Perspectives on the valuation of upstream oil and gas interests: An overview

C.R.K. Moore*

1. Introduction

In any business endeavour, quantifying value is important. Investment decisions are made on the basis of the perceived value to be generated. Assets, indeed entire businesses, are bought and sold regularly. Legal and commercial disputes arise for which the appropriate remedy is either compensation or damages, which must be quantified. All these situations require a consistent rational approach in determining value. Valuing upstream oil and gas interests faces particular challenges because of the high probability of failure (in the exploration phase), the extreme ranges of uncertainty in technical performance and the significant differences in other, non-technical, risks.

Appropriate valuation techniques should be theoretically sound and must also take into account the practice in the market and explain observed behaviour. Because of the nature of the assets, historical and current performance is useful only to the extent it allows extrapolation to future performance. The value should be based on the future performance, which is why discounted cash flow (DCF) analysis is not only the most appropriate, but also the most widely used starting point. This paper provides some perspectives on issues surrounding industry approaches to DCF analysis and argues for particular approaches for adjusting the initial results to account for risk.

2. Empirical determination of fair market value

The rights to explore for and produce oil and gas from the subsurface are obtained in the first instance from the host government, with the notable exception of private lands in the US where ownership was vested in the landowner. Such rights are generally not in perpetuity, but terminate after a fixed period of time. Subject to applicable laws, regulations and contractual arrangements between right-holders, these rights may be assigned to third parties. The consideration for the purchase of a participating interest may be cash, an undertaking to pay future costs (either a specified amount or an unlimited amount to cover a specific operation – drilling a well, for example), or rights over a different area. A participating or working interest (WI) is an interest which bears a share of costs and receives a share of revenues, subject to applicable laws and contracts. Other types of interests exist, such as overriding royalties, net profit interests and carried WIs, where the

* Managing Director, Moyes & Co, Inc, 8235 Douglas Avenue, Suite 1221, Dallas, Texas. Moyes & Co, Inc is an independent energy consulting firm which specialises in economic evaluations. cmoore@moyesco.com. Many of the arguments presented here were developed in collaboration with colleagues CP Moyes and PD Patterson. J Durst compiled the crude oil price data. Further information can be found at <http://www.moyesco.com>. The author is grateful to D Johnston for critically reviewing the draft.

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owner does not contribute directly to the costs. All of these interests are traded in a worldwide marketplace.

The details of such transactions are frequently made public. This is especially true of relatively small public companies whose stock exchanges require them to disclose the details of material transactions. With these details, it is generally possible to calculate the cash equivalent of even the most complex farm-in. It should be noted that a promise, for example, to fund 100 per cent of a $120 million exploration programme to earn a 75 per cent WI does not mean that the interest is valued at $120 million. In this case, $90 million of the programme is for the account of the company farming in. The result would be identical if the company farming in pays $30 million in cash to the company farming out. Both companies then pay their own WI shares of the future programme. The cash transaction is thus $30 million to purchase a 75 per cent interest, valuing 100 per cent WI at $40 million.

Where transactions include reserves, companies are often required to file third-party reserves' reports compiled under either standardised or explicit and transparent assumptions. Actual purchase prices may be compared to such evaluations.

Analysis of thousands of such transactions provides actual fair market value (FMV) data for particular interests. It is tempting to use these as comparable sales in valuing other interests. However, extreme caution is required in defining a 'comparable' interest. A checklist for determining what is comparable is daunting (date, location, contractual terms, life cycle stage, geologic risk, reserves and contingent or prospective resources, etc). Indeed it may be argued that the only truly comparable interest is another WI in the same petroleum right, provided that there have been no material economic or technical changes since the prior transaction (and there are no differences in the WIs' rights – both are non-operators). One only has to look at the difference in bids for adjacent tracts in US Gulf of Mexico lease sales to see that values vary significantly over short distances.

Despite this limited applicability in determining absolute value, analysis of comparable transactions provides market information to assist in determining FMV. Normalised metrics (value per acre or value per unit reserves or unit production) are frequently quoted and are useful, both as a reality check on values determined analytically and in determining the relation between FMV and expected present value (EPV). Comparables can also provide other useful informations. They can provide evidence for the premium, if any, being offered for interests with control or a veto (operatorship or a large WI). They can provide evidence of either a premium or a discount for a small WI (both have been observed).[1] Finally, the general terms being offered for comparable farm-ins (such as two-for-one or a third for a quarter) can provide a useful starting point for valuing other exploration opportunities.

[1] A small WI may trade at a discount to a large WI because a small WI owner may have no influence in determining how the project is executed and, especially, when and how money is to be spent. In some circumstances, however, that disadvantage may be more than offset by other advantages. Acquiring a small producing WI may be desirable or necessary to become qualified to acquire properties from a host government or to obtain a tax advantage – an example is discussed in Section 7.

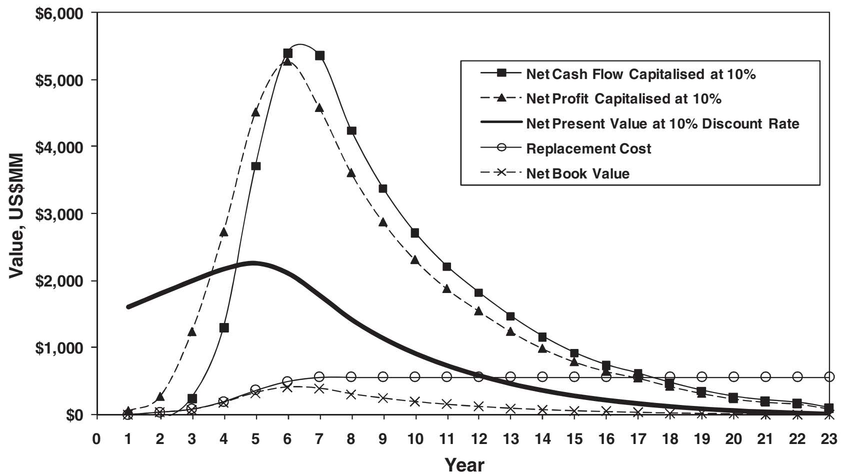

Fig. 1. Profiles of different measures of value through the life cycle of an oil and gas asset.

3. Characteristics of oil and gas interests and their impact on valuation methods

The character of an oil and gas asset changes over its life cycle. Before drilling takes place, its value depends on estimates of its potential to contain commercially viable hydrocarbon accumulations. After a discovery, its value is based upon estimates of its economic performance if the accumulation is developed. After development, its value is based on estimates of how the accumulation will continue to perform. The risk (here, chance of failure) and uncertainty (here, range of quantitative outcomes) are reduced significantly through the life cycle. Nevertheless, an accurate account of its economic performance is not available until it is abandoned.

