## AUSTRALIAN COUNCIL OF LEARNED ACADEMIES (ACOLA)

## Securing Australia's Future: Project Six
## Engineering Energy: Unconventional Gas Production

# INTERIM REPORT ON SHALE GAS FINANCIAL MODELLING

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### SUMMARY

This interim report summarises the work undertaken so far for the ACOLA Securing Australia's Future: Project 6, Engineering Energy: Unconventional Gas Production. It takes knowledge and experience previously developed in other ATSE projects and applies it to the financial analysis of shale gas extraction. It represents the first step in analysing the potential costs of extracting shale gas in Australia. In order to progress this objective, this interim report describes the financial analysis of shale gas in the USA, where some public data is available.

The interim report describes the development of the financial model to date in terms of both the methodology and the input data. The model calculates the gas price required to make an investment in shale gas financially viable, and does this probabilistically. The important input parameters in the model are the capital costs of both drilling and completion of the necessary wells and the land lease costs. The input parameters in the form of the initial gas production distribution and the gas production decline over time are also important. This is because the former has a large variability, and the gas production decline from a well is rapid.

The results are sensitive to the key input parameters and show reasonable agreement with the gas prices required in the USA for a range of gas field input variables and US gas fields. It has also been found that, based on this data, the required gas price correlates to the capital intensity of the investment.[1]

The model development has reached the stage where it should be able to financially model any gas field, provided the necessary data is available or can be estimated.

### INTRODUCTION

This interim report to the EWG summarises the work undertaken to date to financially model the extraction of shale gas. It involves the development of a model that calculates the gas price

[1] Capital intensity is defined here as the capital investment per unit of initial gas production from a shale gas well.

necessary for a firm to just earn the cost of capital for an investment in a shale gas field. It is termed "required gas price" or RGP.

The extraction of shale gas from tight geological structures involves new technologies. These include deep and directional (e.g. horizontal) drilling to access the shale formations, as well as shale fracturing adjacent to the borehole (fracking) to increase permeability. It has been found in the USA that the production from any given well is relatively uncertain, although investment in a multiplicity of wells provides a geologically suitable field with an aggregated gas flow that is reasonably certain over time. A financial model for shale gas should therefore be probabilistic in nature at the individual well level, but aggregate the well gas flows over the field to give a probabilistic range in gas prices required for the overall investment to be financially viable.

ATSE has previously undertaken studies on financial viability of technologies in the power generating industry.[2] These involved the calculation of real option values (NPOV) for technologies using probabilistic techniques and standard financial methodologies to determine cash flows and net present values. ATSE also undertook calculations of Levelised Cost of Electricity (LCOE), which is defined as the constant price of electricity required over its life to ensure financial viability of a new power generating investment. These techniques form the basis of the current model development. However, shale gas differs considerably in the detail of the cash flow calculation and in the uncertainty of the operating parameters.

The fundamental methodology of the present study is similar to an LCOE calculation, except that it is probabilistic rather than deterministic and involves gas price rather than electricity price.

The production of liquids from a shale gas field also influences the economics of shale gas extraction. This is because the price of liquid petroleum products is at present higher in the USA than that for gas. The financial model presented here does not include liquids production, although the model could be expanded in the future to account for this.

In terms of financial effect, as wells are drilled in a shale gas field there is a probability distribution in the initial gas production from each well. Moreover, the well gas production declines rapidly after operation commences, and this decline varies within and between fields.[3] The revenue stream from a shale gas field each year is thus the consolidated gas production from these wells, times the gas price. The capital cost each year comprises the cost of drilling and fracking the wells and any up-front land lease costs prior to the drilling. Shale gas is different to a conventional investment, since the capital cost are ongoing as more wells are drilled over the life of the investment. Operating costs are expressed as cost per MMBtu of gas produced, and so are treated as being variable. Royalties and taxes represent charges against the:

*cash flow = (revenue – capital costs – operating costs)*

relationship for each year of operation. Free Cash Flows (see later in the report) are the relevant cash flows for calculation of the present value and have been used here.

[2] "Low Carbon Energy: Evaluation of New Energy Technology Choices for Electric Power Generation in Australia", Australian Academy of Technological Sciences and Engineering (ATSE), Nov 2010.
[3] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, pp. 32-33

Given adequate data to calculate gas productions and relevant costs, royalties and taxes, the probabilistic financial calculation for shale gas may be accomplished through an interative process. In this way, each well in a field is ascribed a probabilistic gas flow and gas flow decline over time. The number of wells for each year of operation is then used to determine the annual capital costs and probabilistic gas production aggregated over the field. Net Present Value (NPV) can then be calculated for an assumed gas price over the life of the field, the calculated free cash flows and a given cost of capital. An iterative procedure is then used to calculate the gas price for zero NPV for the probabilistic gas production conditions selected. This yields the gas price for that iteration. The whole calculation is then iterated probabilistically for new well production and decline values governed by the relevant probability distributions over thousands of iterations to develop a gas price probability distribution. Other parameters, such as cost per well drilled or operating costs, can also be described probabilistically. The present model utilises this approach and this interim report is a description of the model development to date.

The focus of the model development for this interim report has been to model the shale gas price in the USA and to evaluate the key sensitivities. These include the form of the gas production decline for individual wells, capital costs associated with land acquisition, drilling and production, and operating costs including royalties. Further work will involve improving these USA estimates and attempting to financially model the future situation in Australia (not covered here).

## DESCRIPTION OF THE FINANCIAL MODEL

### *Cash Flow Relationships*

As in the previous ATSE report, the relevant cash flows for an investment opportunity are the *free cash flows* (FCF)[4]. These are defined as:

FCF = EBIT (1-tax) + depreciation - capital expenses (1)

where: EBIT = earnings before interest and taxes, after depreciation

= revenues – operating costs –royalties[5] – severance tax[6] − depreciation

tax = income tax rate

In the present model development, free cash flows are calculated from equation (1) each year for the life of the investment. These free cash flows are then discounted at an appropriate rate to determine the NPV, which is the sum of all the discounted free cash flows.

