company's cumulative deal repertoire is valued, structured, and balanced from the beginning of a company's evolution and development.

Discussion and Conclusion

The historical deal evaluated in this case study was a preclinical, product-licensing deal for a biopharmaceutical with one major therapeutic indication. For collaborative deal structures containing licensing fees, R&D funding, milestone payments, and royalties, each deal component has definable expected values, variances, and widely varying risk characteristics. Alternative deal structures were developed and optimized, all of which had different expected returns and risk levels with the primary risk measure being the CV of cash-flow present values. Thus, nearly any biomedical collaborative deal with the types of financial terms described here can be quantitatively valued, structured, and optimized using financial models, Monte Carlo analysis, stochastic optimization, real options, and portfolio theory.

During this study, the author was at a considerable disadvantage because the historical deal valued and optimized here had already been signed, and he was not present during the negotiation process. Therefore, the author had to make a large number of assumptions when restructuring the financial terms of the agreement. Considering these limitations, this case is not about what is appropriate in the comparative financial terms for a biomedical licensing deal and what is not; rather, the data described here are valuable in showing the quantitative influence of different deal structures on the overall valuation of a biomedical collaborative agreement, and most importantly on the level of overall deal risk, as well as the risk of the individual deal components. The most effective approach using this technique is to work with a negotiator during the development and due diligence, and through the closing process of a collaborative agreement. During this time, data should be continually gathered and the financial models refined as negotiations and due diligence proceed.

CASE STUDY: OIL AND GAS EXPLORATION AND PRODUCTION

This case study was contributed by Steve Hoye. Steve is an independent business consultant with more than 23 years of oil and gas industry experience, specializing in Monte Carlo simulation for the oil and gas industry. Starting with a bachelor of science degree from Purdue University in 1980, he served as a geophysicist with Texaco in Houston, Denver, and Midland, Texas, before earning the MBA degree from the University of Denver in 1997. Since then, Steve has held leadership roles with Texaco as the midcontinent

BU technology team leader, and as asset team manager in Texaco's Permian Basin business unit, before starting his consultancy in 2002. Steve can be reached at steve@hoyeconsultinggroup.com.

The oil and gas industry is an excellent place to examine and discuss techniques for analyzing risk. The basic business model discussed involves making investments in land rights, geologic data, drilling (services and hardware), and human expertise in return for a stream of oil or gas production that can be sold at a profit. This model is beset with multiple, significant risk factors that determine the resulting project's profitability, including:

- *Dry-Hole Risk*. Investing drilling dollars with no resulting revenue from oil or gas because none is found in the penetrated geologic formation.
- *Drilling Risk*. High drilling costs can often ruin a project's profitability. Although companies do their best to estimate them accurately, unforeseeable geological or mechanical difficulties can cause significant variability in actual costs.
- *Production Risk*. Even when oil or gas reservoirs are discovered by drilling, there is a high probability that point estimates of the size and recoverability of the hydrocarbon reserves over time are wrong.
- *Price Risk*. Along with the cyclical nature of the oil and gas industry, product prices can also vary unexpectedly during significant political events such as war in the Middle East, overproduction and cheating by the OPEC cartel, interruptions in supply such as large refinery fires, labor strikes, or political uprisings in large producing nations (e.g., Venezuela in 2002), and changes in world demand.
- *Political Risk*. Significant amounts of the world's hydrocarbon reserves are controlled by nations with unstable governments. Companies that invest in projects in these countries take significant risks that the governments and leaders with whom they have signed contracts will no longer be in power when earned revenue streams should be shared contractually. In many well-documented cases, corporate investments in property, plants, and equipment (PPE) are simply nationalized by local governments, leaving companies without revenue or the equipment and facilities that they built to earn that revenue.

Oil and gas investments generally are very capital-intensive, often making these risks more than just of passing interest. Business units and entire companies stake their survival on their ability to properly account for these risks as they apportion their capital budgets in a manner that ensures value to their stakeholders. To underline the importance of risk management in the industry, many large oil companies commission high-level corporate panels of experts to review and endorse risk assessments done across all of their business units for large capital projects. These reviews attempt to ensure consistency of risk assessment across departments and divisions that are often under pressure to make their investment portfolios look attractive to corporate leadership as they compete for capital.

