frontier economics

STRATEGIC FINANCE GROUP
SFG CONSULTING

Draft methodology for energy cost consultancy and retail costs/margin consultancy

A DRAFT REPORT PREPARED FOR IPART

October 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 has been retained to assist IPART to develop an allowance for the energy costs to be factored into regulated retail prices, and to develop a cost allowance for the mass market new entrant (MMNE) retail costs and retail margin to be factored into regulated retail prices. Frontier will work in conjunction with Strategic Finance Group (SFG) on developing an allowance for the MMNE retail margin.

This paper sets out the methodology that Frontier will use to determine cost allowances for energy costs, retail costs and retail margin. The methodology is governed 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.

This paper is structured as follows:

- Section 2 briefly describes Frontier Economics' scope of works;
- Section 3 describes the interpretation of the Minister's ToR;
- Section 4 describes the proposed analytical approach;
- Section 5 sets out the proposed methodology for estimating energy costs;
- Section 6 sets out the proposed methodology for estimating retail costs; and
- Section 7 sets out proposed methodology for estimating retail margins.

2 Scope of work

Frontier and SFG 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. The analysis is also to highlight any significant differences between the costs of a standard retailer and the costs of a Mass Market New Entrant (MMNE).

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

- MMNE retail costs; and
- MMNE retail margin.

Costs are to be expressed as a $/customer, and further split into fixed and variable components. The analysis is to consider each year in the determination period, with a focus on the position in 2010. The analysis is also to highlight any significant differences between the costs of a standard retailer and the costs of a MMNE.

3 Terms of reference

The Minister's ToR set the framework within which Frontier will develop cost allowances for energy costs and for retail costs and margin.[1][1]

The ToR are aimed at ensuring that regulated retail electricity prices are set at cost reflective levels. Setting tariffs at cost reflective levels is aimed at encouraging efficiency by ensuring that retailers can compete for customers. If regulated prices are set at prices below costs, then competing retailers will have limited scope to encourage customers to switch from regulated prices. This will undermine the ability of competing retailers to develop a critical mass of customers and this, in turn, undermines the Government's objective of creating a vibrant competitive market to serve the needs of consumers.

In terms of the project that Frontier Economics has been commissioned to undertake, the ToR require IPART to develop an allowance for electricity purchase costs based on an assessment of the LRMC of electricity generation. In considering these energy costs the ToR indicates that these costs should reflect the characteristics of the regulated customer load for each standard retailer. Importantly, given the winding down of the Electricity Tariff Equalisation Fund (ETEF), which means that the retailers will have to buy electricity for an uncertain load at uncertain prices and sell at fixed, regulated prices, the energy cost allowance (and retail margin) is to have regard to the risks of these additional uncertainties. Frontier Economics interprets these requirements to mean that the allowed energy cost ought to reflect the efficient generation costs that would be incurred to separately meet the regulated load of each standard retailer, adjusted by the likely prudent costs of hedging the component of regulated load not protected by the ETEF.

In developing this cost allowance the ToR also states that account needs to take of the costs associated with statutory obligations to comply with the various greenhouse schemes, including the MRET and the GGAS scheme. Retailers buy meet these obligations from 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 of all existing or any new schemes.

The ToR require that IPART make allowance for the retail costs and margins that would be appropriate for a MMNE. While the While the ToR indicates that a MMNE is of sufficient size to achieve economies of scale, it does not define the form of a MMNE. To be consistent with the overall thrust of the ToR, which seeks to ensure energy costs reflect the costs that retailers are likely to incur in practice, in practice the nature of retailers that are likely to compete to attract regulated customers on to market contracts will be the incumbent retailers. Therefore, for the purposes of the assessment of an appropriate allowance for retail costs and margins, it is proposed that this be based on the (efficient) costs of an existing business, and one that currently does not serve regulated customers in NSW.

4 Analytical approach

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. During the regulatory period for the current review, ETEF will cease. As a result, standard retailers will increasingly be exposed to energy purchase risk, which will need to be reflected in regulated prices.

Allowing for energy purchase risk creates difficulties because there are many possible efficient energy purchasing strategies, and different retailers are likely to adopt different strategies. The most appropriate energy purchasing strategy for a retailer depends on the risk preference of the firm, and a retailer's appetite for risk will have implications for its energy purchase costs:

- 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).

Whatever energy purchasing strategy retailers adopt, they are likely to be exposed to some residual risk (for example, risk that contract counterparties default, risk that load is higher than forecast at times of high prices). The retail margin ought to reflect the value of these risks, which fundamentally derive from the risks associated with the energy market.

As a result, there is an important link between the appropriate allowance for energy costs and the appropriate allowance for retail margin. The appropriate cost allowances must reflect this link by adopting a consistent framework for the estimation of energy costs and retail margin.

Frontier's approach will ensure a consistent approach to energy purchase risk. As discussed in detail in the following sections, Frontier's estimation of energy costs will result in a risk/reward frontier setting out the efficient combinations of energy cost and risk for a particular load shape. This frontier will reflect the many possible efficient energy purchasing strategies. The distribution of risk that is represented by this risk/reward frontier, and the particular level of risk associated with the allowed energy costs, will form an important input into the estimation of the appropriate allowance for retail margin: the riskier the energy purchasing strategy that is associated with the allowed energy costs, the greater the allowance for risk in the retail margin.

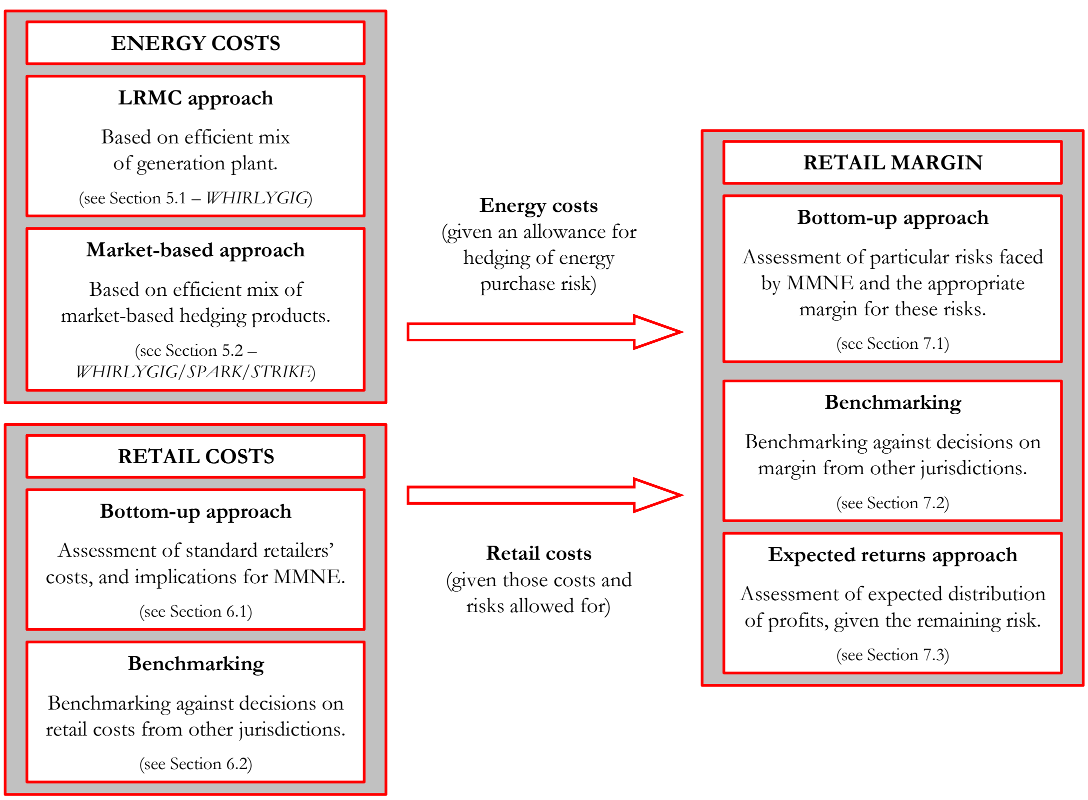
Frontier's approach will also ensure a consistent approach to estimating an allowance for retail costs and retail margin. To the extent that particular costs or risks are allowed for in retail costs, they will not be allowed for in the retail margin.

