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NOTES
PROBABILITY METHODS IN OIL EXPLORATION
August 20-22, 1975
Stanford, California

by

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EARLY BASIN STATISTICAL ANALYSIS TO PREDICT SUBSEQUENT OIL FIELD DISCOVERIES

Claude G. Abry

SUMMARY: A discriminant function technique, coupled with computerized contouring, was used in a hindsight analysis to statistically "predict" the location of oil fields in the Tatum Basin, New Mexico. The predictions, based on the analysis of isopach and structure maps, were made for a series of geographic cells, each one-mile by one-mile square, over the entire area of study (37 by 41 miles in extent). The statistical technique ranked the geologic factors by order of usefulness in finding oil fields. The predictive model successfully located the majority of the new economic fields in the study area.

INTRODUCTION: The discrimination problem was to assign wildcat wells before they were drilled to one of three groups of previously drilled wells (dry holes, wells in small fields, and wells in large fields) on the basis of nine quantified geologic variables.

Since it might be years before the prospects identified by this method would be drilled, there was no easy way to test the validity of the method except to make a hindsight experiment by going back to some particular time. I chose the end of year 1951, using only the data available at that time, to make statistical predictions that were then compared with our current knowledge of oil fields in the area. However, this method put me in the unique position of knowing in advance the location of oil fields that were subsequently found. To compensate for this unrealistic situation and preserve the objectivity of the study, the data were processed entirely and uniformly by computer. The machine was used to contour structure and isopach maps, to interpret these maps in terms of positive and negative anomalies, and to compute probabilities of oil occurrence over the study area.

GEOLOGIC SETTING: The study area is a 37 by 41 mile rectangle that extends over most of the Tatum Basin, which is a northern appendix of the Delaware Basin. The producing interval considered is a Siluro-Devonian dolomitic limestone, which is locally cherty and has a maximum thickness of about 1000 feet in this area. Oil traps are formed by elevated fault blocks, anticlinal structures, and by buried hills below the unconformity at the top of the unit.

To supplement the sparse Siluro-Devonian data, structure and isopach maps of the lower Permian Abo formation were used as potential predictors of oil field locations in the Siluro-Devonian. This involved making assumptions that (1) structural features in both intervals are generally conformable, and (2) a relationship exists between isopach thins in the Abo and structural highs in the Siluro-Devonian.

REASONS FOR SELECTING THE STUDY AREA: The basin is relatively mature insofar as its oil field development is concerned, and the density of oil fields is adequate for statistical analysis. The predictive experiment was made at the end of year 1951, to test its usefulness at an early stage of development in the basin. At this time, five oil fields had been discovered in the study area; thirteen additional fields have been discovered since then (Fig. 1). The stratigraphic data available for the study consists of 111 Siluro-Devonian tops, 182 Abo tops and bases, and a few seismic profiles that were useful to supplement the well data.

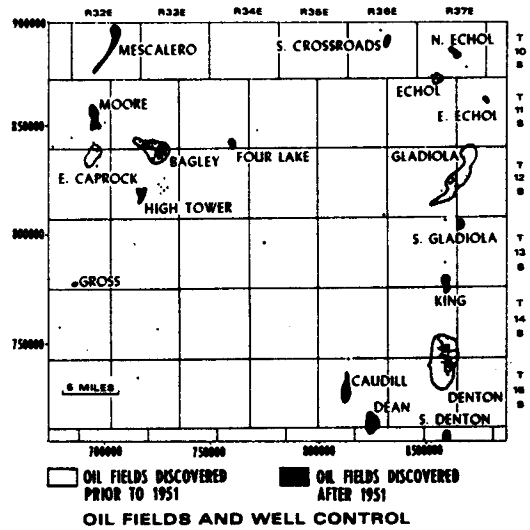


Fig. 1. Oil fields in study area. Five oil fields discovered before end of 1951 are distinguished from 13 fields found after 1951. Wells drilled prior to end of 1951 are shown with small crosses.

SELECTION OF GEOLOGIC FACTORS: Nine geologic factors, listed in Table 1, were chosen as predictors of petroleum occurrence. Their selection was dictated by several considerations, as follows:

1. The factors should be known to some extent before drilling. For example, subsurface structure and isopach maps can be constructed from seismic profiles and limited well data.

2. The geologic factors must be capable of being quantified for statistical processing. Although it is possible to use qualitative variables in a statistical study, it is more efficient to treat all variables as quantities. This requires, for example, that the usual descriptive terms such as anticline, dome, homocline, or syncline are replaced by their quantitative equivalents, such as the combination of vertical closure and area of closure, which are complementary structural parameters relating to the volume within a closed anticline or dome. The vertical closure is defined as the vertical distance between the top of the structure and its spill points. The area of closure is the area of the structure, as projected on a horizontal plane which passes through the spill point. Both terms were also applied to isopach anomalies, following the analogy observable on a contour map between anticlines and isopach thicks, or between synclines and isopach thins.

The study involved the automatic delineation of individual structures and isopach anomalies, using a pattern recognition procedure, and also the computerized interpretation of these anomalies in terms of vertical closure and area of closure.

Table 1. Quantified geological factors used in statistical forecasting of oil occurrence in this study. Isopach anomalies represent thins and thicks.

VARIABLE NO.	GEOLOGIC VARIABLE DESCRIPTION
1	VERTICAL CLOSURE OF SILURO-DEVONIAN STRUCTURES
2	VERTICAL CLOSURE OF ABO STRUCTURES
3	VERTICAL CLOSURE OF ABO ISOPACH ANOMALIES
4	SUBSEA DEPTH OF SILURO-DEVONIAN TOP
5	SUBSEA DEPTH OF ABO TOP
6	ABO THICKNESS
7	AREA OF CLOSURE OF SILURO-DEVONIAN STRUCTURES
8	AREA OF CLOSURE OF ABO STRUCTURES
9	AREA OF CLOSURE OF ABO ISOPACH ANOMALIES

MACHINE CONTOURING OF OIL CONTROLLING FACTORS, ITS BEARING ON SUBSEQUENT ANALYSIS

Whether done by hand or by machine, contouring is necessary to interpolate between control points and thereby describe the configuration of structural and isopach anomalies. Computer contouring is particularly attractive in the case of a hindsight experiment, since consistency and objectivity are very important. Obviously, machine contouring involves arbitrary assumptions, as incorporated in the contouring algorithm, but the assumptions are uniformly applied over the mapped area. Most contouring programs also produce numerical grids or arrays of numbers arranged on a regular square mesh that represents a continuous surface in machinable form, and thus provide information from which the computer can delineate anomalies and compute closures.

COMPUTER INTERPRETATION OF GRIDDED MAPS

The absolute value and sign of the vertical closure are sufficient to differentiate between anticlines, homoclines, and synclines. Anticlines are described by positive vertical closures, homoclines by zero vertical closure, and synclines are characterized by negative vertical closures. Complementary information about a structure is found in the area of closure. A computer program was written to search the numerical grid from which contours are drawn, and to delineate anticlinal and synclinal structures. At the same time, vertical closure and area of closure were calculated for each structure.

Figure 2 is an example of the vertical closure of structures on the Siluro-Devonian top, as interpreted by the computer program. Other similar maps were made for the other geological factors listed in Table 1, yielding nine items of geologic information at each of 1500 points on the map, for subsequent statistical analysis.

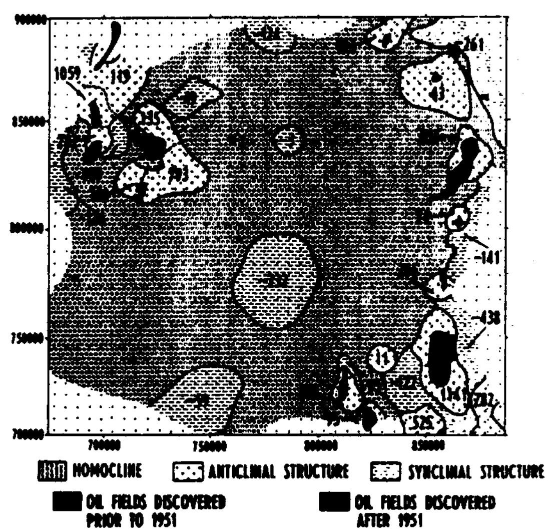


Fig. 2. Computer interpretation of the vertical closure of Siluro-Devonian structures, expressed in feet. The dot matrix is the basic grid with a one-mile mesh size. Positive numbers indicate anticlines, negative numbers indicate synclines, and homoclines have zero values.

STATISTICAL ANALYSIS OF OIL FIELDS DISCOVERED PRIOR TO 1951

The numerical data for the nine geological factors at 1500 grid locations were statistically analyzed by multiple discriminant function analysis. The questions posed in the study are:

1. Can discriminant function analysis be used to assign the wells drilled before 1951 to their proper oil reserve class, on the basis of the nine geologic factors listed in Table 1?

2. If so, which geologic factors are most important in the classification?

3. Can the technique be used to predict production characteristics of future wildcat wells?

To answer the first question, the locations drilled prior to 1951 were arbitrarily divided into three groups, according to the size of the oil field in which they occur. Group A includes dry holes and wells associated with total recoverable reserves smaller than one million barrels of oil, group B involves wells associated with 1 to 26 million barrels, and group C is for wells with more than 26 million barrels. At first, discriminant analysis was used to check whether the three groups are different in terms of their geologic variables.

The multiple discriminant function analysis can be conveniently visualized by plotting the data points (wells or grid locations) in a nine-dimensional space, where each axis represents a geologic variable. The data form swarms of points in the nine-dimensional Cartesian space, and the swarms are dispersed about their centers of gravity in ellipsoid shapes. Since it is not possible to illustrate graphically a nine-dimensional space, a scatter plot of the data points as a function of the first two canonical variables, which are independent factorial axes summarizing the nine original variables, is presented in Fig. 3. The discriminant functions divide the space into three regions, which are respectively the domains of dry wells (A), wells associated with small reserves (B), and wells associated with large reserves (C). The diagram shows that the three production groups are very distinct on the basis of the nine geologic factors. In this test all the wells drilled before 1951 were classified in the proper production group, with the exception of one dry well from group A which was improperly classified with the small producers in group B. This high success ratio indicates that the selected geologic variables are very likely to be good predictors of oil occurrence in the study area.

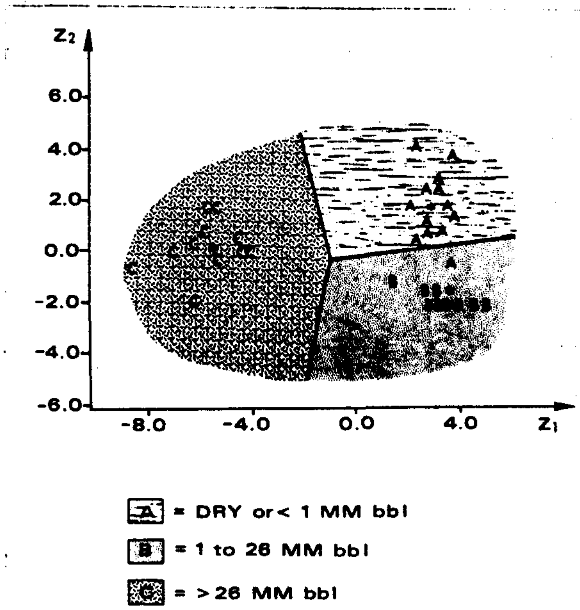


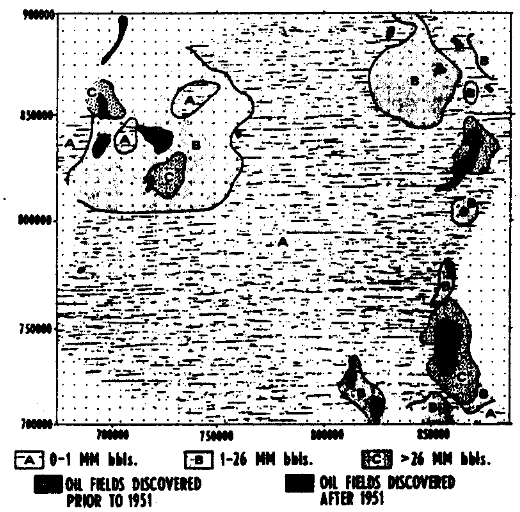
Fig. 3. Scatter plot of grid locations drilled before 1951, as a function of the two best canonical variables z1 and z2, whose values represent numerical transformations of original geologic variables. The three groups A, B, and C are separated by discriminant functions. Asterisks indicate the multivariate means of the groups.

DISCRIMINATION POWER OF THE GEOLOGIC VARIABLES

The second question concerns the relative importance of the geologic factors in classification. Discriminant analysis also has the capability of recognizing the usefulness of each variable in statistically discriminating between groups. The most important variable from this standpoint is the vertical closure of the Siluro-Devonian structures. Unexpectedly, the second most important parameter is the subsea depth of the Siluro-Devonian top. But this surprising result is probably due to the presence of two shallower shelf areas in the NE and the W that are rich in oil discoveries and a centrally located basinal area that is deeper and as yet barren. The premise is that shelf areas are more likely to have been exposed and dolomitized before deposition of the Woodford Shale, and therefore represent better prospective areas than deeper portions of the basin where effective porosity and permeability are expected to be lower. The next three factors establish the Abo as a good predictor of oil occurrence in the Siluro-Devonian. Other variables have little effect on the classification process. The study also showed that the four best geologic variables gave results practically equivalent to those obtained with all nine variables together. Significant reduction of effort and computing time can be realized by concentrating efforts on the most important variables.

PREDICTION OF FUTURE WILDCAT OUTCOMES

Fig. 4. Oil discovery prediction map. Areas labelled A are unfavorable, B are favorable to small fields, C to large oil fields.



The last objective of the study was to evaluate the remaining undrilled grid locations, and predict their production potential in terms of groups A, B, or C. Grid locations yet undrilled were assigned to a particular production group on the basis of the values of the nine geological variables that govern the portion of the Cartesian space in which they fall.

The resulting oil discovery prediction map shown in Fig. 4 was divided into four distinct regions on the basis of the quality and type of results obtained.

1. The large central region which extends to the northern border and to the southwestern corner is a type A area, unfavorable to oil occurrence.

2. The central east and southeastern portions of the map had relatively good well and seismic control. Here, the method gave very detailed and accurate predictions, pinpointing the oil fields and properly classifying them in the correct production groups.

3. The northwestern part of the area had good well control, but no seismic data to help define the petroleum traps. Here, the method interpreted a broad area favorable to oil occurrence that included all but one of the oil fields in that region.

4. In a smaller area in the northeastern corner, there was poor well and seismic control and although the two small oil fields are properly classified in group A, predictions are probably not very reliable.

With this predictive model, 85 percent of the oil reserves discovered after 1951 were either pinpointed or included in the areas favorable for exploration. An experiment using all the well data available in 1972 suggests that some parts of the Tatum Basin may still have exploration potential, but the unavailability of recent seismic data has prevented a thorough evaluation of the new prospects.

