Energy costs

PUBLIC DRAFT REPORT

PREPARED FOR THE INDEPENDENT PRICING AND REGULATORY TRIBUNAL

December 2006

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1 Introduction

The Independent Pricing and Regulatory Tribunal (IPART) has received Terms of Reference (ToR) from the Minister for Energy to set the regulated retail electricity prices charged by Country Energy, EnergyAustralia and Integral Energy to small retail customers on standard form customer contracts.

Frontier Economics (Frontier) has been retained to assist IPART to develop an allowance for the energy costs to be factored into regulated retail prices. This paper sets out the methodology that Frontier will use to determine cost allowances for energy costs, and Frontier's estimates of energy costs. The methodology adopted to determine the energy cost analysis is guided by the Minister's Terms of Reference (ToR) that identify the matters that need to be taken into account by IPART and provides an indication of the manner in which costs should be determined for the purposes of setting the regulated retail electricity prices.

Frontier has also been retained to assist IPART to develop a cost allowance for mass market new entrant (MMNE) retail costs and retail margin to be factored into regulated retail prices. Frontier, in conjunction with Strategic Finance Group Consulting (SFG Consulting), has prepared a separate draft report that describes how retail costs and retail margin have been estimated, and the results of this analysis.

This draft report sets out the results of Frontier's assessment of appropriate allowances for energy costs. This report will be released for public comment. Frontier will then produce a final report.

This paper is structured as follows:

- Section 2 describes the ToR that have guided the review of energy costs, and how they have been interpreted for the purposes of the review.
- Section 3 sets out the approach that is used to estimate energy costs. Two aspects of costs are estimated: efficient plant costs and efficient energy purchase costs from the market.
- Section 4 presents and discusses the results of the analysis of efficient generation plant costs.
- Section 5 presents and discusses the results of the efficient energy purchase cost using market prices.
- Section 6 presents and discusses the result of the expected costs of retailers meeting their statutory obligations to reduce the greenhouse gas intensity of their sales to customers.
- Section 7 presents the estimated NEMMCO-related costs that retailers are expected to pay.

2 Terms of Reference

2.1 SCOPE OF WORK

Frontier and SFG Consulting have been retained by IPART to provide assistance on two separate, but closely related, consultancies: one for energy costs, and another on retail costs and retail margin.

For the energy costs consultancy, Frontier is to provide IPART with advice on the cost range that should be allowed for energy costs in determining regulated retail tariffs in accordance with the Minister's ToR, including advice on key assumptions. Frontier is required to determine a cost range for each of the following elements, which are to be included in the regulated prices:

- an allowance for electricity purchase costs based on an assessment of the Long Run Marginal Costs (LRMC) of electricity generation from a portfolio of new entrant generation to supply the load profile of customers remaining on regulated tariffs;
- an allowance based on LRMC for retailers' compliance with any Commonwealth Mandatory Renewable Energy Target (MRET) requirements and the licence requirements relating to the NSW Greenhouse Gas Benchmark Scheme (GGAS);
- fees (including all charges for ancillary services) as imposed by NEMMCO under the National Electricity Rules; and
- an allowance for hedging, risk management and transaction costs.

Cost ranges are to be defined for each standard retailer area, broken down into appropriate tariff component categories. The analysis is to consider each year in the determination period, with a focus on the position in 2010.

2.2 INTERPRETATION OF THE TERMS OF REFERENCE

Since 1995 the NSW Government has been committed to the provision of electricity through a competitive market. A key aspect of these competitive reforms was the development of a competitive retail market where customers are allowed to choose their electricity retailer.

The largest electricity customers were given the choice of retailer in October 1996. Since this time, progressively smaller customers have been allowed to choose their retailer. Finally, on 1 January 2002, all customers were given the choice of electricity retailer under a program known as Full Retail Competition (FRC).

The ToR aim to ensure that regulated retail electricity prices are set at cost reflective levels. Setting tariffs at cost reflective levels is intended to encourage efficiency by ensuring that retailers can compete for customers.

The ToR require IPART to consider an allowance for electricity purchase costs based on an assessment of the LRMC of electricity generation. The ToR indicate that these costs should reflect the characteristics of the regulated customer load for each standard retailer.

The ToR also require IPART to consider the hedging, risk management and transaction costs faced be retailers in the absence of the Electricity Tariff Equalisation Fund (ETEF).

In developing this cost allowance the ToR also states that account needs to taken of the costs associated with statutory obligations to comply with the various greenhouse schemes, including the MRET and the GGAS scheme. It may also be necessary for IPART to make provision for the inclusion of an allowance to meet the costs of complying with the proposed NSW Renewable Emissions Target (NRET). Retailers meet these obligations by buying abatement certificates at unregulated costs. The green cost allowance will need to reflect the likely prudent costs of securing adequate supply of abatement certificates to meet these statutory obligations.

Finally, the ToR identifies the requirement to make provision for the fees that retailers have to pay NEMMCO to operate in the NEM. These fees cover NEMMCO's costs as well as ancillary services purchased by NEMMCO to ensure the power system remains in a secure state.

3 Methodology

3.1 ENERGY COSTS, HEDGING AND RISK

A principal difference between IPART's current review of regulated retail electricity prices and IPART's previous reviews is that IPART's previous reviews have all taken place in the presence of either vesting contracts or the ETEF. Under these arrangements there was a very high degree of certainty of energy costs. However, during the regulatory period for the current review, ETEF will cease. There will be no vesting contracts to replace the ETEF, and no other arrangements are proposed to shield the standard retailers from volatile market prices. This presents a serious risk to the standard retailers who are required to purchase electricity at uncertain and volatile costs and sell at regulated prices that are fixed for a three year period from 1 July 2007. There is a risk that standard retailers will be required to sell electricity at prices that are less than the costs of purchasing this electricity. This risk will grow as the ETEF roll-off progresses. It is for this reason that the ToR require IPART to consider the standard retailers' costs of managing this risk.

Allowing for energy purchase risk creates difficulties as there are many possible efficient energy purchasing strategies depending on a retailer's risk preference. In general:

- More risk-averse retailers will incur higher energy purchase costs. Highly risk-averse retailers will enter into contracts that guarantee their energy purchase costs for all plausible levels of load (for instance, swap contracts).
- Less risk-averse retailers may choose to enter into a suite of contracts that caps their exposure to the pool price but provides opportunities to get access to low prices (for instance, cap contracts).

In addition to this complexity, there is a great deal more uncertainty surrounding future spot and hedging contract prices compared to efficient plant cost.

Importantly, there are significant risks of miscalculating the future energy purchase costs. If this cost is underestimated then standard retailers face a potential financial loss of selling electricity more cheaply than the costs of purchasing electricity. If the cost is overestimated this will provide standard retailers with a windfall that they could use to price more competitively than retailers that do not serve regulated customers. This could act as a barrier to entry for competing retailers. This barrier could further entrench the incumbency of the standard retailers and have the opposite outcome to that envisaged by the ToR – that is, a degradation of retail competition.

The approach that is developed by Frontier to estimate the energy cost allowance has been explicitly designed to take account of the increased energy purchase cost uncertainties facing standard retailers. At the same time the approach considers the trade-off between costs and risk and the unique characteristics of the customer load that each standard retailer serves.

This approach is based on portfolio optimisation theory. Standard portfolio theory provides a robust framework for evaluating the trade-off between risk and return. Portfolio theory was developed as a response to the adage that "putting all your eggs in one basket" is not a sensible investment strategy in a risky environment. However, since the returns on different assets are correlated in various ways, it is not obvious how a business might best diversify its assets when attempting to balance risk and return. In a paper published in 1952, Markowitz solved this problem for assets that have normally distributed returns.[1] Markowitz's solution has become known as the minimum variance portfolio (MVP).

More specifically, portfolio theory sets out how rational investors could use diversification to optimise their portfolios (i.e. maximise returns or minimise costs), and how an asset should be priced given its risk relative to the market as a whole. Portfolio theory estimates the return of an asset as a random variable and a portfolio as a weighted combination of assets. The return of a portfolio is therefore a random variable and consequently has an expected value and a variance. Risk in this economic model is usually identified with the standard deviation of portfolio return (although other measures of risk can be used). For a given return a rational investor would choose a less risky portfolio. In portfolio theory this relationship between risk and reward is represented by an *efficient frontier*.

The efficient frontier describes the outer edge of every possible combination of assets that could be plotted in risk-return space. Combinations of assets along this line represent portfolios for which there is lowest risk for a given level of return. Conversely, for a given amount of risk, the portfolio lying on the efficient frontier represents the combination of assets offering the best possible return.

In general, the efficient frontier will be concave, as seen in Figure 1. It is not possible to construct a portfolio that lies above the frontier and portfolios below the frontier are suboptimal.

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1 Markowitz, H. (1952), "Portfolio selection", *Journal of Finance*, 7, 77-91.

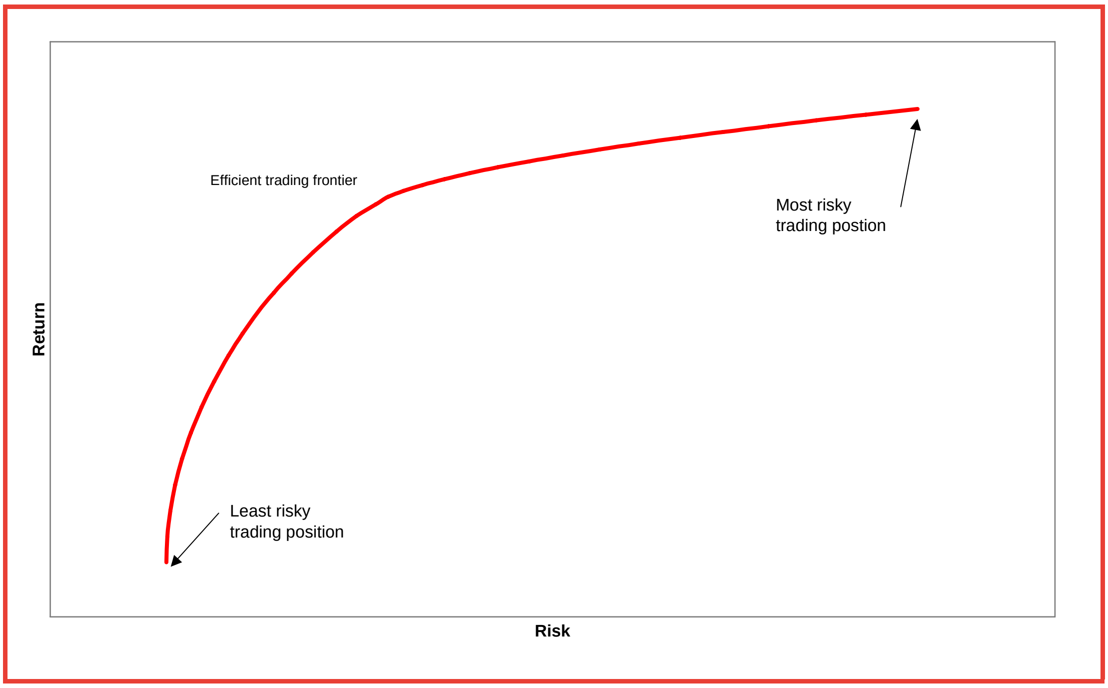

Figure 1: A generalised efficient frontier

To understand Markowitz's approach to obtaining the minimum variance portfolio (MVP), consider a collection of *n* possible assets. We assume that we can characterise each asset by two measures:

- **Expected return**: the average level of return expected from the asset.
- **Variance**: a measure of risk that captures how much actual returns might deviate from the expected return in any period.

In addition, we require information on the correlations between the returns.

In the electricity industry, values for all these measures are typically estimated using historical data, calculated via simulations of systems operation, based on expert judgement, or a combination of the above.

Given information on the expected returns of the *n* assets, the variances of the returns and the correlations, it is possible to calculate the expected return and variance for any portfolio consisting of a mix of the assets. By varying the mix of assets, one obtains portfolios with different expected returns and variances (risk levels).

In general, a portfolio with a higher expected return also involves greater risk, so that expected return needs to be traded off against risk. Markowitz showed how, for any desired level of expected return, we can construct the mix of the *n* assets that has the least risk as measured by the variance.

By solving this problem for different expected returns, and graphing the solutions, we can map out a so-called MVP frontier. It has become common to plot the MVP frontier by placing the standard deviation of the portfolio returns on the X-axis,[2] and the expected return on the Y-axis.

Figure 2 shows such a frontier for combinations of two assets, A and B. Portfolio R is obtained by having a mix of 67.5 per cent of asset A and 32.5 per cent of asset B, while portfolio C has a mix of 35 per cent of asset A and 65 per cent of asset B.