The appropriate rate of discount for the yearly free cash flows is the weighted average cost of capital (WACC):

$$WACC = \{(1-tax)K_D D + K_E E\}/(D+E) \quad (2)$$

where: $K_D$ = cost of debt

[4] Higgins R C, "Analysis for Financial Management", 6th Edition, Irwin McGraw-Hill, Boston, 2001, pp. 326
[5] Royalties are paid to the private owners of the mineral resource in the USA.
[6] Severance tax is a tax in the USA levied by State governments against gas revenue.

$K_E$ = cost of equity

D = firm's level of debt

E = firm's level of equity

For any given year, the free cash flows are discounted according to:

$$FCF_{n,disc} = FCF_n/(1+WACC)^n \qquad (3)$$

where n = number of years since the start of investment, over the life of the investment.

The NPV is then given by:

$$NPV = \Sigma(FCF_{n,disc}) \qquad (4)$$

The relationships described by equations (1) to (4) above have been used in the present model development.

### *Fiscal Regime in USA, Capitalised Costs and Operating Costs*

In order to calculate the present value of an investment, the fiscal regime of the country in question must be employed in the cash flow calculations. The fiscal regime that applies to the petroleum industry in the USA consists of a combination of corporate income tax, severance tax and royalty payments.[7] Capital and operating costs for shale gas extraction must also be considered. The following USA situations generally apply:

Royalties: Royalties are 12.5 to 25% onshore, negotiated with the mineral interest owner. Royalties are taken as 12.5% in this work, payable to the private owner after gas production commences.

Income Tax: Income taxes are 35% applied at the federal level, plus generally 5% applied at the State level (range 0% to 12%), giving an overall income tax level of 38.25% applied to net earnings (EBIT).

Severance Tax: The severance tax is payable to the State where the product is extracted. Severance tax varies from State to State, and is payable against revenue regardless of any profits made. It is taken as 5% in this work.[8]

Land Leases: In the USA, land leases are paid to the private owner of land on which drilling and extraction is carried out. Land leases are variable, with an average value taken as $5,000 per acre in this work[9] (range $2,500 to $10,000 per acre). The land size required for one well in the USA is 640 acres (one square mile)[10], so the average

[7] "Global Oil and Gas Tax Guide", Ernst and Young, 2012, pp. 532
[8] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, pp. 1.
[9] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, Table 2D.1(b).
[10] Hefley W E, et al., "The Economic Impact of the Value Chain of a Marcellus Shale Well", University of Pittsburgh, August 2011, pp. 11.

lease cost per well is \$3.2M. Lease costs are capitalised in the year in which they are incurred.

Drilling costs: Drilling and Completion costs (IDC) are variable depending on the field.[11] Ranges of between \$3.5M to \$7M per well have been reported.[12,13] Drilling and completion costs are capitalised in the year in which they are incurred.

Depreciation: *Drilling and Completion Capital Costs:* It is beneficial in terms of cash flow to depreciate capital expenditures as fast as possible. The current US law allows development costs to be depreciated in the first year in which they are incurred for an independent producer.[14] In other words, the depreciation rate is 100% for this type of investor. If the producer is an integrated oil and gas company, the law allows 70% depreciation in the first year, with the remaining 30% depreciated over the next 60 years (0.5% per year after the first year). In this work, the 100% depreciation rate on drilling and completion has been assumed, as for an independent producer.

*Lease Costs:* Depreciation on lease costs is allowed as a function of depletion rate of the well.[15] The depreciation rate is determined as the (*original cost*) times (*the current year production*), divided by the (*ultimate total production*) from the well. Because shale gas production rates decline quickly, depreciation of lease costs is rapid in the USA situation. This method has been adopted in the present work to determine the lease cost depreciation value each year.

Operating Costs: Operating costs are taken as being variable, with an average value of \$0.75/MMBtu of gas produced (range \$0.50 to \$1.00/MMBtu).[16]

Cost of Capital: The weighted average cost of capital (WACC)of the investing firm has been taken as 10% for the present study.

As mentioned previously, the model at its present stage of development does not include credits for the sales of co-produced liquids.

### *Methodology for the Financial Model*

The financial model developed in this work calculates the gas price required to ensure that an investment in shale gas earns at least the cost of capital. It is a probabilistic calculation, which means that several of the important variables are probabilistically distributed. These include:

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[11] Hefley W E, et al., "The Economic Impact of the Value Chain of a Marcellus Shale Well", University of Pittsburgh, August 2011, pp. 65.
[12] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, Table 2D.1(a).
[13] Hefley W E, et al., "The Economic Impact of the Value Chain of a Marcellus Shale Well", University of Pittsburgh, August 2011, pp. 65
[14] "Global Oil and Gas Tax Guide", Ernst and Young, 2012, pp. 539.
[15] "Global Oil and Gas Tax Guide", Ernst and Young, 2012, pp. 538.
[16] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities, Table 2D.1(b).

- The parameters for the gas well decline rate over time
- The probability distributions of the initial decline rates for a gas field
- The development and completion costs, and leasing costs, of gas wells
- Operating costs

The Appendix gives details on the probability distributions determined and assumed for these parameters in the calculation.

Figure 1 below shows the flowchart for the present financial model.

By way of explanation of Figure 1, the calculation overall is iterative in order to build up the probability distribution of the required gas price to make the shale gas investment viable for the owners of the gas extraction company. The overall iteration is undertaken by Oracle "Crystal Ball" (CB), a plug-in for Microsoft Excel. Thousands of iterations for each run are available under this software.

Any given CB iteration calculates the financial outcomes, including gas price, for a fixed set of input variables. These input variables are either fixed throughout the whole calculation procedure (e.g. the cost of capital), or constant for each CB iteration (e.g. a capital cost selected from a probability distribution defined in CB). Virtual Basic language, a component of Microsoft Excel, has been used to undertake most of the calculations and to control CB in the model via a "Macro".