A PROBABILISTIC ASSESSMENT OF ALBERTA'S UNDISCOVERED PETROLEUM

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INTRODUCTION:

After 30 years of intensive exploration, 11.2 billion barrels of initial recoverable crude oil, 66.3 Tcf of initial marketable gas and 2.5 billion barrels of initial recoverable NGL'S have been found in the 200,000 square mile sedimentary area of Alberta. These reserves amount to 80% of Western Canada's reserves. During the past decade, explorationists have experienced rather disappointing results in finding significant reserves and as of 1970 have been unable to find as much as is being produced. There is growing concern about whether the undiscovered volumes of hydrocarbons are significant and whether the associated finding costs will prove prohibitive. This paper attempts to answer these concerns and to propose a model of an ideal exploratory cycle. Conventional, initial recoverable (marketable) reserves, credited to the year of discovery are used, and gas is converted to barrels of equivalent oil (BOE) on a value basis at 10 Mcf/barrel. Gas associated sulphur is not included in BOE but NGL'S are.

DISCUSSION:

1. *How much oil and gas is left to be found?*

Figure 1 shows Alberta's reserves growth as a function of exploratory drilling, projected to an arbitrary ultimate well density of eight square miles per well. As in subsequent figures, three alternative projections are presented, dependant on the amount of reserves appreciation applied to recent years discoveries. Case C, is considered to be the maximum possibility, and implies that although the province is only 60% drilled up, about 85% of the recoverable reserves (URR) have already been discovered, and that 4 billion BOE is yet to be found. Case C is favored through straight line projection of past growth rates, and because the growth curve has over the past 20 years shown increasing steepness with further drilling and for other reasons discussed later. Which projection will ultimately prove correct is the linchpin to the future of exploration in Alberta, and of the validity of the following concepts.

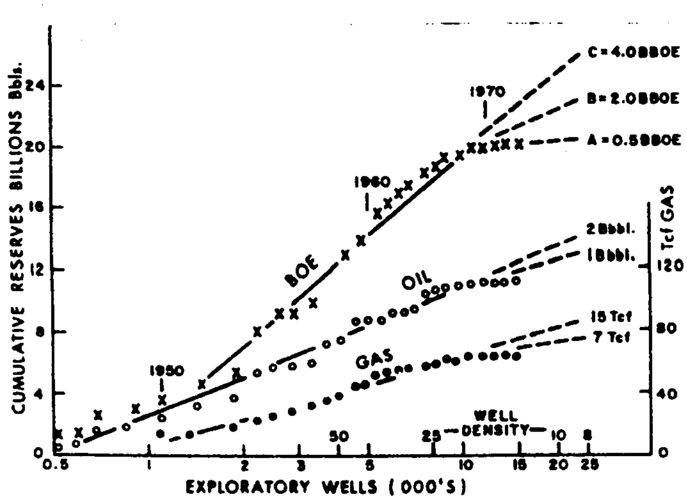

FIG. 1. Reserves Growth vs Drilling

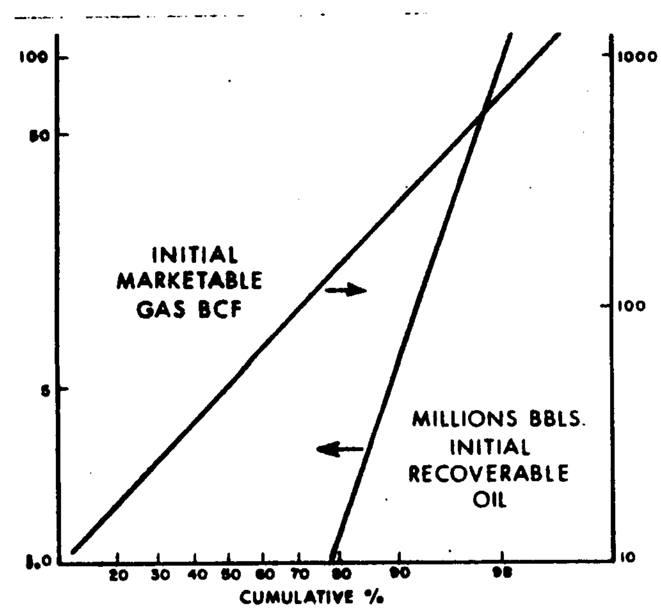

FIG. 2. Cumulative Pool Size Distribution

2. *How big and how many are the target pools?*

Cumulative size distribution frequency curves for Alberta pools may be drawn as shown in Fig. 2. Since explorationists are mainly interested in significant sized pools, estimates were only done for pools over 5 million barrels and 100 Bcf in size, which respectively account for 89 and 84% of the oil and gas reserves to date. On a proportionality basis of "found" vs "to be found" of reserves and numbers of significant fields, it is estimated that for Case C, roughly 50 significant pools remain to be found with the next 10,000 exploratory wells. This compares to about 262 such pools which had been discovered to the end of 1971 by the drilling of 12, 758 wells. An example of the speculative size distribution of these 50 pools is presented, which infers that if Case C is correct there are still appreciable targets remaining to be found. These targets could compare to the combined potential of Alberta's flanking sister provinces as of 30 years ago.

3. *What kind of finding rates can be expected?*

Drilling to date in Alberta indicates that, as previous authors have observed, the reserves discovered per unit of exploratory drilling have been declining since the first series of significant discoveries in the late 1940's.

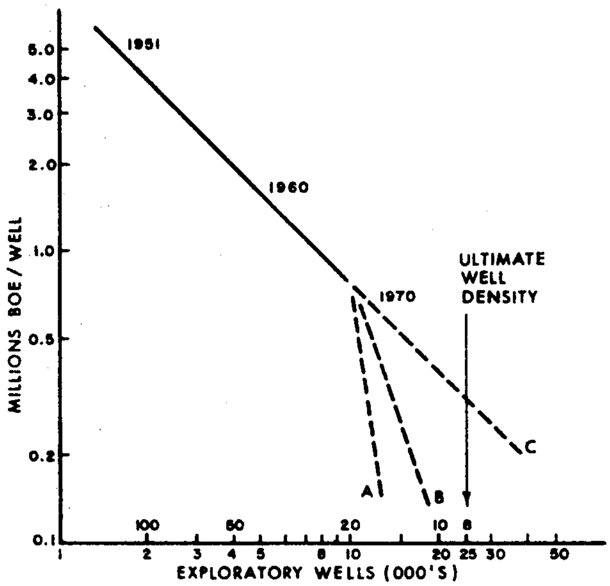

FIG. 3. Discovery Rates - Smoothed Averages

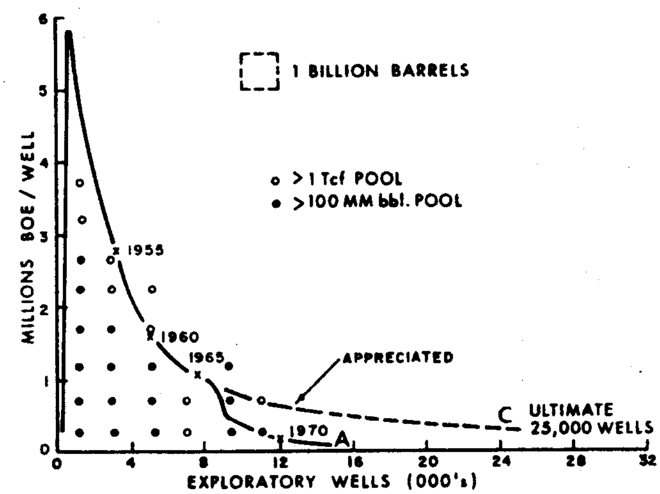

FIG. 4. Discovery Rates in BOE/well

Figures 3 and 4 which show this decline, were derived from the smoothed curve of Figure 1, and appear to show the following fundamental relationship for Alberta.

The finding rate, expressed in volume of reserves per unit of exploratory effort (wells or footage), shows an inevitable hyperbolic decline directly proportional to the well density expressed in square miles per well, or inversly proportional to the cumulative amount of exploratory drilling (wells or footage) in the basin.

For example, between 1950 and 1960 the well density went from 100 to 25, and the finding rate from four to one million BOE/well. The present finding rate, appreciated to Case C, is 500,000 BOE/well and should decline to about 300,000 ultimately. If the hyperbolic decline relationship is valid to a well density of eight, it presents a third reason as to why Case C is the most probable since it fits this theoretical projection.

Three possible reasons why finding rates should suddenly depart from the theoretical Case C curve, would be (1) that the curve should be exponential rather than hyperbolic; (2) that there are no new major plays to be found; (3) that a point of critical well density will be achieved before the arbitrary eight square miles/well is arrived at. For example if the maximum areal distribution of reserves is ultimately 5% of a productive basin, there should be a sudden drop off in finding rate at a well density of 20, qualified by the fact that only a small percentage of these wells may have tested the entire sedimentary section. As long as the critical well density is less than eight (i.e. over 12½% of the basins area productive), Case C should be the most probable projection.

Expressed as a formula, the smoothed average finding rate R at a given point in exploration may be expressed as:

$$R = R \max \frac{(W1)}{(W2)}$$

Where R max is the maximum finding rate established early in the exploration of the basin, W1 is the number of wells at the time of R max, and W2 the cumulative number of wells at a subsequent point in time. The area under the above curve indicates the volume of oil discovered at a point in time, and can be expressed as follows:

$$V = W_1 \ (R \max) \ (\mathrm{Log}_e \frac{W2)}{W1)} + (\text{Volume discovered to W1})$$

$$\text{e.g. For Alberta the URR} = 1200\ (6{,}000{,}000)\ (\mathrm{Log}_e \frac{25{,}000)}{1{,}200} + 3.5 \text{ billion BOE}$$

$$= 22 + 3.5 = 25.5 \text{ billion BOE}$$

The practical application of the above observations, as most geologists know intuitively, is that the largest volumes of reserves per unit of effort are found during the early stages of exploration. Also the relative potential URR of basins, and finding rates may be predicted (within the limitations imposed by the accuracy of R max).

Figure 4 also shows that there is a close correlation between the number of giant fields discovered and volume of reserves.

4. *Future Finding Costs*

Figure 5 shows reserves growth as a function of industry's exploratory expenditures, showing a linear relationship on semi log paper. Again Cases A, B and C are presented and projected to an anticipated ultimate cumulative wells, as well as actual average annual finding costs.

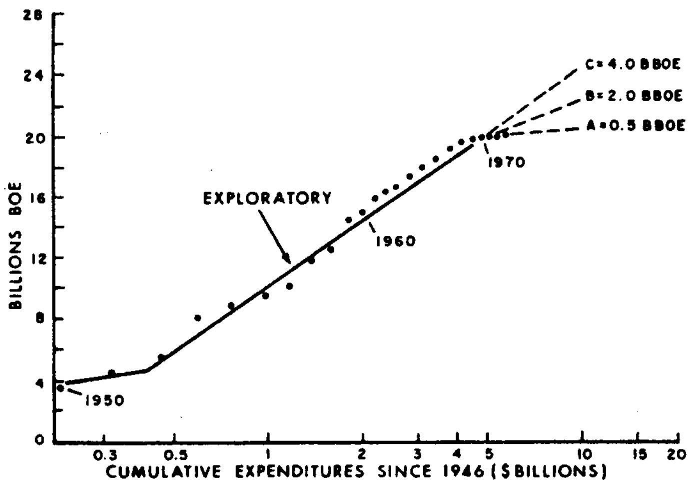

FIG. 5. Reserves Growth vs Expenditures

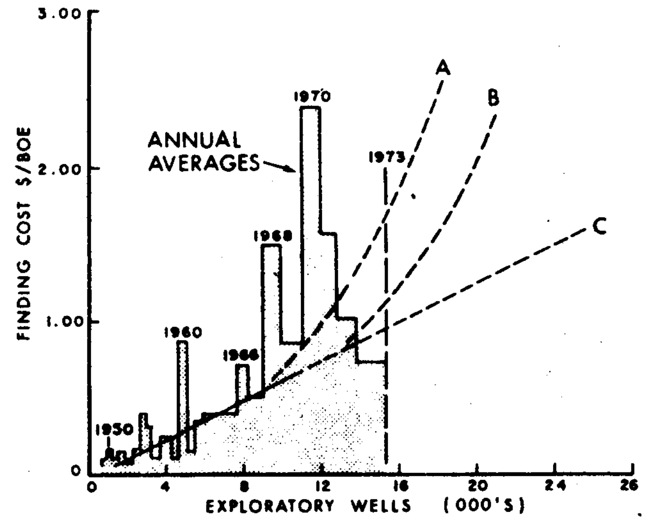

FIG. 6. Finding Costs

Because total exploratory expenditures/well have remained relatively constant during the past 25 years, the smoothed curve show that:

Assuming that exploratory expenditures/well remain essentially constant (due to increasing efficiencies), the finding costs per unit volume of BOE, inevitably increase at a rate inversly proportional to the finding rate, or directly proportional to the cumulative number of exploratory wells drilled in a basin.

Therefore if Case C proves to be actual, it is probable that although finding costs have increased about 20 fold since 1947, they should not even double over the next twenty or so years. However, if Case C is incorrect, exploration will rapidly die out in Alberta, probably within the next decade.

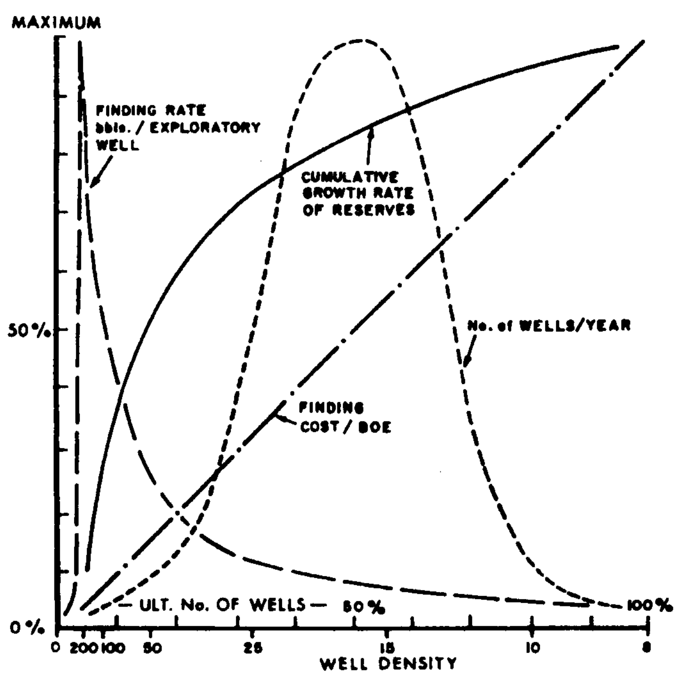

FIG.7. Model of Ideal Exploratory Cycle

SUMMARY

The concepts expressed above can be summarized graphically as shown in Figure 7. The inherent productivity of a basin pre-determines the maximum finding rate which normally should occur early in the exploratory cycle of a basin. Subsequent smoothed finding rates ideally show a hyperbolic decline from this maximum point at a rate inversly proportional to the cumulative number of exploratory wells. This relationship is postulated to hold until the exploratory well density reaches the critical percentage of total area that will ultimately be productive. Cumulative reserves may be mathematically derived from the finding rate curve. Also, if the total exploratory expenditures/well can be reasonably predicted, the finding rate curve may be used to project finding costs per unit volume of reserves. As illustrated in Figure 7, if the exploratory expenditures/well remain relatively constant with time, the finding costs inevitably increase at a rate directly proportional to the cumulative number of exploratory wells.