To ensure that Frontier's estimates are as robust as possible, Frontier will use more than one approach to estimate each of energy costs, retail costs and retail margin. These are discussed in more detail in the sections that follow.

Frontier will look for convergence between results from the different approaches, so that estimates can be made with greater confidence. This will be particularly relevant for the estimation of retail costs and retail margin, where different approaches are used to estimate the same cost allowance. For both retail costs and retail margin, likely explanations for any differences in the results of the different approaches will be considered. Where these explanations suggest that a particular approach is more appropriate, the development of ranges for retail costs and retail margin will give greater weight to the results of that approach.

The approaches used to estimate each of energy costs, retail costs and retail margin, and the relationships between the estimates of energy costs, retail costs and retail margin, are outlined below.

Figure 1: Summary of analytical framework



5 Energy costs

There are two broad approaches to estimating the energy costs associated with meeting a particular load profile: estimating the LRMC of electricity generation to meet the load, and estimating the market price of hedging products to meet the load. The Minister's ToR clearly require that IPART consider both the LRMC approach and the market price approach.

The two approaches to estimating energy costs are obviously related. With a well functioning market, the LRMC of electricity generation and the market price of hedging products will be equivalent. The reason is that the LRMC of electricity generation provides an indication of the price that a generator will require to recover its costs. In reality, market imperfections will cause the two estimates to diverge. These realities need to be reflected in the formation of the energy purchase cost allowance. In the remainder of this section the approach and models for measuring these costs are described. In summary, energy costs will be measured using a three staged modelling system, summarised in Figure 2:

- A model to determine when, where, what type and how much generation capacity should be invested in to maximise profits - *WHIRLYGIG*
- A model to predict spot electricity prices – *SPARK*
- A model to simultaneously optimise contracting position, customer mix, fuel, and other hedging activities - *STRIKE*.

The relationships between these models are summarised in the following figure.

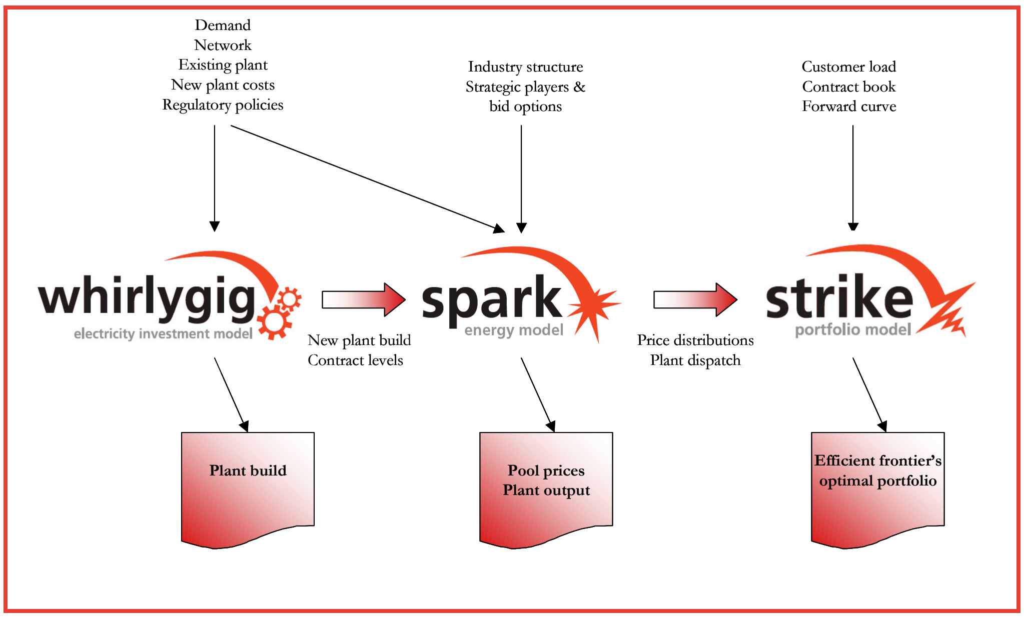


Figure 2: Three staged electricity modelling process

The basis of and relationship between these models are described below.

5.1 LRMC OF ELECTRICITY GENERATION

The LRMC of electricity generation is typically determined on the basis of the least cost combination of meeting load to a particular security standard. The necessary security standard is set out in the market rules, and put into operation by NEMMCO. The LRMC of electricity generation must also have regard to other statutory obligations, including obligations to meet greenhouse targets. These targets can be meet through a combination of generation, load management and, in some cases, carbon sequestration.

5.1.1 WHIRLYGIG

The optimal (least-cost) mix of generation and greenhouse abatement investments will be determined using a total cost optimisation model of the NEM system – *WHIRLYGIG*.

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). *WHIRLYGIG* can estimate 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 will be used, in accordance with the Terms of Reference.

It is worth noting that the fundamental features and formulation of *WHIRLYGIG* are very similar to the market (price) simulation model described in Section 5.2.3 of this report – *SPARK*. The key difference lies in the operation of the model.

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. In *SPARK* the objective function is to choose the pattern of bids that maximises generator profits (within a game theoretic framework). For time series analysis of prices, *SPARK* uses the pattern of investment produced by *WHIRLYGIG* to test the effects of new generation/transmission/greenhouse investment on competition and prices.

Both *WHIRLYGIG* and *SPARK* are formulated as mixed-integer programming (MIP) problems – 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, denoted by *i*,
- generation plant, denoted by *j*;
- non-generation greenhouse emission abatement options (including load management), denoted by *k*.

Data required

The model 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.

General data requirements are given in Table 1 The data required for interconnection options are given in Table 2.

Table 1: General input variables

Variable	Units	Description
$D_{r,p}$	MW	Demand in region r, period p
$PD_r^{10\%POE}$	MW	Peak demand in region r (10% probability of exceedence) – could also be other X% probability of exceedence, but for meeting reliability criteria, 10% is considered appropriate
H_p	Hours	Frequency of period p in year in hours
IRF_i	Region	Notional 'from' region for interconnect I
IRT_i	Region	Notional 'to' region for interconnect I
ICX_i	MW	Capacity of interconnect i from IRF_i to IRT_i
ICM_i	MW	Capacity of interconnect i from IRT_i to IRF_i
RES_r	MW	Reserve capacity requirement in region r
RATE	%	Discount rate
GT	tCO_2-e	Greenhouse emission target
GC	\$/tCO_2-e	Excess greenhouse emission penalty
RT	GWh	Renewable energy target
RC	$/MWh	Deficit renewable energy penalty
VoLL	$/MWh	Value of Lost Load. Acts as the cap on the spot price.

Table 2: Input variables for interconnection options

Variable	Units	Description
IRF_i	Region	Notional 'from' region for interconnect I
IRT_i	Region	Notional 'to' region for interconnect I
ICX_i	MW	Capacity of interconnect i from IRF_i to IRT_i
ICM_i	MW	Capacity of interconnect i from IRT_i to IRF_i
F_i	$/ yr	Fixed cost of interconnect i per year amortised over the life of the interconnect

The model requires the following data for generation plant and potential greenhouse abatement options:

- fixed and variable costs of production;
- greenhouse emissions intensity coefficients;
- capacities and annual energy output potential; and
- plant commissioning timeframes.

The data required for generation plant and greenhouse emission abatement options are given in Table 3 and Table 4, respectively.

Table 3: Input variables for generation plant

Variable	Units	Description
FT_j	Fuel Type	Fuel type of plant j
F_j	$/MW/yr	Fixed cost of plant j per MW of capacity per year amortised over the life of the plant
C_j	MW	Maximum potential capacity of plant type j
BS_j	MW	Block size of plant j, for new investment
CF_j	%	Maximum capacity factor of plant j
V_j	$/MWh	Variable cost of plant j per MWh produced
G_j	TCO_2-e/MWh	Tonnes of CO_2 equivalent emitted by plant j per MWh of electricity produced
R_j	Region	NEM region where plant j is located

Table 4: Input variables for greenhouse emission abatement options

Variable	Units	Description
F_k	$/tCO$_2$-e/yr	Fixed cost of option k per tonne of CO_2 equivalent abated per year amortised over the life of the option
C_k	tCO_2-e	Maximum potential capacity of option k per annum
V_k	$/tCO$_2$-e	Variable cost of option k, per tonne of CO_2 equivalent abated

Some of the data required for *WHIRLYGIG* has been requested from the standard retailers – in particular, information on the load shape. Other input variables – in particular, those for interconnection options, generation plant and greenhouse abatement options – are based on assumptions made by Frontier, as informed by data from a variety of sources. These assumptions will be set out in detail in an assumptions document provided with Frontier's draft report.

