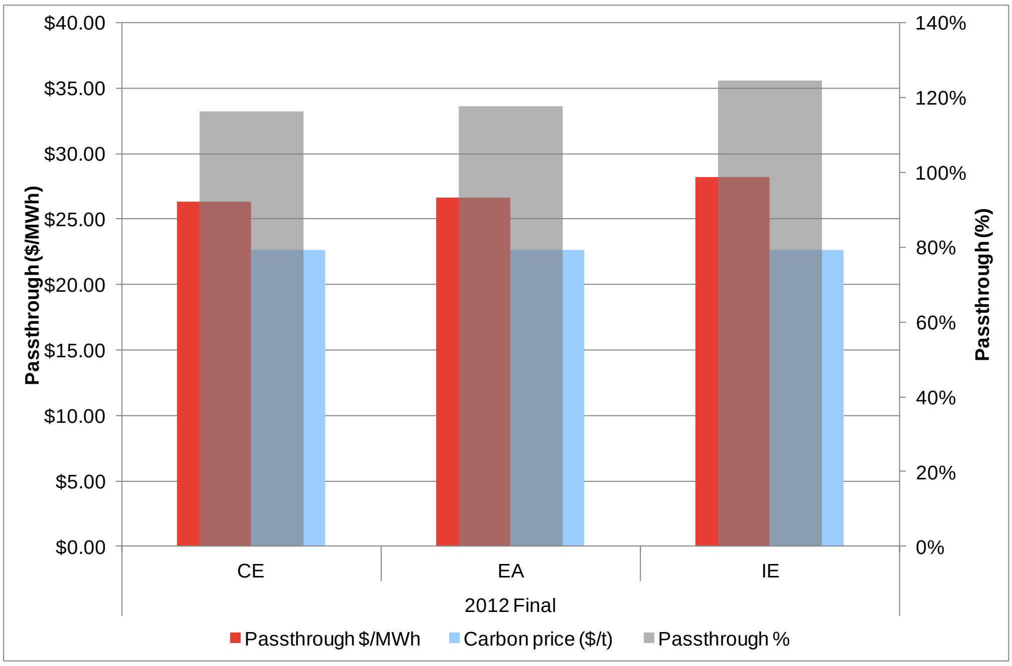
Source: Frontier Economics

5.4.2 Energy purchase cost effect

The impact of carbon on energy purchase costs is higher than the impact on the wholesale pool price. This is because energy purchase costs capture the shape of the standard retailers' load (which is peakier than system demand) and the additional costs of reducing risk be entering into financial contracts (which include an assumed 5 per cent premium over spot prices). These factors amplify the impact of carbon price on wholesale electricity prices.

For the energy purchase costs, the pass-through percentage is in the order of 120 per cent across the Standard Retailers. In $/MWh terms, the impact is roughly $26/MWh. These levels are higher than under the stand-alone LRMC approach, which assumes the same demand profiles. This difference reflects the higher emissions intensity of the NEM compared to an efficient new build system (which includes a larger percentage of lower emissions intensive gas fired generators).

Figure 17: Carbon pass-through in energy purchase costs by Standard Retailer ($2011/12)



Source: Frontier Economics

5.5 Response to submissions

In its submission to IPART's draft report, Australian Power & Gas stated that "it is no longer appropriate to make cost allowances for energy purchases based on an optimisation model combining contract cover and spot price exposure for given levels of risk for Standard Retailers. The costs incurred and risks faced by Standard Retailers for purchasing wholesale electricity to meet the regulated retail load is not representative of other retailers operating in the NSW retail electricity market. For example, vertically integrated market participants do not face the same level of pricing and cash flow risk as stand-alone retailers because the ownership of generating assets provides an alternative means of managing these risks."

It is certainly the case that vertical integration is one option that retailers have in managing their risk. And it is possible to incorporate ownership of physical generation assets into *STRIKE* when calculating the efficient frontier. However, in modelling the market-based energy purchase cost we do not take account of this option. That is, the efficient frontiers calculated using *STRIKE* reflect efficient risk management options making use only of standard swap contracts and cap contracts. As a result, these risk management options would be available to any retailer serving the regulated load shape that is able to trade standard swap contracts and cap contracts.