Note that for any portfolio on the lower (red) arm of the MVP frontier, there is a corresponding portfolio with exactly the same risk on the top (blue) arm that has a higher expected return. Thus, even though points on the lower branch of the frontier are minimum variance portfolios for their specified level of expected return, there is always a preferable portfolio with a higher return and the same risk. For this reason, the top branch of the frontier, starting at portfolio C, is called the 'efficient' portfolio frontier.

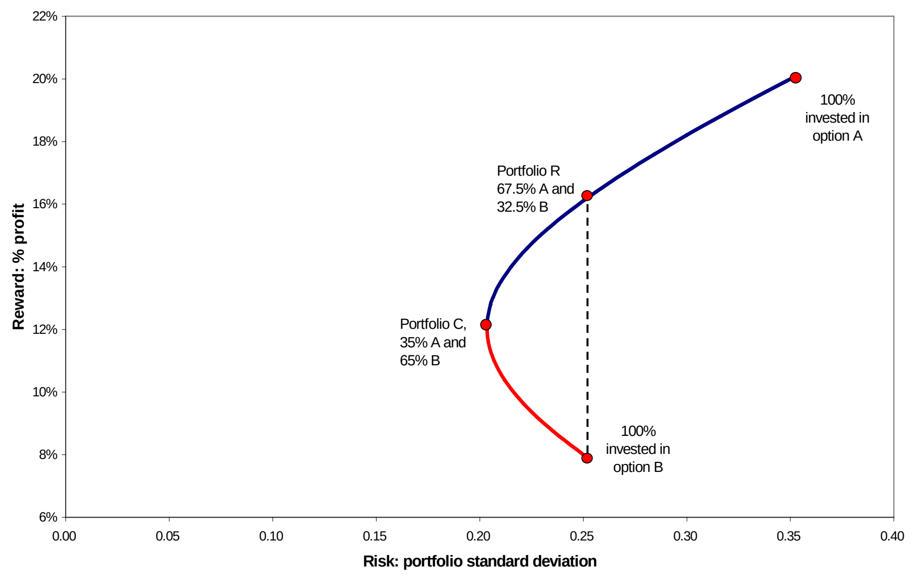

Figure 2: Risk-return curve for investment in assets A and B for correlation coefficient, $\rho = 0$

2 Using the standard deviation as the risk measure, instead of the variance, leads to algebraically identical solutions, and is easier to interpret.

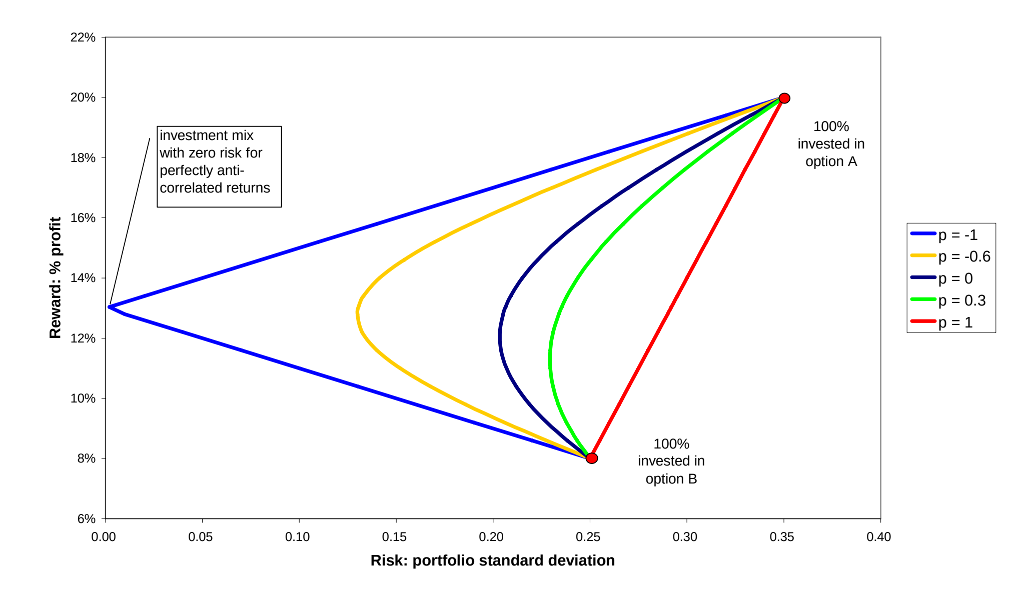

Figure 3: Risk-return frontiers for investment in assets A and B with different levels of correlation, *ρ*

Figure 2 assumes that there is no correlation between the returns on the two assets. Figure 3 shows a number of MVP frontiers for different levels of correlation between the two assets. We can see that as the correlation between the returns on assets A and B become more negative, the risk associated with a portfolio of these assets becomes smaller. Hence the benefits associated with diversification, called the portfolio effect, increases as the correlation between the assets decreases.

The situation illustrated in Figure 2 and Figure 3, with only two assets, is in fact somewhat artificial, since every mix of the two assets lies on the MVP frontier. The situation with more than two assets is illustrated in Figure 4. By plotting the expected return against the standard deviation for all the possible portfolios of the assets, we obtain the so-called feasible region. The left-hand edge of that region is the MVP frontier. As before, the upper arm (green in this case) represents the 'efficient' portfolio frontier.

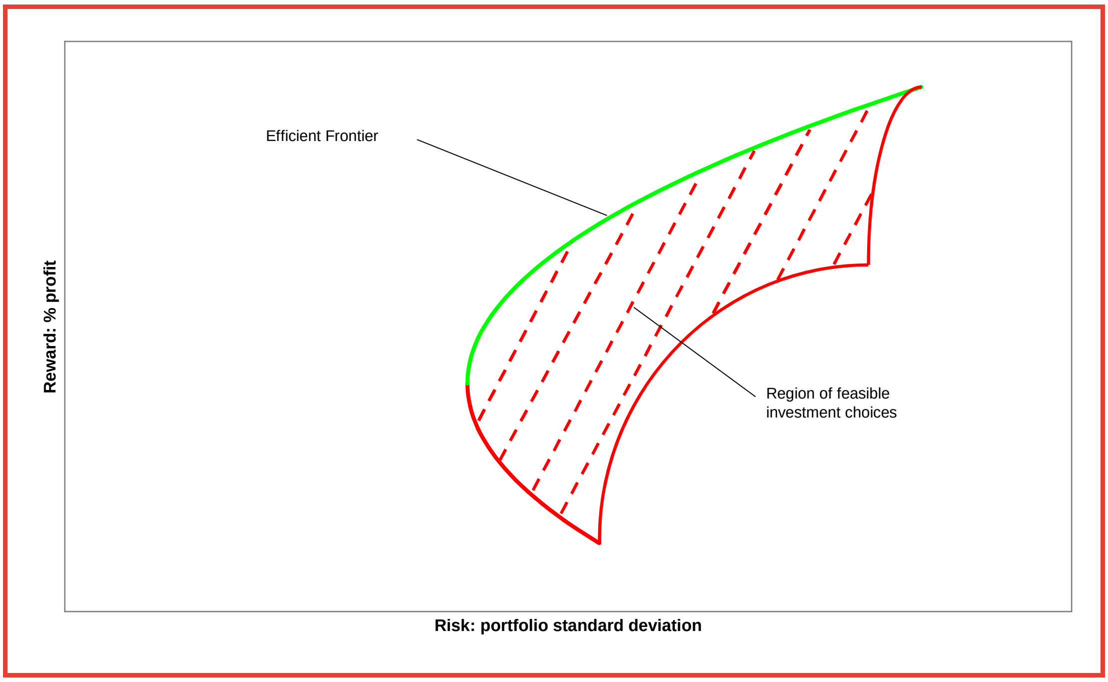

Figure 4: Feasible region and the efficient frontier when there are more than two assets

Adopting this approach, an efficient frontier is formulated for each retailer's regulated load for each year of the Determination period. The range of 'assets' to be evaluated/optimised will be a standard and well-accepted suite of energy purchasing options available to standard retailers. For example, all standard retailers are able to purchase flat and peak swap contracts and cap contracts. Other, more exotic, contracts are also available, but the analysis will generally be confined to those contract forms where there is reasonable quality data available, including a reasonable estimate of forward prices. The efficient frontier will provide IPART with a range of possible efficient costs that vary according to the level of risk.

In addition to these market based costs, the analysis of the energy allowance involves the estimation of the costs of the most efficient mix of (new entrant) generating plant that would notionally be required to serve each standard retailer's regulated load. The results of this analysis is expected to assist IPART in judging the most appropriate level of market costs.

A more detailed description of the analytical approach is available in Frontier's Draft Methodology Report.[3] In the following two sections of this report the approach for measuring the efficient plant costs and market costs are described, and results are presented.

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3 Frontier Economics (2006), Draft methodology report for energy cost consultancy and retail cost/margin consultancy, October.

http://www.ipart.nsw.gov.au/files/Frontier Economics - Draft methodology paper - FINAL - 27 October 2006.PDF

4 Efficient generation costs

As discussed, the ToR require that IPART consider two different aspects of energy costs – the least cost mix of generation plant and the costs associated with purchasing energy from the market. The former is generally known as the long run marginal cost (LRMC) of generation. Results of Frontier's LRMC modelling are presented in this section.

The LRMC of electricity generation is estimated using *WHIRLYGIG*, Frontier's total cost optimisation model of the National Electricity Market (NEM). *WHIRLYGIG* computes the least-cost mix of generation and greenhouse abatement investments to meet a particular load, subject to meeting a system reliability target (as determined by NEMMCO) and any greenhouse emission targets.

4.1 METHODOLOGY FOR ESTIMATING LRMC

There are two broad approaches to modelling the LRMC of generation:

- **Stand-alone load** – this approach assumes that there is currently no plant available to serve the load. This approach will effectively build, and price, a whole new generation system that is least cost. This approach has the effect of re-pricing all existing capacity at efficient levels.
- **Incremental load** – this approach measures the incremental fixed (therefore, long run) and variable costs of supplying an additional unit of load. This approach seeks to price load on the basis of the least cost way of adding to the existing stock of plant.

The incremental approach tends to produce a lower estimate of LRMC than the stand-alone approach. The reason is that it is often cheaper to expand an existing facility (as can occur under the incremental approach) than to build new 'greenfield' plant (as occurs under the stand-alone approach).

The ToR do not clearly indicate which approach should be used. However, the ToR do require IPART to consider "an allowance for electricity purchase costs based on an assessment of the long-run marginal cost of electricity generation from a portfolio of new entrant generation to supply the load profile of customers remaining on regulated tariffs." Given the stand-alone approach measures the costs of a portfolio of new generation plant, the stand-alone approach seems more consistent with the ToR. Also, it is difficult to conceive of how to appropriately attribute the incremental costs of the *system* to each different regulated load of the retailers. This would involve arbitrary cost allocation assumptions, which would be highly contentious.

4.2 MODELLING APPROACH

The optimal (least-cost) mix of generation and greenhouse abatement investments will be determined using *WHIRLYGIG*, Frontier's total cost optimisation model of the NEM system. A detailed description of *WHIRLYGIG* is provided in Frontier's Draft Methodology Report.

WHIRLYGIG computes the least-cost mix of generation and greenhouse abatement investments, subject to meeting a system reliability target (as determined by NEMMCO) and any greenhouse emission targets (including, for instance, MRET and GGAS – explained in more detail in Section 6.1).

WHIRLYGIG estimates the least-cost mix of generation, interconnection, demand side management and greenhouse abatement investments on the basis of the existing mix of generation plant, or on the basis of the mix of generation plant that a new entrant would build for a particular load. For the purposes of estimating the LRMC of electricity generation, a mix of new entrant generation is used, in accordance with the ToR. Generally well-accepted and publicly available data sources are used, so that the analysis presented here can be easily replicated.

In *WHIRLYGIG* the objective function is to minimise the *total cost* (fixed and variable costs) of meeting demand for electricity, subject to meeting a given greenhouse emission target and available greenhouse abatement options.

WHIRLYGIG is formulated as mixed-integer programming (MIP) problem – a specialised linear programming problem where usually some, and sometimes all, decision variables are constrained to integer values.

In *WHIRLYGIG* the investment options are categorised into three groups:

- interconnection options;
- generation plant; and
- non-generation greenhouse emission abatement options (including load management)

WHIRLYGIG requires general system data for:

- the regional demand levels over a representative set of dispatch periods;
- the frequency of occurrence (hours per year) of each representative period;
- the interconnection capacities between regions; and
- the reserve capacity requirements for each region.

4.3 MODELLING RESULTS

Table 1 sets out the estimated stand-alone LRMC of a portfolio of new entrant generation to meet the load profile of each retailer's regulated customers. These estimates are based on publicly available generation costs from a report commissioned by NEMMCO (the so-called ACIL cost estimates)[4].

