# Methodology Report – input assumptions and modelling

A DRAFT REPORT PREPARED FOR IPART

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# 1 Introduction

The Independent Pricing and Regulatory Tribunal (IPART) has received Terms of Reference for an investigation and report on regulated retail tariffs and regulated retail charges to apply between 1 July 2013 and 30 June 2016 (current Determination).

Frontier Economics has been engaged by IPART to provide advice to IPART for the current Determination.

## 1.1 Terms of Reference

IPART's Terms of Reference require it to determine three distinct cost components for Standard Retail Suppliers: energy costs, retail costs and retail margin. Our engagement, discussed further in Section 1.2, is related to certain aspects of the energy cost component for Standard Retail Suppliers.

In regard to energy costs, the Terms of Reference state:

> Energy costs include energy purchases from the National Electricity Market (NEM), greenhouse and renewable costs, NEM fees and energy losses.
>
> The Energy Purchase Cost Allowance should be set, using a transparent and predictable methodology.
>
> The Energy Purchase Cost Allowance for each year must be set no lower than the weighted average of the market based approach and the long run marginal cost with the market based approach ascribed a 25% weighting and the long run marginal cost ascribed a 75% weighting.
>
> In addition, IPART must determine the appropriate Energy Purchase Cost Allowance (subject to the floor price) that facilitates competition and promotes efficient investment in, and the efficient operation and use of, electricity services for the long term interests of consumers of electricity.

The Terms of Reference define the Energy Purchase Cost Allowance as follows:

> Energy Purchase Cost Allowance for a Standard Retail Supplier is an allowance to at least cover the efficient costs of purchasing electricity and managing the risks associated with purchasing electricity, from the National Electricity Market in order to supply electricity for its regulated load, excluding:
>
> - Costs of compliance with greenhouse and energy efficiency schemes (other than the Carbon Pricing Mechanism, which is included in the wholesale energy costs)
> - Costs of compliance with any obligations imposed under an applicable law relating to the reporting of greenhouse gas emissions, energy production or energy consumption

- Costs related to physical losses of energy arising during the transporting of energy over the transmission and distribution systems, as published by AEMO
- Any other costs (not referred to in the dot points above) relating to Standard Retail Supplier's retail supply business or the recovery of any retail margin relating to that business.

The Terms of Reference require that Energy Purchase Cost Allowance is determined for two regulated load shapes:

> IPART must determine two separate regulated load forecasts for the purposes of this determination; one for customers who consume between zero and 40 MWh per year and one for customers who consume between zero and 100 MWh per year. This will be developed, in consultation with the Standard Retail Suppliers to ensure that the efficient costs of a reasonable forecast regulatory load are recovered.

In regard to renewable costs, the Terms of Reference state:

> Additionally, IPART should have regard to the efficient costs of meeting any obligations that Standard Retail Suppliers must comply with, including the costs of complying with greenhouse and energy efficiency schemes (including State and Commonwealth schemes in place or introduced during the period this referral is in force).

## 1.2 Frontier Economics' engagement

Frontier Economics has been engaged by IPART to provide advice in relation to the Energy Purchase Cost Allowance and the cost of complying with the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

This advice is to consist of two related scopes of work:

- **Input Assumptions** – we have been engaged by IPART to advise on a set of key cost and technical input assumptions used in modelling wholesale electricity costs. These assumptions include capital costs and fixed operating costs of generation, short run marginal costs of generation (including fuel and operating costs) and other technical aspects of generation including operating characteristics.
- **Wholesale energy costs and regulated load profiles** – we have been engaged by IPART to provide advice on:
  - Developing the forecasts of each Standard Retailers' regulated load profile, in consultation with the Standard Retailers.
  - Modelling of energy purchase costs for the three Standard Retailers (using both a long run marginal cost of electricity generation approach and a market-based energy purchase cost approach) and the efficient costs of complying with the LRET and SRES.

Frontier Economics has also been engaged by IPART to provide advice in relation to the costs of ancillary services and market fees.

## 1.3 Frontier Economics' previous advice to IPART

Frontier Economics has previously advised IPART on estimating wholesale energy costs for IPART's 2007 Determination and IPART's 2010 Determination.

The high-level modelling methodology that we adopted in the 2007 Determination and 2010 Determination was essentially the same. This was consistent with IPART's intention at the time of undertaking the 2010 Determination to draw on and expand on the methodology that was used in the 2007 Determination.

We propose to continue with this same high-level modelling methodology for the current Determination. Our view is that this modelling methodology is appropriate to, and consistent with, the Terms of Reference for the current Determination:

- Our modelling methodology involves estimates of both the long run marginal cost of meeting the regulated load and the market-based energy purchase costs of meeting the regulated load. Our view is that these estimates will enable IPART to calculate the floor price for energy costs as required under the Terms of Reference.
- Our view is that our modelling methodology for estimating the market-based energy purchase costs of meeting the regulated load reflects the efficient costs of purchasing electricity, and managing the risks associated with purchasing electricity, from the NEM as required under the Terms of Reference.
- Our view is that our modelling methodology for estimating the costs to Standard Retailers of complying with their LRET obligations reflects the efficient costs of meeting these obligations as required under the Terms of Reference.

## 1.4 This Draft Methodology Report

This Draft Methodology Report provides an overview of our proposed approach to the two scopes of work for which we have been engaged.

The intention of this Draft Methodology Report is to explain our preliminary views on the approach to developing input assumptions and modelling wholesale energy costs. It is important to note that, at this early stage, no firm decisions have been made by us, or by IPART, on our approach to developing input assumptions or modelling wholesale energy costs. Stakeholders will have an opportunity to provide comments in response to this Draft Methodology Report before we proceed to undertake the required analysis and modelling. Throughout the course of our engagement with IPART we expect that we will release updates of this report in order to respond to stakeholder comments and to provide further detail of our approach.

This Draft Methodology Report is structured as follows:

- Part A provides an overview of our energy market modelling framework:
  - Section 2 provides an overview of the electricity market models that we propose to use in our advice to IPART
  - Section 3 discusses our approach to estimating LRMC
  - Section 4 discusses our approach to estimating market-based energy purchase costs
  - Section 5 discusses our approach to estimating the costs of the LRET and the SRES
  - Section 6 discusses our approach to estimating ancillary services costs.
- Part B provides an overview of our approach to developing the input assumptions required for our modelling:
  - Section 7 provides an overview to our approach to developing input assumptions
  - Section 8 discusses our approach to system load and regulated load forecasts
  - Section 9 discusses input assumptions for existing generation plant
  - Section 10 discusses input assumptions for new generation plant
  - Section 11 provides an overview of our approach to fuel cost input assumptions
  - Section 12 provides an overview of our approach to carbon cost input assumptions.

A detail description of our energy market models – *WHIRLYGIG, SPARK, STRIKE* and *WHIRLYGAS* – is provided in Appendix A through Appendix D.

# PART A – Modelling methodology

# 2 Overview of modelling methodology

This section provides a brief overview of our electricity market models. We have used these models in our previous advice to IPART on wholesale energy costs and propose to use these models to estimate both LRMC and market-based energy purchase costs for the current Determination.

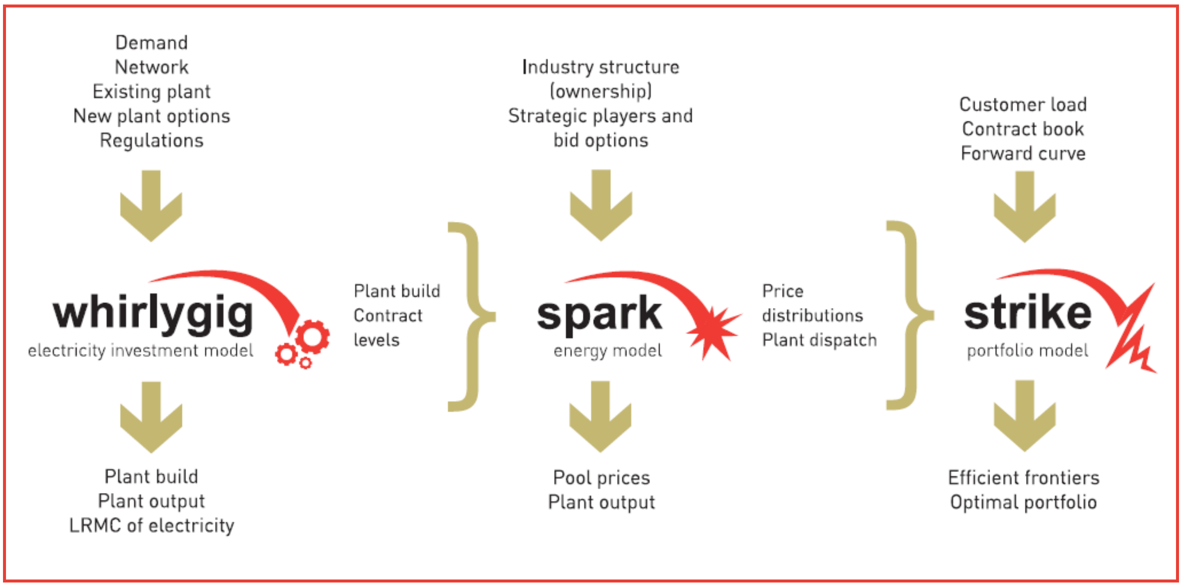
## 2.1 Frontier Economics' energy market models

For the purposes of estimating wholesale energy costs, Frontier Economics adopts a three-staged modelling approach, which makes use of three inter-related electricity market models: *WHIRLYGIG, SPARK* and *STRIKE*. These models were used in our advice to IPART for both the 2007 Determination and the 2010 Determination. The key features of these models are as follows:

- *WHIRLYGIG* optimises total generation cost in the electricity market, calculating the least-cost mix of existing plant and new plant options to meet load. *WHIRLYGIG* provides an estimate of LRMC, including the cost of any plant required to meet modelled regulatory obligations. *WHIRLYGIG* can be configured to perform a stand-alone LRMC estimate of wholesale energy costs or to model the NEM in order to provide estimates of the cost of meeting the LRET target and an investment pattern that can be used as an input to *SPARK*.
- *SPARK* uses game-theoretic techniques to identify mutually-compatible and hence stable patterns of bidding behaviour by generators in the electricity market. *SPARK* determines Nash Equilibrium sets of generator bidding strategies by having regard to the incentives for generators to alter their behaviour in response to the bids of other generators. The model determines profit outcomes from all possible combinations of bidding strategies (taking into account assumed contract positions) and finds Nash Equilibrium sets of bidding strategies in which no generator has an incentive to deviate from its chosen strategy. The output of *SPARK* is a set of equilibrium dispatch and associated spot price outcomes.
- *STRIKE* uses portfolio theory to identify the optimal portfolio of available electricity purchasing options (spot purchases, derivatives and physical products) to meet a given load. *STRIKE* provides a range of efficient purchasing outcomes for different levels of risk where risk relates to the levels of variation of expected purchase costs.

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

Figure 1: Frontier Economic' electricity market modelling framework




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

The economic theories underlying these electricity market models, and the specifications of these models, are discussed in more detail in Appendix A through Appendix C.

The way that these models are used to estimate wholesale energy costs is discussed in the Section 3 and Section 4.

# 3 Long run marginal cost modelling

There are numerous ways that long run marginal cost (LRMC) can be estimated for electricity markets. This section describes the alternative approaches, discusses the implications of each approach and addresses some implementation issues.

## 3.1 LRMC of a single plant or a mix of plant?

Two broad methods have been used to estimate the LRMC of electricity generation:

- The first method (Method A) is based on predicting the next power station to be built and its costs (irrespective of when that plant is required to meet demand or reliability requirements). This approach is often referred to as 'new entrant cost' approach. The costs of the new entrant generation plant are then used to establish LRMC. The underlying logic of this approach is that no incumbent generator could price above this 'new entrant cost' level for a sustained period because an investor would build a plant to undercut the incumbent's price, thus eventually bringing average prices down to the costs of the new entrant.
- The second approach (Method B) recognises that system load will be met by a combination of generation plant with varying cost structures (i.e. base load, mid merit and peaking plant). Thus, the price in a perfectly competitive market would reflect the least cost *mix* of these plants, as distinct from the cost of a single plant type predicted to be commissioned next.

In the context of the Australian NEM, Method A tends to result in higher prices than Method B. This is because most power systems across Australia tend to have a requirement for more peaking plant, which tends to be more expensive than base load plant. A common approach is to use a combined cycle gas turbine (CCGT) plant to provide the cost benchmark for the next increment of capacity required. This is because these plants can be run as peaking plants and later, as demand increases, they can operate as intermediate plants.

In our view, there are two main issues with adopting Method A to determine LRMC in the context of retail price regulation.

First, Method A requires a prediction of the next plant to be built, from which the price of all energy sold to regulated customers will be priced. While an analysis of the economics of different plant types will assist in making the choice about the appropriate reference plant, the use of a single plant type to determine the wholesale energy cost for all regulated customers potentially exposes retailers and customers to the risk that in reality, having regard to a range of commercial factors, the next power station built is different to the one chosen by the regulator. To a large degree the approaches that fall into the Method B category overcome the plant selection risk associated with Method A. It does this by developing a portfolio of plant types to meet future demand. With a portfolio of generation plant it is more likely that the actual plant being developed will be reflected in the estimation of the LRMC using Method B approaches.

Second, Method A fails to recognise the economic reality of the generation system. That is, it is economically optimal to use a mix of generation plant types – for example, high capital/low operating cost plants for base load operation and low capital/high operating cost for peaking plant (and plants with different capital and operating cost relativities in between). By failing to recognise the efficiencies of using a mix of generation plant types, Method A is likely to result in an LRMC that reflects inefficient plant costs.

Due to the risks and inefficiencies associated with selecting an inefficient, single candidate plant to provide a reference price for all regulated electricity sold in NSW, our advice to IPART is to adopt Method B for the purposes of determining LRMC.

## 3.2 Determining the LRMC of a mix of plant

There are two broad approaches for determining an LRMC using Method B. The two approaches differ in the way that they determine the combination of generation plant to meet demand:

- **Stand-alone approach** – 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 (this is the approach we used to determine the LRMC of the regulated load in our advice to IPART for the 2007 Determination and 2010 Determination).
- **Incremental approach** – 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. There are two key ways of measuring the cost of the incremental load:
  - The cost shock is measured by determining the present value of meeting a system reliability criteria. This approach considers the requirement for new capacity having regard to the current scarity or abundance of capacity in the actual generation system. If there is an abundance of plant then new plant will not be required for some time and the present value of the required new generation will be small, and *vice versa* when there is a scarcity of available generation plant

- The cost shock is initiated by a sustained step change in the demand for electricity. This sustained step in demand does not have to be associated with an actual requirement for capacity. However, if there is a relative abundance of generation plant a given sustained step in demand will result in a smaller LRMC cost than if the same increment in demand was applied if spare capacity was relatively scare. This is the classic approach described by Munasinghe & Warford, and Turvey and Anderson (henceforth in this report known as the 'Turvey Approach').[1]

For the purposes of estimating the LRMC of the regulated load, our advice to IPART is to adopt the stand-alone approach. This is consistent with our advice to IPART for the 2007 Determination and the 2010 Determination. The reasons that we would not advise estimating the LRMC of the regulated load using an incremental approach in general, or a Turvey approach in particular, are discussed in the following sections.

### 3.2.1 Implications of the incremental approach

The key difference between the stand alone and incremental approaches is the status of existing plant and hence the need for new capacity in the system. Under a stand-alone LRMC calculation, where existing generation plant is ignored, by definition all generation required to serve load involves new investment. Under an incremental LRMC, where the existing generation plant is incorporated in the modelling, new investment is generally only required to meet load growth or to replace existing plant that retires.

This key difference has implications for the estimation of LRMC. In estimating incremental LRMC, the capital costs of existing and committed generation plant are treated as sunk, and therefore irrelevant to economic decisions. In deciding whether to run existing plant, only variable costs are taken into account. In contrast, capital costs of uncommitted new plant are relevant to economic decisions, as these costs are not yet sunk. Therefore, in deciding whether it is efficient to build new plant, the estimation of the LRMC takes both capital costs and variable costs into account. An implication of this is that in estimating incremental LRMC, the capital cost of generation plant will not be reflected in the estimate of LRMC unless there is a requirement for new generation plant. Where there is sufficient existing and committed plant to meet forecast load, this is unlikely to be the case.

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1 Munasinghe, M. & J.J. Warford (1982), *Electricity Pricing, Theory and Case Studies*, published by the World Bank, The John Hopkins University Press. Baltimore and London.

Turvey, R and D. Anderson (1977), *Electricity Economics*, Baltimore, The John Hopkins University Press.

This treatment of existing and committed plant has important consequence for the estimation of LRMC over a short timeframe. Given that likely investment over a short timeframe would have already been committed (and hence would be treated as sunk), an incremental LRMC estimate may in the short term consistently fail to reflect the capital costs of generation plant required to serve load. Using this approach to estimate the LRMC of the regulated load, and using such an estimate to inform regulated retail prices, would risk putting retailers in a financially unsustainable position.

More generally, the incremental LRMC approach is problematic for estimating the LRMC of meeting any load other than the system load. This is because investments in the existing mix of generation plant have been undertaken to meet total system load; as such, it does not make sense to treat the entire stock of existing plant as sunk in the estimation of costs to serve a subset of system load, such as the regulated load of an individual Standard Retailer.

For these reasons we would not advise estimating the LRMC of the regulated load using an incremental approach.

### 3.2.2 Implications of the Turvey approach

Turvey (and others) have argued that the text-book definition of marginal cost as the first derivative of cost, with respect of output, is too simple to be useful.[2] In particular, both costs and output have time dimensions, and both are subject to uncertainty.

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

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

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

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

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

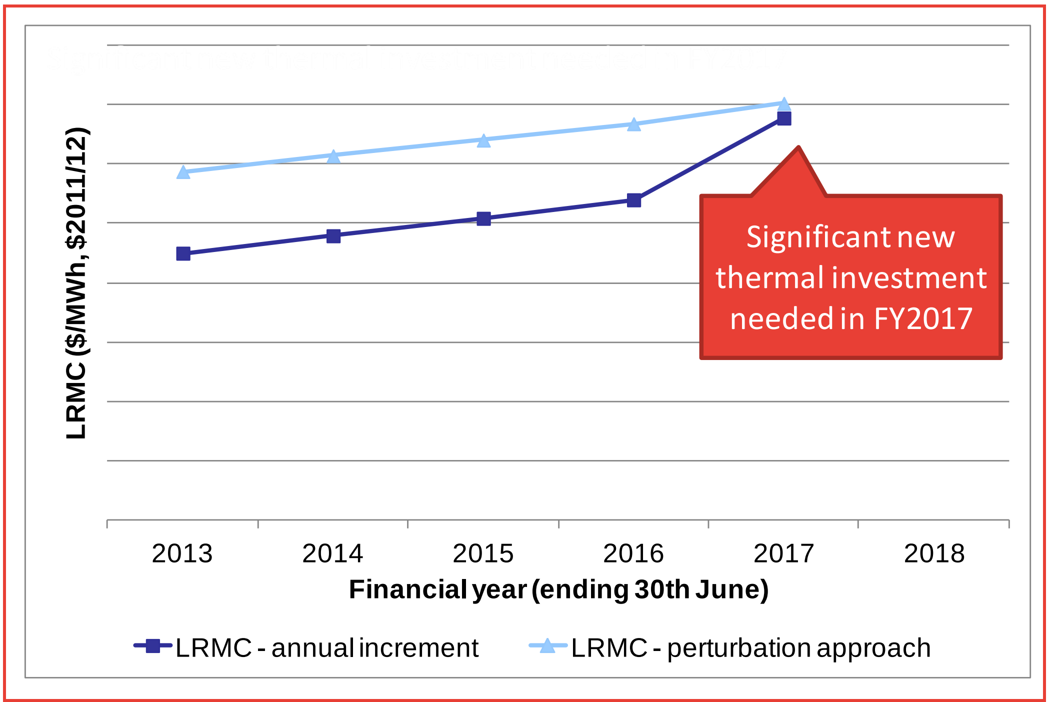
While Turvey's approach to estimating LRMC can provide useful information about costs in electricity markets, it is important to understand the implications of using these approaches.

