The American Association of Petroleum Geologists Bulletin
V. 63, No. 12 (December 1979), P. 2183-2192, 14 Figs.

Methods of Estimating Oil and Gas Resources[1]

DAVID A. WHITE and HARRY M. GEHMAN[2]

Abstract Assessment of undiscovered oil and gas potentials can be made and presented in a probability format reflecting the inherent uncertainties and risks. A cumulative probability curve shows the chances of occurrence of possible hydrocarbon volumes, the risk that there is little or no potential, the average or expected value, and the "highside" potential. Such a curve can be drawn directly as a delphic consensus of expert opinions. Preferably, however, a curve can be constructed by multiplying, in a Monte Carlo simulation, several factors whose product is potential barrels of oil or cubic feet of gas. Each factor is entered as a range of values whose spread depends on the uncertainties. An example is the multiplication of the possible volumes of prospective sedimentary rock (e.g., in cubic miles) by their potential hydrocarbon yields (e.g., barrels per cubic mile). Other geologic approaches depend mainly on estimated volumes of subsurface hydrocarbon trap space, on areal yields, on geologic analogies with other producing areas, on summation of individual prospect assessments, on the numbers and sizes of potential fields, or on the geochemical material balance of hydrocarbons generated, migrated, and trapped. More purely statistical methods involving the extrapolation of past discovery rates can be used only in maturely explored areas where data are abundant.

INTRODUCTION

The methods of estimating oil and gas resources ahead of the drill are many and varied. Different approaches are needed for different levels of geologic knowledge and for different purposes. Recent trends have been toward use of more sophisticated computer models, toward a more realistic accounting of geologic risk, and toward reporting results as ranges of values rather than as single numbers.

Two basic questions are to be answered in an assessment. First, are any conventional oil or gas fields present in the area? The answer depends on an analysis of the geologic risks. If, for example, there is zero chance that source or reservoir or trap conditions are adequate for at least one field, the answer is no. If there is some chance that the answer is yes, the second question that naturally follows is, how much oil or gas? This question is usually answered by multiplying a series of hydrocarbon volume factors, whose end product is barrels of oil or cubic feet of gas.

The answers to these two questions give what is known as the resource base, which we define as the total hydrocarbon that is potentially recoverable, regardless of the size, accessibility, or economics of the postulated fields involved.

Government and industry economists alike want to know more about the attainability of the resource—that is, how much might actually be found and produced under currently foreseeable economics and technology. The numbers and size distributions of potential fields are important, for in every setting some will be too small to pay back drilling and production costs. Assessors also need to predict whether the product will be oil or gas; in very remote areas, the added difficulties and costs of handling natural gas may be prohibitive. Next, it may take too much time and expensive drilling to find some deposits, such as subtle stratigraphic traps in areas that are difficult to explore. Other deposits, even if found, may be in such poor, impermeable formations that wells produce too slowly to be economical. Furthermore, locations under Arctic ice, or in very deep water, or at great distances from shore may be effectively inaccessible.

ASSESSMENT PROBABILITY CURVES

Even at best, the geologic and economic uncertainties inherent in these questions can be awesome. That is why more and more assessors now report their results as ranges of values, qualified even further by the risk that the whole range might be wrong (see Hedberg, 1976, p. 1015-1016, and the "analogy ratio" of Semenovich et al, 1977, p. 147). Figure 1 is an example of assessment probability curves for a single prospect for a potential oil field. The lower risked curve is derived from the upper unrisked curve. The horizontal scale shows the possible range of answers

[1]Manuscript received, February 5, 1979; accepted, June 21, 1979.

Read before the American Association for the Advancement of Science, Houston, Texas, January 5, 1979. Abstract republished from *Abstracts of Papers of the 145th National Meeting, January 3-8, 1979*, p. 83.

[2]Exxon Production Research Co., Houston, Texas 77001.

Article Identification Number
0149-1423/79/B012-0004$03.00/0

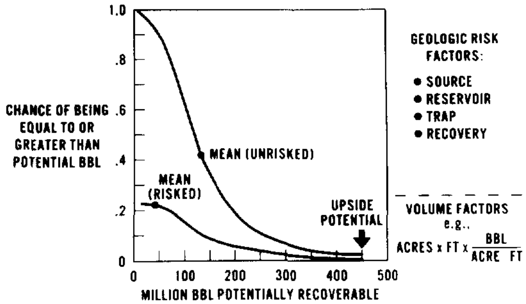

FIG. 1—Assessment probability curves (after Gehman et al, 1975).

from zero to 450 million bbl. On the vertical scale is the chance of exceeding any given barrel value along the curve. On the risked curve, for example, there is an indicated 0.05 or 1-in-20 chance that the potential will be equal to, or greater than, 200 million bbl.

In practice, the potential volume distribution of hydrocarbons is usually determined first. The unrisked curve (Fig. 1) is produced by multiplying several volume factors together in a Monte Carlo simulation. Monte Carlo is a procedure that simulates probability distributions by running many trials; the range of possible answers reflects different combinations of values selected at random from within specified ranges of input parameters. Examples of prospect volume factors are potentially productive area in acres, times estimated pay thickness in feet, times a possible yield in barrels per acre-foot. Each volume factor is entered into the simulation as a range of values reflecting the uncertainties about that factor. (Capen, 1976, outlined some of the problems and principles of establishing realistic ranges.) The computer simulation multiplies many possible combinations from these ranges to give, for example, 500 possible answers. These answers are lined up in order from smallest to largest, giving the unrisked probability curve. Of the 500 answers, 300 or 60%, for example, are larger than 100 million bbl. The unrisked mean is the average of all 500 trials.