Model formulation

WHIRLYGIG optimises (minimises) the total fixed and variable costs of meeting demand for electricity in the NEM while meeting a given reliability and greenhouse emission target. The decision variables used in the problem relate to the decisions to invest in the various options (fixed costs) plus the output levels of these options over time to meet demand and the greenhouse target (variable costs). These decision variables are given in Table 5.

Table 5: Decision variables

Variable	Types (bounds)	Description
I_i	Binary {0,1}	Represents the decision to invest in interconnect i, (1=yes, 0=no)
$I_{j,k}$	Integer $\{0,C_{j,k}/BS_{j,k}\}$	Represents the number blocks of type j/k to invest in
O_k	Real $[0,C_k.I_k]$	Represents the total output of option k in tCO_2-e abated
$O_{j,p}$	Real $[0,BS_j.I_j]$	Represents the output of plant j in MW in period p
$X_{i,p}$	Real $[-ICM_i,ICX_i]$	Represents the flow on interconnect i in period p
GX	Real [0,infinity)	Represents excess greenhouse emissions
RX	Real [0,infinity)	Represents the deficit renewables energy
$RD_{r,p}$	Real [0,infinity)	Represents the deficit supply in region r, period p
$RS_{r,p}$	Real [0,infinity)	Represents the surplus supply in region r, period p

Using the input variables and the decision variables a number of key calculated variables can be determined. These variables are given in Table 6.

Table 6: Calculated variables

Variable	Formula	Description
O_j	$\sum_p H_p . O_{j,p}$	Total output of plant j in MWh
$NM_{r,p}$	$\sum_{i \forall IRT_i = r} X_{i,p} - \sum_{i \forall IRF_i = r} X_{i,p}$	Net imports into region r, period p
$S_{r,p}$	$NM_{r,p} + \sum_{j \forall R_j = r} O_{j,p}$	Total supply in region r, in period p
TC_j	$I_j . F_j . BS_j + O_j . V_j$	Total cost of plant j
TC_k	$I_k . F_k . BS_k + O_k . V_k$	Total cost of option k
TCSD	$VoLL . \sum_p \left(\sum_r \left(RD_{r,p} + RS_{r,p} \right) \right)$	Total cost of surplus/deficit supply
TC	$\sum_j TC_j + \sum_k TC_k + TCSD + GC.GX + RC.RX$	Total system cost (to be minimised)
TR	$\sum_{j \forall FT_j = \text{"Renewable"}} O_j$	Total renewable energy output (MWh)
TG_j	$O_j . G_j$	Total greenhouse emissions from plant j
TG_k	O_k	Total greenhouse emission abatement from option k
TG	$\sum_j TG_j - \sum_k TG_k$	Total greenhouse emissions

Certain constraints need to be applied to the decision variables in order to take account of:

- capacity limits of plant and interconnects;
- greenhouse emission target limits;
- supply/demand balancing; and
- regional reserve requirements.

These constraints can be placed directly on the allowable values of the decision variables, or indirectly on the allowable values of any of the calculated variables.

- The constraints placed directly on the decision variables are given in Table 5 as the bounds on the variables, and relate mainly to capacity constraints on the plant and interconnects.
- Indirect constraints, placed on the calculated variables and relating to the supply/demand balance, reserve level and greenhouse target constraints, are given in Table 7.

Table 7: Constraints

Constraint	Formula	Description
Plant capacity factor constraint	$O_j \le I_j.BS_j.CF_j.\sum_p H_p$	Ensures that the plant does not run at a capacity factor higher than is practicable for the technology
Regional energy balance	$S_{r,p} + RD_{r,p} - RS_{r,p} = D_{r,p}$	Supply (including deficit/surplus) equals demand in each region r, and in each period p
Regional reserve requirement	$\sum_{j \forall R_j = r} I_j.BS_j + \sum_{i \forall IRF_i = r} I_i.IM_i + \sum_{i \forall IRT_i = r} I_i.IX_i \ge PD_r^{10\% POE} + RES_r$	Available capacity (including import capacity) exceeds demand by at least the reserve level in each period
Renewable energy target	$TR + RX \ge RT$	Renewable energy output (including any penalised deficit) is at least at the target level
Greenhouse target	$TG - GX \le GT$	Greenhouse emissions (less any penalised surplus) are capped at the target level

The regional energy balance constraint ensures that supply meets demand in each NEM region. The model allows for a deficit/surplus of supply, the quantity of which is priced at the value of lost load (VoLL) – currently \$10,000/MWh.

The regional reserve requirement constraint allows for a single plant/interconnect outage contingency by ensuring that, at all times, each region has a minimum level (RES_r) of spare capacity available relative to either the 10%, 50% or 90% probability of exceedence peak demand forecast. RES_r is generally set to the size of the largest generating unit or interconnector transmission line capacity in the respective region, and is published by NEMMCO for each region.

The renewable energy target constraint ensures that the renewable energy target is met, taking into account any deficit that incurs a penalty cost of RC $/MWh to the system.

5.2 MARKET COSTS AND RISK

As identified earlier the ETEF is being progressively phased out. Between September 2008 and June 2010 the percentage of the NSW regulated load that is supported by the ETEF will reduce to zero, in a series of steps. As a result, retailers will need to take steps to manage their energy purchase risk.

The Minister's ToR require consideration of the hedging, risk management and transaction costs faced by retailers in the absence of the ETEF. This suggests that the full range of risks to which a retailer is exposed should be estimated on the basis of the market price of hedging products that a retailer would purchase to manage these risks.

The principal risk to which retailers are exposed is risk due to the volatility of spot prices for wholesale electricity. Retailers operate in a market where their costs vary enormously, but the vast majority of their customers want fixed prices. In this environment, retailers' margins can be quickly eroded by a short period of high spot prices, if retailers are not adequately hedged.

In the past, standard retailers have been protected from energy purchase risk by vesting contracts and the ETEF. Under the ETEF scheme, standard retailers contribute to and/or withdraw from the fund on the basis of differences between the price they pay for electricity in the wholesale market and the wholesale electricity price assumed in setting regulated prices. If the wholesale price is above the assumed price, retailers withdraw the difference from the fund. If the wholesale price is below the assumed price, retailers contribute the difference to the fund. The ETEF covers all of a standard retailers regulated load, no matter how volatile this load. This is an important feature of ETEF as it supports to two key features of the retail market in NSW:

- Customers eligible to be served under regulated arrangements retain the right to leave their regulated arrangements for market based contracts and to return again as many times as they like. This choice was aimed at reducing any barriers for small customers to experience the operation of the competitive retail market.
- Retailer of Last Resort (ROLR) – each standard retailers is obliged to supply customers for a period at regulated rates in the event that their retailer of choice became insolvent and could no longer service their contract. This obligation potentially places considerable risk on standard retailers as they would have to buy additional energy at the prevailing market price to serve customers at fixed, regulated prices. The removal of ETEF will mean that other arrangements will need to made to account for such contingencies.

The risks associated with the standard retailers continuing to meet these obligations in the absence of ETEF need to be taken into account for formulating the regulatory arrangements and the costs of managing these new risks.

Frontier's assessment of energy costs using the market price of hedging products will take into account the energy purchase risks to which standard retailers are exposed. Frontier's *STRIKE* model will determine the efficient mixes of hedging products to meet the load profile of standard retailers, and the energy costs and risks associated with each of these efficient mixes. *WHIRLYGIG*, Frontier's electricity investment model, and *SPARK*, Frontier's electricity market model, will provide inputs into *STRIKE*, as outlined in Figure 2. To the extent that the mix of hedging products used as the basis for estimating energy costs exposes a retailer to energy purchase risk, this risk will be reflected in the retail margin, as discussed in Section 7.