An important characteristic of oil and many gas fields is that the production naturally declines from some peak value usually reached early in the life of the field. There may be opportunities to accelerate production with additional investment, or to invest in secondary or tertiary recovery. Nevertheless, production will still decline naturally after project implementation. Eventually, it will terminate either because the deposit no longer generates positive cash flow, or the period of the right to produce (the lease, concession, contract, etc) terminates. This has important consequences for the valuation method.

Of course, an individual interest may include numerous individual assets, and may simultaneously include declining mature fields and opportunities for growth (exploration opportunities). Ultimately, however, decline is inevitable.

Valuation techniques based on either replacement cost or net book values are wholly unsuited to the valuation of oil and gas interests as can be seen from Fig. 1.[2] While the

[2] Data are from an actual evaluation. Net cash flow is after taxes and capital expenditures without financing. Net profit is after tax and unit-of-production depreciation based on proved developed reserves. Discount and capitalisation rates reflect weighted average cost of capital (WACC). Note that the chronic mismatch of the shapes of the profiles is not materially affected by the choice of discount rate, accounting method, etc.

amount of sunk costs may affect future revenue streams, sunk costs alone are poor predictors of total future revenues. Similarly, capitalising current year profit or free cash flow should not be used to value oil and gas interests. Their unsuitability should be obvious from the shape of the cash flow profile because of the inevitable post-peak decline in future performance compared to current measures.

4. DCF analysis and EPV

The most widely used and preferred method for valuing oil and gas interests is DCF analysis. This form of analysis was the method preferred by 88 per cent of respondents to the most recent Society of Petroleum Evaluation Engineers' survey.[3] DCF analysis involves forecasting the future costs and revenues to which the interest holder is entitled. Each future year's cash flow is reduced by a discount factor to account for the time-value of money. The sum of these discounted annual cash flows over the life of the project is here called the net present value (NPV). The forecast cash flows are typically obtained from a spreadsheet model or a software package with a model built-in. Input to this model comprises a discount rate, forecasts of oil and gas production schedules, product prices, inflation, exploration and development costs and schedules, operating costs and other costs. All of these forecasts are uncertain, even for producing fields with a long history.

Similar techniques are used for both producing properties and exploratory rights. The approach used to value exploration properties is to carry out DCF analysis of one or more defined prospects. Representative but hypothetical outcomes are modelled, based on the technical assessment of the probable size of the accumulations. The results of these analyses are combined to give the value of the success 'leg'. The discounted cost of an unsuccessful programme, the 'failure leg', is also estimated. The EPV for an exploration prospect is calculated by multiplying the success leg NPV by the probability that a commercial field will be discovered, and subtracting the discounted cost of failure multiplied by the probability of failure.

Note that the term NPV is used not only for individual cash flow analyses, but also for mean values of distributions of present values before incorporating exploration risk. The term EPV is generally restricted to values that incorporate exploration risk. For much of this paper EPV may be taken to mean the risk adjusted present value regardless of whether there is exploration risk (unless the context dictates otherwise).

There are numerous pitfalls and issues in DCF analysis. These are discussed below under the assumption that the analysis is carried out by an unbiased independent expert

[3] Society of Petroleum Evaluation Engineers, *Twenty-Seventh Annual Survey of Economic Parameters Used in Property Evaluation* (SPEE, Houston June 2008) 52pp. This proportion has been growing and is up from 72% in 2000. A total of 156 professionals, 97% of whom are members of SPEE, responded to the survey. The scope of the respondents' experience may be judged from the following statistics. Fifty-two per cent of respondents each had, in the preceding year, valued properties with a total value exceeding US$250 million, and 21% had each valued properties with a total value exceeding US$1 billion. The survey primarily refers to practice in US and Canada, but techniques applied to an unspecified number of international properties are included in the results.

who is familiar with industry practice.[4] It should be noted that the analysis carried out by experts for the two sides in a commercial dispute may not be unbiased, despite being supplied by experts working to appropriate professional and ethical standards. Indeed, one frequently sees duelling experts. As an extreme example, the plaintiff's expert will not argue against the determination of damages of the defendant's expert if it is a higher amount than that suggested by his analysis.

5. Issues in DCF analysis: Subsurface evaluation

The evaluation of geologic risk (chance of success) remains a largely subjective exercise dependent only on the experience of the expert. Success rates may be used to validate subjective assessments. However, this comparison is much like using comparable sales to determine FMV – truly comparable analogue data sets are rarely available.

Estimation of reserves, well and field production performance is subject to significant uncertainty, although the range of uncertainty diminishes substantially through the life cycle of the asset. Techniques of varying sophistication are used to account for this uncertainty, including statistical and analytical techniques, which combine alternative outcomes or cases (from as few as two or more usually three, to as many as several thousands in a computer simulation). Where large numbers of cases are analysed it is customary (and statistically correct) to quote and use the average or mean value (where a single point of reference is required). Where a single case is used, it is customary to use a case representative of the central tendency. Use of probabilistic approaches is increasing, according to the SPEE survey, up from 46 per cent in 2007 to 54 per cent in 2008.[5]

There continues to be some confusion, perhaps even controversy, over the choice of mean or median case in representing the central tendency. This is important because, with a wide range of uncertainty and the skewed nature of the probability distribution, the median may be significantly lower than the mean. The more useful and appropriate measure is the mean, and this is more properly the 'best estimate'. However, the industry standard now equates the best estimate of reserves to Proved plus Probable ('2P') Reserves but defines this as the median value when probabilistic approaches are used.[6] The mean value should be used in valuations, despite this being different from (greater than) the more widely reported and accepted 2P value.

4 An excellent textbook is available: PR Rose, *Risk Analysis and Management of Petroleum Exploration Ventures* (AAPG Methods in Exploration Series, No 12, AAPG, Tulsa 2001) 164pp. This author's personal experience, with particular reference to pitfalls, is available: CRK Moore, 'Exploration Program Evaluation at ARCO International – A Case Study in Techniques and Pitfalls' presented at Geological Society Petroleum Group Risk & Reward Conference, Bath, England, 13–15 May 2001. The proceedings were not published, but the abstract and presentation are available from the author.

5 SPEE, see n 3. Respondents were asked at which stage in the field life was a probabilistic approach most commonly used; 70% said in the pre-drill stage, 20% in the early stages of production, 9% in the middle stages of production and 1% in later stages of production. This is ambiguous, but it is interpreted to mean that the use falls off as the level of uncertainty diminishes throughout the life cycle.

6 See Petroleum Resources Management System, sponsored by Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council and Society of Petroleum Evaluation Engineers [2007], available at <http://www.spe.org>.

This assertion is consistent with the widely reported phenomenon of reserves' growth.[7] If the mean estimate were correct, and remained constant throughout the life cycle of the asset, both the Proved (90th percentile) and 2P (median) reserves must increase as the variance of the distribution is reduced through time. Both converge to the mean at abandonment.