Monte Carlo simulation is a preferred approach to the evaluation of the multiple, complex risk factors in the model we discuss. Because of the inherent complexity of these risk factors and their interactions, deterministic solutions are not practical, and point forecasts are of limited use and, at worst, are misleading. In contrast, Monte Carlo simulation is ideal for economic evaluations under these circumstances. Domain experts can individually quantify and describe the project risks associated with their areas of expertise without having to define their overall effect on project economics.[1] Cash-flow models that integrate the diverse risk assumptions for each of the prospect team's experts are relatively straightforward to construct and analyze. Most importantly, the resulting predictions of performance do not result in a simple single-point estimate of the profitability of a given oil and gas prospect. Instead, they provide management with a spectrum of possible outcomes and their related probabilities. Best of all, Monte Carlo simulation provides estimates of the sensitivities of their investment outcomes to the critical assumptions in their models, allowing them to focus money and people on the critical factors that will determine whether they meet the financial goals defined in their business plans. Ultimately, Monte Carlo simulation becomes a project management tool that decreases risk while increasing profits.

In this case study, we explore a practical model of an oil-drilling prospect, taking into account many of the risk factors described earlier. While the model is hypothetical, the general parameters we use are consistent with those encountered drilling in a mature, oil-rich basin in the United States (e.g., Permian Basin of West Texas) in terms of the risk factors and related revenues and expenses. This model is of greater interest as a framework and approach than it is as an evaluation of any particular drilling prospect. Its value is in demonstrating the approach to quantifying important risk assumptions in an oil prospect using Monte Carlo simulation, and analyzing their effects on the profitability forecasts of the project. The techniques described herein are extensible to many other styles and types of oil and gas prospects.

Cash-Flow Model

The model was constructed using Risk Simulator, which provides all of the necessary Monte Carlo simulation tools as an easy-to-use, comprehensive add-in to Microsoft Excel. The model simulates the drilling outcome as being a dry-hole or an oil discovery using dry-hole risk factors for the particular geologic formation and basin. Drilling, seismic, and land-lease costs are incurred whether the well is dry or a discovery. If the well is a discovery, a revenue stream is computed for the produced oil over time using assumptions for product price, and for the oil production rate as it declines over time from its initial value. Expenses are deducted for royalty payments to landowners, operating costs associated with producing the oil, and severance taxes levied by states on the produced oil. Finally, the resulting net cash flows are discounted at the weighted average cost of capital (WACC) for the firm and summed to a net present value (NPV) for the project. Each of these sections of the model is now discussed in more detail.

Dry-Hole Risk

Companies often have proprietary schemes for quantifying the risk associated with not finding any oil or gas in their drilled well. In general, though, there are four primary and independent conditions that must all be encountered in order for hydrocarbons to be found by the drill bit:

1. *Hydrocarbons* must be present.
2. A *reservoir* must be developed in the rock formation to hold the hydrocarbons.
3. An impermeable *seal* must be available to trap the hydrocarbons in the reservoir and prevent them from migrating somewhere else.
4. A *structure* or *closure* must be present that will cause the hydrocarbons (sealed in the reservoir) to pool in a field where the drill bit will penetrate.

Because these four factors are independent and must each be true in order for hydrocarbons to be encountered by the drill bit (and a dry hole to be avoided), the probability of a producing well is defined as:

$$P_{\text{Producing Well}} = P_{\text{Hydrocarbons}} \times P_{\text{Reservoir}} \times P_{\text{Seal}} \times P_{\text{Structure}}$$

Figure 7.11 shows the model section labeled “Dry-Hole Risk,” along with the probability distributions for each factor’s Monte Carlo assumption. While a project team most often describes each of these factors as a single-point estimate, other methods are sometimes used to quantify these risks. The most effective process the author has witnessed involved the presentation of the geological, geophysical, and engineering factors by the prospect team to a group of expert peers with wide experience in the proposed area. Thes peer experts then rated each of the risk factors. The resulting distribution of risk factors often appeared near-normally distributed, with strong central tendencies and symmetrical tails. This approach was very amenable

Dry-Hole Risk

Risk Factor	Prob. of Success	Mean	Stdev	Min	Max
Hydrocarbons	89.7%	99.0%	5.0%	0	100%
Structure	89.7%	100.0%	0.0%	0	100%
Reservoir	89.7%	75.0%	10.0%	0	100%
Seal	89.7%	100.0%	0.0%	0	100%
Net Producing Well Prob.:	**64.8%**				
Producing Well [0=no,1=yes]	1				

FIGURE 7.11 Dry-hole risk.

to Monte Carlo simulation. It highlighted those factors where there was general agreement about risk and brought the riskiest factors to the foreground where they were examined and specifically addressed.

