ECONOMIC EVALUATION OF OIL & GAS PROPERTIES

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Contents

Chapter 5

Chapter 6

Chapter 7

Chapter 8

Chapter 9

1

PURPOSES OF ECONOMIC EVALUATION

The objective of petroleum property evaluation is to examine, define, and implement methods and procedures for developing and extracting crude oil and natural gas as well as any associated products to optimize profits and, at the same time, to obtain an economic return that is commensurate with the risk incurred in making the investment. *The term "optimize" is used rather than "maximize" because there are factors other than financial considerations that can influence both the decision to make an investment in an oil and gas project and the return to be obtained from the investment; the project may not provide the maximum economic return, but may provide an optimal return when other considerations are included.*

Hereafter, to avoid repetition of the phrase "oil and/or gas," the terms **oil, hydrocarbon,** or **petroleum** are used as a reference to both oil & gas, unless specific reference to one or the other is necessary.

The economic evaluation of a property or project consists of two broad functions:

- Estimation of the potential volumes of producible oil and/or gas attributable to a property or project, and derivation of one or more schedules of recovery of the producible volume.
- Estimation of the economic benefit of the anticipated production.

These are not separate functions. Some aspects of the first are necessary to accomplish the second objective and, in that respect, the two functions meld at the boundary so that one influences the other. The first part of this discussion will deal **briefly** with estimating the amount of producible oil & gas along with estimating the future production schedule. The second part will define the procedures for estimating the economic benefit of future production.

There are many reasons for estimating the economic value of an oil & gas project. A number of methods can be used to make the estimate. However diverse the reasons for an evaluation, they can generally be placed in one of two groups: Investment Analysis or Required Valuation.

which reflect three distinct methods of data analysis – cost, sales comparison, and income capitalization. One or more of these approaches are used in all estimations of value; the approaches employed depend on the type of property, the use of the appraisal, and the quality and quantity of the data available for analysis."[7] The potential application of these approaches to petroleum property evaluation requires discussion of the methods.

Cost Approach

The **Cost Approach** estimates value based on the cost to replace or reproduce a structure or facility such as an office building, factory, HVAC unit, or other equipment. Essentially, this method estimates the value of a 20-year-old factory building by determining the cost to reproduce the building, as of the evaluation date, using current construction expenses, building codes, and other requirements. Similarly, the approach could value a stand-alone facility, such as a power generation plant, by estimating the cost to replace it with current equipment and construction requirements.

Comparable Sales Approach

The **Comparable Sales Approach** relies upon the process in which a value estimate is derived by analyzing the market for similar properties that have been recently sold (the comparables) and comparing these properties to the property being valued (the subject). This approach is commonly used in real estate appraisal for residences, land, farms, and commercial/industrial buildings. It is simple in concept and is usually thought to give a good estimate of value for the appropriate types of property. The process has several steps. The appraiser researches the market for sales of properties with characteristics similar to the subject property. After verifying the data regarding both the property and the sale, the appraiser defines the similarities and differences between the comparable and subject property and then makes adjustments to the value of the comparables to match the attributes of the subject property.

This method works well for the types of properties to which it is normally applied. In residential real estate, all the necessary data is relatively easy to obtain from public records and from realtors' listings and databases. Banks and other sources provide financing and market information. If necessary, the appraiser can go to each property and accumulate data directly – measure the house and the rooms, check the heating, the roof, the plumbing, etc. He can talk to the buyer and the seller, real estate agents, finance company, and escrow agents. For further discussion, refer to Appendix A, Comparable Sales Method of Appraisal and Petroleum Properties.

gravity, location, and virtually every other characteristic of the property. The contribution of each characteristic may not be definable or quantifiable, and the influence of one may be partially offset by another, but there can be no argument that operating costs reflect the character of the property – and that they are not readily transferable except in broad terms.

