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BIRCH RESOURCES (A)

Randy Spade sat in his office looking over the proposed drilling program for the upcoming year. Spade had joined Birch Resources six months earlier, after working for almost 10 years as a reservoir engineer for King Oil, one of the largest exploration and production companies in the world. While Spade had enjoyed his work at King Oil, he eventually grew tired of the bureaucracy of a large company, as well as the slow pace at which his managers were beginning to adopt new evaluative techniques. Spade was looking forward to using decision-analytic techniques to improve the drilling-program results at Birch. With the beginning of the year only two months away, Spade was eager to get to work. The first drilling prospect to be analyzed was in Terrebonne Parish, Louisiana.

Spade's Background

While at King Oil, Spade had worked as part of a team of reservoir engineers to evaluate drilling prospects and to design the company's annual drilling program. At King, the team of reservoir engineers would meet monthly to evaluate potential drilling sites. Typically, the team would analyze reserve data and tests for a particular site, review production profiles from nearby drill sites, "gut-check" the potential site's value using current commodity prices, and then make a decision.

Early last year, Spade attended an industry seminar on oil-and-gas-investment evaluation. He was introduced to the use of decision trees and Monte Carlo simulation in valuing potential oil and gas investments. Intrigued, Spade began running simulations before each monthly team meeting. While these types of evaluative methods were coming into use at King, Spade's fellow reservoir engineers considered his approach, which involved analyzing each individual well, to be unrealistic. Part of this resistance stemmed from the fact that King drilled over 600 wells a year. The company truly employed a portfolio strategy, and the outcome of any one well barely impacted the overall results of the drilling program.

This case was written by Jennifer Spillane, MBA '01, under the supervision of Professors Dana R. Clyman, of the University of Virginia, and Michael R. Walls, of the Colorado School of Mines. It was written as a basis for class discussion rather than to illustrate effective or ineffective handling of an administrative situation.

Regardless, Spade continued to compare the results of his decisions trees and simulation models with the actual results of King's drilling program, and his confidence in this method grew. As a result, he was extremely interested when Birch Resources contacted him about a position as head of Exploration and Development. As Birch was a much smaller company than King, each well Birch drilled had a significant impact on the bottom line and thus had to be carefully analyzed. In the past, Birch had employed a project-review system similar to the one at King Oil, and had met with mixed results. Spade saw the opportunity to employ these new techniques to improve the drilling-program results at Birch.

Birch Resources

Birch Resources was an independent oil and gas company engaged in the acquisition, exploration, development, production, and marketing of oil and natural gas. Birch's principal reserves and producing properties were located in the Gulf of Mexico, Louisiana, and Texas. As of December 31, 1998, 45 percent of Birch's proved reserves were located offshore in the Gulf of Mexico. Approximately 70 percent of Birch's net estimated proved reserves were oil and approximately 50 percent of these proved reserves were classified as proved developed (see glossary in **Exhibit 1**).

The Opportunity

The first opportunity that Spade needed to evaluate was a potential well in Terrebonne Parish, Louisiana, just off the Gulf of Mexico (see map of Louisiana in **Exhibit 2**). A few months earlier, Hugo Energy, another independent oil and gas company operating primarily in Louisiana, had offered Birch an interesting deal on a lease that Hugo had obtained in a Louisiana Minerals Management Service (MMS) auction two years earlier. The terms of the original lease agreement with the MMS stated that Hugo had three years to drill in the field covered by the terms of the lease or ownership would revert to the MMS. Unfortunately, Hugo had recently overextended itself in some other drilling projects and lacked the capital and management to drill on this lease in the remaining year. Rather than lose the lease rights, Hugo offered to "farm out" or contract the field to Birch Resources.

The terms of the venture stated that Hugo would grant Birch initial drilling rights for one productive well in the field. Birch would have the remainder of the year to drill the well. If Birch failed to drill, the lease would revert to the MMS and no one would be any worse off. If, however, Birch did drill a well, Hugo would allow Birch to operate the well and take all profits (and losses) during the first full year of operations in compensation for having to bear the upfront drilling and development costs—a capital investment of $2 million. Thereafter, Hugo and Birch would share any additional profits (and losses) 55 percent to Birch and 45 percent to Hugo for the remaining lifetime of the well. The contract also specified that if Birch drilled a productive well, it would earn the right to drill a second well two years after drilling the first well. Both Hugo and Birch would have working interests in this second well. The contract stipulated that they would share all profits and costs for this well (including the upfront costs) 40 percent to Birch and 60 percent to Hugo.