Accordingly, the assumptions regarding dry-hole risk in this model reflect a relatively low risk profile.[2] Each of the four risk factor assumptions in Figure 7.11 (dark shaded area) are described as normally distributed variables, with the mean and standard deviations for each distribution to the right of the assumption fields. The ranges of these normal distributions are confined and truncated between the *min* and *max* fields, and random samples for any simulation trial outside this range are ignored as unrealistic.

As described earlier, the *Net Producing Well Probability* field in the model corresponds to the product of the four previously described risk factors. These four risk factors are drawn as random samples from their respective normal distributions for each trial or iteration of the simulation. Finally, as each iteration of the Monte Carlo simulation is conducted, the field labeled *Producing Well* generates a random number between zero and one to determine if that simulation resulted in a discovery of oil or a dry hole. If the random number is less than the *Net Producing Well Probability*, it is a producing well and shows the number one. Conversely, if the random number is greater than the *Net Producing Well Probability*, the simulated well is a dry hole and shows zero.

Production Risk

A multiyear stream of oil can be characterized as an initial oil production rate (measured in barrels of oil per day, BOPD), followed by a decline in production rates as the natural reservoir energy and volumes are depleted over time. Reservoir engineers can characterize production declines using a wide array of mathematical models, choosing those that most closely match the geology and producing characteristics of the reservoir. Our hypothetical production stream is described with two parameters:

1. *IP*. The initial production rate tested from the drilled well.
2. *Decline Rate*. An exponentially declining production rate that describes the annual decrease in production from the beginning of the year to the end of the same year. Production rates in BOPD for our model are calculated by:

$$\text{Rate}_{\text{Year End}} = (1 - \text{Decline Rate}) \times \text{Rate}_{\text{Year Begin}}$$

Yearly production volumes in barrels of oil are approximated as:

$$\text{Oil Volume}_{\text{Year}} = 365 \times (\text{Rate}_{\text{Year Begin}} + \text{Rate}_{\text{Year End}})/2$$

For Monte Carlo simulation, our model represents the IPs with a lognormal distribution with a mean of 441 BOPD and a standard deviation of 165 BOPD. The decline rate was modeled with a uniform probability of occurrence between 15 percent and 28 percent. To add interest and realism to our hypothetical model, we incorporated an additional constraint in the production model that simulates a situation that might occur for a particular reservoir where higher IPs imply that the production decline rate will be higher. This constraint is implemented by imposing a correlation coefficient of 0.60 between the IP and decline rate assumptions that are drawn from their respective distributions during each trial of the simulation.

The production and operating expense sections of the model are shown in Figure 7.12. Although only the first 3 years are shown, the model accounts for up to 25 years of production. However, when production declines below the economic limit,[3] it will be zeroed for that year and every subsequent year, ending the producing life of the well. As shown, the IP is assumed

		End of Year:			
	Decline Rate	**0**	**1**	**2**	**3**
BOPD	21.5%	442	347	272	214
Net BBLS / Yr			143,866	112,924	88,636
Price / BBl			$ 20.14	$ 20.14	$ 20.14
Net Revenue Interest	77.4%		77.4%	77.4%	77.4%
Revenue			**$ 2,242,311**	**$ 1,760,035**	**$ 1,381,487**
Operating Costs [$/Barrel]	$ 4.80		$ (690,558)	$ (542,033)	$ (425,453)
Severance Taxes [$]	6.0%	rate	$ (134,539)	$ (105,602)	$ (82,889)
Net Sales			$ 1,417,214	$ 1,112,400	$ 873,145

FIGURE 7.12 Decline rate.

to occur at the end of Year 0, with the first full year of production accounted for at the end of Year 1.

Revenue Section

Revenues from the model flow literally from the sale of the oil production computed earlier. Again there are two assumptions in our model that represent risks in our prospect:

1. *Price*. Over the past 10 years, oil prices have varied from $13.63/barrel in 1998 to nearly $30/barrel in 2000.[4] Consistent with the data, our model assumes a normal price distribution with a mean of $20.14 and a standard deviation of $4.43/barrel.
2. *Net Revenue Interest*. Oil companies must purchase leases from mineral interest holders. Along with paying cash to retain the drilling and production rights to a property for a specified time period, the lessee also generally retains some percentage of the oil revenue produced in the form of a royalty. The percentage that the producing company retains after paying all royalties is the net revenue interest (NRI). Our model represents a typical West Texas scenario with an assumed NRI distributed normally with a mean of 75 percent and a standard deviation of 2 percent.

