VALUING PUD RESERVES: A PRACTICAL APPLICATION OF REAL OPTION TECHNIQUES

*by John McCormack, Stern Stewart & Co., and Gordon Sick, University of Calgary**

The oil industry was among the first of the large industries both to adopt discounted cash flow methods in valuing assets and projects. Discounted cash flow (DCF) tools are fundamental to engineering and financial analysis in the oil industry. They are well understood by managers and generally provide accurate valuations of developed hydrocarbon reserves. Unfortunately, DCF techniques systematically undervalue undeveloped reserves. Moreover, they may encourage premature development of certain reserves, and may also fail to identify important risk management opportunities.

Managers in the oil industry have long been aware that the market value of individual oil properties, not to mention entire E&P companies, is usually greater than the value of their discounted cash flows.[1] This is particularly true in cases where there are significant quantities of undeveloped reserves. For this reason, E&P managers have often been willing to pay a premium above a DCF value for some undefinable "upside" associated with undeveloped reserves. Unfortunately, the analytical discipline usually imposed by the DCF method is lost when managers value properties or companies on the basis of rules-of-thumb or simple intuition.

Real option models address these shortcomings. Though more complex than traditional DCF analysis, real option models provide a far more complete picture of not only reserve values but also the drivers of that value. Proven undeveloped reserves (PUDs) lend themselves to real option analysis because owners of PUDs have the right, but not the obligation, to develop those reserves in the future, so that the total value of a PUD includes both a DCF value plus some additional option or "volatility" value. There is a sound economic reason to assess undeveloped reserves at more than their DCF value, and real options models provide the means to do so.

---

*Computational routines for this analysis were developed by Dan Calistrate.

1. See, for example, James L. Paddock, Daniel R. Siegel and James L. Smith, "Option Valuation of Claims on Real Assets: The Case of Offshore Petroleum Leases," *Quarterly Journal of Economics*, V. 103 #3, (1988)

TABLE 1
PUDS VIEWED AS REAL OPTIONS

Call option on shares of stock	Proven Undeveloped Reserve (PUD)
Underlying share price	DCF value of reserve when developed
Strike price	Capital Exp. needed to develop reserve
Time to expiration	Time remaining on mineral lease
Dividend	Value decay resulting from waiting
Time value of money (Treasury rate)	Time value of money (Treasury rate)
Volatility of share price	Volatility of developed reserve value
In-the-money value (share price minus strike price)	NPV of project

PUDS VIEWED AS REAL OPTIONS

A simple example illustrates this option value. Consider undeveloped natural gas reserves that would have a DCF value of $1 million when developed but that would also require $1 million to develop now. According to traditional DCF analysis, this is a zero-NPV project. The traditional analysis would tell us, correctly, that developing this reserve now would provide no benefits. That would not mean, however, that these undeveloped reserves have zero economic value. If, as is usually the case, the owner of the reserves has years to wait before losing the right to develop them, then these reserves have option value.

Real options have value because conditions may change that would increase the value of the right to develop the reserves in the future. For example, if gas prices rise in the future, then the NPV of the project would become positive. But because the PUD owner has no obligation to develop the reserves, he would not do so when the NPV is negative. Zero NPV really becomes the lower bound of the range of ultimate values of these reserves if they are managed as real options. While the lower bound may be zero, the upper bound has no inherent limit. This is what gives economic value to a real option like a PUD even if immediate development would result in a zero or negative NPV project.

The difficulty, of course, lies in applying standard option valuation methods to undeveloped hydrocarbon reserves. The Black-Scholes option pricing model, first published in 1973, provides an analytical solution to the value of a call option on a share of stock. The value is a function of the underlying share price, the strike price, the annual dividend, the Treasury bill rate, the expected volatility of the underlying shares (where volatility is measured as the annualized standard deviation of share price movements), and the time to expiration or life of the option.

As shown in Table 1, the inputs to valuing a call option on a share of stock and a real option such as a PUD are analogous. Engineers know what future volumes to expect from a PUD and can see the relevant futures prices in the marketplace. This provides them with the value of the developed reserves, which corresponds to the underlying share price in a standard call option. Engineers also know the cost of development, which corresponds to the strike price. The value erosion suffered by PUD owners who hold off on developing the reserves corresponds to the dividends paid on a share of stock. The NPV of the developed reserves will fluctuate depending upon other factors. This fluctuation or volatility corresponds to the volatility of the stock price in a standard financial option. Finally, the life of the lease corresponds to the life of an option.