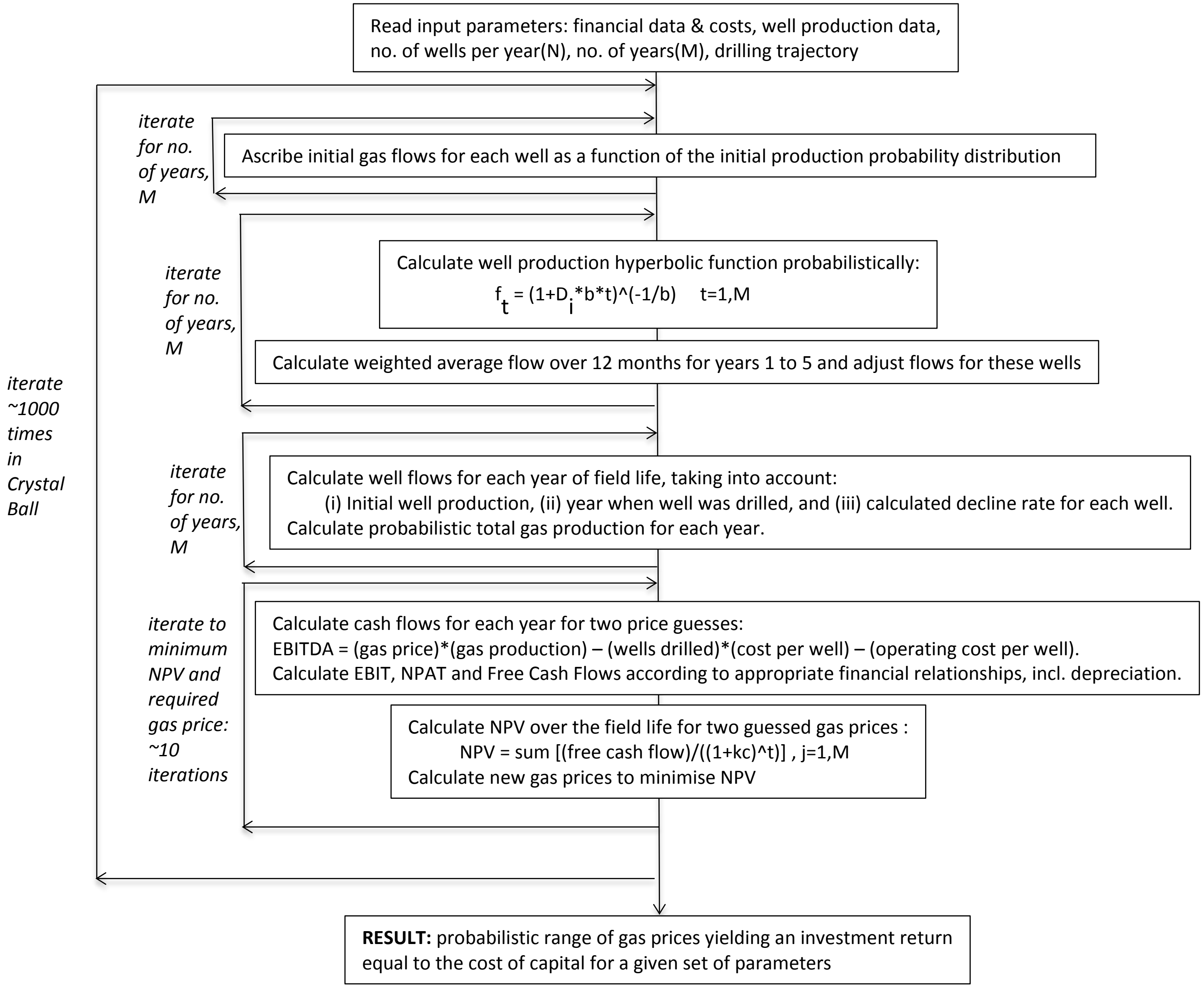


*Figure 1: Flowchart for shale gas financial model*

For each iteration of CB, the following calculations are undertaken as illustrated in Figure 1:

- The number of wells in the field and the rate of drilling and completing wells is assumed as input to the model. Associated costs per well are also defined. The shape of the drilling trajectory in terms of when drilling and completion ceases during the life of a field is also input as data. At this stage of model development, up to 5 wells per year for up to 30 years may be simulated (a total of 150 wells).
- Each well has the same probability distribution for the initial rate of production. These probability distributions can be field dependent, assuming data is available. In the work to date, a log-normal distribution for this parameter has been assumed, based on a best-fit of the data in CB (see below). CB selects a different initial rate of production for each well based on the probability distribution.
- A hyperbolic gas production rate decline has been assumed, as per gas industry practice (see further detail below).[17] The two key parameters in this decline are also probabilistically distributed, as detailed in the Appendix. In this way, each well in every CB iteration not only has a different initial gas production, but a different decline trajectory over the life of the field. Appropriate correction is applied in the early years of the wells life ( years 1 to 5) to determine the weighted average gas production over the full year in these years for the financial calculation. This is necessary because of the steep decline in production in these years and the fact that the financial calculation is undertaken incrementally at integer one year periods.
- The production of each set of wells for each year is tracked over the life of the field in the calculation. In this way, an aggregated gas production for each year of the field is determined from a well based on (i) its initial production, (ii) when it was drilled and (iii) calculated decline over the years. Capital costs (*viz*. drilling and completion costs, and leasing costs) are also tracked for each year of operation.
- Revenue each year is calculated from the gas production times the assumed gas price. Operating cost is calculated from the gas production times cost in $/MMBtu. Severance tax and royalties are also deducted from the revenue stream. Thus:

  *EBITDA= (revenue – operating cost – royalties – severance tax)* for each year.