Reserve report

Neble and Sears, a local reserve-audit firm, had estimated that the entire field had approximately 100 million barrels of oil equivalent (BOE) in gross reserves. Typically, many wells would be drilled in a field this size. However, as Birch had the initial right to drill only one well, Neble and Sears produced a report on the probable production that could be expected from one well. Reservoir-engineering firms like Neble and Sears were hired as independent third parties to verify the amount of reserves that a company claimed were in a field—much like the practice of hiring an accounting firm to audit financial results. Because of the credibility that an official reserve report held (it was often used to value a company), reservoir engineers went to great lengths to avoid overstating reserve amounts, which often led to their quoting the lowest-possible pay (or flow) in a field as the expected production stream.

According to the Neble and Sears report, first-year production was expected to be around 100,000 BOE. Spade believed that this estimate was conservative, perhaps underestimating the average BOE by about 5 percent. He also knew that the actual amount of first-year production was uncertain. And while he did think that the 100,000 BOE predicted by Neble and Sears was probably the most likely outcome, he also believed that the actual amount could be as much as 15 percent less or 30 percent more. Spade also knew that he had to take into account the unfortunate but realistic possibility that Birch could miss the "pay zone" and drill a dry hole. After careful reflection on similar experiences, Spade estimated that there was about a 15 percent chance that this would occur. And if it were to occur, Birch would likely abandon the field because of what a dry hole suggested about all of the geologists' original assessments.

Production decline

Given the underlying geography of southern Louisiana where the field was located, it was not unusual for the year-to-year output of a well to decline significantly. Indeed, a 25 percent year-to-year annual decline in production was common. But as with everything, this value was also uncertain and ranged from as little as 20 percent to as much as 40 percent. As a result, wells in this region played out rather quickly, and by the seventh year, production frequently became uneconomical, as the level of revenues was rarely high enough to cover fixed costs.

This production-decline trend was expected regardless of the level of production achieved in the first year. If production was higher than expected, then the reserve report had simply understated the reserve potential and the entire production curve would shift upward to the new level, but the slope of that curve would not change. The same was true in the case of lower-than-expected production in the first year. What's more, the production decline wasn't constant as there was some year-to-year variability, and while, the best predictor of next year's decline was this year's, the actual decline could be off by as much as 10 percent in either direction with every value in between equally likely.

Given this complexity, Spade decided to evaluate each well using a six-year production-lifetime to simplify the analysis. If oil prices declined to a point where production became uneconomical over an extended period, Birch might suspend production or even abandon the well before the six-year period expired. However, because of the difficulty of predicting when and how quickly prices could recover and when and how Birch management would make this decision, Spade chose to stick with his original six-year time horizon. Nevertheless, he knew that an analysis might be done to determine the optimal boundaries for abandoning the prospect or for suspending and restarting production, but given the time frame over which Spade needed to make this decision, he decided to leave that analysis for another day. After all, it could only make the prospect look better.

Oil prices

Naturally, oil prices and how they might change were a major consideration when valuing oil and gas investments. Although oil prices had been known to range from \$10 a barrel to \$50 a barrel, a recent analysis of oil prices from 1900 to 1994 revealed that prices tended to revert to a long-run average price (adjusted for inflation).[1] While Spade often used a simple mean-reverting model for 15-to-20-year projects, because of the relatively short span of this project, he was more concerned about capturing the potential volatility in oil prices than the mean reversion, and he wanted to keep his model as simple as possible. Therefore, Spade decided to use a simple geometric Brownian-motion process to model oil prices, and he used an annual volatility of 20 percent. Thus, to model oil prices, he used the following equation:[2]

$$P(t+1) = P(t) + P(t) * \left(volatility * Z \sqrt{(\Delta t)} \right)$$

where P(t) represented the price this period, P(t+1) represented the price next period, Z was a normally distributed random variable with mean 0 and standard deviation 1, and Δt represented one unit of time (in this case, one year).