5.2.1 Portfolio 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).

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).

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

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

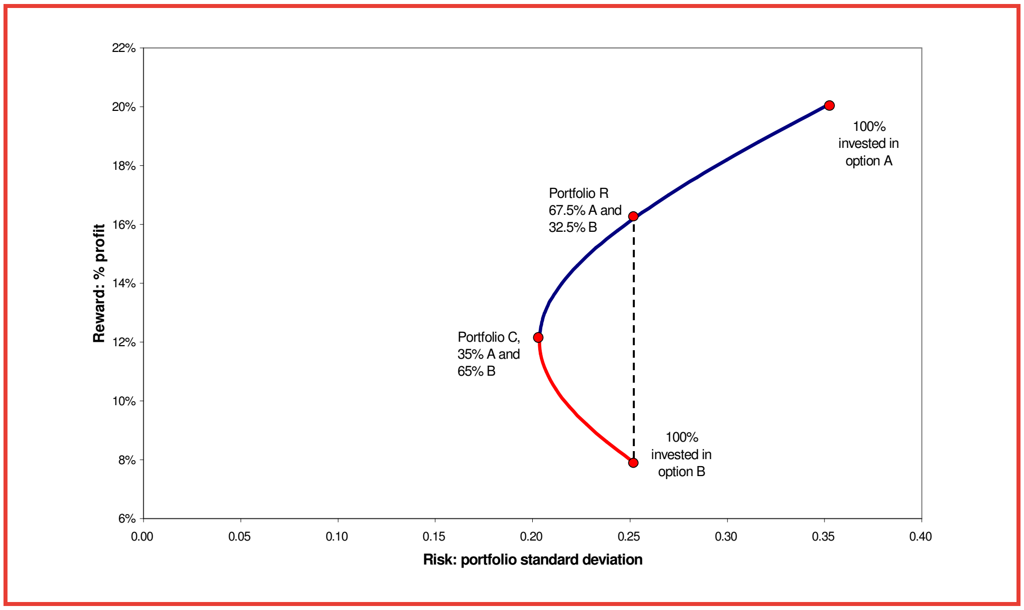

Figure 3: Risk-return curve for investment in assets A and B for correlation coefficient, $\rho = 0$

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

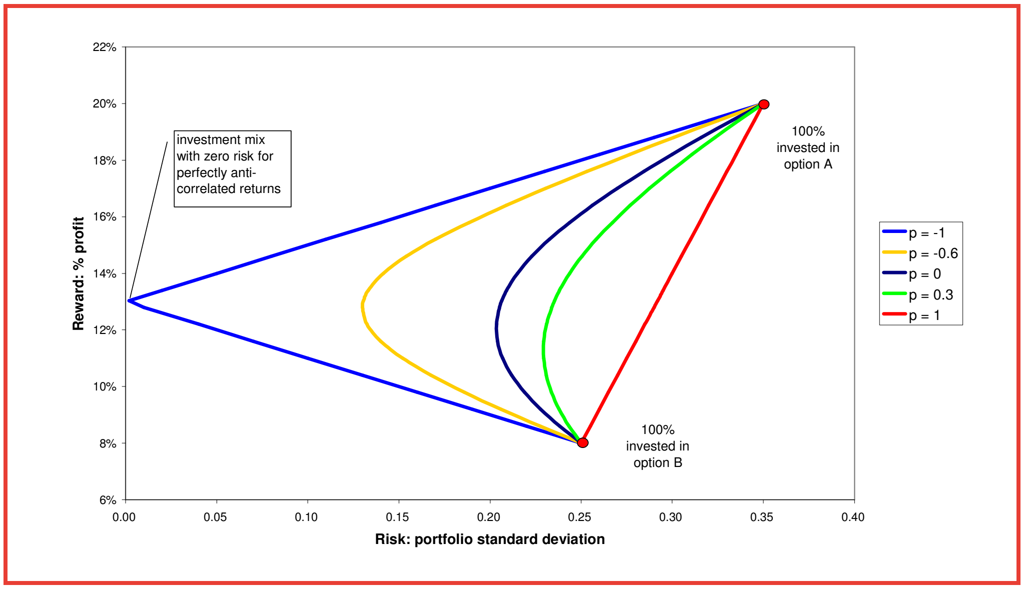

Figure 4: Risk-return frontiers for investment in assets A and B with different levels of correlation, *ρ*

Figure 3 assumes that there is no correlation between the returns on the two assets. Figure 4 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 3 and Figure 4, 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 5. 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.

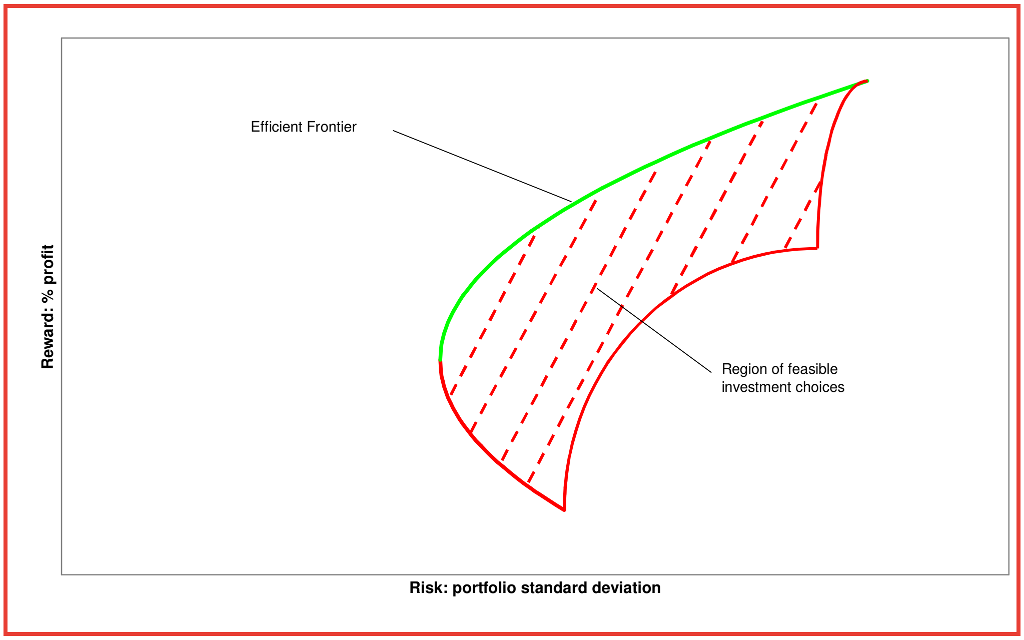

Figure 5: Feasible region and the efficient frontier when there are more than two assets

Algebraically, we can formulate the MVP portfolio problem as follows using matrix notation. Let the vector $\boldsymbol{w}$ denote the set of proportions that each of the n assets constitutes within the portfolio (these must add up to 1); let $\boldsymbol{\mu}$ denote the vector of n expected returns, and let $\boldsymbol{\Sigma}$ denote the n by n matrix of the variances and covariances of the returns.

Then for a specified level of expected return for the portfolio as a whole, say r, the minimum variance portfolio with expected return r can be found by solving the following constrained minimisation problem:

(1) $\min\{\boldsymbol{w}'\boldsymbol{\Sigma}\boldsymbol{w}\}$ w.r.t the $\boldsymbol{w}$ vector. (ie find the $\boldsymbol{w}$ that minimises $\boldsymbol{w}'\,\boldsymbol{\Sigma}\,\boldsymbol{w}$)

subject to:

$\boldsymbol{w}'\,\boldsymbol{\mu} = r$

and $\boldsymbol{w}'\boldsymbol{\iota} = 1$

where $\boldsymbol{\iota} = (1,1,\ldots,1)'$

The MVP frontier is obtained by solving this problem for different levels of expected return r. The vector $\boldsymbol{w}$ associated with the solution for any given expected return r, tells us how to construct the portfolio on the frontier that has that expected return. If there are no other constraints on the $\boldsymbol{w}$ the above optimisation problem has a closed-from solution.[3]

[3] See Campbell. Lo and McKinley (1997), *The Econometrics of Financial. Markets*, p. 184

5.2.2 STRIKE

STRIKE adopts the basic structure of the MVP approach, but has adapted it to incorporate the types of assets that are typical in the electricity industry, rather than just shares. *STRIKE* also generalises the MVP approach by allowing for different measures of risk, in addition to variance, and by allowing for arbitrary distributions of returns, in addition to normality.