- Depreciation is calculated for the US fiscal rules outlined above. In the case of leasing cost depreciation, the deductible cost is calculated from the initial lease cost and each well's decline, aggregated for each year. Thus:

  *EBIT = (EBITDA – depreciation)* for each year.

- Taxation is applied according to US fiscal rules outlined above. The combined effect of State and Federal income taxes is 38.25% in the USA. Thus,

  *NPAT = EBIT times (1 – 38.25%),* provided EBIT is greater than zero.

[17] Cheng Y, Wang Y, McVay D A, Lee W J, "Practical Application of a Probabilistic Approach to Estimate Reserves Using Production Decline Data", *SPE Economics and Management*, April 2010, pp.19.

- Free Cash Flow for each year is calculated by adding back depreciation for that year to NPAT[18] and deducting all capital expenditures for that year (eq. 1). The Free Cash Flows are then discounted at the cost of capital to give a list of discounted free cash flows as a function of year in the gas field's life (eq. 3). Net Present Value (NPV) is determined by summation of all the discounted free cash flows over the life of the field (eq. 4).
- In order to calculate the gas price that gives a return equal to the cost of capital, a zero NPV situation is required. This means that an internal iteration is required (for each CB iteration) to determine the gas price for the set of assumptions taken from the input probability distributions. In order to undertake this calculation in each CB iteration, two separate gas prices are assumed, and the financial calculations are undertaken twice to determine two different NPVs. A simple optimisation routine is then used to iterate down to a minimum NPV by adjusting the two gas prices so that they converge. In this way, a required gas price is determined for each CB iteration.

In order to build up a probability distribution of gas prices for a given gas field, thousands of iterations of CB are required using the above methodology. In most of the results presented in this interim report, 1000 iterations of CB were undertaken to develop the probability distributions.

## *Shale Gas Well Properties*

As mentioned above, the properties of the shale gas wells in a field need to be defined probabilistically in order to undertake the financial calculation. There are two key parameters in this regard: (i) the probability distribution of the initial gas production levels from wells in the field, and (ii) the decline rate of production over time from the wells in the field.

### *Initial Gas Production Distribution*

Figure 2 shows a typical probability distribution of initial gas production. In this case it is from the Barnett shale gas field. Also shown is the CB best fit to the data using a log-normal distribution. The best-fit parameters from CB in this example are: mean=1,700, standard deviation=1,250 and location=-550. The fitted distribution is the best fit to the original data, which was taken manually from a diagram in a publication.[19]

As can be seen from Figure 2, the initial gas production probability distribution is skewed towards lower gas production rates and has high variance. In the absence of other data at this point in time, the distribution curve shown in Figure 2 for the best-fit by CB has been employed for all gas fields in the present simulations, with the mean, standard deviation and location parameters changed in proportion to the stated initial production rate from the field in question. During the model runs, any selected values less than a small value (100 Mscf/d) were truncated from the distribution.

[18] Higgins R C, "Analysis for Financial Management", 6th Edition, Irwin McGraw-Hill, Boston, 2001, pp. 326
[19] Jacoby H D, O'Sullivan F M, Paltsev S, "The Influence of Shale Gas on US Energy and Environmental Policy", *Econ Energy Env Policy*, Vol 1, No. 1, 2012, pp. 41.

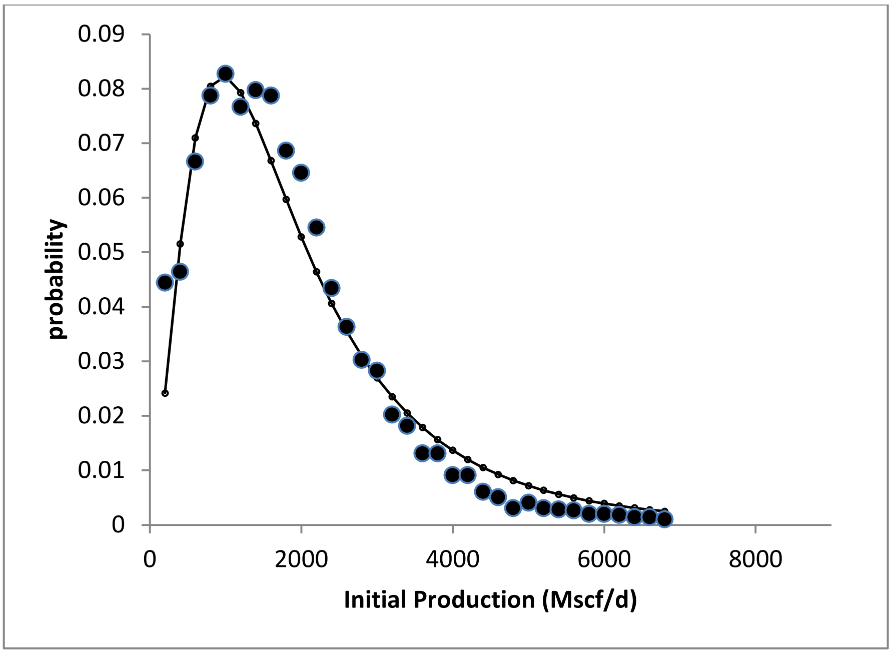


*Figure 2: Probability distribution of initial gas production in Barnett shale gas field 2005-10*

*Hyperbolic Gas Production Decline*

Each well in a shale gas field declines rapidly in production. This rapid decline is usually modelled as a hyperbolic decline[20] of the form:

$$q = q_i(1+D_i bt)^{-1/b} \qquad (5)$$

where $0 <= b <= 1$ and $D_i >= 0$

A diagram showing several reported hyperbolic decline curves for gas fields in the USA has been reported for the Haynesville, Marcellus, Eagle Ford, Woodford and Fayetteville fields[21] The data presented in this publication are available in a spreadsheet, so this was downloaded and the data for each of the fields was fitted to the decline equation (5) above using Excel "Solver" to minimise the least squares error and estimate the parameters. Figure 4 shows a typical fit, in this case for the Marcellus field.