[4] The NEMMCO LRMC values were based on an assumed capacity factor and would differ for different a capacity factor assumption. The LRMC values were split into fixed and variable components to allow the optimisation process the ability to determine the optimal capacity factor for each plant. The variable component comprised fuel and variable operations and maintenance costs (in $/MWh). The fixed component comprised all other costs and was converted to an hourly cost per MW amortised over the economic life of the plant. Costs for Coal, CCGT and OCGT plant in NSW were used.

Cost component	Year	**Country Energy**	**Energy Australia**	**Integral Energy**
Energy	2007/08	$39.0	$45.3	$45.7
	2008/09	$39.2	$45.5	$46.1
	2009/10	$39.1	$45.6	$45.3
MRET[5]	2007/08	$1.1	$1.1	$1.1
	2008/09	$1.4	$1.4	$1.4
	2009/10	$1.7	$1.7	$1.7
NRET	2007/08	$0.4	$0.4	$0.4
	2008/09	$0.6	$0.6	$0.6
	2009/10	$0.9	$0.9	$0.9
GGAS	2007/08	$2.6	$2.6	$2.6
	2008/09	$3.0	$3.0	$3.0
	2009/10	$3.5	$3.5	$3.5
Total LRMC	**2007/08**	**$43.2**	**$49.5**	**$49.9**
	2008/09	**$44.2**	**$50.5**	**$51.2**
	2009/10	**$45.2**	**$51.7**	**$51.4**

Table 1: LRMC based energy costs

These estimates for LRMC include the following components:

- **Energy cost** – measures the demand weighted average cost of new non-renewable generation plant, as well as the cost of meeting the reserve constraint, divided by each retailer's average MWh of use. Obviously, where there is a peakier load (e.g. for Integral Energy and EnergyAustralia) the costs of the reserve constraint are spread over a smaller base of sales, which raises the average price. As a result, Integral Energy and EnergyAustralia have a higher energy charge than Country Energy.
- **GGAS charge** – measures the cost of purchasing NGACs. GGAS costs are estimated on the basis of incremental costs, that is, having regard to the existing system. This is necessary to achieve a more realistic cost allowance.

5 See discussion in Section 6.1 on the basis of the LRMC estimation for MRET.

The GGAS scheme aims to encourage retailers to reduce greenhouse gases by adopting newer, cleaner technology. When a new power system is built in the stand-alone analysis the model naturally constructs newer, cleaner generators (for example, it would be nonsense to allow the model to construct a 1970's style plant). This newer, cleaner technology produces a lower rate of greenhouse gas emissions than the current stock of older generating plant. Indeed, the higher greenhouse efficiency of this new generation plant is sufficient to meet the GGAS target without requiring any special purpose investments. Given this low emmissions outcome is a by-product of meeting the *energy* needs of regulated customers in the stand-alone analysis, there are no incremental costs associated with meeting the GGAS target. Therefore, the retailers would not require any additional allowance from IPART to meet their GGAS obligations. This outcome is obviously not realistic as, in practice, standard retailers buy energy from the NEM, which is dominated by older, less greenhouse friendly generation technologies. In reality, retailers have to buy certificates to meet their GGAS targets. For this reason we have used the costs associated with meeting the various greenhouse gas reduction schemes from the incremental approach, which takes account of the emission rates of the current stock of plant.

The modelling of the NGAC price incorporates the effect of the recently passed legislation to extend the GGAS scheme to 2020. Section 6 provides a comparison between these efficient prices and the forward prices derived from third-party data sources.

- **NRET/MRET charge** – measures the cost of meeting the NRET/MRET targets. These costs have been estimated on the same basis as the GGAS charge.

The differences in LRMC between the three retailers are driven by differences between the retailers' load profiles for regulated customers. A less peaky load is cheaper to supply since less peaking plant is required to meet load, which means that the stock of plant is utilised more throughout the year, thereby reducing average costs.

The peakiness of a load can be summarized by the 'load factor'. Load factor measures the relationship between average and peak load. A relatively low load factor indicates a peaky load, while a relatively high load factor indicates a flat load.

The annual LRMC based cost estimates have been decomposed into Peak, Shoulder and Off-peak and are shown in Table 2 below for each standard retailer.

The definitions of Peak and Shoulder varied slightly between each standard retailer, however the Off-peak definition was consistent. To aid in comparison between costs for each retailer, an additional column is presented in the tables, "Peak & Shoulder", combining the Peak and Shoulder periods to provide a cost measured on a consistent basis for each retailer.

The allocation of costs between Peak, Shoulder and Off-peak periods was determined by:

- allocating all variable costs (predominantly fuel costs) to each respective period;
- allocating the half-hourly capacity costs of plant required for energy production to each respective period; and
- allocating the remaining capacity costs (spare capacity in each half-hour) to each period according to the relative scarcity of capacity (using the loss-of-load probability, or LOLP).

This approach effectively values spare capacity over the year according to relative scarcity. For example, at times of peak demand, capacity will be relatively scarce, LOLP will be relatively high and hence the value of capacity will be relatively high.

		Peak	Shoulder	Off-peak	Peak & Shoulder	All periods
Country Energy	2007/08	$79.1	$30.8	$31.4	$50.0	$39.0
	2008/09	$79.9	$30.8	$31.3	$50.3	$39.2
	2009/10	$79.8	$30.8	$31.3	$50.2	$39.1
Energy Australia	2007/08	$96.1	$32.4	$31.5	$52.0	$45.4
	2008/09	$96.7	$32.5	$31.6	$52.4	$45.6
	2009/10	$97.9	$32.4	$31.6	$52.9	$45.7
Integral Energy	2007/08	$94.1	$33.8	$32.7	$54.2	$45.8
	2008/09	$96.7	$33.8	$32.8	$55.0	$46.2
	2009/10	$93.2	$34.1	$33.2	$53.9	$45.4

Table 2: LRMC (energy only) based energy cost breakdown to Peak, Shoulder & Off-peak

For EnergyAustralia and Integral Energy, the Peak cost is higher than the Shoulder, which is in turn higher than the Off-peak cost. However, for Country Energy, the Shoulder cost is marginally lower than the Off-peak cost. This is due to the nature of the regulated customer load combined with Country Energy's Off-peak and Shoulder time period definition with regard to weekends. Country Energy defines all weekend hours as Off-peak, whereas both EnergyAustralia and Integral Energy define weekends between the hours 7am to 10pm as Shoulder periods (for a significant proportion of customers at least). The nature of regulated customer load is such that consumption on weekends can be comparable to weekday consumption patterns, hence the Country Energy Off-peak load shape is more peaky than the Shoulder load shape.

5 Market-based approach

5.1 METHODOLOGY

The approach for measuring the appropriate allowance for managing the energy purchase cost risk associated with the roll-off of the ETEF was explained in Frontier's Draft Methodology Report, and is summarized in Section 1 of this report.

The most important aspect of this stage of the analysis is the estimation of the cost of the future energy purchasing options available to standard retailers as the ETEF rolls off. The portfolio optimisation model will find the least cost mix of these energy purchasing options, based on the assumed costs of each option and the characteristics of each standard retailer's regulated customer load.

There are several different sources of data available on the future costs of these different energy purchasing options, none of which are without shortcomings. These sources include:

- The standard retailers' own estimate of future costs – the difficulty with using these cost estimates is that the businesses have a strong pecuniary interest in the outcome of using this data and therefore may be inclined to inflate their cost estimates. In any case the businesses would legitimately argue that their current view of future cost may well change depending on other developments in the market. For example, within the Determination period a major power station may suffer a major fault that increases the scarcity of reserves and increases the opportunity cost to generators of signing hedging contracts. This will cause contract prices to rise. The opposite may occur if the development of a major new power station proceeds, which increases the availability of reserves and reduces the opportunities for generators to raise prices. It may also be argued that these uncertainties are embodied in the businesses' views about future prices, and that little further consideration of the possible effects of such events need occur. For example, market participants understand that ETEF will be rolling off over the Determination period. They will have already factored the effects of the roll-off in ETEF into their price expectations. However, this does not suggest that their expectations might change as their experience of the effects of the roll-off of ETEF improves.
- Third-party sources such as estimates from AFMA, ICAP, d-cypha – these cost estimates are generally based upon a limited survey of industry participant views about future prices, or on the basis of trades that have occurred in the market. Many would argue that the survey data is unrepresentative and unreliable due to the small and changing sample of participants. Also, many would argue that the hedge price data based on actual trades represents a relatively small and unrepresentative quantity of total trade in the market as most hedging occurs in the Over-The-Counter (OTC) market, the results of which are not publicly available.

- Simulated market prices – this approach seeks to predict future prices based on a simulation of the operation of the NEM, including known and possible changes in market structure and operation. The advantage of this approach is that the influence of significant expected changes in the market structure can be analysed, such as the roll-off of ETEF. Also, many different scenarios can be modelled to provide a range of prices. Moreover, the results of a simulation exercise are not reliant on the views of a small number of market participants or on the results of a small number of trades in the market. The disadvantage of the simulation approach is that the results are largely determined by the assumptions in the model. The most important of these assumptions is the price and quantity that generators offer to supply the market. Bidding behaviour is driven by a very large number of interacting factors. It is very difficult to define with any precision how each of these factors influence a generator's bidding decisions and harder again to define the relationship between these factors. This means that assumptions about the future bidding behaviour of generators are speculative and should be treated with caution.

The approach that is used in this analysis is to rely on all three methods to come to a view on the range of possible cost outcomes. The view of the appropriate energy cost allowance will to some degree be guided by the range and consistency of the broader view of future prices. In addition, it would be expected that the view on the energy cost allowance would be guided by the relative position of the expected market costs and the costs of the most efficient plant mix required to meet the regulated load.

5.2 MODELLING APPROACH

Using the first two sources of energy purchase cost data the efficient energy purchase costs for each retailer are measured using the portfolio optimisation approach summarized above and described in more detail in the Draft Methodology Report.

Using the third source of energy purchase cost data – simulated market prices – is a more intensive three-staged modelling exercise:

- Stage 1 – The first stage involves modelling the future characteristics of the NEM power system over the Determination period, focusing on the requirement for new generation capacity by location to meet the NEM reliability criteria and accounting for possible changes in the NEM rules, such as the possible treatments of the Snowy region. This stage involves the use of Frontier's long-term NEM investment model, *WHIRLYGIG*. The structure and operation of *WHIRLYGIG* is summarized in Section 1 and detailed in the Draft Methodology Paper.
- Stage 2 – Involves modeling the price outcomes in the NEM based on the market structure derived in the Stage 1 modelling using Frontier's market model, *SPARK*. This stage focuses on identifying optimal (i.e. mutually profit maximizing) generator bidding patterns and using these to determine future prices. This analysis is used to understand the effects on the market price

from the roll-off of ETEF, together with the tightening of the balance of supply and demand over the Determination period. The results of this modelling are a set of half hourly spot price forecasts for the Determination period. Contract prices can be derived from these spot forecasts. The most contentious issue in forming these estimates is the appropriate contract premium compared to the spot price *in the absence of the contract* (as distinct from the observed difference between contract and spot prices once the contract has been agreed).

- Stage 3 – This stage involves drawing together the spot and contract price data derived from Stage 2, together with each standard retailer's regulated load, into Frontier's portfolio optimisation model, *STRIKE*. *STRIKE* determines the efficient mix of energy purchasing instruments (i.e. spot and contracts of various kinds) for each level of risk.

This 3-staged modelling process and the relationship between each model is summarised in Figure 5.