The most probable estimates would then indicate that Alberta should contain up to 4 billion undiscovered conventional BOE (2 billion of which is crude oil); the major part of this predicted volume should be contained in about 50 significant sized fields; the finding rates and costs per barrel should not worsen much beyond 60% and 160% respectively, of the present averages. There are many other factors, beyond the scope of this paper, which will determine at what point an individual company will decide to cease exploring in Alberta, however, at this time it would appear that, on the average, finding rates should not be the key deterrent factor.

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Analysis of the Rate of Wildcat Drilling and Petroleum Deposit Discovery

by

Lawrence J. Drew

The success in exploring for petroleum deposits in the Powder River Basin has been examined for the 22 year period, 1950-71. During this period 3691 wildcat wells were drilled and 665,000,000 barrels of petroleum were discovered. It was found in this study that the total wildcat drilling record consisted of two components. The first is referred to as the "ambient" component of wildcat drilling and is characterized by relatively low drilling rates in regions where no significant discoveries have been made in the recent past. Such wells were, therefore, drilled on prospects which looked favorable on the basis of long range regional geological and geophysical evaluations. The second, called the "cyclical" component of wildcat drilling, is that portion of the total number of wildcat wells which were drilled during periods when exploration plays were active. This component is characterized by a rapid rise in the rate of wildcat drilling above the mean ambient rate followed by a more gradual return to the ambient rate. These cyclical surges in the wildcat drilling rate are usually initiated ("kicked off") by the discovery of a large deposit and, although the duration of exploration plays ranges widely, they usually continue 3 to 5 years. During the 1950-71 period, two major exploration plays occurred in the Basin; the Minnelusa play, during the late 1950's and early 1960's, and the Muddy play in the late 1960's and early 1970's. Several minor plays involving exploration for deposits in the Dakota and Parkman Sandstones occurred during the middle 1950's.

The total number of wildcat wells drilled during the ambient phase of exploration was determined to be 1,146 wells or 31.05 percent of the total 3691 wildcat wells drilled. The total number of wildcat wells drilled during the cyclical phases of exploration was determined to be 2545 wells or 68.95 percent of the total. Of the total volume of petroleum discovered, 371,131,000 bbl (55.80 percent) is attributed to the ambient component of wildcat drilling. Inasmuch as 31.05 percent of the total wildcat drilling resulted in discovery of 55.80 percent of the reserves, the ambient component is 2.80 times as effective as the cyclical component. In terms of the mean quantities of petroelum discovered per well, the average ambient wildcat well discovered 323,734 bbl and the average wildcat well drilled during the cyclical phases of exploration discovered 115,520 bbl.

Although the average quantity of petroleum discovered per wildcat well was nearly three times smaller during periods when exploration plays were active, the practice of following exploration plays rather than drilling regional prospects was not without its reward. The risk of failure was found to be substantially higher during the ambient phase, with only three and one half chances of success per hundred wildcat wells drilled. During the cyclical periods the chance of success rose to five wildcat wells per hundred. Accepting a nearly three-to-one reduction in expected returns in order to increase the proportion of successful wells by 43 percent shows that the average operator in the basin had a strong aversion to risk. This aversion is so strong that it forced the average operator to accept and drill during exploration plays those prospects which returned on the average about 36 percent of that which was gained by drilling prospects based upon long-range regional evaluations.

The nearly three-to-one inefficiency of the cyclical wildcat drilling component over the ambient component could, perhaps, be significantly reduced through exploration lease-unitization procedures in which the rate of exploratory drilling in a region is restrained during the more active period of a play, thereby releasing substantial amounts of exploration capital for use in the more efficient ambient component of exploration.

The frequency distributions of the volume of petroleum contained in the deposits discovered during both phases of exploration are shown in figure 1. Both of these distributions are bimodal in form. This bimodality is a consequence of the difference in the sizes of the deposits discovered in the two major productive units in the study area. The deposits forming the peaks in the 6.0 to 7.0 logarithmic-units range are predominantly in the Minnelusa Sandstone, whereas the peaks in the 4.0 to 5.0 logarithmic-units range are predominantly small, single-or double-well deposits in the Muddy Sandstone. The distribution of the discovery of deposits during ambient phase of exploration is nearly uniform in shape, whereas that of the cyclical periods of exploration declined rather steeply with increasing deposit size. Therefore, the volume of petroleum contained in the deposits discovered during the ambient phases of exploration occurred with nearly equal probability across the entire range. In contrast, during the cyclical phases of exploration of the basin, smaller deposits are discovered more frequently than larger deposits.

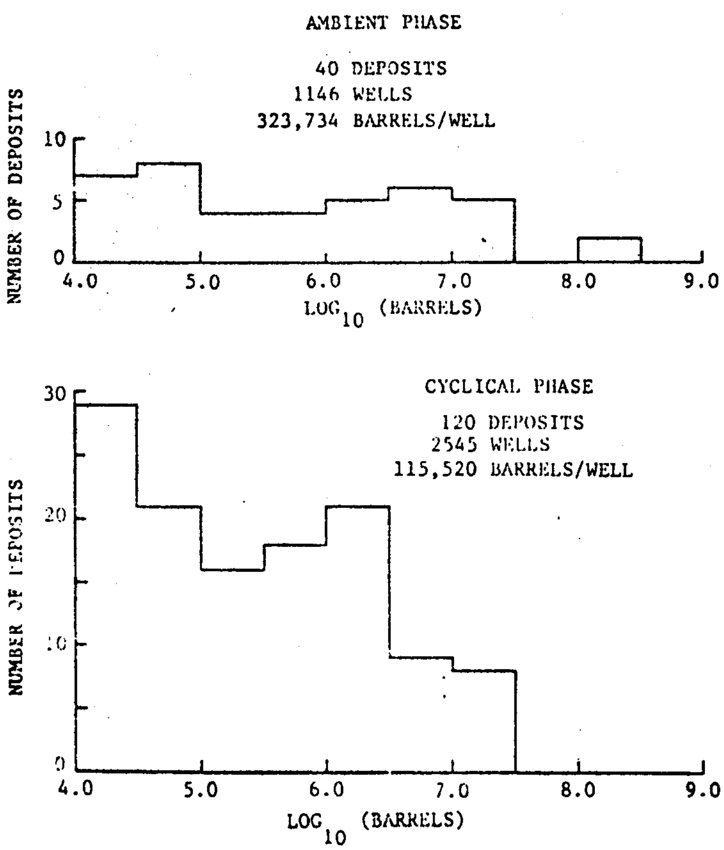

Fig. 1 - Frequency distribution of the volume of discovered in the ambient and cyclical phases of exploration.

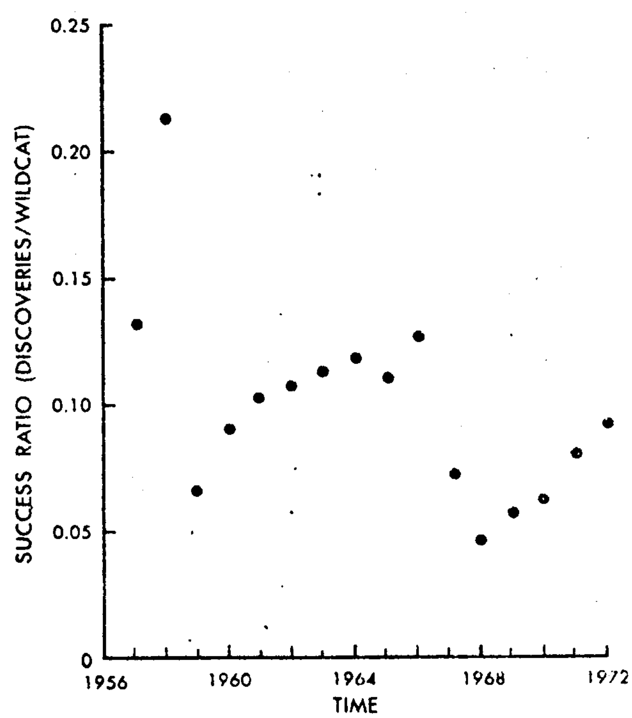

Fig. 2 - Relationship between discovery success ration and time

The above conclusions lead to an additional and somewhat more detailed examination of the behavior of the exploration process in this Basin. In this second study attention was focused upon the eastern flank of the basin where both the Minnulusa and Muddy plays occurred. A three equation regression model[1] was constructed to explain:

1. The yearly wildcat drilling rate, W.
2. The number of deposits discovered each year, N.
3. The aggregate volume of petroleum discovered each year, V.

$$W = -43.098 + \underset{(5.06)}{1.896\, V_{-1}} + \underset{(1.51)}{943\ 738\ P_{-1}/C_{-1}} \underset{(-1.18)}{-0.013\, D_{-1}} \qquad (1)$$

$$R^2 = 0.731 \qquad F = 10.85^{**} \qquad df = 12$$

$$N = 7.999 + \underset{(3.00)}{0.029 W} - \underset{(-2.17)}{4.709\, h_1} + \underset{(0.85)}{1.630\, h_2} \qquad (2)$$

$$R^2 = 0.734 \qquad F = 11.04^{**} \qquad df = 12$$

$$V = 133.958 - \underset{(0.122)}{0.114\, W} - \underset{(5.476)}{12.280\, t} - \underset{(3.260)}{101.963\, h_1} - \underset{(2.423)}{51.648\, h_2} \qquad (3)$$

$$R = 0.558 \qquad F = 3.47^{*} \qquad df = 11$$

where:

V_{-1} = volume of petroleum discovered in the region during the previous year (discovery expectation variable).

P_{-1}/C_{-1} = ratio of the price of crude petroleum over the cost of drilling during pervious year.

D_{-1} = depth of deposits during pervious year.

t = time in years from start of each play.

$h_1 = 1$ and $h_2 = 0$ when no play was active.

$h_1 = 0$ and $h_2 = 1$ when "Minnelusa" play was active.

$h_1 = 0$ and $h_2 = 0$ when "Muddy" play was active.

The t - statistic for each coefficient is shown in parenthesis under each coefficient.

The number of wildcat wells drilled each year was found to be highly dependent upon the discovery expectations of the exploration operators. The volume of petroleum discovered the previous year in the region (V_{-1}) was used as a surrogote variable for this expectation variable. Neither the depth of the deposits nor the price of crude petroleum, nor the cost of drilling had a significant effect upon the wildcat drilling rate (equation 1).

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[1]The system was estimated by a two stage procedure, where the ordinary least squares estimate of this wildcat drilling rate variable (W) was used as an instrumental variable in equations (2) and (3); see D. H. Rhymes, 1971, p. 296-302.

The number of deposits discovered each year was found to be highly dependent upon the number of wildcat wells drilled (equation 2) but the aggregate volume of petroleum discovered was found to be independent of the number of wildcat wells drilled (equation 3). This latter result while initially puzzling can be interpreted as a direct consequence of the cyclical character of the exploration-play mechanism. Both the exploration plays which occurred in the study area during the 1957-72 period previously were interpreted as responses on the part of exploration operators to the discovery at different points in time of unexpectedly large deposits in two quite geologically different stratigraphic units. During the years (1958 and 1967) when these two exploration plays were initiated however, the wildcat drilling rate was at a relatively low level. During the second year of both these exploration plays, the wildcat drilling rate increased markedly. The number of deposits discovered increased as a result of this increase in the wildcat drilling rate, but on the average these deposits found tended to be much smaller in size than those discovered during the initial year of both exploration plays, and, as a result, less petroleum was discovered in the aggregate. Even though the discovery-success ratio continued to improve throughout the remainder of both exploration plays, the aggregate volume of petroleum discovered varied in an erratic manner with respect to the number of wildcat wells drilled; consequently, the non-significant relationship between these two variables.

Figure 2 shows the variation through time of the discovery success ratio in the study area. Clearly, this success ratio exhibits a cyclical pattern of variation. This cyclicity can be interpreted as a learning process and, it is directly attributable to the two exploration plays which developed in the region. During the initial phases of both the Minnelusa and Muddy exploration plays, the success ratio fell sharply. This marked decline was then followed by a gradual recovery during the following years. The initial phases of both the "Minnelusa" (1958-60) and "Muddy" (1967-68) exploration plays are characterized by a marked surge in the wildcat drilling rate. This is judged to be the manner in which exploration operators will usually react when a large deposit is discovered in a stratigraphic unit not previously thought to contain such a large deposit. During these initial periods the enthusiasm of the exploration operators was greatly heightened and in their haste to test the "Minnelusa" and "Muddy" stratigraphic units for additional large deposits many poor quality exploration prospects were drilled, and as a consequence, the success ratio fell sharply. As both these exploration plays matured and went into decline, the operators drilled progressively better quality prospects which were developed from the steadily increasing volume of geologic information accumulated as the exploration plays progressed. As a result, the success ratio within each play showed a steady improvement through time. This learning process associated with exploration plays has been recognized by Ryan (1973) in an analysis of the volume of petroleum which ultimately will be produced from the Province of Alberta, Canada.

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PROSPECT RISK ANALYSIS

by

H. M. Gehman[1], R. A. Baker[1] and D. A. White[2]

The method described here is a systematic assessment 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 and interpretations are laid out for management's use in comparing prospects realistically and for judging the reliability of the estimates. The result is a cumulative probability curve of potential reserves (Fig. 1) that can provide the basis for more complete economic analysis.

It is convenient to consider the method in two parts. First the estimation of the volume factors that control the size of the potential reward and then the geologic controls or risk factors that may deny the reward. The method will be illustrated with a simplified but typical example, Prospect Beta. The gross trap volume (Fig. 2) can be estimated from measurements of area of closure at the spillpoint, average reservoir facies thickness, and average effective porosity. An estimate of percent hydrocarbon fill, multiplied by the trap volume gives hydrocarbon-in-place, and an estimate of recovery efficiency gives the final answer in recoverable barrels of oil or cubic feet of gas.

Since none of these volume factors is known exactly, it is important that we make not only our best or most likely estimate but also include an estimate of minimum and maximum (Fig. 3) for each volume factor. The range in the estimates includes the uncertainty in our seismic and facies maps and in our historical experience with porosity, hydrocarbon fill, and recovery efficiency. The range not only serves to record the relative uncertainty in each estimate but also allows for the possibility that the reward will be greater than indicated by the most likely values alone.