5.6 Volatility allowance

As discussed, even hedging the Standard Retailer's load consistent with the conservative point on the efficient frontiers will leave an element of risk in the Standard Retailers' portfolios. The volatility allowance is intended to compensate for this residual risk.

Consistent with the approach in the 2010 Determination, the volatility allowance is calculated based on the cost of holding working capital to fund cashflow shortfalls that could arise at times when the actual market-based energy purchase cost is below the expected market-based energy purchase cost. The working capital requirement is based on the standard deviation associated with the conservative point of each retailer's frontier. More specifically, Frontier Economics has estimated the difference between the expected market-based energy purchase cost and the expected purchase cost plus 3.5 standard deviations from the expected value.[24] We then estimate the cost of holding sufficient working capital, applying a WACC of 7.1%, to fund a shortfall of this magnitude.

5.6.1 Volatility allowance results

The volatility allowances calculated using this framework are set out in Table 4, for both the draft report and the final report. The differences in the volatility allowances between the Standard Retailers and the years are consistent with the risk associated with the conservative point on the relevant efficient frontier. Volatility premiums in the medium demand case are slightly higher reflecting the slightly higher level of pool prices under that case.

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24 The amount of working capital allowed for each year was calculated as 3.5 times the standard deviation in energy costs. If energy costs were normally distributed, energy costs would only ever exceed 3.5 standard deviations above the expected cost about 1 in every 3000 years, or 99.97% confidence level. However, the energy cost distributions are slightly skewed, with a marginally higher probability of high cost outcomes compared to a normal distribution. Allowing for this, a conservative estimate of the confidence level associated with a 3.5 standard deviation working capital allowance would be 1 in every 200 years, or 99.5%. The working capital cost was therefore calculated as 3.5 times the standard deviation (at the conservative point of the frontier) times the annual cost of capital (WACC). For example, if the standard deviation was $3/MWh, the amount of working capital allowed each year would be 3.5 x $3/MWh = $10.50/MWh. Assuming a WACC of 10%, the annual cost of holding the working capital would be $10.50 x 10% = $1.05/MWh.

Table 4: Volatility allowance results ($2011/12)

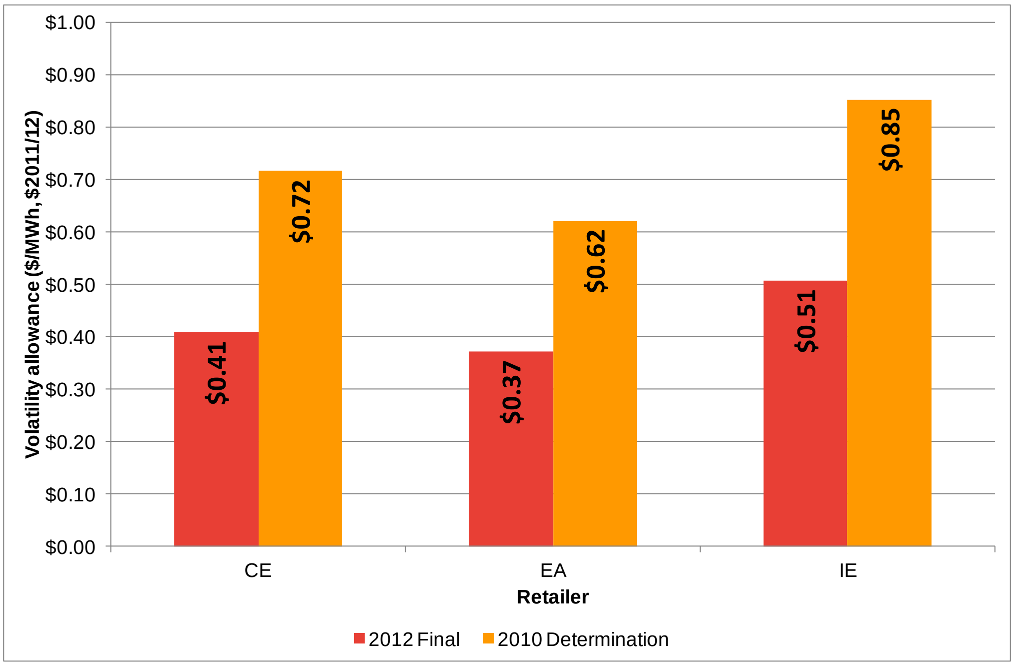
Financial Year	Draft Report Volatility premium ($/MWh)	Final Report Volatility premium ($/MWh)
Country Energy		
2012/13	$0.38	$0.41
EnergyAustralia		
2012/13	$0.34	$0.37
Integral Energy		
2012/13	$0.46	$0.51