An evaluator must also define the **operating system** that is necessary to obtain the production. The operating system will be determined, in part, by the physical characteristics of the hydrocarbon source, but will also be related to the business plan for the property as implemented by an owner/operator. The choice of operating system will influence the costs of production, such as the costs of lifting, gathering, and processing produced fluids. Such costs may include capital investments for wells and surface equipment plus other expenditures to meet regulatory requirements.

Incorporation of Current and Future Economics

Construction of an income stream for a property allows the evaluator to incorporate not only existing economic conditions of the property but also to apply expectations for oil prices, gas prices, operating costs, taxes, and other factors. While the discussion of economics usually centers on future product price and operating costs, other areas such as the need for further investment, production or ad valorem tax increases, changes in royalty or other ownership, and federal and state regulation and income taxes, where applicable, must be considered. These expectations for the future are not trivial matters. Expectations are what drives investment decisions. Expectations also have influence on the remaining life and future production of a property by defining the economic limit of production and by invoking other economic conditions such as the cost of abandonment and clean-up.

Reduction of Differences Among Properties

If constructed so that it reflects the characteristics of the property and includes reasonable economic expectations, the income stream can then render its greatest service to investors, owners, and evaluators by providing a means of directly comparing one property or investment to another on a quantifiable basis.

Consider, for example, two properties: Property A is a multi-well lease in Kern County producing steamflood oil from the South Belridge-Tulare Formation. Property B is a multi-well lease producing from the Seminole-San Andreas reservoir in western Texas. An evaluator knowledgeable of both properties could doubtless list a large number of characteristics that differ between the properties. However, at the same time, he or she would be hard pressed to find a characteristic that is not reflected by some part of the income stream.

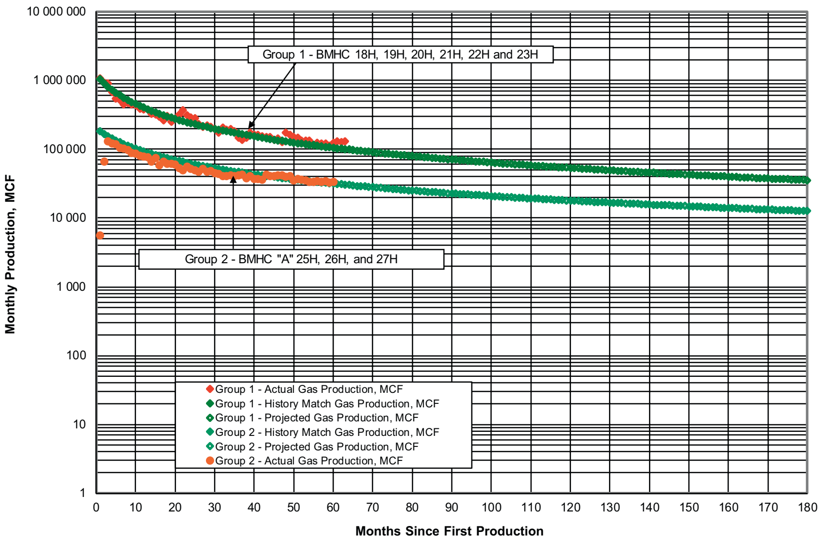

Figure 29. Bobst Mountain Hunting Club Lease, Lycoming County, Pennsylvania

That analysis was confirmed by a second evaluation (Figure 30) done after about 123 months of production which is shown to continue to follow the 63-month history-match projection. The analysis of Group 2 confirmed the decision to match the production for month 42 through 63 as the prevailing decline trend. This approach has been used on literally hundreds of oil & gas properties.