First, both approaches are oriented to measuring the incremental cost of the generation system since they use the existing generation system as the base against which the optimal increment to capacity is selected. This makes determining the incremental cost of serving a particular load (such as the regulated load) difficult. Theoretically it may be possible to allocate the incremental cost to the regulated load using the perturbation method (Technique 1) by assuming a permanent increase in just the regulated load. Or, using Technique 2, allocating a share of the cost of the next increment of capacity to regulated customers based on matching the generation and load profile of regulated customers. However this approach is very similar to Method A (selection of a technology), which is not recommended. Indeed, Technique 2 is more problematic than Method A because it requires the selection of a candidate plant as well as the time at which the plant is required.

Second, by positing a permanent increase in demand, the perturbation approach results in an estimate of LRMC that incorporates a capital component in each year's estimate of LRMC; but, where the capital investment is not required for a number of years, the capital component will be discounted. This can be seen in Figure 2, which compares the LRMC for the NEM under a perturbation approach and under an approach in which the demand increment is only for the year in question (and not permanent). Based on this illustrative modelling, new investment to meet demand is not required in the NEM until 2017. Where the LRMC is based on annual increases in demand, this results in the capital component first appearing in the LRMC in 2017, leading to a significant increase in the LRMC from 2016 to 2017. Using the perturbation approach, however, a capital component is incorporated in the LRMC for all years, despite the fact that new investment is not required until 2017. However, the capital component in early years is a discounted capital cost, resulting in a gradual increase in the capital component of costs. This results in a more gradual increase in the LRMC.

While either of these approaches might be valid as an indicator of where market prices (in a competitive and efficient market) might be expected to head in the long term, there are issues with using either as an indicator of short-term market prices. In particular, the LRMC under the perturbation approach is unlikely to adequately capture the effect of excess supply on market prices. Conversely, in years where excess supply exists in the market, the LRMC under the annual incremental approach will not include capital costs associated with the supply of wholesale energy.

Figure 2: LRMC – annual and permanent increase in output




*Source: Frontier Economics*

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

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

For these reasons we would not advise estimating the LRMC of the regulated load using a Turvey approach.

## 3.3 Implementation of the stand-alone LRMC approach

Frontier Economics estimates the stand-alone LRMC by configuring *WHIRLYGIG* to model the marginal cost of meeting the regulated load shape using an entirely new generation system. The key modelling inputs under this approach are:

- Regulated load profiles for each Standard Retailer in NSW (discussed in Section 8.2).
- The costs and technical parameters of new generation options in NSW. Relevant costs are capital costs, fixed operating and maintenance (FOM) costs, variable operating and maintenance (VOM) costs, fuel costs and carbon costs. Relevant technical parameters include characteristics such as the emissions intensity, heat rate and outage rates (discussed in Section 10).
- The assumed reserve margin of this stand-alone system. We have adopted a 15 per cent reserve margin in our advice to IPART for the 2007 Determination and the 2010 Determination, and propose the same for the current Determination.

While this approach to estimating the stand-alone LRMC is consistent with the approach used in previous determinations, it is nevertheless worth highlighting some of the key implications of this approach.

### 3.3.1 Plant types

A key driver of the stand-alone LRMC will be the generation plant options that the model can use to optimise costs. Our proposed approach is to incorporate in the model all generation plant options that are likely in the modelling period. In practice, it is likely that the generation plant that are part of a least-cost mix will consist of coal-fired generation plant, CCGT plant and OCGT plant. Because we do not include the LRET in our stand-alone LRMC modelling (but separately account for the cost of complying with the LRET), more expensive renewable generation plant has not, in our work for IPART to date, formed part of a least-cost mix of generation plant.

We propose to include coal-fired generation plant options in the modelling despite the fact that there is some debate about whether it is feasible to develop a coal fired generator in the NEM (even if it is economic to do so in the presence of a carbon price). Planning restrictions, fear of environmental activism towards developers and financiers of these types of plant could deter investors from making otherwise economic investment decisions.

In spite of these difficulties, we propose to include coal-fired generation plant options in the modelling for two reasons. First, it is noted that coal-fired generators have been developed in recent times knowing that a carbon price was possible (eg Kogan Creek and Bluewaters). While there is little doubt that developers and financiers of thermal power stations will face greater environmental pressure in future, it is expected that once new base load generators are required the market will respond and overcome these hurdles. Second, in our view it is important to understand the most economically efficient mix of generation plant reflecting the underlying costs of that generation (including fuel costs and carbon costs). In particular, there will be combinations of fuel costs and carbon costs for which both coal-fired generation and gas-fired generation are part of the least-cost mix of generation plant.

### 3.3.2 Plant locations

As well as a decision about what generation plant options should be included in the stand-alone LRMC modelling, there is also a decision about what locations for generation plant should be included in the stand-alone LRMC modelling.

Our proposed approach is to limit the locations for new generation plant options only according to two criteria:

- The generation plant must be located within the NSW region (on the grounds that the generation plant should settle against the NSW spot price).
- The generation plant must be located within a sub-region of NSW in which fuel is available.

It may be the case that historically generators have not located in particular sub-regions of NSW. However, given that the stand-alone LRMC approach abstracts from the existing generation system, aside from the physical availability of fuel, our proposed approach is to model the location of generation plant according only to economic factors (primarily the cost of fuel supply in various sub-regions of NSW). We propose this approach for the same reason that we consider it is important to consider all plant types – to ensure there is a good understanding of the most economically efficient generation system that responds to the incentives created by the market and various regulatory arrangements.

While this is our proposed approach, we invite submissions on whether stakeholders consider that there are other objective criteria by which investment decisions should be constrained in the stand-alone LRMC approach.

### 3.3.3 Treatment of carbon

The cost of carbon is taken into account in estimating both stand-alone LRMC of supplying the regulated load and market-based energy purchase costs.

However, the way that the cost of carbon affects the results is different under these two approaches. The reason is the existing generation system is taken into account in our market-based modelling but the existing generation system is ignored in our stand-alone LRMC modelling.

In the short to medium term the extent of carbon pass through to wholesale prices will be determined by the change of the merit order of the existing stock of plant. In the short term it is expected that the carbon tax will have little effect on the merit order and, hence, carbon emissions. For this reason it is expected that the level of pass through would be remain high. Given the current oversupplied market and the uncertainty surrounding the longevity of the carbon pricing scheme it may be some time before there is significant new investment in cleaner generation technology (aside from that which results from renewable subsidy schemes such as the RET).

Since the recommended approach for determining the LRMC is based on the stand-alone method, where a carbon price is applied this will tend to produce a 'power system' that has a higher proportion of cleaner generation. This is because the approach is based on building a whole new power system. It does not have regard to legacy investments in the same way that the market price approach does. There are some important aspects to consider here. The first is that the 'cleaner' stand alone generation system will produce fewer emissions. This means that there will be less pass through of carbon than would occur in reality. Against this lower cost, the cleaner technology involves higher capital cost. In net terms it is likely to be the case that, using the proposed stand-alone LRMC approach, the higher capital costs outweighs the lower carbon pass through, resulting in a wholesale energy cost that errs on the high side (compared to the market price approach).

With an enduring carbon price, the generation system would, over time, move towards the type of 'cleaner' generation that is seen in the stand-alone LRMC approach. This is because retailers would seek to contract with generators with lower emissions to remain competitive in the retail market.

## 3.4 Implementation of the incremental LRMC approach

While our advice to IPART is to adopt a stand-alone LRMC approach to estimate the LRMC of the regulated load, an incremental LRMC approach nevertheless forms part of our modelling framework. Specifically, we use an incremental LRMC approach to determine least-cost investment in generation plant in the system (which is an input into our market modelling) and to determine the LRMC of meeting the LRET.

Frontier Economics models the incremental LRMC by configuring *WHIRLYGIG* to model the marginal cost of meeting the system load in each NEM region using existing generation plant in the NEM and new generation plant where required to meet demand or regulatory constraints. The key modelling inputs under this approach are:

- System load profiles for each NEM region (discussed in Section 8.1).
- The costs and technical parameters of existing generation plant in the NEM. Relevant costs are variable operating costs, fuel costs and carbon costs (fixed costs for existing generation plant are sunk and, therefore, irrelevant to economic decisions). Relevant technical parameters include characteristics such as the emissions intensity, heat rate and outage rates (discussed in Section 9).
- The costs and technical parameters of new generation options in the NEM. Relevant costs are capital costs, fixed operating costs, variable operating costs, fuel costs and carbon costs. Relevant technical parameters include characteristics such as the emissions intensity, heat rate and outage rates (discussed in Section 10).

As discussed above, our view is that the stand-alone LRMC approach is preferable to the incremental LRMC approach for the purposes of determining regulated electricity tariffs. Nevertheless, we undertake incremental LRMC modelling for two reasons. First, it provides inputs – including new investment in generation plant and information on likely contract levels – for use in subsequent stages of Frontier Economics' modelling approach. Second, the incremental LRMC approach also provides an estimate of the marginal cost of meeting the LRET target. Accurate estimation of marginal Large Generation Certificate (LGC) costs requires consideration of the regional structure of the NEM and the existing stock of plant.

# 4 Market-based energy purchase costs

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

- forecasting spot prices
- forecasting contract prices
- based on these forecast prices, and forecasts of the regulated load that the Standard Retailers supply, determining an efficient hedging strategy and the cost and risk associated with that hedging strategy.

This section provides an overview of our proposed approach to estimating the market-based energy purchase costs for the purposes of the current Determination, including:

- an overview of our approach to forecasting spot prices
- an overview of our approach to forecasting contract prices
- an overview of our proposed approach to estimating market-based energy purchase costs.

## 4.1 Forecasting spot prices

Broadly speaking, spot electricity prices can be modelled under two different approaches.

- Under a cost-based approach, spot prices are forecast on the basis of the resource costs involved in the supply of electricity. This approach typically uses an estimate of LRMC as a proxy for market prices. In this case, given that the intention is to reflect system spot prices, an incremental LRMC approach would generally be the preferred LRMC approach.
- Under a market-based approach, spot prices are forecast by taking into account strategic behaviour in the market. The market-based approach relaxes the assumption that market prices perfectly reflect costs.

In markets where there is perfect competition and where the mix of generation and transmission assets is optimal, a market-based approach and a cost-based approach would provide the same forecast of spot prices – spot prices would reflect efficient costs. However, this will not be the case in electricity markets. Electricity markets are characterised by investments in generation and transmission assets that are both long-lived and lumpy. For this reason, the mix of generation and transmission assets will never be optimal in the short-term. The result is market prices that diverge from efficient costs.

Given that market prices are likely to diverge from efficient costs in electricity markets, a market-based approach to modelling spot prices is likely to provide important information about the costs that retailers face in buying energy from the wholesale market. Consistent with the approach that we used in advising IPART for the 2007 Determination and the 2010 Determination, and as required by the Terms of the Reference for the current Determination, we propose to estimate market-based energy purchase costs by adopting a market-based approach to modelling spot prices.

Some of the issues associated with forecasting contract prices using a market-based approach, and our proposed methodology, are set out in this section.

### 4.1.1 Issues in forecasting spot prices

Spot prices can be forecast under a market-based approach using a model of the electricity market. Models are used to gain an understanding of the strategic incentives that market participants face within the physical and economic characteristics of the market, and the implications of these strategic incentives for bidding behaviour and market outcomes.

More than a decade of experience in electricity markets has shown that bidding behaviour can change substantially over time in response to regulatory changes, new investments, new owners, and changing contracting forms and levels. The result is that historical patterns of bidding behaviour are of limited use for predicting future patterns of bidding behaviour and future market outcomes. This is particularly important within the context of the current Determination, with the impact of the carbon price, expectations of lower demand growth and the mothballing of several generation units in response to lower wholesale prices all having the potential to alter bidding behaviour and market outcomes.

In this context, electricity market models are useful tools for understanding the impacts of various inter-related developments on outcomes in the market. To usefully predict future patterns of bidding behaviour and future market outcomes, models of electricity markets need to reflect the interactions between the physical and economic characteristics of the electricity market and the strategic incentives that market participants face.

#### *Physical and economic characteristics of the market*

Competitive wholesale electricity markets are generally highly organised, with rules governing the way participants interact with the market, rules on the physical operation of the integrated power sector and, most importantly, rules on how prices are determined. These price setting rules need to be incorporated into any model of the market.

In addition, economic characteristics – such as the supply-demand balance in the market and the shape of the market supply curve – provide a context within which market outcomes can be sensibly determined.

It is relatively straight forward to incorporate within a electricity market model 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.

#### *Generator bidding strategies*

Bidding can be captured in electricity market models in a number of ways, all of which have shortfalls:

- Bidding in the model can be based on historical bidding patterns. This approach does not capture the impact of significant structural change on bidding patterns and outcomes. For instance, the introduction of a carbon price may result in a change in bidding patterns.
- Bidding in the model can be based on an educated guess of future bidding patterns. This approach is very subjective, not easily repeatable and not systematic. In particular, where the market is subject to a number of changes at the same time, it is very difficult to guess the ultimate impact of these various changes on bidding patterns.
- Bidding in the model can be established using a theoretical framework such as game theory. Game theory offers a systematic and objective framework for examining future patterns of bidding. However, game theoretic models can quickly become computationally intensive.

Game theory provides a systematic tool for examining future patterns of bidding, reducing the need for subjective judgements on bidding behaviour. This effectively makes generator bids an output of the model rather than an input. This allows an investigation of the changes in pricing and output behaviour resulting from changes in market rules or structure.

### 4.1.2 Frontier's proposed methodology

We model spot prices using *SPARK*, our electricity market model.

Like all electricity market models, *SPARK* reflects the dispatch operations and price-setting process that occurs in the market. The physical and economic characteristics of the market are configured in *SPARK* in much the same way as they are configured in *WHIRLYGIG* under the incremental LRMC approach. The key modelling inputs under this approach are:

- System load profiles for each NEM region (discussed in Section 8.1).

- The costs and technical parameters of existing generation plant in the NEM. Relevant costs are variable operating costs, fuel costs and carbon costs (fixed costs for existing generation plant are sunk and, therefore, irrelevant to economic decisions). Relevant technical parameters include characteristics such as the emissions intensity, heat rate and outage rates (discussed in Section 9).
- The costs and technical parameters of new generation plant that is found to be part of the least cost investment mix in our incremental LRMC modelling. Relevant costs are variable operating costs, fuel costs and carbon costs (in *SPARK*, these investments are treated as sunk, so that fixed costs for these generation plant are irrelevant to economic decisions). Relevant technical parameters include characteristics such as the emissions intensity, heat rate and outage rates (discussed in Section 10).

Unlike most other electricity markets models, however, generator bidding behaviour is a modelling output from *SPARK*, rather than an input assumption. That is, *SPARK* calculates 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 in Appendix B.

## 4.2 Forecasting contract prices

Consistent with adopting a market-based approach to forecasting spot prices we propose to base forecast contract prices on modeled, or observed, market prices.

Some of the issues associated with forecasting contract prices, and our proposed methodology, are set out in this section.

### 4.2.1 Issues in forecasting contract prices

#### *Modelled prices and market prices*

In our advice to IPART for both the 2007 Determination and the 2010 Determination we developed forecasts of contract prices using two approaches.

The first approach was to base forecasts of contract prices on the spot prices modelled using *SPARK*. In adopting this approach we calculated contract prices by applying a contract premium of 5 per cent to the relevant spot prices modelled using *SPARK*.

The second approach was to base forecasts of contract prices on publicly available contract prices for the NEM. In our advice to IPART for both the 2007 Determination and the 2010 Determination we used prices for NSW electricity contracts published by d-cyphaTrade.

We consider that there are a number of advantages to continuing with both of these two approaches for the current Determination:

- The use of d-cyphaTrade contract prices is arguably more transparent than using contract prices based on modelled spot prices. d-cyphaTrade contract prices are observable by all stakeholders and are based on actual trades occurring in the market.
- The use of contract prices based on modelled spot prices arguably provides greater opportunity to explore the factors that drive contract prices. For instance, the impact of different input cost assumptions (including different carbon prices) can be investigated through modelling spot prices and contract prices. However, these impacts cannot be reliably inferred from d-cyphaTrade data. This may be particularly relevant in the event of an application for a cost pass-through as a result of a regulatory change affecting input costs during the period of the determination.
- The current Determination is for the period from 2013/14 to 2015/16, with IPART required to determine an energy purchase cost for each year of the determination. Trading volumes for d-cyphaTrade NSW electricity contracts become increasingly small over the period for the current Determination. There are legitimate questions about the reliability of published prices where trading volumes are very small. In contrast, forward prices can be modelled for each year of the determination, and modelled to incorporate the best available knowledge about factors that would affect the market over the modelling period.

### *Point in time prices and rolling average prices*

In our advice to IPART for both the 2007 Determination and the 2010 Determination, when basing our forecasts of contract prices on prices published by d-cyphaTrade, we used only the prices published by d-cyphaTrade on the most recent trading day for which data was available when we undertook our modelling. This is known as a “point-in-time”, or “mark-to-market”, approach.

An alternative approach to prices published on d-cyphaTrade is to take an average of d-cyphaTrade prices published over a period of time (for instance, two years). This approach, known as a “rolling average” approach, has been used by regulators in other jurisdictions and has been supported by some retailers.

Our view is that the “point-in-time” approach is appropriate to estimating wholesale energy costs because it is consistent with the idea that economic decisions should be based on the current value of assets, rather than their historic value. Others have argued that a “rolling average” approach reflects the fact that retailers tend to purchase contracts over a period of time rather than at a single point in time. No doubt this is true but, in our view, it does not alter the logic of basing economic decision on current values. The extent to which retailers have entered into contracts historically that are either cheaper or more expensive than to today's contract prices is irrelevant as these costs are sunk. Retailers' decisions around what retail price should be offered to customers should reflect expectations of the cost of supplying that customer in the future and not reflect the consequence of prior decisions.

A consequence of this approach is that point-in-time contract prices will tend to be higher than historical average contract prices in a market where supply and demand is tightening, or other factors are leading to higher contract prices over time. In these circumstances, the mark-to-market approach will reflect the expectation that serving a marginal retail customer in the future is likely to be more expensive than was expected in the past. Using a mark-to-market approach will ensure that increasing expected costs are reflected in wholesale energy costs estimates.

Conversely, in a market where supply and demand is loosening, or other factors are leading to lower contract prices over time, the point-in-time contract prices will tend to be lower than historical average contract prices. In these circumstances, the mark-to-market approach will reflect the expectation that serving a marginal retail customer in the future is likely to be cheaper that was expected in the past.