[20] Cheng Y, Wang Y, McVay D A, Lee W J, "Practical Application of a Probabilistic Approach to Estimate Reserves Using Production Decline Data", SPE Economics and Management, 2010, pp. 19-29.
[21] Annual US Energy Outlook 2012, US Energy Information Administration, DOE/EIA 0383(2012), Fig. 54, pp. 59. Diagram not shown here because of copyright has not yet been granted to reproduce it.

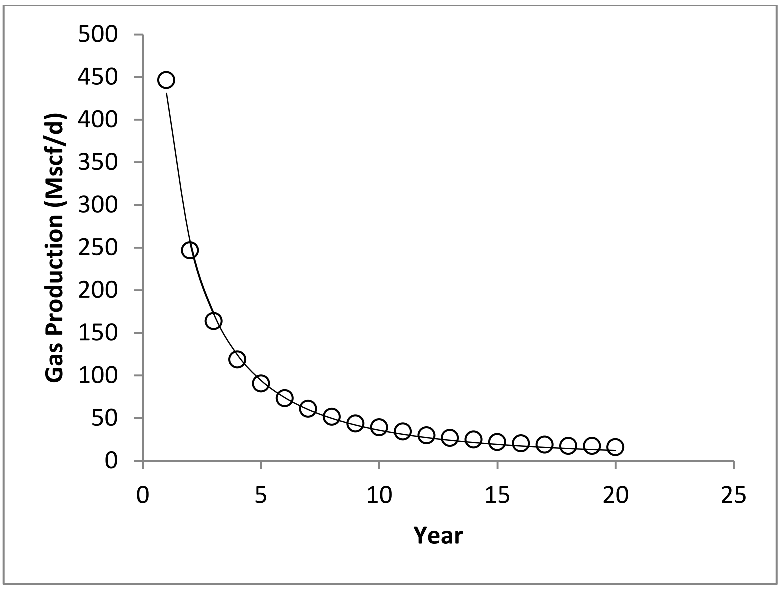


*Figure 3: Fitted hyperbolic decline example – Marcellus field. Circles are data and line is the hyperbolic fit.*

The $D_i$ and $b$ parameters for the different fields from the curve fitting process are as shown in Table 1 below.

| Field | Year 1 Initial Production(Mscf/d) | $D_i$ | $b$ |
|---|---|---|---|
| Haynesville | 1690 | 0.81 | 0.01 |
| Eagle Ford | 1160 | 0.77 | 0.02 |
| Woodford | 731 | 0.93 | 0.51 |
| Marcellus | 446 | 0.90 | 0.56 |
| Fayetteville | 420 | 0.90 | 0.47 |

*Table 1: Hyperbolic decline parameters for some shale gas fields in the USA*[22]

The average parameter values for the fields in Table 1 are $D_i$=0.86 and $b$=0.31, and these were the parameters used in the generic decline curve in the present financial model. In addition, each of these parameters was made probabilistic, with the probability distribution characteristic given in the Appendix to account for the variability reported. Sensitivity analysis was performed by inputting the actual fitted hyperbolic decline data for the different fields in the model, but it was found that the model result was relatively insensitive to these parameters relative to the initial production rate parameter, to which it was very sensitive.

[22] Annual US Energy Outlook 2012, US Energy Information Administration, DOE/EIA 0383(2012), pp. 59.

## RESULTS and CONCLUSIONS

### *Input Data*

A report from Massachusetts Institute of Technology (MIT) has described aspects of the economic modelling of shale gas extraction.[23] An appendix to this MIT report provides more detail on the assumptions made.[24] For the purposes of comparison here, the MIT data were used together with the initial production distribution and production decline curves described above to model the required gas prices in the USA in the present study.

The following assumptions were made in the MIT report:

| | |
|---|---|
| Royalties: | 12.5% |
| Severence tax rate: | 5% |
| Corporate tax rate: | 38.25% |
| Depreciation: | According to US fiscal rules (assumed to be 100%) |
| | Lease costs depreciated according to percentage production depletion |
| Cost of capital | 10% |
| Operating costs | $0.75/MMBtu (range $0.5 to $1.00) |
| Land required per well | 640 acres (one square mile) |

High, Mid and Low estimates for well drilling and completion costs were given by Table 2:

| **$ Million** | **Low** | **Mid** | **High** |
|---|---|---|---|
| Barnett | 3.0 | 3.5 | 4.0 |
| Fayetteville | 3.0 | 3.5 | 4.0 |
| Haynesville | 6.5 | 7.5 | 8.5 |
| Marcellus | 3.5 | 4.0 | 4.5 |
| Woodford | 4.5 | 5.0 | 5.5 |

*Table 2: MIT estimates of well drilling and completion costs for various fields.*

High, Mid and Low estimates for lease costs ($/acre) and operating and maintenance costs ($/MMBtu) were given by Table 3.

[23] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011.
[24] "The Future of Natural Gas – An Interdisciplinary MIT Study", 2011, Appendix 2D: Shale Gas Economic Sensitivities.

| Item | Low | Mid | High |
|---|---|---|---|
| Lease ($/acre) | 2,500 | 5,000 | 10,000 |
| Opex ($/MMBtu) | 0.50 | 0.75 | 1.00 |

*Table 3: MIT estimates of lease and operating costs for all fields.*

### *Model Results*

The financial model outputs the probability distribution of the price of gas required for the investment to achieve the cost of capital. Some typical example results from the simulation for the Barnett field are shown in Figures 4 to 6 for 1000 CB iterations. Figure 4 shows the CB input probability distribution function of the Barnett field initial gas production, Figure 5 shows the CB calculated gas price distribution, while Figure 6 shows the average well decline function in the simulation for the Barnett field.

