

OVERVIEW



What does it mean to manage reserves and assets in the context of the oil- and gas-production business? It really means making the right decisions under significant, yet potentially calculable, uncertainty. Whether you are a small independent or a large state-owned oil company, you face many of the same problems—only the scale or magnitude is different. In our industry, we face more than our fair share of uncertainties in managing assets. Those “unknowns” are pervasive throughout the many aspects of oil and gas exploration. A few of the more significant ones are as follows:

- Geological (structure)
- Petrophysical (rock properties)
- Drilling success
- Effectiveness of completions
- Drive mechanism (recovery efficiency)
- Political (country risk)
- Contractual complexities and reversions
- Timing of first oil for new developments
- Impact of weather
- Product price

This set of uncertainties obviously comprises a nonexhaustive list of the many factors that should enter into the review and planning processes. In spite of the unknowns that complicate our work, we still need to make decisions—decisions that are made to maximize true asset and/or shareholder value. As engineers, we can help to make those decisions the correct ones by providing decision makers with as much relevant information as possible, along with the appropriate risks and uncertainties associated with that information. Many times, we make less-than-optimal decisions because of a lack of desired information. However, we continuously strive to make the best decisions possible on the basis of the data at hand. The papers highlighted in this segment should help illustrate some ways that others are reducing uncertainty to help make their decisions the correct ones. In addition, some of the referenced papers help provide guidance and consistency in the reserves-estimation process. Ultimately, that type of consistency will reduce the uncertainties of asset valuation and improve asset management.

JPT

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Reserves/Asset Management additional reading available at the SPE eLibrary: www.spe.org

SPE 107709

“Beyond Portfolio Optimization” by L.C. Faya, Constellation Energy Commodities Group, et al.

SPE 109012

“Reservoir-Management Aspects of the Rejuvenation of the Forties Field, UKCS” by Owen Vaughan, SPE, Apache Corporation, et al.

SPE 110617

“Methods for Incorporating Costs, Pricing, Gas Shrinkage and Transport Tariffs, NGL and Inert Revenues, and Working Interest in Gas Plants and LNG Projects Into Reserves Estimates” by John McLaughlin, SPE, Ryder Scott Company, et al.

Integrated Project Management for Hydrocarbon-Portfolio Analysis and Optimization

Aligning hydrocarbon investments with constantly shifting business goals and priorities is a major challenge for E&P staff. There are many factors that can contribute to project failure, resulting in large investments to improve the predictability, producibility, and quality of evaluations. While, techniques such as estimating, risk assessment, process management, deliverables management, and project management improve project execution, they do not address the critical issue of scheduling or that of achieving satisfactory cost performances. This study explored the strategic significance of modern portfolio theory and its applicability to various oil and gas investments.

Introduction

Petroleum exploration and field development deal with many unknowns. Risks and uncertainties associated with income and life-cycle-cost factors [such as potential reserves, capital expenditures, operating expenditures, production rate, oil and gas pricing, geological success ratios, and intervention vessel expenses (especially for subsea wells)] make it difficult to forecast earnings and cash flow for prospects. Managing risk in petroleum ventures is very important, with the possibility of massive cost overruns and delays.

Decision making and project management are disciplined work pro-

cesses that can be measured and optimized with uniform templates and procedures. A project profile outlining the ideal outcome reduces decision analysis because proposed solutions are aligned directly to goals, not solutions. Decisions, therefore, must be made in full alignment with the project's ideal intended outcome. This paper demonstrates balancing the strategic value of projects, financial return, and risk profile to select an optimal portfolio before committing funds and resources.

Applying Project-Management Principles

Although upstream petroleum operations are not a traditional area for conventional practice of project-management techniques, recent literature has shown an increasing rate of embracing project-management principles in exploration, drilling, and production operations. Project management has been defined as applying knowledge, skills, tools, and techniques to project activities to meet project requirements. Project management is accomplished through the application and integration of various management processes; knowledge areas; and technical and management skills, methods, and techniques, which facilitate a successful project outcome.

A project can be considered as a temporary endeavor undertaken to create a unique product, service, or result. Here, a temporary project has a definite beginning and end, and a unique product, service, or result is different in some distinguishing way from all other products, services, or results. Oil exploration and field development are temporary endeavors that have the ultimate goal of producing hydrocarbons and, therefore, fit within the definition of a project. It begins when a creative

idea is moved officially into the concept-evaluation phase and ends when a field is abandoned.

In the past, E&P staffs were charged with the responsibility of exploring and producing hydrocarbons. The current challenge has gone beyond finding and developing oil or gas; the staff must make complex decisions about managing technical performance, risk, economics, and corporate strategy.

Suitable decisions are made when projects are risked appropriately, described consistently in economic and technical terms, and assessed relative to how they interact through time with other investments to deliver value to the company. Merging risk assessment and operational management is a critical first step.

Project objectives, or the measure of project success or failure, often are defined in terms of cost, schedule, and technical performance. Risk management is intended to increase the likelihood of attaining these objectives by providing a systematic approach for analyzing—controlling and documenting identified threats during both the planning and execution of a project.

The project-management process will remain constant throughout the different phases of the project life cycle. Various project-management tools and techniques used for planning, evaluating, and controlling also will remain constant. What will vary over the project life cycle is the quality of the available risk-related information, the competence needed to compile and filter information, and the kind of decisions that are supported by the project- and risk-management activities. Thus, the E&P-project life cycle addresses all phases of the project—prestudy, feasibility, development, execution, and operation phases.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 100967, "Applying Integrated Project-Management Methodology to Hydrocarbon-Portfolio Analysis and Optimization," by Sholarin E. Adekunle, Curtin University of Technology, prepared for the 2006 SPE International Oil & Gas Conference and Exhibition in China, Beijing, 5–7 December.