In cases where probabilistic approaches are not employed, particularly in producing fields, three deterministic reserve cases are generally used: Proved, Proved plus Probable (2P) and Proved plus Probable plus Possible (3P). The problem then remains of how to combine these. The most common approach, according to the SPEE survey, is to use reserve adjustment factors.[8] These are fractional multipliers applied to each separate category of reserves. The survey results are reported specifically for those used in acquisition evaluations. The fractions may be thought of in two ways. Firstly, they may incorporate the chance that the reserves do not exist or will not be developed. An alternative view is that the fractions are weights to be used in calculating the mean value, in the same way that Swanson's rule is used as a method of deriving the mean of a lognormal distribution.[9] It is instructive to look at the result if the reserves follow a lognormal distribution and the deterministic reserve cases are similar to their probabilistic equivalents (noting that this is **not** a requirement of the current guidelines). The survey results may be slightly misleading as they are presented as if each factor is independent. Four cases are shown in Fig. 2. The proportion of the true mean value obtained by using the factors to obtain a weighted average is plotted against the ratio of 2P to Proved reserves. This ratio is a function of the variance of the distribution, but is probably easier to relate to than the variance itself. Note that a ratio of unity is where there is no uncertainty and all the reserves are Proved. The results using the Swanson's rule approximation are also shown. Although most fields contain a mix of producing, shut-in, behind pipe and undeveloped reserves, two simple end members are shown. One has only developed producing reserves and the other has only undeveloped reserves. For each case, two sets of Reserve Adjustment Factors have been taken from the survey results – the mean factor for each category, and the most frequently used factor. For developed reserves, the mean factors are 96.4 per cent for Proved, 42.9 per cent for Probable and 30.8 per cent for Possible; the most frequently used factors are, respectively, 100 per cent, 50 per cent and 50 per cent. For undeveloped reserves, the mean factors are, respectively, 62.7 per cent, 34.7 per cent and 30.8 per cent, while the most frequently used factors are 50 per cent, 50 per cent and 0 per cent respectively. Note that the uncertainty of the reserves is likely to be greater before development than after development, and the developed fields are more likely to plot towards the left of the diagram.

7 This is illustrated graphically using United States Geological Survey domestic reserves statistics in Moore, see n 4.

8 SPEE, see n 3. Seventy-seven per cent of respondents report using Reserve Adjustment Factors, 52% as the sole method for accounting for reserves' uncertainty and 27% in conjunction with discount rate adjustments discussed later.

9 Rose, see n 4, Appendix A. For lognormally distributed reserves using the currently accepted probabilistic reserve definitions (see reference at fn 6), Swanson's rule can be re-stated as Reserve Adjustment Factors of 100% for Proved, 70% for Probable and 30% for Possible.

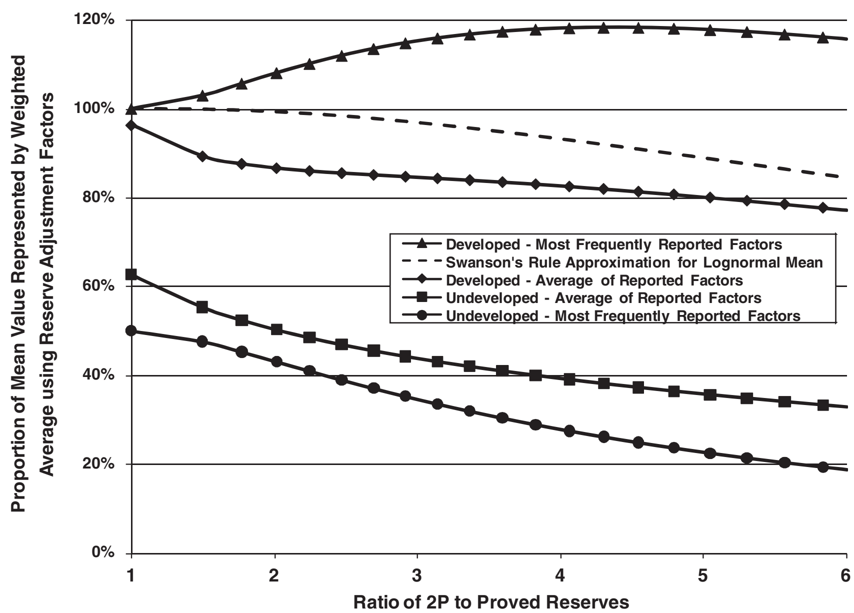

Fig. 2. Weighted averages using common industry reserve adjustment factors for a range of reserves' uncertainty, shown as a proportion of the true mean value for lognormally distributed reserves.

It is not clear what to conclude from this data. It is tempting to suggest that the results for developed reserves are attempts to find the mean. The reduction in calculated value at high variance is because the approximation of the mean is deteriorating (as it does with Swanson's rule). If so, the results for undeveloped reserves can be explained to be similar to (parallel to) the results for developed reserves, but undeveloped reserves are reduced by the chance that the development will occur.

An alternative view is that the discounts to the mean are real and intentional, and they represent an increasing aversion to paying full value for an asset as both its risk (here, chance of not occurring) and uncertainty increases. If so, some evaluators may be surprised to learn that the most frequently used Reserve Adjustment Factors for producing reserves yield a value that represents a substantial premium to the implied mean value. Moreover, the premium increases with increasing uncertainty across the range of variance associated with producing fields.

The use of statistical and analytical techniques where a mean value is calculated is preferred. However, FMV is, at least in part, determined according to what is done by those supplying the buyers with evaluations. Practice among those evaluators cannot be ignored.

6. Issues in DCF analysis: Operational and development plans, costs and schedules

As a general rule, operational and development plans, costs and schedules in such analyses represent best-in-class scenarios, executed flawlessly and trouble-free. This is not necessarily an inappropriate initial analysis, but it is misleading to regard this as the expected case. Delays and cost overruns are far more likely than project acceleration or cost savings if the base case is best-in-class performance.[10] The probability distribution about the plan is therefore severely skewed towards value reduction, but this is rarely incorporated into the analysis. It is believed that this systematic bias is an agency effect, due to experts' experience providing scenarios in internal capital allocation competitions in earlier corporate careers. A better approach is to include allowances for expected delays and cost increases (other than inflation, treated separately).

A second issue is whether the plan is consistent with a business plan, either that of the right-holder or that of a hypothetical 'prudent operator'. The most flagrant abuse of this requirement is valuing exploration portfolios as if all wells will be drilled, immediately and simultaneously. In practice, a prudent business plan would recognise operating and budgetary constraints, rig availability and other practical limits, and incorporate some limit on the number of wells to be drilled based on an appropriate dry hole tolerance.