If the estimates of the volume factors were right, the upper unrisked curve (Fig. 1) would itself show the chance of finding each different level, or more, of recoverable potential. The assessor uses an analysis of geologic risk to estimate the chances that the volume factors *are* right. In geologic risk analysis it is necessary to consider the basic controls of hydrocarbon occurrence—source, reservoir, trap, and our ability to recover the oil or gas. If any of these four controls is missing or inadequate, then the prospect will be dry and there is no reward. We estimate the adequacy of each factor and multiply all four estimates to get the overall chance for the prospect. If our estimated individual chances were 0.5, 0.5, 1.0, and 1.0, respectively, the overall chance would be 0.25. This is the estimated combined chance that the real answer lies within the product of the ranges specified for our volume factors. Thus there remains a 0.75 risk that the real answer falls below the assessed range and is essentially zero. (Risk equals one minus the chance of adequacy.)

The unrisked curve of Figure 1 is discounted to the risked curve by reducing the probabilities in accordance with the risk analysis. In this example, the probability for each potential is reduced to 25% of what it is on the unrisked curve. The actual range of barrel values remains the same, including the upside potential. Of every 100 possible outcomes, only 25 would successfully fall within this range on the risked curve itself. The other 75 would all have essentially zero barrels. There is a 75% risk that there will be no oil in the prospect, because of the inadequacy of the geologic controls. The risked mean is the arithmetic average of all possible outcomes, including the 25 values sampled along the curve plus the 75 zeroes. Thus the risked mean is 25% of the unrisked mean expectation. Gehman et al (1975) and Energy, Mines, and Resources Canada (1977) gave more details on risking procedures.

If assessment methods are realistic and systematic, the final risked probability curve can give a good idea of potential exploration rewards, in terms of barrels of oil and cubic feet of gas, and of the associated geologic risks that may deny these rewards. All basic geologic data, assumptions, and interpretations can be laid out for reviewers, and the curve provides the foundation for economic analyses.

Geologic risks are very real but also are very difficult to evaluate. Risk magnitudes often are based on interpretation of geologic maps of the area being assessed and on historical experience with drilling success in nearby or similar areas. No assessment is complete without some kind of risk analysis. In discussing methods, we will concentrate on the differences in volume factors that distinguish different approaches. However, every method can have, and should have, some measure of risk built into it.

ASSESSMENT METHODS

Figure 2 lists the various methods that have been used. Principally, these are geologic analogy, delphi, areal and volumetric yields, geochemical yields, field number and size, summations, and extrapolations. There are many variations and

	VARIATIONS APPLICABLE TO: PROSPECT	PLAY	BASIN
• GEOLOGIC ANALOGY	✓	✓	✓
• DELPHI	✓	✓	✓
• AREAL YIELD	✓	✓	✓
• VOLUMETRIC YIELD	✓	✓	✓
• GEOCHEMICAL MATERIAL BALANCE	✓	✓	✓
• FIELD NUMBER AND SIZE		✓	✓
• SUMMATION OF PROSPECTS, PLAYS		✓	✓
• EXTRAPOLATION OF DISCOVERY RATE			✓

FIG. 2—Quantitative methods of assessing potential volumes of undiscovered hydrocarbons.

combinations of methods, with more or less overlap. The checks (Fig. 2) show whether variations can be applicable to prospects, plays, or basins. Specifically for assessment purposes, we define a prospect as a location of a single potential oil or gas pool or field. A play is a group of geologically similar prospects. A basin is a larger volume of sedimentary rock that contains one or more plays. Multibasin areas can also be handled by summations and extrapolations.

We have omitted from this list the older A-B-C-D and numerical grading systems that give qualitative answers instead of hydrocarbon volumes in barrels or cubic feet.

Geologic Analogy

In its simplest form, assessment by analogy says that, if untested area A looks geologically like known producing area B, then it must have a similar oil and gas content. In practice, most approaches use also some of the scaling factors of other methods to compensate for obvious differences. If basins A and B are geologically similar except that one has a much smaller sedimentary volume, for example, it is necessary to normalize the volume factor.

Some geologic analogies single out one of the key geologic controls of hydrocarbon occurrence, such as similar source beds (Conybeare, 1963), or similar reservoir beds (Zhdanov, 1962), or similar trap closures. Some of these methods use very sophisticated computer techniques to compare the geology of a thoroughly drilled area with that of an adjacent, less drilled, prospective area. An example is the study of structure maps in Kansas by Hambleton et al (1975). Abry (1975) used multiple discriminant function analysis for similar studies of the structural trap closures in west Texas.

Other geologic analogies are based on broader comparisons, such as the genetic basin types of Weeks (1952) and the subsequent basin classification of many other authors (e.g., Klemme, 1971, 1975; McCrossan and Porter, 1973; Bally, 1975; Pitcher, 1976).

Perhaps the most comprehensive analog approach is that described by Gess and Bois (1977). They used computerized cluster analysis of historical data to find the known play most like the one being assessed. A play, or "petroleum zone," is described by 153 parameters directly observed or estimated, 76 ratios calculated from these, and 106 qualitative judgments transformed into numbers. From 20 to 120 of these 335 parameters are used to place a new play in one of seven classes and to pick the closest known look-alikes within that class. Nalivkin et al (1976) also dealt with multiple geologic analogies.