A simple computer program is used to combine the individual ranges into an overall probability distribution for the Beta's reserves. Each of the

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[1]Exxon Production Research Company.

[2]Exxon Company, U.S.A.

The authors thank these companies for permission to publish.

volume factors is represented as a triangular distribution function with the apex at the most likely value. Thus, the computer's random selections from each volume factor tend to be most frequent near that value and decline to zero at the extremes. Random selections from each triangular distribution are multiplied together to get 500 possible values for recoverable reserves. These values are plotted from smallest to largest to give a cumulative frequency curve (Fig. 4). In practice, ten curves are generated, for a total of 5000 trials, and the results averaged into a single final curve. The arithmetic mean of the 5000 trials is usually repeatable within one percent, and the highest one in 500 within three or four percent.

If the estimates of the volume factors are right, the curve (Fig. 4) shows the chance of finding each different level, or more, of recoverable reserves. The analysis of geologic risk is used to estimate the chances that they <u>are</u> right. We have found it convenient to consider four basic controls of hydrocarbon occurrence and to group typical geologic risks under each (Fig. 5). If any of these four controls (reservoir, trap, source, or the ability to recover the hydrocarbon) is missing, then the prospect will be dry and there is no reward.

There is a substantial chance that the reservoir facies is missing in Prospect Beta. The regional map shows sand thickness to be highly variable in the area where it is located. In estimating reservoir facies thickness as a volume factor, the best interpretation is an average of 50 feet with the possibility of up to 100 feet, <u>if the sand is there</u>. However, about half of the possible interpretations showed little or no sand to be present.

The problem is to express this very real risk that there will be little or no reservoir sand in the prospect. The two-step approach used in this method requires that some kind of non-zero minimum be set for the volume factor estimate. The associated geologic control factor is then used to assign the probability of exceeding that minimum. The effect is to treat anything less than the minimum as zero. In Beta, a minimum of 10 feet was set for reservoir thickness and the chance of exceeding that minimum was specified as 50 percent. The key to setting a minimum is to have it low enough to include all thicknesses that would have economic potential under the circumstances. The advantage is that it excludes the whole range of very thin reservoir units that are hard to observe regionally and would be uneconomic even if found.

Source adequacy is also a risk at Beta because the prospect lies between known production and dry structures which apparently lack source. Source obviously is one of the elements that contributes to the volume factor called hydrocarbon fill, and the most likely and maximum cases were based on observing nearby productive structures. The minimum case, however, was set rather arbitrarily. The minimum was adjusted by trial and error to give a 20 million barrel minimum (at $P = .998$) to the resulting cumulative probability curve - a value that was close to the economic threshold for the prospect. This minimum value is the one against which our judgment of source adequacy can be gauged. Beta was assigned a 50 percent probability of achieving that minimum for source potential. The other control factors appear to offer no problems. They represent zero risk.

We can now combine the risk analysis with the volume analysis to produce an assessment of Prospect Beta. As shown in figure 6, the overall chance is 25 percent for achieving the minimum 20 million barrels in Beta. When that chance factor is applied to the cumulative probability curve (Fig. 4), the probability of achieving each reserve level is reduced oorrespondingly (Fig. 1). The gap in the curve below 20 million barrels results from our selection of minimum values, but since it lies at the economic threshold, it causes no problems and moreover has the advantage of separating productive from nonproductive cases. Obviously there is no fixed minimum. It must be tailored to the economics of each prospect, but certainly it will be significantly larger than zero.

One advantage of separating out the risk is that it allows for an analysis of the interaction of the geologic controls. Such a careful analysis is important, for example, when the assessment curves for a group of prospects are to be summed together to provide an assessment of a concession. A simple example would be the summation of six prospects like Beta, with individual geologic control factors as tabulated in figure 7. How these prospects are summed depends on how we treat the individual chances of adequacy of the control factors. If we consider the risk in each prospect to be independent of the others, then the resulting curve (Fig. 8) shows an 82 percent chance of having at least one productive prospect in the concession. If, however, we consider that the risk of inadequate source applies to the group as a whole, then that part of the risk is applied after the summation of the curves and a different curve results. Although the means are the same, the chance of having at least one productive prospect is reduced to about 49 percent. Moreover, the potential for larger reserves is greater in the second case and might lead to an entirely different economic decision.

There are many variations of interrelated risk within prospect groups. These interrelations require a careful analysis of whether risk is to be applied before or after Monte Carlo summation. Once that is done, it is a relatively simple procedure to compute an assessment. Recognizing that risk interrelations reduce to questions of when they are to be applied in summation makes the geologist's problem of dealing with interrelations simpler. Though simple, it is a powerful means of applying our understanding of geologic events to make a better analysis of the economic potential of the group.

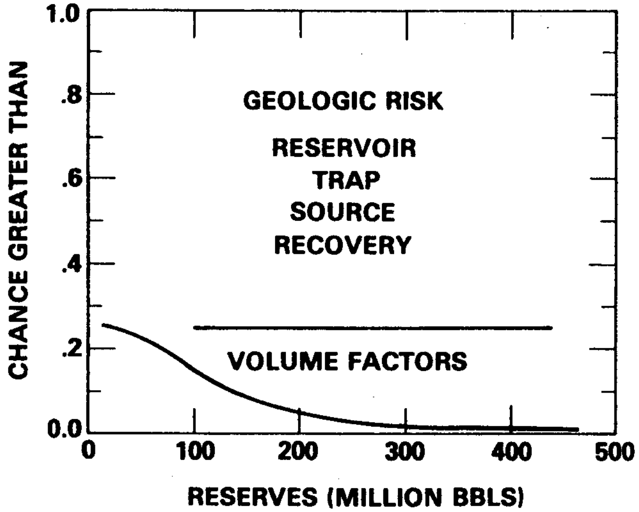


FIG. 1 ASSESSMENT CURVE FOR PROSPECT BETA

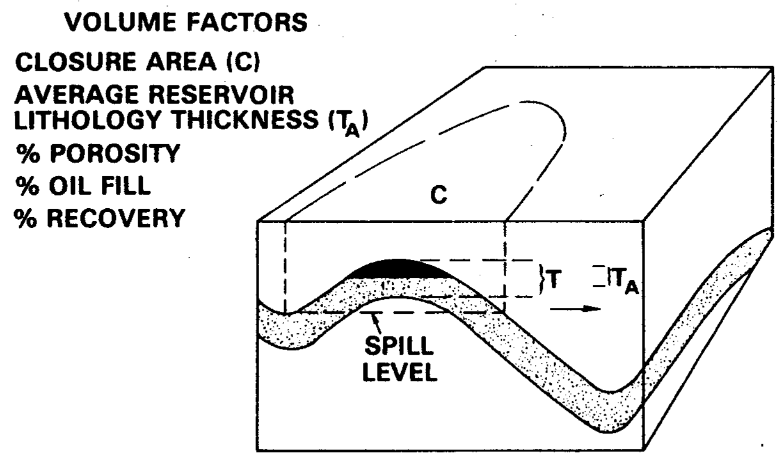


FIG. 2 DIAGRAM OF PROSPECT BETA AND VOLUME FACTORS USED IN ASSESSMENT

VOLUME FACTOR	MINIMUM	MOST LIKELY	MAXIMUM
AREA OF CLOSURE (SQUARE MILES)	20	25	30
AVERAGE RESERVOIR THICKNESS (FEET)	10	50	100
AVERAGE POROSITY	.15	.20	.25
HYDROCARBON FILL	.05	.20	.60
RECOVERY EFFICIENCY	.30	.35	.40

FIG. 3. VOLUME FACTOR ESTIMATES, PROSPECT BETA

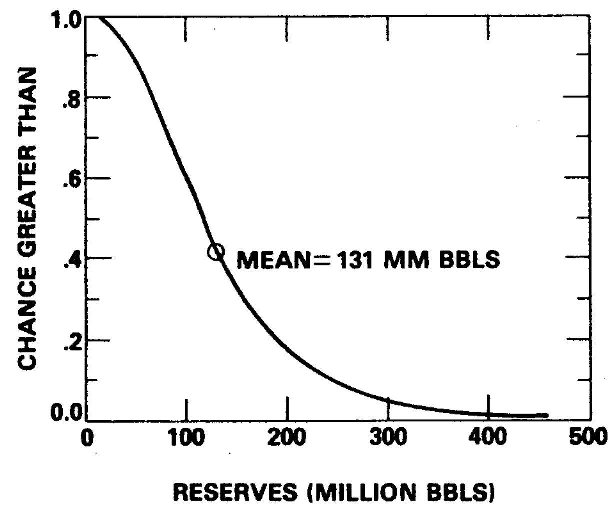


FIG. 4 PROSPECT BETA ASSESSMENT CURVE BEFORE RISK DISCOUNT

RESERVOIR FACIES	MISSING BY FACIES CHANGE MISSING BY UNCONFORMITY POROSITY DESTROYED OR NOT DEVELOPED
TRAP	NO CLOSURE NO SEAL WRONG TIMING
SOURCE	POOR QUALITY INSUFFICIENT VOLUME BAD MIGRATION PLUMBING
RECOVERY	LOW PERMEABILITY OIL TOO VISCOUS

FIG. 5. GEOLOGIC CONTROLS AND TYPICAL RISK FACTORS

GEOLOGIC CONTROL	CHANCE OF ADEQUACY (1.0 – RISK)
RESERVOIR FACIES	.5
TRAP	1.0
SOURCE	.5
RECOVERY	1.0

OVERALL CHANCE OF MINIMUM = .5 x 1.0 x .5 x 1.0 = .25

FIG. 6. ANALYSIS OF RISK, PROSPECT BETA

	PROSPECTS					
GEOLOGIC CONTROL	A	B	C	D	E	F
RESERVOIR		.5		.5		.5
TRAP			.5		.5	
SOURCE	.5	.5	.5	.5	.5	.5
RECOVERY	.5					
OVERALL CHANCE	.25	.25	.25	.25	.25	.25

CHANCE OF AT LEAST ONE PRODUCTIVE $= 1 - (1 - .25)^6 = .82$

OR

$= 0.5\,(1 - .5)^6 = .49$

FIG. 7. RISK ANALYSIS OF A PROSPECT GROUP

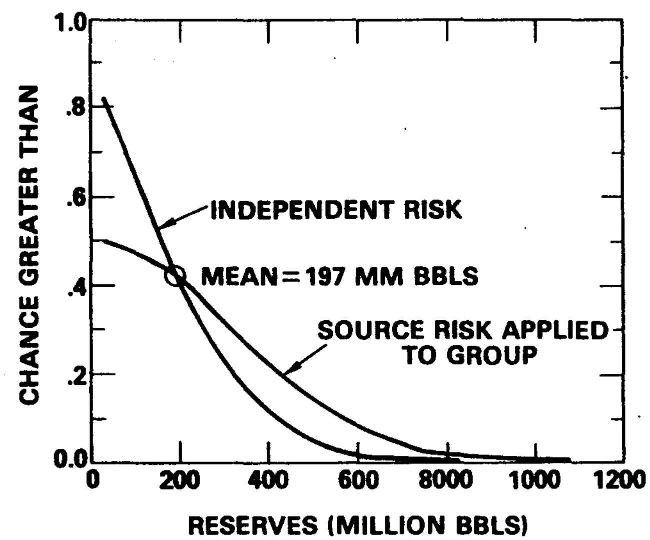


FIG.8 ASSESSMENT CURVE FROM SUM OF PROSPECTS A-F

Exploration for and Evaluation of Natural Resources

by

J.C. Griffiths, D.W. Menzie and M.L. Labovitz

Exploration for and Evaluation of Natural Resources

"There are no definable diagnostic criteria as to age, lithology, type of trap or depositional environment - although to be sure, a shelf position in shallow marine sediments is to be preferred.....
.....The only obvious requirement is a trap of such capacity that a giant accumulation can be accommodated." Moody et al., 1970, p. 14.[1]

1. Introduction

To paraphrase an outstanding petroleum geologist, the search for natural resources begins in our heads; this together with the above quotation from Moody suggests that we should re-examine the paradigms (Kuhn, 1962) we use to define the problem of search. In general, present procedure is based upon 'cause and effect' reasoning - knowing the origin of some specific resource it would appear likely that other occurrences of this resource could be located by finding similar geological conditions. A possible algorithm epitomizing this procedure is exhibited in the left-hand half of figure 1. From the quotation, however, this outcome hardly seems likely and the search procedure leads to a Goedel-type question; the problem needs a metalanguage for redefinition. The problem of 'origin', unless carefully defined, often leads to such a paradox (Griffiths, 1969).

An alternative algorithmic procedure is outlined in the right-hand half of figure 1 and two options are presented; the first is the grid drilling approach (Griffiths, 1967) and the second the use of a simulation model, the Engel Model, as an evaluation procedure (Griffiths and Drew, 1964; Griffiths, 1966; Griffiths and Singer, 1972).

