APPENDIX 1B

Schlumberger on Real Options in Oil and Gas

The following is contributed by William Bailey, Ph.D., Senior Research Engineer at Schlumberger—Doll Research, Ridgefield, Connecticut. The company is involved in global technology services, with corporate offices in New York, Paris, and The Hague. Schlumberger has more than 80,000 employees, representing 140 nationalities, working in nearly 100 countries. The company consists of two business segments: Schlumberger Oilfield Services, which includes Schlumberger Network Solutions, and Schlumberger-Sema. Schlumberger Oilfield Services supplies products, services, and technical solutions to the oil and gas exploration and production (E&P) industry, with Schlumberger Network Solutions providing information technology (IT) connectivity and security solutions to both the E&P industry and a range of other markets. Schlumberger-Sema provides IT consulting, systems integration, managed services, and related products to the oil and gas, telecommunications, energy and utilities, finance, transport, and public-sector markets.

Long gone are those heady days in the petroleum industry when a pith-helmeted geologist could point to an uninspiring rock outcrop, declare confidently "drill here," and then find an oil field the size of a small country. Over the past 30 years, however, the situation for the oil industry has become very different indeed. As we search to replenish our ever-decreasing hydrocarbon supplies, oil explorationists now find themselves looking in some of the most inaccessible parts of the globe and in some of the deepest and most inhospitable seas. What could have been achieved in the past with a relatively small investment is now only attainable at a considerably greater cost. In other words, developing an oil and/or gas field nowadays is subject to considerably larger investments in time, money, and technology. Furthermore, such large investments are almost always based on imperfect, scant, and uncertain information. It is no accident, therefore, that when teaching the concepts of risk analysis, many authors cite the oil industry as a classic case in point. This is not by accident for few other industries exhibit such a range of uncertainty and possible downside exposure (in technical, financial, environmental, and human terms). Indeed this industry is almost ubiquitous when demonstrating risk analysis concepts.

Consequently real options have a natural place in the oil industry management decision-making process. The process and discipline in such an analysis captures the presence of uncertainty, limited information, and the existence of different—but valid—development scenarios. The fact that petroleum industry management are faced with multimillion (sometimes billion) dollar decisions is nothing new. Such people are used to making critical decisions on a mixture of limited information, experience, and best judgment. What is new is that we now have a coherent tool and framework that explicitly considers uncertainty and available choices in a timely and effective manner.

This short appendix is intended to provide just a brief glimpse into the types of applications real options have been used for in the petroleum industry. To guide the reader unfamiliar with the finer points of the oil and gas industry, it may be prudent to outline the basic process in an "average" petroleum development. In so doing, the reasons why the oil industry is deemed such a prime example for use of real options (and risk analysis in general) will become clear.

In the 1959 film of Jules Verne's 1864 novel *Journey to the Center of the Earth,* James Mason and others found themselves sailing on a dark sea in a mighty cavern many miles down in the earth's crust. This was, of course, just science fiction, not science fact. Unfortunately it is still a common misconception that oil is found in such caverns forming black lakes deep beneath our feet. While such images may be romantic and wishful, reality is far more intricate. For the most part, oil (and gas) is found in the microscopic pore spaces present between individual grains making up the rock. For example, hydrocarbon-bearing sandstone may have porosity levels (the percentage of pore space in the rock) of about 15 percent. This means that if all the pore space in the rock is full of oil, then 15 percent of the total rock volume contains oil. Of course, things are not as simple as that because water and other minerals serve to reduce the available pore volume.[1] As oil and gas are liquid, they will flow. Unless the rock itself provides some form of seal (or trap) to contain these fluids, over time they will simply seep to the surface and be lost. (Azerbaijan has some good examples of such seepage with whole hillsides being awash with flame from seeping gas for as long as recorded history.) So not only do we need a rock that contains oil (or gas) but also the oil (or gas) must be trapped somehow, ready for exploitation. For a readable and well-informed summary of petroleum geology, refer to Selley (1998).[2]

Extraction of oil (and/or gas) from a virgin field is undertaken in typically four stages: exploration and appraisal; development; production; and abandonment. This is a gross simplification, of course, for within each phase there are a multitude of technical, commercial, and operational considerations. Keeping one eye on real options, in their crudest form these phases can be briefly described as follows:

- ***Exploration and Appraisal.*** Seismic data is obtained and a picture of the subsurface is then revealed. Coupled with geological knowledge, experience, and observations, it is then possible to generate a more detailed depiction of a possible hydrocarbon-bearing zone. Seismic data cannot tell what fluids are present in the rock, so an exploratory well needs to be drilled, and from this, one is then able to better establish the nature, size, and type of an oil and gas field.

  Exploration and Appraisal Phase—Where Real Options Come In. The decision maker has numerous options available to him/her, which may include:
  - Extent of investment needed in acquiring seismic data. For example should one invest in 3D seismic studies that provide greater resolution but are significantly more expensive? Should 4D (time-dependent) seismic data be considered? While advanced seismic data (and interpretation) certainly provides improved representation of the subsurface environment, one needs to assess whether it is worthwhile investing in this information. Will it reduce uncertainty concerning the size and nature of the reservoir sufficiently to pay off the investment?
  - Given inherent uncertainty about the reserves, if possible, how much should the company share in the risk (extent of contract partnership)?
  - How many exploration wells are appropriate to properly delineate the field? One, two, five, or more?
- ***Development.*** Once sufficient data has been obtained (from seismic or exploratory wells) to make an educated judgment on the size of the prize, we enter into the development phase. Here we decide on the most commercially viable way for exploiting this new resource by engineering the number (and type) of producing wells, process facilities, and transportation. We must also establish if, at all, any pressure support is necessary.[3]

  Development Phase—Where Real Options Come In. This phase is where decision makers face possibly the greatest number of valid alternatives. Valid development options include:
  - How many wells should be drilled? Where should they be located? In what order should they be drilled?
  - Should producers be complex (deviated/horizontal) wells located at the platform, or should they be simple but tied-back to a subsea manifold?