The chief advantages of geologic analogies are the many ties with experience and the resulting possibilities of making realistic and meaningful comparisons. Geologic analogy, in one form or another, enters into almost every method. Disadvantages may develop if only one geologic factor is selected for comparison, and then some other key factor changes or is different in the compared areas. In our present state of knowledge, we cannot be sure that we have the whole story even when multiple factors are considered. Indeed, the success or failure of analog methods probably depends less on the similarlities, and more on the differences, as weighed by whatever scaling and risking factors are used. If only one critical factor is different, the analogy may be very misleading.

Delphi

The delphi approach (Fig. 3) takes the average of several expert opinions of the probability distribution of potential resources. The procedure is

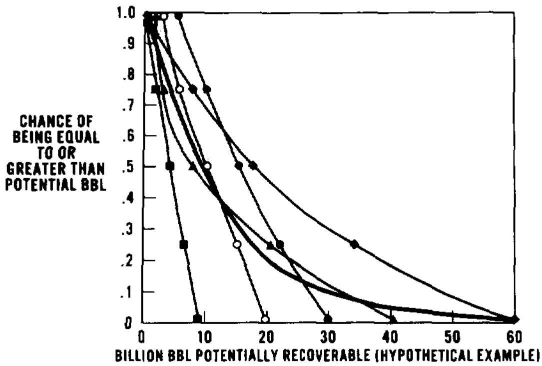

FIG. 3—Example of delphi averaging of five opinions expressed as probability curves (from Megill, 1977).

named after the ancient Grecian oracle, but experts replace the priestesses and prophets. This method was used by the Geological Survey of Canada (Energy Policy for Canada, 1973), and a modification was later used by Miller et al (1975) of the U.S. Geological Survey. As the method is usually practiced, a group of experts reviews all the available geology and visualizes the critical factors. Then each member constructs his own probability curve of the potential resources. The group reviews all individual results, some of which may be modified. Then all the curves are averaged. As shown on Figure 3, the probabilities of the five individual curves are averaged at each barrel amount to give the final curve, which is taken as the consensus.

The main advantages of delphi are its ease of application and its full probability format. Delphi provided the main bridge from the older qualitative rankings and one-number assessments to the preferable ranges of values with stated probabilities. It also provides a useful judgment check on other methods. The principal disadvantages are that it contains no built-in scaling factors or documentation of the direct input. One must know how expert are the experts in order to assess the assessment. It is asking a lot of most human beings to have them estimate such a complex product as oil barrels in one mental operation. It seems more realistic to break the problem down into its component volume and risk factors. At these levels much judgment is still required, and delphi can be used advantageously on the parts rather than the whole.

Areal Yield

The use of areal yields (Weeks, 1949) is shown on Figure 4, which represents a block diagram of a basin. Listed are the factors that determine the barrel volume of hydrocarbon to be expected. To make an assessment, the basin area is multipled by the estimated fraction that might be productive, which is multiplied by a yield factor in barrels per unit area. As in other methods that follow, each factor can be entered as a range of values in a Monte Carlo simulation. The results give a probability curve, which then can be discounted for any geologic risk.

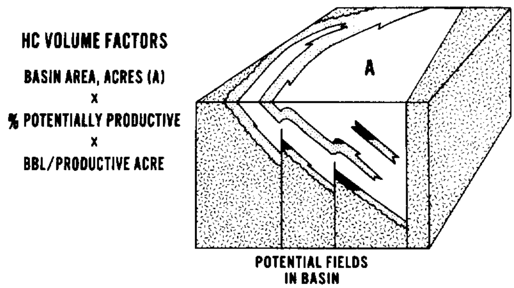

FIG. 4—Basin assessment by areal yield. Stippled beds are sandstones (potential reservoirs), which are enclosed by shales (potential source beds for hydrocarbons). Shown in black are potential oil or gas fields. Hatched pattern represents nonprospective basement rocks. Factors in list are multiplied together to produce assessment. Third dimension, depth, is not considered in areal approach.

An advantage is that areal yields can relatively quickly be derived from known areas for use in similar prospective ones. A disadvantage is that this method does not take into account any variations in the third dimension, depth. As a result, areal yields have largely been supplanted by methods using yields per unit volume of rock.

Volumetric Yield

Volumetric methods of various kinds have been the workhorses of the assessment business for years. For this reason we will give three different examples used in assessing prospects, plays, and basins, respectively.

In prospect assessment, a common approach has been to multiply potentially productive area by estimated net pay thickness by a yield in barrels per acre-foot (Fig. 5). There are more complicated variants that identify related factors such as porosity and hydrocarbon saturation. This application of Monte Carlo methods has been excellently described by Stoian (1965), Walstrom et al (1967), Smith (1968), Megill (1971), and Newendorp (1975).

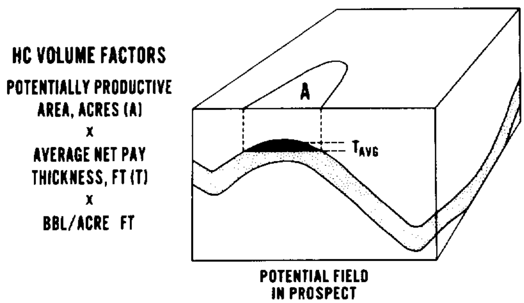

FIG. 5—Prospect assessment by volumetric yield. See Figure 4 for explanation of symbols.