2. Summary of outcomes for the Alternative Algorithm

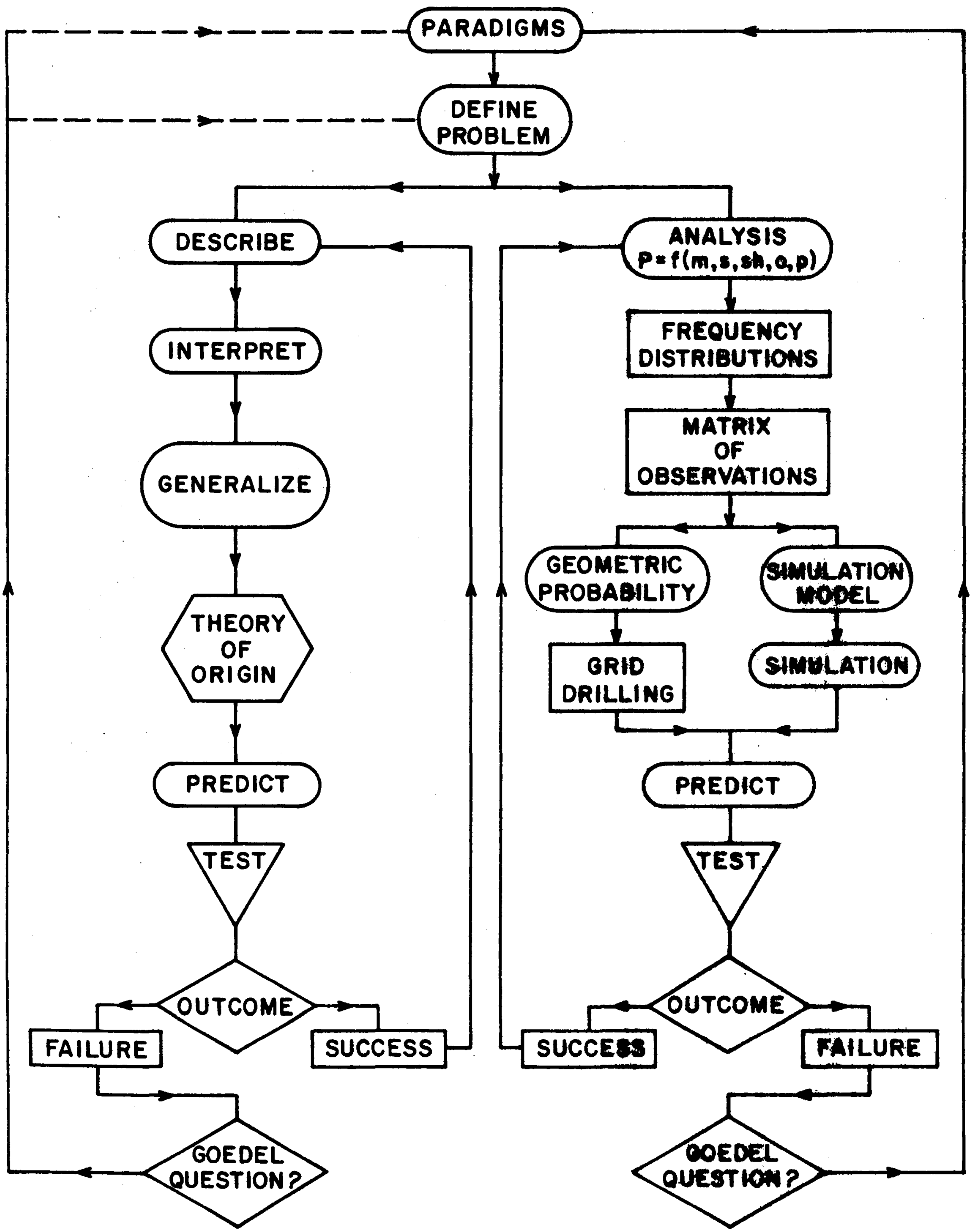
Grid-drilling is based on a knowledge of the geometrical characteristics of targets and the relationship between their sizes, shapes, and values; selecting the largest targets, a suitable grid spacing may be chosen to locate prizes with a specified degree of uncertainty (Drew, 1967; Griffiths and Singer, 1972; Singer and Wickman, 1969; Singer, 1972). For example giant oilfields vary from 2.37 square miles (Santa Fe Springs) to 600 square miles (Pembina) and almost half (22 out of 45, see fig. 7, p. 11, Moody, op. cit.) are less than 40 square miles. Given that these fields are elliptical in projected surface shape, i.e. that they possess a long dimension, then a 20 mile square grid spacing would find at least one of these targets with probability $p \approx 0.99$.

This becomes an extremely conservative claim if the targets are extended to include ore deposits, coal, non-metallics, water and reservoirs for storage and waste-disposal etc. There is therefore, little reason to doubt, that this represents a profitable strategy. Since a grid of this kind would give equal coverage to all the area included in the search it would also form the basis for an inventory of the natural resources of say the U.S.A. The geological information accruing from such a program would be of inestimable value in forming the basis for more detailed search and would lead to discovery of many smaller prizes.

The second option embraces the use of the Engel simulator and again the returns from this procedure suggest that, given a large enough number of prizes, its profitability is assured (Griffiths and Drew, 1964; Griffiths, 1966; Griffiths and Singer, 1971 a). Since these claims are also based on using a single kind of resource as a target and because the procedure has now been applied to the search for oil and gas, uranium and other resources (Sampey, et al., 1974) it represents a generally applicable program. If all resources are included in the search then once more the claims are conservative and profitable outcomes are

[1] see references

Figure 1. Alternate Exploration Strategies



assured with high probability.

Use of the Engel Model demands certain specific information on numbers of targets, their sizes and shapes, and values and, in addition, a firm knowledge of the characteristics of the sensor system and its interaction with the terrain under exploration. One of the advantages of the model is that it may be used for decision-making in which options include the recognition that inadequate information exists to make a decision. This leads either to abandonment of the search or collection of additional information if the potential rewards exceed the expected penalties.

3. The Black Box Approach

There are many general conclusions which emerge from these several research investigations; the first and perhaps the most important, is that "single resource" search is inefficient; generalizing, it is most advantageous to regard all profitable prizes at one and the same time. This is the 'total systems' approach. When one considers any and all resources then the number of potential prizes increases by several orders of magnitude and the probability of failure becomes vanishingly small; this is a most desirable feature of any search program.

From this basic paradigm the question arises almost naturally - what is unit area or volume of the earth's crust worth? This line of enquiry leads to many intriguing questions, for example, is there any region which is relatively valueless? The answer, in terms of potential value is emphatically no! Is it appropriate to claim that some areas are worth more than others? The easy answer is 'yes, obviously' but more intensive examination suggests that a qualified maybe is all we can safely accept. It is advisable to put this entire problem, including the search and the reward, into one overall model and a simple one at the present juncture is the black box model.

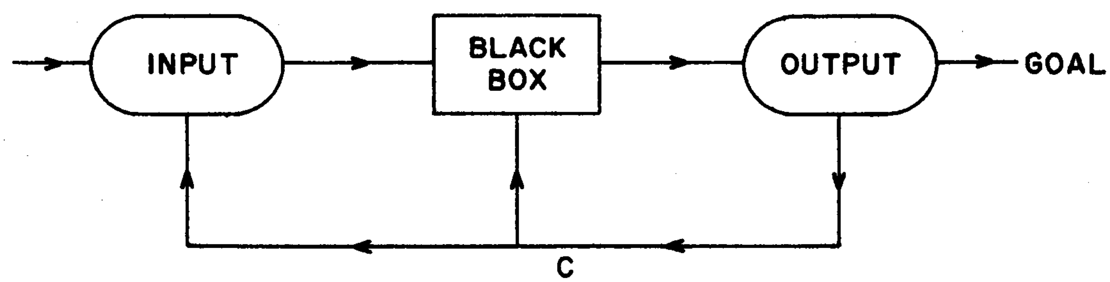


Figure 2. Black Box Model of the Natural Resource Sector

The input includes the ultimate volume of resources in the earth's crust plus the efforts by geoscientists and others to find these resources. This is the source material which passes through a process, including search, exploitation, processing and production and eventually emerges as output; the output we may represent as the weight or volume and value of the mineral resources of an area. It is possible, at least in principle, to "manage" this system by manipulating the input to produce some desirable output (i.e. goal). Many "managers" are compelled to treat the system they manage in this fashion because they cannot comprehend, within their human capacities and the time at their disposal, what goes on in the black box - presidents of most large institutions certainly have to behave in this manner.

Quite clearly the balancing of input to achieve a desired output requires a sensitive feedback loop (c in fig. 2). The "boom and bust" behavior displayed by many resource industries reflects the effectiveness of this loop and emphasizes that there is a lag in the transfer of effects. Naive cause-and-effect reasoning is liable to be confusing in black box situations because the "cause" becomes the "effect" and vice versa at different stages of the process.

The concept of "unit regional value" was proposed as a basis for evaluation of the output of mineral resources (Griffiths, 1969; Griffiths and Singer, 1971b). Applied to the U.S.A. the arithmetic mean value (1880-1972 in 1967 dollars) of a square mile is $305,000; 63 percent of this total accrues from fuels, 19 percent from non-metals and 17 percent from metals (Griffiths and Menzie, in press). The value of sedimentary rocks which supply all the fuels and some of the non-metals and metals, far exceeds the value of igneous and metamorphic rocks.

When the aggregate value of mineral resources is broken down by state (1905-72 in 1967 dollars) the range is from $7000 per square mile for Alaska to 2 million dollars per square mile in Pennsylvania. The frequency distribution of value per square mile is log normal and the weighted geometric mean is $144,544 dollars per square mile.

On the basis of components analysis an economic growth factor accounts for close to 60 percent of the variation among the states. This effect must be removed before the remaining sources of variation may be established. Such an outcome emphasizes that socio-economic characteristics far outweigh all others in determining the value per square mile of a state. For example the value of fuels, petroleum and coal, almost certainly accounts for the lead position of seven of the eight states worth more than $500,000 per square mile. The eighth state, New Jersey ($744,000/square mile), owes its position largely to the value of sand and gravel and the contiguity of two very large urban centers. The type of resource, therefore, is not always the dominant factor.

To evaluate the 'geologic factor' the effect of the socio-economic factor, a time trend, must be removed and to proceed beyond the broad perspective of sedimentary, igneous and metamorphic rocks, it will be necessary to examine the variation in volume and value of individual commodities.

4. Acknowledgements

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Preliminary U.S.G.S. Oil and Gas Resource Estimate for Federal OCS Lease Sale #35 off Southern California

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I. Introduction

In response to a request by the Bureau of Land Management, The Conservation Division of the U. S. Geological Survey has prepared a preliminary estimate of the recoverable oil and gas resources within the southern California Federal OCS tracts under consideration in OCS lease sale #35. The proposed Federal OCS lease sale includes 297 tracts encompassing 1.55 million acres which are located beyond the three mile line dividing State and Federal jurisdiction offshore. Water depths within the proposed sale area vary from 56 ft. (17 m.) to more than 2,460 ft. (750 m.) and average about 1,200 ft. (366 m.).

In southern California, offshore leasing to date has been confined to State and Federal areas of the Santa Barbara Channel and State areas in Santa Monica and San Pedro Bays. Oil and gas have been discovered and production established in each of these areas.

Some preliminary offshore studies had been completed by early 1974 when the resource estimate was made. These studies indicated that geologic conditions were quite variable offshore, therefore the method used to determine the preliminary resource estimate was designed to account for these variable geologic conditions as well as to utilize all available usable data in the proposed lease sale area.

II. Regional Geology

Tracts included in the proposed lease sale off southern California lie primarily within the Peninsular Ranges province. This province is characterized by northwest trending basins and ridges, some of which are separated by parallel major faults. Islands and rocks protrude above the ocean surface on several of the offshore ridges while water depths are as great as 6,912 ft. (2,107 m.) in the basins.

The major geomorphic features (see figure I-1) within the proposed lease sale area include:

- Offshore extensions of the Los Angeles Basin and the Palos Verdes Arch.
- The ridge extending from Santa Catalina and Santa Barbara Islands to Santa Cruz Island; which separates the Santa Monica, Santa Cruz and Catalina Basins.
- The northern and southern portions of the Santa Rosa-Cortes Ridge, including Tanner, Cortes and Northeast Banks.

With the exception of the tracts in portions of San Pedro and Santa Monica Bays, the areas proposed for leasing are located on ridges because water depths in the offshore basins are beyond present day technological capabilities for exploration and production.

Franciscan-like basement rocks composed of metamorphosed sediments and basic igneous rocks underlie the sedimentary and volcanic sequence in the proposed lease sale area.

Pre-middle Miocene sediments do not appear to be present in the offshore reaches of the Los Angeles Basin, the Palos Verdes Arch, nor in the Santa Catalina-Santa Barbara Islands area; however, thick sequences of sandstone, conglomerate, and shale ranging in age from Upper Cretaceous to lower Miocene may be present south of Point Dume and in the southern portion of the San Pedro Bay area, as well as on the Santa Rosa-Cortes Ridge.

The middle Miocene section is relatively thin or absent in much of the Los Angeles Basin as well as on the crestal portions of the Santa Rosa-Cortes Ridge, Palos Verdes Arch and northwest of Santa Catalina Island, however; thick sequences of predominantly coarse grained middle Miocene breccia, conglomerate, sandstone and interbedded shale with volcanic flows and intrusives of variable thickness and distribution may be present offshore, south of Pt. Dume and in the southern portion of the San Pedro Bay area, as well as on the Santa Rosa-Cortes Ridge close to the Northern Channel Islands. Middle Miocene sediments occurring elsewhere on the Santa-Rosa Cortes Ridge and on the Palos Verdes Arch appear to be composed of shale and claystone with possibly some sandstone and conglomerate. In the vicinity of Santa Catalina and Santa Barbara Islands the thin middle Miocene section consists of diatomaceous shale and volcanic flows.

A thick upper Miocene sandstone-shale sequence is present east of the Palos Verdes Arch. Elsewhere, the upper Miocene consists primarily of fine grained diatomaceous mudstone and claystone. The section is relatively thin or missing on the crestal portions of the Santa-Rosa Cortes Ridge, the Palos Verdes Arch and northwest of Santa Catalina Island.

Pliocene age sediments are probably present in all of the basins, but within the proposed lease sale area may occur only in San Pedro and Santa Monica Bays east and west of the Palos Verdes Arch. Nearshore, the Pliocene is a sandstone-shale sequence but may become increasingly fine grained in the western basins.

III. Oil and Gas Producing Zones in California

The overwhelming bulk of California oil and associated gas production is from sandstone reservoirs in thick marine sand-shale sequences of upper Miocene and lower Pliocene age. Significant production is also obtained from fine grained upper and middle Miocene rocks, which have been extensively fractured; as well as from marine lower Miocene and marine and non-marine Oligocene sandstone reservoirs. There is also minor hydrocarbon production from Eocene, Paleocene, and Upper Cretaceous sandstone reservoirs and fractured basement rock.

Most dry gas production in the Sacramento Valley is from Eocene, Paleocene, or Upper Cretaceous sandstone reservoirs. Elsewhere in California, dry gas reservoirs are primarily sandstone of Pliocene or lower Miocene age.

IV. Available Data

The following data was available to the Conservation Division of the U. S. Geological Survey at the time the preliminary resource study was made in early 1974:

- Deep and shallow geophysical coverage over the proposed lease sale area.
- Preliminary geophysical structure maps.
- Preliminary offshore stratigraphic studies.
- Deep corehole data (San Pedro and Santa Monica Bays).
- Shallow (punch or jet) corehole data.
- Ocean floor samples with paleontological determinations and lithologic descriptions.
- Published geologic studies of contiguous or pertinent onshore areas.
- Published geologic and well data and production statistics of onshore and some offshore California oil and gas fields.

V. Method Used for Preliminary Resource Estimate

A. Introduction

The method devised by the Conservation Division of the U. S. Geological Survey to determine a preliminary estimate of the recoverable oil and gas resource on tracts included in the proposed Federal OCS lease sale #35 off southern California was designed to utilize all usable available data as well as to account for the variable geologic conditions that exist both onshore and offshore in California.

A considerable amount of published information was available describing onshore oil and gas fields, but the quantity and quality of available offshore data was limited. Therefore, in the final analysis, while a large number of onshore field parameters were considered and tabulated; the paucity of offshore data and the applicability of onshore data to the sale area controlled the selection of the parameters ultimately used.

B. Tabulation of Onshore Oil and Gas Field Data

1. Introduction

A total of 414 oil and gas fields and areas within fields in California thought to be analogous to areas included in the proposed offshore lease sale were studied. Data from each field and areas was categorized by stratigraphic unit, (eg. lower Pliocene, Eocene). After the data from the individual fields was tabulated by stratigraphic unit, it was grouped and averaged by geomorphic or geographic region, (eg. Santa Maria Basin, southwest Los Angeles Basin).