7. Issues in DCF analysis: Fiscal terms

It is assumed that the DCF model accurately takes into account even the most complex fiscal terms. Where the particular interest is not 'ring-fenced', its value to the owner may be affected by fiscal positions generated by its other interests. This is usually an issue with tax/royalty regimes, but may also apply for cost recovery under production sharing arrangements. However, the value in the marketplace will be determined by the potential buyer's position. Indeed it may be argued that FMV will be determined by buyers able to take advantage of tax efficiencies, since they will offer the most, other things being equal.

A well-known example is used to illustrate this. The 1983 UK budget removed the ring fence for the deduction of exploration for Petroleum Revenue Tax (PRT), then at a 75 per cent rate.[11] This dramatic reduction in failure leg exploration costs for those paying PRT gave those firms a significant competitive advantage. This resulted in the marketing by British Petroleum (BP) of PRT-paying Forties Field units, which enabled even the smaller explorers to acquire tax efficiency. From then on, it was unrealistic to determine the FMV of exploration opportunities in the UK North Sea without recognising the PRT benefit, even if it was not available to the owner of a particular interest.

This is also an interesting example of a situation where a very small WI was valued at a premium to the entire interest. Without that premium, there would have been no incentive for BP to sell.

8. Issues in DCF analysis: Leverage

It is assumed that there is agreement that the DCF value should be based on free cash flows after tax excluding the effect of debt financing. This ignores the capital structure of the company, which is taken care of in the discount rate (see below). However, there are some situations where it may be appropriate to include benefits from debt financing.

[10] For example, systematic underestimation of expected well costs was documented at ARCO International. See Moore, n 4.
[11] For a summary of this episode, see D Johnston, 'Higher prices, lower government take?' (Fall 2004) PAFMJ.

Interest expense is cost recoverable under some production sharing contracts. Moreover, this may extend to parent company loans to subsidiaries at arm's length rates, even if the parent company does not incur actual interest costs on any external debt. In this and similar cases, the interest cost benefit should be included (but not the drawdown or repayment of principal).

9. Issues in DCF analysis: Surface risk

'Surface risk' is used here to describe the variety of political, environmental, logistical, commercial or bureaucratic issues that may impact project performance, particularly by causing delays. It includes low probability but catastrophic events such as expropriation or natural disaster. It is synonymous with 'country risk', which covers the same issues but implies, incorrectly, a uniform application throughout a particular country. It can be argued that the US Gulf of Mexico shelf is relatively free of surface risk, due to the extensive infrastructure, efficient spot markets for oil and natural gas, widespread availability of services and people, and a transparent and well-established business framework. Nevertheless, it is not risk-free, as demonstrated by the ravages of recent hurricane seasons and threats of a windfall profit tax. Similarly, the UK North Sea shares many of the positive characteristics of the Gulf of Mexico, and is less prone to catastrophic natural disasters, but has historically had an extremely unstable fiscal regime for oil and gas companies. Surface risk differences within countries may be illustrated in Nigeria, where deep water offshore developments do not share the operating difficulties onshore in parts of the Niger Delta.

It would be preferable to incorporate these risks into the DCF analysis by adjusting the cash flows. Some elements may be incorporated into the development plans where there is historical data to support project performance forecasts, such as elapsed time for development projects. However, most surface risk remains unpredictable, with respect to both timing and scope. In these circumstances, an alternative approach is required.

There have been a number of attempts to use an adjustment to the discount rate to account for surface risk. Objections to using increased discount rates to account for any type of risk are discussed below. The empirical observation that the FMV in a 'risky' place is less than the FMV of a similar project in a less risky place does not by itself imply the use of a higher discount rate. The same is true while considering the use of different discount rates for different reserve categories.

10. Issues in DCF analysis: Price forecasts

There does not appear to be a consensus on incorporating price uncertainty into valuations. In contrast to the statistical techniques used to manage subsurface uncertainty, price uncertainty is frequently treated by preparing arbitrary 'upside' and 'downside' sensitivities. While apparently useful to those making investment decisions, these sensitivities cannot be incorporated into the valuation unless they are associated with some probability. If the expected price case is used, the result will be the required mean NPV. However, the variance of the result will be understated if price uncertainty is not quantified.

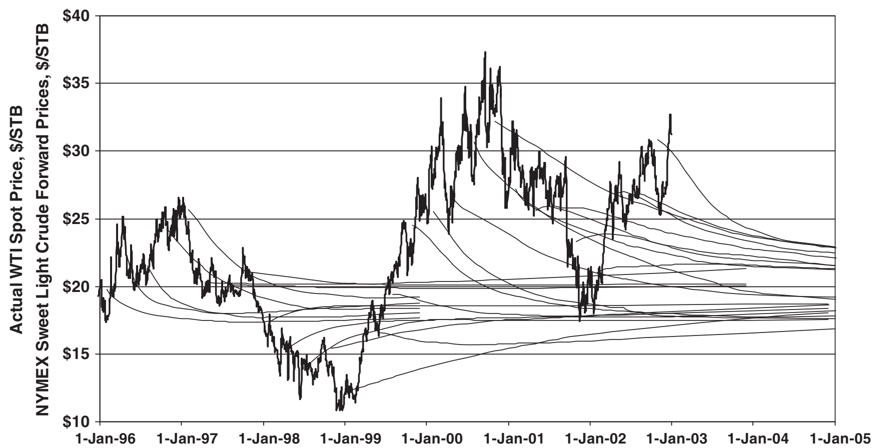

Fig. 3. Daily Spot WTI with NYMEX Sweet Light Crude forward contract strips at the start of each quarter, January 1996 to December 2002.

Much has been written about the poor track record of price forecasts, from the 'hockey sticks' of the early 1980s to sub-$20 flat-real-for-ever in the early 2000s. It is important to note that for market value purposes, it does not matter whether these predictions are ultimately correct or woefully short-sighted. What matters is the consensus in the market as this determines market values.

About five years ago, there was a trend of companies moving from arbitrary corporate planning forecasts to the use of forward price strips such as New York Mercantile Exchange (NYMEX) Sweet Light Crude forward contracts based on West Texas Intermediate (WTI) crude oil. Hedging had become more common such that companies were often realizing strip prices. There appeared to be consensus about long-term prices, as the end of the forward strip tended to regress towards a mean.

In Fig. 3, the thicker spiky line shows the WTI spot price. Thin lines show the NYMEX forward strip for the first day of each quarter. Note the tendency of the NYMEX futures curves to be rising when the spot price is low, and falling when the spot price is high. Longest dated NYMEX prices were confined to a relatively narrow band. The consistency of the longest dated futures prices until 2003 is shown in Fig. 4.[12]

More recent history has demonstrated that there is no longer the same stability in the futures strip (Fig. 4). A gradual rise in the long-term price started in 2003, and accelerated in 2005. The longest dated futures have more recently mirrored the volatility in spot prices. It is argued that the volatility in long-term price outlook is real and is accompanied therefore by real volatility in asset values. If true, the effective date of a valuation becomes very important. The forecast (future strip) from that date should be used even if current forecasts are substantially different.