The advantages and disadvantages of this basic approach are good examples of those involved in almost every assessment. It is good to have the key volume factors systematically laid out. Obviously it is very tough to estimate productive areas, pay thicknesses, and yields before the drill. Comparative data from other producing areas is helpful. Again, the only prudent solution in such uncertainty is to employ ranges of values, and to acknowledge the risks that even these ranges might be wrong.

The use of volumetric methods in play assessment has been discussed by Roadifer (1975). Figure 6 shows a single reservoir play with three prospects. The volume factors to be multiplied include trap closure area, fraction productive, pay thickness, and a yield in barrels per acre-foot. Jones (1975) gave a more complex application of this type of approach.

The advantage of this approach is its good tie to some of the most important aspects of the geology—namely, the number and size of the prospects. A possible disadvantage is that a great deal of data is required, and the method may not be readily applicable in areas of limited seismic control.

The approach to basin assessment that is most frequently cited in the literature is the volumetric yield generally credited to Weeks (1949). The usual multiplication is basin area times total sediment thickness times a yield in barrels per cubic mile (Fig. 7). For variation, assessors can use the volume of reservoir facies only, or the volume of source facies only, together with appropriately modified yield factors.

Basin assessment by volumetric yield has the advantage of being useful in early exploration stages when data are scarce. For many years the yield has been the main yardstick for comparing assessments (e.g., Cram, 1971). As with other assessment methods, however, there are pitfalls. Yields for explored basins range from 0 to 4 million bbl/cu mi (Klemme, 1975); selecting a piece of this wide range for a particular untested basin is both critical and difficult. Basins with large volumes can be almost totally lacking either in adequate reservoir rocks or in good source rocks. In either situation the actual amount of hydrocarbons may prove to be nearly zero, even though assignment of even a modest yield could suggest the possibility of billions of barrels. Again, proper risking is essential.

Geochemical Material Balance

The geochemical material balance (Fig. 8) is a special form of volumetric yield that deals with the fundamentals of petroleum generation, migration, and entrapment. The Russians (e.g., Neruchev, 1962; Semenovich et al, 1977) have been working on this method since 1936, and McDowell (1975) has illustrated its use. Halbouty and Hardin (1959) and Conybeare (1963) gave examples of the concepts of hydrocarbon generation and drainage areas.

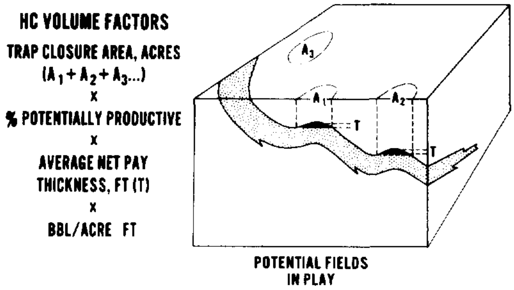

FIG. 6—Play assessment by volumetric yield. See Figure 4 for explanation of symbols.

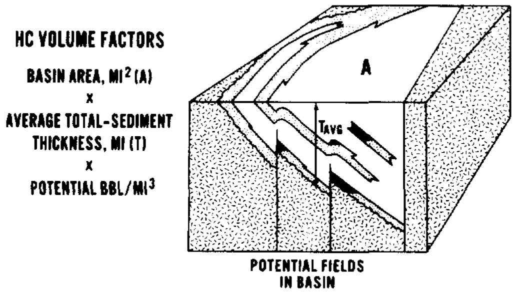

FIG. 7—Basin assessment by volumetric yield. See Figure 4 for explanation of symbols.

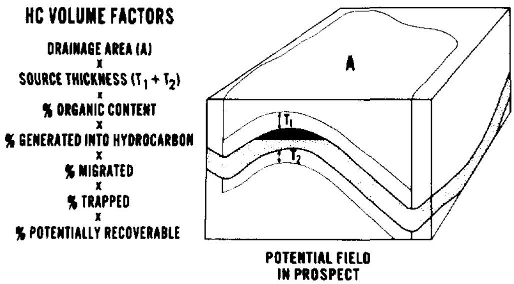

FIG. 8—Prospect assessment by geochemical material balance. See Figure 4 for explanation of symbols.

There is a long list of factors to be multipled. For a prospect example (Fig. 8), the drainage area extends down to the synclinal troughs, from which any hydrocarbons could migrate updip to the crest of the structure. Certain thicknesses of shale above and below the sandstone reservoir are the presumed source beds for the hydrocarbons. Shales commonly contain from 1 to 2% organic matter or kerogen, although the amount varies considerably. Only a fraction of this organic matter is actually converted into hydrocarbons, with time and increased temperature after burial. Only a fraction of the amount generated is able to migrate out of the source beds into the carrier or reservoir beds. Again, only part of the migrating hydrocarbons may actually be concentrated and trapped; a large part may be dispersed or may leak out to the surface. Finally, of all the hydrocarbon that passes these rigorous tests and accumulates in place in fields, only a part can actually be brought out of the ground. Typically, only about 30% of the oil in place, and 70 to 90% of the gas in place, has been recovered in conventional fields.