The revenue portion of the model is also shown in Figure 7.12 immediately below the production stream.

The yearly production volumes are multiplied by sampled price per barrel, and then multiplied by the assumed NRI to reflect dilution of revenues from royalty payments to lessees.

Operating Expense Section

Below the revenue portion are operating expenses, which include two assumptions:

1. *Operating Costs*. Companies must pay for manpower and hardware involved in the production process. These expenses are generally described as a dollar amount per barrel. A reasonable West Texas cost would be $4.80 per barrel with a standard deviation of $0.60 per barrel.
2. *Severance Taxes*. State taxes levied on produced oil and gas are assumed to be a constant value of 6 percent of revenue.

Operating expenses are subtracted from the gross sales to arrive at net sales, as shown in Figure 7.12.

Drilling Costs	$ 1,209,632
Completion Cost	$ 287,000
Professional Overhead	$ 160,000
Lease Costs / Well	$ 469,408
Seismic Costs / Well	$ 81,195

FIGURE 7.13 Year 0 expenses.

Year 0 Expenses Figure 7.13 shows the Year 0 expenses assumed to be incurred before oil production from the well (and revenue) is realized. These expenses are:

1. *Drilling Costs.* These costs can vary significantly as previously discussed, due to geologic, engineering, and mechanical uncertainty. It is reasonable to skew the distribution of drilling costs to account for a high-end tail consisting of a small number of wells with very large drilling costs due to mechanical failure and unforeseen geologic or serendipitous occurrences. Accordingly, our distribution is assumed to be lognormal, with a mean of $1.2 million and a standard deviation of $200,000.
2. *Completion Costs.* If it is determined that there is oil present in the reservoir (and we have not drilled a dry hole), engineers must prepare the well (mechanically/chemically) to produce oil at the optimum sustainable rates.[5] For this particular well, we hypothesize our engineers believe this cost is normally distributed with a mean of $287,000 and a standard deviation of $30,000.
3. *Professional Overhead.* This project team costs about $320,000 per year in salary and benefits, and we believe the time they have spent is best represented by a triangular distribution, with a most likely percentage of time spent as 50 percent, with a minimum of 40 percent, a maximum of 65 percent.
4. *Seismic and Lease Costs.* To develop the proposal, our team needed to purchase seismic data to choose the optimum well location, and to purchase the right to drill on much of the land in the vicinity of the well. Because this well is not the only well to be drilled on this seismic data and land, the cost of these items is distributed over the planned number of wells in the project. Uncertain assumptions are shown in Figure 7.14, and include leased acres, which were assumed to be normally distributed with a mean of 12,000 and a standard deviation of 1,000 acres. The total number of planned wells over which to distribute the costs was assumed to be uniform between 10 and 30. The number of seismic sections acquired was also assumed to be normally distributed with a mean

Lease Expense		**Comments**
Project Lease Acres	12,800	20 sections
Planned Wells	20.0	
Acres / Well	640	
Acreage Price	$ 733.45	$ / acre
Acreage Cost / Well	**$ 469,408**	

Seismic Expense		
Seismic Sections Acquired	50.0	
Seismic Sections / Well	2.50	
Seismic Cost	$ 32,478.18	$ / section
Seismic Cost / Well	**$ 81,195**	

FIGURE 7.14 Uncertain assumptions.

of 50 sections and a standard deviation of 7. These costs are represented as the final two lines of Year 0 expenses in Figure 7.13.

Net Present Value Section

The final section of the model sums all revenues and expenses for each year starting at Year 0, discounted at the weighted average cost of capital (WACC—which we assume for this model is 9 percent per year), and summed across years to compute the forecast of NPV for the project. In addition, NPV/I is computed,[6] as it can be used as a threshold and ranking mechanism for portfolio decisions as the company determines how this project fits with its other investment opportunities given a limited capital budget.

Monte Carlo Simulation Results

As we assess the results of running the simulation with the assumptions defined previously, it is useful to define and contrast the point estimate of project value computed from our model using the mean or most likely values of the earlier assumptions. The expected value of the project is defined as:

$$\begin{aligned} E_{\text{Project}} &= E_{\text{Dry Hole}} + E_{\text{Producing Well}} \\ &= P_{\text{Dry Hole}} NPV_{\text{Dry Hole}} + P_{\text{Producing Well}} NPV_{\text{Producing Well}} \end{aligned}$$

where $P_{\text{Producing Well}}$ = probability of a producing well and $P_{\text{Dry Hole}}$ = probability of a dry hole = $(1 - P_{\text{Producing Well}})$. Using the mean or most likely point estimate values from our model, the expected NPV of the project is $1,250,000, which might be a very attractive prospect in the firm's portfolio.