### 4.2.2 Frontier's proposed methodology

Given that there are arguments in favour of basing forecast prices on modelled spot prices and on published contract prices we intend to advise IPART on market-based energy purchase costs using both of these approaches. We invite stakeholder comment on which approach should be adopted for establishing market-based energy purchase costs.

When using published contract prices, we consider that it is appropriate to adopt a "point-in-time" to determine the relevant prices of those contracts.

In both cases, this methodology is consistent with the methodology that we adopted in our advice to IPART for the 2007 Determination and the 2010 Determination.

## 4.3 Modelling market-based energy purchase costs

Electricity retailers buy energy in a wholesale market characterised by volatile spot prices, but sell energy to customers at prices that tend to be fixed (particularly for small retail customers). In this environment, retailers' margins can be quickly eroded by a short period of high spot prices, if retailers are not adequately hedged. In order to manage the price risk associated with buying at variable prices and selling at fixed prices, retailers enter into a range of hedging contracts.

In order to calculate the market-based energy purchase costs, it is important to take into account the contracts that retailers purchase to hedge their price risk, and the cost of these contracts. Frontier proposes to use *STRIKE* to determine the efficient mixes of hedging products that retailers would enter into over the period of the determination, and the energy costs and risks associated with each of these efficient mixes.

*STRIKE* is a portfolio optimisation model. It 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.

### 4.3.1 Accounting for risk in energy purchase costs

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

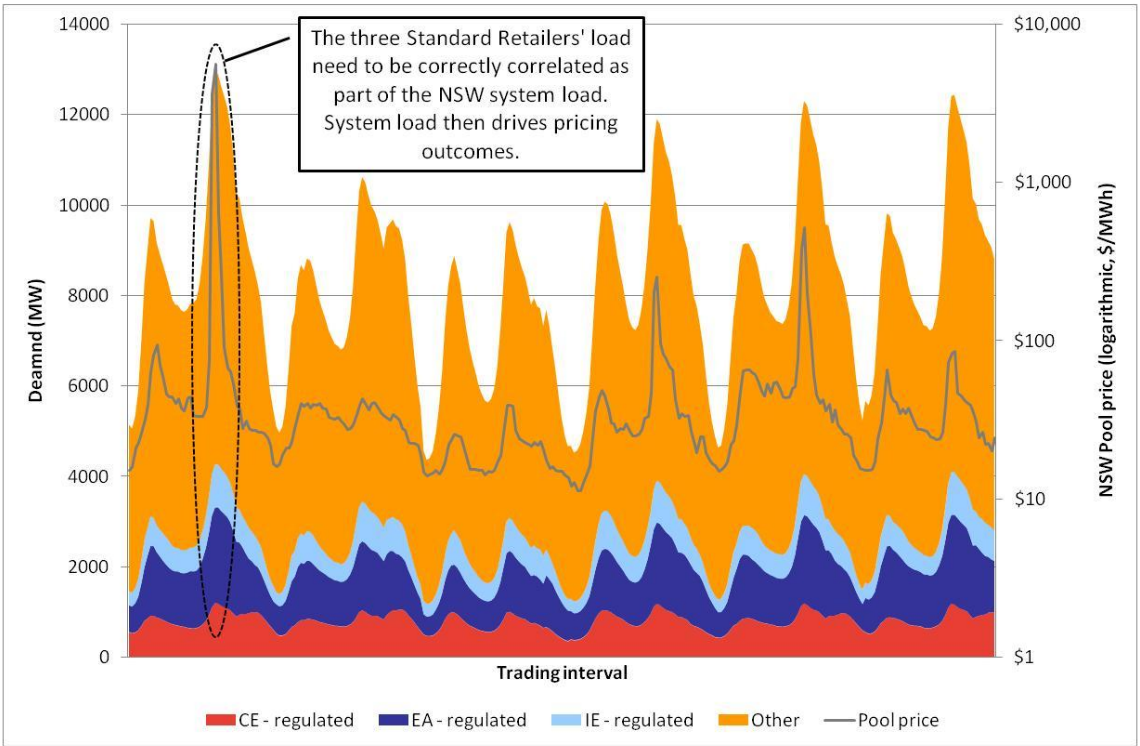
- load volatility;
- price volatility; and
- the correlation of load and price.

Load volatility is accounted for in our modelling by using, for each Standard Retailer, three forecast load shapes, which represent a realistic range of load volatility outcomes. We use *STRIKE* to determine the efficient mix of hedging products across three different load forecasts, as represented by three probability of exceedence (POE) load forecasts: a 10% POE load forecast, a 50% POE load forecast and a 90% POE load forecast. *STRIKE* co-optimises an efficient hedge position for each level of residual risk across these three POE load forecasts. In doing so, *STRIKE* implicitly quantifies the cost of efficiently hedging an uncertain load forecast, where load uncertainty can result in less costly (90% POE) or more costly (10% POE) outcomes than the 'expected' cost of serving an 'expected' level of demand or volatility (50% POE). Obviously, a key input to the estimation of the market-based energy purchase cost is, therefore, three sets of forecast half-hourly regulated load data for each Standard Retailer: a 10% POE load forecast, a 50% POE load forecast and a 90% POE load forecast. Our proposed approach to forecasting Standard Retailer regulated load is described in Section 8.2.

Appropriately accounting for price volatility – and the correlation between load and price – requires that, for each forecast load shape for each Standard Retailer, the regulated load is properly correlated to the NSW system load. Given that NSW spot prices reflect NSW system load, ensuring an appropriate correlation between the forecast load shape for each Standard Retailer and the NSW system load also ensures an appropriate correlation between the forecast load shape for each Standard Retailer and NSW spot prices[3].

This concept is illustrated in Figure 3, using hypothetical time series data for the regulated loads of each of the Standard Retailers, the NSW system load and the NSW spot prices. The circled area shows how the peaks in each of the regulated loads are co-incidental to (correlated with) the peak in NSW system load. The NSW system load then drives the NSW spot price. Our approach is designed to capture this correlation between residential load and spot prices and to consider the risk that retailers face through consideration of a range of forecast load/price outcomes.

Figure 3: Correlation between the Standard Retailers' regulated loads, system load and system price (illustrative only)




For a given Standard Retailer and for each regulated load forecast shape there is an associated system load shape and resultant system price shape that is appropriately correlated to the regulated load. For a given Standard Retailer, the

3 The approach to forecasting residential load shapes, and correlating them to system load shapes such that correlated pool prices can be forecast using *SPARK,* is discussed in more detail in Section 8.

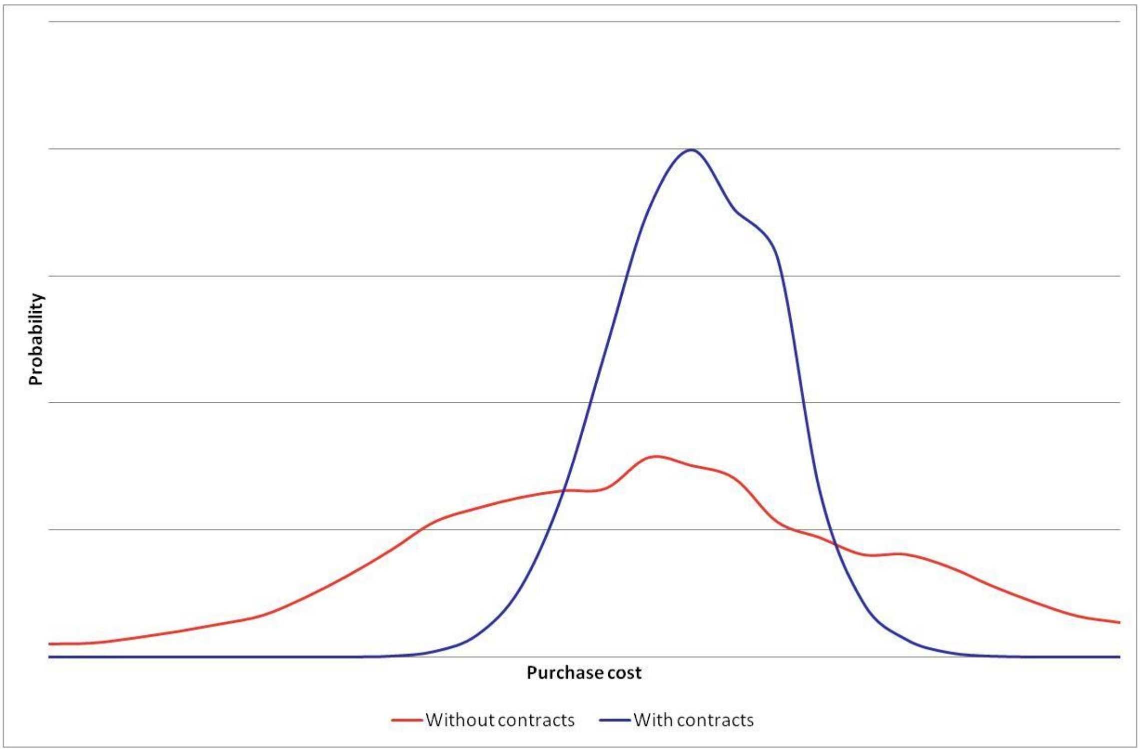
outcomes across the three price-load shape pairs, and the correlation between them, account for variation in the energy purchase cost (risk) that the Standard Retailers face for regulated load in NSW.

Using these inputs *STRIKE* sees a distribution of likely pool purchase cost for a given year. An example is shown diagrammatically in Figure 4 (which is not based on any real data). If the entire load is priced at the pool price (no contracts are entered into) then the distribution of purchase costs will be very wide representing a high level of volatility associated with the expected purchase cost. Adding contracts to the portfolio:

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

In Figure 4 we see these effects in the distribution of energy cost with contracts. The expected purchase cost is higher and its distribution is narrower. The trade off between reduced cost and reduced risk is exactly what *STRIKE* quantifies when it constructs the efficient frontier of contracting options.

Figure 4: Distribution of purchase cost – with and without contracts (illustrative only)



Each point on the efficient frontier calculated by *STRIKE* represents an optimal bundle of contracts for a given risk profile. At the high risk end of the efficient frontier, very little weight is placed on risk in the portfolio and *STRIKE* tries to find the set of contracts that minimise the expected purchase cost regardless of how risky this is (indicated by how wide the distribution of purchase costs gets). In the extreme this may involve the entire load being purchased at spot prices. Conversely, at the conservative end of the efficient frontier, a high weight is put on risk. In this case, *STRIKE* seeks to minimise risk with little regard to cost, which is equivalent to finding a set of contracts that minimises the spread in the distribution of expected purchase costs notwithstanding that this will increase expected purchase costs. It is the cost associated with this conservative position that is was used in the 2007 and 2010 Determinations.

### 4.3.2 Likelihood of price cap events

The inputs used to construct a likely distribution of purchase costs in *STRIKE* will not necessarily include the possibility of a price cap event for every discrete contracting period. That is, it may be the case that forecast prices for a given quarter and peak/offpeak period do not reach (or approach) the market price cap. This is particularly the case for offpeak periods. Whilst this outcome reflects the reality that price cap events are unlikely to occur during offpeak times, retailers need to contract in recognition of the fact that high price outcomes are a possibility at all times.

In order to replicate this in *STRIKE*, in our previous work for IPART we have included additional data in the model. Specifically, eight additional 'half hours' were included for each retailer in each year – one for each quarter, peak and offpeak. For these half hours the NSW price was assumed to be the market price cap (currently $12,900/MWh) and the regulated load for each retailer was assumed to be the maximum load for that quarter, peak/offpeak. That is, these additional half hours involved the maximum spot price occurring at the same time as the maximum demand for the relevant period.

These additional half hours were given a relatively lower weighting than the actual data that is input into *STRIKE*. This results in the cost impact of this additional data being minimised. However, the resultant optimal contracting position at the conservative end of the efficient frontier reflects the possibility of high priced events occurring for every period over which discrete contracting decisions are made.

We propose to adopt this same approach for the current Determination.

### 4.3.3 Blocky contracting options and residual risk

Even at the conservative end of the efficient frontier, there is still some residual risk in the portfolio. This arises because the contracts available in *STRIKE* –

quarterly, peak and offpeak swaps and caps – do not allow a riskless portfolio to be constructed: difference payments on swaps and caps can never perfectly mirror the pool costs of a time varying load shape priced at a time varying price. In our advice to IPART for the 2007 Determination and the 2010 Determination, this residual risk was compensated for through a volatility allowance, which is discussed in Section 4.3.4.

We consider that the fixed menu of contracts in *STRIKE* – quarterly, peak and off-peak swaps and caps – is a broad enough collection of products for the purposes of this analysis. These products trade in the market and forward prices for them are available publically. By entering into combinations of these products across quarters, longer term products can be created by proxy. Similarly, flat products can be created by combining contracts across peak and off-peak periods. In our work for the 2007 Determination and the 2010 Determination we did not include more sculpted or otherwise exotic contracts in the menu of options. The reason is that such products are usually very specific to the overall load shape being hedged or the strategic optionality that the seller and buyer are willing to agree on. This prevents the creation of an objective set of exotic contracts that would be available to, and systematically priced for, each of the Standard Retailers. Because *STRIKE* calculates optimal hedging strategies, the inclusion of exotic contracts in the analysis would, if anything, result in a lower cost and/or lower risk hedging strategies.

### 4.3.4 Residual risk and the volatility premium

As discussed, even the conservative point on the efficient frontiers still leave an element of risk in the portfolio. Consistent with the approach that we used in advising IPART for the 2007 Determination and the 2010 Determination, we consider that it is appropriate to compensate the retailers for this residual risk through a volatility allowance. This volatility allowance is distinct from any form of load or price volatility premium, which has already been accounted for in the assumed load-price shapes input into *STRIKE*.

The efficient purchasing frontiers calculated by *STRIKE* relate to the efficient prices that we *expect* each retailer to have to pay over the period of the current determination. More specifically, for any given energy purchase strategy represented on the efficient frontiers, we would expect that roughly 50 per cent of the time the actual market-based energy purchase cost would be above the market-based energy purchase cost implied by that strategy, and 50 per cent of the time the actual market-based energy purchase cost would be below the market-based energy purchase cost implied by that strategy.

At times when the actual market-based energy purchase cost is above the expected market-based energy purchase cost, retailers will be earning a net margin below the allowed margin (all other things being equal). At times when the actual market-based energy purchase cost is below the expected market-based energy purchase cost, retailers will be earning a net margin above the allowed margin (all other things being equal). Ideally, retailers would use margin windfalls to offset shortfalls. However, there is a risk that shortfalls may occur prior to earning any windfalls. One way of managing this risk is to hold working capital to fund these cashflow shortfalls. To ensure that retailers are able to fund any additional working capital requirements, we have previously estimated the maximum amount of working capital that each retailer is expected to require in each year over the determination period to manage the risk of cashflow shortfalls.

This working capital requirement is based on the standard deviation associated with the conservative point of each retailer's frontier. More specifically, we have estimated the difference between the expected market-based energy purchase cost and the expected purchase cost plus 3.5 standard deviations from the expected value.[4] We then estimate the cost of holding sufficient working capital, adopting a WACC to be determined by IPART.

We propose to adopt this same approach for the current Determination.

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

# 5 LRET and SRES

In addition to reviewing wholesale energy costs, our engagement also includes estimating the costs that Standard Retailers will face in complying with the LRET and the SRES. This section considers the approach to estimating these costs.

## 5.1 Costs of complying with the LRET

The LRET places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable electricity from large-scale generators. Liable entities support additional renewable generation through the purchase of Large-scale Generation Certificates (LGCs). The number of LGCs to be purchased by liable entities each year is determined by the Renewable Power Percentage (RPP).

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

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

In our advice to IPART for the 2007 Determination and the 2010 Determination, we estimated the cost of LGCs (then known as RECs) on the basis of the LRMC of meeting the scheme target. This was calculated as an output from our least-economic cost modelling of the power system, using an incremental LRMC approach.

The alternative would be to use published prices at which LGCs are currently trading (including forward prices for LGCs where available) as a basis for estimating the cost of obtaining LGCs.

As with the choice between using modelled contract prices or published contract prices for the purposes of determining market-based energy purchase costs, there are arguments in favour of both approaches:

- The use of published prices for LGCs is arguably more transparent than using an LRMC approach. Published prices are observable by all stakeholders and are based on actual trades occurring in the market.
- The use of an LRMC approach arguably provides greater opportunity to explore the factors that drive the costs of LGCs. For instance, the impact of different input cost assumptions (including different carbon prices) can be investigated through modelling the LRMC of LGCs. However, these impacts cannot be reliably inferred from published prices. This may be particularly

relevant in the event of an application for a cost pass-through as a result of a regulatory change affecting input costs during the period of the determination.

- The current Determination is for the period from 2013/14 to 2015/16, with IPART required to determine costs for each year of the determination. Where forward prices for LGCs are available, there may be questions about the liquidity of trade in LGCs in the latter years of the determination and, therefore, the reliability of these published prices.

Given that there are arguments in favour of using published prices for LGCs and using an LRMC approach to model the costs of LGCs we intend to advise IPART on the cost of complying with the LRET using both of these approaches. We invite stakeholder comment on which approach should be adopted for the purposes of determining the cost of complying with the LRET.

## 5.2 Costs of complying with the SRES

The SRES places a legal liability on wholesale purchasers of electricity to proportionately contribute towards the costs of creating small-scale technology certificates (STCs). The number of STCs to be purchased by liable entities each year is determined by the Small-scale Technology Percentage (STP).

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

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

For the 2010 Determination, we estimated the cost of STCs on the basis of the fixed price of $40 per STC. However, there are reasons to consider whether this remains an appropriate approach for the current Determination. First, since the commencement of the scheme, STCs have traded on the open market at prices well below $40 per STC. Some stakeholders have suggested that using the fixed price of $40 per STC in these circumstances overstates the cost of complying with the SRES. Second, the Climate Change Authority has recently made a draft recommendation that would make the STC Clearing House a “deficit sales facility”. This means that certificates would only clear through the STC Clearing

House when there is a deficit of STCs. The Climate Change Authority suggests that this would make it clear to participants that the STC Clearing House cannot provide a guaranteed price for STCs.

It should be recognised, however, that there are issues with estimating the cost of STCs on the basis of open market prices. The first is that the discounted prices available on the open market are quite possibly the result of market dynamics that will turn out to be short term, which would imply that market prices could return to levels closer to the fixed price during the determination period. The second is that it would be very difficult to model the market for STCs in any robust way: there would be significant difficulties in reliably forecasting both the supply of STCs and the holding costs faced by producers of STCs.

We invite stakeholder comment on what methodology should be adopted for the purposes of determining the cost of complying with the SRES.

# 6 Ancillary services costs

In addition to reviewing wholesale energy costs, our engagement also includes estimating the ancillary services costs that Standard Retailers will face. This section considers the approach to estimating these costs.

## 6.1 Ancillary services

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

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

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

## 6.2 Estimating ancillary services costs

In our advice to IPART for previous determinations we have forecast ancillary services costs on the basis of econometric modelling of historic ancillary services costs. We propose to adopt the same approach for the current Determination.

# PART B –
# Input assumptions

# 7 Overview of input assumptions

For the purposes of the 2007 Determination and the 2010 Determination, IPART instructed us to adopt input assumptions for our electricity market modelling that were sourced from third-party reports, typically prepared for AEMO or other regulators. Over time there have been difficulties in sourcing the input assumptions required for our modelling in this way.