This method has the advantage of covering all the key genetic factors of oil and gas occurrence. At the same time it has the disadvantage of highlighting our ignorance about some of these fundamentals. It is difficult to reconstruct drainage areas and thicknesses back through geologic time. Although present organic contents can be measured, it is difficult to account for what is no longer there, particularly the amounts of hydrocarbons that have migrated and escaped the traps. Nevertheless, geochemists (e.g., Tissot et al, 1974; Hood et al, 1975; Philippi, 1976; Dow, 1977) have recently made great strides in understanding the processes of hydrocarbon generation. As our knowledge increases, we can look forward to seeing this method, by stages, replacing some of the more empirical, short-cut approaches to assessment.

Field Number and Size

Atwater (1956) has provided a good example (Fig. 9) of the use of field numbers and sizes in play assessment. He counted all the major structural traps in part of offshore Louisiana. He multiplied the number of prospects by an assumed success ratio to estimate the number of potential fields. He took the success ratio from the well-drilled, geologically similar, adjacent part of onshore Louisiana. The onshore success ratio was simply the number of discovered fields divided by the total number of tested prospects. Atwater then multiplied the postulated number of fields by an average field size, which was also taken from the onshore data.

The Russians (e.g., Belov, 1960; Semenovich et al, 1977) have used a similar approach, which they call the "average structure" method. The Canadians (Roy et al, 1975; Energy, Mines, and Resources Canada, 1977) have added the refinement of using a whole distribution of field sizes, rather than just the average. They also use a range for the potential number of prospects. They enter the number range and the size range in a Monte Carlo simulation to get a probability curve for the assessment. Ivanhoe (1976) also used field-size distributions, and Nehring (1978) used numbers and sizes of giant fields to assess world oil resources.

The advantages of this approach are that it deals with prospects and fields, which are the natural units of exploration. The chief disadvantage is the large amount of seismic control needed to define most of the prospects. The method is particularly difficult to apply where prospects, such as stratigraphic traps, are not easily defined.

Summation of Prospects or Plays

Assessments of larger areas commonly are made by summing the assessments of smaller areas. Thus, prospects can be added to assess plays, plays summed to assess basins, and basins summed to assess countries. The smaller units can be assessed by any of the methods previously outlined. In Figure 10, the two assessments at the

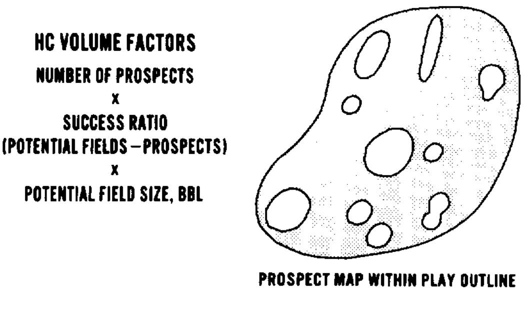

FIG. 9—Play and basin assessment from field number and size distribution. Prospect outlines are shown within mapped boundaries of play or basin.

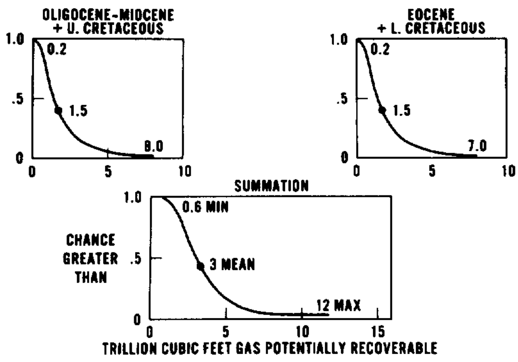

FIG. 10—Example of Monte Carlo summation of play assessments (from White et al, 1975).

top, which represent plays in south Louisiana, were made using the volume and yield of reservoir sandstone facies. These two curves were added in a Monte Carlo simulation to arrive at the lower curve for the whole area. In each of many trials in the Monte Carlo addition procedure, a value is selected at random from each curve, and the two selections are added. The results of, for example, 500 such additions are lined up from smallest to largest to produce the summation curve. Only the means add directly—namely, 1.5 + 1.5 = 3. The final high side is not as big as the absolute sum of the two individual high sides, because there is no reasonable chance that two such unlikely events as the high sides can occur together.

The advantage of Monte Carlo summation is that the probability distributions are kept in the right perspective. Any disadvantages stem from the methods used to assess the parts before summation. If the parts are defective, so will be the sum. Also, as with any method, it is all too easy to miss an important prospect or to leave a significant play unrecognized and unassessed.

Extrapolation of Discovery Rates

Various systems of extrapolating historical discovery rates have been used to predict future discoveries. One of the earliest was proposed by Davis (1958). On the horizontal scale (Fig. 11) he

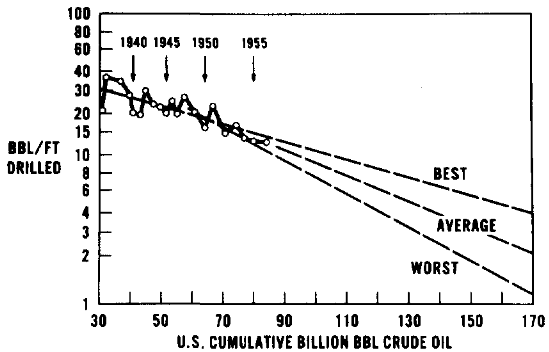

FIG. 11—Extrapolation of discovery rate expressed as barrels discovered per foot drilled (from Davis, 1958).

plotted cumulative United States reserve additions of crude oil from all sources—new discoveries, as well as extensions and revisions in old fields. The point for each year shows all the oil found and developed as of that date. On the vertical log scale he plotted the number of barrels added each year per foot of total United States drilling, including development as well as exploration wells. Each point on the solid curve represents a year's activities. The period covered by all the data shown is 1936-56. Recognizing the uncertainties, Davis extrapolated three trends. The one labeled "best" is an extrapolation of the whole 21-year period. The one labeled "worst" is an extrapolation of the last 9 years of data, 1947-56. The "average" line was drawn midway between the other two.