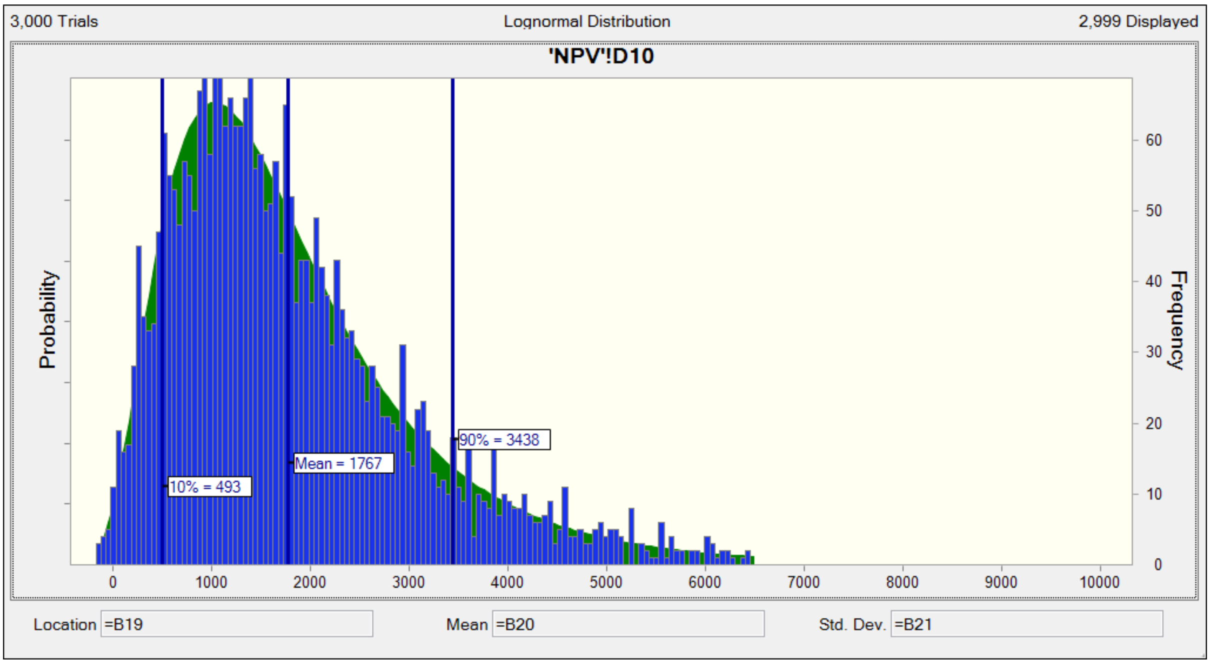


*Figure 4: Input Barnett field initial gas production distribution.*

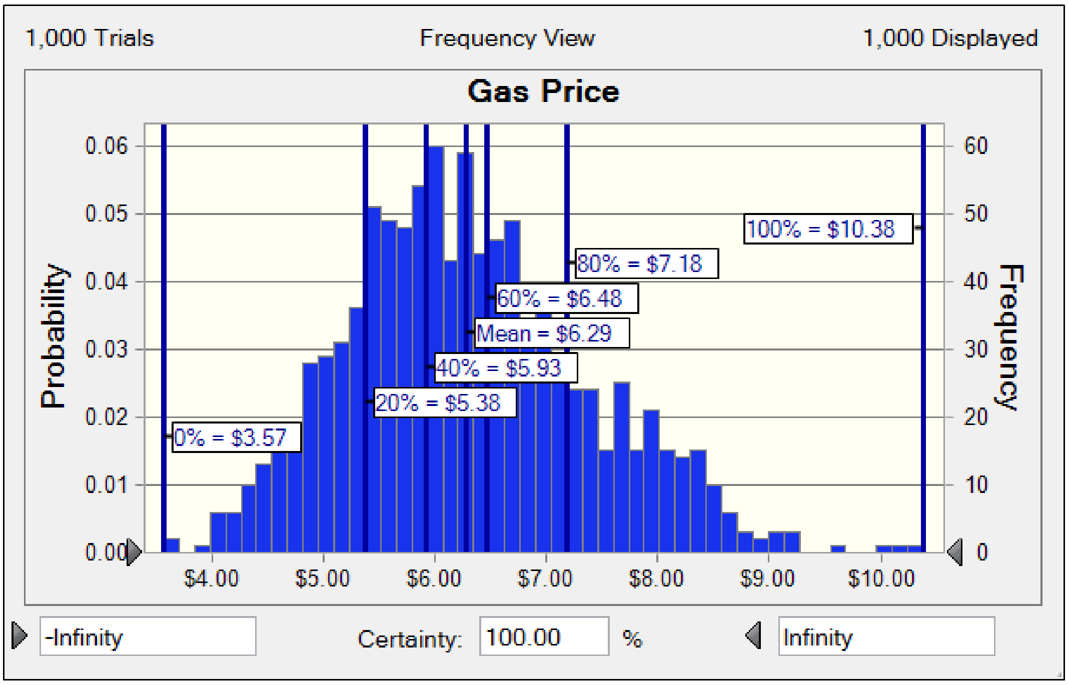


*Figure 5: Predicted required gas price distribution for the Barnett field.*

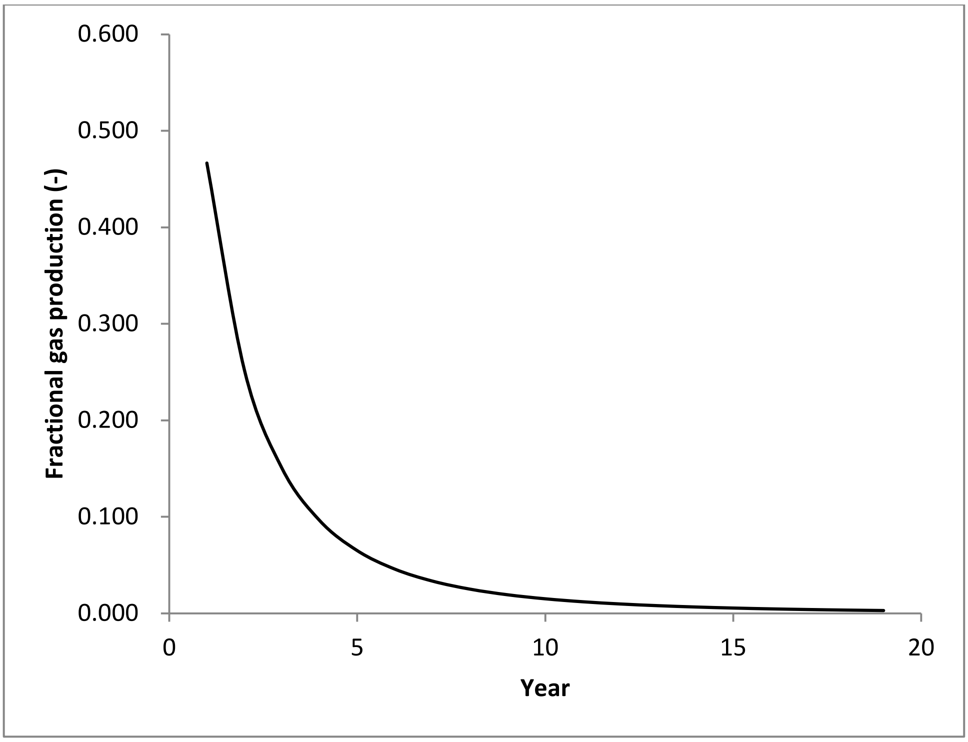


*Figure 6: Well decline function for the Barnett field simulation (average value shown – in the simulation the decline curve varies probabilistically as the parameters $D_i$ and $b$ vary in each CB iteration)*

The calculated prices from the present model are compared with the prices from the MIT study (using the same parameters as described previously) in Table 4. In this table, the calculated gas price is represented by "required gas price" or "RGP" in \$/MMBtu.

| Field | MIT | MIT | THIS WORK |
|---|---|---|---|
| | IP Rate (Mscf/day) | RGP ($/MMBtu) | RGP ($/MMBtu) |
| Barnett | 1,840 | $6.53 | $6.29 |
| Fayetteville | 2,090 | $5.53 | $5.53 |
| Haynesville | 7,880 | $5.12 | $3.22 |
| Marcellus | 3,500 | $4.02 | $3.94 |
| Woodford | 2,530 | $6.34 | $5.64 |

*Table 4: Comparison between MIT "required gas price" (RGP) and those calculated in the present work for a variety of shale gas fields in the USA*