For the purposes of the current Determination, IPART has decided to develop its own input assumptions. We have been engaged to advise IPART on these input assumptions, with a particular focus on regulated load forecasts, capital costs of new entrant generation plant and fuel costs for existing and new entrant generation plant. Based on detailed research and analysis, and many years of experience advising in the energy sector, we have developed our own views on these key input assumptions. In some of the work that we do we do not make use of our own input assumptions. There are a variety of reasons for this: in some cases our clients direct us to use a specific set of input assumptions because they have their own views on key input assumptions and in other cases our clients have a preference for using publicly available input assumptions (such as those developed as part of AEMO's NTNDP) and in other cases a particular third-party source of input assumptions is more appropriate to our engagement.

The following sections provide an overview of our proposed approach to developing input assumptions for demand (Section 8), input assumptions for existing and new entrant generation plant (Section 9 and Section 10), inputs assumptions for fuel costs (Section 11) and input assumptions related to the carbon pricing mechanism (Section 12).

# 8 Demand

Frontier Economics' energy market modelling requires demand forecasts. The incremental LRMC modelling approach (using *WHIRLYGIG*) and our market modelling (using *STRIKE*) both require forecasts for system load in each NEM region. The stand-alone LRMC modelling approach (using WHIRLYGIG) and our estimation of the market-based energy purchase cost both require forecasts for regulated load for each Standard Retailer. This section sets out our proposed approach for developing these required demand forecasts.

## 8.1 System load

In advice to IPART for both the 2007 Determination and the 2010 Determination IPART instructed us to base our forecasts for system load in each NEM region on the forecasts published by AEMO.

IPART's proposes to adopt the same approach for the current Determination, making use of demand forecasts from AEMO's National Electricity Forecasting Report 2012 (AEMO 2012 NEFR). [5] In particular, IPART's preliminary view is that we should use in our modelling the medium growth, 50% POE projections from the AEMO 2012 NEFR, unless there is a reason to adopt an alternative forecast.

In addition to using medium growth, 50% POE projections from the AEMO 2012 NEFR, we propose to use other forecasts for specific purposes:

- We propose to use the medium growth, 10% POE projections for summer and winter for the purpose of modelling reserve constraints. These 10% POE projections are assumed to be 100% co-incident, implying that maximum demand occurs in each NEM region at the same time. This assumption of co-incidence is made to ensure consistency with AEMO's reported regional reserve margins in the reserve constraints.
- When calculating wholesale energy costs under the market-based approach, costs are calculated with consideration to a range of possible load outcomes (further discussed in Section 4.3). We propose to construct system demand cases using both the 10% and 90% POE projections from the AEMO 2012 NEFR in addition to the (expected) 50% POE case to reflect this range of demand uncertainty.

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5 AEMO, *National Electricity Forecasting Report*, For the National Electricity Market (NEM), 2012.

Available at:

http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/National-Electricity-Forecasting/National-Electricity-Forecasting-Report-2012

Rather than modelling every half-hour of the year, which would be very computationally intensive, we model a representation of the demand duration curve. We choose a set of representative demand points, each of which is used in our modelling to represent similar levels of demand on the demand duration curve. These representative demand points are weighted to ensure that the full 17,520 half-hours of the year are captured.

## 8.2 Regulated load

The Terms of References for the 2007 Determination and the 2010 Determination required consideration only of the load shape for all regulated customers of each of the Standard Retailers. In both the 2007 Determination and the 2010 Determination we used forecasts of this regulated load provided by the Standard Retailers.

The Terms of Reference for the current Determination, however, require consideration of both the load shape for all regulated customers of each of the Standard Retailers and the load shape for a subset of these regulated customers:

> IPART must determine two separate regulated load forecasts for the purposes of this determination; one for customers who consume between zero and 40 MWh per year and one for customers who consume between zero and 100 MWh per year.

For the current Determination, we have been engaged by IPART to advise on developing the forecasts of these two regulated load profiles, in consultation with the Standard Retailers. Obviously, our approach to developing these regulated load profiles will depend on the data that the Standard Retailers and the distributors are able to supply. Nevertheless, this section provides an overview of the approach that we intend to pursue with the Standard Retailers, including:

- the general approach that we would adopt for forecasting half-hourly demand
- sources of data with which we are likely to be able to implement this approach for sub-100 MWh per annum regulated customers and for sub-40 MWh per annum regulated customers.

### 8.2.1 Using historical data to develop load forecasts

Our proposed approach to estimating wholesale energy costs, as outlined in Part A, is dependent on the regulated load forecasts that are used as an input. The regulated load forecast is important for both the stand-alone LRMC and the market-based energy purchase cost because a peakier load shape results in higher wholesale energy costs under both methods.

The market-based energy purchase cost approach, in particular, requires a sophisticated approach to forecasting regulated load. There are two reasons for this. First, in order to accurately capture the risks that retailers face in hedging the regulated load, it is important to accurately capture the correlation between regulated load, system load and spot prices. Second, in order to reflect the uncertainty that retailers face regarding regulated load forecasts, we estimate market-based energy purchase costs across three possible load outcomes: a 10% POE regulated load, a 50% POE regulated load and a 90% POE regulated load. As a result, the market-based energy purchase cost approach requires, for each Standard Retailer, three half-hourly forecasts of regulated load (corresponding to a 10% POE, a 50% POE and a 90% POE) each of which can be lined up against an appropriately correlated forecast of system load and (based on our SPARK modelling) of spot prices.

The general approach that we have developed for generating the load forecasts required in our modelling, and which we propose to adopt for the purposes of advising IPART, is discussed below.

### Normalising historical data

The approach that we have developed makes use of historical half-hourly demand to forecast half-hourly demand. The first step is to collect a number of years of historical half-hourly demand and to 'normalise' this demand. For instance, each year of half-hourly demand could be normalised to represent 1 GWh per annum, and in such a way that the load factor is unaffected. The intention of this step is to isolate the shape of half-hourly load in each of the historic years.

### Generating synthetic load forecasts using a Monte Carlo process

The second step is to use the normalised historic half-hourly data to generate a large number of 'synthetic' forecast half-hourly load shapes using a Monte Carlo sampling process. A synthetic forecast half-hourly load shape is constructed by randomly drawing a day of load for a given day type and month from the historical set of data for each corresponding day type and month in the forecast period. By sampling an entire day of load data we preserve the intra-day load shape and by sampling from the same day type and month we account for the fact that the shape of load across months and seasons are important drivers of the cost of serving load.

For example, the first day of the synthetic forecast half-hourly load shape is 1 July 2013, which is a Monday in July. In order to populate this day with data, a (uniform) random draw from all the previous Mondays in July[6] over the period for which we have historic data will be taken. This process is repeated for each day in the forecast period to create 1 synthetic forecast half-hourly load shape.

[6] Based on the 10 years of historical load data, 1 day of July Monday load will be sampled from 43 historical days of July Monday load. A statistically meaningful sample should contain at minimum 30 observations, hence the minimum number of years of historical load data needed for this approach is roughly 7 years.

This process is then in turn repeated 5,000 times to create 5,000 different synthetic forecast half-hourly load shapes.

### *Selecting synthetic load forecasts*

The third step is to select each of a 10% POE, a 50% POE and a 90% POE load shape from the 5,000 different synthetic forecast half-hourly load shapes. To do this, each synthetic forecast half-hourly load shape is summarised by two statistics: (i) the annual energy under the shape and (ii) the ratio of the average level of load across the whole year to some measure of the peak level of load in the year. The second statistic is a load factor, which is commonly calculated as the ratio of the average to the maximum level of load across a year. The load factor is a measure of how 'peaky' the load shape is – the lower the load factor, the higher is the ratio of peak demand to average demand.

Having calculated these two statistics for each of the 5,000 synthetic forecast half-hourly load shapes, the load shapes are ranked in order of their load factors (excluding those shapes whose annual energy are material outliers).[7] The 10% POE load shape is taken as the $10^{th}$ percentile of the final ranking, the 50% POE load shape as the $50^{th}$ percentile[8] and the 90% POE load shape as the $90^{th}$ percentile. An example distribution of load factors, and the three POE shapes selected, is shown in Figure 5.

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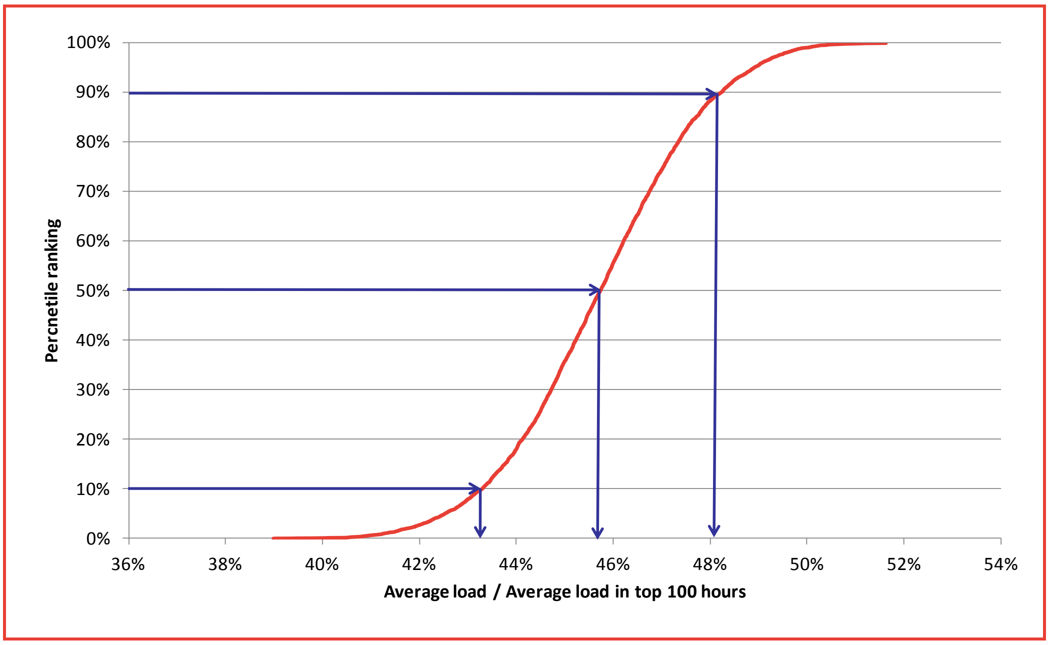
7 Load shapes whose annual energy exceeds +/- 1% of average energy of the set of 5000 load shapes will be excluded. This process typically excludes less than 50 shapes (i.e. less than 1%).

8 Selecting a POE50 load forecast as the $50^{th}$ percentile of this sampled distribution implicitly weather normalises the load data for the purposes of forecasting an expected load outcome.

Figure 5: Selecting load shapes for the POE10, POE50 and POE90 cases




*Source: Frontier Economics*

We propose to select a consistent POE case across all three Standard Retailers. For example, the 50% POE case for all three Standard Retailers will represent a selection of the same set of historical days in the corresponding synthetic trace. For this reason it is very important that the set of historical load data used for each Standard Retailer is consistent across all three businesses. To the extent that the sets of load data across the businesses are incomplete or cover different time periods, simultaneously selecting a common load trace across each business will not be possible. This simultaneous selection of a common load trace is important to enable the residential load shapes to be correlated to system demand (without needing to model a different system demand shape for each Standard Retailer).

### *Capturing trends in the load shape*

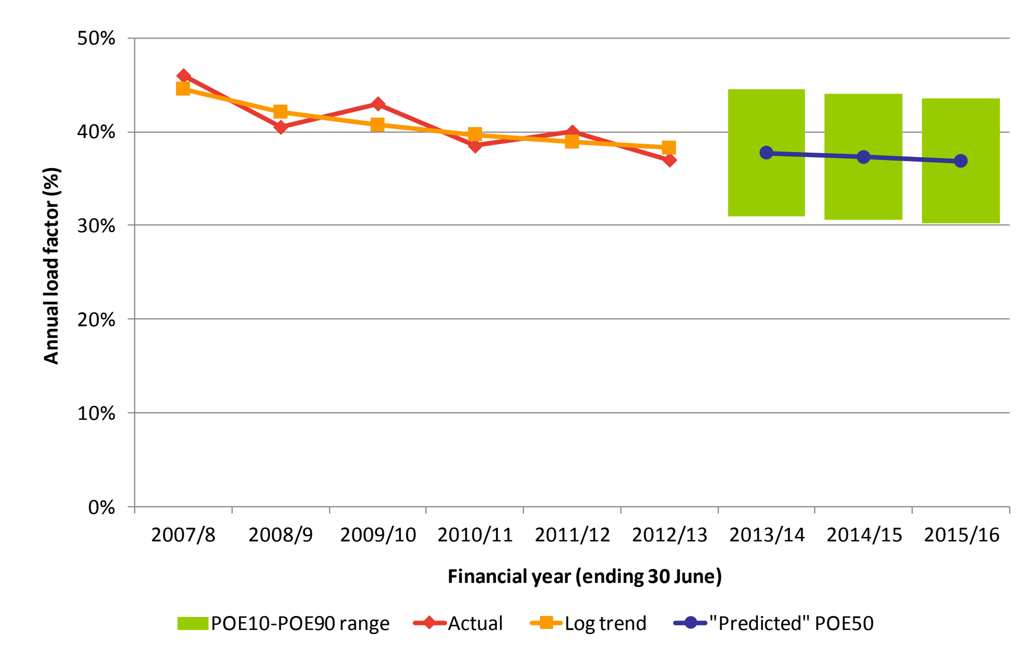
The final step is to investigate whether any trends in load shape over time should be reflected in the forecast half-hourly load shapes.

Over the past decade, a number of factors are likely to have affected the level of end-use electricity demand in the NEM, including climatic conditions, appliance penetration, policy measures such as energy savings schemes and changes in electricity prices. The challenge when forecasting customer load is to identify and understand the drivers behind any resulting trends in the shape of load and to account for those factors that are expected to persist into the future. This challenge is made especially difficult when factors that have driven historical shifts in the shape of load are based on stochastic factors (such as climatic conditions) or unexpected changes in policy.

One approach to accounting for these factors is to seek to capture the broad trends in the historical shape of regulated load at a more aggregate level. This approach would take at face value historical energy and peak demand outcomes and project them forward as a means of forecasting the future likely level of these variables. This approach is not based on statistical analysis of significant explanatory variables that have driven changes to the level and shape of demand. Rather, it assumes that the pattern of outcomes for regulated load that are apparent in the historical data offers a reasonable basis for forecasting future outcomes. Part of this process would involve detailed 'sanity checking' of the outputs to ensure that they are consistent with outcomes seen in the NEM and a review of other data sources where available to help inform an opinion of the factors affecting demand.

An example of how a declining historical trend in annual load factors would be used to adjust the forecast shape of demand is outlined in Figure 6. This example uses illustrative data. We observe, based on 6 years of illustrative load data, that annual load factors have been declining (as shown by the red line). Based on a log trend of this these historical observations (as shown by the orange line) we forecast the future expected, or 50% POE, load factors using this log trend relationship (as shown by the blue line). The 50% POE load shape is then scaled to this load factor. The 10% POE load shape and the 90% POE load shape are then also scaled with reference to the new 50% POE load factor. Thus the relativity between 10% POE, the 50% POE and the 90% POE load factors as remain the same, but the level of the load factors is adjusted based on a log trend of historical load factors.

Figure 6: Adjustment to forecast load shape based on historical log trend




*Source: AEMO profile data, Frontier Economics analysis*

Our view is that this approach offers some advantages. First, we consider that the data requirements for implementing this approach are relatively achievable: there may be some issues with acquiring historic half-hourly data for regulated load (see Section 8.2.2 for a discussion of these issues) but this approach would not also require data on all the factors that are potential determinants of regulated load. Second, the approach is relatively transparent.

Against this, however, this approach will be unable to systematically identify the extent to which various underlying factors have contributed to changes in the historic regulated load and, by implication, will also be unable to systematically reflect expected future changes in these underlying factors will affect the regulated load shape in future. In our view, this kind of analysis would require econometric investigation of historic data for regulated load, which would be much more data intensive. There is also the potential for such an approach to be less transparent.

We invite submissions on whether stakeholders consider that the approach outlined above – in which any observed historic trends in regulated load shape are rolled forward to forecasts of future regulated load shape – is appropriate for this current Determination. If stakeholders think that this approach is not appropriate, we invite submissions on a methodology for forecasting regulated load that is considered to be more appropriate.

### *Preserving the correlation between regulated load, system load and spot prices*

In order to accurately capture the risks that retailers face in hedging the regulated load, it is important to accurately capture the correlation between regulated load, system load and spot prices. Capturing this correlation is an important element of our proposed approach to developing regulated load forecasts.

In order to ensure appropriate correlation between the regulated load forecasts and system demand (and hence between regulated load forecasts and spot prices), our proposed approach maps each half-hour of each of the 10% POE, 50% POE and 90% POE forecast half-hourly load shapes to actual NEM demand and prices in that half-hour. This is possible because we retain the mapping of each day in each of the 10% POE, 50% POE and 90% POE forecast half-hourly load shapes back to the historical days that have been sampled in the Monte Carlo process. This means that there is a different system load shape for each POE case, but that the same system load shape applies to a given POE case for each retailer. We believe that it is important that wholesale energy cost estimates reflect all three Standard Retailers facing the same pool prices.

This process ensures that when modelling system prices in *SPARK,* the system demand shape used under each POE case is correctly correlated with each Standard Retailer's load shape.

## 8.2.2 Source of data

As discussed above, our proposed approach to forecasting regulated load is ultimately based on historic half-hourly data that represents, or can be used as a proxy for, the load of regulated customers for each Standard Retailer. Since the Terms of Reference require a forecast of regulated load both for sub-100 MWh per annum regulated customers and for sub-40 MWh per annum regulated customers, we need historic half-hourly data that represents, or can be used as a proxy for, both these groups of regulated customers.

Ultimately, the historic data that we will use as the basis for our approach to forecasting regulated load will depend to some extent on what data can be provided by the Standard Retailers. Nevertheless, this section discusses some of the options that are likely to be available, and issues with these options.

### *Customers less than 100 MWh per annum*

For regulated customers that consume less than 100 MWh per annum, the first option is to discuss with each of the Standard Retailers what historic data they have available that represents, or can be used as a proxy for, the load of regulated customers that consume less than 100 MWh per annum. It may be that some or all of the Standard Retailers are able to provide half-hourly data for these customers, potentially based on a sample of interval metered regulated customers.

A second option is to use historic data from AEMO on the Net System Load Profile (NSLP) and Controlled Load Profile (CLP) for each distribution area in NSW. The NSLP is the half-hourly load profile of all customers that remain on accumulation meters; effectively, it is a proxy for the half-hourly load profile of small customers. The CLP is the half-hourly load profile of a sample of customers with controlled load that are on interval meters for that load. The shape can be used as a proxy for the shape of all customers with controlled load. The advantage of using the NSLP and CLP is that provides a long historic dataset for each distribution area in NSW. However, the set of customers whose load is measured by the NSLP and CLP is not the same as the set of customers who are regulated: to use the NSLP and CLP as the basis for forecasting regulated load would be to implicitly assume that the load shape for regulated customers is the same as the load shape for all customers than remain on accumulation meters.

A third option is to use a combination of data from the Standard Retailers and the NSLP and CLP data. For instance, if the Standard Retailers are able to provide some summary statistics for the regulated load (such as the annual load factor) it would be possible to scale the NSLP and CLP data to match that annual load factor.