With 1999 coming to a close, analysts predicted that the year-end average West Texas Intermediate (WTI) crude oil price would be approximately \$19.30 a barrel.[3]

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[1]E. James Smith and F. Kevin McCardle, "Options in the Real World: Lessons Learned in Evaluating Oil & Gas Investments," *Operations Research* 47, no. 1 (January-February 1999).

[2]Assuming an average annual oil price of \$19.30 for 1999, the equation for a log-normally distributed oil price in the year 2000 would be as follows: $P(t+1) = \$19.30 + \$19.30 * \left(20\% * cb.normal(0,1)\sqrt{1}\right)$, where \$19.30 = 1999 oil price, 1 = time change of one year, 20% = volatility, and cb.normal(0,1) = normally distributed random error.

[3]Michael Schmitz, Exploration and Production Analyst with Salomon Smith Barney, phone interview (January 2001).

Operating and production costs

Based on a proposal submitted by Red Bird Drilling, Spade estimated that the upfront costs would be approximately $2 million, including approximately $1 million to drill the well and another $1 million to develop the well's capability to produce hydrocarbons. Spade then analyzed Birch's historical production costs for wells in South Louisiana in an effort to estimate potential future costs in Terrebonne Parish. Other major cost components that Spade included in his P&L were operating costs, production taxes, regional oil-price adjustments, transportation, and general and administrative charges. Of these, fixed costs generally included operating and general & administrative costs, which Spade expected to be approximately $150,000 a year and $100,000 a year, respectively. Spade estimated the remaining costs—variable production and transportation, regional oil-price adjustments, and production taxes—on a BOE basis as follows:

Variable Costs	Per BOE
Variable production, transportation, and regional oil-price adjustments	$2.00
Production taxes	8% of revenue

Spade generally evaluated projects on a pretax basis, as Birch usually had losses generated by unsuccessful projects to offset any corporate tax liabilities generated by successful projects. Therefore, Spade was interested in arriving at an EBITDA (earnings before interest, taxes, depreciation, and amortization) number (though he did include production taxes in his evaluation). In evaluating projects of this type, Birch usually used a discount rate of 10 percent.

The Second Well

As part of the process of determining whether Birch should accept Hugo's offer, it was important that Spade fully understand the opportunity presented by the second well. Spade knew that he could learn a lot about the possible production of a second well from the results of the first well. He believed that if the second well were drilled, it would most likely result in an initial production level comparable to that of the first well, though he knew that production could be better or worse. However, because of the information that they would have gained about the field from working the first well, Spade thought that while the initial production level of the second well could be as much as 20 percent lower than that of the first well, he also believed that it might be as much as 30 percent greater than that of the first well.

Spade also knew that the initial production decline of the second well would most likely be similar to the initial production decline realized by the first well, though he also knew that initial number could be as much as 20 percent lower or higher. As far as the year-to-year variability was concerned, he again had no reason to believe that any number from 10 percent lower to 10 percent higher was more likely than another. Finally, because of the information gained from working the first well, Spade was also willing to assume that there was no possibility that the second well would be a dry hole, making the second well a substantially better investment.

Settling back into his chair, Spade prepared to build a model that would help him decide whether to add the Terrebonne Parish prospect to Birch's 2000 Drilling Program.

Exhibit 1

BIRCH RESOURCES (A)

Glossary of Terms

Mcf	A standard measurement unit for volumes of natural gas that equals one thousand cubic feet. Six Mcf of natural gas is approximately the energy equivalent of one barrel of oil.
MMcf	Million cubic feet
BCF	Billion cubic feet
TCF	Trillion cubic feet
Bbl	Barrel of oil
MBbl	One thousand barrels
MMBbl	Million barrels
BOE	Barrel of oil equivalent. A method of equating oil, gas, and natural-gas liquids. Gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil. Natural-gas liquids are converted based on volume, where one barrel of natural-gas liquids equals one barrel of oil.
MMBOE	Million barrels of oil equivalent
3-D Seismic	Technology that bounces sound waves off underground rock formations, processed to create a three-dimensional picture of the subsurface. Identifies rock formations most likely to contain accumulations of oil and gas.
Development Well	A well drilled in the area of an oil or gas reservoir known to be productive. These wells are generally low-risk.
Dry Hole	A well that does not provide oil or gas in sufficient quantities to justify completion.