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

TABLE 1—OPPORTUNITY SET OF INVESTMENTS

Project Name	Capital USD million	NPV @ 10% USD million	Ranking by NPV	PWR @ 10%	Ranking by PWR
1	100	42	1st	0.42	3rd
2	200	40	2nd	0.20	4th
3	75	35	3rd	0.47	2nd
4	150	20	5th	0.13	5th
5	50	30	4th	0.60	1st
Total	300		82		122

Modern Portfolio Theory

It has been suggested that each portfolio of assets would have a given level of risk and reward. However, for any level of risk, there would be only one portfolio that would return an optimum reward. Conversely, for any level of reward, there would be only one portfolio that would minimize the risk.

Originally, portfolio optimization was a securities-investment-optimization tool. It assumes that given the expected return and risk of a security, along with its correlation with other securities in a portfolio, a selection of stocks can be chosen that maximizes the return for any level of risk. The fundamental objective of the portfolio-optimization application used for this study was to derive the optimal mix of investment opportunities that minimized risk for a given level of return, or maximized return for a given level of risk.

Traditionally, oil and gas companies allocate capital to projects if current hurdle rates are achieved by certain economic indicators, such as net present value (NPV), internal rate of return (IRR), or return on investment. When capital is allocated in a portfolio-budgeting process, there usually are more opportunities available than capital to fund them. In such circumstances, E&P decision makers have been advised to rank their project-

investment opportunities by a metric reflecting the marginal return on capital employed (e.g., NPV divided by investment) and to fund the projects in descending order until the available capital pool is exhausted. This approach maximizes the economic return and provides the firm with the maximum expected value creation for given investment.

Over the past 2 decades, a different view has emerged—one that takes explicit account of risk. Monte Carlo simulation, decision-tree analysis, and modern portfolio theory have enhanced petroleum-investment decision making. The focus of this paper is portfolio theory. The mechanics of portfolio theory is based on the underlying assumptions that investors are risk averse (i.e., given investments with the same expected value, they prefer higher returns to lower returns, but will also prefer less risk to more risk).

Monte Carlo Simulations. A Monte Carlo (stochastic) simulation generates discrete values in a computer model (sampled from relevant probability distributions) to build a realistic or “typical” lifetime scenario of the expected outcome. In this study, the model was used to estimate the oil and gas volumes that would be delivered from the projects under review on a yearly basis and the life-cycle

costs associated with producing these volumes. All failures and incidents that would result in loss of production relative to specified market demand were included. Also, a strategy on how to manage the engineering, procurement, and construction activities was developed.

Sensitivity Analysis. In this study, several sensitivities were run. Individual parameters were varied one at a time, keeping all other parameters fixed at their base values. The sensitivity analysis was taken from a Monte Carlo simulation during which all stochastic inputs vary at the same time. The sensitivity analysis gave a fuller account of the total picture because correlations and interactions between inputs were included.

Results were affected most by oil revenue, followed closely by operating expenses. A sensitivity chart provided visual representations of the effects that each variable was expected to have on a given economic indicator. Scenarios for reserves, oil/gas prices, capital expenditure, operating costs, and discount factor were important parameters included in a sensitivity chart.

Typical Results. In the Monte Carlo simulation analysis, each of five investment drivers was varied randomly over 10,000 trials from a normal probability distribution. The solution quality of the different cases was evaluated in terms of expected NPV and IRR. Real, but significantly disguised, data were obtained from an existing oil field for the evaluation. Prevailing inflation and rate of depreciation of petroleum assets also were integrated into the model. Simulation results indicated a mean IRR of 18.73%. On this basis, a decision to drill would be made because there is 0.99 probability that the project will yield an IRR at or above the 14% hurdle rate.

Portfolio-Optimization Model

As an example, a set of five investment opportunities, a mix of natural-gas and oil E&P projects, was evaluated under various scenarios to develop a robust understanding of an upstream-project portfolio. Their NPV and present-worth-ratio (PWR) (PWR equals NPV divided by capital expenditure) indicators are displayed in **Table 1**. Each project responded as expected under the respective scenarios (ranking by NPV vs. ranking by PWR).

TABLE 2—PORTFOLIO COMBINATIONS

Portfolio	Projects	Total Cost USD million	Total NPV USD million	Mean NPV USD million	SD USD million
A	1, 3, 5	225	107	110.8	15.65
B	1, 2	300	82	80.4	5.97
C	2, 3	275	75	76.1	4.31
D	3, 4, 5	275	85	83.8	4.98
E	1, 4, 5	300	92	90.8	7.1

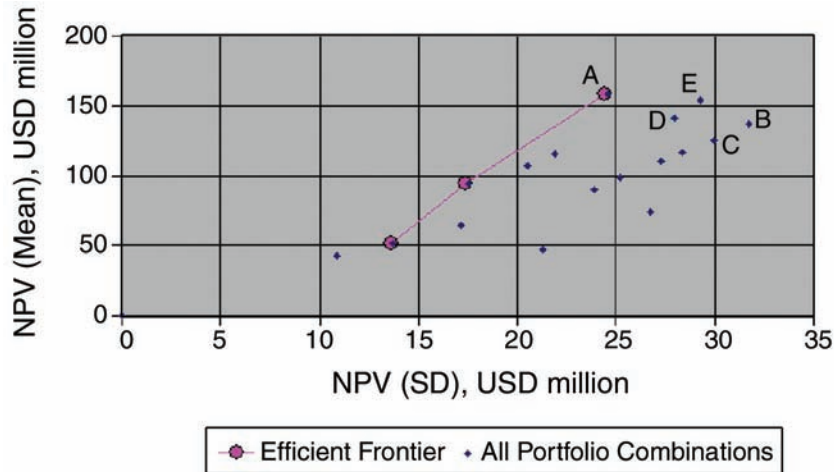


Fig. 1—Risk vs. return graph overlaid with efficient-frontier results.