### *Customers less than 40 MWh per annum*

For regulated customers that consume less than 40 MWh per annum, the first option is the same: discuss with each of the Standard Retailers what historic data they have available that represents, or can be used as a proxy for, the load of regulated customers that consume less than 40 MWh per annum.

To an extent, the second option is also the same: the NSLP and CLP could be used as a proxy for the load shape of regulated customers that consume less than 40 MWh per annum. However, doing this would result in precisely the same load shape for customers that consume less than 40 MWh and customers that consume less than 100 MWh. In other words, relying solely on the NSLP and CLP as a proxy for the load shape of regulated customers would not allow us to form any meaningly conclusions about the relative costs of supplying sub-100 MWh per annum regulated customers and sub-40 MWh per annum regulated customers.

This suggests that, in the absence of good historic half-hourly data from the Standard Retailers, pursing the third option may be necessary. If the Standard Retailers are able to provide some summary statistics (such as the annual load factor) for the regulated load shape for both sub-100 MWh per annum regulated customers and sub-40 MWh per annum, it would be possible to scale the NSLP and CLP data to match these individual statistics.

# 9 Existing generation plant

Frontier Economics' incremental LRMC modelling and market modelling require input assumptions for all currently existing and committed generation plant in the NEM. This section discusses the key input assumptions required for these existing and committed generation plant:

- the identity of existing and committed generation plant
- relevant costs of existing and committed generation plant
- relevant technical characteristics of existing and committed generation plant.

This section sets out our proposed approach, and sources of data, to estimating these input assumptions. Details of the results of our analysis will be presented in subsequent reports.

## 9.1 Identifying existing generation plant

In the first instance, our modelling requires us to identify each existing and committed generation plant in the NEM, its generation capacity and its ownership.[9]

We propose to identify each plant, and its capacity, using the latest information available from AEMO's website[10] on existing and committed scheduled and semi scheduled generation plant in each region of the NEM. This provides both the identity of existing and committed generation plant and the summer and winter capacity of these generation plant.

In addition to these assumptions on cost and technical information, our modelling also requires information on ownership of existing generation plant. We maintain a database of plant ownership information which is based on public information.

## 9.2 Costs

For existing and committed generation plant, our modelling requires information on all variable costs of generation: VOM costs, fuel costs and carbon costs.

Fixed costs for existing and committed generation plant are sunk and, therefore, irrelevant to economic decisions. For this reason, we do not include either capital

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9 The ownership of generation plant is relevant for our market modelling, in which payoffs are calculated for generation portfolios.

10 AEMO, Generation Information. Available from:

http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information costs or fixed operating and maintenance costs in our modelling for existing and committed generation plant.

### 9.2.1 Variable operating and maintenance costs

VOM costs typically make up a relatively small component of power stations' total variable costs. Fuel costs and carbon costs account for the majority of variable costs. Given this, the focus of our work in developing cost information for existing generation plant is the fuel costs and carbon costs for these plant.

Nevertheless, VOM costs will be included in our modelling. Typically, companies reported costs do not provide specific information on VOM costs: where operating and maintenance costs are reported they the reported costs will tend to include both fixed and VOM costs (and potentially fuel costs or carbon costs). For this reason, we will rely primarily on reported specifications of generation plant and engineering reports to estimate VOM costs.

### 9.2.2 Fuel costs

Our proposed approach to developing fuel costs input assumptions is discussed in detail in Section 11.

### 9.2.3 Carbon costs

Our proposed approach to carbon costs input assumptions is discussed in detail in Section 12.

## 9.3 Technical characteristics

The key technical characteristics for each power station that are incorporated in our modelling (other than capacity) are heat rates, carbon rates, auxiliary power rates, maximum capacity factor and outage rates.

Compared to costs, these characteristics tend to be relatively stable over time and subject to less uncertainty. Our proposed approach is to rely primarily on reported specifications of generation plant and engineering reports to determine these technical characteristics. Where information is not reported for specific plant, we will base our estimates on similar plant of the same age.

## 9.4 Verification based on historical data for existing generation plant

To a significant extent, our estimates of cost and technical data for existing power stations can be cross-checked against historical data, at least at an aggregate level.

For instance, estimates of capacity, maximum capacity factor and outage rates can be cross-checked against historic half-hourly dispatch information for each power station that is published by AEMO. Information on carbon rates can be cross-checked against reported total emissions and total dispatch. Information on costs is more difficult to verify: certainly costs estimates can be compared against generators bids, but there are complications involved with this comparison, not least of which is the question over the basis on which generators choose to reflect their fuel costs in their bids.

# 10 New generation plant options

Frontier Economics' stand-alone LRMC and incremental LRMC modelling require input assumptions for new generation plant options that are available in the NEM over the modelling period. The least cost mix of investment in new generation plant options (output from the incremental LRMC modelling) is also incorporated in Frontier Economics' market modelling. This section discusses the key input assumptions required for these new generation plant:

- the generation technologies considered as options
- relevant costs of new generation plant options
- relevant technical characteristics of new generation plant options.

This section sets out our proposed approach, and sources of data, to estimating these input assumptions. Details of the results of our analysis will be presented in subsequent reports.

## 10.1 Generation technologies

Our modelling requires us to identify generation technologies that have the potential to form part of the least cost mix of generation plant over the modelling period.

For the purposes of our stand-alone LRMC modelling approach, this task is relatively straight-forward: the generation technologies that have the potential to form part of the least cost mix of generation technologies over the period from 2013/14 to 2015/16 are essentially the generation technologies that are available today.

For the purposes of our incremental LRMC modelling approach, however, this task is somewhat more difficult. Because we undertake our incremental LRMC modelling over the long-term (which is necessary to adequately model the cost of the LRET) we need to form a view on the generation technologies that have the potential to form part of the least cost mix of generation technologies between now and 2030.

For the purposes of the 2010 Determination, the input assumptions that IPART decided to adopt included the following new entrant generation technologies:

- supercritical black coal
- supercritical brown coal
- CCGT
- OCGT
- wind

- biomass
- geothermal (hot dry rocks)
- small hydro.

Each of these technologies was included in our modelling for the 2010 Determination and, for the purposes of the current Determination, our current view is that we should retain all of these technology options. However, we do invite stakeholder comment on whether each of these technologies should be included as options in our modelling.

In addition to the technologies included as options in our modelling for the 2010 Determination, we also propose to include as options the following new entrant generation technologies:

- ultra-supercritical black coal
- ultra-supercritical brown coal
- IGCC
- solar thermal.

We recognise that there are a range of other potential new technologies, including some that are yet to be commercially demonstrated at a utility-scale. We consider that these other technologies are much less likely to form part of the least cost mix of generation over the modelling period and, therefore, propose not to include them in our analysis. This includes carbon capture and storage technology which, at current carbon price expectations, is unlikely to form part of the least cost mix of generation plant over the modelling period. However, we do invite stakeholder comment on whether any other technologies should be included as options in our modelling.

## 10.2 Costs

For new generation plant options, our modelling requires information on all fixed and variable costs of generation: capital costs, FOM and VOM costs, fuel costs and carbon costs.

Unlike for existing and committed generation plant, fixed costs for new generation plant are not sunk: these costs will be incurred in the event that a decision is made to build the new plant. Therefore, these fixed costs are relevant to economic decisions. For this reason, we include both capital costs and fixed operating and maintenance costs in our modelling for new generation plant options.

### 10.2.1 Capital costs

For generation plant the largest fixed cost is their up-front capital cost. Our modelling requires information on the capital costs of all new generation plant options, expressed as $/MW/year. There are two stages to developing these required capital cost input assumptions.

First, we develop estimates of up-front capital costs, expressed as $/kW. These up-front capital cost estimates are developed based on a Frontier Economics database of public estimates of capital costs for power stations. The data is sourced from company reports, engineering reports, financial reports and reports from the trade media and covers projects that are, or have been, constructed and projects that are at various stages of planning. The database covers the full range of generation technologies that are likely to be available in the NEM over the modelling period. Given that Australian cost estimates for some technologies is limited, our database is international. And given that actual experience with the construction of some generation technologies is limited even internationally, our database covers both reports of the costs of actual plant as well as estimates of the costs of generic new plant.

Cost estimates are reported in nominal terms. We adjust these nominal costs to current dollar costs using indices that reflect the construction costs of generation plant.[11] In forecasting capital costs over the modelling period, a view will need to be formed on how these costs are likely to escalate in future. While all our modelling is undertaken on a real basis, future cost escalation for the construction of generation plant may result in real increases or decreases in these costs. To an extent, the rate of cost escalation will depend on assumptions regarding key economic indicators. These assumptions will be developed and agreed with IPART.

Second, the estimate of up-front capital costs, expressed as $/kW, are converted into annual capital costs, expressed as $/MW/year. This is achieved using a financial model developed for IPART as part of the 2010 Determination. We propose to use this same financial model in order to calculate capital costs in $/MW/year for the current Determination.

### 10.2.2 Fixed and variable operating and maintenance costs

Just as VOM costs typically make up a small component of power stations' total variable costs, FOM costs typically make up a small component of power

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11 We do not use a consumer price index to adjust nominal costs to current dollar costs because doing so would fail to capture the extent to which the construction costs of generation plant have changed over time at a faster (or slower) rate than consumer prices. In our view, using an index that reflects the construction of costs of generation plant ensures that any historic costs of construction that we use are as relevant to today's the cost of construction as possible.

stations' total fixed costs. Capital costs account for the majority of fixed costs. Given this, the focus of our work in developing cost information for new generation plant options is the capital costs, fuel costs and carbon costs for these plant.

Nevertheless, both FOM and VOM will be included in our modelling for new generation plant options. Our proposed approach to developing input assumptions for VOM and FOM costs for new generation plant options is essentially the same as our proposed approach to developing input assumptions for VOM costs for existing generation plant: we will rely primarily on reported specifications of generation plant and engineering reports to estimate FOM and VOM costs. In order to cross-check these estimates we will also endeavour to compare total operating and maintenance costs, where these are reported by generators, with our estimates of FOM and VOM costs (taking account of the relevant operating pattern of the generation plant).

### 10.2.3 Fuel costs

Our proposed approach to developing fuel costs input assumptions is discussed in detail in Section 11.

### 10.2.4 Carbon costs

Our proposed approach to carbon costs input assumptions is discussed in detail in Section 12.

## 10.3 Technical characteristics

Our proposed approach to developing input assumptions for technical characteristics for new generation plant options is essentially the same as our proposed approach to developing input assumptions for VOM costs for existing generation plant, as in Section 9.3.

# 11 Fuel cost assumptions

Frontier Economics' energy market modelling requires input assumptions for fuel costs for all generation plant – existing, committed and new entrant – in the NEM.

This section sets out our proposed approach, and sources of data, to forecasting gas costs and coal costs for generation plant in the NEM. At this stage, we are not providing any detailed information on input assumptions to be used in our forecasting of gas costs and coal costs. This information will be provided in subsequent reports, once key underlying assumptions and scenarios for this analysis have been developed and agreed with IPART.

## 11.1 Gas markets forecasts

We propose to forecast gas costs for generation plant in the NEM using *WHIRLYGAS*, our gas market model.

*WHIRLYGAS* optimises total production and transport costs in gas markets, calculating the least cost mix of existing and new infrastructure to meet gas demand.

Like *WHIRLYGIG* for the electricity market, *WHIRLYGAS* can be used to estimate an incremental LRMC for the gas market. To do this, *WHIRLYGAS* is configured to incorporate a representation of the physical gas infrastructure in eastern Australia – including demand forecasts for each region, all existing production plant, all existing transmission pipelines and new plant and pipeline investment options – and calculates the marginal cost of meeting demand in each region. The key modelling inputs for *WHIRLYGAS* under this approach are:

- Gas demand forecasts for each gas demand area.
- Existing gas reserves in eastern Australia.
- The relevant costs and technical parameters of existing production plant in eastern Australia.
- The relevant costs and technical parameters of new production plant options in eastern Australia.
- The relevant costs and technical parameters of existing transmission pipelines in eastern Australia.
- The relevant costs and technical parameters of new transmission pipeline options in eastern Australia.

The input assumptions used in *WHIRLYGAS* are discussed in more detail in the sections that follow. The specification of the model is discussed in more detail in Appendix D.

### 11.1.1 Gas demand forecasts

When used to model the gas system in eastern Australia, *WHIRLYGAS* is structured so that the demand regions in the model are the same as the demand areas used by AEMO in their Gas Statement of Opportunities (GSOO). As a result, the gas demand forecasts from the GSOO can be directly incorporated in *WHIRLYGAS*. Our advice to IPART is to adopt the gas demand forecasts from the AEMO 2011 GSOO as the starting point for our gas market modelling.[12]

As with our electricity market modelling, our gas modelling makes use of a representation of the annual demand curve. Rather than attempting to model demand for every day in the year, we model a number of representative demand points. These representative demand points for each year are chosen to reflect peak demand in summer and winter and average demand for each quarter of the year. For each year we also include a representative demand point for a 1-in-20 year winter peak demand and a 1-in-20 year summer peak demand in that year. These are used for the purposes of implementing a reserve constraint in the model.

### 11.1.2 Existing gas reserves

We collate information on remaining gas reserves by gas field from a range of sources, including company reports, reports by government departments and agencies and other public information. Key sources of aggregated information on gas reserves include Geoscience Australia, The Queensland Department of Mines and Energy, the Victorian Department of Primary Industries and information developed for the AEMO 2012 GSOO.

### 11.1.3 Gas production

#### *Existing gas production facilities*

We collate information on existing gas production facilities from a range of sources.

Basic information such as the identity, the location and the capacity of existing gas production facilities is sourced primarily from company reports. This information is cross-checked (and, in some cases, supplemented) by information that is available through the Gas Bulletin Board, the Short Term Trading Market (STTM) and information developed for the AEMO 2012 GSOO.

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12 It is expected that the AEMO 2012 GSOO will be released during the consultation period for the current Determination. At that point, we propose to adopt the updated gas demand forecasts from the AEMO 2012 GSOO.

The actual output from these existing gas production facilities will depend on both the capacity of the gas production facility itself as well as the capacity of the upstream gas fields. The capacity of upstream gas fields can be a relevant constraint for gas fields that are in decline and producing at rates below the capacity of the associated production capacity. For gas fields that are in decline and are producing below plant capacity, we propose to constrain annual production to levels not in excess of the highest annual production achieved in the previous two years.

The required cost information for existing gas production facilities is limited to the VOM costs of these plant (fixed costs for existing production plant are sunk and, therefore, irrelevant to economic decisions). VOM cost information is based on a Frontier Economics database of public estimates of operating costs sourced from company reports, engineering reports, financial reports and reports from the trade media. While operating costs for gas production are not widely reported, our database nevertheless has operating cost estimates for a range of different gas production plant, including gas production plant with different characteristics.

The required technical information for existing gas production facilities includes key technical characteristics of gas production plant such as auxiliary gas use, outage rates and carbon rates.[13] This technical information is based on a Frontier Economics database of information on these characteristics. This information is supplemented, where relevant, by analysis of historical data available through the Gas Bulletin Board.

### *Options for new gas production facilities*

Investments in new gas production facilities are an output from *WHIRLYGAS*: the model chooses those investments in new gas production facilities (and new transmission pipelines) that enable demand to be met at least cost. In order for the model to optimise investment decisions the input assumptions need to extend to feasible options for new gas production facilities in eastern Australia.

Information on the identity of potential new gas production facilities in eastern Australia is derived from a number of sources. For potential new gas production facilities that are at a more advanced stage of planning, information on the identity and the likely capacity and location of production facilities can be sourced from company reports and reports from the trade media. For potential new gas production facilities that have not yet reached any advanced stage of planning, generic gas production facilities are included as an investment option.

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13 Whether carbon rates for gas production facilities are incorporated in our gas market modelling or electricity market modelling is an issue that is addressed further in Section 12.1.

These generic facilities are located where existing undeveloped gas reserves are known to exist.

The required cost information for potential new gas production facilities includes capital costs, fixed operating and maintenance costs and VOM costs.

Information on capital costs is based on a Frontier Economics database of public estimates of capital costs sourced from company reports, engineering reports, financial reports and reports from the trade media. Our database of capital costs includes capital cost estimates for a wide range of different production plant and includes gas production plant with different characteristics. This enables us to specify capital costs for generic gas production facilities based on their likely characteristics (including the type of gas produced, their capacity and their location).

As with existing gas production facilities, information on operating costs and technical characteristics for potential new gas production facilities are based on Frontier Economics databases. Estimates of operating costs and technical characteristics for generic gas production facilities are based on their likely characteristics (including the type of gas produced, their capacity and their location).

### 11.1.4 Gas transmission

#### *Existing gas transmission pipelines*

We collate information on existing gas transmission pipelines from a range of sources.

Basic information such as the identity, the injection and withdrawal points and the capacity of existing gas transmission pipelines is sourced primarily from company reports. This information is cross-checked (and, in some cases, supplemented) by information that is available through the Gas Bulletin Board, the Short Term Trading Market (STTM) and the AEMO 2012 GSOO.

The required cost information for existing transmission pipelines is limited to the variable operating costs of these transmission pipelines. The available information suggests that the vast majority of operating costs for transmission pipelines are fixed operating costs. Our approach has been to characterise all operating costs as fixed operating costs. In other words, once an investment in a transmission pipeline has been committed all of its costs (other than as a result of auxiliary power requirements) are sunk.

The required technical information for existing transmission pipelines includes key technical characteristics of transmission pipelines such as auxiliary gas use, outage rates and carbon rates.[14] This technical information is based on a Frontier Economics database of information on these characteristics. This database has been populated by company reports and engineering reports (particularly engineering reports produced in support of access arrangements for existing transmission pipelines). This information is supplemented, where relevant, by analysis of historical data available through the Gas Bulletin Board.

### Options for expansions to existing gas transmission pipelines

The cheapest option for adding new transmission pipeline capacity to a gas network is to expand the capacity of existing transmission pipelines, either through looping or through the addition of compression. Compression of free-flow pipelines, in particular, enables capacity to be expanded at a relatively low capital cost.

Information on options for expanding the capacity of existing gas transmission pipelines through compression is largely based on company reports of pipeline capabilities. The capital costs and operating costs associated with the addition of compression are based on a Frontier Economics database of costs of transmission pipeline capacity expansions. This database has been populated by company reports, reports in the trade media and engineering reports (particularly engineering reports produced in support of access arrangements for existing transmission pipelines).

### Options for new transmission pipelines

Investments in new gas transmission pipelines are an output from *WHIRLYGAS*: the model chooses those investments in new transmission pipelines (and new gas production facilities) that enable demand to be met at least cost.

Information on the identity of potential new gas transmission pipelines in eastern Australia is derived from a number of sources. For potential new gas transmission pipelines that are at a more advanced stage of planning, information on the identity, the injection and withdrawal points and the capacity of transmission pipelines can be sourced from company reports and reports from the trade media. Generic options are also included where growth in gas demand for a particular gas region is such that the limits to the capacity of existing pipelines is insufficient to meet demand growth.

The required cost information for potential new gas transmission pipelines includes capital costs, FOM costs and VOM costs.

14 Whether carbon rates for gas transmission are incorporated in our gas market modelling or electricity market modelling is an issue that is addressed further in Section 12.1.

The capital costs associated with the new transmission pipelines are based on a Frontier Economics database of these capital costs. This database has been populated by company reports, reports in the trade media and engineering reports (particularly engineering reports produced in support of access arrangements for existing transmission pipelines).

