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Forecasting Oilfield Economic Performance

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Summary

This paper presents a general method for forecasting oilfield economic performance that integrates cost data with operational, reservoir, and financial information. Practices are developed for determining economic limits for an oil field and its components. The economic limits of marginal wells and the role of underground competition receive special attention. Also examined is the influence of oil prices on operating costs. Examples illustrate application of these concepts. Categorization of costs for historical tracking and projections is recommended.

Introduction

Ultimate recoverable oil and gas volumes (" reserves") are estimated for many purposes, including internal company planning, external asset valuation, and government and financial reporting. A key element of field performance forecasting is quantification of hydrocarbons that are both "technically" and "economically" recoverable. In the U.S., a number of regulatory agency and industry guidelines have evolved over the years to reduce subjectivity, but reserves estimation and reporting continue to be debated.

Technical reserves are usually calculated by estimating original oil in place (OOIP) and recovery factor. OOIP is a measure of reservoir size and is mainly a function of rock and fluid properties. Recovery factor is an engineering estimate based on geology, reservoir development, and reservoir management strategies. A wide variety of methods to estimate recovery factors are used, including analytical calculations, performance-based correlations, and numerical simulations.

Estimation of technical reserves is better understood by the industry than determination of economic producibility. Technical and economic components of reserves often are calculated independently by different professionals. Sometimes technical recovery is predicted in more detail than is commensurate with the economics.

Campbell noted that the advent of the computer in performance analysis has "enhanced precision and detail without a necessary increase in accuracy." He called for a "new paradigm" in evaluation methods in which petroleum professionals are not only technically competent but also possess a "higher degree of economic literacy."

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Recommended Approach

Oil fields, like other businesses, should be operated to maximize returns to shareholders (subject to legal and health, safety, and environmental quality constraints). Performance forecasting should reflect this philosophy. Projections of field activities, costs, and production must be integrated to predict economic performance. Field operations/activities that are and will likely remain uneconomical should be identified and shut down.

Although it may reduce fieldwide oil rate, the shutdown or consolidation of large portions of the field may be necessary to maximize cash flow in mature fields. Such an operation, which we call "de-development," might involve groups of wells, projects, or surface processing facilities.

Field production will be maintained until continued negative net cash flows are expected and further operational reductions would reduce revenues faster than expenses. (This paper does not consider the distinction between shutdown and abandonment decisions.)

Company and industry analysts speculate about future oil prices, but generally do not have control of this parameter. Maximizing the value of an oil field will depend on understanding and controlling operating costs.

Published Cost Models

Three basic methods are discussed within the published literature for prediction of future operating costs: constant lifting cost per barrel, constant lifting cost per well per year, and constant lifting cost per platform (or field) per year. Cost per well per unit time is the most commonly used. Next is the total field/platform basis with or without adjustments for real cost or oil price inflation rates. All three methods have limitations. Use of constant cost per barrel is optimistic for fields with declining production because fixed costs are ignored. By contrast, the other two methods incorrectly assume all costs are independent of fluid rates and time.

Techniques with fixed and oil-rate dependent components of operating costs have been presented. These methods, however, do not include the influence of associated gas and water production on costs. Also volumes, prices, and costs are assumed independent.

Cost Relationships

Cash profit is maximized by producing to the point where the marginal cost (MC), defined as the change in total costs to supply an additional unit, for each activity is equal to its marginal revenue (MR), defined as the change in total revenues received after selling one more unit. For a competitive industry (no single producer can affect market price), MR is average realized price per unit. MC, however, is rarely the same as average cost (total costs/total produced units), as the example in Fig. 1 illustrates. Use of average unit costs instead of MC will rarely maximize profits (defined as total revenues minus total costs).

Accurate prediction of future operating expenses requires a good understanding of cost relationships and the factors that influence them. The shape and magnitude of the MC curve will vary with short-term changes in activities and long-term economic forces. Activities that determine costs over a relatively short period of time are called cost drivers. Internal or external forces acting to change the cost-driver relationships over time (and thus shift the MC curve) are called cost accelerators.

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Cost Drivers

Short-term operating costs are estimated at a given time by determining cost drivers. We believe that, for a producing property, three categories of cost drivers exist.

1. Costs related to production. Usually fuel/power and chemicals, but could include some maintenance.
2. Costs that vary with well count.
3. Costs that are "fixed" over the short-term but are subject to upward or downward pressure in the long-term.

This may be expressed as

(CT)t=f(fluid rates, well count, field fixed costs)t

(1)

where (2)

and (3)

The equations in this paper are based on oil production. Similar relations can be developed for gas fields and sales.

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Subjects: **Asset and Portfolio Management**, **Energy Economics**, **Market analysis /supply and demand forecasting/pricing**, **Project economics/valuation**, **Reserves replacement, booking and auditing**

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Suggested Reading

The Pitfalls of Capital Budgeting When Costs Correlate to Oil Price

J Can Pet Technol (August,2008)

A Quantitative Method for Estimation of Volatility of Oil Production Projects

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A Method Study of Economic Evaluation for Development Program Project

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