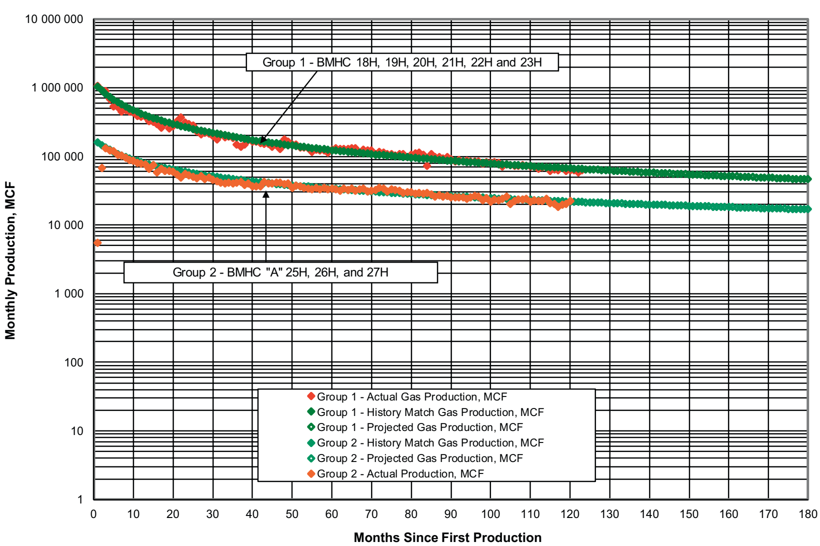

Figure 30. Bobst Mountain Hunting Club Lease, Lycoming County, Pennsylvania

method, can be used to analyze the effect of cyclic steaming on a particular property or reservoir and to estimate the change in unstimulated production (q_p) to stimulated production (q_s) with each cycle. Studies of California fields in the early 1970s[10] found that cyclic steam recovery from wells and properties was influenced by reservoir conditions but also by engineering and operational management of the project such as the control of steam volumes injected and the "quality" (heat content) of steam generated for the project and then reaching the well-bore.

Cyclic steaming has been applied in many forms in different reservoirs. Experience in California and elsewhere found that the thickness of the steamed zone could introduce a near-wellbore gravity-drainage effect. A zone thickness of 100 or 200 feet or more of continuous sand could result in heated, less viscous oil draining into the wellbore due to a gravity effect. This variation of cyclic steaming, known as Steam-Assisted Gravity Drainage (SAGD) has been applied in tar sand reservoirs in Alberta and China.

Fracturing

The use of hydraulic energy to create fractures in the reservoir is a primary production stimulation method that alters the near-wellbore reservoir characteristics, permanently or temporarily, to enable production to increase. Hydraulic fracturing generally increases the rate of production and, thereby, can have an economic benefit but does not usually add to ultimate recovery. There are exceptions: fracturing could have the effect of creating contacts between fractures and pore space that was not previously connected and extending the drainage volume of a well, thereby increasing potential production.

The combination of hydraulic fracturing and horizontal drilling, introduced in the 1990s and applied primarily to shale reservoirs, has allowed development of oil & gas from previously undeveloped reservoirs such as the Marcellus, Haynesville, Eagle Ford, and Barnett shales. Analysis of production data from fractured shale wells in these and other formations indicates that the production performance is clearly defined as being hyperbolic with a sharp decline rate from initial production over the first 24-36 months, followed by a transition to exponential decline.

Acidizing

The use of acid to improve near-wellbore permeability is not nearly as exciting a method of production stimulation but, when applied to an appropriate reservoir and under the correct circumstances, can often result in an increase in production. The effect of acidizing is to improve porosity and thereby permeability in the near-wellbore portion of the reservoir. The method seems to work best in calcareous reservoirs, particularly when combined with hydraulic fracturing, Stepping back a bit, crude oil and natural gas (in this discussion all reference is to crude oil unless specific mention of gas is necessary) can have two prices at the same time – a **spot price** and a **futures price**. Both are a function of "physical" markets in that their purpose is to exchange actual volumes of oil and/or gas between buyers and sellers. The main difference between spot and futures prices are the timing of the transaction and the date of delivery. The spot price of a volume of oil is the present cost, for current purchase and delivery. The transaction occurs on the spot and reflects the price at which the oil is being traded in the marketplace.[13] The oil volumes that are bought and sold in the spot market happen promptly – the buyer accepts delivery of the goods right after the money is exchanged. The posted prices discussed above as a source for initial price information are examples of the spot market for specific fields and crude types. The price of the spot contract demonstrates the immediate or current market price.