STRIKE determines the efficient mix of hedging products to meet a particular load profile, and the cost of that mix of hedging products. Instead of assessing the expected return and associated risk for each asset in isolation, *STRIKE* applies the concepts of portfolio theory to evaluate the contribution of each asset to the risk of the portfolio as a whole.

STRIKE adapts the MVP efficient frontier approach to suit the specific context of the electricity industry. The MVP methodology was developed in the context of portfolios of traded shares. By contrast, electricity industry assets are more varied and include physical assets such as generating plant, different classes of customers with particular load characteristics, short and long-term supply contracts, and hedging contracts. Many of these assets involve quantity constraints.

STRIKE uses a slightly different, but equivalent, formulation of the optimisation problem. For any value of k, the 'risk-adjusted' expected return of the portfolio can be defined as:

$$(2) \qquad r_A = r - k\gamma$$

where γ is the chosen risk criterion, such as variance, or the value-at-risk, or profit-at-risk, and k is an indicator of the level of risk. If γ is equal to the variance then maximisation of (2) is equivalent to the minimisation problem in (1).[4]

In practice, given the nature of the assets and the quantity constraints, there is no closed solution to this maximisation problem. Hence *STRIKE* solves the problem using quadratic mixed integer programming (QMIP) techniques. By maximising (2) for different values of k, *STRIKE* is able to map out the 'expected-return risk' frontier. This can be done not only when γ is the portfolio variance, but also for other measures of risk.

When variance is used as the measure of risk, the distributions of the returns on all the potential assets in the portfolio do not affect the determination of the optimal portfolio. However, with other measure of risk this is not the case. For non-normal returns simulation methods are used to determine the risk associated with any portfolio of assets.

The uncertainty associated with any stream of returns can be estimated from historical data, or by simulating actual operations. Similarly, the uncertainty in spot prices can be modelled using existing pool modelling approaches and/or historical data. However, when using simulation to determine the distribution of returns, the relationship between the various simulated quantities must also be

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4 This formulation is equivalent to the Lagrangian formulation of the minimisation problem in (1).

taken into account. For example, it is likely that a generator outage will result in higher prices, as the supply-demand balance is tightened. Frontier will model spot prices using *SPARK*, which uses game theory to develop a distribution of prices.

Data required

To formulate the efficient frontier *STRIKE* requires data on energy purchasing cost options (costs and quantities) and the characteristics of the customer load that energy is being purchased for.

The energy costs used in *STRIKE* are derived from the outputs of the energy cost simulation modelling described above and sensitivities are undertaken based on the energy purchasing cost estimates provided to the Tribunal by industry participants. Data on the characteristics of customer load data is provided by each of the standard retailers. Full details on the assumptions used in *STRIKE* will be set out in detail in an assumptions document provided with Frontier's draft report.

5.2.3 SPARK

Nature of organised electricity markets

Competitive wholesale power markets are generally highly organised with strict rules governing the way participants interact with the market, on the physical operation of the integrated power sector and, most importantly, on how prices are determined.

Typically, prices are determined in organised power markets each hour, half hour or 5 minute interval. That is, the process of bidding, dispatch and price setting occurs repeatedly throughout the day, day after day. With this constant interaction in a market place, where participants face the same rules and where market outcomes can generally be readily observed, participants have an opportunity to experiment with alternate commercial strategies to identify the circumstances in which they can improve their profitability, having regard to the reactions by competitors to these new strategies. The consequence of this process can be that participants end up tacitly colluding and raising the price above strictly competitive levels. In general, this outcome is more likely where there are fewer competitors. With fewer competitors it is easier to consider and monitor reactions to alterations in market behaviour. It is also generally easier to detect and then punish defectors seeking to gain additional profit at the expense of other producers.

Requirement for market simulation

Market participants, investors, governments and regulators often want to understand the level and volatility of future wholesale electricity prices. In the current context IPART needs to develop a view of the future energy purchase costs of standard retailers. For all intents and purposes, retailers have to buy all of their electricity from the NEM at the prevailing spot price. For load covered by the ETEF these purchases are subsequently settled out at a price determined by IPART. The difference between spot purchase price and sale price is typically covered by customers. In some rare events the difference is covered by the NSW generators. In the future, as the ETEF progressively rolls off, the standard retailers will, almost inevitably, hedge the risks associated with volatile spot prices by entering into financial derivative style contracts. The removal of ETEF is widely expected to have an effect on the spot market price and these spot price changes may also have an effect on the price and quantity of hedging contracts. These changes will alter the energy purchase costs and risks.

These changes involve complex interactions between a large number of physical, regulatory, structural and commercial factors. Given the complex interplay between these (uncertain) factors it would not be prudent to rely on the guesswork of even an experienced analyst to determine the effects that policy changes, new investments and other factors will have on spot and contract prices. In this situation, some form of market simulation can play a valuable role in understanding the range of market outcomes that could emerge in the future and to inform any process involving the estimation of energy costs.

In considering the appropriate form of simulation model to forecast energy costs, it is important to choose an approach that best reflects the real world. Having said this, it is important to acknowledge that no economic model will ever be able to precisely forecast outcomes in such a complex environment.

Electricity market simulation models are fairly common. Most electricity market models do a good job at incorporating the key physical and economic characteristics of the power system and the price setting rules. While it is certainly important to ensure that these features of the model are accurate, they are generally not the most important determinant in forecasting market outcomes. By far the most important variable in these models is predicting the bidding behaviour of generators.

More than a decade of experience in power markets has shown that bidding behaviour can change substantially over time in response to regulatory changes, new investments, new owners, amalgamations and demergers, changing contracting forms and levels, and operation of greenhouse gas reduction schemes. These dynamic power market forces mean that historical patterns of behaviour are of little use for predicting the future.

To overcome these limitations Frontier Economics has developed an electricity market model – *SPARK* – that does all the normal dispatch operations of every other model, but has an important difference – generator bidding behaviour is a model *outcome*, not an arbitrary input assumption. *SPARK* produces a set of 'best' (i.e. sustainable) generator bids for every market condition. As the market conditions change, so does the 'best' set of bids.

SPARK finds the 'best' set using advanced game theoretic techniques. This approach, and how it is implemented in *SPARK*, is explained in more detail below.

Game theory and organised power markets

Game theory is a branch of mathematical analysis which is designed to examine decision making when the actions of one decision maker (player) affects the outcomes of another player, which may then elicit a competitive response that alters the outcome for the first player. Game theory provides a mathematical, and therefore systematic, process for selecting an optimum strategy (and equilibrium) given that a rival has their own strategy and preferred position. Organised power markets are well suited to the application of game theory:

- there are strict rules of engagement in the market place;
- there is a well defined and consistent method for determining prices and, hence, profits; and
- the interaction between market participants is repeated at defined intervals throughout the day.

There are several basic concepts that underpin the game theoretic approach:

- **Players**: players are generators who are able to make decisions based on the behaviour they know or expect from other players. *Strategic players* are given a range of different strategies allowing them to respond to changes in the behaviour of other players. Non-strategic players have a fixed strategy and hence are unresponsive to the behaviour of other players.
- **Payoffs**: in every game, players seek to maximise pay-off (i.e. operating profit) for a given set of competitor strategies.
- **Nash Equilibrium:** an equilibrium describes a best or optimal set of choices by the players in the game. An equilibrium is an optimum in the sense that each player is choosing its profit maximising strategy subject to the strategies being pursued by the other players. Thus, an optimal outcome is not necessarily one that maximises a particular player's profits.

Applying game theory to the electricity market

Consider a single regional market, with 2 players, A and B, of equal size (say 100MW) and costs (say $10/MWh). There are other higher cost generators in the market as shown in the aggregate supply and demand diagram in **Figure 6**. Demand is at a level above the combined capacities of A and B, and intersects at a slightly higher cost generator, at price $15/MWh.