Source: Frontier Economics

5.6.2 Differences relative to the 2010 Determination

Results for the volatility allowance from this final report are compared with the equivalent results (from the scenario with a carbon price) from the 2010 Determination in Figure 18. The volatility allowances for the current analysis are lower than the volatility allowance from the 2010 Determination. This is driven by the significantly lower forecast pool prices in the current work.

Figure 18: Volatility allowance results compared to 2010 Determination ($2011/12)



Source: Frontier Economics

6 Carbon pass-through

This section summarises the impact of carbon pricing in the results presented in previous sections.

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.[25]

These measures are presented for:

- the stand-alone LRMC results for each Standard Retailer
- NSW time-weighted, annual average pool prices
- the market-based energy purchase costs for each Standard Retailer

The impact of carbon is different for each of these results. In the stand-alone LRMC approach, investment can respond immediately to the imposition of a carbon price helping to mitigate some of the impact, resulting in the lowest impact of carbon. For NSW pool prices, however, there is no investment response in the short term, only a change in dispatch, so the impact of carbon is greater. The market-based energy purchase cost, which incorporates the peakiness of the Standard Retailers load shapes relative to system demand and also the additional costs of hedging (at an assumed premium of 5 per cent), leads to a higher impact again.

6.1 Stand-alone LRMC

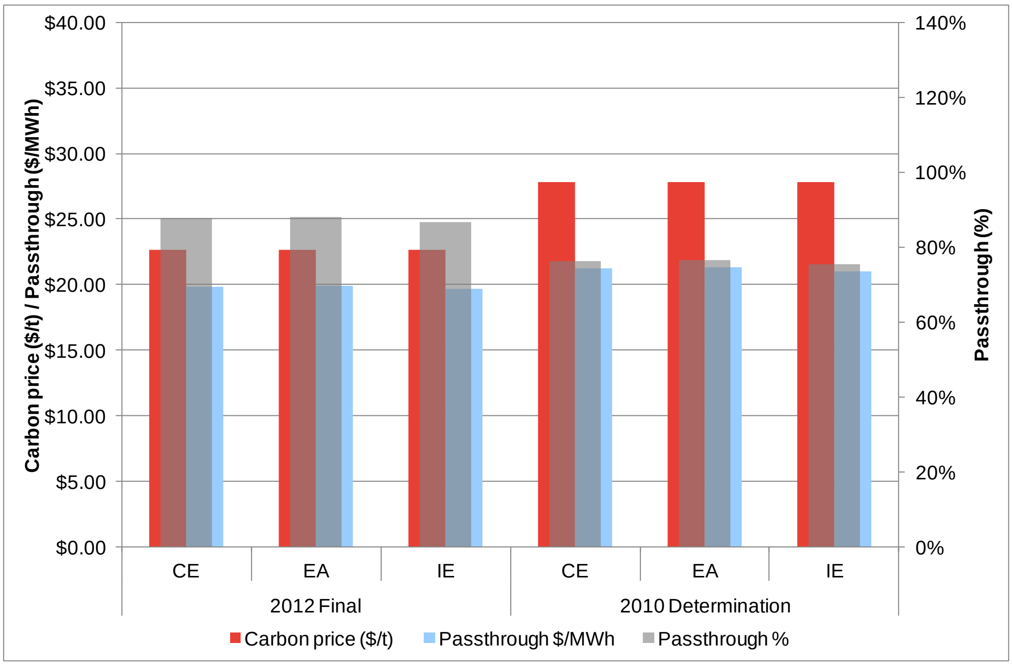
Figure 8 shows the assumed carbon prices (red bars), pass-through in $/MWh (blue bars) and pass-through percentage (grey bars) for both the current analysis and for the 2010 Determination, for the stand-alone LRMC approach. Pass-through is forecast to be around $20/MWh and at a rate of roughly 88% in the current analysis. This pass-through rate accounts for an immediate investment response and the peakier assumed residential load profiles.