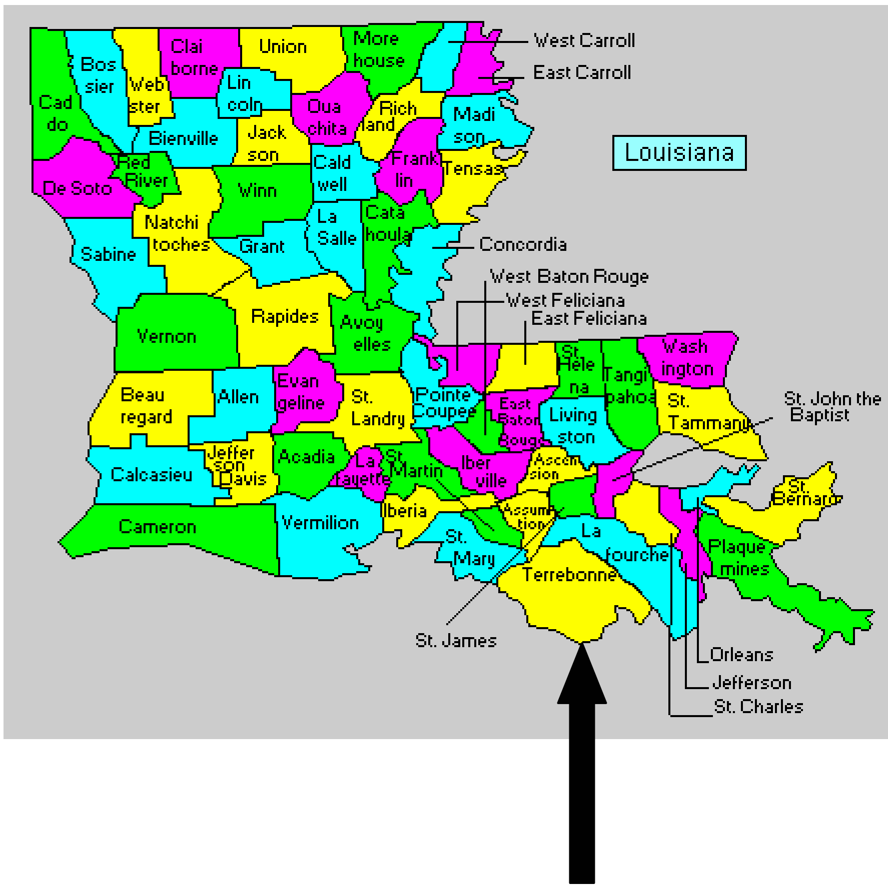
Enhanced Recovery	Techniques used to increase or prolong production from oil and natural-gas fields.
Exploratory Well	A well drilled in an unproved area, sometimes referred to as a wildcat.
Field Formation	A geographical area with one or more oil and gas reservoirs. An identifiable layer of rocks named after its geographical location and dominant rock type.
Lease	A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral-rights holder on a specific tract.
Net Acres	Gross acres multiplied by the fractional working interest in the property.
Production	Total production refers to all the oil and gas produced from a property. Gross Production: Total production before deducting royalties. Net Production: Gross production, minus royalties, multiplied by the company's fractional working interest.
Prospect	An area designated for the potential drilling of development or exploratory wells.
Proved Developed	Characterization of reserves that are nearly certain and available to be extracted. The highest classification.
Reserves	Oil or gas contained in underground rock formations called reservoirs. Proved reserves are the estimated quantities that geologic and engineering data demonstrate can be produced with reasonable certainty from known reservoirs under existing economic and operating conditions. Recoverable reserves are those that can be produced using all known primary and enhanced recovery methods.
Royalty Interest	An interest in an oil and gas property entitling the owner to a share of oil and gas production free of costs of exploration, development, and production.
Working Interest	The operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and to share in the production.
Waterflood	A method of increasing oil recovery from an existing reservoir. Water is injected to force unrecovered oil out of reservoir rock and into nearby oil wells.

Glossary is available at http://www.stmaryland.com/corporate/glossary

Exhibit 2

BIRCH RESOURCES (A)

Map of Louisiana by Parish



Terrebonne Parish

Map is available at http://www.state.la.us/icons/plandist