A fundamental objective of the portfolio-optimization application was to derive the optimal mix of investment opportunities that minimized risk for a given level of return, or maximized return for a given level of risk. By use of commercial optimization software, a portfolio optimization was conducted for the same group of projects, resulting in an efficient frontier (i.e., locus of portfolio selections for which no lower-risk selection was available with as great a return and no selection with a higher return was available without higher risk). In this case, risk was estimated by standard deviation (SD) of portfolio NPV as calculated across various scenarios.

At the portfolio level, a USD 300-million budget was imposed, enabling one-to-one comparison of the computer-optimized portfolio solution to the PWR portfolio. On a standalone basis, Project 5 had the highest PWR. Under traditional decision-making guidelines, for a risk-averse investor, Project 5 would be preferred over other projects. Although Project 1 had the highest NPV, its PWR is less than that of Projects 3 and 5. However, when viewed from the portfolio framework, the results were different. **Table 2** shows the portfolio mean and SD of NPV for five possible portfolio investments.

Fig. 1, the risk vs. return graph, shows that the conventional decision rule does maximize return as expected. However, by ignoring risk, it also maximizes risk. Fig. 1 includes the efficient-frontier results for comparison. Portfolio A represents an opti-

mized opportunity set generated by selecting projects according to their PWR ranking. This opportunity mix includes three projects and has little or no risk compared with other portfolios with similar returns. Portfolio B is an opportunity mix of Projects 1 and 2 and is the selection of projects when ranking them by NPV. This solution has 31% more risk than the portfolio based on PWR ranking. Portfolios C, D, and E from Table 2 have high values for NPV but also have high-risk levels compared with Portfolio A.

In addition to showing the overall risk and return tradeoffs, portfolio analysis provided another significant insight: Project selection could be compared within and across efficient portfolios, and the relative project importance could be determined. In addition, the use of sensitivity analysis in portfolio optimization enabled the effect of existing and new projects to be explored and various objectives and constraints re-examined. This triggered new and creative efficient frontiers and informed management of more-robust portfolio strategies.

Conclusion

This paper describes integrated-project-management principles and risk-assessment techniques for selecting and optimizing oil and gas investment projects. An approach that uses a sound project-management method, life-cycle economics, and stochastic optimization in a probabilistic fashion can provide a useful tool for planning and tracking complex oil and gas projects. **JPT**

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Validating the Use of Experimental-Design Techniques in Exploratory Evaluations

This work presents a validation of the use of experimental-design techniques in exploratory evaluations. The results indicated that the quadratic technique showed the best cost/benefit ratio and suggested that the proposed methodology generates reliable results in most cases. The most influential parameter on the quality of the results was the range of possible results emulated by the proxy model. The quality of the risk analysis performed with these experimental-design techniques was influenced by the ability of the proxy model to emulate the flow-simulator response. The efficiency of different experimental-design techniques in different reservoirs was analyzed, and the reliability and limitations of this evaluation methodology were assessed.

Introduction

When evaluating exploratory prospects, a large number of variables are considered, each with a certain degree of uncertainty. Therefore, probabilistic approaches have long been used to quantify the effects of those uncertainties in the economic evaluation of these prospects.

The authors recommend use of flow simulators together with experimental-design techniques and response-surface methods to obtain a better understanding of the effect of dynamic uncertainties in the prediction of the cumulative production and the production profile.

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 107441, "Validating the Use of Experimental-Design Techniques in Exploratory Evaluations," by T. Amorim, SPE, and B. Moczydlower, SPE, Petrobras, prepared for the 2007 SPE Latin American and Caribbean Petroleum Engineering Conference, Buenos Aires, 15–18 April.

The experimental-design technique was used to plan a certain number of flow simulations and attempt to build a response surface (i.e., a proxy model of the objective function being studied). Use of this proxy model made it possible to run thousands of simulations quickly and perform risk analysis with the Monte Carlo method.

The quality of the risk analysis will be influenced greatly by the ability of the proxy model to emulate the flow-simulator's response. Three cases were studied: a nonassociated-gas reservoir and two oil reservoirs. The 10,000 results of the proxy model used to make the risk analysis were compared with 10,000 flow simulations. Thereby, it was possible to compare the efficiency of different experimental-design techniques and to assess the reliability and the limitations of the evaluation methodology proposed by the authors.

Methodology

One limitation in this process is that it can handle only parameters that vary continuously. Therefore, parameters that can assume only discrete values [e.g., pressure/volume/temperature (PVT) tables] were not used. The authors used commercial software to make a risk analysis of the proposed models. First, this software planned a certain number of simulations with experimental-design techniques. After those simulations were completed, it gathered information from the simulations (e.g., 20-years' cumulative production) and generated a proxy model of the objective function being studied with the response-surface method. Then the Monte Carlo method was used on this proxy model to develop a risk analysis. To enrich this study, two designs were used: quadratic and full.

The software's default quadratic design was used—face-centered com-

posite. Three values for each uncertain parameter were used to perform the flow simulations: the minimum, maximum, and average of the minimum and maximum. Not all combinations were used. Combinations were selected such that it was possible to estimate linear, interaction, and quadratic terms for all parameters. The full design, unlike the quadratic, used all possible combinations of the three values of each uncertain parameter.

The quadratic design is economical to use compared with the full design. For a study with five uncertain parameters, the quadratic design required 27 simulations, and the full design required 3^5 (or 243) simulations.

Another possible design would be the linear one. However, the linear design is recommended for performing sensitivity analysis only (i.e., determine the effect of each uncertain parameter on the response of the model). Thereby, it is possible to simplify a more expensive design, such as the quadratic, ignoring uncertain parameters that have little or no influence on the objective function. Quadratic and full designs are recommended for use in risk analysis.