Important Differences between PUDs and Stock Options

Given these analogous elements, it might seem that we could simply plug the appropriate figures into a Black-Scholes option pricing model and calculate the value of the real option. Unfortunately, these analogies are imprecise. There are important differences between a financial option and a real option such as a PUD. Among the most important differences are the following:

1. Exercising a call option on a stock provides the owner with underlying shares, which have a single, readily observable market price. Drilling a PUD results in a series of cash flows, usually over a period of years. To be sure, these cash flows have a present value, but oil company managers must estimate this. This calculation is complicated because the cash flows will fluctuate with oil and gas prices. Expected hydrocarbon futures prices are different from spot prices and lie along a "futures curve" that changes shape from time to

time. In November of 2000, for example, the futures market for oil was in "backwardation," meaning that prices for delivery in the current month were higher than for delivery further in the future. The first-month futures contract traded for $35 per barrel while oil for delivery in December of 2006 was trading for $20 per barrel. During early 1998, on the other hand, oil futures prices for delivery in the distant future were significantly higher than for immediate delivery. The natural gas curve is even more complicated. Not only can year-on-year gas prices be either upward sloping or downward sloping, but there are seasonal variations within each year as well. Generally, futures prices for winter months are higher than for summer months.

2. The cash flows expected from the development of a PUD change over time not only because prices expected in the future change over time but also because the hydrocarbon volumes a field is expected to produce will also vary. Generally, production volumes peak upon initial development of an oil or gas field and then decline steadily thereafter. This means that the economic life of an oil field is at least somewhat "front-loaded." The more front-loaded is a field (i.e., the shorter the duration of production), the more volatile is the net present value of the developed reserves because, as we discuss later, the mean-reversion of petroleum prices causes a decline in long-term volatility.

3. While the shares of a company may be listed on more than one stock exchange, there is only one market price. Otherwise, arbitrageurs would be able to earn riskless profits by simultaneously buying on one exchange and selling on another. Unlike share prices, however, oil and gas prices do differ according to geographical delivery point. For example, there are significant differences between the price of gas at Henry Hub (in south Louisiana) and at AECO (in Alberta). These "basis relationships" may also shift over time.

4. The strike price of a call on shares of stock or a futures contract is a given. However, the strike price of a PUD—that is, the expected present value of development costs—is uncertain. Moreover, because the prices of drilling rigs and oilfield services tend to rise as oil and gas prices increase, the strike price of a PUD is often correlated with the value of the developed project. PUD owners, of course, would prefer that the costs of development *not* rise when oil and gas prices jump—in which case the NPV of a project would increase very significantly with an increase in hydrocarbon prices. At the same time, the PUD owner would also prefer to see development costs fall when oil and gas prices fall. Here option pricing offers an interesting insight: Although a strong positive correlation between hydrocarbon prices and extraction costs creates a natural hedge for the PUD owner, such a hedge may end up reducing overall value by reducing the volatility that is an important source of real option value for the PUD. The stronger the correlation between the value of a developed property and the costs of development, the lower the option value inherent in the PUD.

5. The value of a financial option is driven in part by the expected volatility of the underlying stock (or by the expected volatility of a futures contract for a specific delivery month). But the volatility of the value of a developed oil or gas project is not the same as the volatility of either spot prices or of a particular futures contract. Like hydrocarbon futures prices themselves, the expected volatilities of particular futures contracts are strongly "mean-reverting." This means that the expected volatility of an oil and gas project is influenced by the expected volatility of prices all along the futures curve. Additionally, the "operational leverage" resulting from operational costs increases the volatility of the project's cash flows.

6. Exercise of a financial option results in immediate ownership of the underlying assets. By contrast, a decision to convert a PUD into a PDP leads to a drilling and completion process that takes time.

7. Stock option models use a risk-free discount rate (the Treasury rate) because they compute the value of the option relative to the underlying. This is often called "risk-neutral pricing"; it takes advantage of the fact that the stock is already priced in the market. PUDs, on the other hand, are options on future cash flows that may be correlated with the stock market. To the extent that cash flow components such as petroleum prices or drilling costs are correlated with the stock market index, a risk premium must be incorporated in the real options model to adjust for the change in value. This means that the risk-neutral probability of changes in drilling costs and petroleum prices must be adjusted to incorporate the risk premium. As a result, the risk-neutral expectation becomes a certainty-equivalent, which is appropriately discounted at the risk-free rate.