Although the assumed carbon price is lower in the current analysis than for the 2010 Determination, the level of pass-through in percentage terms is higher. This is because the lower assumed carbon price means that CCGT plant is relatively less competitive when compared to coal fired generation. As seen in the investment results for the stand-alone LRMC, this leads to coal making up a greater proportion of investment in the current analysis and results in a higher percentage pass-through rate. These two effects – lower carbon prices but higher

[25] That is, the $/MWh difference in pool prices or energy costs with and without carbon divided by the assumed carbon price in $/tCO2e.

pass-through rates – offset each other such that pass-through in $/MWh terms is roughly the same in the current analysis and the 2010 Determination at around $20/MWh.

Figure 19: Carbon pass-through in the stand-alone LRMC results compared to the 2010 Determination ($2011/12)



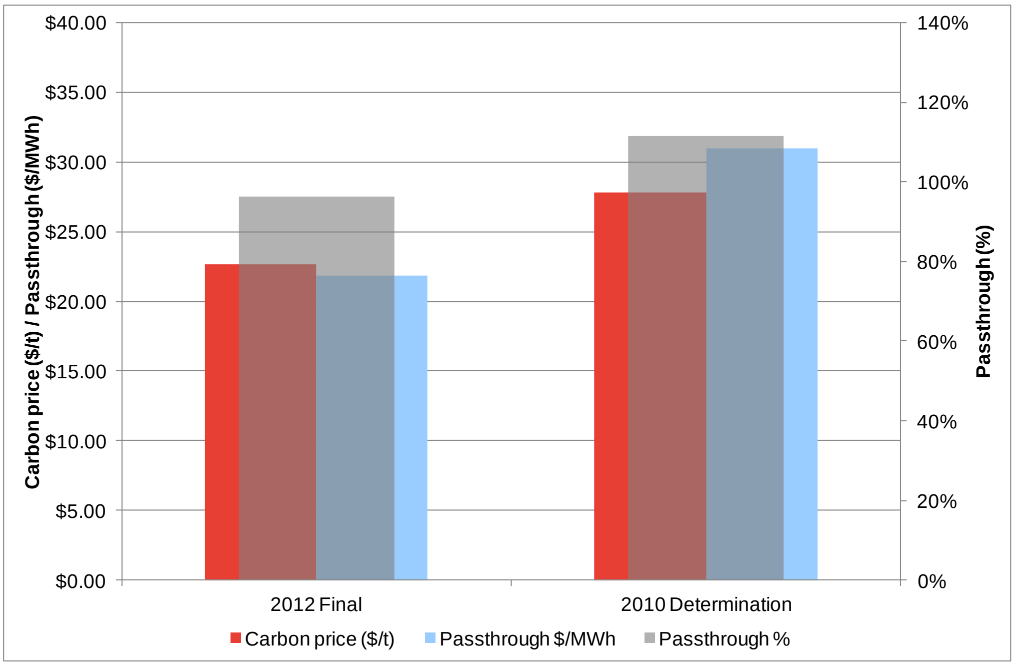
Source: Frontier Economics

6.2 NSW pool prices

Figure 8 shows a similar chart for the NSW wholesale pool price forecasts for the current analysis and for the 2010 Determination. Wholesale price pass-through is forecast to be around $23/MWh and at a rate of roughly 100 per cent in the current analysis.

The higher pass-through rate in the NSW pool prices when compared to the stand-alone LRMC is primarily the result of the fact that NSW pool prices are the result of the bidding of the existing mix of generation plant, rather than a mix of generation plant that is optimised to serve the regulated load after the introduction of a carbon price.