Davis was ahead of his time, both in his extrapolated parameters and in his handling of uncertainty with ranges of answers. Hubbert did not use this type of approach until 1967, and he believed (Hubbert, 1967) that it was originated by A. D. Zapp in about 1960. Hubbert, of course, made many improvements in methodology, and he had long been working on another approach, which will be reviewed next. But surprisingly enough, Davis (1958) ended his graph at 170 billion bbl, which is the exact number later predicted by Hubbert, using two different methods. Both men predicted that United States oil production, exclusive of Alaska and the offshore frontiers, would peak in 1967. It actually peaked in 1970.

Extrapolations have an important place in resource assessment. They have the advantage of being tied directly to the realities of experience. This particular approach by Davis has the further quality of taking into account the drilling effort and not being dependent directly on time.

Like other methods, however, extrapolations have limitations. There is always some ambiguity about exactly what areas and drilling depths are represented. Presumably, frontier areas without either drilling or discoveries are not included. A vast array of accurate historical data is required. Extrapolations can be very sensitive to small variations in data points, particularly the recent ones. Changing economic, political, and regulatory conditions may alter the curves. There is some question as to the most appropriate mathematical form—log or linear—of Davis' projection. The study area must be in a relatively mature stage of exploration in which the discovery rates are declining; if discoveries are on the increase, an uncontrolled extrapolation would go to infinity.

Figure 12 shows the notable prediction by Hubbert (1962). He had stated his approach using discovery and production rates as early as 1949; at first he based his analysis on the resource assessments of others, but in 1962 he made his own independent projection. He plotted United States discovery and production rates in billions of barrels per year on the vertical scale versus years on the horizontal scale. He fit the data with a logistic curve that models the inevitable rise and decline of the exploitation of an exhaustible natural resource.

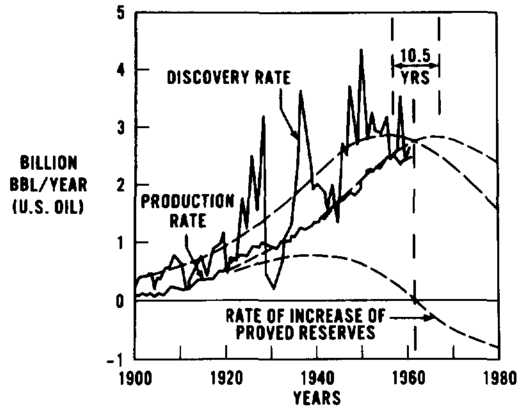

FIG. 12—Extrapolation of discovery rate expressed as barrels discovered per year (from Hubbert, 1962, p. 60).

The production curve lags behind the discovery curve by about 10 years. Hubbert figured that the discovery rate had peaked in 1957 and that the production rate would therefore peak in about 1967. Where the two curves cross, discovery additions and production subtractions are equal, and the net growth of proved remaining reserves is zero. Excluding Alaska, United States proved reserves peaked in 1961, almost exactly as Hubbert indicated.

Figure 13 shows Hubbert's results in total billions of barrels, rather than rates. Basic data are the same as those shown on Figure 12, but here the discoveries and production are plotted cumulatively. The ultimate production is shown as 170 billion bbl, with the production lagging 10.5 years behind the discoveries. The absolute amount of proved reserves is shown peaking in about 1961.

Later, Hubbert (1967) repeated these extrapolations, with similar results. He also got the same answer using the barrels-per-foot projection previously discussed. Still later results (Hubbert, 1974) further confirmed the earlier ones. At that time, Hubbert added 43 billion bbl for Alaska, which was not included in his earlier estimates. The Alaskan frontiers had practically no production data, and Hubbert made the estimate by multiplying sedimentary volumes by a yield factor. This illustrates the advantageous use of a combination of methods, each approach being applied to the areas to which it is best suited.

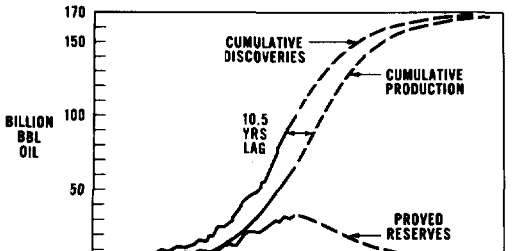

FIG. 13—Projection of United States ultimate oil discoveries and production (from Hubbert, 1962, p. 61).

The final form of extrapolation that we will review is the projection of the number of fields found per foot of wildcat drilling (Fig. 14). This example is by Menard and Sharman (1975), who developed a novel modification of approaches pioneered by Hubbert. On the vertical log scale, Menard and Sharman plotted the discovery rate in terms of fields found per 10 million ft (3 million m) of new-field wildcat drilling. The total drilling footage is plotted on the horizontal scale. Four different size classes of fields are shown, the larger ones being at the bottom. The size range of each class, in millions of barrels, is shown in the right-hand column.