DEVELOPING A MODEL TO VALUE PUDs

Stern Stewart has developed a specialized model for the XYZ Company to use in evaluating its extensive portfolio of PUD drilling opportunities. The following features were most salient:

1. The model recognizes the relevant forward curves for oil and gas from the listed futures and options markets (with appropriate delivery point and physical basis adjustments). It accomplishes this by applying a mean-reverting random process to the current spot (i.e. near-month futures) price that drifts (or reverts) towards a long-term mean price. Any sufficiently long-dated futures price (for example, the six-year NYMEX WTI futures price) approaches the long-term price. If the spot price is above the long-term mean, then the futures price curve declines towards the long-term mean.[2] If the spot price is below the long-term mean, the futures price curve tends to drift upward towards the long-term mean. The "strength of mean reversion" refers to the rate at which this reversion occurs and thus is impounded in the curvature (shape) of the current market futures or forward curve. It also determines the "half-life" of a random price deviation from the long-term mean. Stern Stewart found the half-life of gas and oil price deviations to be approximately one year.

2. The model recognizes seasonal variations in gas prices as well. This is particularly important for wells that produce large volumes at first and then experience sharp declines in production. The "right" price is always the price that XYZ could get in the marketplace at any one time. In order to ensure consistency across XYZ Petroleum, Stern Stewart strongly recommended that these price parameters be established at the corporate level as a matter of company policy. Other well- or project-specific parameters can be established by analysts on a case-by-case basis.

3. The model recognizes that while some development costs will be nearly certain, other costs will vary. Uncertain development costs will vary with both hydrocarbon prices and other economic factors such as inflation. The model allows XYZ to assume that some development costs will rise over time in line with inflation, while some may actually be expected to fall, for example, because of advances in technology. Other uncertain costs, such as drilling costs, will be volatile (i.e. have their own probability distribution just as commodity prices do) and will be positively correlated with hydrocarbon prices over time.

4. The model requires engineers and analysts to input appropriate "time to build" periods between the decision to drill a well and the start of production.

5. Because PUDs are options on future cash flows rather than on a share of stock with a current market, the model allows the user to input a risk premium to reflect the systematic risk of the project. To make this as meaningful as possible to the typical analyst, this was characterized in terms of a premium above the risk-free rate of return. However, the risk premium was implemented as an adjustment to the risk-neutral probability in a manner consistent with the Capital Asset Pricing Model. If the cash flows from an oil or gas field are correlated with returns from the stock market, then those cash flows have a systematic risk component (i.e. a positive Beta) and should command a risk premium. The present value of those cash flows would, of course, be lower.

Most of the inputs to the model depend on either the judgment of the engineer (underlying volumes, costs, production decline rates, time to build, and so forth) or on factors clearly observable in markets, such as future hydrocarbon prices and implied volatilities. Because the correlation between certain drilling costs and commodity prices is not observable in markets, that parameter had to be estimated from historical data.

SURPRISING RESULTS FROM THE DRILLING COST STUDY

A team of analysts from XYZ set about examining a wealth of drilling cost data from the period 1987-1999. Much of the company's drilling had taken place in a particular region in the continental U.S. where the gas was trapped in fractures rather than

2. If there is a positive market risk premium in the petroleum prices, the long term futures price will trend towards a value below the long-term mean to reward speculators who go long a premium for bearing the commodity price risk. In practice, the futures price curve does not provide enough information to precisely calculate the risk premium, so it is often convenient to set this value to zero unless there is other evidence of a risk premium. Chen, Roll and Ross studied which macro-economic factors command a risk premium and found that petroleum price risk commands no risk premium in North American markets. This is likely because the North American stock markets contain both producers (petroleum companies) of energy and consumers of energy (e.g. airlines, railroads and trucking companies), so that the net exposure of the typical well-diversified investor to energy prices is already hedged. (See Nai-Fu Chen, Richard Roll and Stephen A. Ross, "Economic forces and the stock market," *Journal of Business*, v 59(3) (1986).

porous rock. In such cases, developed wells tend to produce modest volumes of natural gas and to decline quickly. Horizontal drilling is used in order to expose as much of the well bore as possible to the producing formation, but this requires precise engineering and geophysical technology.

Because of the short duration of these wells, the volatility of the value of to-be-developed reserves was high. On the other hand, managerial intuition and anecdotal evidence suggested that drilling costs rose and fell nearly in tandem with commodity prices. If this had been the case, then the real option component of value in PUDs would be quite modest.

To our surprise, there was little evidence of a positive correlation between drilling costs (measured as a drilling rig day rate or as a cost per drilling foot) and oil and gas prices. While not prepared to conclude that there is no relationship at all, we do feel confident in saying that the correlation appears weak enough that the real option value in PUDs is significant.

How could managerial intuition have been so inaccurate? Several factors may account for this. Managers may have been overly conscious of a loose, general correlation between hydrocarbon prices and posted rig day rates. To be sure, rig day rates often rise after commodity prices have increased. And such rig rates often remain relatively high until increased drilling demand leads to another round of drilling rig construction. Nevertheless, there are considerable lags between increases in commodity prices and increases in rig rates, and there are unpublished discounts from daily rig rates that appear only after the drilling is complete and costs are analyzed. This means that short duration PUDs of this sort can be very valuable to oil companies that can exploit their PUDs quickly.