[12] The longest dated contract is always for December, resulting in a reduction through the year from about 7 years to about 6 years for the longest date. Two additional years were added in 2007, so the latest quotes go out about 9 years reducing to about 8 years.

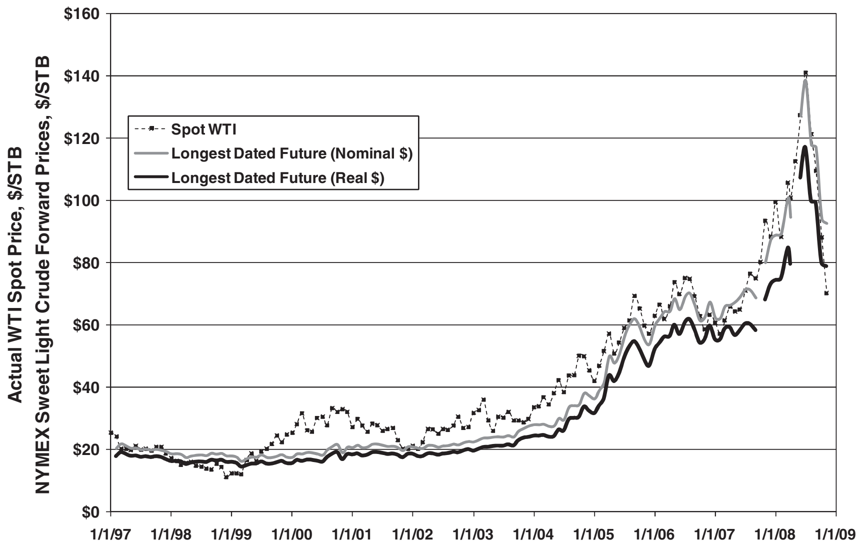

Fig. 4. Spot WTI and that day's longest dated NYMEX Future Prices, for the first business day of each month. Nominal $ is quoted price, 'Real' $ are deflated using 2 per cent annual inflation for the period to the longest date.

Beyond the strip, it is argued that a neutral and justifiable approach is to maintain prices flat in real terms. Thus, prices beyond the strip are escalated at the assumed US$ inflation rate. As an aside, it is interesting to note that despite record oil prices in 2008, for the most part the NYMEX strip continued to show declining nominal oil prices for the duration of the strip. This backwardation is counter-intuitive if the cause of the record prices was fear of future demand significantly outstripping supply. Indeed since mid-1999, the longest dated future contract has consistently implied falling real prices.

11. Issues in DCF analysis: Inflation and foreign exchange rates

The effect of inflation on product prices is assumed to be incorporated into the price forecast expressed in money of the day. Estimates of future costs are assumed to be provided in current money, and so an inflation adjustment is required. The alternative (deflating revenues and discounting at a real rather than a nominal discount rate) still requires an explicit inflation forecast. Explicit inflation forecasts may (with appropriate justification) vary through time, in which case a single real discount rate cannot be employed. One area where this may be important enough to incorporate is the observation that significant real increases in oil and gas prices may be accompanied by significant real increases in the cost of oil field services and equipment. The converse may be true for real price decreases. This dampens the impact of price swings in both upside and downside cases.

Foreign exchange and local inflation rates are required if there are significant elements of the cash flow denominated in a local currency. Two approaches are possible. With no change in purchasing power, future exchange rates are determined by differential inflation. There will be no difference between the results of carrying out the analysis in local currency with local inflation and, say, US$ and US$ inflation. No local exchange rate/inflation forecast is required. The second approach (recognising future changes in purchasing power) requires a forecast.

12. Issues in DCF analysis: Discount rates

It is assumed that any project adds value to a firm if the internal rate of return (IRR) exceeds the firm's weighted average cost of capital (WACC). In these circumstances, the NPV calculated from DCF analysis using the WACC as the discount rate will be positive. This sum equals the surplus cash generated over and above the return on capital required, adjusted for its time value. A firm is supposed to be indifferent in carrying out the project or having the NPV in the bank today and investing in different projects. Note that the cash flows are not assumed to be risk-free in this approach. The perceived risk is priced into the cost of equity component of the WACC. The return on equity required by investors in a firm with one single risky asset should completely account for all risks associated with the cash flows. The value obtained by discounting at the WACC that includes that return on equity should require no further adjustment for risk.

Although theoretically sound, there are practical difficulties in determining WACC, particularly for private companies. A more intractable problem is that the capital structure of a company may reasonably be expected to vary through the asset life cycle. It is unlikely that a pure exploration company will have access to corporate debt. If successful, however, it will undoubtedly attempt to finance a development with as much debt as the quality of the asset allows.

However, it is argued that the WACC of the owner is not relevant in the determination of FMV. What matters is the discount rate used by the market. This will be either the discount rate used by the highest bidder (the lowest discount rate in the market, other things being equal) or some generally accepted discount rate used throughout the industry.

A consensus industry standard is appropriate. The recent SPEE survey results showed that 71 per cent of respondents used a cost-of-capital discount rate in the range 9 per cent to 11 per cent, with an average of 10.4 per cent.[13] It appears that 10 per cent is the rate most frequently quoted since (a) US companies are required to report Standardized Measures of Oil and Gas (SMOG) values to the Securities Exchange Commission (SEC) using a discount rate of 10 per cent[14] and (b) it approximates to US companies' after federal income tax WACC.[15]

The practice of using a higher discount rate to account for risk is widespread but not pervasive; 48 per cent of SPEE respondents used a higher Risk Adjusted Discount Rate (RADR) to account for 'a profit or expected rate of return for the buyer, and any risk/uncertainty

[13] SPEE, see n 3.

[14] This is not an endorsement of SEC reporting guidelines. The prohibition, until recently, on disclosing Probable Reserves, was illogical and potentially misleading. Firms make investment decisions and base valuations on the estimates of central tendency (see discussions in other sections).

[15] An average of 10.1% for the period 1985–2004 is reported by Miller based on an evolving group of public companies (40 in 2004): RJ Miller, *California Oil and Gas Property Transactions 1983 through 2004* (Report for WSPA and CIPA, December 2005) online at <http://www.rjmanda.com/pdf/CIPA2005.pdf>.

that the evaluator may choose to impute to the asset'.[16] There are two variations to this approach, used about equally. One group used the RADR to account for all risks, including reserves' uncertainty. The second group used the RADR for all risks excluding reserves' uncertainty, for which they used reserve adjustment factors. These are fractional multipliers used to reduce the reserves or value for different categories of reserves. Their use was explored in the earlier section on subsurface evaluation. The mean RADR for the first group was 12.9 per cent. The mean RADR for the second group was higher, 15.3 per cent, despite the fact that this group had already applied a fractional multiplier to reduce the values. This illogical result is attributed to the arbitrary nature of this approach.