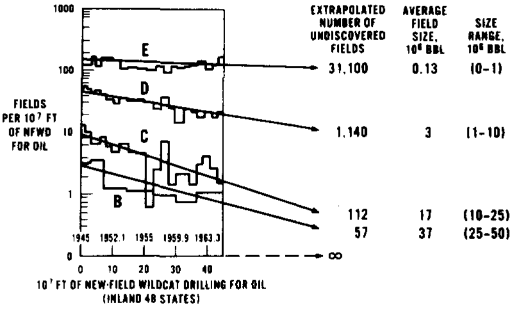

FIG. 14—Extrapolation of discovery rate expressed as number of fields discovered per foot drilled (from Menard and Sharman, 1975, p. 339, 341).

The discovery rates for the larger fields are declining more steeply than those for the smaller fields (Fig. 14). For an extrapolation to infinity, the ultimate number of undiscovered fields is shown in the left-hand column of numbers. The assessment is made by multiplying these numbers by the respective average field sizes.

Advantages and disadvantages of this method are about the same as those for other extrapolations.

CONCLUSIONS

As we have seen, each approach has its own benefits and limitations. There are many variables to consider and many different ways to consider them. The problem is that a lot of definitions and qualifications are needed to explain how one assessment really compares with another. Key assumptions may be buried in the nature of the basic data or comparisons used. Some of the main things to consider are discussed in the following.

To compare assessments, we need first to know what actual geographic area is covered. Next, some assessments report only undiscovered hydrocarbons, whereas others lump these with past discoveries or with the future growth of old fields. Results given as oil in place are apt to be three times larger than those given as recoverable oil; even a few points difference in assumed recovery percents can make large differences in answers. Some assessors lump natural gas liquids with crude oil, others do not; the difference may be only 10%, but such differences can add up.

Key factors are the geologic assumptions, such as those implicit in the selection of look-alike yield factors. Also important are any economic constraints that differentiate an attainable potential from a resource base. All assessments have some minimum field size built in, but this value is rarely specified. Some predictions are for a limited number of years; others go to infinity. It is hard to get good data, and poor data can seriously impair forecasts.

Risking is one of the most important factors, and it is one of the most easily overlooked. Similarities with known producing areas are often stressed, but differences may not be adequately risked. Finally, most older assessments are reported as a single number with no attached probability; many of these may represent average predictions with about 50-50 chances, but others are long shots more akin to high sides.

The situation is complicated but not hopeless. More effective approaches are being developed by government, industry, and academic institutions, here and in other countries. Assessments are built of three ingredients—fundamentals, experience, and judgment. In the early assessments, judgment was the biggest factor. Today we are relying more and more on experience. In the future we will use all three but will be guided mostly by the fundamental principles.

REFERENCES CITED

Abry, C. G., 1975, Geostatistics can indicate highest potential acreage: World Oil, August, p. 38-44.

Atwater, G. I., 1956, Future of Louisiana offshore oil province: AAPG Bull., v. 40, p. 2624-2634.

Bally, A. W., 1975, A geodynamic scenario for hydrocarbon occurrences: 9th World Petroleum Cong., Tokyo, Proc., v. 2, p. 33-44.

Belov, K. A., 1960, Geological prospects of discovery of new oil and gas fields in the Stavropol district and Kalmyk ASSR: Petroleum Geology, v. 4, p. 185-192.

Capen, E. C., 1976, The difficulty of assessing uncertainty: Jour. Petroleum Technology, v. 28, p. 843-850.

Conybeare, C. E. B., 1963, Hydrocarbon-generation potential and hydrocarbon yield capacity of sedimentary basins: Bull. Canadian Petroleum Geology, v. 13, p. 509-528.

Cram, I. H., 1971, Future petroleum provinces of the United States—their geology and potential: summary, *in* Future petroleum provinces of the United States—their geology and potential: AAPG Mem. 15, v. 1, p. 1-34.

Davis, W., 1958, A study of the future productive capacity and probable reserves of the U.S.: Oil and Gas Jour., February 24, p. 105-119.

Dow, W. G., 1977, Kerogen studies and geological interpretations: Jour. Geochem. Exploration, v. 7, p. 79-99.

Energy, Mines, and Resources Canada, 1977, Oil and natural gas resources of Canada, 1976: Ottawa, Report EP77-1, 76 p.

Energy Policy for Canada, 1973, Energy reserves and potential resources: Ottawa, Phase 1, v. 2, app. 1, chap. 2, p. 31-98.

Gehman, H. M., R. A. Baker, and D. A. White, 1975, Prospect risk analysis, *in* J. C. Davis et al, conveners, Probability methods in oil exploration: AAPG Research Symposium, Stanford Univ., Notes, p. 16-20.

Gess, G., and C. Bois, 1977, Study of petroleum zones—a contribution to the appraisal of hydrocarbon resources, *in* R. F. Meyer, ed., The future supply of nature-made petroleum and gas: New York, Pergamon Press, p. 155-178.

Halbouty, M. T., and G. C. Hardin, Jr., 1959, A geological appraisal of present and future exploration techniques on salt domes of the Gulf region of the United States: 5th World Petroleum Cong., New York, Proc., sec. 1, p. 95-108.

Hambleton, W. W., J. C. Davis, and J. H. Doveton, 1975, Estimating exploration potential, *in* Methods of estimating the volume of undiscovered oil and gas resources: AAPG Studies in Geology 1, p. 171-185.