2. The field data tabulated and their use in the preliminary resource estimate are as follows:

a. Total ultimate production/productive area
   .Total ultimate recoverable oil and gas.
   .Maximum proved acreage.
b. Stratigraphic adjustment
   .Average stratigraphic unit thickness.
   .Average net pay thickness.
c. Structure success ratio
   .Presence or absence of stratigraphic unit in field.
   .Presence or absence of oil or gas in the stratigraphic unit.
   .Oldest stratigraphic unit drilled in field.

C. Geomorphic or Geographical Regional Summaries

Geomorphic or geographic regional summaries were also listed by stratigraphic unit and included:

.Total ultimate recoverable oil and gas.
.Total proved acreage.
.Total ultimate recoverable oil and gas/productive acre.
.Average stratigraphic unit thickness.
.Average net pay thickness.
.Number of structures in which stratigraphic unit was present and was drilled.
.Number of structures in which stratigraphic unit was present and was drilled from which commercial quantities of oil and gas were produced.
.Structure success ratio.

D. Offshore Geologic Conditions

Data available for determining the geologic conditions existing offshore has been noted in a previous section. Some of the condition determined from this data include:

.Presence or absence of stratigraphic units.
.Depth of burial of stratigraphic units.
.Lithology.
.Depositional environments.
.Approximate thickness of stratigraphic units.
.Estimated quality and quantity of potential reservoirs.
.Potential reservoir characteristics.
.Location of structures.
.Area of structures (to lowest closing contours).
.Area of upper 30 percent of structures (arbitrarily selected).

E. Structure analysis

All stratigraphic units believed to be present on each structure were analyzed in the following manner:

1. Total ultimate production/productive acre

   Values were taken from the onshore regional summaries which appeared to most closely approximate conditions existing offshore. When several onshore regions were believed to be analogous, the regions which would reflect a minimum and maximum range of values that might be expected offshore were selected. In portions of San Pedro and Santa Monica Bays and elsewhere, values from only one region were used because either the analogy appeared to be quite precise or because only one region was believed to be analogous.

   Because of variations in occurrence, thickness, lithology and depositional environments of stratigraphic units both onshore and offshore; each stratigraphic unit on the offshore structure was compared with the onshore analogies independently. Thus, the onshore analogies used for the upper Miocene might be different from those used for the Eocene on the same structure.

2. Stratigraphic adjustment

   This parameter was introduced to reflect the stratigraphic differences known or inferred between the most similar regions onshore and the areas offshore. Differences in unit thicknesses, the quality and quantity of the potential reservoirs, source rock thicknesses, depositional environments, as well as incomplete distribution of units over the entire offshore structure were among the conditions considered. A stratigraphic adjustment was determined for each onshore region used in the structure analysis.

3. Structure Success Ratio

   The structure success ratio used for each stratigraphic unit was based on ratios determined for the onshore regions. When the onshore-offshore similarity appeared to be highly valid, (eg. offshore extensions of the Los Angeles Basin), the value from the single most analogous onshore region was used. When the onshore-offshore similarity was less precise, either the average of the several most analogous regions or the entire California average structure success ratio was used.

4. Potentially Productive Area

   The acreage within the lowest closing contours for each structure offshore believed to contain potentially productive stratigraphic units was determined from preliminary geophysical structure maps. These values were arbitrarily reduced to 30 percent of the original acreage values (30% "fillup" assumed), to determine the potentially productive area on each structure.

5. Preliminary Resource Estimate Formula

   The resource estimate was determined by the following formula:

   Total ultimate production (BBL oil, MCF gas) productive acre
   X stratigraphic adjustment X Structure success ratio
   X potentially productive area = Preliminary resource estimate
   (BBL oil, MCF gas)

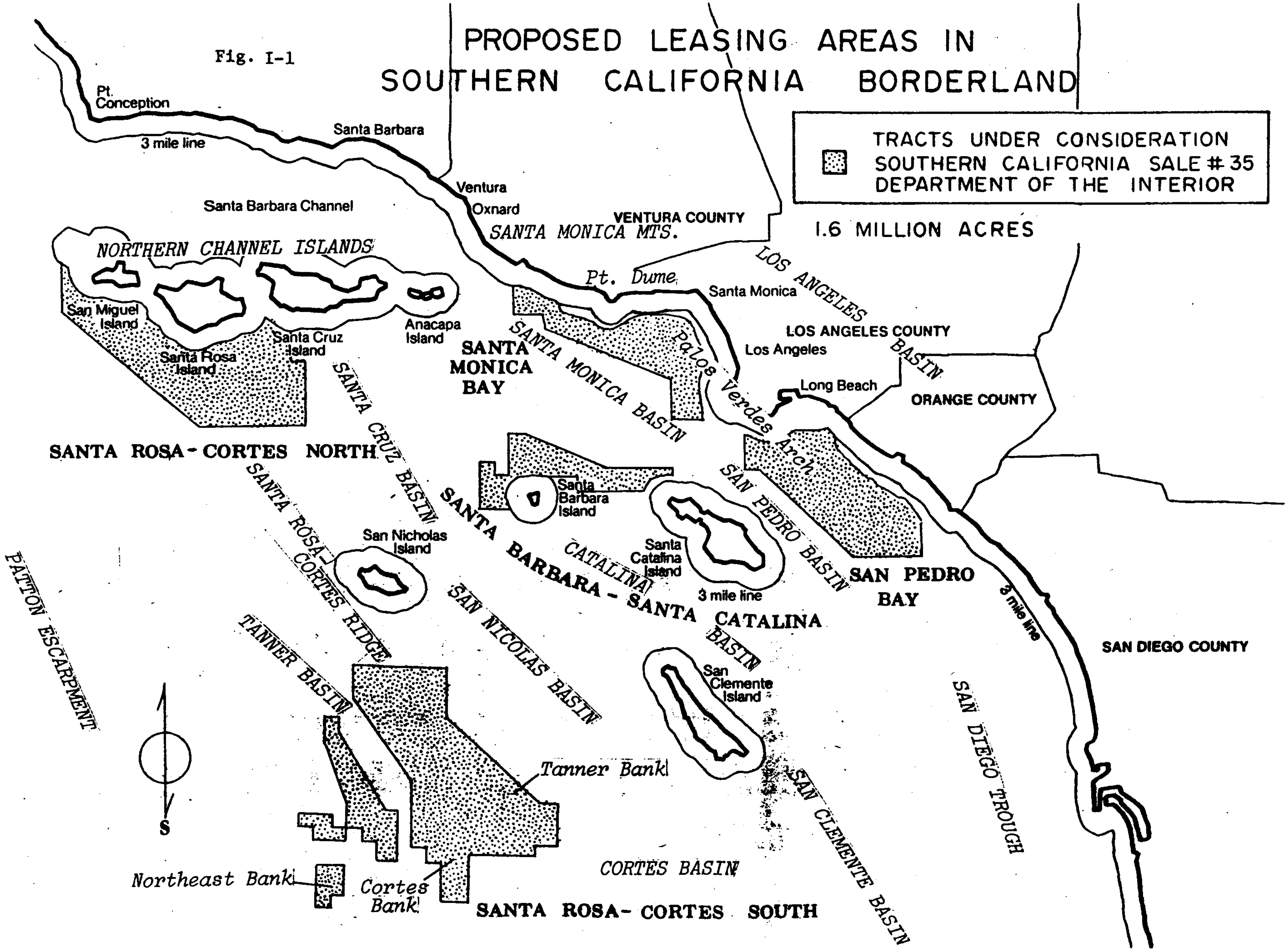
   This formula was applied to each potentially productive stratigraphic unit believed to be present on the structure to arrive at the total estimated recoverable oil and gas for the structure.

VI. Preliminary Resource Estimate For Proposed Federal OCS Lease Sale #35

Listed below are the ranges of estimated recoverable oil and gas from the proposed OCS Lease sale area.

AREA	MILLION BBL OIL	BILLION FT^3 GAS
San Pedro Bay	709-946	602-821
Santa Monica Bay	329-440	479-711
Santa Rosa-Cortes North	242-431	603-1108
Santa Rosa-Cortes South	239-660	613-1785
Santa Barbara-Catalina	67-219	103-342
Totals	1,586-2,696	2,400-4,767

Fig. I-1



PROPOSED LEASING AREAS IN SOUTHERN CALIFORNIA BORDERLAND
TRACTS UNDER CONSIDERATION
SOUTHERN CALIFORNIA SALE # 35
DEPARTMENT OF THE INTERIOR
1.6 MILLION ACRES
Pt. Conception
3 mile line
Santa Barbara
Ventura
Oxnard
Santa Barbara Channel
VENTURA COUNTY
SANTA MONICA MTS.
NORTHERN CHANNEL ISLANDS
Pt. Dume
Santa Monica
LOS ANGELES BASIN
LOS ANGELES COUNTY
Los Angeles
Long Beach
ORANGE COUNTY
San Miguel Island
Santa Rosa Island
Santa Cruz Island
Anacapa Island
SANTA MONICA BAY
SANTA MONICA BASIN
Palos Verdes Arch
SANTA CRUZ BASIN
SANTA ROSA-CORTES NORTH
SANTA ROSA-CORTES RIDGE
Santa Barbara Island
SANTA BARBARA - SANTA CATALINA BASIN
CATALINA
Santa Catalina Island
3 mile line
SAN PEDRO BASIN
SAN PEDRO BAY
San Nicholas Island
SAN NICOLAS BASIN
PATTON ESCARPMENT
TANNER BASIN
San Clemente Island
3 mile line
SAN DIEGO COUNTY
SAN DIEGO TROUGH
SAN CLEMENTE BASIN
Tanner Bank
S
Northeast Bank
Cortes Bank
CORTES BASIN
SANTA ROSA- CORTES SOUTH

INTEGRATED EXPLORATION DECISION SYSTEMS

by

John W. Harbaugh

At this point we have a sufficiently broad overview to appreciate the possibility of developing a fully integrated, analytical exploration decision system. Such a system would necessarily treat both geological and economic information. The ultimate objective of developing such a system would be to provide a means of obtaining a sequence of optimum decisions that are custom-tailored for a particular oil operator's financial goals and risk position. Figure 1 provides a simplified organization chart for such a system. The treatment of geological, geophysical and production data is represented on one side of the diagram, whereas business information is represented on the other. The linkage between the two sides is provided by outcome probability estimates.

The oil industry actually makes use of a general system that has the main elements identified in Figure 1. Geological, geophysical and production information is maintained in various kinds of files, regardless whether computers are used. Information is selectively searched for and extracted from the files and is interpreted. The interpretations are evaluated and exploration prospects are appraised as to their probable outcomes. Given an estimate of various outcomes, financial analyses are made (often in the form of cash flow forecasts). Finally decisions are made, almost invariably with the intention that each decision is an optimum one in light of the operator's objectives.

All of these steps involve uncertainty, and are therefore probabilistic by definition. My thesis is that formalized, analytical, mathematically based methods can be used in parallel with the established, traditional methods. In mathematically based systems the human decision-maker is not replaced, but instead he is aided. The mathematical tools used with computers, have the advantage that many factors can be weighed simultaneously. Furthermore, the decision-maker can consistently and objectively examine a large number of alternatives.

Developing a fully integrated, mathematical, computer-based oil-exploration decision system is a very large task. To my knowledge, no one has developed such a system although most major oil companies have developed components of such a system. The KOX (Kansas Oil Exploration) System is perhaps one of the most currently advanced systems. While the KOX system is not complete, it will eventually incorporate the components which are arranged in somewhat greater detail in Figure 2.

Figure 1 emphasizes the sole principal connection between the "geological" and the "business" sides of the overall system are provided by probabilities. This implies that the activities on the geological side are ultimately directed principally toward the estimation of probabilities. In turn, the analytical business tools symbolized on the business side require probabilities for their application. As the diagrams imply, techniques of modern probabilistic decision analysis, such as EMV payoff tables, expected utility tables, and decision trees, all require probabilities. Thus, the design of the overall system provides for harmonious interdependence between the various components and subcomponents.

PROBABILITY, MONETARY, EMV, AND EXPECTED UTILITY MAPS

Geologists and exploration managers appreciate the usefulness of contour maps for display of a variety of information. Contour maps are widely used to display geological features, such as structures and facies. Furthermore, contour maps can be used to represent statistical measures applied to geological data. By the same token, contour maps can also be effectively used to represent relationships that incorporate information from both the geological and business sides, as defined in Figure 1. For example, if expected monetary value (EMV) tables are feasible for prospects at specific localities, it follows that "EMV surfaces" can be calculated and represented over an area by means of contours. Thus, a final step in an integrated decision system would be to express investment opportunities on a regional basis by means of maps. At least four kinds of maps could be used. Probability maps could be used to express the outcomes of specific acts over the area. In turn, a series of monetary maps could express the financial consequences of particular outcomes stemming from a specific act. Finally, the information represented by both the probability maps and the monetary maps could be incorporated in EMV maps, and in turn in expected utility maps.

As we have emphasized, the concept of mapping a real surface by use of contour lines is readily extended to the mapping of imaginary surfaces. Since the probability of a particular event, such as the drilling of a dry hole, varies with respect to our interpretation of the geology, it is logical to express variations in probability with contour maps. Figure 3 illustrates a family of hypothetical probability surfaces. Assume that we are drilling a wildcat well which can be located anywhere within the area of Figure 3. Furthermore, assume that we consider only four possible outcomes for the drilling of a well; a dry hole, a discovery of 15,000 barrels of recoverable reserves, a 40,000 barrel discovery, and a 80,000 discovery. In the real world, we would regard pool magnitudes as part of a continuum of possible sizes. For the illustration here, however, we will consider only the four outcomes.

The sum of the values at a particular geographic location over the area must be 1.0, because there is absolute certainty of some outcome, and we have defined the outcomes as necessarily falling into one of four mutually exclusive classes. Thus, four probability surfaces are necessary to represent the variations over the area, and the surfaces, in toto, form a complementary relationship so that their sum at any geographic point is 1.0.

The probability contours represented in Figure 3 must be regarded as probability estimates that are conditional upon the present state of knowledge. Assume that no wells have been drilled in the area. As soon as an exploration well has been drilled, new information becomes available, and the contours of the probabilities must be readjusted. If the well is dry, the probability of drilling another dry hole immediately adjacent to the existing dry hole will be quite high (almost 1.0), and the probability estimates for the various magnitudes of success (B, C, and D of Figure 3) would necessarily have to be adjusted so that they are quite low in the immediate vicinity of the dry hole.