There are several problems with increasing the discount rate to account for risk. Firstly, the relation between discount rate and present value is nonlinear and the method has some intuitively inappropriate effects. Secondly, attempts to quantify the higher rate are entirely arbitrary. This is apparent not only from the RADR survey data, but also from attempts to justify the rates in the literature.[17] Thirdly, it does not provide a value system consistent with behaviour.

Fig. 5 is a plot of NPV *v* discount rate for success cases for three large gas projects. Measured by the NPV at a 10 per cent discount rate (NPV10), Project A has the highest NPV10 but the lowest IRR (the discount rate at which NPV equals zero). The development is to supply an LNG facility and is characterised by a long delay to development sanction and a long, flat production profile. Project B is an onshore development in a spot market. The production profile has a rapid rise to a much higher plateau rate (as a proportion of reserves) and then a very rapid decline. Moreover, early cash flow covers much of the incremental development costs. The NPV10 of Project B is 5 per cent lower than that of Project A, but the IRR is dramatically higher (off-scale on the plot at 130 per cent). This very large value is a reminder of a more general problem with IRR as a measure. The return on investment of a project only equals the IRR if all the proceeds are re-invested at that rate. If, for example, the excess cash flow is re-invested at the marginal rate for other projects (the WACC), the resulting growth rate of return is 31 per cent.[18] Project C is a hypothetical offshore project, identical to Project B except that the development drilling and most of the spending on facilities are accelerated to occur prior to production startup. The resulting NPV10 is lowered, but only by 9 per cent, but the IRR drops dramatically to 35 per cent, and the growth rate of return drops, although less dramatically, to 17 per cent.

At a 15 per cent discount rate, Project A's NPV has dropped by two-thirds, but those of Projects B and C have dropped by much less, 33 per cent for Project A and 39 per cent

[16] SPEE, see n 3. Respondents were also asked what factors affect their choice of RADR. They were allowed to choose from a list that included Profit, Reserve Risk, Price Uncertainty, Expense Uncertainty, Unidentified Reserve Potential, Mechanical Risk, Political/Regulatory Uncertainty and Others. Excluding Reserve Risk, no single factor was considered by more than 40% of respondents, implying a lack of consensus over what should be used to determine the RADR.

[17] See for example, JB Gustavson, 'Valuation of International Oil and Gas Properties' *SPE 52957, Proceedings 1999 SPE Hydrocarbon Economics and Evaluation Symposium*, pp 145–51. Note that much of the empirical justification hinges on explaining the apparent high discount rates implied by the ratios of FMV to NPV, which can be explained without recourse to discount rates.

[18] This measure is similar to that described by Capen *et al* but compounds to the end of the project, rather than being compounded to a fixed future time. See EC Capen, RV Clapp and WW Phelps, 'Growth rate – a rate-of-return measure of investment efficiency' (May 1976) JPT 531–43.

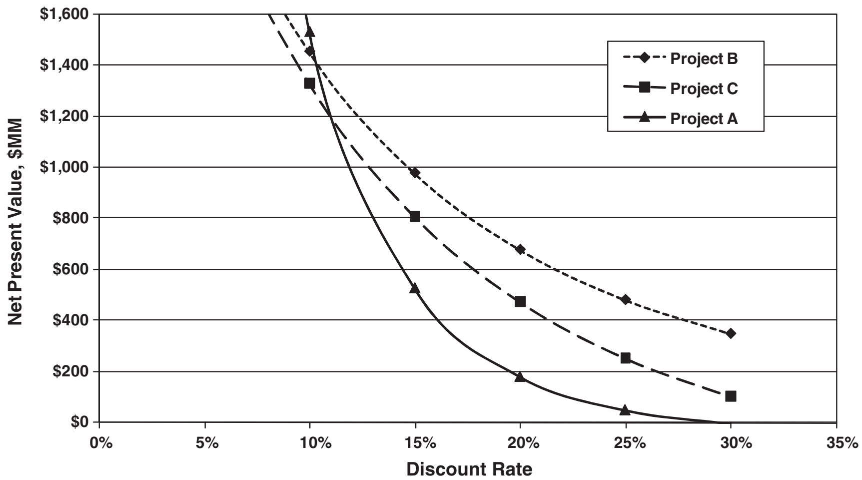

Fig. 5. NPV *v* Discount Rate for three success case gas field developments.

for Project C. If the 15 per cent discount rate is being used to account for comparable levels of, for example, surface risk, the impact should affect each comparably. Here, it affects A much more than B or C. This is because the impact is a function of the particular shape of the cash flow profile, a characteristic that has little to do with surface risk or subsurface risk. Indeed it may be argued that the subsurface risk in Project A is likely to be less than that in Project B because of unusually high level of reserves' certainty required to support or finance an LNG project. The use of a higher discount rate simply introduces a bias against long-lived projects, which is not only unwarranted, but also counter-productive.[19] The disparity increases with discount rate – note that at a 30 per cent discount rate, Project A has a negative value (its IRR is 27 per cent), Project B's NPV30 is 24 per cent of its NPV10 and Project C's NPV30 is 8 per cent of its NPV10.

The proponents of the use of higher discount rates argue that some decision-makers make decisions based on higher discount rates and this logically dictates valuing them at the higher discount rate. This is misleading. In the author's experience, decision-makers expect, based on history, projects to underperform against evaluation scenarios. They attempt to compensate by setting higher hurdle rates. A much better approach is to demand more realistic projections for project timing, costs and technical performance. Note that there is no evidence that the same decision-makers are attempting to incorporate surface risk by using higher hurdle rates.

13. The Disparity between EPV and FMV

Despite the issues discussed above, present values derived from DCF analysis are widely accepted evaluation yardsticks. Experts' detailed reports containing these analyses, usually with precision that cannot be justified by the underlying uncertainties, are required and

[19] Indeed Rose argues that **any** conventional DCF analysis technique is biased against precisely those "large new fields having long-term stable production potential – just the kind of fields that build companies ... ", p 50: PR Rose, see n 4.

accepted by stock exchanges and tax authorities as well as arbitration panels and courts. However, these reports, at least for stock exchanges, generally feature a prominent disclaimer that the results do not represent an opinion as to the market value of the property.

Analysis of transactions involving exploration and production assets shows a substantial difference between FMV and EPV, usually a discount and frequently a large discount. This may be explained as the application of a fractional multiplier, either to the underlying cash flows or the EPV itself or the use of a higher discount rate.