As with existing gas transmission pipelines, information on operating costs and technical characteristics for potential new gas transmission pipelines are based on Frontier Economics databases. Estimates of operating costs and technical characteristics for generic gas transmission pipelines are based on their likely characteristics (including the pipeline diameter and the pipeline length).

### 11.1.5 Escalation of relevant costs

As discussed, for a number of relevant costs required in our modelling we propose to rely on Frontier Economics databases of those costs. Costs are reported in nominal terms. We adjust these nominal costs to current dollar costs using indices that reflect the underlying activity (for instance, indices relating to the costs of gas production or the costs of gas transmission).

In forecasting costs over the modelling period, a view will need to be formed on how these costs are likely to escalate in future. While all our modelling is undertaken on a real basis, future cost escalation for gas production and gas transmission may result in real increases or decreases in these costs. To an extent, the rate of cost escalation will depend on assumptions regarding key economic indicators. These assumptions will be developed and agreed with IPART.

### 11.1.6 LNG export facilities

A key consideration in forecasting gas costs for generators in eastern Australia is the impact of exports of LNG from Gladstone. A number of LNG export facilities are already committed and currently under construction, and other LNG export facilities (or expansions to committed facilities) are likely over the modelling period.

Exports of LNG will have an impact on forecast gas costs for generators in eastern Australia. This impact is taken into account in our modelling in two ways. First, committed LNG export facilities are incorporated in the model. The model ensures that gas is produced, transported, liquefied and exported in line with the committed plans of these facilities. Second, potential new LNG export facilities can also be incorporated into the model. In order to constrain the modelling problem to a manageable size, we are not proposing to model the global LNG market as part of this project. As a result, we will need to make an assumption about the likely development of new LNG export facilities over the modelling period. By incorporating in the model a global LNG price, and the costs of any new LNG export facilities that are assumed to be developed, *WHIRLYGAS* will optimise total production and transport costs in the gas market in eastern Australia accounting for the export of domestic gas through both existing and new LNG export facilities.

## 11.2 Coal market forecasts

Frontier Economics will work with a related sub-contractor, Metalytics Pty Limited, to provide coal market analysis and forecasting. Metalytics is an established mineral resource economics consultancy based in Sydney with experience in forecasting supply, demand and pricing of thermal coal in the Asia-Pacific region as a whole and for individual countries and sub-regions.

Together, we will construct forecast coal supply curves for each sub-market. This will enable us to estimate a range of annual market clearing prices that also take into account agreed assumptions relating to global and country-specific economic variables, international coal markets, carbon pricing, and other factors. Sensitivity analysis using these and other domestic and international economic parameters will allow plausible ranges to be established around these estimates.

### 11.2.1 Sources of coal industry data

Metalytics maintains detailed and extensive mining and information databases covering the global coal industry. While these databases have a particular focus on the international seaborne traded markets in thermal and metallurgical black coal products, they also cover Australian domestic coal supply and demand. Data includes current and forecast production and cost statistics and estimates for every mine supplying coal-fired power stations in each region of the NEM.

Information in these databases is sourced from company reports and government authorities around the world. In addition, Metalytics collects and utilises statistical and other information on the coal, energy and steel industries provided on subscription or for public access from a wide range of sources including The Tex Report (daily and annual publications), International Longwall News, Australian Bureau of Statistics, Japan's Ministry of Finance, Indonesian Coal Mining Association, China National Bureau of Statistics, and Korea International Trade Association, as well as relevant conference presentations, technical and trade literature, press reports and Internet news and statistical archive services provided by Reuters, Bloomberg, and Financial Times. Additional data sources specifically relating to the coal industry in Australia include Port Waratah Coal Services, NSW Coal Services, Queensland Department of Natural Resources and Mines and Register of Australian Mining.

Metalytics utilises these information sources to analyse the coal industry and generate comprehensive tables of historical and forecast statistics covering supply, demand, prices, trade and markets at global, national and regional levels as appropriate. Each mine's annual forecast saleable coal production is allocated into four categories, as appropriate, based on usage (thermal and metallurgical) and market (domestic and export) using criteria that reflect current practice, product quality and forecast market conditions. Metalytics' market evaluation and price forecasting methodology for thermal coal incorporates assessment of changes in domestic and international demand fundamentals including each country's current and planned primary energy sources for electricity generation.

### 11.2.2 Coal mining and production costs

Metalytics' supply-side coverage includes detailed mine-by-mine analysis and forecasting of production tonnages by coal type, together with the feasibility and timing of new operations, in Australia, Indonesia, Colombia, Canada, Russia, the USA and South Africa – the principal countries that export into the internationally traded market. It also estimates current and forecast cash costs of coal supply on a mine-by-mine basis for these operations. These estimates include costs of mining, processing to saleable product, transport to port or power station (by truck, rail, barge, conveyor, etc.), royalties, and port loading and ocean freight costs if appropriate.

Because most coal mining companies do not publicly report cost information, Metalytics' production cost estimates are generated using proprietary modelling based on engineering principles, and factors such as mine depth, overburden ratios, seam thickness, mining equipment and method (e.g. longwall vs bord and pillar), and operational and processing flowsheets, together with current and forecast market prices and reported statistics for labour, energy, consumables, transport loading and freight rates, royalty levels in particular jurisdictions, and other cost categories relevant to specific operations, supplemented by in-house expertise. As far as possible, results are audited using company financials, client feedback, and comparative analysis based on a wide range of technical data and industry experience.

Mine-by-mine cost analysis permits generation of a range of current and forecast FOB and CFR cost curves for domestic, regional and global markets in both thermal and metallurgical coal.

### 11.2.3 Coal market and price forecasting methodology

#### *International export prices*

Metalytics forecasts thermal coal export prices (typical basis 6,300kcal/kg FOB Newcastle) by first determining annual internationally-traded global market balances and then allocating supply sources to the demand forecasts on a country-by-country and mine-by-mine basis. These allocations and the resulting price forecasts take into account:

- tonnage estimates of import requirement and/or export availability for all major market participants

- magnitude of surplus/deficit balances between these estimates
- historical and current benchmark pricing levels and trends
- global and regional economic parameters
- existing trade patterns
- coal quality factors
- mine-by-mine production capabilities
- port, transport infrastructure and other constraints
- costs of production for each mine
- transport costs for individual trade routes (principally ocean freight).

This methodology includes comparing and validating the supply, demand and price forecasts against data from other reputable market forecasters such as the International Energy Agency.

Metalytics' forecasts of country-by-country demand for thermal coal are predominantly driven by existing, proposed and potential electricity generation requirements, and the current mix and forecast adoption of alternative primary energy sources, including renewables. It is clear there is potential for enormous growth in the energy consumption of developing countries that are transitioning from an agricultural base to a manufacturing one. Under Metalytics' base case forecasts, coal's abundant global reserves and cheap cost relative to many alternatives drive its continued growth as an energy source for base-load electricity despite the high levels of carbon dioxide emissions that result from its consumption. Metalytics' global forecasting models take a number of risk factors into account. The resulting alternative price curves are useful when considering various scenarios, such as Indonesia's current attempts to slow or even reverse export growth in unbeneficiated mineral commodities. Similarly, these models can generate price curves that incorporate varying degrees of economic growth in the major importing nations of the Asia-Pacific region and are also responsive to a range of estimates of long-term shifts away from fossil fuels to renewables.

### Domestic thermal coal prices

Domestic thermal coal may command prices lower than export levels because of inferior product quality. Much of the black coal consumed at mine-mouth power stations has a lower calorific value (energy content) than export-grade product and is unwashed. Many export mines pass a certain proportion of their output to domestic utilities; this coal is commonly a by-product of obtaining higher-quality quality export thermal or metallurgical products.

As an example of evolving industry trends, in 2010, 27 of the total of 55 operating coal mines in New South Wales sold some or all of their production to domestic consumers. By contrast, only eight mines conveyed or trucked their entire outputs to adjacent power stations. Five of these eight had no access to port facilities, and the remaining three have now closed.

In the past, lower-quality by-product coal was frequently sold at prices close to production cost in the absence of any other market. This situation is now changing. Because of improved rail and port capacity, as well as emerging offshore markets for this material, mine operators are increasingly able to sell even sub-optimum product into export markets. While exceptions are certain to remain, this coal will increasingly be sold at prices based on export benchmarks discounted for lower energy and higher ash content.

Different market dynamics apply in regions of the NEM where brown coal is consumed for electricity generation. For example, it is not commercially viable to export Victorian brown coal because of its high moisture and relatively low energy content. However, the success of emerging briquetting technologies may change this position in the longer term.

### 11.2.4 Coal pricing in domestic markets

Export pricing influences domestic markets by placing pressure on production costs of total coal supply. In recent years, mining costs in Australia and elsewhere have risen well above inflation rates. Booming international price levels have led many export producers to increase output, leading to inevitable rises in production costs as a result of competition for experienced miners at remote locations and increased prices for consumables, mining equipment and overheads. These factors affect the industry as a whole, regardless of whether an individual mine is supplying the export market or a domestic utility.

#### *Existing mine-mouth power stations*

Coal-fired generators that are located adjacent to mines that supply all or most of their thermal coal requirements typically purchase coal from these mines under long-term contracts where an agreed base price is subject to annual escalation linked to various indices. Production costs set a lower limit to base prices in these situations. Although contractual pricing terms are commercially confidential, some domestic pricing information is available in the public domain, for example in the annual financial statements of some coal producers.

As existing contracts expire, Metalytics expects domestic pricing to move closer to export price levels, depending on each mine's port access and quality of coal. Base prices in new contracts will reflect both costs of production (including adequate returns to operators) and the export parity values of mine production, while also taking account of the reduced price and volume risks associated with long-term offtake agreements.

In Queensland, three coal-fired generators are supplied exclusively by adjacent mines owned by those generators. In these integrated situations, the utility simply incurs the cost of coal production.

Where our long-term demand forecasts require the development of new mines to supply thermal coal for electricity generation in the NEM, we will collaborate with Metalytics to generate coal supply curves that reflect capital costs of new mine construction (taking account of IPART's view on the WACC appropriate for these capital investments) in addition to marginal production costs and the export market parity factors discussed above.

### *Existing export-exposed and new entrant power stations*

Metalytics' analysis concludes that the most important factor affecting the domestic selling prices of thermal coal from mines with significant exposure to export markets will be the international export price. One of the reasons for this is that new coal mines in Australia will generally only be developed where they have access to a port. Depending on global market conditions, such new mines may require commercial incentives to sell to domestic power stations rather than to overseas customers. While such incentives will always include price, other advantages may include lower transport costs, reduced credit risk, lack of exposure to exchange rate fluctuations and the security of long-term offtake agreements.

## 11.3 Average or marginal fuel costs

In the 2007 Determination and the 2010 Determination, IPART has relied on third party sources of fuel price forecasts for generation plant to use in estimating wholesale energy costs. These estimates have provided projections of fuel prices for existing generators and potential new entrant generators located in different sub-regions of the NEM.

Unfortunately there has been very little information available about how these fuel price forecasts are formed. This is of concern because the way that fuel price forecasts are formed can be an important consideration in determining regulated retail prices for electricity.

For example, with coal price forecasts, it is unclear whether the third party coal price forecasts used in previous determinations are based on actual prices currently being paid by generators or on the price that a generator would expect to pay for additional coal supplies in that particular sub-region of the NEM. There are also further uncertainties:

- In the event these estimates of coal prices are based on actual prices being paid by generators it is unclear whether these prices reflect the average of all coal contracts that generators have (recognising that the majority of power stations have multiple coal supply contracts) or the price of the most expensive coal contract held by a generator. If the actual prices are based on average prices being paid by generators it is unclear whether this is a quantity weighted price or simple average price.

- In the event that the these third party estimates are based on the price that a generator would expect to pay for additional coal supplies (that is, the marginal coal price) it is important to know whether this estimate is based on the price of the most expensive coal contract held by an existing generator or the coal price that a generator would have to pay if they negotiated a further coal contract to replace, or in addition to, the fuel they are currently burning. Moreover, it is important to know how this estimate of the marginal cost price is determined.

These uncertainties highlight the type of questions that need to be considered in determining the appropriate fuel prices to be used for the assessment of wholesale energy costs. This section discusses these and other relevant fuel pricing issues. We take coal as an example because in many respects the issues posed by coal supply are more difficult. To put this discussion in context it is worth first describing the two broad types of coal supply arrangements that exist in the NEM.

### 11.3.1 Broad coal supply arrangements

Coal fired generators are either supplied by mines that are remote from their power stations or they are supplied by a mine co-located with the power station. The latter is known as a mine mouth power station.

#### *Mine mouth power stations*

Typically, mine mouth power stations are supplied by a single large mine, although sometimes they can be supplied by more than one co-located mine. Mine mouth power stations and the associated mines are often integrated businesses. In this case, the cost of coal to the power station represents the extraction costs of coal and coal supply contracts do not exist between the coal mine and power station. This situation describes the majority of brown coal power stations operating in the LaTrobe Valley. However, some mine mouth power stations buy coal from the co-located mine under contract from a separate operator (e.g. Leigh Creek in South Australia and Callide C in Queensland). In these cases the contract price for coal tends to reflect the cost of mining plus a return to the miner. Coal from mine mouth coal pits tend to be priced closer to the costs of mining because they usually have no other opportunity to sell the coal to, say, an export market. This is usually because the coal is of relatively poor quality and presently there is no international market for this coal (such as for brown coal), or because the costs of preparing the coal for sale into the international market is prohibitively high. It can also be the case that higher quality mine mouth coal attracts a supply price close to the mining costs because the coal is located too far from transport infrastructure that would give the miner access to other markets (i.e. the miner has no other economic opportunity than to sell the coal to the power station).

### *Non-mine mouth power stations*

Non-mine mouth power stations generally receive coal from multiple mines supplied under long term contracts. The terms and conditions and duration of these supply contracts can vary widely, reflecting the commercial requirements of the buyers and sellers and market expectations at the time these contracts were concluded. For a range of reasons variations in coal prices tend to be greater for non-mine mouth coal supplies. One explanation for this variation is the ability of these mines to access alternative markets. Access to alternative markets means that prices tend to reflect world supply and demand conditions, which in turn tends to produce prices that are more volatile than mining costs. Variations in coal quality also play a significant role in influencing the price paid for coal that can be sold into the wider market. Poorer quality coal (lower calorific value, high ash and moisture content) attracts a lower price in the international market. This is because, to get the same energy, firms will need to burn more low calorific, moist coal than higher calorific, drier coal. This means that firms will have to handle more poor quality coal which costs more and involves more wear on coal handling plant and furnaces. Higher ash coal will increase the wear and tear on plant and will involve greater ash handling and disposal costs. These additional costs of burning and handling poorer quality coal are reflected in the (lower) price buyers are willing to pay for the coal.

In some cases the coal is of such poor quality that it is only economic to burn in a power station because the costs of washing and grading coal exceed the return the miner will achieve from this processing. In these cases power stations can acquire coal this coal relatively cheaply.

Power stations can also acquire relatively good quality coal at reasonable prices if their purchases are large enough to be a 'foundation' customer for the development of a new mine. In these cases the power station agrees to meet a large portion of the mine development and operating cost, at a price close to miner's costs, and the miner sells surplus coal to higher value markets. In this way the power station gets the benefit of relatively cheap coal while the miner has its costs underpinned but retains the potential to access higher value markets with surplus coal.

Power stations that are supplied by coal fields that contain high quality coal that is able to be transported to an export terminal can expect to have coal prices increasingly determined by international coal markets. This is not to say that power stations in these situations will face international coal prices. At worst, coal suppliers ought to be indifferent to charging a quality adjusted net-back price to power stations. At a high level this is determined by the international price less the costs of grading, washing, handling and transport of coal that would be incurred by the miner if they were to export their coal instead of supplying the same coal to a local power station. More realistically, a power station located in an area where miners have economic access to a wider market would likely receive some concession on the net-back price because the miner will avoid the risks associated with organising and contracting to process and transport coal. Also, miners value the security that comes with selling a large and steady quantity of coal to a customer located in the same market facing the same laws as the miner. These factors taken together mean that it is likely that generators located in these areas are likely to pay somewhat less than the net-back price.

### 11.3.2 Coal pricing

An understanding of the various arrangements under which power stations can access coal, and the different economic forces that bear on these arrangements, illustrates the potential for divergence in coal price estimates that are based on the different approaches discussed previously. For instance, as discussed, it is unclear whether third party coal price forecasts are based on the costs currently being incurred by generators or on the price that a generator would expect to pay for additional coal supplies.

In terms of which is appropriate, this depends in part on the objectives of setting regulated retail prices.

If the purpose of the regulated prices is to ensure cost recovery then it may be more appropriate to base coal price estimates on actual cost prices. In practice, the use of marginal coal prices could result in under or over recovery of actual costs. It is likely for the vast majority of coal contracts in the market that marginal prices will be greater than actual prices. This is because in recent times the growth in demand for Australia's coal has driven prices well above those that prevailed when the majority of the existing coal contracts were concluded. This recent upward trend in coal prices means that it is more likely than not that coal prices based on marginal coal prices will result in retail prices that exceed actual generation costs.

If the purpose of the regulated prices is to reflect the costs that consumers impose on the economy from an incremental unit of consumption (to ensure they consume a socially efficient amount of power), then it is more appropriate to base coal price estimates on marginal coal prices than actual coal prices. If actual coal prices are used, this could result in regulated retail prices that are economically inefficient. For example, if IPART were to take the volume weighted average of a series of coal contracts for a generator to form a single dispatch price for that generator then the modelling would tend to result in under-dispatch or over-dispatch of that generator (depending on how the volume weighted average price compares to the marginal coal price for that generator).

This leads to another issue that must be considered. Should there be a single marginal coal price or would there be a supply curve for each location where the marginal coal price could vary according to the level of generation? From a practical viewpoint it is already an ambitious exercise to determine a marginal coal price on a locational basis. Any attempt to form a supply curve at each location in the NEM risks being considered an exercise in spurious accuracy. The data is simply not available to determine a coal supply function for each location.

In any case, from an economic viewpoint it is more appropriate to use a single coal price than a supply curve. There are two reasons for this.

Firstly, any new coal fired power station is likely to be supplied as a mine mouth power station (just as the last three coal fired generator have been – Callide C, Millmerran and Kogan Creek). The reason for this is that it is too risky to sink such a large amount of capital into the development of a power station unless the owner can be guaranteed to have secure access to commercially priced coal over the majority of the life of the power station. Generally, mine mouth pits are priced at extraction costs, sometimes including a return to the miner where the miner is a separate entity to the power station. Whilst mining costs may vary over time according to the geological conditions of the mine, by and large these costs are expected to be fairly stable in a single year. For existing coal fired power stations that are not mine mouth stations the Governments that built each one of these plants overcame these contracting risks by developing a remote but Government-owned mine that supplied the power station under contracts that resembled a mine mouth power station contract (i.e. coal prices that were closer to the costs of mining).

Secondly, for existing coal fired power stations, if they hold coal contracts that are cheaper than the marginal price of coal, then, if these generators are behaving commercially they ought to be pricing each tonne of coal they burn at the replacement value of the coal – that is, the assumed marginal price. For these two reasons our advice to IPART is that it is more appropriate to apply a single marginal price for fuel for each time for each location in the NEM.