Hedberg, H. D., 1976, Ocean boundaries and petroleum resources: Science, v. 191, p. 1009-1018.

Hood, A., C. C. M. Gutjahr, and R. L. Heacock, 1975, Organic metamorphism and the generation of petroleum: AAPG Bull., v. 59, p. 986-996.

Hubbert, M. K., 1962, Energy resources: Natl. Acad. Sci.-Natl. Research Council Pub. 1000-D, 141 p.

——— 1967, Degree of advancement of petroleum exploration in United States: AAPG Bull., v. 51, p. 2207-2227.

——— 1974, U.S. energy resources, a review as of 1972: U.S. Senate Comm. on Interior and Insular Affairs, Rept. 93-40 (92-75), pt. 1, 260 p.

Ivanhoe, L. F., 1976, Evaluating prospective basins: Oil and Gas Jour., December 6, p. 154-156; December 13, p. 108-110; December 20, p. 82-84.

Jones, R. W., 1975, A quantitative geologic approach to prediction of petroleum resources, *in* Methods of estimating the volume of undiscovered oil and gas resources: AAPG Studies in Geology 1, p. 186-195.

Klemme, H. D., 1971, What giants and their basins have in common: Oil and Gas Jour., March 1, p. 85-

90; March 8, p. 103-110; March 15, p. 96-100.

——— 1975, Giant oil fields related to their geologic setting—a possible guide to exploration: Bull. Canadian Petroleum Geology, v. 23, p. 30-66.

McCrossan, R. G., and J. W. Porter, 1973, The geology and petroleum potential of the Canadian sedimentary basins—a synthesis, *in* Future petroleum provinces of Canada—their geology and potential: Canadian Soc. Petroleum Geologists Mem. 1, p. 589-720.

McDowell, A. N., 1975, What are the problems in estimating the oil potential of a basin: Oil and Gas Jour., June 9, p. 85-90.

Megill, R. E., 1971, An introduction to exploration economics: Tulsa, Okla., Petroleum Pub. Co., 159 p.

——— 1977, An introduction to risk analysis: Tulsa, Okla., Petroleum Pub. Co., 199 p.

Menard, H. W., and G. Sharman, 1975, Scientific uses of random drilling models: Science, v. 190, p. 337-343.

Miller, B. M., et al, 1975, Geological estimates of undiscovered recoverable oil and gas resources in the United States: U.S. Geol. Survey Circ. 725, 78 p.

Nalivkin, V. C., et al, 1976, Criteria and methods for the quantitative assessment of oil and gas occurrence in large, poorly studied territories: Sovetskaya Geologiya no. 1, p. 28-39.

Nehring, R., 1978, Giant oil fields and world oil resources: Santa Monica, California, Rand Corp. Rept. R-2284-CIA, 162 p.

Neruchev, S. G., 1962, Oil generating suites and the migration of oil: Leningrad, Gostoptekhizdat, p. 217-221 (in Russian).

Newendorp, P. D., 1975, Decision analysis for petroleum exploration: Tulsa, Okla., Petroleum Pub. Co., 668 p.

Philippi, G. T., 1976, On the depth, time and mechanism of origin of the heavy to medium-gravity naphthenic crude oils: Geochim. et Cosmochim. Acta, v. 41, p. 33-52.

Pitcher, M. G., 1976, U.S. discovery rate tied to technology: Oil and Gas Jour., March 22, p. 34-35.

Roadifer, R., 1975, A probability approach to estimate volumes of undiscovered oil and gas, *in* J. C. Davis et al, conveners, Probability methods in oil exploration: AAPG Research Symposium, Stanford Univ., Notes, app., 18 p.

Roy, K. J., R. M. Procter, and R. G. McCrossan, 1975, Hydrocarbon assessment using subjective probability, *in* J. C. Davis et al, conveners, Probability methods in oil exploration: AAPG Research Symposium, Stanford Univ., Notes, p. 56-60.

Semenovich, V. V., et al, 1977, Methods used in the USSR for estimating potential petroleum resources, *in* R. F. Meyer, ed., The future supply of nature-made petroleum and gas: New York, Pergamon Press, p. 139-153.

Smith, M. B., 1968, Estimate reserves by using computer simulation method: Oil and Gas Jour., March 11, p. 81-84.

Stoian, E., 1965, Fundamentals and applications of the Monte Carlo method: Jour. Canadian Petroleum Technology, v. 4, p. 120-129.

Tissot, B., et al, 1974, Influence of nature and diagenesis of organic matter in formation of petroleum: AAPG Bull., v. 58, p. 499-506.

Walstrom, J. E., T. D. Mueller, and R. C. McFarlane, 1967, Evaluating uncertainty in engineering calculations: Jour. Petroleum Technology, v. 19, p. 1595-1603.

Weeks, L. G., 1949, Highlights on 1948 developments in foreign petroleum fields: AAPG Bull., v. 33, p. 1029-1124.

——— 1952, Factors of sedimentary basin development that control oil occurrence: AAPG Bull., v. 36, p. 2071-2124.

White, D. A., et al, 1975, Assessing regional oil and gas potential, *in* Methods of estimating the volume of undiscovered oil and gas resources: AAPG Studies in Geology 1, p. 143-159.

Zhdanov, M. A., 1962, Prognostic reserves of oil and gas and problems of methods of estimating them: Petroleum Geology, v. 6, p. 177-184.