An early quantitative approach to valuing interests at substantially less than EPV came from competitive bidding analysis.[20] Because of the significant uncertainties in exploration risk and resource estimation, different evaluators will often generate substantially different results. It may be assumed that the true value is best estimated by the average of a set of independent unbiased estimates. In any competitive bid situation, therefore, the highest bid will be an overestimate compared to the true value. Competitive bidding models were developed to determine an appropriate fraction of the EPV to bid to avoid 'winner's curse'. The limitation of this approach is that it presumes that the true EPV is the true value to the owner.

Any valuation system must be able to account for observed behaviour. A particular characteristic of oil and gas company behaviour is the frequency with which companies deliberately limit their WI to less than 100 per cent. The reduced risk of total failure from participating in five identical but independent prospects with a 20 per cent WI compared to the one with 100 per cent WI is quantifiable (17 per cent *v* 70 per cent for a 30 per cent chance of success). However, the EPV of both holdings are identical. For any given single asset, maximum value occurs at 100 per cent WI. Moreover, the same is true if the EPV is reduced by an arbitrary fractional multiplier or a higher discount rate.

The behaviour is due to risk aversion. An intuitively acceptable technique that explains these behaviours is available from preference theory. Risk adjusted values (RAVs), derived from present value calculations using an exponential utility function, provide a value system that incorporates risk aversion.[21] The method also predicts a WI that maximises value.[22] This is frequently, but not always, less than 100 per cent.

14. RAV at optimum working interest

The calculation of RAV requires an additional parameter, the firm's risk tolerance (RT).

Fig. 6 illustrates some of the intuitively appealing aspects of RAV. RAV equals EPV only at infinite RT, where firms are truly indifferent to a total loss. In contrast, a firm with

[20] EC Capen, RV Clapp & WM Campbell, 'Competitive bidding in high-risk situations' (June 1971) JPT 641–53.

[21] The original application to the oil and gas industry appears to be that of JM Cozzolino, 'A Simplified Utility Framework for the Analysis of Financial Risk' *SPE 6359,* in *Proceedings SPE Hydrocarbon Economics and Evaluation Symposium*, Dallas, 21–22 February 1977. For a mathematical overview of current applications see CRK Moore, CP Moyes & PD Patterson, 'The Use of Risk Adjusted Values in Exploration Portfolio Management' *SPE 94586, presented at SPE Hydrocarbon Economics and Evaluation Symposium*, Dallas, 3–5 April 2005. For a more thorough review, including a suggestion for a modification to the Cozzolino approach, see I Lerche & JA MacKay, *Economic Risk in Hydrocarbon Exploration* (Academic Press, San Diego 1999) 404pp.

[22] See JA Mackay, 'Utilizing Risk Tolerance To Optimize Working Interest' *SPE 30043,* in *Proceedings SPE Hydrocarbon Economics and Evaluation Symposium*, Dallas, 26–28 March 1995, pp 103–9. See also Moore *et al*, ibid.

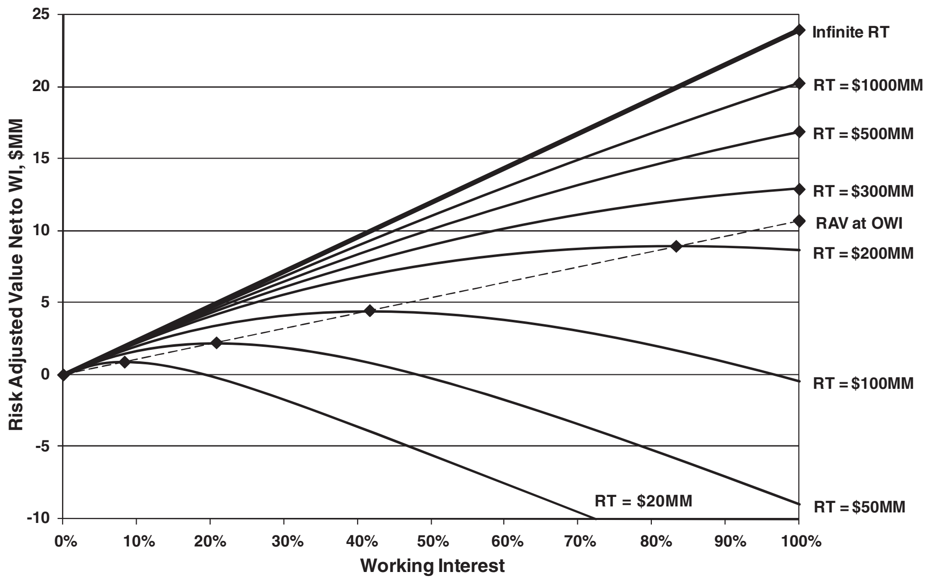

Fig. 6. RAV *v* WI for a variety of RTs.

zero RT will value assets based solely on the potential loss, however likely. In between, the optimum working interest (OWI), the interest at which RAV is a maximum, increases with increasing RT up to the practical limit at 100 per cent WI. Note the straight line relation between RAV at OWI and WI. The gross RAV of the project is, therefore, identical to all participants holding their respective OWI. Of course, this presupposes that the firms' evaluations are identical, which would be unusual, but the property is nevertheless important. Partnerships would be unstable if partners' values differed significantly.

A feature of early work on applying RAV to oil and gas interests focused on defining the firm's RT, which proved to be difficult or at least inconsistent. This is, with hindsight, intuitive. Firms have different levels of enthusiasm for different types of projects independent of any particular project EPV. This is reflected in substantial variation in RT depending on the nature of the project and its location.[23] This is partly to compensate for surface risk, and partly to reflect the firm's strategic focus (preferred types and locations of projects). It explains why large firms will totally ignore small opportunities that would clearly be attractive if the only consideration was the firm's financial RT. By setting rigorous strategic requirements to concentrate on specific core areas or core activities, the firm is setting a much higher RT for those activities. Conversely, the behaviour of some large firms in some theatres is consistent with an extremely low RT.

A powerful feature of the method is that if it is assumed that the firm's WI is at OWI, both RT and RAV may be determined. It may be argued that firms do not fine-tune their WIs, and factors beyond their control contribute to the initial WI level. This is true, but the error in the assumption is believed to be within the accuracy of value determinations

[23] See Moore *et al*, ibid.