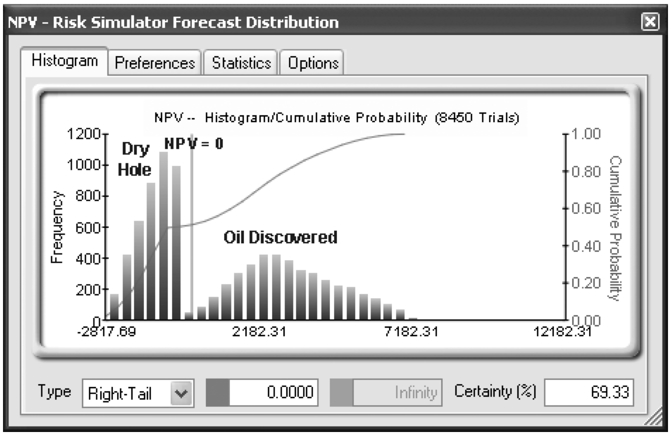

FIGURE 7.15 Frequency distribution of NPV outcomes.

In contrast, we can now examine the spectrum of outcomes and their probability of occurrence. Our simulation was run with 8,450 trials (trial size selected by precision control) to forecast NPV, which provided a mean NPV plus or minus $50,000 with 95 percent confidence. Figure 7.15 is the frequency distribution of NPV outcomes. The distribution is obviously bimodal, with the large, sharp negative NPV peak to the left representing the outcome of a dry hole. The smaller, broader peak toward the higher NPV ranges represents the wider range of more positive NPVs associated with a producing well.

All negative NPV outcomes are to the left of the *NPV = 0* line (with a lighter shade) in Figure 7.15, while positive outcome NPVs are represented by the area to the right of the *NPV = 0* line with the probability of a positive outcome (breakeven or better) shown as 69.33 percent. Of interest, the negative outcome possibilities include not only the dry-hole population of outcomes as shown, but also a small but significant portion of producing-well outcomes that could still lose money for the firm. From this information, we can conclude that there is a 30.67 percent chance that this project will have a negative NPV.

It is obviously not good enough for a project of this sort to avoid a negative NPV. The project must return to shareholders something higher than its cost of capital, and, further, must be competitive with other investment opportunities that the firm has. If our hypothetical firm had a hurdle rate of NPV/I greater than 25 percent for its yearly budget, we would want to test our simulated project outcomes against the probability that the project could clear that hurdle rate.

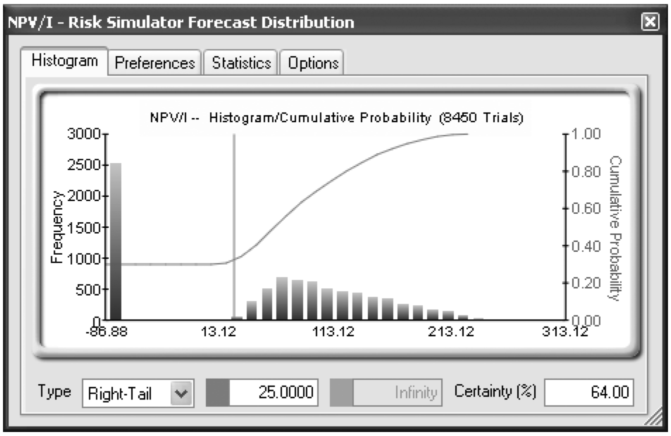

FIGURE 7.16 Forecast distribution of NPV to I ratio.

Figure 7.16 shows the forecast distribution of outcomes for NPV/I. The large peak at negative 100 percent again represents the dry-hole case, where in fact the NPV of the outcome is negative in the amount of Year 0 costs incurred, making NPV/I equal to –1. All outcomes for NPV greater than the hurdle rate of 25 percent show that there is a 64 percent probability that the project will exceed that rate. To a risk-sensitive organization, this outcome implies a probability of greater than one in three that the project will fail to clear the firm's hurdle rate—significant risk indeed.

Finally, our simulation gives us the power to explore the sensitivity of our project outcomes to the risks and assumptions that have been made by our experts in building the model. Figure 7.17 shows a sensitivity analysis of the NPV of our project to the assumptions made in our model. This chart shows the correlation coefficient of the top 10 model assumptions to the NPV forecast in order of decreasing correlation.