On the other hand, the price of oil in the future may be estimated by way of a futures contract.

The recognition of oil & gas as tradable commodities has led to the development of vehicles for estimating the price that would be paid for a future delivery of a certain volume of oil and/or gas. The New York Mercantile Exchange or "NYMEX" (now CME Group) maintains markets in crude oil and natural gas by the trading of contracts for future delivery of a specific volume of crude oil or natural gas. These **futures markets** operate in the same manner as the stock exchanges; the prices for future contracts vary continuously over a trading session and from day to day. The resulting market activity is published daily by market sources, newspapers, and various on-line reporting agents. Oil contracts can be defined for up to 10 years, while natural gas contracts extend up to 12 years. The contract prices can give a sense of the direction of future prices (up or down) and the anticipated degree of change in prices.

There are two major oil futures contracts. West Texas Intermediate ("WTI") crude is the benchmark crude for North America and trades on the NYMEX.[14] Brent Crude is the benchmark for Africa, Europe, and the Middle East and trades on the Intercontinental Exchange.

The futures contract shows how much buyers are willing to pay for delivery of a certain volume of oil at a predetermined date. In the absence of otherwise reliable guidance regarding future oil & gas prices, an evaluator can make use of the futures market for crude oil and for natural gas (and other products) as a source of data. A futures contract represents trading a commodity for delivery at a later date and reflects a "future" price agreed upon by the buyer and seller for a specific volume of crude oil. An oil futures contract is a legal agreement to trade a particular volume of oil at a predetermined price at a specific date.

Oil futures contracts are simple in theory. The specifications for crude oil futures contracts are set by the exchange in a way that allows market participants

Periodic costs may be of sufficient magnitude that specific budget authorization is required. In that case, an evaluator must decide whether the costs should be treated as operating costs or as capital investment. The inclusion of these costs should be reviewed as the property nears economic limit to determine whether it is appropriate to adjust the scheduling of the expenditures.

Fuel Costs

Fuel Costs can and should be a separate category when the source of the fuel and the cost justifies special consideration. This category usually refers to the cost of natural gas to fuel steam generators or other special use facilities and/or electric power for pumping units and other field uses. The governing criteria is that if natural gas and/or electric power are obtained from a third party, whether a utility or another operator, in sufficient volume to impact the property if that fuel/power were not available. The source of this data should be purchase contracts, and purchase and payment records.

Certain special cases regarding fuel source require mention. If produced oil and/or gas is retained for use on the property as lease fuel, commonly referenced as Used-on-Lease (UOL), the volume used for fuel can be included in the income stream by reducing the amount of production available for sale, or by deducting the equivalent value of the fuel volume as an operating cost. The UOL production serves an economic purpose even though it does not produce revenue by substituting for costs for fuel that would otherwise have to be purchased. The choice of treatment usually depends on whether or not the lease agreement requires payment of royalty on production used as lease fuel (most leases do not) or whether fuel usage can be deducted for production tax calculation (generally, no). Deduction of fuel usage from production may distort the income stream; therefore, the best approach may to treat produced fuel usage as a separate operating cost subject to the prevailing price for oil or gas used. Another judgement call.

Overhead

Overhead is considered carefully, whether valuing a single property or multi-property project. Overhead is often an indirect expense that is incurred off the lease but is then allocated to the property. Such costs might be district or head office supervisory and engineering staff. Overhead also includes distributed costs of environmental, regulatory, or other programs that are applied across several properties or which have no property-specific application. The overhead to be considered should only be the cost of direct management supervision of the property and staff services related to the property. The usual approach is to develop overhead costs as a percentage of recurring operating costs. An alternative