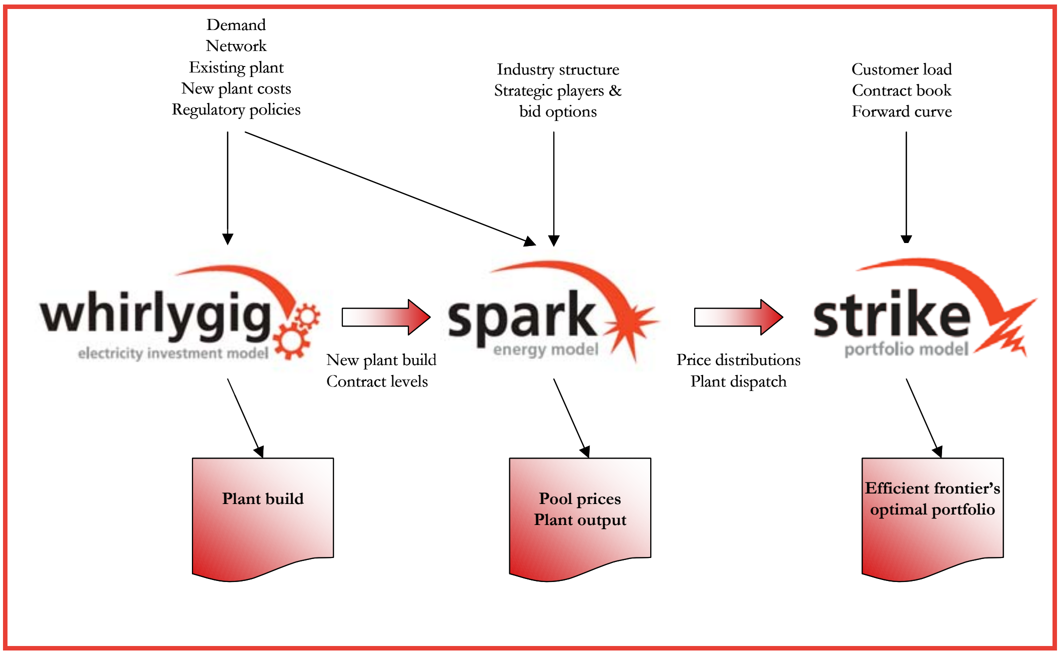


Figure 5: Three staged electricity modelling process

5.3 MODELLING RESULTS

In this section of the report the results of the energy purchase costs are presented and discussed. The *STRIKE* analysis is undertaken using the standard retailers' own estimates of future spot and contract prices together with Frontier's estimates.

5.3.1 STRIKE data

The *STRIKE* analysis requires a correlated time-series of load and spot price data as an input. It is important that the data capture the likely correlation of load and spot price, as this relationship will ultimately impact on the efficient energy purchase costs. For example, a given load shape with a relatively high correlation to spot prices will have a higher efficient purchase cost than the same load shape with a lower correlation to spot prices.

The standard retailers provided half-hourly regulated load forecasts spanning the Determination period. However, spot price forecasts were given at an average level by quarter and peak/off-peak. Spot price data is required on a half-hourly level for the *STRIKE* analysis, and should ideally capture the likely correlation between load and spot price.

To the extent that the regulated load shape has not changed significantly over time, we can use historic load and price data for the *STRIKE* analysis. Five years of actual half-hourly regulated load data (used for settlement of the ETEF, supplied by NSW Treasury) and matching half-hourly NSW spot prices (sourced from NEMMCO) have been used, covering the period 1-July-2001 through 30-June-2006.

The load and spot price data has been adjusted for the purpose of the analysis as described in the following sections.

5.3.2 Regulated load

To test whether the historic regulated load shape is a reasonable match to the forecast load shape, load duration curves (LDCs) of actual historic and forecast regulated load are plotted. The LDCs have been normalised to an average demand of 1 MW (over each financial year) for comparison.

The *STRIKE* analysis combines the (normalised) historic regulated load and spot price for all five available years creating a distribution of possible load shapes and spot prices for each standard retailer.

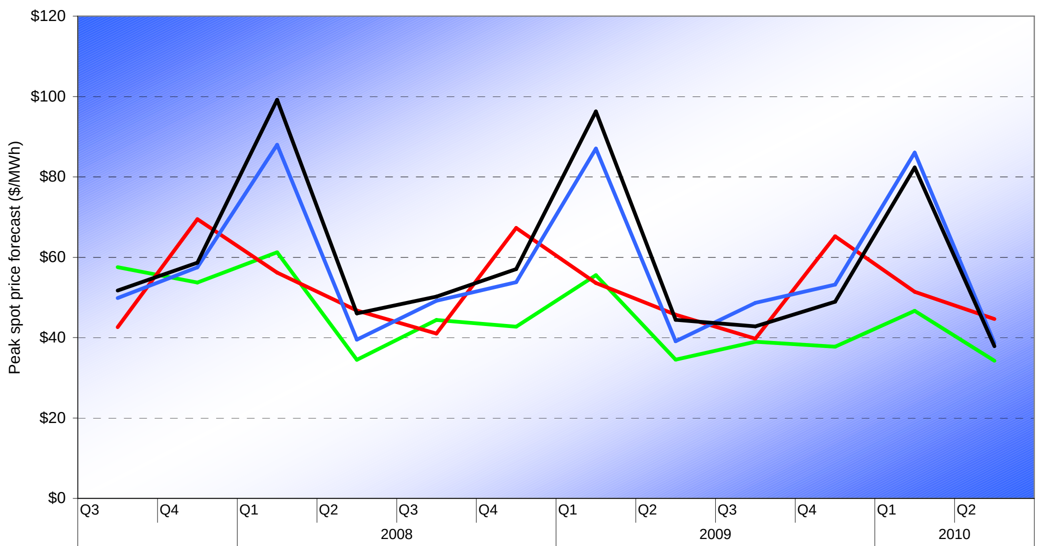
5.3.3 Spot price forecasts

IPART issued a data request asking for, among other things, the standard retailers' estimates of future spot and contract prices over the Determination period.

Historic half-hourly spot prices provided by the standard retailers were scaled (linearly) to match the quarterly peak/off-peak price forecasts provided by the standard retailers. The linear scaling preserves the observed historic correlation between load and prices.

Figure 6 and Figure 7 summarise, respectively, the peak and off-peak price forecasts provided by the standard retailers. These figures also include Frontier's spot price forecasts for the same period.

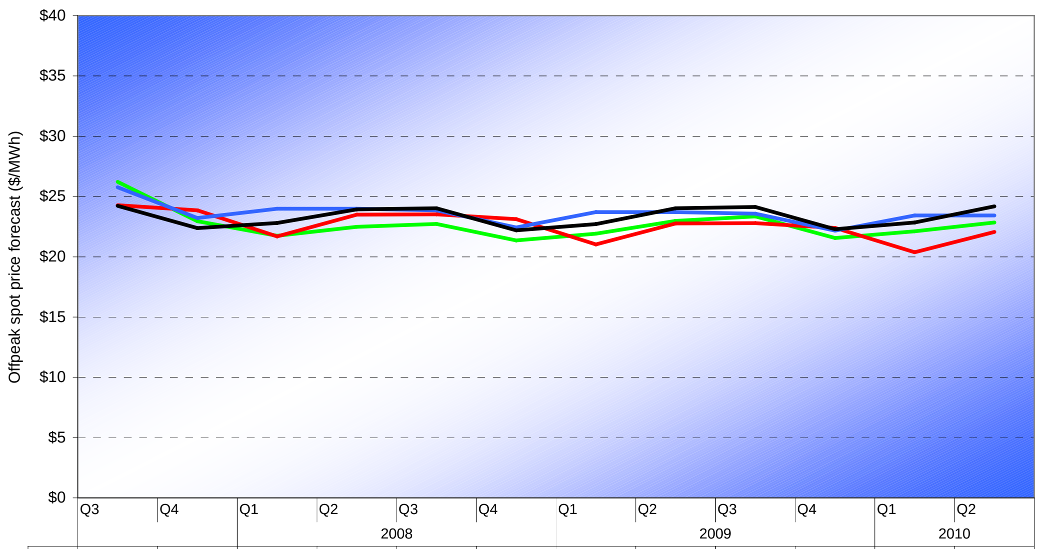
As discussed above, the half-hourly spot prices were matched with the half-hourly load to maintain the historic correlation between regulated load and spot price in the *STRIKE* analysis.



	2008						2009				2010	
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
1	$57.5	$53.7	$61.2	$34.5	$44.4	$42.7	$55.5	$34.5	$39.0	$37.7	$46.7	$34.2
2	$42.6	$69.4	$56.2	$46.8	$41.0	$67.3	$53.6	$45.7	$39.7	$65.2	$51.4	$44.6
3	$49.8	$57.5	$88.0	$39.5	$49.2	$53.8	$87.0	$39.1	$48.6	$53.2	$86.1	$38.7
4	$51.7	$58.7	$99.2	$46.0	$50.2	$57.1	$96.3	$44.5	$42.8	$48.9	$82.3	$37.8

Figure 6: Peak spot forecasts

The differences between views on the forecast off-peak spot prices is less pronounced. This is to be expected, given that, historically, these prices have been far more predictable. Having said that, the differences in off-peak prices more or less match those for the forecast peak prices, as described above.



	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
	2008						2009				2010	
1	$26.2	$23.0	$21.7	$22.5	$22.7	$21.4	$21.9	$23.0	$23.4	$21.6	$22.1	$22.8
2	$24.3	$23.8	$21.7	$23.5	$23.5	$23.1	$21.0	$22.8	$22.8	$22.4	$20.4	$22.1
3	$25.8	$23.2	$24.0	$24.0	$23.8	$22.4	$23.7	$23.7	$23.6	$22.2	$23.4	$23.4
4	$24.2	$22.4	$22.8	$23.9	$24.0	$22.2	$22.7	$24.0	$24.1	$22.3	$22.8	$24.2

Figure 7: Off-peak spot forecasts

5.3.4 Contract price forecasts

As with spot prices, the range of forecast contract prices across the retailers, including Frontier's forecast contract prices, were used to provide a range for contract prices.

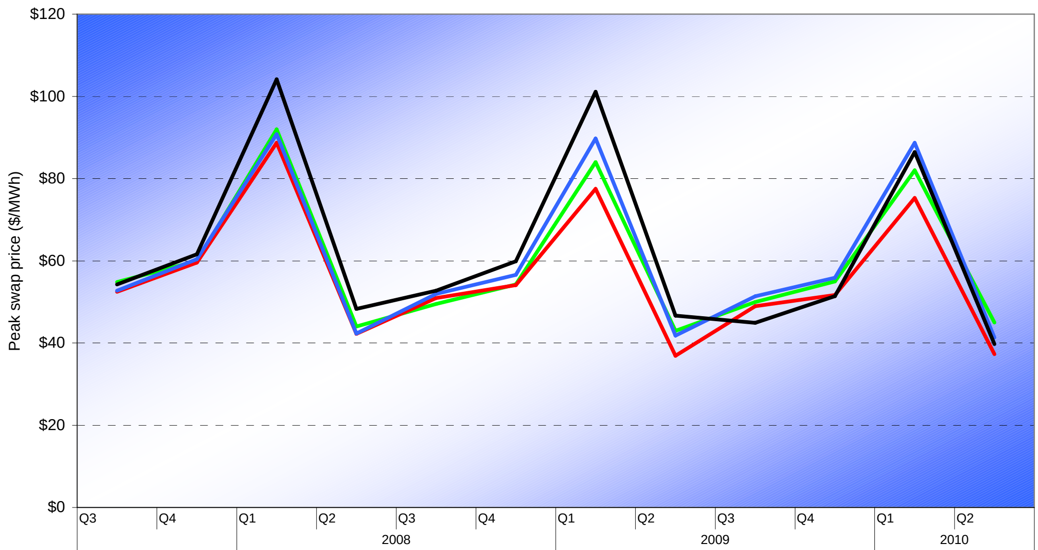
To check the reasonableness of the standard retailers' view of future prices, their estimates have been checked against three other sources – AFMA, ICAP and d-cypha. Some of these series are incomplete in that they do not cover all the key hedging products typically used by participants or their data does not extend to the end of the Determination period. For this reason, this third-party data has not been used to estimate the efficient energy purchasing costs. Rather, the data has been used to judge whether the standard retailers' data is similar to these third-party sources. This third-party data has been manipulated in the following manner to provide a comparative series to the standard retailer data:

- d-cypha: The d-cypha swap data from Q3 2009 onwards seems unreliable due to little trading activity for these products. Implied off-peak swap prices were calculated from the base and peak prices (assuming 44.65 per cent of each quarter are peak hours). $300 cap premium data was only available up to Q4 2008.
- ICAP: Quarterly peak and off-peak prices were available to Q1 2008. Thereafter quarterly swap prices were calculated based on pro-rating the 2007 quarterly prices over the 2008 to 2010 calendar year prices. Flat quarterly $300 cap premiums were available to Q3 2007. The implied Q4 2007

premium was calculated from the Q1-Q3 premiums and the calendar 2007 premium. A similar pro-rating process as used for swap prices was used to calculate quarterly 2008 through 2010 cap premiums.

- AFMA: Quarterly peak and off-peak swap prices were available for Q1-Q4 2007. Thereafter quarterly swap prices were calculated using a pro-rata basis on the 2008 to 2010 calendar year swap price. No cap premium data was available.