As can be seen from Table 5, most of the gas price predictions from the present work agree reasonably with the MIT study. The main exception is the Haynesville field, where the present study predicts a lower required gas price than the MIT work.

The present model also outputs the range of gas price required in addition to the mean. Table 5 below shows these ranges for the various fields in terms of p50, p20 and p80 required gas prices.

| Field | RGP($/MMBtu) | RGP($/MMBtu) | RGP($/MMBtu) |
|---|---|---|---|
| | p50 | p20 | p80 |
| Barnett | $6.29 | $5.38 | $7.18 |
| Fayetteville | $5.53 | $4.84 | $6.42 |
| Haynesville | $3.22 | $2.86 | $3.55 |
| Marcellus | $3.94 | $3.44 | $4.43 |
| Woodford | $5.64 | $4.88 | $6.35 |

Figure 7 shows a further analysis of the data in the form of a plot of calculated required price *versus* a type of capital intensity parameter: the (*capital cost per well*) divided by the (*initial gas production per well*). A high value of this parameter indicates a field that has a high capital investment intensity, and *vice versa*.

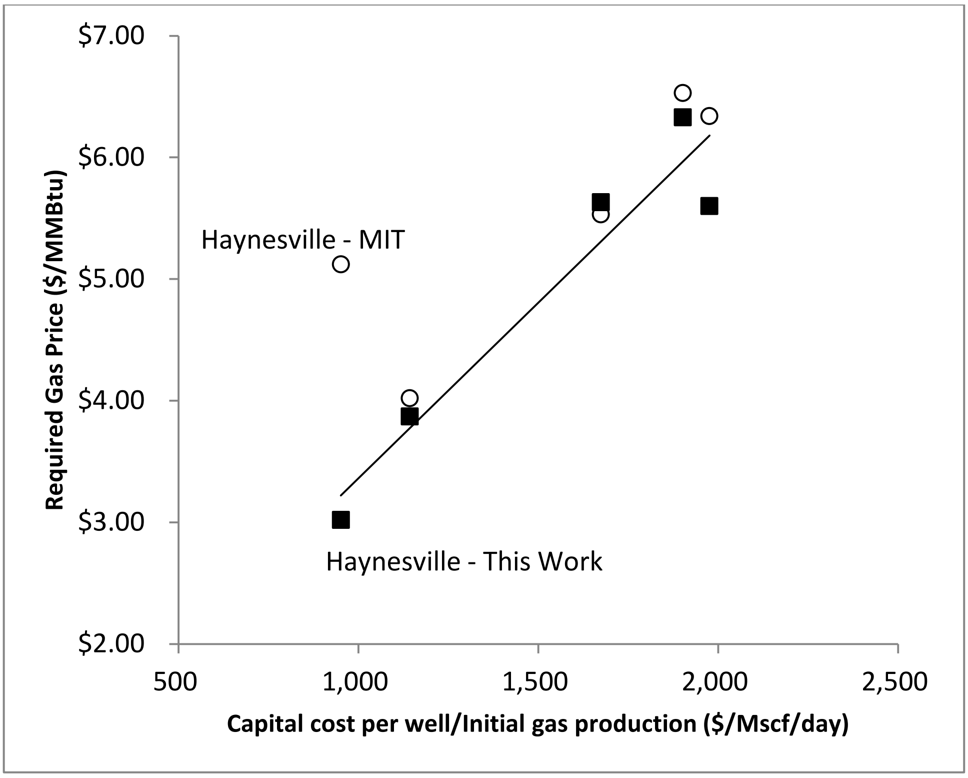


*Figure 7: Plot of required gas price versus capital intensity for both the MIT study and the present work. (Circles represent the MIT data, while filled squares represent the predictions from this work).*