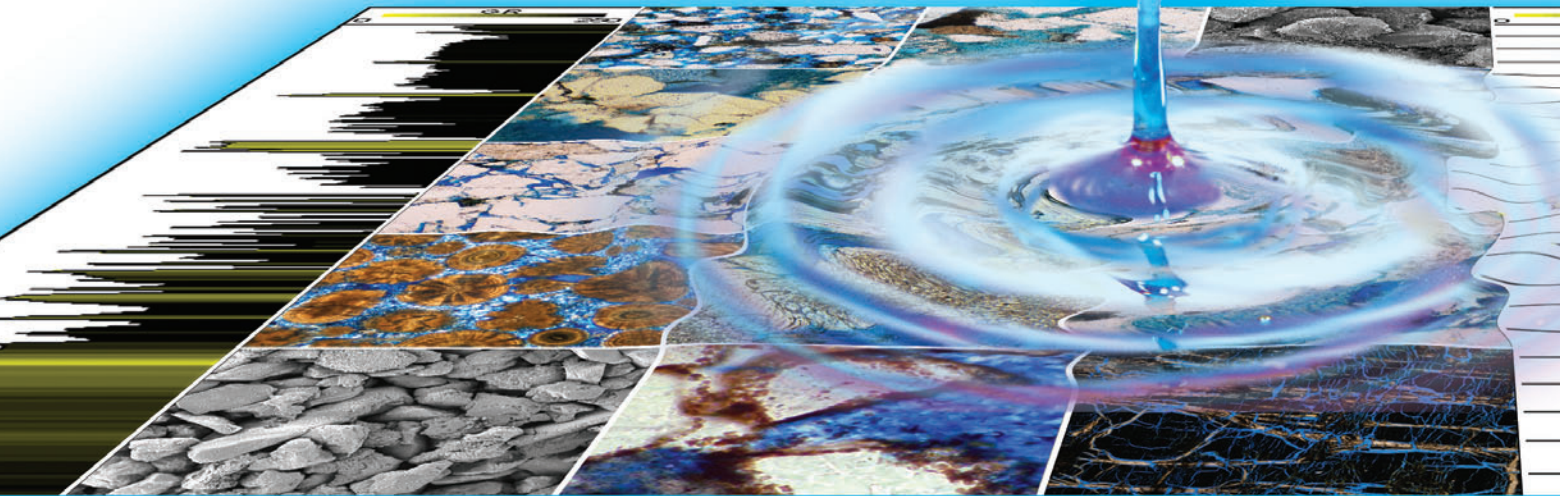
For each design, a risk analysis was performed using 10,000 results from the proxy model. These results were generated with random combinations of the uncertain parameters, and each parameter had a triangular probabilistic distribution associated with it. The combinations that were used in the risk analysis for the quadratic design were exported to generate 10,000 flow-simulation models.

Cases Studied

Three models were studied in this analysis: a nonassociated gas model and two oil models. All uncertain parameters associated with the models had a triangular probabilistic distribution.

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The maximum, mean, and minimum of each uncertain parameter represent the P0, P50, and P100 values, respectively. The P value of a variable represents the probability that a variable have values greater than that P value.

Because this is an exploratory study, both rock and fluid data were considered constant throughout the reservoir. For all models, the PVT data were prepared by use of standard black-oil correlations. All three cases have a water contact, but no active aquifer was considered (i.e., closed boundary). For each model, the wells have multiphase vertical-flow tables associated with it and are constrained by a minimum head pressure. The first oil model has both gas and water injectors, whereas the second oil model has only water injectors.

For both the nonassociated-gas model and the first oil model, the location of the wells was the same. In the second oil model, the range of water/oil contact used had a larger effect on the area; therefore, the authors used several well locations.

The experimental-design techniques used three sets of well locations, associated with the minimum, mean, and maximum values of water/oil contact. For the 10,000 simulations, the range of values for the water/oil contact was divided into 10 evenly spaced ranges. A different set of well locations was created considering the mean value of each smaller range. Every value of water/oil contact fell into one of these smaller ranges and was associated with one of the 10 sets of well locations.

The nonassociated-gas problem had five variables, but some of these variables were actually associated with more than one petrophysical parameter (such as a power law between porosity and permeability). The same method was used with the oil models: The first model had seven variables, and the second model had five variables. One parameter, vertical-/horizontal-permeability ratio, was associated with a dummy variable to have a log distribution of the P0, P50, and P100 values. The productivity-index multiplier was used to attempt to impose the same initial productivity for the wells in any combination of porosity and permeability, emulating the results of production tests performed in the area.

The biggest difference between the first and second oil models was that

in the second model, the range of each variable was much wider. Hence, it was expected that the results for the second oil model would vary more than in the first model, making it more difficult for the proxy model to emulate the results.

Results

The main results analyzed were the probabilistic distribution generated by these proxy models (i.e., quadratic and full) and the result of the 10,000 simulations. Two variables were studied in each model: original gas in place and cumulative gas production after 2 years for the gas model, and original oil in place and cumulative oil production after 25 years for the oil models. In this methodology, the authors recommend use of the cumulative production as the main objective function. The original volume in place should be regarded as an auxiliary result and used to estimate values for the pseudocases.

For the gas model and the first oil model, the results showed that both proxy models had a very good performance. All errors were below 5%. In these cases, there was no real gain in using the full design compared to use of the quadratic design. This was especially true when the number of simulations performed was taken into account: 27 vs. 243 in the gas model and 79 vs. 2,187 in the first oil model for the quadratic and the full designs, respectively.