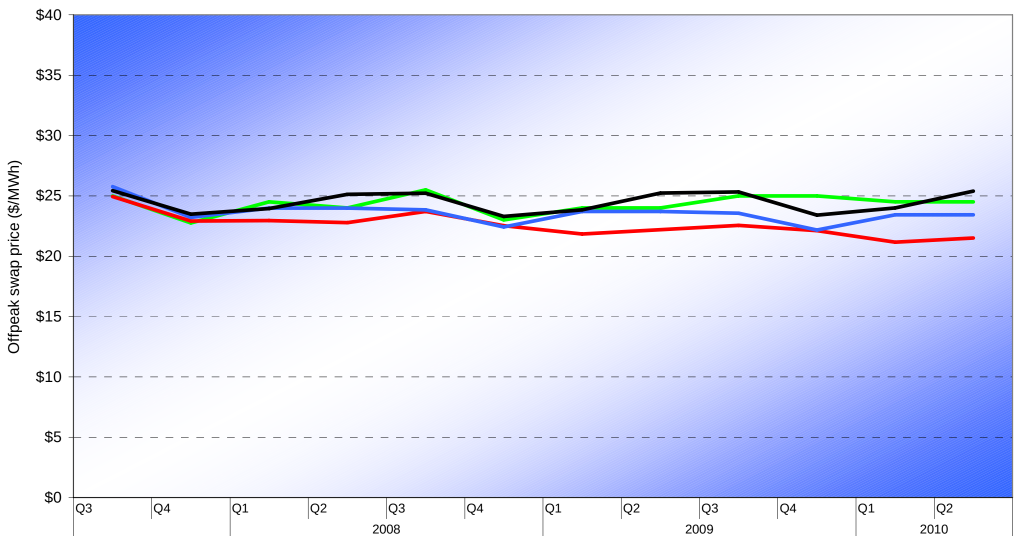
For the most part this third-party price data sits within the distribution formed by the data provided by the standard retailers and Frontier. This comparison suggests that the standard retailers' data is not significantly different to other publicly available sources.



	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2
1	$54.9	$60.0	$92.0	$44.0	$49.5	$54.3	$84.0	$43.0	$50.0	$55.0	$82.0	$45.0
2	$52.5	$59.6	$88.7	$42.2	$50.9	$54.1	$77.5	$36.9	$48.9	$51.7	$75.3	$37.3
3	$52.7	$60.4	$90.8	$42.3	$52.0	$56.6	$89.8	$41.8	$51.4	$55.9	$88.7	$41.3
4	$54.3	$61.6	$104.2	$48.3	$52.7	$59.9	$101.1	$46.7	$44.9	$51.4	$86.5	$39.7

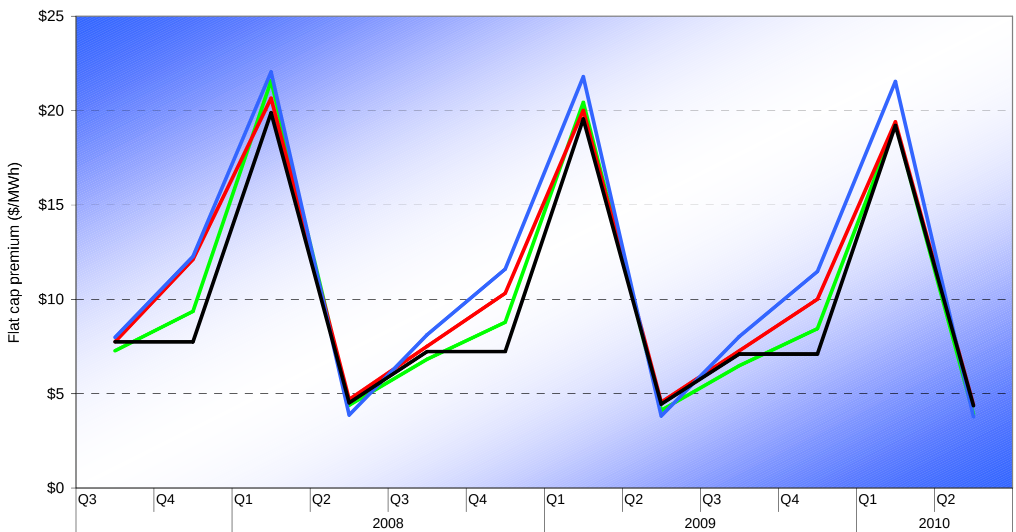
Figure 8: Peak swap forecasts

Public draft



	Q3	Q4	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009	Q1 2010	Q2 2010
1	$25.0	$22.8	$24.5	$24.0	$25.5	$23.0	$24.0	$24.0	$25.0	$25.0	$24.5	$24.5
2	$25.0	$22.9	$23.0	$22.8	$23.7	$22.5	$21.8	$22.2	$22.6	$22.1	$21.2	$21.5
3	$25.8	$23.2	$24.0	$24.0	$23.8	$22.4	$23.7	$23.7	$23.6	$22.2	$23.4	$23.4
4	$25.4	$23.5	$23.9	$25.1	$25.2	$23.3	$23.8	$25.2	$25.3	$23.4	$24.0	$25.4

Figure 9: Off-peak swap forecasts



	Q3	Q4	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009	Q3 2009	Q4 2009	Q1 2010	Q2 2010
1	$7.3	$9.4	$21.6	$4.4	$6.8	$8.8	$20.4	$4.1	$6.5	$8.4	$19.3	$3.9
2	$7.8	$12.1	$20.7	$4.7	$7.5	$10.3	$20.0	$4.5	$7.3	$10.0	$19.4	$4.4
3	$8.0	$12.3	$22.1	$3.9	$8.1	$11.6	$21.8	$3.8	$8.0	$11.5	$21.5	$3.8
4	$7.8	$7.8	$19.9	$4.5	$7.2	$7.2	$19.6	$4.4	$7.1	$7.1	$19.2	$4.4

Figure 10: Flat cap premium forecasts

Energy costs

5.3.5 Efficient purchase costs

In this section, the efficient energy purchasing frontiers are presented for each year and for each retailer. For each year and each retailer, four efficient frontiers are calculated, reflecting the range of price forecasts.

Figure 11, Figure 12 and Figure 13 presents the efficient frontiers for, respectively, Country Energy, EnergyAustralia and Integral Energy. The vertical axes of these figures present the expected annual average energy costs for the efficient (lowest cost) mix of energy purchasing options. The horizontal axes of these figures represent risk as the standard deviation for each level of efficient costs. These cost efficiency 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 – more 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 the least increase in risk. The less risky position (i.e. most conservative) is indicated by the top left point of the cost frontier.

Each frontier has been truncated at the point the standard deviation exceeds $10/MWh to permit a closer view of the detail around the area of interest.