- How many platforms or rigs will be needed? If offshore, should they be floating or permanent?
- What potential future intervention should be accommodated? Intervention refers to an ability to reenter a well to perform either routine maintenance or perform major changes—referred to as a work-over.
- How many injectors (if any at all) should be drilled? Where should they be located?
- How large should the processing facility[4] be? If small, then capital expenditure will be reduced but may ultimately limit throughput (the amount of hydrocarbons sent to market thereby restricting cash flow). If the process facility is made too large, then it may be costly and also operationally inefficient.
- Are there adjacent fields waiting to be developed? If so, should the process facility be shared? Is this a valid and reasonable future possibility in anticipation of uncertain future throughput?
- Should a new pipeline be laid? If so, where would it be best to land it, or is it possible to tie it into an existing pipeline elsewhere with available capacity? Should other transportation methods be considered (e.g., FPSO, or floating production and storage operation[5])?

The number of different engineering permutations available at this stage means that management may be faced with several viable alternatives, which are contingent on the assumptions on which they were developed. Real options enable uncertainty to be explicitly quantified at this stage.

- ***Production.*** Depending on the size of the reserve (and how prolific the wells are) the engineer must manage this resource as carefully as any other valuable asset. Reservoir management (the manner and strategy in which we produce from a field) has become increasingly important over the past few years. Older, less technically advanced, production methods were inefficient, often leaving 75 percent or more of the oil in the ground—oil that cannot be easily extracted afterward, if at all. Increasing the efficiency of our production from our reservoirs is now a crucial part of any engineering effort (unfortunately, nature prevents us from extracting 100 percent of the oil; there will always be some left behind).

Production Phase—Where Real Options Come In. Valid production options include:

- Are there any areas of the field that are unswept[6] and can be exploited by drilling more wells?
- Should we farm out (divest) some, or all, of the asset to other companies?
- Should we consider further seismic data acquisition?
- Should we consider taking existing production wells and converting them into injection wells to improve the overall field performance?

  - What options does one have to extend the life of the field?
  - Should we consider reentering certain wells and performing various actions to improve their performance (e.g., reperforating some or all of the well, shutting off poorly producing zones, drilling a smaller branch well [known as a *sidetrack*] to access unswept reserves, etc.)? What information needs to be collected to be able to make these operational decisions? How is such information best obtained? At what cost and at what operational risk? (Reentering a well may be a hazardous and potentially damaging act.)

Once again, there are many opportunities during the production phase to make decisions that are still subject to considerable uncertainty. Even though the field may be mature and much experience has been accumulated, the operator is still faced with many management options that can impact ultimate reservoir performance and economic viability.

***Decommissioning (also known as* Abandonment).** Once reserves have been depleted, the infrastructure can either be left to decay or—increasingly—it must be dismantled in an environmentally and economically efficient manner. This is especially true for the North Sea and offshore United States.

- ***Decommissioning Phase—Where Real Options Come In.*** Valid production options include:
  - What will the ultimate abandonment cost be, and what is the likelihood that this will remain true at the end of the life of the field?
  - Should the full cost of abandonment be included in the initial development strategy, or is there a way to hedge some or all of this cost?
  - What contingency should be built in to account for changes in legislation?
  - At what threshold does abandonment cost make the project unprofitable, and how would this impact our initial development strategy?

This brief (and admittedly incomplete) list of bullet points at least demonstrates why the oil industry is ideally suited for a real options-type analysis because the companies exhibit all the necessary ingredients:

- Large capital investments.
- Uncertain revenue streams.
- Often long lead times to achieve these uncertain cash flows.
- Uncertainty in the amount of potential production (reservoir size and quality).
- Numerous technical alternatives at all stages of development.
- Political risk and market exposure (external influences outside the control of the operating company).

Final Word: Early examples of options-based analysis are found in the oil and gas industry.[7] The impact and wholesale adoption so far has been limited. Why this is the case in the oil industry raises important issues that should be kept in mind when considering adopting real options as a practice in any company.

Real options are technically demanding, with a definite learning curve in the oil industry, and have three main hurdle classifications:[8]

- ***Marketing Problem.*** Selling real options to management, appreciating the utility and benefit, understanding their capabilities and strengths (as well as weaknesses), and ultimately communicating these ideas (companies usually have a few volunteer champions/early adopters, but they often remain isolated unless there is suitable communication of these concepts, particularly in a nontechnical capacity, which may be easier said than done).
- ***Analysis Problem.*** Problem framing and correct technical analysis (not too difficult to resolve if suitably trained technical people are available—and have read this book).
- ***Impact Problem.*** Not really the interpretation of results but rather acting on them, implementing them, monitoring and benchmarking them, then communicating them (a recurring theme), and finally managing the whole process.

These issues should be kept in mind when communicating the concepts and results of a real options analysis.