Figure 20: Carbon pass-through in NSW wholesale pool price forecasts compared to the 2010 Determination ($2011/12)



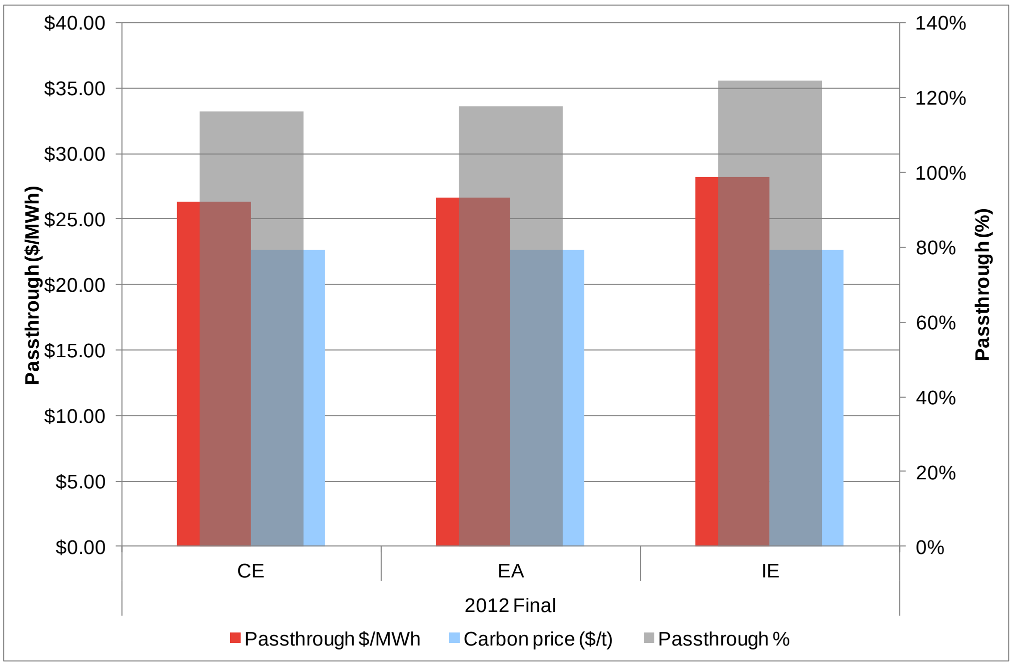
Source: Frontier Economics

6.3 Energy purchase costs

Figure 21 shows the impact of carbon pricing on the energy purchase costs. The energy purchase cost pass-through percentage is on the order of 120 per cent across the Standard Retailers. In $/MWh terms, the impact is roughly $26/MWh.

Carbon pass-through is much higher in percentage terms in the market-based energy purchase costs (at around 120 per cent) relative to the stand-alone LRMC approach (at around 88 per cent). 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.

Figure 21: Carbon pass-through in energy purchase costs by Standard Retailer ($2011/12)



Source: Frontier Economics

7 LRET, SRES and ESS

In addition to reviewing the energy purchase cost allowance for 2012/13, Frontier Economics' scope of work also includes reviewing estimates for a range of other energy-related costs that Standard Retailers will face over the period of the determination.

This section considers the costs that Standard Retailers will face in 2012/13 as a result of the following related schemes:

- the LRET
- the SRES
- the ESS.

Where the 2010 Determination considered the cost associated with the expanded RET, with the splitting of the expanded RET into the LRET and the SRES this 2012 annual review considers both the cost to the Standard Retailers of complying with the LRET and the cost to the Standard Retailers of complying with the SRES.

7.1 LRET

The LRET is essentially a continuation of the RET. The LRET places a legal liability 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 each year by the Office of the Renewable Energy Regulator (ORER). 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 to a Standard Retailer of complying with the LRET, it is necessary to determine the RPP for the Standard 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. ORER 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.