Under the bids as shown, and assuming a dispatch period of an hour, the price is set at $15/MWh and both A and B make small profits equal to $5/MWh ($15-$10), multiplied by their output of 100MWh, giving $500 each.

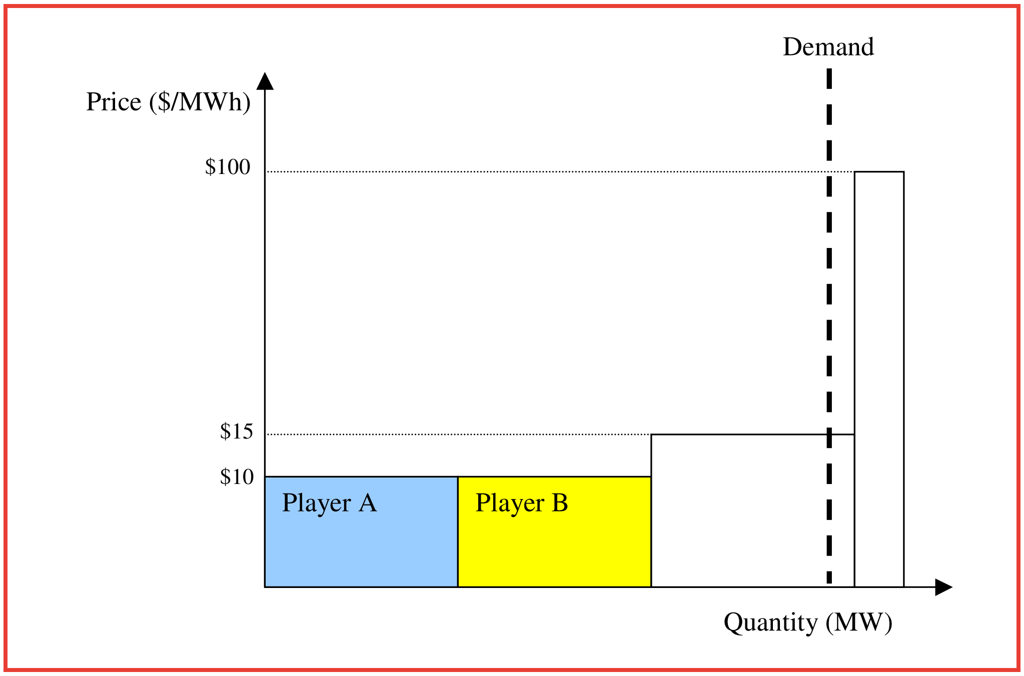

Figure 6: Example supply/demand diagram

Under these conditions, either player could withdraw a small amount of capacity to push the price up to $100/MWh. Assume A withdraws 10MW and price is just set at $100/MWh. Then A's profit becomes 90MW*($100-$10) = $8,100 and B's profit becomes 100MW*($100-$10) = $9,000. Conversely, B could withdraw 10MW, and the profit results would be reversed. Further, if both A and B withdrew 10MW each, the price would be set at $100/MWh and their profits would be 90MW*($100-$10) = $8,100 each.

Using these results, we can construct a game payoff matrix as shown in Figure 7.

		Player B	
		Bid 100MW	Bid 90MW
Player A	Bid 100MW	$500, $500	$9,000, $8,100
	Bid 90MW	$8,100, $9,000	$8,100, $8,100

Figure 7: Payoff matrix (Player A, Player B)

Note: Payoffs are in Player A, Player B order.

Now consider Player A's incentives. If A thought B would bid 100MW, A would do best by bidding 90MW for a profit of $8,100 (compared to $500 by bidding

100MW). If A thought B would bid 90MW, A does best by bidding 100MW for a profit of $9000 (compared to $8100 by bidding 90MW). As the game is symmetric, B would choose likewise. In this example, we have two equilibria, (A=90MW, B=100MW) and (A=100MW, B=90MW). At either equilibrium point, no player can increase its profits by unilaterally changing its bid – that is, both these points are Nash Equilibria.

Operation of SPARK

As explained above in Section 5.1.1, *SPARK* is fundamentally formulated in the same manner as *WHIRLYGIG*. *SPARK* is provided with a choice of capacity or price bids (equivalent to altering C_j or V_j, in the case of, respectively, a capacity (Cournot) or price (Bertrand) bidding game in Table 3).

The first step in SPARK is to divide generators into two categories:

- *strategic players* are given a set of strategies (i.e. choices of capacity or prices to bid into the market), and will respond to changes in the choices of others, in order to maximise their payoffs; and
- *non-strategic players* are assigned fixed bids (i.e. their bids remain constant no matter how other players bid – fixed bids can be in any form or level, just as so long as they are fixed).

The next step involves selecting the type (capacity or price bids, or a combination) and range of bidding choices (e.g. the increments of capacity withdrawals in a Cournot game, or the multiples of short run marginal cost in a Bertrand game). Given the computational demands of game theory it is important to limit the choices as the number of dispatch operations rises exponentially as the number of strategic players and bidding choices increases.

SPARK considers each demand point individually when running a game, i.e. a game is considered to be at a particular (representative) demand point. In analysing multiple demand points, a number of games, one for each point, are run.

For each combination of bids and for each demand point, SPARK computes prices and operating profits. The operating profits are used to measure the 'payoff' for a game. Once all possible combinations of bids have been computed, *SPARK* searches for the Nash Equilibrium.

In effect, SPARK identifies equilibrium strategies on the basis of a grid search of the possible strategy space, as illustrated (for a two strategic player game) by Figure 8. PAi and PBj represent the pricing strategies of players A and B respectively. VAij and VBij represent the pay-offs (contribution to profit) for the strategy combination. SPARK searches the set of possible outcomes of the one-shot game for Nash Equilibria without considering how the players arrive at a particular outcome.

PA_n	VA_{n1} VB_{n1}	VA_{n2} VB_{n2}	VA_{n3} VB_{n3}	VA_{n4} VB_{n4}	.	.	.	VA_{nm} VB_{nm}
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.
PA_4	VA_{41} VB_{41}	VA_{42} VB_{42}	VA_{43} VB_{43}	VA_{44} VB_{44}	.	.	.	VA_{4m} VB_{4m}
PA_3	VA_{31} VB_{31}	VA_{32} VB_{32}	VA_{33} VB_{33}	VA_{34} VB_{34}	.	.	.	VA_{3m} VB_{3m}
PA_2	VA_{21} VB_{21}	VA_{22} VB_{22}	VA_{23} VB_{23}	VA_{24} VB_{24}	.	.	.	VA_{2m} VB_{2m}
PA_1	VA_{11} VB_{11}	VA_{12} VB_{12}	VA_{13} VB_{13}	VA_{14} VB_{14}	.	.	.	VA_{1m} VB_{1m}
	PB_1	PB_2	PB_3	PB_4	.	.	.	PB_m

Figure 8: Hypothetical example of SPARK's strategy search

In game theory it is possible for more than one equilibria set of bids to be found for a representative demand point. In theory each equilibrium is just as likely as another. To summarise the results we have developed a technique for forming a distribution of the annual average market price from the equilibrium prices estimated for each representative demand point.

Given that an equilibrium price is more likely than a price that is not an equilibrium price, these distributions can be thought of as distributions of 'likely' prices.

To form these distributions of average equilibrium prices we take a random sample (say, 100) of the 17,520 dispatch intervals (there are 17,520 half-hour intervals in a year). Each equilibrium (for a given year) is assigned a probability of occurrence equal to the probability of occurrence of the associated demand point divided by the number of equilibria found at that demand point. Each of the 100 sample sets independently selects 17,520 intervals from the pool of potential equilibrium outcomes (given each equilibrium's probability of occurrence), producing 100 different sets of annual outcomes, and hence 100 different annual average pool prices.

This same approach can also be employed to produce distributions of all other model outputs, e.g. hours of constraint, generation dispatch etc.

To ease the presentation of these distributions we have smoothed the curves using the Kernel Density Estimation approach. In short, the Kernel Density Estimation approach treats each observation (of 100 observations in our case) as a normally distributed random variable with mean equal to the observation, and an assumed (small) variance.