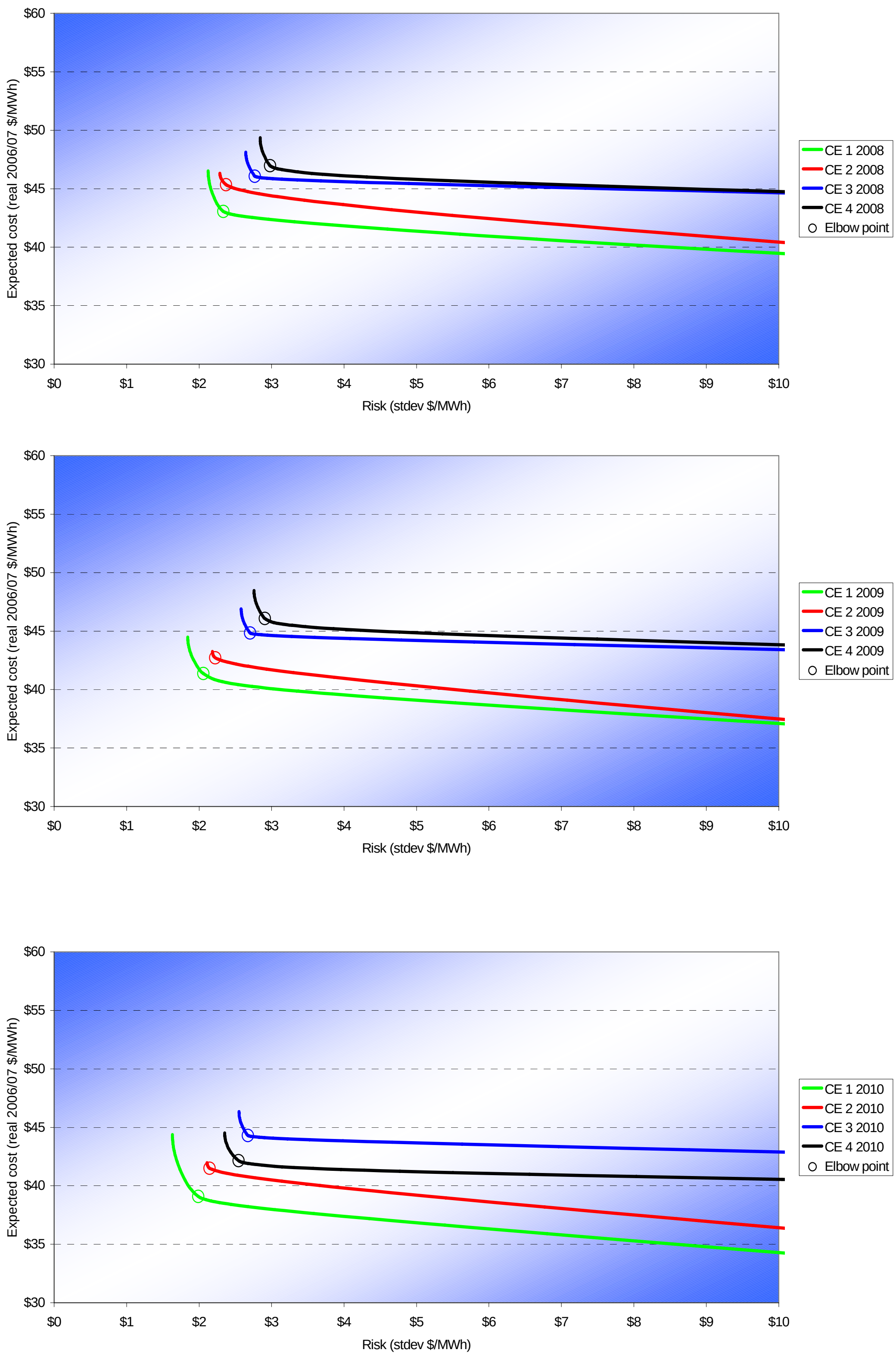


Figure 11: Country Energy efficient frontiers

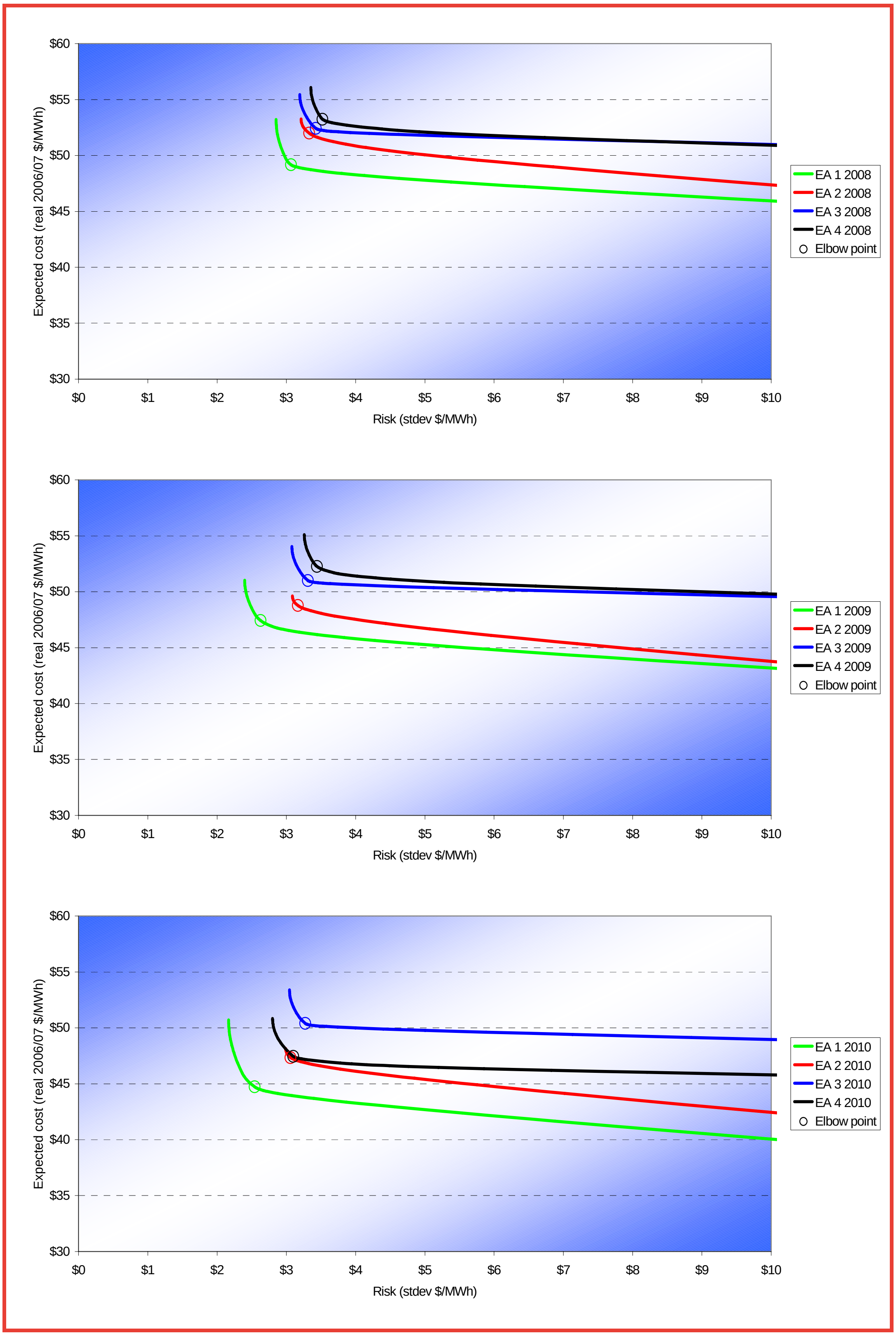


Figure 12: EnergyAustralia efficient frontiers

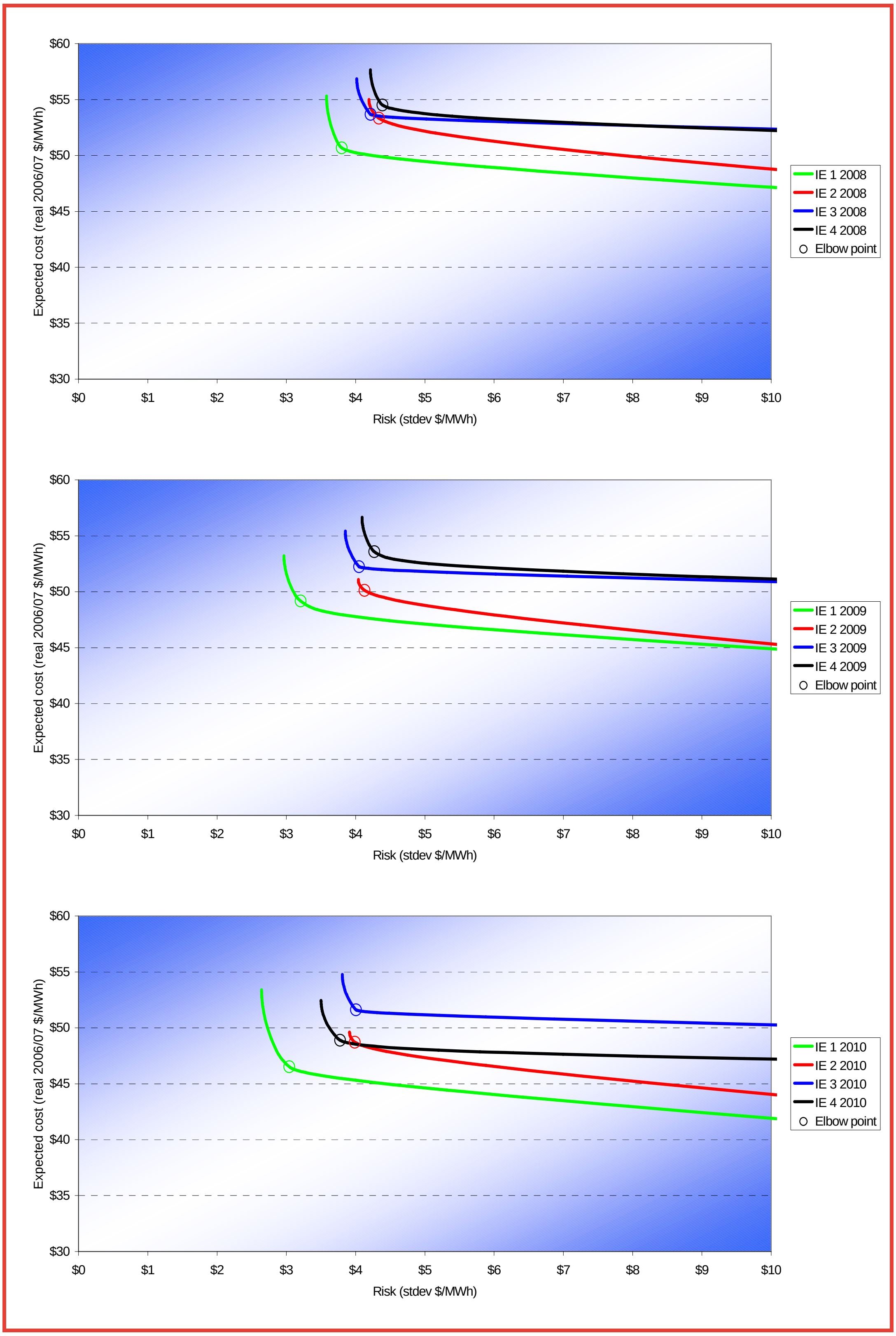


Figure 13: Integral Energy efficient frontiers

5.3.6 Summary of energy purchase cost and risk

Figure 14 summarises the results of the efficient energy purchase costs using the standard retailers' and Frontier's estimates of the future prices of the main energy purchasing options. This figure presents the efficient purchasing cost for each retailer at the most conservative (least risky) and, hence, most expensive position on the frontier. By way of comparison, the grey bar represents the LRMC estimate presented in Section 4 for each retailer (excluding green costs).

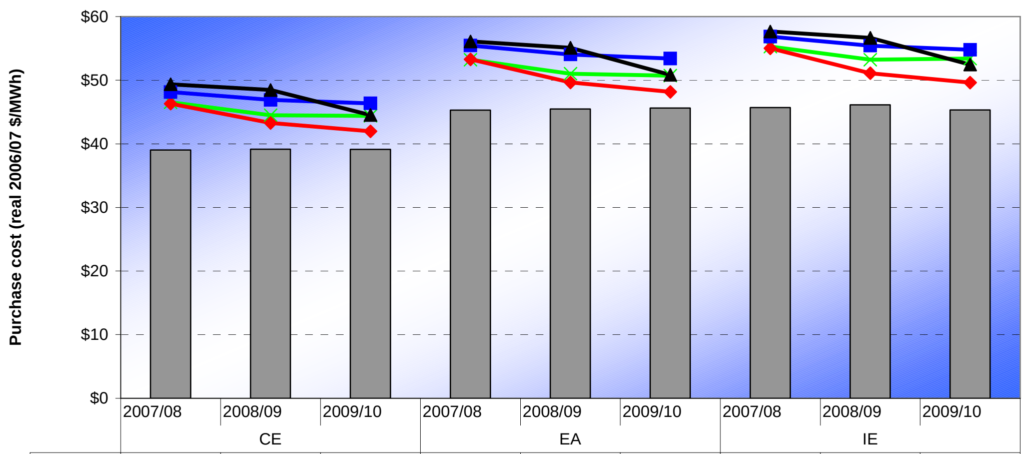
The most notable feature of the energy purchase cost results is the difference between the businesses and the difference between the estimated costs using the lowest forecast cost and the highest forecast costs. The factor that drives the cost difference between Country Energy and the other two retailers is the same factor that drove the plant cost differences presented in Section 1 – load shape. Country Energy's flatter, more stable load means that it does not need to purchase as many peaking contracts to manage peak price conditions.

Even though Integral Energy's and EnergyAustralia's load factors are very similar, this analysis shows that Integral Energy's load is generally somewhat more expensive to serve than EnergyAustralia's. This is due to Intergral Energy's load having a higher correlation to spot prices.

Another notable feature is that the estimated efficient energy purchase cost (at the most conservative point) is at or below the energy price included in the current retail determination.

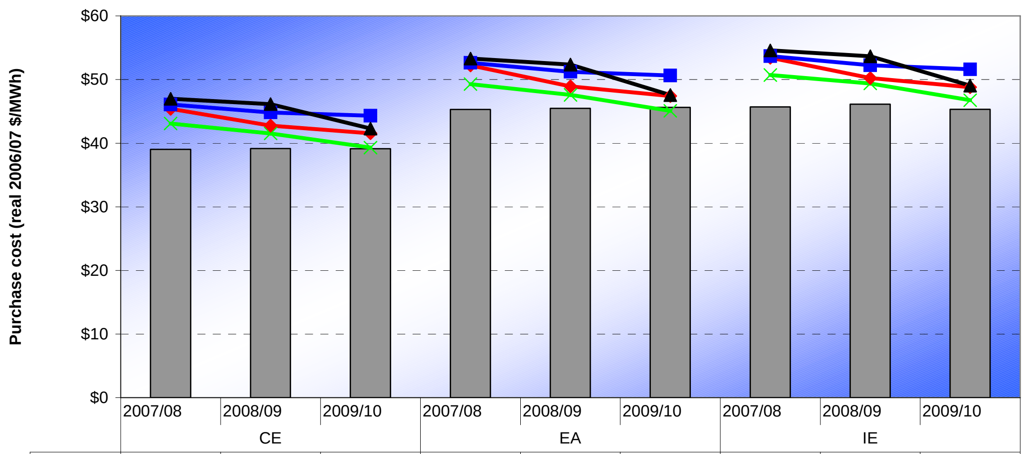
In terms of EnergyAustralia and Integral Energy the conservative efficient costs range from $48/MWh to $58/MWh with the higher costs in the first two years of the Determination. In almost all cases, the real energy purchase costs decline over the Determination period.

Figure 15 summarises the results of the efficient energy purchase costs at the *elbow point*. By way of comparison the grey bar represents the LRMC estimate presented in Section 1 for each retailer (excluding green costs). In the main these elbow point prices are $2-$4/MWh lower than at the conservative point, with only a small increase in risk (as indicated by the increase in the standard deviation of costs, presented in Figure 11 to Figure 13).



	CE 2007/08	CE 2008/09	CE 2009/10	EA 2007/08	EA 2008/09	EA 2009/10	IE 2007/08	IE 2008/09	IE 2009/10
LRMC	$39.0	$39.2	$39.1	$45.3	$45.5	$45.6	$45.7	$46.1	$45.3
1	$46.5	$44.5	$44.4	$53.2	$51.0	$50.7	$55.3	$53.2	$53.4
2	$46.3	$43.3	$42.0	$53.3	$49.6	$48.1	$55.0	$51.1	$49.6
3	$48.1	$46.9	$46.4	$55.4	$54.0	$53.4	$56.9	$55.4	$54.8
4	$49.4	$48.5	$44.5	$56.1	$55.1	$50.8	$57.7	$56.7	$52.4

Figure 14: Energy purchase costs – conservative point (Real $2006/07)



	CE 2007/08	CE 2008/09	CE 2009/10	EA 2007/08	EA 2008/09	EA 2009/10	IE 2007/08	IE 2008/09	IE 2009/10
LRMC	$39.0	$39.2	$39.1	$45.3	$45.5	$45.6	$45.7	$46.1	$45.3
1	$43.1	$41.5	$39.3	$49.3	$47.6	$45.1	$50.7	$49.4	$46.8
2	$45.4	$42.8	$41.5	$52.2	$48.9	$47.4	$53.4	$50.2	$48.8
3	$46.1	$44.8	$44.3	$52.6	$51.2	$50.6	$53.7	$52.3	$51.6
4	$47.0	$46.1	$42.3	$53.3	$52.3	$47.6	$54.6	$53.7	$49.0

Figure 15: Energy purchase costs – elbow point (Real $2006/07)

The annual market cost estimates have been decomposed into Peak, Shoulder and Off-peak and are shown in Table 3 through Table 4 below for each of the conservative and elbow points respectively.

The definitions of Peak and Shoulder varied slightly between each standard retailer, however the Off-peak definition was consistent. To aid in comparison between costs for each retailer, an additional column is presented in the tables, "Peak & Shoulder", combining the Peak and Shoulder periods to provide a cost measured on a consistent basis for each retailer.

The allocation of costs between Peak, Shoulder and Off-peak periods was determined by allocating the half-hourly spot load costs and contract difference payments to each respective period. Cap contract premiums were allocated between the Peak, Shoulder and Off-peak periods on a pro-rata basis according to the value of difference payments received in respect of the cap contract.