# 12 Carbon cost assumptions

Assumed carbon prices are incorporated in all of our modelling – our *WHIRLYGAS* modelling of gas prices, our *WHIRLYGIG* modelling under both the incremental LRMC approach and stand-alone LRMC approach and our *SPARK* modelling.

This section discusses how a given carbon price is incorporated in our modelling and then summarises potential forward carbon price assumptions.

## 12.1 Incorporating carbon costs

Our general approach to carbon costs is to incorporate them as an increase in the variable operating costs of production. Emissions from various sources incur an assumed carbon cost in each of our models is as follows:

- ***WHIRLYGAS***: Auxiliary gas usage (for compression and processing) will incur carbon costs according to the assumed combustive emission content of the gas. Gas fields and pipelines will incur additional carbon costs due to an assumed fugitive emission rate.
- ***WHIRLYGIG* and *SPARK***: Thermal generators (burning coal, gas or oil/diesel) will incur carbon costs according to the assumed combustive emission content of the fuel. This approach is applied consistently across the stand-alone LRMC, incremental LRMC and market-based approaches.
- ***STRIKE:*** *STRIKE* takes carbon inclusive prices as an input and does not need a specific treatment of carbon within the model.

Note that for fuel, our proposal is to capture fugitive emissions and emissions associated with the production and transport of fuel in the unit cost of the fuel. Under this approach, electricity generators would be treated as only being directly liable for the combustive emissions associated with delivered fuel. However, the delivered price of such fuel will reflect carbon cost incurred up to the delivery point. In previous advice to IPART, we have incorporated fugitive emissions into the assumed emission rate for electricity generators (as opposed to the delivered price of fuel). Either approach leads to the same SRMC value for electricity generators in $/MWh terms. Nevertheless we invite submissions from stakeholders on whether they see any issues with this slight change to the treatment of carbon.

## 12.2 Potential carbon forward prices

Carbon prices directly increase our estimates of wholesale energy costs during the period of the current Determination. Our estimate of LGC costs is a function of the carbon price during the current Determination *and* in the longer term. As such, we need to assume a carbon price path for the entire modelling period for the purpose of estimating LGC costs.

With the passage of the Clean Energy Act there is now certainty about the level of the carbon price for the fixed price period (2012/13, 2013/14 and 2014/15). Beyond the fixed price period of the current legislation, and most relevantly in the final year of the current Determination, there is uncertainty associated with the level of the carbon price. Prices in this period will be set by the market and influenced by the linkage of the Australian scheme to the European ETS.

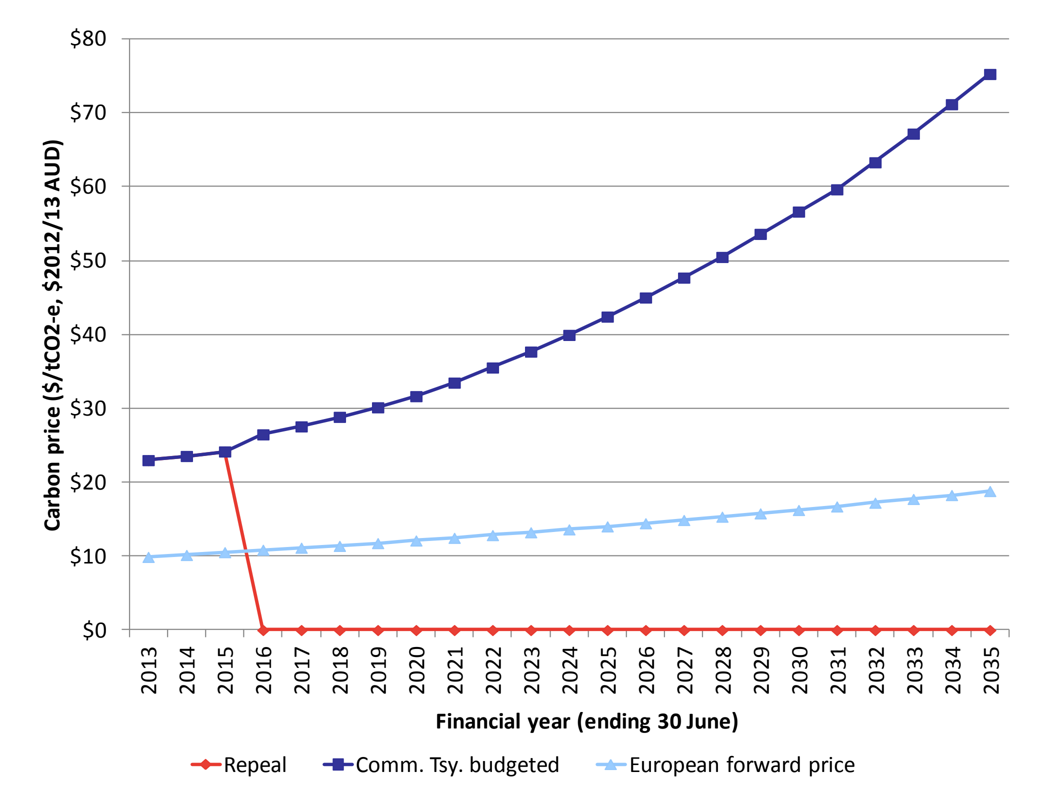
Current estimates for the carbon price during the market period range from Commonwealth Treasury's Core Policy scenario[15] to repeal of the scheme and a zero carbon price. These carbon price paths are shown in Figure 7.

For the sake of comparison, Figure 7 also shows a forecast of the forward price of carbon in the European Union (EU), sourced from publically available data from the Intercontinental Exchange (ICE). With the announcement of the scrapping of the carbon price floor that was to have applied following the fixed price period, and given that carbon permits can be imported from the EU, the EU carbon price is likely to set the carbon price in Australia.

For the first two years of the current Determination our advice to IPART is to adopt the fixed carbon price. For the final year, however, there is significant uncertainty about the likely carbon price. We invite submissions from stakeholders on the appropriate approach for developing an input assumption for the carbon price for 2015/16.

15 Commonwealth Department of Treasury, *Strong Growth, Low Pollution*, July 2011 (see: Chart 5.1, http://treasury.gov.au/carbonpricemodelling/content/chart_table_data/chapter5.asp)

Figure 7: Potential carbon prices (real 2012/13)




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

# Appendix A – *WHIRLYGIG*

*WHIRLYGIG* is a mixed integer linear programming model. The model is used to optimise investment and dispatch decisions in electricity markets. Specifically, the model seeks to minimise the total cost (including fixed and variable costs) of meeting electricity demand, subject to a number of constraints. These constraints include that:

- supply must exactly meet demand at all times;
- minimum reserve requirements must be met;
- generators cannot run more than their physical capacity factors; and
- additional policy constraints, including greenhouse policies, are met.

*WHIRLYGIG* essentially chooses from an array of investment and dispatch options over time, ensuring that the choice of investment and dispatch options is least-cost.

The following sections provide an overview of the data that is required for the model and the formulation of the model.

## *Data required for WHIRLYGIG*

*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 reserve capacity requirements for each region.

General input variables required for the model are set out in Table 1.

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) – 10% probability of exceedence is used because this is used by AEMO in determining system reserve |
| $H_p$ | Hours | Frequency of period p in year in hours |
| $RES_r$ | MW | Reserve capacity requirement in region r |
| RATE | % | Discount rate |
| GC | $/tCO_2$-e | Assumed carbon cost |
| 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. |

The model incorporates a representation of the inter-regional interconnectors, and the constraints on these interconnectors. The input variables required for interconnection options are set out in Table 2.

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 incorporates a representation of generation plant (both existing plant and new plant). *WHIRLYGIG* requires the following data for generation plant:

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

## Carbon cost assumptions

- plant commissioning timeframes.

The input variables required for generation plant are set out in Table 3. The input variables for any greenhouse emission abatement options that are included in the model are set out in Table 4.

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 |
| $MCF_j$ | % | 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 |
| $EOR_i$ | % | Expected outage rate |
| Date In | Date | Commissioning date |
| Date Out | Date | De-commissioning date |
| $R_j$ | Region | NEM region where plant j is located |

Table 4 Input variables for greenhouse emission abatement options

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

## *Model formulation*

The decision variables used within *WHIRLYGIG* 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 set out 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 of blocks of type j/k in which to invest |
| $O_k$ | 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 carbon emissions |
| RX | Real [0,infinity) | Represents the deficit renewable 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 |

Note: Deficit and surplus energy are included as decision variables consistent with Linear Programming best practice of always including a penalty or 'slack' term in constraints. Slack terms impose a penalty in the event that the constraint is violated.

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;
- carbon emission costs;
- other greenhouse requirements (e.g. GGAS and MRET targets);
- 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 cost and constraints, are given in Table 7.

Table 7 Constraints on decision variables

| Variable | Formula | Description |
|---|---|---|
| Plant capacity factor constraint | $O_j \le I_j.BS_j.MCF_j.\sum_p H_p$ | Ensures that the plant does not run in excess of its energy constraint (particularly for hydro plant) |
| 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* |

Note: If the greenhouse target, *GT*, is set to zero then actual emissions is less than or equal to penalised emissions, *TG* <= *GX*. Penalised emissions are penalised at the assumed carbon cost of *GC*, to minimise this cost penalised emissions will be set exactly equal to actual emissions (rather than greater) resulting in carbon being priced at the assumed cost for the entire NEM.

The regional energy balance constraint ensures that supply meets demand in each NEM region.

*WHIRLYGIG* allows for a deficit/surplus of supply, the quantity of which is priced at the Market Price Cap (MPC) – currently $12,900/MWh. Typically, MPC events are not seen in *WHIRLYGIG* because of the reserve constraints included in the modelling.

## Carbon cost assumptions

New investment in *WHIRLYGIG* is driven by the regional reserve constraints. These constraints are applied at the regional level and ensure that a sufficient amount of capacity, plus a margin, is built relative to demand. AEMO publishes the reserve margin for each year. AEMO calculates these reserve margins relative to an abstract forecast of maximum demand – namely the medium, 10% probability of exceedence maximum demand where all NEM regions are assumed to peak simultaneously (100% co-incident demand). This outcome is extremely unlikely to occur in practice as the NEM is widely geographically distributed. However, as AEMO publishes reserve margins relative to demand on this basis, the 100% co-incident maximum demand for each region is included in the modelling with a weight of half an hour so that the reserve constraints work as intended. These constraints ensure that for realistic demand levels, which include interregional diversity of peaks, there is sufficient capacity to meet demand at all times. Historically, AEMO's 10% POE forecasts and associated reserve margins have been conservative to the extent that they lead to a large reserve margin in the NEM relative to expected conditions.

# Appendix B – *SPARK*

Like all electricity market models, *SPARK* reflects the dispatch operations and price-setting process that occurs in the market. Unlike most other models, however, generator bidding behaviour is a modelling output from *SPARK*, rather than an input assumption. That is, *SPARK* calculates 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.

## Data required for *SPARK*

The fundamental features and formulation of *SPARK* are very similar to *WHIRLYGIG*: just as *WHIRLYGIG* requires a representation of the physical and economic characteristics of the market in order to determine least-cost investment and dispatch, *SPARK* requires a representation of the physical and economic characteristics of the market in order to determine the 'best' set of generator bids for every market condition.

The differences between the two models lie in assumptions about generator behaviour. *WHIRLYGIG* assumes that the market is perfectively competitive. In *SPARK* this assumption is relaxed and game theory is used to determine market outcomes where at least some market participants are allowed to behave strategically in the spot market. This strategic behaviour of market participants within *SPARK* occurs within the constraints of the physical and economic characteristics of the market and the market rules.

Given this, the data requirements for *WHIRLYGIG* and *SPARK* are very similar. *SPARK* shares the same input assumptions as *WHIRLYGIG* regarding supply and demand. *SPARK* also uses some of the *WHIRLYGIG* outputs – such as the investment path and greenhouse permit costs – as inputs.

In addition to these common input assumptions, *SPARK* also requires input assumptions about which assets can behave strategically and what strategies are available. In most cases some level of firm contract cover is also assumed for the strategic assets to model the actual incentives of generators.

## Model formulation

Game theory is a branch of mathematical analysis which is designed to examine decision making when the actions of one decision maker (player) affect the outcomes of other players, 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 given that a rival has their own strategy and preferred position. Organised electricity 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:

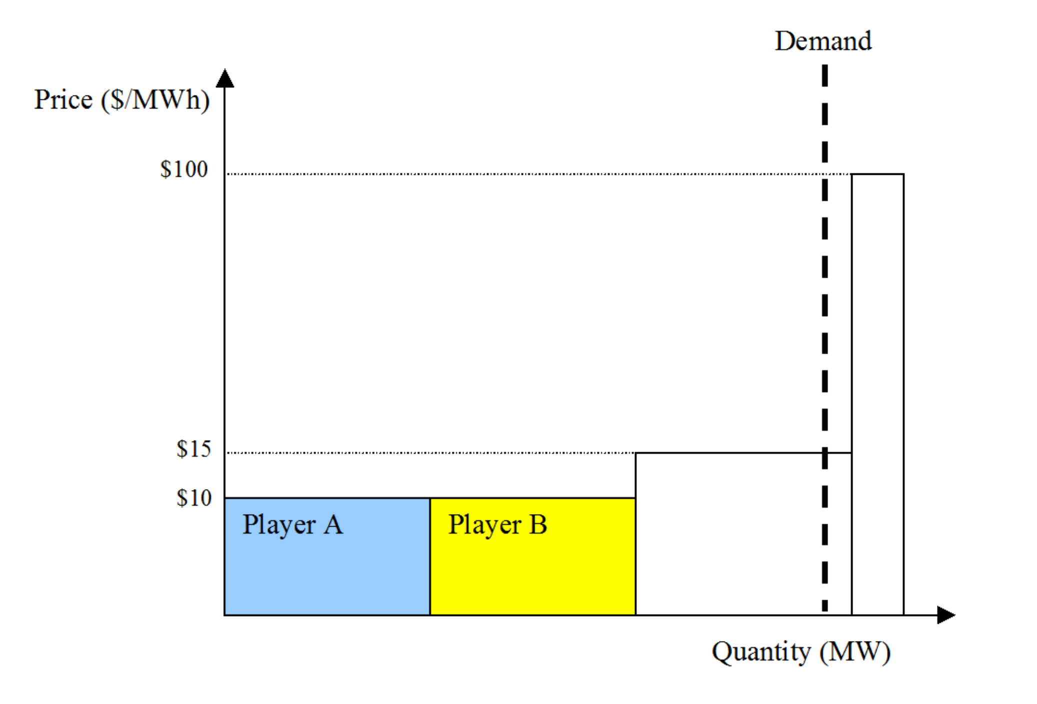
- **Players**: players are generators who are able to make decisions based on the behaviour they know or expect from other players. *Strategic players* are given a range of different strategies allowing them to respond to changes in the behaviour of other players. *Non-strategic players* have a fixed 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' set of choices by the players in the game. An equilibrium is 'best' 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 simple example of an electricity market. The market is a single regional market, with 2 Players, A and B. Players A and B are of equal size (say, 100MW) and have equal costs (say, $10/MWh). There are also other generators in the market, with higher costs (one at $15/MWh and another at $100/MWh). An aggregate supply and demand diagram for this simply market is shown in Figure 8.

In this example, demand is at a level above the combined capacities of Players A and B, intersecting with the first higher cost generator. The result is that the market price is determined by the bids of the first higher cost generator, at $15/MWh. Both Player A and Player B make a small profit equal to $5/MWh, multiplied by their output of 100MWh, giving $500 each.

Figure 8 Example supply/demand diagram




Under these conditions, either Player A or Player B could withdraw a small amount of capacity to push the price up to the cost of the second higher cost generator ($100/MWh). Assume Player A withdraws 10MW, and that this is sufficient to set the price at $100/MWh. This results in the following profit outcomes:

- Player A's profit becomes 90MW*($100-$10) = $8,100.
- Player B's profit becomes 100MW*($100-$10) = $9,000.

Conversely, Player B could withdraw 10MW, and the profit results would be reversed. If both Player A and Player B withdrew 10MW, the price would be set at $100/MWh, resulting in the following profit outcomes:

- Player A's profit becomes 90MW*($100-$10) = $8,100.
- Player B's profit becomes 90MW*($100-$10) = $8,100.

Using these results, we can construct a game payoff matrix as shown in Figure 9.

| | | 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 9: Payoff matrix (Player A, Player B)

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

Now consider Player A's incentives:

- If Player A thought Player B would bid 100MW, Player A would do best by bidding 90MW for a profit of \$8,100 (compared to \$500 by bidding 100MW).
- If Player A thought Player B would bid 90MW, Player A would do best by bidding 100MW for a profit of \$9000 (compared to \$8100 by bidding 90MW).

As the game is symmetric, Player B faces the same incentives. 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.

### Game Theory in SPARK

*SPARK* is fundamentally formulated in the same manner as *WHIRLYGIG*. The model includes a representation of the physical and economic characteristics of the market (including technical and cost data for generation plant, interconnectors between regions and greenhouse and renewable energy policies) that is the same as used in *WHIRLYGIG*. In addition, *SPARK* adopts a number of outputs from *WHIRLYGIG* – including new investment patterns and the costs of meeting greenhouse and renewable energy targets) as inputs into the modelling.

There are a number of additional steps required in *SPARK* modelling.

First, generators need to be divided 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.
- *Non-strategic players* are assigned fixed bids (i.e. their bids remain constant no matter how other players bid), which do not respond to changes in the choices of others.

The definition of strategic players is based on observation of historic bidding behaviour. In effect, the generators that are defined as strategic players are those generators in the market that have the largest portfolios of generation plant.

As well as defining strategic players and non-strategic players, it is necessary to identify ownership of each generation plant (including new entrant plant) in the system.

Second, the type of bidding and the range of bidding choices must be defined. Regarding the type of bidding, *SPARK* can be operated with a choice of capacity bids or price bids. Capacity bids (Cournot modelling) are equivalent to withdrawing capacity (altering $C_j$, which is seen in Table 3). Price bids (Bertrand modelling) are equivalent to increasing prices (altering $V_{j,}$, which is seen in Table 3). Regarding the range of bidding choices, under Cournot games, bidding choices are represented by increments of capacity withdrawals. Under Bertrand games, bidding choices are represented by multiples of SRMC. Given the computational demands of game theory it is important to limit the number of bidding choices as the number of dispatch operations rises exponentially as the number of strategic players and bidding choices increases.

Third, the contract levels of players must be defined. Contract levels affect the operating profits that players receive under each set of strategies. *SPARK* computes prices and operating profits for each combination of bids and for each demand point.

Operating profits for a portfolio of assets are calculated as pool revenue less variable costs of generation plus any difference payments on a contract position. Mathematically, this can be expressed for a single bidding combination and level of demand as:

$$\pi_{portfolio} = \left[ \sum_{Generators,i} (P - MC_i).Q_i \right] + \left[ \sum_{Swaps,j} (S_{Swap} - P).V_{Swap} \right] + \left[ \sum_{Caps,k} Min(P - S_{Cap}, 0).V_{Cap} \right]$$

Where,

P = Market price

MCi = Marginal cost of generator i

Qi = Output of generator i

SSwap = Assumed strike price of portfolio swaps

VSwap = Assumed volume of portfolio swaps

SCap = Assumed strike price of portfolio caps

VCap = Assumed volume of portfolio caps

Note that contracts are only included in order to capture their effect on marginal bidding decisions. Put another way, we are only interested in whether a particular bidding combination leads to a better or worse outcome for a Player relative to its other bidding options. As such the premium paid on caps is irrelevant as it is a constant across all bidding combinations and is not included in the calculation. The particular strike price of swaps is also irrelevant as it only changes the level of payoffs, it does not change the relative payoffs between bidding combinations. Any swap strike price will give the same set of optimal bidding outcomes. Floors and more exotic contracts can also be included in the model however Frontier does not propose to utilise these contract types as part of this analysis.