The kernel density probability P(x) is calculated for a given variable, x, as:

$$P(x) = \frac{1}{n}\sum_{i=1}^{n} N(x, x_i, \sigma)$$

where:

n = the number of sample observations

N(x,m,s) gives the normal probability density at point x, with a mean of m and standard deviation s

σ = the assumed standard deviation of each observation

x_i = the sample variable for i = 1 to n.

Using this approach a 'smoothed' probability density figure can be presented from the 100 randomly drawn observations. It is important to note that this approach has only been used for the purpose of *presenting* the price distribution curves. The smoothed distributions are *not* used in the calculation of the efficient energy purchasing frontiers.

Data required

As discussed, the fundamental features and formulation of *SPARK* are very similar to *WHIRLYGIG*. The data requirements are also very similar. As with *WHIRLYGIG*, some of the data has been requested from standard retailers. The rest will be based on informed assumptions made by Frontier, which will be set out in detail in an assumptions documents provided with Frontier's draft report.

5.3 NEMMCO FEES

NEMMCO fees are based on the costs of running the organisation. A large proportion of these costs are, nowadays, fairly predictable and are related to staff and IT costs for operating the market. Annually NEMMCO proposes a business plan approved by the Board to jurisdictions for approval. These plans determine the future costs and, hence, fees by NEMMCO. NEMMCO fees during the period of the determination will be estimated using a combination of historic forecasts and actual fees.

5.4 RECOMMENDED ENERGY COSTS

For each of the standard retailers, *WHIRLYGIG* will provide a range for the LRMC of electricity generation. The range of estimated costs will reflect variations in demand and supply and the costs of plant options.

For each of the standard retailers, Frontier will also provide a range for hedging, risk management and transaction costs. The range of costs for each standard retailer will reflect, in part, different risk management strategies that each retailer may adopt. It may be the case that the risk/reward frontier estimated using Frontier's three electricity models has a particular range of costs and risks that are more likely to be adopted than others. For instance, where the risk/reward frontier has a point of inflection, so that moving from that point requires trading significantly higher risk for only slightly lower costs (or significantly higher costs for only slightly lower risk) the range of costs around this point of inflection will form the basis for the recommended range of energy costs. Likewise, and as discussed in further in Section 7, the range of risks around this point of inflection will be used in the estimation of the allowance for retail margin, and will be reflected in estimates of the appropriate margin.

The recommended range for energy costs for each standard retailer will reflect the results of both the estimate of the LRMC of electricity generation to meet the load profile and the estimate of the market price of hedging products to meet the load profile.

6 Retail costs

Two approaches will be used to estimate retail costs: a bottom-up estimation of the retail costs of a MMNE, principally based on information provided by standard retailers, and benchmarking against information from other jurisdictions.

There are two key issues that emerge in each of these approaches.

The first is the allocation of the costs and risks that a MMNE faces to either the allowance for retail costs or the allowance for retail margin. The choice between allocating a particular cost or risk to retail costs or the retail margin should not materially affect the results of the price review, as long as allowance is made for each relevant cost and risk, and no cost or risk is counted twice. For each of the two approaches, cost components allowed for within retail costs are principally operating expenditure associated with retailing to small customers. Also included are customer acquisition costs that would be faced by a MMNE. As discussed in Section 7, an allowance for bad debt, depreciation and amortisation is allowed for in the retail margin.

The second key issue is the extent of economies of scale. The Minister's ToR require the estimation of retail costs for a MMNE, where a MMNE is defined as being of sufficient size to achieve economies of scale. In adopting each approach, therefore, it is necessary to determine the scale at which retail costs can be minimised. As indicated earlier in Section 2, the interpretation of the MMNE proposed for this review is grounded in what is expected to occur in practice. In practice it is expected that existing retail businesses that do not currently serve regulated customers will increasingly compete for these customers. Generally these retailers (e.g. AGL, TRUenergy, Origin, etc) are large scale retailers serving retail customers across the NEM. Many of these are of a similar scale to the NSW Government owned retailers. It is proposed that the cost structure of these retailers be used as a *basis* for developing an appropriate cost structure for the MMNE.

6.1 BOTTOM-UP APPROACH

6.1.1 Information request

The information request asked the standard retailers to report their retail costs of supplying small retail customers in NSW. The information request asked for the fixed and variable components of the following categories of retail operating costs:

- call centre costs;
- customer information costs;
- corporate overhead costs;
- regulatory compliance costs;
- marketing costs; and

- billing and revenue collection costs.

Actual costs were requested for financial years from 2002/03 to 2005/06, and forecast costs were requested for financial years from 2006/07 to 2009/10.

The information request also asked the standard retailers for actual small retail customer numbers for financial years from 2002/03 to 2005/06, and small retail customer numbers assumed for financial years from 2006/07 to 2009/10 for the purposes of forecasting retail operating costs.

Retailers were also asked for details of their customer acquisition costs, including any discount necessary to attract new customers, and the average number of years that a new customer typically stays with a retailer. This information was requested for financial years from 2002/03 to 2009/10.

6.1.2 Estimating costs

On the basis of the information provided by the standard retailers, an average annual cost per customer will be calculated for each standard retailer for each year from 2002/03 to 2009/10. This will provide a range for retail costs for each year during the regulatory period.

Costs will be calculated in two categories: retail operating costs and customer acquisition costs. Given that customer acquisitions costs have not been allowed for in IPART's previous determinations, and are not commonly allowed for in other jurisdictions, separately calculating these costs will facilitate benchmarking retail costs.

On the basis of the information on retail operating costs provided by the standard retailers, an average annual retail operating cost per customer will be calculated for each standard retailer for each year from 2002/03 to 2009/10. Similarly, on the basis of the information provided by the standard retailers, an average annual cost per customer of acquiring a customer will be calculated for each standard retailer for each year from 2002/03 to 2009/10. This will provide a range for customer acquisition costs for each year during the regulatory period. To the extent that reported costs differ between standard retailers, the reasonableness of these differences can be evaluated by assessing the source of these cost differences. The combination of retail operating costs and customer acquisition costs will provide an estimate of the total retail costs per customer per annum for a MMNE. It may be that the range of retail costs for a MMNE differs across standard retail areas. This will be informed, in part, on the basis of the information provided by standard retailers, and the reasonableness of differences in reported costs.

Comparing the average annual cost per customer across retailers, given the retailers' actual or assumed customer numbers, will likely provide some indication of the extent of economies of scale. The breakdown of retail costs into fixed and variable costs will also provide an indication of the extent of economies of scale.

6.1.3 Reasonableness of results from bottom-up approach

The reasonableness of the retail costs estimated using the bottom-up approach can be checked in several ways:

- cost estimates can be compared over time (including against estimates from previous reviews) to ensure that changes in costs are reasonable;
- the breakdown of costs into various categories can be compared across retailers, to the extent that the reported information permits such a comparison, in order to identify the source of different cost estimates;
- the information request also asked the standard retailers to explain how they allocated total retail costs to small retail customers in NSW – responses to this question may help identify the source of different cost estimates.

6.2 BENCHMARKING

The results of the bottom-up estimation of retail costs for a MMNE can also be compared against allowances for retail costs in other jurisdictions.

In many cases, previous regulatory decisions have recognised that benchmarking must be undertaken with regard to the differing scales (and therefore different costs) of retailers in different jurisdictions. In this case it will be important that benchmarking is undertaken with regard to the scale of the MMNE. Greater weight will be given to regulatory decisions in which retailers operate at a similar scale to the MMNE.

The scale of the MMNE will be informed by the results of the bottom-up assessment of costs. The scale of the MMNE will also be informed by examining the scale on which electricity retailers in NSW and in other jurisdictions have effectively entered.

6.3 RECOMMENDED RETAIL COSTS

The range of retail costs recommended by Frontier will be informed by the results of both approaches. Where the results of the two approaches converge, the estimated cost range can be estimated with greater confidence. Where the results of the two approaches do not converge, consideration will be given to the explanations for the different results. Where these explanations suggest that one of the two approaches is more appropriate, the results of this approach will be given greater weight in estimating the appropriate cost range.