Price forecast	Retailer	Finyear (ending 30 June)	Peak	Shoulder	Off-peak	Peak & Shoulder	All periods
Range across all price forecasts	CE	2008	$69.7 - $76.9	$73.2 - $78.6	$28.5 - $29.6	$71.8 - $77.9	$46.3 - $49.5
		2009	$64.3 - $74.8	$67.0 - $76.6	$27.4 - $29.4	$65.9 - $75.9	$43.3 - $48.6
		2010	$62.8 - $69.1	$64.9 - $74.1	$26.5 - $29.6	$64.1 - $72.1	$42.0 - $46.4
	EA	2008	$104.5 - $108.8	$47.2 - $52.7	$27.6 - $30.1	$65.4 - $68.6	$53.2 - $56.2
		2009	$96.8 - $107.0	$44.3 - $51.8	$27.1 - $30.2	$60.7 - $67.5	$49.7 - $55.2
		2010	$91.8 - $106.3	$43.2 - $48.2	$26.1 - $30.7	$59.4 - $66.4	$48.2 - $53.4
	IE	2008	$114.9 - $119.4	$47.2 - $54.5	$29.8 - $31.6	$71.3 - $74.9	$55.0 - $57.8
		2009	$107.5 - $117.7	$44.3 - $53.7	$29.2 - $31.5	$65.6 - $73.6	$51.1 - $56.8
		2010	$101.4 - $118.0	$43.7 - $49.5	$28.5 - $32.4	$64.5 - $71.8	$49.6 - $54.8

Table 3: Market cost Peak/Shoulder/Off-peak breakdown – conservative

Price forecast	Retailer	Finyear (ending 30 June)	Peak	Shoulder	Off-peak	Peak & Shoulder	All periods
Range across all price forecasts	CE	2008	$62.7 - $78.9	$67.8 - $69.3	$27.2 - $29.3	$65.8 - $72.8	$43.1 - $46.6
		2009	$64.9 - $75.8	$58.7 - $67.5	$27.4 - $28.3	$61.4 - $70.8	$41.5 - $45.7
		2010	$61.7 - $69.0	$49.6 - $66.8	$26.6 - $28.4	$56.7 - $67.6	$39.3 - $44.3
	EA	2008	$89.8 - $123.7	$36.9 - $52.1	$22.5 - $30.2	$62.0 - $64.2	$49.3 - $52.8
		2009	$87.7 - $120.6	$35.9 - $51.2	$22.0 - $30.7	$59.3 - $62.5	$47.6 - $51.8
		2010	$87.5 - $106.4	$31.3 - $50.7	$20.3 - $33.8	$53.7 - $62.2	$45.1 - $50.7
	IE	2008	$97.9 - $133.6	$35.7 - $52.7	$23.9 - $31.6	$68.0 - $69.5	$50.7 - $54.0
		2009	$95.2 - $130.2	$35.2 - $52.0	$24.2 - $31.7	$63.7 - $67.2	$49.4 - $53.1
		2010	$95.3 - $119.5	$31.3 - $51.9	$21.8 - $34.4	$58.3 - $66.4	$46.8 - $51.6

Table 4: Market cost Peak/Shoulder/Off-peak breakdown – elbow

6 Greenhouse cost allowance

An increasingly important aspect of a retailer's business is meeting various greenhouse gas reduction schemes. NSW retailers are currently subject to two schemes: the Commonwealth Mandatory Renewable Energy Target (MRET) and the broader based GGAS scheme. Since the Tribunal received the ToR, the NSW Government has also announced that it intends to establish its own renewable scheme to supplement the GGAS scheme, known as the NSW Renewable Energy Target (NRET). The NRET is aimed at promoting a significant increase in the role that renewable energy plays in meeting customer energy requirements.

6.1 ESTIMATING GREENHOUSE COST ALLOWANCES

Estimating the future costs of greenhouse schemes is very difficult because there is a limited history of prices, new schemes are being introduced which interact with existing schemes, rules amendments are ongoing, and there is uncertainty about the future of these schemes.

With these concerns in mind, there are two broad approaches to estimating the future costs of the greenhouse schemes that the standard retailers are subjected to in NSW:

- rely on the prevailing market prices for future periods; or
- estimate the future market price using a simulation approach.

For completeness, both approaches have been applied in this review.

In estimating the market-based greenhouse cost allowance, forward price data for Renewable Energy Certificates (RECs – for the MRET scheme) and NSW Greenhouse Abatement Certificates (NGACs – for the GGAS scheme) have been obtained from two independent sources, NGES and ICAP.

The LRMC is estimated using the *WHIRLYGIG* model summarised in Section 4, and described in more detail in the Draft Methodology Report.

The estimated costs of satisfying the targets, based on current forward prices and LRMC estimates, are presented in Figure 16 (financial year forward prices were calculated as the simple average of the corresponding two calendar year prices).

Two LRMC modelling scenarios are presented. One is refereed to as the "Underlying LRMC" and the other as the "LRMC – committed capacity". The "Underlying LRMC" reflects the long run costs if new plants were required to meet the target. The "LRMC – committed capacity" reflects the future (and low) LRMC of meeting the current target having regard to presence of a number of projects that are committed to proceed, and which, therefore, have costs that are sunk and unavoidable.[6] In both these cases the LRMC has been estimated in conditions where the NRET scheme does and does not proceed.

6.2 RESULTS

Figure 16 shows that the ICAP prices are marginally lower than the NGES price for both MRET and GGAS certificates. However, these forward prices for MRET certificates (~$18-22/certificate over the period) are significantly lower than the "Underlying LRMC" estimate (~$39-44). This is expected given that, in reality, much of the plant that would be required to meet the target has already been committed. In this case, the Underlying LRMC provides a guide as to the costs that retailers would have had to incur to develop this committed capacity.

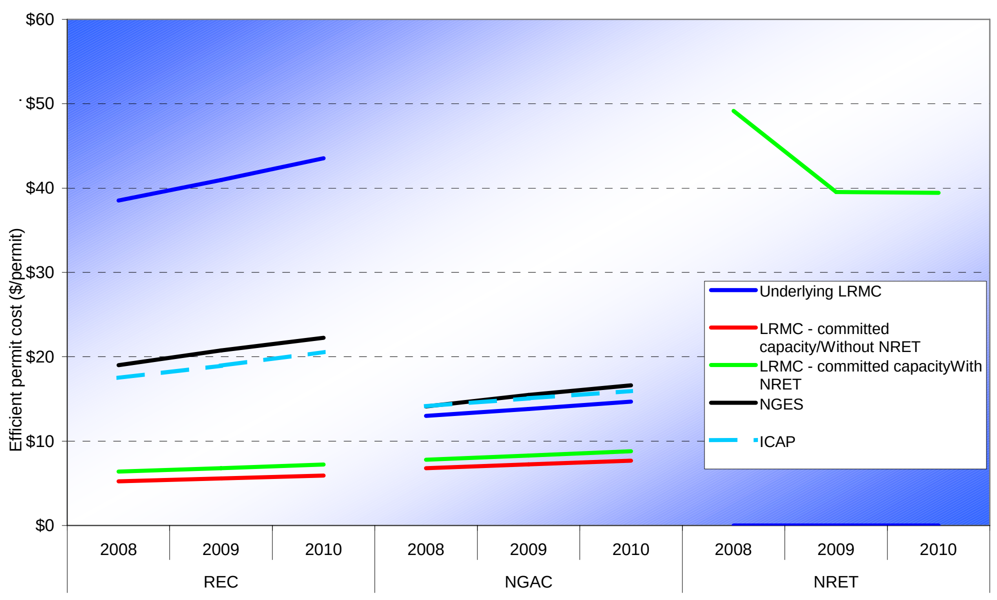


Figure 16: Green certificate prices/costs

In contrast, the "LRMC – committed capacity" estimate, with or without the NRET scheme, result in lower LRMC of certificates (~$5-7) indicating low avoidable costs for retailers. The fact that the actual market forward price is currently within this range reflects a number of factors, including:

- delivery risk, or the extent of market confidence that these planned renewable projects will proceed, and hence the certainty of future supply of certificates; and

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6 For example, the Business Council of Sustainable Energy's (BCSE) "Carbon Markets Report" (2006) suggests that, given deemed RECs and Generators under construction as at September 2006, no further renewable investment would be required to meet current MRET targets.

- market sentiment regarding regulatory risk, which in this case would include the potential for either: (a) changes to the existing scheme target and/or duration; (b) additional state-based renewable energy schemes; or (c) the potential that carbon trading may be introduced which may enhance the value of existing certificates.

Discounting of certificate values (or adding a risk premium, in the case of buyers) to account for project or policy uncertainty is not unknown in green energy markets. For example, the REC price fell from around $39/MWh to around $15/MWh in 2004 soon after the Government release of the Energy White Paper which did not extend the life, or toughen the target, of the MRET scheme. Until this point the market had been factoring in the possibility that the scheme may be extended or the target increased.

Similarly, in the European Emission Trading Scheme (ETS) there is a spread between the price of Certified Emissions Reduction certificates (CER)[7] and EU emissions allowances (EUA) which is usually attributed to the regulatory and the delivery risk associated with Clean Development Mechanism (CDM) projects. For example, between April 2005 and March 2006 the price of CERs was approximately 30 per cent of the price of EUAs, even though one EUA will be issued in exchange for one CER.

In terms of the GGAS scheme the current forward prices for NGACs (both ICAP and NGES) are very close to the "Underlying LRMC" price for NGACs. Under the scenarios with/without the NRET scheme (and the assumption that all planned renewable projects will proceed), the projected NGAC price is lower, though this is not reflected in the current market price. This could be due to the lack of detail about the scheme or that the scheme has yet to be formalised. It could also be the case that the market does not yet appreciate the interactions between the schemes that affect the price of NGACs.

Finally, in relation to the NRET prices, it is estimated that certificates will cost between $40-$50. This higher cost for renewable energy is due to the more ambitious renewable target than in the MRET scheme.

The sum of these green energy costs are presented in Figure 17. This figure shows the total per MWh cost for each year using each source of data – the prevailing future market price of each instrument (as reported by NGES and ICAP) and the LRMC estimate (based on the "Underlying LRMC").

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7 Under the EU's Linking Directive, carbon credits from Clean Development Mechanism (CDM – Non-Annex 1 countries) and Joint Implementation (JI – Annex 1 Countries) projects under the Kyoto Protocol will be able to be imported for use in the EU Emissions Trading Scheme (EU ETS). Certified emission reductions (CERs) from CDM projects, and Emission Reduction Units (ERUs) from JI projects, can be used within the EU ETS independent of the Kyoto Protocol's entry into force. EU member states may allow operators of installations that fall under the EU ETS to use CERs from 2005 on. After 2008 CERs and ERUs can be used towards their emissions targets in line with installation level import caps. Technically, the use will occur through the issuance and immediate surrender of one EU emissions allowance (EUA) in exchange for one CER or ERU.

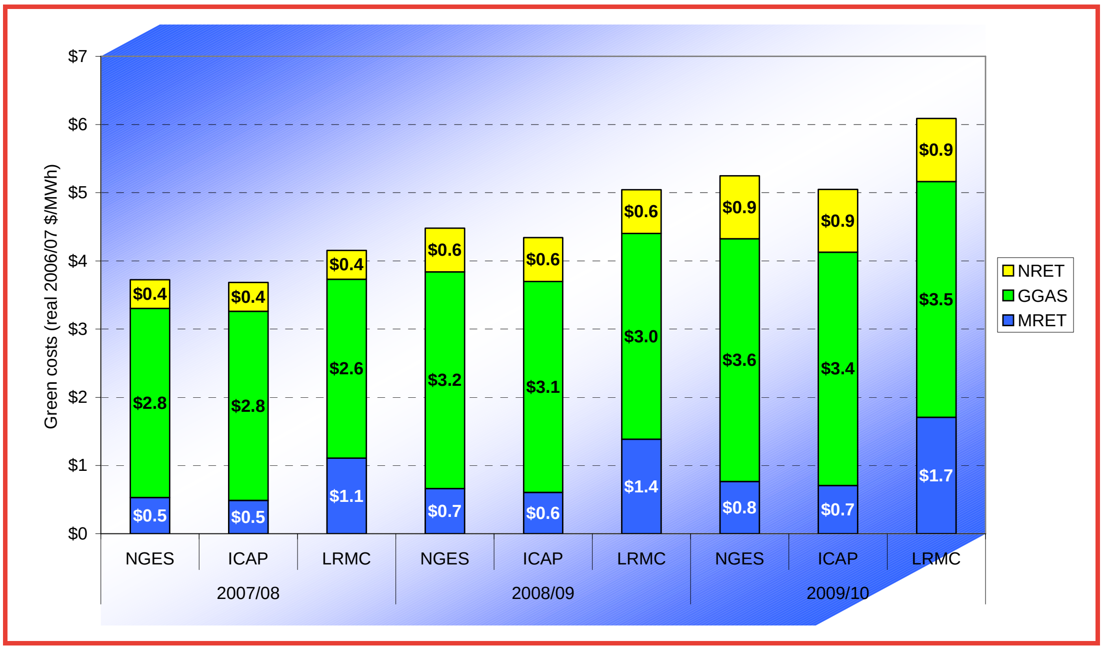

Figure 17: Green energy cost estimates

7 NEMMCO-related costs

There are three elements to the NEMMCO-related costs that are included in the allowance for energy costs:

- general participant fees;
- FRC fees; and
- ancillary service charges.