The results for the second oil model were not as good as the other cases. The range of possible results was much greater: The P10/P90 ratio was approximately 2 for each of the first two models, while for the last model the P10/P90 ratio was approximately 4.5. Thus, the nonlinearities of the responses became more important and difficult to interpolate with the response surface that was used. Because the variables were considered to have a triangular probabilistic distribution, it was nearly impossible to have all their values near the maximum or minimum. Overall, the full design had a better performance than the quadratic design, but it performed 243 simulations, whereas the quadratic design used 27. Most of the errors were less than 10%, which is acceptable for an exploratory evaluation.

The authors suggest checking the number of estimates that are less than the minimum or greater than the maximum possible values (i.e., usually

the combination of all minimum or all maximum values of the variables used). In this case, 28 estimates for the original oil in place were less than the minimum possible value, and 51 for the cumulative oil production (less than 1% of the estimates). No estimates were greater than the maximum possible value for either the original oil in place or cumulative oil production. A large number of points outside the expected limits could indicate the proxy fails to emulate the response studied. Another possible check is to examine the errors committed by the proxy model when estimating original oil in place and cumulative oil production values for the same combinations used to build the proxy.

Conclusions

In the gas model and the first oil model, simpler studies of the applied methodology produced accurate results in the evaluation of the probabilistic distributions of hydrocarbon in place and cumulative hydrocarbon production. The small differences between the results from the quadratic and full designs indicated that the first design was the most cost-effective. Also, the results showed that both proxy models generally had good performance when generating individual results.

The response surfaces had a poor fit to the actual flow simulation results from the second oil model. This difficulty was a result of the wider range of the variables used and responses from the model. The second-order polynomial showed problems emulating the model when it converged toward zero. This flaw in the proxy model produced worse estimates for the probabilistic distributions studied. The authors suggest running extra simulations to check the reliability of the proxy models, especially near the areas of interest (usually P10, P50, and P90). Should problems arise, a design that makes use of more simulations is advised.

This methodology has limitations, and the user must take great care to not trust all the results immediately that are generated by the proxy model. Still, it proved to be a very promising tool in the evaluation of exploratory prospects. The authors encourage researchers and software developers to investigate smarter proxy models and better analysis tools. **JPT**

Reserves and Resources Classification, Definitions, and Guidelines: Defining the Standard!

In late 2004, a focused effort was begun to update the 1997 SPE/World Petroleum Council (WPC) Petroleum Reserves Definitions and the 2000 SPE/WPC/American Association of Petroleum Geologists (AAPG) Petroleum Resources Classification and Definitions. Evolution of the industry, driven by advancements in technology, the international expansion of the E&P sector, and the increasing role of unconventional resources in meeting global energy needs, drove the update. The 2007 system builds on previous industry efforts to provide sufficient guidance to achieve a high level of consistency in estimating resource quantities; it incorporates best practices identified in other international petroleum and minerals classification systems. Assessments may be conducted using deterministic and/or probabilistic methods. To satisfy requirements of the full range of industry stakeholders, the 2007 system introduces additional classification and categorization terminology. The resulting document is a set of technical guidelines that can be adopted by oil and gas companies to manage their business better. Moreover, it forms a standard that can be referenced by government agencies in defining reporting requirements.

Introduction

All assessments of in-place and recoverable petroleum quantities, their forecast

This article, written by Technology Editor Dennis Denney, contains highlights of paper SPE 107693, "The 2007 SPE/AAPG/WPC/SPEE Reserves and Resources Classification, Definitions, and Guidelines: Defining the Standard!," by John R. Etherington, SPE, PRA International, and John E. Ritter, SPE, Occidental Petroleum, prepared for the 2007 SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, 1–3 April.

delivery profile, and associated costs and revenues have significant inherent uncertainty. However, it is essential for future planning that governments, lenders, investors, and producers have access to consistent and reliable assessments, and that results be presented in a common format to communicate these underlying risks and uncertainties. The task of creating and maintaining the framework and language to support such communication has been assumed primarily by a consortium of professional societies: SPE, WPC, AAPG, and the Society of Petroleum Evaluation Engineers (SPEE). Their work is coordinated through the SPE Oil and Gas Reserves Committee (OGRC).

The OGRC was charged to recommend revisions and clarifications to maintain a standard for petroleum evaluations. The 2007 petroleum reserves and resources classification, definitions, and guidelines has been titled the *Petroleum Resource Management System* (RMS) (SPE 2007) and is hereinafter referred to as SPE-RMS or simply the SPE system; this label is intended to recognize the valuable contributions of the cosponsoring organizations (WPC, AAPG, SPEE), without whose input the resulting product would not have been generated.

SPE Mapping Study

Before drafting potential revisions, the OGRC sought to improve its understanding of other international clas-

sification and reporting systems. By carefully comparing (mapping) key features, best practices could be identified for potential incorporation into the revised SPE system. The mapping study was completed in late 2005 and is available on the SPE website. The study is focused on systems published by the following agencies:

- US Securities and Exchange Commission
- UK Statement of Recommended Practices
- Canadian Security Administrators
- Russian Ministry of Natural Resources
- China Petroleum Reserves Office
- Norwegian Petroleum Directorate
- US Geological Survey
- United Nations Framework Classification

External Standards

The OGRC also was asked to accommodate standards under parallel development by two external international organizations: the United Nations Economic Council of Europe through the United Nations Framework Classification, and the International Accounting Standards Board. It should be recognized that, while separate groups undertook these efforts, there exists a great deal of ongoing interface between them.

Resource-Evaluation Process

As an integral part of the overall process, the initial analysis consisted of a high-

Editor's Note

The *Petroleum Resources Management System* was approved by the SPE Board of Directors in March 2007 and was announced in "SPE Approves New Reserves/Resources Document" by John Ritter, Chairperson, SPE Oil and Gas Reserves Committee [JPT 59(6): 34]. This synopsis does not cover all the detail presented in the original paper or in the SPE-RMS. Please refer to the complete 2007 *Petroleum Resources Management System* and supporting documentation available online at www.spe.org.