At this point, the project manager is empowered to focus resources on the issues that will have an impact on the profitability of this project. Given the information from Figure 7.17, we could hypothesize the following actions to address the top risks in this project in order of importance:

- *IP*. The initial production rate of the well has a driving influence on value of this project, and our uncertainty in predicting this rate is causing the largest swing in predicted project outcomes. Accordingly, we could have our team of reservoir and production engineers further examine known production IPs from analogous reservoirs in this area, and perhaps attempt to stratify the data to further refine predictions of

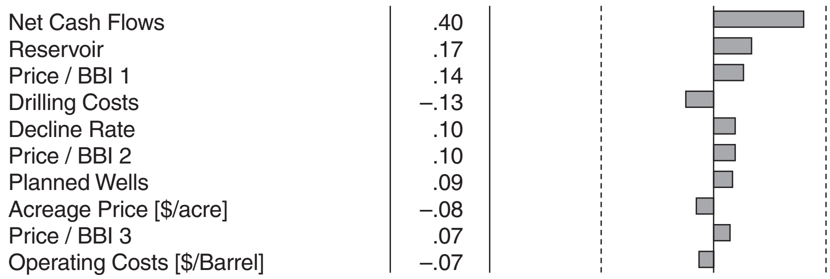

FIGURE 7.17 NPV sensitivity analysis.

IPs based on drilling or completion techniques, geological factors, or geophysical data.

- *Reservoir Risk*. This assumption is the driver of whether the well is a dry hole or producer, and as such it is not surprising that it is a major driving factor. Among many approaches, the project team could investigate the possibility that inadequate analysis of subsurface data is causing many companies to declare dry holes in reservoirs that have hidden producing potential.
- *Oil Price (Year 1) and Drilling Costs*. Both of these items are closely related in their power to affect NPV. Price uncertainty could best be addressed by having a standard price prediction for the firm against which all projects would be compared.[7] Drilling costs could be minimized by process improvements in the drilling team that would tighten the variation of predicted costs from actual costs. The firm could seek out companies with strong track records in their project area for reliable, low-cost drilling.
- *Decline Rate*. The observant reader will note a positive-signed correlation between decline rate and project NPV. At first glance this is unexpected, because we would normally expect that a higher decline rate would reduce the volumes of oil to be sold and hurt the revenue realized by our project. Recall, however, that we correlated higher IPs with higher decline rates in our model assumptions, which is an indirect indication of the power of the IP on the NPV of our project: Despite higher decline rates, the positive impact of higher IPs on our project value is overriding the lost production that occurs because of the rapid reservoir decline. We should redouble our efforts to better predict IPs in our model.

Conclusion

Monte Carlo simulation can be an ideal tool for evaluating oil and gas prospects under conditions of significant and complex uncertainty in the assumptions that would render any single-point estimate of the project outcome nearly useless. The technique provides each member of multidisciplinary work teams a straightforward and effective framework for quantifying and accounting for each of the risk factors that will influence the outcome of his or her drilling project. In addition, Monte Carlo simulation provides management and team leadership something much more valuable than a single forecast of the project's NPV: It provides a probability distribution of the entire spectrum of project outcomes, allowing decision makers to explore any pertinent scenarios associated with the project value. These scenarios could include break-even probabilities as well as scenarios associated with extremely poor project results that could damage the project team's credibility and future access to capital, or outcomes that resulted in highly successful outcomes. Finally, Monte Carlo simulation of oil and gas prospects provides managers and team leaders critical information on which risk factors and assumptions are driving the projected probability of project outcomes, giving them the all-important feedback they need to focus their people and financial resources on addressing those risk assumptions that will have the greatest positive impact on their business, improving their efficiency and adding profits to their bottom line.

CASE STUDY: FINANCIAL PLANNING WITH SIMULATION

Tony Jurado is a financial planner in northern California. He has a BA from Dartmouth College and is a candidate for the Certified Financial Planner designation. Tony specializes in the design and implementation of comprehensive financial plans for high-net-worth individuals. He can be contacted at tony.jurado@alum.dartmouth.org.

Corporate America has increasingly altered the retirement landscape by shifting from defined benefit to defined contribution plans. As the baby boomers retire, they will have different financial planning needs than those of previous generations because they must manage their own retirement funds. A thoughtful financial planner has the ability to positively impact the lives of these retirees.

A Deterministic Plan

Today was the last day of work for Henry Tirement, and, until just now, he and his financial planner, Mr. Determinist, had never seriously discussed