For each particular act and outcome, we could calculate a "monetary surface" and represent this by contours of dollars over the area. For example, the outcome of small discovery would involve quite different monetary consequences (as expressed over an area) for the act of drilling with 100 percent working interest as compared with the act of having the prospect drilled on a farmout basis by someone else. By treating the various economic aspects the dollar consequences over the area can be calculated. These may vary, depending on differences in drilling and producing costs from place to place. For example, assume that the regional dip is toward the southwest because the potential producing horizons become steadily deeper in that direction. The cost of a dry hole (Figure 4) in the northeastern corner of the area is only about $30,000 but is about $115,000 in the southwestern corner. These differences in drilling costs, of course, also will affect the dollar consequences in the event a discovery is made. Discoveries in the northeastern part of the area will be more profitable (or involve less loss) than those in the southwest because of the differences in drilling costs. The monetary values also incorporate the effect of the discount rate. The large discoveries are assumed to take longer to be produced, and therefore some of the oil to be produced in the comparatively distant future has a smaller dollar value when discounted to the present.

Monetary surface, as illustrated by the hypothetical examples of Figure 4, do not involve probabilities. Each monetary surface pertains to a specific act and a specific outcome. An expected monetary value surface, however, would involve the probabilistic representation of a series of possible outcomes resulting from a specific act. The value at each point on an EMV surface would involve the probability estimates and the corresponding monetary consequences for all possible outcomes that stem from that particular act. Calculation of an EMV for each point thus involves multiplying a succession of probabilities times monetary consequences, and summing. Figure 5A provides an example of an EMV surface that pertains to the act of drill with 100 percent working interest. It has been calculated by combining the information from Figures 3 and 4 at a succession of points over the area. EMV surfaces for other possible acts could be similarly computed.

The final step would be to produce maps of expected utility. A map could be prepared for each particular act. Figure 5B illustrates an expected utility map for the act of drill with 100 percent working interest, with the utility function of the hypothetical individual shown in Figure 6. The usefulness of an expected utility map lies in the fact that it brings together virtually all relevant aspects in making a decision. The geology is considered in the probabilities, exploration costs are considered in the expenses, gains from oil produced (if discovered) are considered, and involve producing costs, royalties, taxes, a forecast of future oil prices, and a discount factor, and finally, the operator's willingness to take risks versus his desire for gains are incorporated via his utility function. The expected monetary consequences and expected utility could be calculated either in pre-tax or after-tax dollars.

Selection of the optimum investment in the hypothetical area of Figures 3 to 6 should be a matter of finding the largest expected utility value. This involves selection of a particular act at a particular location. If this particular act at that location cannot be consummated (if, for example, the desired land is already leased), the operator should then consider the location with the next highest expected utility, and so on. All acts should have positive utility.

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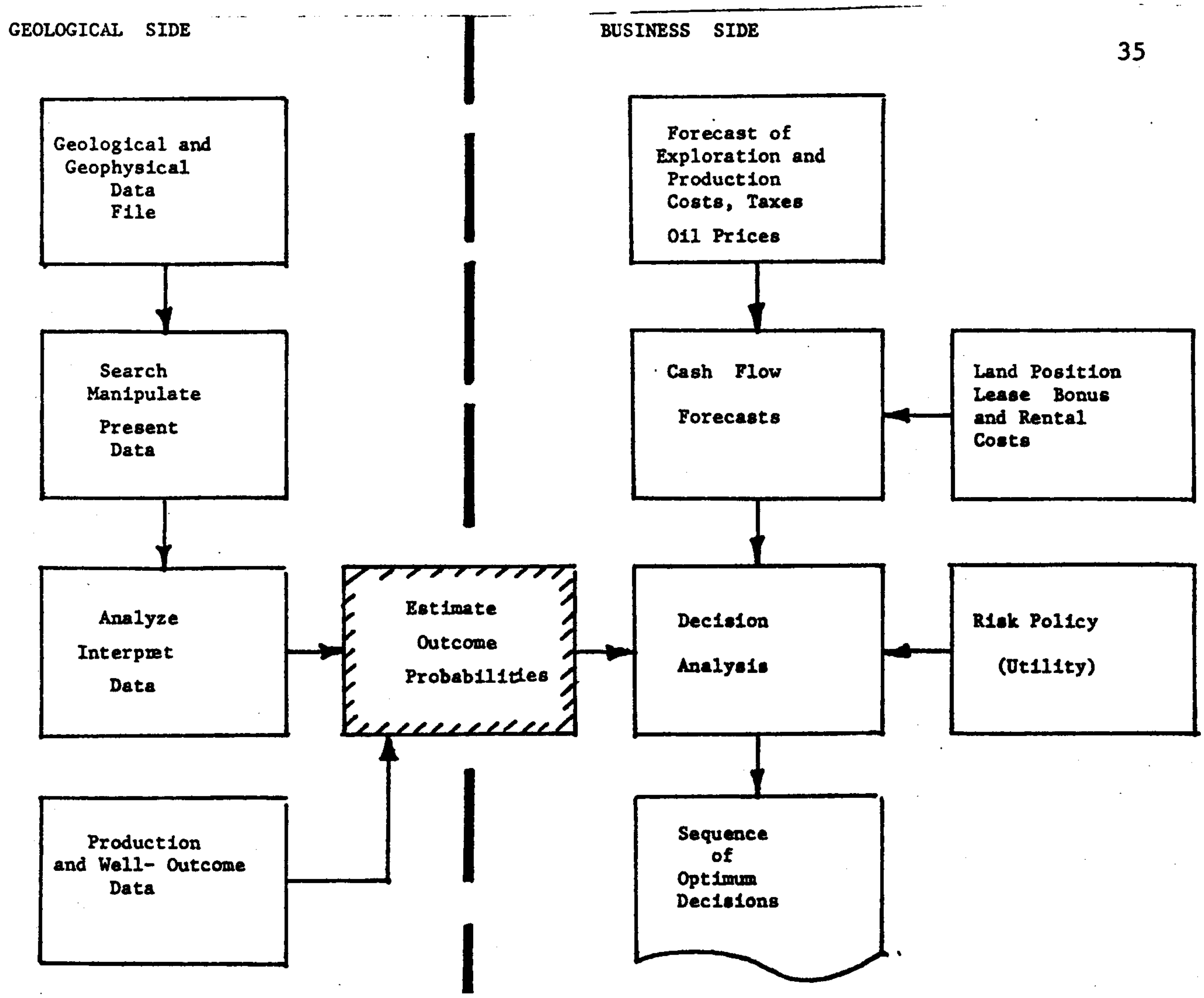

Figure 1. Simplified organization chart showing main components in a probabilistic exploration decision making system.

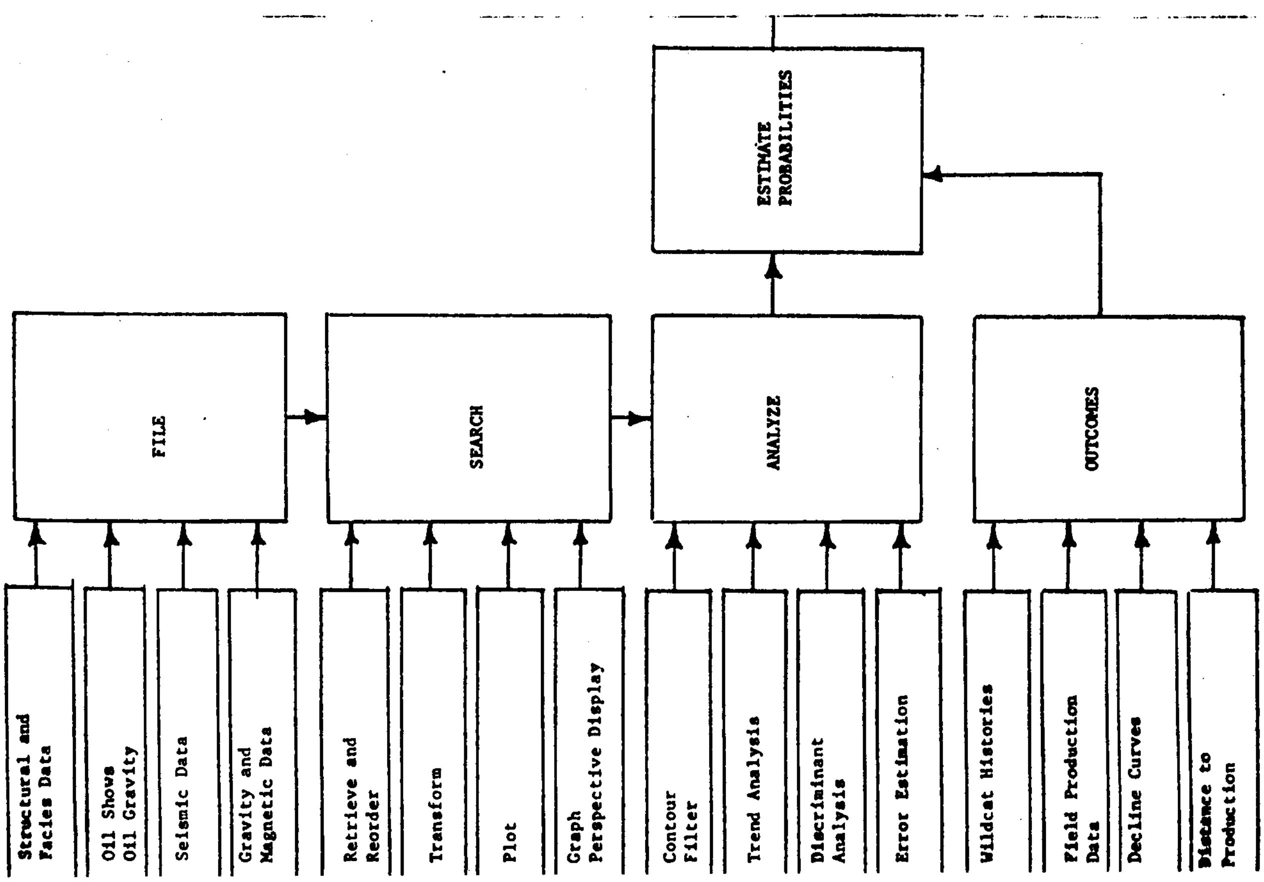

Figure 2. More detailed organization chart of the "geological" side of the exploration decision system organization chart shown in Figure 1.

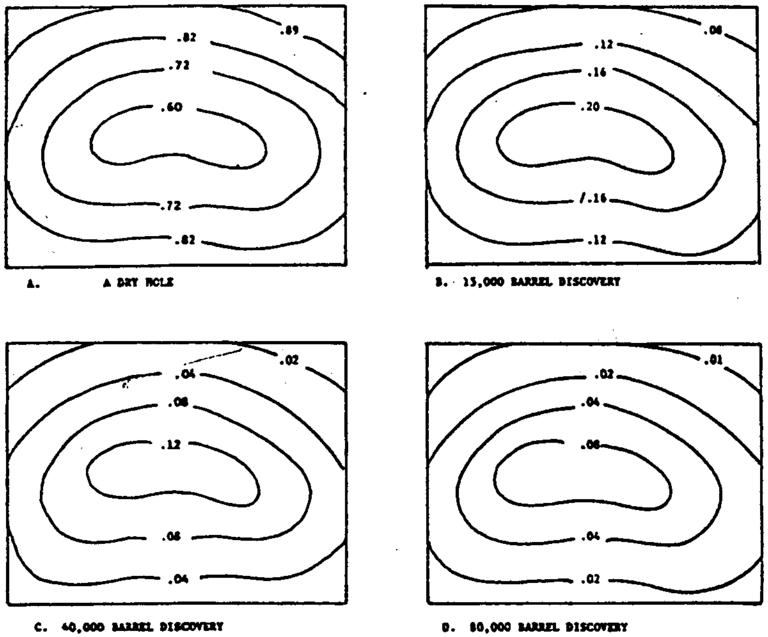

Figure 3. Series of four hypothetical probability maps which pertain to four mutually exclusive outcomes of a wildcat well drilled anywhere within the area.

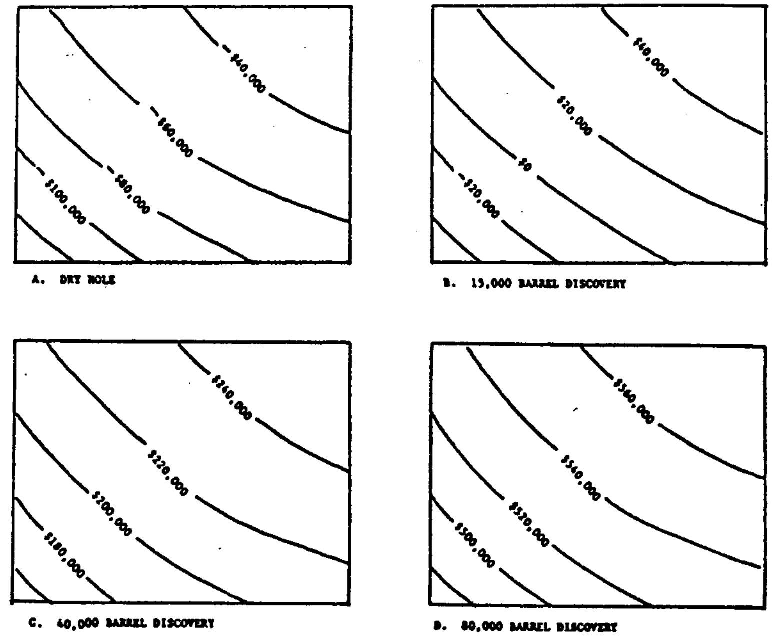

Figure 4. Series of maps of hypothetical area showing four different monetary outcomes. The four outcomes are mutually exclusive and represent all possible outcomes.

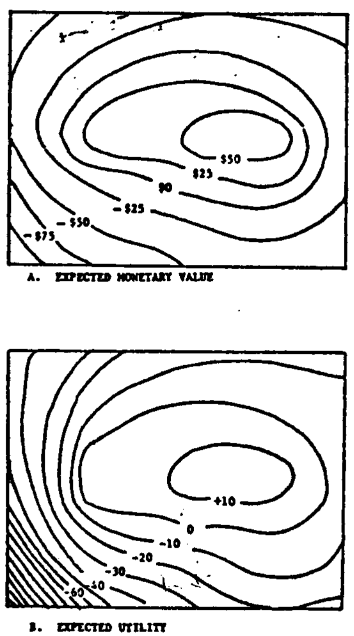

Figure 5. A. EMV map for the act of drilling with 100 percent working interest. EMV contours are in thousands of dollars.

B. Expected utility map of the same area. Contours are in utiles. EMV's in map A have been transformed to utiles with utility function of Figure 6.