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt. The paper has not been peer reviewed.

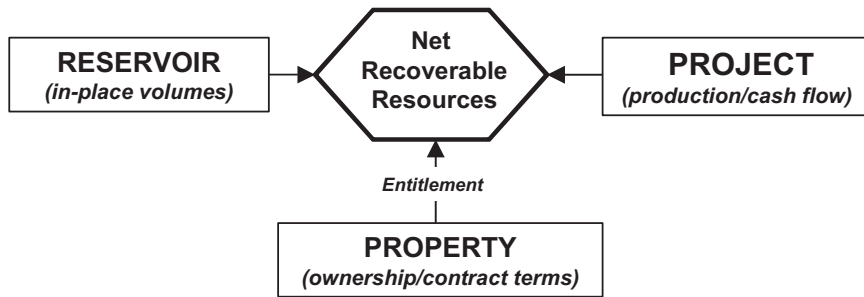


Fig. 1—Logical data model for resource assessment.

level review of the basic logic underlying resource evaluations. As shown in Fig. 1, the process focuses on the three main data elements, their key attributes, and their relationships that affect assessments of recoverable quantities:

- The reservoir and its associated accumulation of hydrocarbons—Key attributes focus on the total volume of petroleum initially in place (PIIP).
- The project (i.e., facilities and activities designed to recover a portion of the in-place petroleum)—Key attributes include the forecast schedule of production, costs, and revenues.
- The property associated with the reservoir—Key attributes are the allocation of costs and entitlements to

production defined in the property agreement or lease contact.

The following key logical data relationships were recognized:

- One project may target multiple reservoirs or one reservoir may be targeted by several projects. Production results from applying one project initially but possibly several projects sequentially or, in some cases, simultaneously, and at different stages of maturity.
- One property may encompass several reservoirs, or, in some cases, a large reservoir may extend over several adjacent properties.
- One property may have several participants with varying cost interests and production or revenue entitlements.

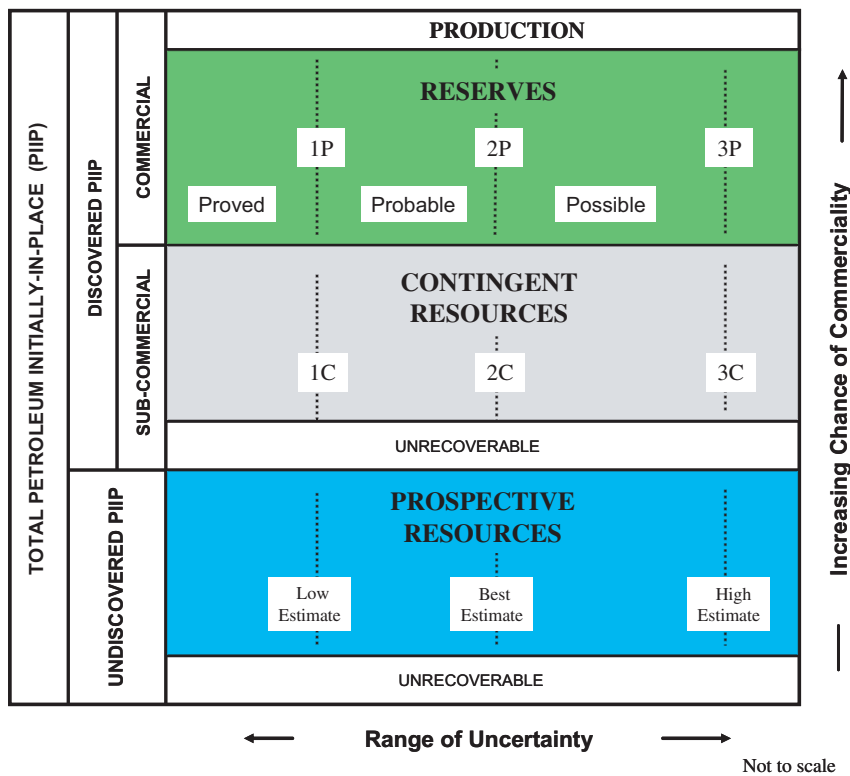


Fig. 2—Resource-classification system (SPE. 2007. Petroleum Resource Management System).

The quantities of interest are those that can be recovered and marketed by a specific project under defined conditions including those imposed by the lease contract. Some projects may be technically feasible but are not economic; that is, they do not result in a positive net present value. Evaluations ultimately focus on recoverable sales quantities and the associated future net revenues; thus, any classification system should be primarily project-based.

Classification System

To promote consistency in petroleum-resources evaluations, results reporting, and portfolio management, the basic classification framework shown in Fig. 2 was proposed.

All resources evaluations should be conducted in the context of the full classification system. A property evaluation that reports only reserves is typically incomplete; in almost all cases, there will be additional quantities of contingent and prospective resources. The system provides information on all future recoverable petroleum sales products. Within this 2D framework, projects are classified according to their commercial certainty (i.e., chance of being developed through to producing status), and estimates of recoverable quantities associated with each project are categorized on the basis of recovery certainty. The actual workflow of classification vs. categorization processes varies with individual evaluations and often is an iterative set of interpretation steps.

Resource-Classification Criteria

Prospective resources are those quantities estimated as commercially recoverable from yet undiscovered accumulations, assuming a discovery is confirmed. While there always are exceptions, a discovery is declared when the results of one or more exploratory wells support the existence of a significant quantity of potentially moveable hydrocarbons.

Discovered quantities should be classified initially as contingent resources. A portion of these quantities that can be recovered by a defined commercial project then may be reclassified as reserves. Commerciality requires that the project form part of an economic venture and the organization claiming commerciality has a firm intention to develop and produce these quantities. Firm intention implies that there is high confidence that any current con-

straining contingencies will be overcome and that development will be initiated within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives.