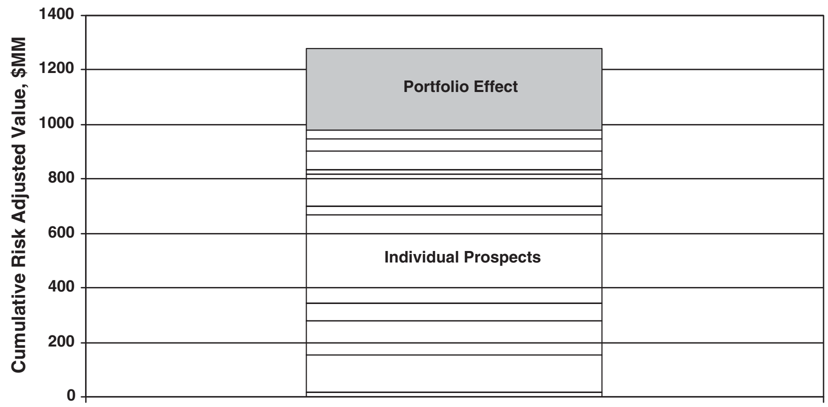

Fig. 7. Cumulative RAV of a portfolio of prospects. Gray area indicates additional value above the sum of the individual prospects.

generally. When WIs become significantly different from OWI, firms acquire or divest interests. Indeed the corollary is that acquisitions and divestments of interests are driven entirely by changes in OWI (as EPV evolves or following a change in strategic direction and thus RT).

A valid criticism of using RAV as a proxy for FMV is that the method is not in widespread use. Instead firms rely on the experience of the decision-makers to determine the preferred WI and the appropriate discount to EPV. This author's limited experience has been that these decisions and valuations are nevertheless consistent with calculated RAV, in line with other research in this area.[24]

15. Portfolio effect

A further benefit of the RAV approach is that it can be used to explain the value of a portfolio. The EPV of a portfolio is the sum of the EPV of its constituent projects. However, the RAV of a portfolio is greater than the RAV of the constituents. This is because the value is dominated by the product of the chance of failure and the cost of failure. The overall chance of total failure of the portfolio is much less than the chance of failure of each component, while the overall cost of failure remains constant.

The method is approximate because it requires a single overall RT. The example shown in Fig. 7 uses the average RT for all portfolio members. It can be argued that the value of an individual project should be calculated as the difference between the portfolio with the project and the portfolio without the project, rather than the stand-alone project RAV. However, the difference may not be significant when compared with the uncertainty in the underlying analysis.

[24] See Moore, n 4, for data from ARCO International, and Moore *et al*, ibid, for a more general discussion of other research on this subject.

16. Problems with an RAV approach

The traditional application of RAV, assumed above, is based on a simple lottery with all successful outcomes represented by the mean success case. This is a simplification but is appropriate where risk averse behaviour is dominated by the desire to avoid total loss, as in a dry hole in exploration. Setting the chance of failure to zero in this formulation yields an RAV equal to the EPV.

The failure of this measure to account for the underlying uncertainty (the underlying probability distribution of the value of successful outcomes) has been raised[25] but has not attracted any attention, as far as the author is aware. However, it becomes crucial if the concept of RAV is to be extended to projects where there is considerable uncertainty but no significant likelihood of total loss.

A very simple approach is to assume a normal distribution of value. The RAV is then the EPV minus a discount equal to the variance of the underlying distribution divided by twice the RT.[26] The formula is simple yet accurate, but its use is limited to situations where a normal distribution is realistic, possibly approached only by very mature fields. Development projects are usually characterised by lognormal distributions. Work continues on the search for a simple yet robust approach for these more complex distributions.

A further difficulty with this expanded approach is that the risk discount is independent of WI, and so RT cannot be determined from the data. Guidelines for RT have been suggested for exploration projects.[27] At present the author is unaware of any systematic studies relating the ratio of FMV to NPV to the underlying variance for development and production assets. This would provide the basis for guidelines. Since RT varies between groups of exploration projects within a firm, it may be expected to vary between groups of assets in later life cycle stages. There may also be differences between classes of projects based on their position in the life cycle.

17. Application of EPV, RAV and FMV in expert determinations

If EPV and RAV can be determined, it raises some interesting questions about their application, particularly in expert determinations. The author is not a legal expert and this is not intended to be a legal opinion.

For a fair trade to occur, the Buyer's RAV must be greater than or equal to the Seller's RAV. Since an actual transaction takes place, the FMV is the Buyer's RAV and the Buyer's RT may be determined. The Seller's RAV and RT remain undetermined but are largely of academic interest. For identical EPV, the Seller's RT must be less than the Buyer's.

One may be required to determine FMV where there is no actual fair trade. This might be for valuation purposes for an intra-company transfer or as part of dispute resolution. The expert determines the 'Seller's' RAV and the Seller's RT is also determined. However,

[25] See Moore *et al*, ibid.

[26] Ibid, for a discussion of the results of incorporating underlying uncertainty distributions into the traditional RAV approach. The normal distribution result given here is attributed to Raiffa in MR Walls and JS Dyer, 'Ex Ante Risk Propensity and Firm Performance: A Study of the Petroleum Exploration Industry' (1992) Working Paper 92-9, Department of Mineral Economics, Colorado School of Mines.

[27] See Moore *et al*, ibid.

the hypothetical Buyer's RAV is likely to differ from the Seller's RAV. From here, there are perhaps two valid approaches.

The first argument is that the FMV is the Seller's RAV (since the latter is the minimum Buyer's RAV). Any incremental value is speculative because there is no direct evidence that a Buyer with a higher RT exists in the market. It is noted that there is no 'winner's curse' overbid possibility because the existence of a Buyer with an EPV exceeding that of the expert is also speculative. This argument offers the advantage that the FMV is not subjective because the RAV is determined explicitly. However, it fails to take into account the market information.

The second argument is that the FMV is different from the Seller's RAV and the issue to be determined is the Buyer's RT (since the expert's EPV applies equally to both). Although this appears speculative, it mimics the determination of FMV using comparable transactions. Comparable transactions will have been priced according to the RT of active buyers in the market, and may provide compelling evidence of Buyers' RT. A weaker argument in the absence of comparable transaction data is to estimate RT based on the nature of the project and the likely range of Buyers' RT using guidelines. In either case, it should be noted that the FMV could be less than the Seller's RAV if the Seller's RT is the highest in the market. Thus, the likelihood is that the FMV so determined exceeds the Seller's RAV, but this is not necessarily so. This is an improvement on the previous approach which ignored the market, but becomes more subjective as the availability of good market data diminishes.

Finally, it should be noted that the EPV is the best estimate of future economic performance taking into account the time value of money. FMV (whether or not it is determined using the RAV approach) represents the exchange of a risky future cash flow for certain cash today. To the extent that firms are risk averse, FMV will therefore be at a discount, and perhaps a substantial discount, to EPV. It is not necessarily appropriate to equate lost or damaged economic performance with FMV. If an EPV is required, several of the FMV assumptions may require revision (WACC, business plan considerations). In the determination of FMV, these were taken to be those of the market, not the owner. Experts require careful instruction on the proper analysis to undertake, based on a legal opinion of what is appropriate.