This section estimates an allowance for each of these elements.

7.1 GENERAL PARTICIPANT FEES AND FRC FEES

General participant fees and FRC fees are based on the operational expenditure of NEMMCO. Given this operational expenditure is relatively easy to predict, the fees themselves are also relatively easy to predict.

In its *2006-07 Statement of Corporate Intent*, NEMMCO provides forecasts for both general participant fees and FRC fees up to 2008/09, based on NEMMCO's forecasts of its operational expenditure and its forecasts of load.

NEMMCO forecasts operational expenditure relating to general participant fees and FRC fees for each year to 2008/09. NEMMCO notes that the majority of expenses relating to these operational expenditures are expected to increase in line with CPI. In other words, the operational expenditure is expected to remain constant in real terms. For the purposes of estimating fees, we use NEMMCO's forecast expenditures up to 2008/09, and assume that expenditures then remain constant in real terms in 2009/10.

With operational expenditures remaining relatively stable over the period of the determination, reductions in fees will occur due to forecast increases in load. In forecasting general participant fees and FRC fees in its 2006-07 *Statement of Corporate Intent*, NEMMCO used load forecasts from its *2005 Statement of Opportunities for the National Electricity Market*. We will use the more up-to-date forecasts of load in the *2006 Statement of Opportunities for the National Electricity Market*.[8]

The forecast operational expenditure associated with general participant fees, the forecast load and the general participant fees that we estimate are set out in Table 5. The forecast operational expenditure associated with FRC fees, the forecast load and the FRC fees that we estimate are set out in Table 6.

8 NEMMCO used load forecasts associated with medium economic growth figures, adjusted for transmission losses. We use equivalent forecasts from the 2006 SOO.

	2007/08	*2008/09*	*2009/10*
Operational expenditure ($)	65,640,000	63,420,000	63,420,000
Energy MWh	190,069,837	193,467,321	196,312,367
Estimated general participant fees ($/MWh)	$0.35	$0.33	$0.32

Table 5: General participant fees (2006/07 dollars)

	2007/08	*2008/09*	*2009/10*
Operational expenditure ($)	11,260,000	10,670,000	10,670,000
Energy MWh	190,069,837	193,467,321	196,312,367
Estimated general participant fees ($/MWh)	$0.06	$0.06	$0.05

Table 6: FRC fees (2006/07 dollars)

7.2 ANCILLARY SERVICE CHARGES

Ancillary services include:

- automatic generation control;
- governor control;
- load shedding;
- rapid generating unit loading;
- reactive power;
- rapid generating unit unloading; and
- system restart.

These services are sourced by NEMMCO on a competitive basis. To some degree, these costs are related to energy costs. For example, the price at which generators are prepared to sell services that require them to hold their capacity in reserve or to reduce their level of generation will be dependent on how much they would expect to earn in the market if they produced energy instead. Other services are less dependent on the opportunity cost in the energy market. For example, reactive power prices will depend more on the costs of alternatives such as network elements.

To estimate the future costs of ancillary services, the past levels and movements of ancillary service costs are subject to statistical modelling, as set out in detail in Appendix A. The objective is to test whether these statistical models provide sufficient explanatory power to predict future prices.

Based on the most appropriate statistical model, forecasted ancillary services costs over the period of the Determination period are presented in Table 7.

	2007/08	*2008/09*	*2009/10*
Ancillary service costs ($/MWh)	$0.30	$0.29	$0.29

Table 7: Forecast ancillary service costs (2006/07 dollars)

7.3 CONCLUSION ON NEMMCO-RELATED COSTS

Combining the estimates of three elements of NEMMCO-related costs provides an estimate for total NEMMCO-related costs as set out in Table 8.

	2007/08	2008/09	2009/10
General participant fees ($/MWh)	$0.35	$0.33	$0.32
FRC fees ($/MWh)	$0.06	$0.06	$0.05
Ancillary service costs ($/MWh)	$0.30	$0.29	$0.29
Total ($/MWh)	**$0.71**	**$0.68**	**$0.68**

Table 8: Estimated NEMMCO-related costs (2006/07 dollars)

APPENDIX A – Methodology for estimating ancillary service charges

To estimate the future costs of ancillary services, the past levels and movements of ancillary service costs are subject to statistical modelling. The objective is to test whether these statistical models provide sufficient explanatory power to predict future prices.

The data used in this statistical modelling is sourced from NEMMCO. The NEMMCO website[9] provides weekly ancillary service information from week 23 of 2003 through week 47 of 2006. NEMMCO provides the breakdown of the total ancillary costs into eleven categories, with reactive power and system restart being the largest cost components. NEMMCO recovers about 75 per cent of these costs from customers, with the remainder recovered from other market participants (i.e. generators). The customer ancillary service cost per MWh is created from the total ancillary service costs to be recovered from customers and the total NEM demand.

To forecast these costs the historical ancillary service ('AS') costs are regressed on historical spot price data[10] and a range of dummy variables. The basic forms of these models are described below.

SIMPLE MODELS

The most basic model of the AS costs[11] includes a time trend (*t*) and a constant (α) on the right hand side as the only explanatory variables:

$$AS_t = \alpha + t$$

The R-squared of this model is 0.41, and both coefficients are significant at the 0.1 per cent level.

A cursory examination of the AS cost series revealed a substantial drop at the beginning of July 2005 when NEMMCO updated their estimates of future AS costs. This followed a renegotiation of ancillary service costs. For example, NEMMCO's estimated ancillary service costs fell from $78m in 2004/05 to $46m in 2005/06.[12] To account for this structural break in AS costs, a dummy variable is added to the simple model:

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9 See http://www.nemweb.com.au/REPORTS/CURRENT/Ancillary%5FServices%5FPayments/ and note that all of the files in the directory are indeed spreadsheets despite the lack of file extension (04 Dec., 2006).

10 See "Daily Reports" and "HistDemand" in http://www.nemweb.com.au/REPORTS/ARCHIVE/ and also in http://www.nemweb.com.au/REPORTS/CURRENT/. Frontier Economics maintains a database of historic data collected from these sites, so while NEMMCO may only store a single year online, we have used additional data for this analysis.

11 Logarithm of the cost per MWh is used throughout, unless specified otherwise.

12 NEMMCO (2005), NEM Forum, Non-market ancillary service, Chris Stewart, 25 August 2005

$$AS_t = \alpha + \delta_s + t$$

where δ is the dummy. The R-squared of this model rose to 0.60 and the dummy and the constant were both significant at the 0.1 per cent level.

Finally an interact term is added between the time trend and the dummy to allow for different slopes before and after the structural break:

$$AS_t = \alpha + \delta_s + \delta_s t + t$$

In terms of fit, this model represents a marginal improvement over the non-interact version above. However, the interact term has a negative coefficient, which would cause the forecast costs to disappear over time.

STRUCTURAL MODELS

The weekly average of the NEM spot price is also added to each of the three models described above.[13] The adjusted R-squared values remains about the same as the earlier models, and the spot price is significant in the second of the three models. At a 10 per cent level, the spot price is significant in all of the models:

$$AS_t = P_t + \alpha + t$$
$$AS_t = P_t + \alpha + \delta_s + t$$
$$AS_t = P_t + \alpha + \delta_s + \delta_s t + t$$

where *P* is the spot price at time *t*. The plots of the residuals, fitted values, and the actual AS data can be seen in Figure 18.

MODEL EXTENSION

A model that incorporated lagged values of both the spot price and the AS data is also tested:

$$AS_t = AS_{t-1} + \alpha + t$$
$$AS_t = AS_{t-1} + \alpha + \delta_s + t$$
$$AS_t = AS_{t-1} + \alpha + \delta_s + \delta_s t + t$$
$$AS_t = AS_{t-1} + P_t + P_{t-1} + \alpha + t$$
$$AS_t = AS_{t-1} + P_t + P_{t-1} + \alpha + \delta_s + t$$
$$AS_t = AS_{t-1} + P_t + P_{t-1} + \alpha + \delta_s + \delta_s t + t$$

13 NEMMCO reports spot price in five minute intervals for each region. Frontier Economics create a NEM wide average price using the demand (also reported in five minute intervals by region) as weights.

Ultimately, however, that level of specification does not add to the overall explanatory power of the model, particularly as the longer-term forecasts are of more interest than the weekly forecasts.

Finally, none of these more complicated models (which are still relatively simple) could predict whether NEMMCO will revise the AS estimates as in July of 2005.

FORECAST MODEL SELECTION

The more complex models were eliminated in favour of the relatively simple results reported in Figure 18. The results were dramatically better with the structural break, so the two specifications without the structural break (the top two models) are eliminated.

Of the remaining four, the interact term in the bottom two models that allows the slopes to differ before and after the break would eventually cause the forecast costs to be zero (or less). This is obviously not a sensible outcome. The middle two models that prevent the slope of the two parts of the series from being different (i.e. no interact term) produce more intuitively sensible results.

Given the similarity of the results of these two middle models, the simpler of the two has been used to formulate the basis of the forecast ancillary service costs.

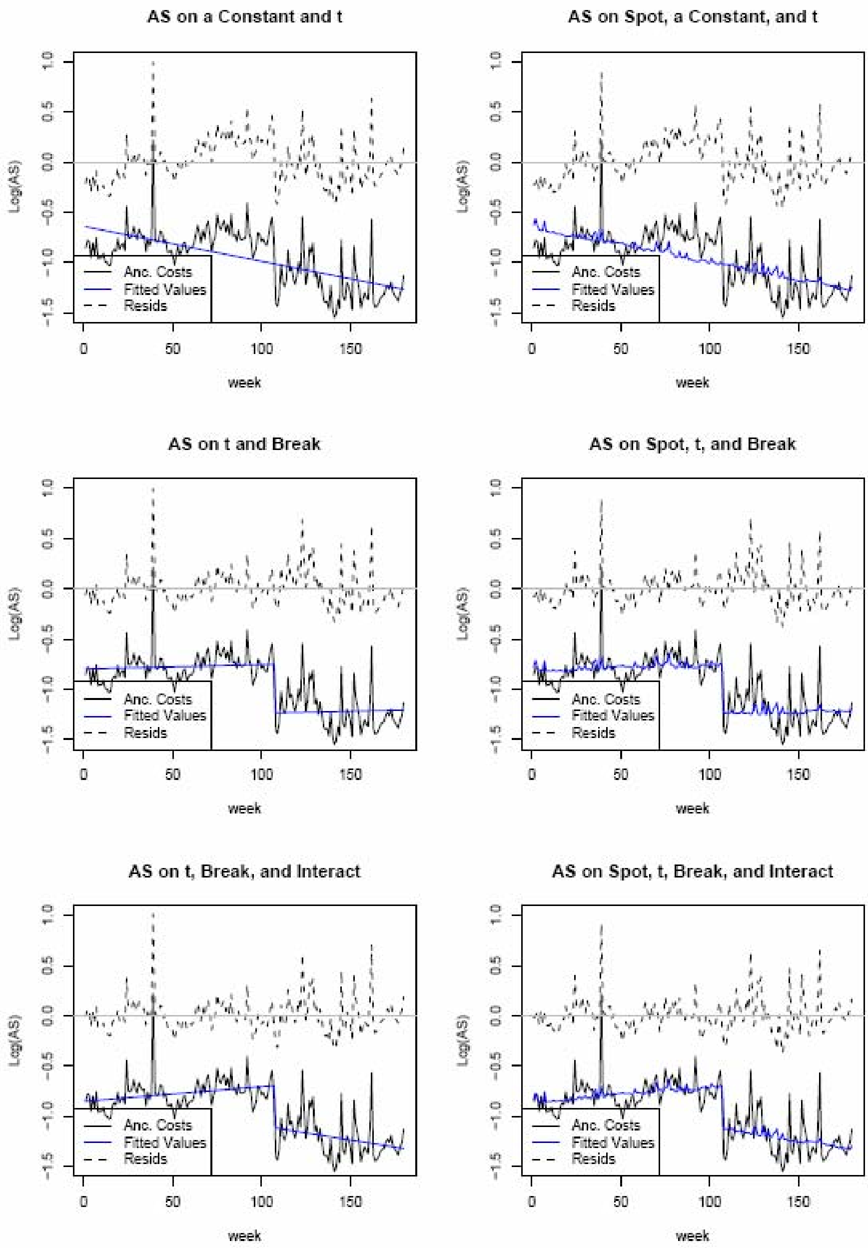

Figure 18: Outcomes of the ancillary service cost models.

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