Frontier Economics has used the published RPPs up to 2012 and the renewable energy target in 2012 and 2013 to calculate the RPP for 2013. 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)
2010/11	5.80%
2011/12	7.39%
2012/13	9.78%

Source: ORER, 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.

As discussed in the Frontier Final Report for 2010, Frontier Economics estimated the cost of RECs on the basis of the LRMC of meeting the expanded RET. Frontier Economics considers that an LRMC approach remains appropriate for the LRET for the purpose of this report.

As discussed in the Frontier Final Report for 2010, 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). As discussed in the Frontier Final Report for 2010, 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, and using the updated input assumptions adopted for this 2012 annual review, provides the estimated LRMC of an LGC as set out in Table 6.

Table 6: LRMC of an LGC ($2011/12)

Financial Year	Draft Report LRMC of LGC ($/certificate)	Final Report LRMC of LGC ($/certificate)
2012/13	$38.24	$45.48

Source: Frontier Economics

The increase in the LRMC of an LGC between the draft report and the final report is a result of the updated WACC for generation used for the final report. Since the LRET is met predominantly be wind generation, and wind generation is capital-intensive, the increase in the WACC has a material impact on the LRMC of an LGC. The LRMC of an LGC for the final report – $45.48 – is above the current spot price for LGCs – around $36.50.

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.[26]

Table 7: Cost of complying with the LRET (ESOO 2011 Low, Medium Carbon scenario) ($2011/12)

Financial Year	Draft Report Cost of complying with LRET ($/MWh)	Final Report Cost of complying with LRET ($/MWh)
	Country Energy	
2012/13	$3.75	$4.44
	EnergyAustralia	
2012/13	$3.72	$4.43
	Integral Energy	
2012/13	$3.74	$4.46

Source: Frontier Economics

7.1.3 Comparison to 2010 Determination

The estimated cost of complying with the LRET has increased since the 2010 Determination, as seen in Table 8. This increase is accounted for by two factors:

- An increase in the estimate of the LRMC of an LGC/REC, resulting from the updated input assumptions used for this annual review. The estimate of the LRMC of an LGC for this 2012 annual review is relatively consistent with the estimate for the 2011 annual review.
- An increase in the RPP for 2012/13. As a result of the increase in the adjusted LRET target during calendar years 2012 and 2013, the RPP for

26 Note that, unlike the 2010 Determination, the cost of complying with the LRET estimated for the purposes of this annual review provides different costs (in $/MWh) for different retailers. The reason is that, since the 2010 Determination, Frontier Economics has received more detailed information on the transmission loss factors applicable to each Standard Retailer. As a result, rather than using a single estimate of the transmission loss factor when converting the cost of complying with the LRET (which is calculated relative to purchases at the connection point between the transmission and distribution networks) to a price in $/MWh at the regional reference node, Frontier Economics has used these individual estimates of the transmission loss factor. The effects of this on the resulting cost in $/MWh are minor.

2012/13 is estimated to be significantly higher under the LRET than it was under the RET. This implies a higher cost of complying with the LRET in 2012/13. The estimate of the RPP for 2012/13 for this 2012 annual review is relatively consistent with the estimate for the 2011 annual review.

Table 8: Cost of complying with the LRET, compared to 2010 Determination ($2011/12)

Financial Year	Cost of complying with LRET – 2010 Determination ($/MWh)	2012 Final Report Cost of complying with LRET ($/MWh)
	Country Energy	
2012/13	$2.78	$4.44
	EnergyAustralia	
2012/13	$2.78	$4.43
	Integral Energy	
2012/13	$2.78	$4.46

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 ORER. 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 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 to a Standard Retailer of complying with the SRES, it is necessary to determine the STP for the Standard 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 ORER and is calculated as the percentage required in order to remove STCs from the STC Market for the current year liability. 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. ORER must also publish a non-binding estimate of the STP for the two subsequent compliance years by March 31. The STPs published by ORER for 2011, 2012 and 2013 are set out in Table 9.

Table 9: Small-scale Technology Percentages

Year	STP (% of liable acquisitions)
2011	14.80%
2012	23.96%
2013 (estimate)	7.94%

Source: ORER.