The operating profits are used to measure the 'payoff' for a game. Once payoffs for 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) in Figure 10. PAi and PBj represent the bidding strategies of players A and B respectively. VAij and VBij represent the pay-offs (operating profits) 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.

Figure 10 Hypothetical example of *SPARK*'s strategy search

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

*SPARK* treats each demand point individually when running a game. That is, a game is considered to occur for a particular representative demand point. In analysing multiple demand points, a number of games, one for each demand point, are run.

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 equilibria 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 the distributions of average equilibrium prices, we take multiple sets (say, 100) of random samples 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. generation dispatch, flows, etc.

# Appendix C – *STRIKE*

*STRIKE* is a portfolio optimisation model. It 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.

## 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.[16] 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 between the returns, 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.

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

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,[17] and the expected return on the Y-axis.

Figure 11 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 11 MVP frontier for investment in assets A and B for correlation coefficient, $\rho = 0$

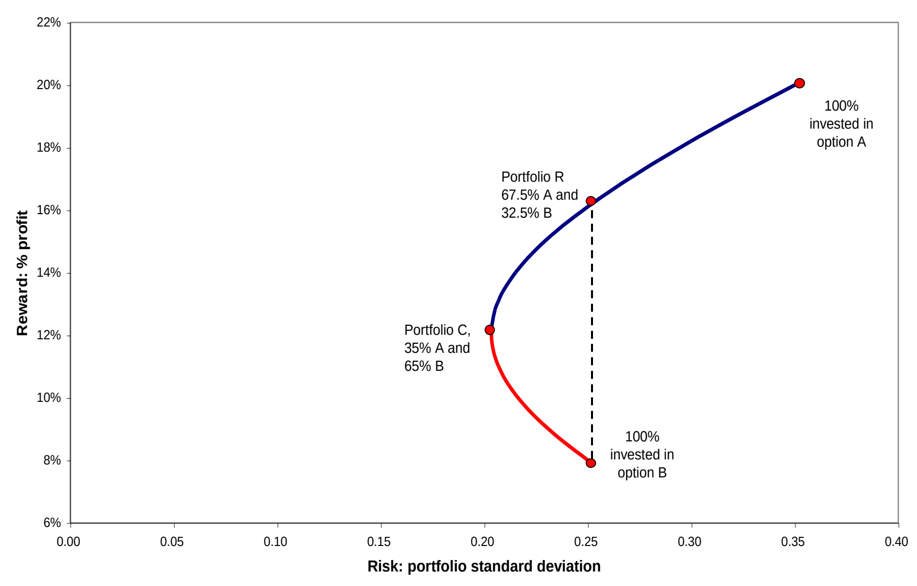
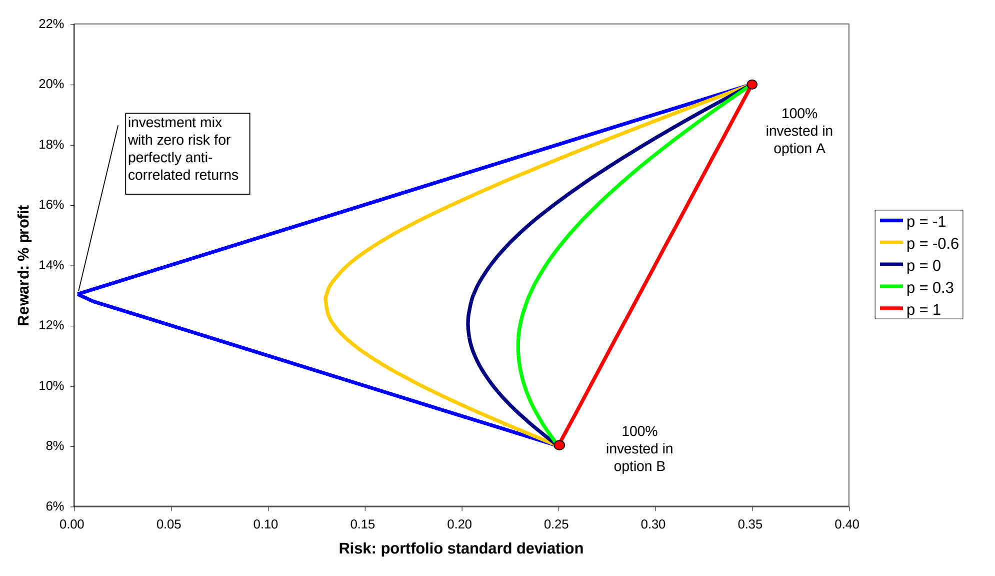



Figure 11 assumes that there is no correlation between the returns on the two assets, A and B. Figure 12 shows a number of MVP frontiers for different levels of correlation between the two assets. We can see that as the correlation between

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

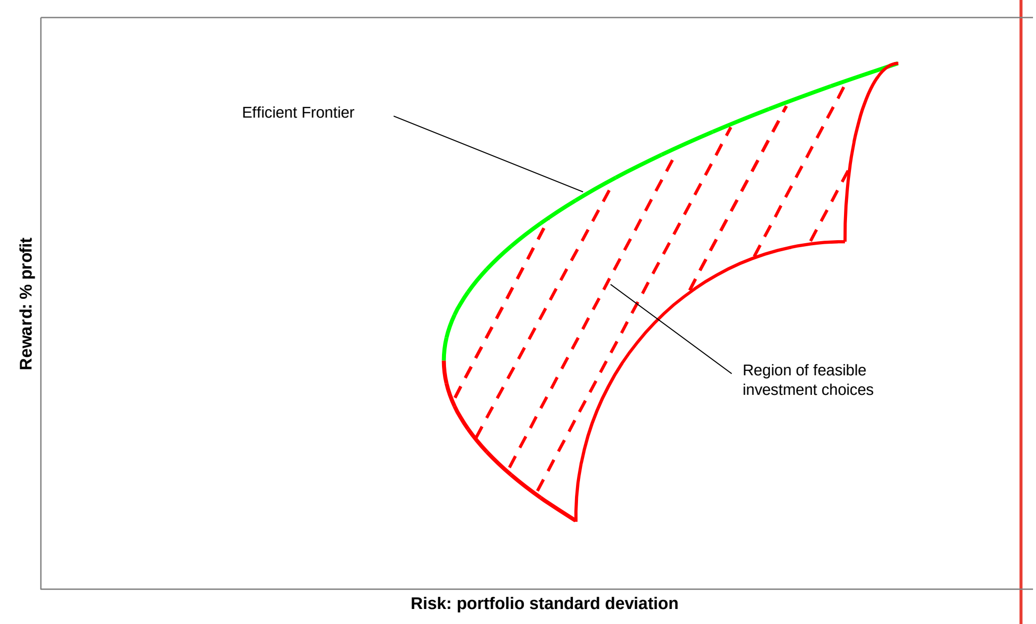
the returns on assets A and B becomes more negative, the risk associated with a portfolio of these assets becomes smaller. Hence the benefits associated with diversification, called the portfolio effect, increases as the correlation between the assets decreases.

Figure 12 MVP frontiers for investment in assets A and B with different levels of correlation




The situation illustrated in Figure 11 and Figure 12, 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 13. 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 13 Feasible region and efficient frontier with 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.[18]

## *Implementation of Portfolio Theory in STRIKE*

*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* 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. 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* 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* 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 $\gamma$ is the chosen risk criterion, such as variance, or the value-at-risk, or the profit-at-risk, and $k$ is an indicator of the level of risk. If $\gamma$ is equal to the variance then maximisation of (2) is equivalent to the minimisation problem in (1).[19]

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 $\gamma$ 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.

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

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

# Appendix D – *WHIRLYGAS*

*WHIRLYGAS* is a mixed integer linear programming model. The model is used to optimise investment and production decisions in gas markets. Specifically, the model seeks to minimise the total cost (including fixed and variable costs) of meeting gas demand subject to a number of constraints. These constraints include that:

- supply must meet demand at all times or pay the price cap for unserved gas demand;
- supply must meet the specified reserve capacity margins;
- gas fields cannot produce more than their respective reserves;
- gas fields, plants and pipelines cannot produce or throughput more than their physical capacities.

*WHIRLYGAS* essentially chooses from an array of investment and supply options over time, ensuring that the choice of these options is least-cost.

The following sections provide an overview of the data required for the model and the formulation of the model. The values in the following tables and explanations are converted to appropriate units and discounted implicitly in order to reduce the size and complexity of the equations.

## *Data required for WHIRLYGAS*

*WHIRLYGAS* requires general system data for:

- the demand levels over a representative set of demand regions (also referred to as nodes) and production periods;
- the international demand levels over a representative set of liquefied natural gas (LNG) terminals (also referred to as nodes) and supply periods, as well as an LNG price for each representative LNG terminal and period;
- the frequency of occurrence (hours per year) of each representative period; and,
- the reserve capacity requirements for the model.

General input variables required for the model are set out in Table 8.

Table 8 General input variables

| Variable | Units | Description |
|---|---|---|
| $D_{n,p}$ | TJ/day | Demand at node $n$, period $p$ |
| $TD_{n,p}$ | TJ/day | International demand at the LNG Terminal at node $n$, period $p$ |
| $TPC_{n,p}$ | \$/GJ | International LNG price at the LNG Terminal at node $n$, period $p$ |
| $RM$ | % | Reserve margin; the surplus supply capacity, as a percentage of forecast peak gas demand, required for reliability. |
| $RATE$ | % | Discount rate |
| $H_p$ | Hours | Frequency of period $p$ in year |
| $PC$ | \$/GJ | Price cap on gas |
| $PF$ | \$/GJ | Price floor on gas |

*WHIRLYGAS* models a representation of pipelines including constraints on their operational capacity, auxiliary losses and the pipeline's connection points (referred to as 'nodes'). The model considers pipelines that are currently commissioned (existing) and potential investment options. *WHIRLYGAS* requires the following data for pipelines:

- fixed costs (including capital costs and fixed operating and maintenance (FOM) costs);
- gas source (gas field, gas plant or demand node) and node supplied;
- minimum and maximum throughput capacities;
- number of investment blocks available;
- auxiliary losses; and
- pipeline commissioning timeframes.

The input variables required for pipeline options are set out in Table 9.

Table 9 Input variables for pipeline options

| Variable | Units | Description |
|---|---|---|
| $FN_i$ | Node | Notional 'from' node for pipeline $i$ |
| $TN_i$ | Node | Notional 'to' node for pipeline $i$ |
| $CT_i$ | TJ/day | Throughput capacity of pipeline $i$ from $FN_i$ to $TN_i$ |
| $MIC_i$ | TJ/day | Minimum throughput capacity of pipeline $i$ |
| $F_i$ | $/block | Fixed cost of pipeline $i$ per block amortised over the life of the pipeline |
| $FOM_i$ | $/year/block | Fixed operating and maintenance costs of the pipeline; these are the annual costs incurred regardless of the level of throughput |
| $A_i$ | Real number | Auxiliary losses |
| $MaxLife_i$ | Years | Maximum life of the pipeline |
| $DateIn_i$ | Date | Commissioning date |
| $DateOut_i$ | Date | Decommissioning date |

*WHIRLYGAS* models a representation of gas processing plants including constraints on their operational capacity and the plants' connection points. The model considers processing plant that are currently commissioned (existing) and potential investment options. *WHIRLYGAS* requires the following data for gas plant:

- fixed and variable costs of production;
- gas source (origin gas field) and node supplied;
- minimum and maximum production capacities;
- number of investment blocks available;
- auxiliary losses; and
- plant commissioning timeframes.

The input variables required for a gas plant options are set out in Table 10.

Table 10 Input variables for gas plant options

| Variable | Units | Description |
|---|---|---|
| $FN_j$ | Node | Notional 'from' node for plant *j* |
| $TN_j$ | Node | Notional 'to' node for plant *j* |
| $CT_j$ | TJ/day | Production capacity of plant j |
| $MIC_j$ | TJ/day | Minimum production capacity of plant *j* |
| $V_j$ | $/GJ | Variable cost of plant *j* |
| $F_j$ | $/block | Fixed cost of plant *j* per block amortised over the life of the plant |
| $FOM_j$ | $/year/block | Fixed operating and maintenance costs of the pipeline; these are the annual costs incurred regardless of the level of production. |
| $A_j$ | Real number | Auxiliary losses |
| $MaxLife_j$ | Years | Maximum life of the plant |
| $Blocks_j$ | Count | Number of 'blocks' (units of this type) available for investment |
| $DateIn_j$ | Date | Commissioning date |
| $DateOut_j$ | Date | Decommissioning date |

*WHIRLYGAS* models a representation of gas fields including constraints on their reserves and the gas fields' connection points. The model considers gas fields that are currently developed (existing) and potential investment options. *WHIRLYGAS* requires the following data for gas fields:

- node supplied (i.e. production plant);
- reserves and minimum and maximum production capacities;
- gas field commissioning timeframes.

The input variables required for a gas field options are set out in Table 11.

Table 11 Input variables for a gas field

| Variable | Units | Description |
|---|---|---|
| $TN_k$ | Node | Notional 'to' node for gas field $k$ |
| $CT_k$ | TJ/day | Production capacity of gas field $k$ |
| $MIC_k$ | TJ/day | Minimum production capacity of gas field $k$ |
| $RES_k$ | PJ | Reserves of gas field $k$ |
| $MaxLife_k$ | Years | Maximum life of the gas field |
| $DateIn_k$ | Date | Commissioning date |
| $DateOut_k$ | Date | Decommissioning date |

## Model formulation

*WHIRLYGAS* can be envisaged as a directed graph with pipelines, plants and gas fields connected via intermediary nodes. These intermediary nodes perform three important functions.

- The nodes can act as aggregators, allowing multiple plants or pipelines to feed different representative demand regions or LNG terminals.
- The nodes can act as the representative demand regions. These nodes represent Australian demand regions and have associated period-level demand levels. Where there is an excess or shortfall of supply to this node, the price cap is incurred.
- The nodes can also act as the representative LNG terminals. Where there is a shortfall of supply to this node, LNG terminal points incur a penalty of the input price international LNG price, $TPC_{n,p}$. Hence, LNG terminal prices are effectively capped at their respective $TPC_{n,p}$.

The decision variables used within *WHIRLYGAS* relate to the decisions to invest in the various options plus the supply levels of these options. These decision variables are set out in Table 12.

Table 12 Decision variables

| Variable | Types (bounds) | Description |
|---|---|---|
| $B_{a,p}$ | Binary $\{0,1\}$ | Represents the decision to build a plant, pipeline or gas field where , $a \in \{i,j,k\}$, (1 = Build, 0 = Do not build) |
| $I_{a,p}$ | Binary $\{0,1\}$ | Represents whether the plant, pipeline or field exists and is available for use, where $a \in \{i,j,k\}$ |
| $IF_{a,p}$ | Real $[0,\infty)$ | Represents gas production from gas fields and plants and throughput from pipelines. |
| $A_{a,p}$ | Real $[0,\infty)$ | Represents auxiliary losses incurred in the movement and/or production of gas within the model. |
| $NE_{n,p}$ | Real $[0,\infty)$ | Represents excess supply of gas at a node. |
| $NS_{n,p}$ | Real $[0,\infty)$ | Represents a shortfall of supply of gas at a node. |
| $TNE_{n,p}$ | Real $[0,\infty)$ | Represents an excess of supply at an LNG terminal node. This performs a similar function to $NE_{n,p}$ but incurs a different cost. |
| $TNS_{n,p}$ | Real $[0,\infty)$ | Represents a shortfall of supply at a terminal node. This performs a similar function to $NS_{n,p}$ but incurs a different cost. |
| $UG$ | Real $[0,\infty)$ | Represents unconsumed gas. |

Note: Deficit and surplus gas are included as decision variables ($NE_{n,p}$,$NS_{n,p}$, $TNS_{n,p}$, and $TNE_{n,p}$) as penalty or 'slack' variables in constraints. Slack variables impose a penalty in the event that the constraint is violated.

Using the input variables and the decision variables, a number of key calculated variables can be determined. These variables are given in Table 13.

Table 13 Calculated variables

| Variable | Formula | Description |
|---|---|---|
| $FV_a$ | $\sum_p H_p \cdot IF_{a,p}$ | Throughput/production from pipelines, plants and gas fields for all supply periods, where $a \in \{i, j, k\}$ |
| $OC_a$ | $\sum_p FOM_a \cdot I_{a,p}$ | Fixed operating cost for pipelines, plants and gas fields for all supply periods where $a \in \{i, j, k\}$ |
| $TC_a$ | $B_a \cdot F_a + OC_a + FV_a \cdot VC_a$ | Total cost of a pipeline, plant and gas field for all supply periods where $a \in \{i, j, k\}$ |
| $TCLS$ | $\sum_p \left(\sum_n (NE_{n,p} \cdot (-PF) + NS_{n,p} \cdot PC)\right)$ | Total cost of local excess / shortfall supply |
| $TCIS$ | $\sum_p \sum_n (TNE_{n,p} \cdot (-PF) + TNS_{n,p} \cdot TPC_{n,p})$ | Total cost of international excess / shortfall supply |
| $TC$ | $\sum_i TC_i + \sum_j TC_j + \sum_k TC_k + TCLS + TCIS - TV$ | Total system cost (to be minimised) |
| $TIR$ | $\sum_k RES_k$ | Total initial reserves |

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

- capacity limits of plants, pipelines and gas fields and reserves of gas fields;
- supply/demand balancing; and
- reserve margin 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 12 as the bounds on the variables, and relate mainly to capacity constraints.
- Indirect constraints, placed on the calculated variables and relating to the supply/demand balance and reserve margin level, are given in Table 14.

Table 14 Constraints on decision variables

| Variable | Formula | Description |
|---|---|---|
| Node balance constraint | $\sum_{n\forall n=TN_a}(IF_{a,p} - A_{a,p}) + \sum_{n\forall n=FN_a} IF_{a,p} - NS_{n,p} + NE_{n,p} = 0$ | 'Throughput' at each node $n$ and in each period $p$, (including the shortfall and excess supply terms) must balance |
| Demand balance constraint | $\sum_{n\forall n=TN_a}(IF_{a,p} - A_{a,p}) + \sum_{n\forall n=FN_a} IF_{a,p} - NS_{n,p} + NE_{n,p} = D_{n,p}$ | Supply equals demand plus/minus a shortfall/excess supply at each node $n$ and in each period $p$ |
| LNG Terminal balance constraint | $\sum_{n\forall n=TN_a}(IF_{a,p} - A_{a,p}) + \sum_{n\forall n=FN_a} IF_{a,p} - TNS_{n,p} + TNE_{n,p} = TD_{n,p}$ | Supply equals demand plus/minus a shortfall/excess supply at each LNG terminal node $n$ and in each period $p$ |
| Initial reserve requirement | $\sum_k \sum_p IF_{k,p} \leq TIR$ | Over all modelled periods, production from a gas field must be less than its initial reserves |

*WHIRLYGAS* allows for supply shortfall/excess at each node, the quantity of which is priced at the Market Price Cap (MPC).

## Carbon cost assumptions

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