7 Retail margin

Three approaches will be used to estimate the retail margin for a MMNE: a bottom-up estimate of the retail margin, benchmarking against information from other jurisdictions, and consideration of the expected returns of an electricity retailer. The results of these three approaches will be compared, and the appropriate retail margin will be chosen on the basis of any convergence in the results of these three approaches.

As discussed in Section 6, the allocation of costs and risks to the allowance for retail costs or the allowance for retail margin must be consistent: an allowance must be made for each relevant cost and risk, but no cost or risk should be allowed for twice. Costs and risks allowed for in the retail margin include an allowance for return on capital, bad debt, depreciation and amortisation, as well as any risks faced by the retailer not allowed for in the estimate of energy costs or retail costs.

Of particular importance is the appropriate allowance for energy purchase risk in the retail margin. As discussed in Section 5, an efficient energy purchasing strategy is likely to leave retailers exposed to some energy purchase risk. The extent to which retailers are exposed to energy purchase risk depends upon the location on the risk/reward frontier. To the extent that retailers' energy purchasing strategy leaves retailers exposed to risk, this risk needs to be allowed for in the retail margin. The estimate of energy costs will provide a detailed distribution of energy purchase risk. Neither the bottom-up approach nor the benchmarking approach can make use of this detailed distribution of energy purchase risks; for both of these approaches, the impact of energy purchase risk is very much a matter of judgement. In contrast, and as discussed in more detail in Section 7.3, the expected returns approach can make use of this information in a systematic way, so that the distribution of energy purchase risk can be reflected in the allowance for retail margin. To the extent that the distribution of energy purchase risk differs across standard retailers (due to differences in the load profile of their regulated customers) these differences can also be reflected in the different estimates of the retail margin for each standard retailer.

7.1 BOTTOM-UP APPROACH

To some extent it is possible to estimate the contribution of individual costs or risks to the total appropriate retail margin. The bottom-up approach enables a retail margin to be built up from its individual components.

The bottom-up approach is most applicable for those components of the retail margin for which costs can be calculated, including return on assets, working capital and depreciation. Other components of the retail margin – in particular the allowance for the risks to which retailers are exposed – are more difficult to estimate individually.

By way of example, the bottom-up approach has been promoted by Integral Energy in its submission to IPART's Issues Paper. The bottom-up approach will broadly follow the methodology used by Integral Energy. However, there will be some key differences:

- the costs and risks included in the bottom-up approach will need to be consistent with the costs and risks allowed for in the estimation of retail costs;
- where possible, the contribution of individual components to the retail margin will be assessed by drawing on market-based evidence from comparable retailers; and
- where possible, the contribution of individual components to the retail margin will be assessed by benchmarking against regulatory decisions in other jurisdictions.

7.2 BENCHMARKING

The retail margin will also be informed by decisions as to the appropriate retail margin by regulators in other jurisdictions, and by decisions by IPART in its previous reviews.

A key issue in benchmarking is to use benchmarks that are as closely comparable as possible. In the case of benchmarking retail margins, the key issue is the degree of risk to which retailers are exposed. With ETEF being phased out, the most relevant benchmarks for the retail margin of a MMNE are benchmarks for electricity retailers in jurisdictions in which retailers are not protected from energy purchase risk. Greater weight will be given to the retail margin allowed in such jurisdictions.

7.3 EXPECTED RETURNS

The third approach is to estimate the expected returns to an electricity retailer, and to ensure that these expected returns compensate investors for the systematic risk of these cash flows.

The first step in this approach is to forecast the expected cash flows to an electricity retailer, assuming a particular retail margin. The expected cash flows will form a distribution, reflecting the risks, particularly the energy purchase risk, to which electricity retailers are exposed. The primary information source regarding the distribution of expected cash flows is current and historical information provided by the businesses themselves. Our primary question is, "Given an assumed retail margin, how much are cash flows likely to vary in different states of the economy?" In other words, the systematic risk of the business is captured by the likely variation of its cash flows in association with overall market movements.

This association will be affected by variables influencing revenue and costs. Revenues are associated with overall market movements via the impact of economic conditions on volumes. This impact is exacerbated by the proportion of fixed costs in the entity's cost structure – the higher the proportion of fixed versus variable costs, the more a change in revenue flows through to a change in cash flows. It is also important to model the impact of economic events on the proportion of bad debts, with provision for bad debts expected to increase during an economic downturn.

The second step is to assess the relationship between the distribution of expected cashflows and market returns. Ideally, we will model market returns as the total return on a broad equity index. However, other indicators of economic performance – such as GDP growth – are likely to prove useful, given the small time series of historical cash flow data. Share prices reflect the market's expectations for future returns, but cash flows measure the performance of the business over the current period of time. If market returns are sufficiently volatile, this volatility can mask the businesses' exposure to economic risks, in terms of how cash flows are affected by these risks.

This relationship gives an indication of the extent to which risks are systematic. It is commonly accepted that investors need only be compensated for those risks that are systematic or market-related. There are two generally-accepted (and equivalent) ways of incorporating the allowance for systematic risk: (1) adjust the cash flows for risk or (2) calculate a risk-adjusted discount rate.

The first of these approaches is known as the certainty equivalent approach. This approach adjusts a series of risky cash flows to a certain cash flow that has equivalent value. The cash flows are adjusted for risk – greater risk requires a greater adjustment. The required adjustment depends on the extent to which cash flows may vary with general economic circumstances.

Our primary method for measuring this relationship is to construct scenarios consistent with varying levels of market performance, where market returns and associated probabilities are derived from historical returns. For each scenario, we will model the cash flows consistent with the economic circumstances – higher volumes and cash flows in a period of robust economic conditions, lower volumes and cash flows in a downturn. These state-dependent cash flows can be estimated using the historical relationship between cash flows and returns, as well as specific information from the businesses about how cash flows are affected by economic conditions.

The association between cash flows and market conditions allows for systematic risk to be explicitly accounted for in expected cash flows, such that the value of the business is estimated according to the equation below:

$$Value = \sum_{t=1}^{\infty} \frac{Risk\text{ - }adjusted\ cash\ flows_t}{\left(1 + r_f\right)^t}$$

This business valuation can be benchmarked against comparable firms. For example, we can examine the implied earnings multiple, the ratio of enterprise value to tangible assets, the implied cost of acquiring each customer, and so on.

An equivalent approach is to discount expected cash flows (not yet adjusted for risk) using a risk-adjusted discount rate. There is, of course, an explicit relationship between the adjustment to the cash flows under the first approach and the risk-adjusted discount rate in the second approach. Using this approach produces exactly the same business valuation:

$$Value = \sum_{t=1}^{\infty} \frac{\text{Expected cash flows}_t}{(1+r)^t}$$

This approach also lends itself to a benchmarking exercise. If the risk adjusted return is appropriate – meaning that it is consistent with the systematic risk of the returns to benchmark listed firms – then the retail margin assumed in determining that return is also appropriate. If the implied discount rate is inappropriate, then the assumed margin must be adjusted so that there is consistency between the two valuation methods.

Outputs from this analysis – a value for the electricity retailer and an implied return on investment – enable the analysis to be tested for reasonableness:

- The ratio of the total value of the retailer to the retailer's tangible assets can be assessed. This ratio can then be compared to similar ratios for comparable retailers.
- The implied return on investment can be compared to the return on capital adopted in other regulatory decisions.

If both of these tests provide results that are comparable to the benchmarks, then we can have greater confidence in the results of the analysis.

The output of the expected returns approach will be a range of retail margins, that will be related to the range of energy costs estimating using the market-based approach. In other words, for each different risk management strategy that is used in estimating energy costs in the market-based approach, there will be an associated retail margin that reflects the extent to which that risk management strategy leaves the retailer exposed to energy purchase risk.

7.4 RECOMMENDED RETAIL MARGIN

The range of retail margin recommended by Frontier will be informed by the results of each of the three approaches. Where the results of the three approaches converge, the estimated cost range can be estimated with greater confidence. Where the results of the three approaches do not converge, consideration will be given to the explanations for the different results. Where these explanations suggest that one of the approaches is more appropriate, the results of this approach will be given greater weight in estimating the appropriate cost range.

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