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 the STC 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 IPART's forecast inflation rate of 1.6%, this nominal $40 results in the real STC costs set out in Table 10.

Table 10: STC costs ($2011/12)

Calendar Year	STC cost
2012	$39.68
2013	$39.06

Source: Frontier Economics

7.2.2 Cost of complying with the SRES

In broad terms, the cost to a Standard Retailer of complying with the SRES is the STP multiplied by the cost of STCs.

However, this is complicated by the fact that liable entities' obligation to surrender STCs under the SRES occurs on a quarterly basis and varies over the course of a calendar year. Determining financial year costs (in order to line up with IPART's 2010 Determination, which is on a financial year basis) therefore requires that the cost of complying with SRES is calculated on a quarterly basis and then aggregated to a financial year basis.

Liable entities' quarterly obligations to surrender STCs in calendar year n are determined as follows:

$$Q1 = 35\% * STP_n * (REA_{n-1} - PEC_{n-1})$$

$$Q2 = 25\% * STP_n * (REA_{n-1} - PEC_{n-1})$$

$$Q3 = 25\% * STP_n * (REA_{n-1} - PEC_{n-1})$$

$$Q4 = STP_n * (REA_n - PEC_n) - (Q1 + Q2 + Q3)$$

Where:

STP_n is the STP for year n

REA_n is the retailer's relevant acquisitions of electricity in year n

PEC_n is the retailer's PECs in MWh in year n

Applying this methodology, and using the real STC costs set out in Table 10, the cost each quarter of these quarterly obligations can be determined in real terms. These quarterly costs can then be summed across financial years to provide financial year costs of complying with the SRES.

Frontier Economics has applied this approach for each of the Standard Retailers. The value of REA for each Standard Retailer and each calendar year is based on the forecast regulated load for that Standard Retailer for each calendar year (as measured at the connection point between the distribution network and the transmission network).[27] The value of PEC for each Standard Retailer and each calendar year has been set at zero, on the basis that retail customers are not eligible for PECs.

Using this approach and these inputs, the cost of complying with the SRES is set out in Table 11.

Table 11: Cost of complying with the SRES ($2011/12)

Financial Year	Draft Report Cost of complying with SRES ($/MWh)	Final Report Cost of complying with SRES ($/MWh)
Country Energy		
2012/13	$5.55	$5.61
EnergyAustralia		
2012/13	$5.28	$5.37
Integral Energy		
2012/13	$5.43	$5.52

Source: Frontier Economics

7.3 ESS

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.

27 Frontier Economics has used the regulated load provided by the Standard Retailers for the 2010 Determination.

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.

7.3.1 Approach to estimating costs of complying with the ESS

In order to calculate the cost to a standard retailer of complying with the ESS, it is necessary to determine the energy savings target for a standard retailer (or the number of ESCs that a standard 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 12.

Table 12: ESS target

Calendar year	Effective scheme target (% of annual NSW electricity sales)	Retailer compliance obligation (% of annual liable electricity sales)
2009 (from 1 July)	0.4 %	0.5 %
2010	1.2 %	1.5 %
2011	2.0 %	2.5 %
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

Consistent with the approach adopted for the 2010 Determination, 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. The penalty price of the scheme for 2012 is $26.45/MWh,[28] which is equivalent to an after-tax price of $37.78/MWh.

7.3.2 Cost of complying with the ESS

Based on the energy savings targets set out in Table 12 and the ESS penalty price of $37.78/MWh, the cost of complying with the ESS is set out in Table 13.

Table 13: Cost of complying with the ESS ($2011/12)

Year	Cost of complying with ESS ($/MWh)
2012/13	$1.51

Source: Frontier Economics

28 The penalty price escalates with CPI.

8 Summary of advice

For this annual review, Frontier Economics has calculated the cost to an efficient standard retailer of supplying the Standard Retailers' regulated load using two approaches:

- Stand-alone LRMC – estimates the resource costs associated with a hypothetical generation system to supply the Standard Retailers' regulated load.
- Market-based energy purchase cost – estimates the purchase costs of energy to meet the Standard Retailers' regulated load, including a volatility allowance.