As can be seen from Figure 7, there is a reasonable trend evident between "required gas price" and "capital intensity". The one notable exception is the Haynesville data point from the MIT study, which resides towards the top left-hand side of the plot. The reason for this wayward prediction by MIT is unknown, but possibly related to the form of the initial production probability distribution at the Haynesville field. Notwithstanding the MIT result, as shown in the next paragraph the Haynesville field is in fact one of the lowest cost producers in the USA, and this has been predicted here.

Further confirmation of usefulness of the relative "required gas prices" predicted by the present model can be found through a comparison with a US shale gas cost curve. A curve of this type was presented in an article by Business Spectator on 13th November 2012.[25] In a cost curve graph provided with the article[26], the following relative gas cost order for US shale fields was presented in the cost curve diagram, with the present model "required gas price" predictions also shown in brackets after the name of the field:

> Gas cost < $5/MMBtu in order low to high: Marcellus ($3.94/MMBtu), Haynesville ($3.22/MMBtu), then Fayetteville ($5.53/MMBtu)

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[25] http://www.businessspectator.com.au/bs.nsf/Article/BHP-Billiton-shale-gas-Kloppers-Yeager-Chesapeake-pd20121113ZYRFW?opendocument&src=idp&utm_source=exact&utm_medium=email&utm_content=132270&utm_campaign=kgb&modapt=commentary "BHP's New Shale Swagger", Liddington-Cox A., Business Spectator, November 13th, 2012.

[26] The actual cost curve is not shown here because copyright permission to reproduce the diagram has not yet been obtained.

Gas cost >$5 and < $6/MMBtu in order low to high: Barnett ($6.29/MMBtu), then Woodford ($5.64/MMBtu).

The present model is thus in broad ranking agreement with the published US cost curve, but differs in the detail. It is particularly noteworthy that the two lowest cost producers studied here (Marcellus and Haynesville) and the two highest cost producers (Barnett and Woodford) have been successfully predicted by the present model. This is according to the assumptions made in the present work regarding capital costs and gas production profiles and the data from MIT. With better data, the required gas prices predicted by the model would no doubt come closer to the values reported in this cost curve. The author is also not sure how much liquid petroleum product credits are affecting the data presented in this cost curve, in the context that the present model does not include the financial effect of liquids production.

## *Conclusions*

The model that has been developed by the present work is predicting required gas prices that agree reasonably with published data from the USA. It also seems to show that required price can be correlated with important shale gas well parameters, such as capital intensity. It is, however, very sensitive to some of the input parameters. Not all these parameters have yet been made available to the author, but this situation may change as the project progresses and more data is obtained from the ATSE secretariat or external consultants.

It is clear from the work undertaken so far that the important parameters that control the required gas price are:

- The capital costs of well drilling and completion in the field, including land and infrastructure costs,
- The initial production rate of wells in the field, and the probability distribution of this parameter,
- Royalties and taxes, as well as the fiscal regime and investment incentives of the location in question, and:
- Any credits from co-produced liquids while there is a price differential between gas and liquids.

These parameters vary with geological conditions, land costs, drilling and completion costs, infrastructure required, nature of the fracking strategy, shale gas field location and state fiscal regime, supply-demand conditions, and so on. They will be site and field specific and could be significantly different in Australia *versus* the USA.

The model is sufficiently developed to analyse the required price of gas for shale gas wells, provided appropriate data is available. It could also be modified to include petroleum liquids co-production, provided that the capital and operating costs of this option are known or can be estimated. It remains to apply the model in the Australian context, and this will represent the next stage of the study.

## APPENDIX

### *Probabilistic Parameters in Key Variables*

The probability distributions of all the appropriate variables were defined in the Crystal Ball plug-in package in Microsoft Excel.

Well drilling and completion costs were modelled probabilistically by a normal distribution function with a mean given by the *Mid* values in Table 2 and a standard deviation given by the difference between the *Mid* and the *High* and *Low* values.

Operating costs were modelled probabilistically by a triangular distribution with a most likely value of $0.74/MMBtu and a high and low value of $1.00/MMBtu and $0.50/MMBtu respectively.

Lease costs were modelled probabilistically by a triangular distribution with a most likely value of $5,000/acre and a high and low value of $10,000/acre and $2,500/acre respectively.

The well decline parameter $D_i$ was probabilistically modelled with a normal distribution with a mean of 0.86 and a standard deviation of 0.07 from a curve fit analysis of the reported data[27] and the data in Table 1. $D_i$ was also constrained by $0 < D_i < 1$[28]. The well decline parameter $b$ was probabilistically modelled with a triangular distribution with a most likely value of 0.31, a minimum value of 0.01 and a maximum value of 1.0.

The initial gas flow probability distributions were described by the log-normal distribution shown in Figure 2, with a *mean* of 1,700 Mscf/d, a *standard deviation* of 1,250 Mscf/d and a *location* of -500 Mscf/d for the Barnett field. Other fields were probabilistically modelled by calculating the ratio of the initial Barnett field flow to the other field's initial flow, and then modifying the *mean*, *standard deviation* and *location* in their log-normal distribution according to this ratio.

[27] www.eia.gov/forecasts/.../fig54_data.xls

[28] Cheng Y, Wang Y, McVay D A, Lee W J, "Practical Application of a Probabilistic Approach to Estimate Reserves Using Production Decline Data", SPE Economics and Management, 2010, pp 20.