Project Status and Commercial Risk

To establish a more detailed resources-reporting system that also can provide the basis for portfolio management, the commerciality axis may be subdivided further according to project maturity. Projects may be characterized by standard subclasses and/or by quantitative estimates of their chance of reaching producing status. Project maturity reflects the actions (i.e., business decisions) required to move it toward commercial production.

Once projects satisfy commercial-risk criteria, the associated quantities are classified as reserves. These quantities may be allocated to the subdivisions based on the development and producing status of wells, associated facilities, and reservoirs. These reserves-status modifiers (developed producing, developed nonproducing, and undeveloped) are unchanged from the previous SPE guidance. Traditionally, reserves status has been applied to only proved reserves, but these same modifiers may be used for all reserves categories; even proved/developed/producing estimates have a range of uncertainty.

Quantities may be subdivided by reserves status independent of subclassification by project maturity. If applied in combination, developed- and/or undeveloped-reserves quantities may be identified separately within each reserves subclass.

Projects may be characterized further by their economic status. All projects classified as reserves must be economic under defined conditions. However, on the basis of assumptions regarding future conditions and their effect on ultimate economic viability, projects currently classified as contingent resources may be divided broadly into two subgroups: marginal contingent

resources and submarginal contingent resources.

Economic status may be identified independently of, or applied in combination with, project maturity subclassification to describe more completely the project and its associated resources.

Resource Categorization

Resources estimates in any class or subclass may be categorized according to the certainty of their recovery. These estimates have several sources of uncertainty:

- The total PIIP in the reservoir.
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects (i.e., recovery efficiency).

- Variations in the commercial conditions that affect the quantities recovered and sold.

The range of uncertainty of the recoverable, or potentially recoverable, quantities of marketable petroleum may be represented either by discrete deterministic scenarios or by a probability distribution. There is no change from the previous SPE guidance. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Historically, recoverable quantities were estimated by use of an incremental rather than a cumulative or scenario approach, and specific deterministic criteria have been associated with each of these incremental categories to promote consistency in resource assessments. Use of consistent terminology, as shown in Fig. 2, promotes clarity in communication of evaluation results.

For reserves, the incremental terminology (proved, probable, and possible) was retained, and, while clarified, there was no significant change in their associated technical criteria. The proposed guidance formalizes terminology for cumulative scenarios: 1P for proved,

2P for proved plus probable, and 3P for proved plus probable plus possible.

For contingent resources, new terminology was recommended to align with that used in reserves. While no formal terminology describes the incremental categories, the cumulative scenario notation is 1C, 2C, and 3C. It is emphasized that the contingent-resource categories use the same criteria as for reserves, but the development projects do not meet commercial specifications.

No incremental category labels were proposed for prospective resources, and cumulative scenarios remain described by the terms low, best, and high estimate.

Commercial Evaluation

An objective of the revised SPE system is to better align the classification guidelines with the actual commercial-evaluation processes. There is general agreement that companies make investment decisions on the basis of their internal forecast of those conditions that are projected to apply during the development schedule through to abandonment. For example, if a field is scheduled to begin production in 5 years with a field life of 20 years, the prices, operating costs, fiscal terms, and regulatory constraints that are applicable are those projected to prevail during this same time frame. These parameters are those that should be entered into economic analyses that define commerciality and future net revenue associated with production schedules, and ultimately affect resource quantities assigned to development projects. While the full range of results is considered, the base economics typically is reported in terms of the 2P and/or 2C forecast-case development scenario(s).

If an entity prefers to accommodate external reporting requirements for proved reserves, yet retain the overall structure of the SPE-RMS, evaluators merge both assessment approaches by substituting the external proved-reserves criteria for SPE proved-reserves criteria.

There may be circumstances in which the project meets SPE criteria to be classified as reserves but does not meet the external criteria for proved reserves. In these specific circumstances, the entity may record 2P and 3P estimates without separately recording proved reserves. As costs are incurred and development proceeds, the low-case forecast eventually will satisfy external

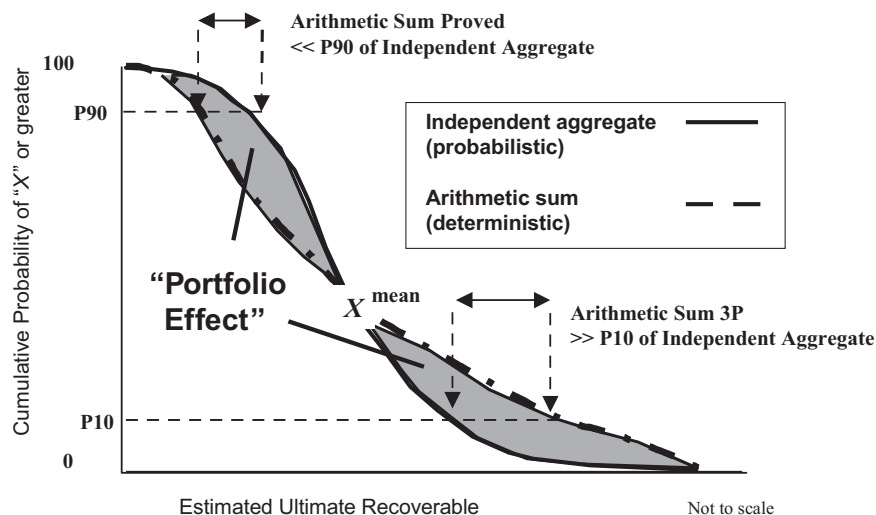


Fig. 3—Portfolio effect in resource aggregation.

requirements and proved reserves then may be assigned.

Note that proved reserves under the previous guidelines were required to be commercially recoverable under current conditions, while the revised guidelines substitute the term “defined conditions” to provide flexibility to meet internal technical criteria along with constraints imposed by lenders and/or regulators.