Consistent with the terms of reference for the 2010 Determination, the total energy purchase cost allowance will be based on the market-based energy purchase cost, with the LRMC providing a floor to the energy purchase cost allowance. Results for the stand alone LRMC and for the market-based energy purchase cost are set out in Table 14 and Table 15. It is clear from this that the LRMC provides the basis for setting the energy purchase cost allowance.

For this annual review, Frontier Economics has also estimated a number of other costs, including:

- LRET costs
- SRES costs
- ESS costs.

These other costs are also set out in Table 14 and Table 15.

Table 14: Total energy purchase cost with LRMC ($2011/12)

	LRMC	Volatility	LRET	SRES	ESS
Country Energy					
2012/13	$82.05	$0.00	$4.44	$5.61	$1.51
EnergyAustralia					
2012/13	$85.37	$0.00	$4.43	$5.37	$1.51
Integral Energy					
2012/13	$89.02	$0.00	$4.46	$5.52	$1.51

Source: Frontier Economics

Table 15: Total energy purchase cost with market-based energy purchase cost ($2011/12)

	EPC	Volatility	LRET	SRES	ESS
Country Energy					
2012/13	$64.63	$0.41	$4.44	$5.61	$1.51
EnergyAustralia					
2012/13	$66.01	$0.37	$4.43	$5.37	$1.51
Integral Energy					
2012/13	$70.15	$0.51	$4.46	$5.52	$1.51

Source: Frontier Economics

Appendix A – Further modelling results

This appendix presents the numerical results for the modelling performed using d-cyphaTrade forward prices and for an alternative case that assumes no carbon pricing.

d-cyphaTrade modelling results

We have estimated the market-based energy purchase cost of meeting each of the standard retailers load using d-cyphaTrade forward contract prices (as opposed to contracts priced at a 5 per cent premium to Frontier's own forecast of NSW pool prices). To ensure consistency with the approach for estimating the market-based energy purchase cost (as outlined in Section 5.2), we scaled the half hourly pool prices to be 5 per cent lower than the d-cyphaTrade forward contract prices. The results, based on d-cyphaTrade contract prices as of 29 May 2012, are shown in Table 16.

Table 16: Market-based energy purchase cost results using d-cyphaTrade forward contract prices ($/MWh, $2011/12)

Financial Year	EPC	Volatility	Total
Country Energy			
2012/13	$63.12	$0.44	$63.56
EnergyAustralia			
2012/13	$64.87	$0.38	$65.25
Integral Energy			
2012/13	$69.04	$0.53	$69.57

Source: Frontier Economics

The market-based energy purchase costs using d-cyphaTrade contract prices are similar to the market-based energy purchase costs based on our market modelling. This is to be expected, given that our spot price forecast is quite close to the implied d-cyphaTrade price.

No carbon modelling results

Frontier Economics also modelled a case that assumes no carbon pricing. The assumption of no carbon pricing was adopted for the stand alone LRMC modelling, the incremental LRMC modelling (to determine the LRMC of an

LGC) and the market modelling. Results for the stand alone LRMC and for the market-based energy purchase cost are set out in Table 17 and Table 18.

Table 17: Total energy purchase cost with LRMC – no carbon case ($2011/12)

	LRMC	Volatility	LRET	SRES	ESS
Country Energy					
2012/13	$62.21	$0.00	$5.90	$5.61	$1.51
EnergyAustralia					
2012/13	$65.44	$0.00	$5.90	$5.37	$1.51
Integral Energy					
2012/13	$69.37	$0.00	$5.92	$5.52	$1.51

Source: Frontier Economics

Table 18: Total energy purchase cost with market-based energy purchase cost – no carbon case ($2011/12)

	EPC	Volatility	LRET	SRES	ESS
Country Energy					
2012/13	$38.32	$0.28	$5.90	$5.61	$1.51
EnergyAustralia					
2012/13	$39.40	$0.26	$5.0-	$5.37	$1.51
Integral Energy					
2012/13	$41.95	$0.35	$5.92	$5.52	$1.51

Source: Frontier Economics

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