The particular circumstances of wells tend to reduce the correlation as well. Some wells are deeper than others and require more expensive rigs. Different parts of an area may be drilled at different times and may therefore face different problems and crew quality. Moreover, a re-entry well may have a different cost structure (just to get the bit to the bottom) than a grassroots well, on a per day basis.

While not strongly correlated with commodity prices, drilling costs are themselves quite volatile. The annualized volatility of the drilling day rate was found to be about 30% over the period. This volatility is another very important source of PUD real option value.

Importantly, we also found no evidence that drilling costs and the S&P 500 were correlated. This meant that the "beta" was close enough to zero so that no premium on top of the risk-free rate was warranted. This is yet another source of real option value in PUDs.

CALCULATING THE VALUE OF A PUD

The calculations regarding a single well serve to illustrate how much real option value a PUD contains. XYZ decided to drill a 21,000 foot (measured depth) horizontal well at the end of 1999. The well was "spudded" early in the first quarter of the year and completed before the end of the quarter. The capital expenditure required was $920,000 and the present value of the cash flows from that investment was $1,108,000. The net present value (calculated on a DCF basis) was the difference between the two figures, or $188,000.

Because the NPV was positive, traditional theory and practice held that XYZ should immediately drill the well. If the right to drill the well was a valuable real option, however, then some amount of option value would be surrendered through exercise of the option (i.e., the decision to drill). If the real option value was trivial, then drilling the well was almost certainly sensible. If, on the other hand, the option value was significant, then the right decision would have been to wait.

We assumed that $610,000 of the $920,000 of drilling costs was uncertain and subject to a random variation with a volatility of 25% (a conservative underestimate of our observed 30% volatility). The remaining $310,000 in costs was assumed to be certain. Commodity futures prices and volatilities were taken from NYMEX data at the end of 1999 when the decision to drill was made. We then calculated the total economic value of that drilling opportunity to have been $364,000. Of this, $188,000 was the NPV captured by the DCF calculation. The other $176,000 represented volatility value.[3] This was clearly a very significant figure.

3. About half of the volatility value was due to random fluctuations in gas prices and half was due to the cyclic variation in gas prices that was predictible from the futures curve.

E&P companies are valued for their reserves. These reserves have both DCF and real option components. The market value of the vast majority of E&P companies is greater than can be accounted for through DCF means, implying that the market pays for real option value as well. By drilling this well, XYZ may actually have reduced its shareholders' wealth. It is almost certain that an opportunity was forfeited.

It is also extremely important to note that this calculation is not made with the benefit of hindsight. Natural gas prices have indeed risen sharply over the past year and we now know that waiting would have produced better results. The key point is that the results of this analysis are based on conditions that were observable in the commodity futures and options markets during the fourth quarter of 1999!

IMPLICATIONS

PUDs are a rich source of option value for E&P companies. In order to extract this value, however, companies must manage them as a portfolio of real options. To do this, managers must have, and be able to use, appropriate real option models as well as the traditional DCF tools. This will require additional managerial education and a general appreciation of real option concepts at the senior management and board of director level.

Managers may inadvertently destroy shareholder wealth by investing in apparently positive NPV projects. Very often, the right thing to do is to wait. This is quite counterintuitive to many managers in the industry. Engineers, in particular, like to be able to point to tangible, physical evidence of their labors. Real options may not be easy to point to, but they are very real economically. Companies need to able to recognize, create, and manage them.

Oil and gas companies can create real options. Every PUD has embedded within it some sort of real option. This value can be increased in a variety of ways. The ability to drill, complete, and produce from some PUDs more quickly than others is a source of wealth creation. Companies that can make their drilling programs more flexible are better able to capture the opportunities provided by seasonality in natural gas prices and by hydrocarbon price volatility generally. The value added through this kind of flexibility can be estimated, or at least approximated, using modified option pricing models.

No company will be able to exploit its real option potential without a financial management system that recognizes them. A forward-looking measure of wealth creation is absolutely essential to such a system. Quite often, delaying development and volumetric production will be the right thing to do. The vast majority of performance measurement metrics in place in the industry today will penalize managers for choosing to delay. Few companies have any way of recognizing, let alone rewarding, managers and teams that create and preserve option value. Incorporating real option valuation methods can help.

■ JOHN McCORMACK

is Senior Vice President of Stern Stewart in charge of the firm's energy consulting practice.

■ GORDON SICK

is Professor of Finance at the University of Calgary in Alberta.