The revised system provides updated guidance that operating costs may be reduced and, thus, field life may be extended by various cost-reduction and revenue-enhancement approaches (e.g., sharing of production facilities, pooling maintenance contracts, or marketing of associated nonhydrocarbons). This guidance reflects the realities of business conditions while adhering to a sound, technically based system; however, it may not be consistent with disclosure rules specified by individual regulatory agencies.

Resource Entitlement and Recognition

Primarily, the leaseholder or host government owns all quantities of resources. Through various contracts and agreements, entitlement to a portion of future production or profit through sales is transferred to an oil and gas company (or consortium of companies). The portion of the total estimated future sales quantities that can be claimed by each stakeholder along with allocation of costs and revenues is defined in the lease agreement or contract.

Guidelines for the Evaluation of Petroleum Reserves and Resources (SPE 2001) examined reserves entitlement from the producing-company (contactor) perspective under a wide range of agreement types. Care should be taken that the resources claimed/reported by individual stakeholders sum to the total recoverable—that is, none is missing or duplicated in the allocation process.

The only significant addition in the revised guidelines in this area was a clarification regarding potential contract extensions. Reserves should not be claimed for those quantities that will be produced beyond the end date of the current agreement unless there is a reasonable expectation that an extension will be granted under the same or similar terms. Such reasonable expectation may be evidenced, for example, by the historical routine granting of contract or concession extensions by a controlling party or host government. Where major doubt exists regarding such extensions, the forecast production should be classified as contingent resources with an associated reduced chance of commercialization. If the renewal is reasonably expected but still subject to uncertainty, such uncertainty may be incorporated in categorization of sales quantities. Similar logic is applied to gas-sales contracts.

Procedures for Estimating Recoverable Quantities

The revised guidelines now include a section on procedures for estimating recoverable quantities on the basis of analogs, volumetrics, and performance-

based methods (reservoir simulation, material balance, and production-history analysis, respectively). In each method, resulting estimates are not a single quantity but rather a range that reflects the underlying uncertainties in both in-place volumes and the recovery efficiency of the applied project(s). Best practices indicate that the confidence in results generally increases when estimates are supported by more than one assessment procedure.

Deterministic and Probabilistic Methods

Regardless of the analytical procedure used, resource estimates may be prepared by use of either deterministic or probabilistic methods. Two methods of aggregation may be applied to a portfolio of projects and their individual ranges of estimates as defined by resource categories: arithmetic summation of deterministic estimates or statistical aggregation of probabilistic distributions. Even if conformance has been achieved at the project level, analysis of aggregation results often indicates significant differences. **Fig. 3** illustrates an extreme case by comparing a totally dependent with a totally independent aggregation. In general, the P90 of the statistical aggregate will exceed the arithmetic sum of project proved-reserves estimates. Conversely the P10 of the statistical aggregate will be less than the arithmetic sum of 3P estimates. Generally, this situation is referred to as the portfolio effect or, in statistical terms, the central-limit theorem. A larger and more diverse (independent) portfolio creates a greater portfolio effect. The P50 of the statistical aggregate shows markedly less variation from the arithmetic sum of 2P because this value approaches the mean of the distribution. In practice, there likely will be a large degree of dependence between reservoirs in the same field, and such dependencies must be incorporated into the probabilistic calculation by use of correlation coefficients.

Other classification systems that are focused on public reporting of portfolio results suggest that the probability limit for proved reserves at the project level may be relaxed as long as the portfolio results achieve P90. Under the SPE system, the uncertainty is defined at the field, project, or property level. However, deterministic cat-

egory constraints at the reservoir level still must be satisfied. Results reporting beyond this level that use arithmetic summation by category should caution that the aggregate proved reserves may be a very conservative estimate and aggregate 3P may be very optimistic, depending on the number of items in the aggregate. However, for detailed portfolio analysis, companies commonly use probabilistic aggregation in which the results incorporate the benefits of portfolio size and diversification in dampening the volatility in aggregate estimates. Thus, the aggregation method depends on the business purpose of the aggregation.

Summary

Major revisions in the proposed system are in the contingent-resources class, with the goal of promoting a more consistent and comprehensive inventory of future recoverable quantities. It was perceived by the OGRC that both internal and external reports were including quantities in reserves where the associated projects had major contingencies that would prevent implementation in

a reasonable time frame. By rigorously applying the recommended project-based approach, together with classification and subclassification criteria, the industry can develop a more thorough understanding of future production profiles with associated project risk. The categorization guidance according to certainty applies equally to reserves and contingent resources.

In the area of reserves, the proposed system clearly recommends that the base case for commercial decisions should use the evaluator's forecast of future conditions including product prices that will exist during the field life. When combined with various sensitivity analyses, this case underpins internal project investment commitments. Typically, recovery scenarios are derived from this base case, with 2P being the single best representation of expected recoverable quantities; whereas proved reserves is a high-confidence estimate that incorporates specific deterministic criteria. The proved-reserves definition has been modified to require that commerciality be demonstrated under

defined conditions to accommodate all stakeholders' requirements.

While recognizing the value of probabilistic methods in resource evaluations, the revised guidelines retain the requirements that results must conform to deterministic criteria for proved reserves. Best practice is to apply combinations of incremental analyses, deterministic scenarios, and probabilistic methods to support resources assessments.

It should be understood clearly that the definitions and guidelines contained in the SPE-RMS document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements unless such regulations (or associated guidelines) explicitly refer to the SPE-RMS document as a part of, or basis for, those regulations.

The SPE system consolidates consensus from a diverse group of stakeholders. The OGRC will continue to maintain and update these best-practice resource-assessment guidelines as technology and commercial conditions continue to evolve. **JPT**

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