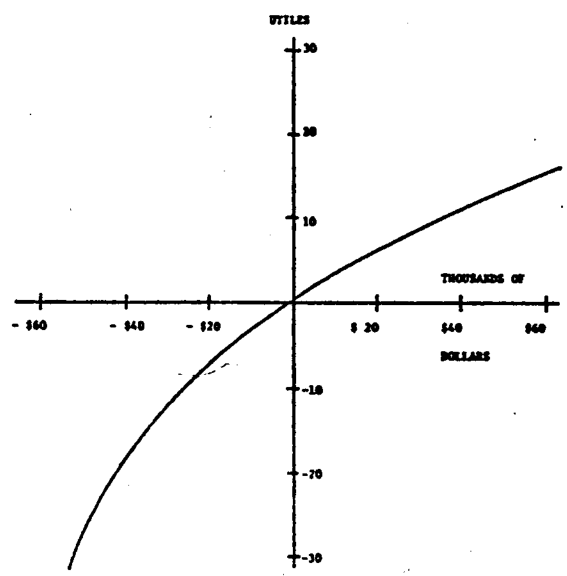

Figure 6. Utility function used in transforming EMV surface of Figure 5 to the expected utility surface of Figure 5.

STATISTICAL FORECASTING OF EXPLORATION PLAYS IN THE MUDDY FORMATION OF THE DENVER AND POWDER RIVER BASINS

John D. Haun

Results of exploration in the Denver basin (Colorado and Nebraska) have been (1) compared with the predictions of Arps and Roberts (1958), (2) compared on an areal basis (Colorado versus Nebraska), (3) used to predict the results of new exploration in the Denver basin, and (4) used to predict the results of new exploration in the Powder River basin of Wyoming and southern Montana.

Analyses of Denver basin Cretaceous "D" and "J" sandstone fields (Fig. 1) reveal trends in field size and areal extent. The 11-county, 10.6 million-acre ("fairway") sample area is in an advanced stage of exploration. During the 1949-1970 period there were 9,871 exploratory wells (10% oil, 2% gas) and 8,840 development wells (52% oil, 2% gas).

The average of 576 producing-interval thicknesses is 9 ft. Fields discovered prior to January 1, 1970, contain approximately 207,442 productive acres; 9 ft X 207,442 acres = 1,866,978 ac-ft. Ultimate production is estimated to be 688,939,300 bbls; 3321 bbls/acre, 369 bbls/ac-ft. An alternate method of analysis shows that 1661 sections (square miles) have one or more oil or gas wells (1445 oil, 216 gas), 10% of the total 16,552 sections--476,775 bbls/productive section. The number of sections explored, to the extent of one or more wells per section, is 6778, 41% (Colorado 35%, Nebraska 54%). Traps are either entirely stratigraphic or result from stratigraphic conditions on minor structural features.

In the 11-county study area, a total of 737 fields was discovered prior to January 1, 1970--218 were abandoned, 339 had production-decline curves that were extrapolatable for determination of ultimate oil recovery, and 180 had production histories for which decline curves could not be used (i.e., the fields were new, extensions had been added recently, or secondary recovery methods had been initiated within the past few years).

For purposes of comparing field size in acres with ultimate production, the 557 abandoned and extrapolated fields were divided into 8 groups, each group having twice the number of acres as the next smaller group (i.e., 40-79, 80-159, 160-319 acres, etc.) The average number of acres and the average ultimate production were determined for fields in each group except the 40-79-acre group--all one-well fields were considered to be 40-acre fields. A log-log plot (Fig. 2) showing areal extent (in acres) versus ultimate oil recovery of the 557 fields is a straight line and may be used, as a first approximation, in estimating the ultimate recovery of fields that have areal definition but insufficient history for extrapolatable decline curves.

Arps and Roberts (1958) similarly divided the 338 fields, discovered prior to January 1, 1958, in a 5.7-million-acre sample area (Fig. 1), into 9 groups. The ranges of productive acres in the 9 groups of Arps and Roberts differed from those of the present study. A comparison of the data of Arps and Roberts with the data of the present study (Fig. 2) shows essentially the same straight-line relationship. Production and reserves attributable to secondary recovery are included in our study, but not in the Arps and Roberts study. Additional recoverable oil in the 67 fields undergoing secondary recovery apparently did not change significantly the relationship of areal extent to ultimate recovery of our 557-field sample.

As an additional test of the relationship between areal extent and ultimate recovery, a least-squares-derived straight-line fit was made by using the total 737 fields without the intermediate step of grouping (Fig. 3). This statistical method results in a much more pronounced influence by the many smaller fields. A plot was made, therefore, without the 40-acre (least accurate) fields and this line (Fig. 3) is considered most appropriate for estimating ultimate recovery.

Oil fields in our sample were divided into 16 size classes (based on ultimate production), each class twice the size of the next smaller class (1000-2000 bbls, 2000-4000 bbls, etc.). The number of fields in each class was plotted versus the ultimate production (logarithmic scale). The resulting histogram of the 737 fields is compared with a histogram of the 338 fields of Arps and Roberts in Figure 4. All fields in our sample smaller than 1000 bbls were arbitrarily included in the smallest class at the left side of the histogram. The most important difference between the two histograms is the greatly increased proportion of fields in the larger classes. The log-normal (Gaussian) distribution results from decreasing numbers of larger fields, on the right, and lack of economic incentive for developing fields with indicated reserves smaller than 100,000 bbls, on the left.

At the time of the Arps and Roberts study there had been 3705 wildcat wells drilled in their sample area (AR area) and, based on the results of this exploration, they predicted the cumulative reserves that should be discovered with additional 1000's of wildcats. Prior to January 1, 1970, a total of 7939 wildcats had been drilled in their sample area. They predicted that 690 fields would be found and there were actually 699 oil fields found. They predicted that 380 MM bbls would be found and actually 635 MM bbls (prim. + second.) were found. A reanalysis of fields in the AR area, discovered prior to January 1, 1958, resulted in our estimate of 499 MM bbls (ultimate production) versus the 280 MM bbls in the AR extimate. This difference in estimates for pre-1958 fields accounts for most of the difference between prediction and results. The AR methods, as modified in the present study, appear to be valid in predicting ultimate numbers of fields and reserves to be found in a sample area.

If the Colorado portion of the basin had been explored prior to the Nebraska portion, or vice versa, could exploration success have been predicted for the unexplored part? Analysis indicates that the number of fields could have been predicted with $\pm$ 7-8% accuracy, and cumulative reserves could have been predicted with $\pm$ 16-19% accuracy. One field (Adena) in Colorado accounts for the entire difference in cumulative reserves and offsets the lower percentage of successful wildcats in Colorado.

Is it possible to predict results of exploration recently developing at the southwest end of the "fairway"? A 44-township area was selected for analysis (Fig. 1). If 1000 wildcat wells are drilled in the area, plus the associated development wells, the drilling density should be similar to that in the AR area. If 12% of these wells are successful (9% oil, 3% gas), there should be 90 oil fields and 30 gas fields discovered. The number of oil fields in each size class, based on ultimate recovery, should be similar to the distribution previously established in the basin. Ultimate reserves to be discovered are estimated at 87 million bbls. Prior to January 1, 1971, 266 wildcat wells had been drilled in the area, 13 oil fields and 3 gas fields had been discovered--a 6% success, typical of an early phase of exploration. We estimate that 38 million bbls of oil have been discovered in the 13 fields. Approximately 44% of the ultimate 87 MM bbls has been discovered with 27% of the 1000 wildcats. If the discovery rate follows that of the AR area, 80% of the ultimate reserves should be discovered by the first 500 wells.

Environments of deposition, geological history, trapping conditions, and size of area of the Muddy Sandstone in the Powder River basin are very similar to those of the "D" and "J" sandstones of the Denver basin. Because there are potentially productive formations older than the Muddy in the Powder River basin, it is not possible to assign a specific number of past wildcat wells to Muddy exploration. Prior to January 1, 1971, there were 98 Muddy fields. The fields were divided into 18 groups based on estimated original reserves (P, Fig. 5). A conservative estimate of numbers of undiscovered fields in each group was made (P', Fig. 5). This estimate is compared with the distribution of the 737 Denver basin fields (D, Fig. 5). The projected maximum number of fields was arbitrarily assigned to the 512,000-1,024,000-bbl group, in contrast to the Denver basin maximum in the 128,000-256,000-bbl group. The deeper, more expensive drilling necessary for future Muddy exploration will make smaller fields uneconomical.

The estimated number of undiscovered fields in each group was multiplied by the average ultimate reserves, derived from the Denver basin sample, except that groups 16-18 were averaged from existing fields in the Powder River basin. The total number of fields is 380 and they are estimated to contain 573 MM bbls (ultimate recovery). Adding 573 MM bbls to the 662 MM bbls (estimated original reserves in 98 previously discovered fields) results in a basin total of 1,235 MM bbls, 16% more than the Denver basin estimate.

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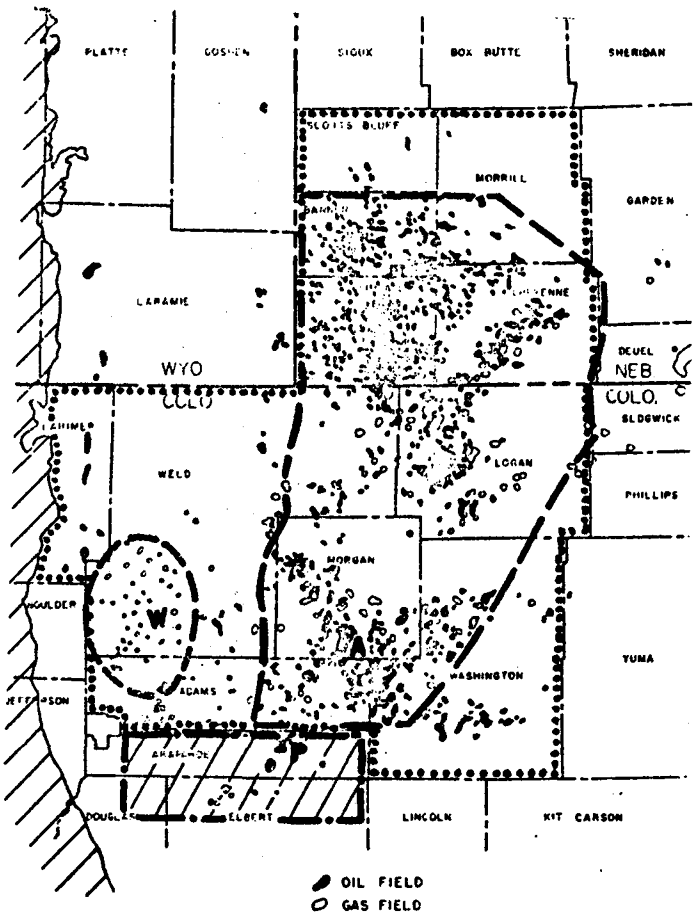


Fig. 1.--Denver basin index map. Dashed line = area of Arps and Roberts (1958) study; dotted line = 11-county area of present study; dash-dot line = 44-township area of projected exploration; A = Adena field; P = Peoria field; W = Wattenberg field.

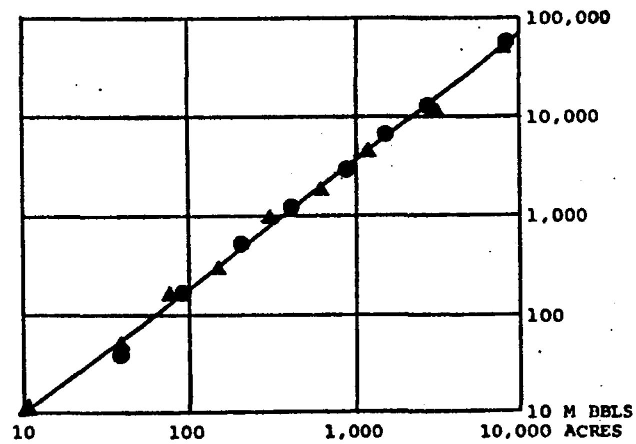


Fig. 2.--Areal extent (acres) versus estimated ultimate recovery (M bbls) of oil fields. Triangles = Arps and Roberts (1958 study (338 fields); circles = this study (557 fields).

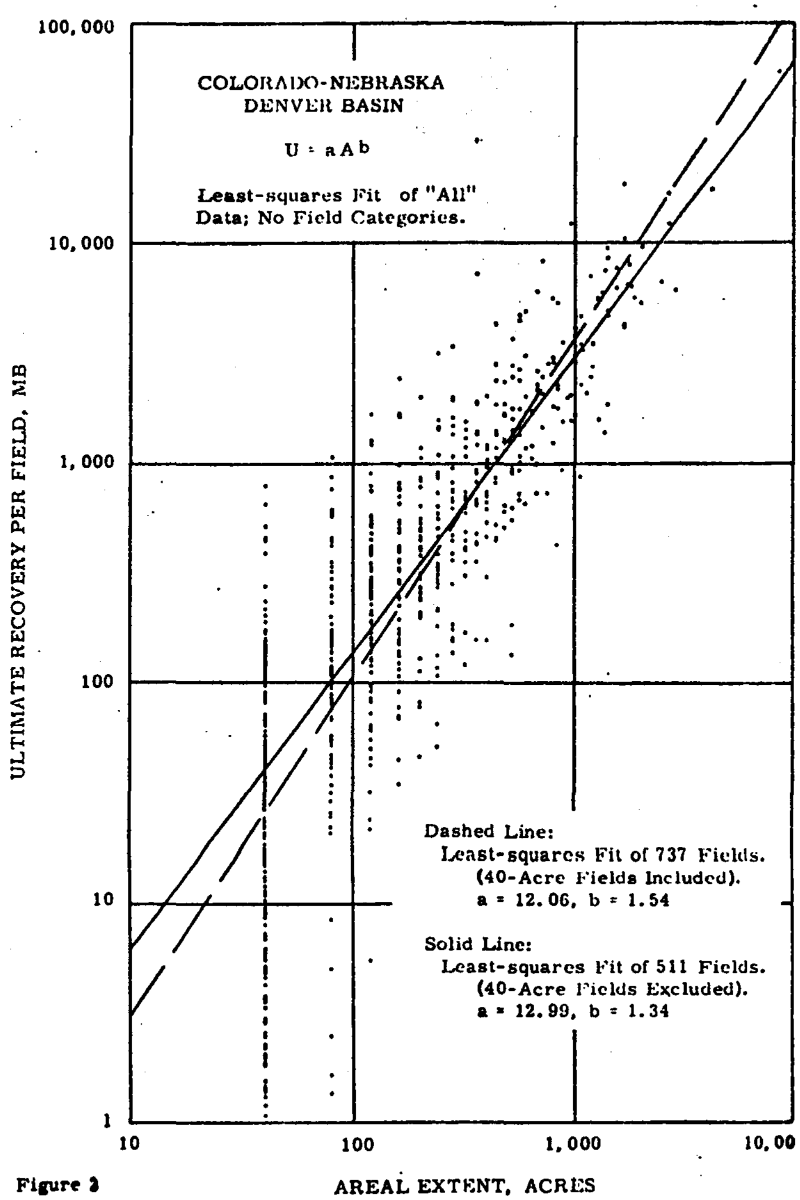


Figure 3

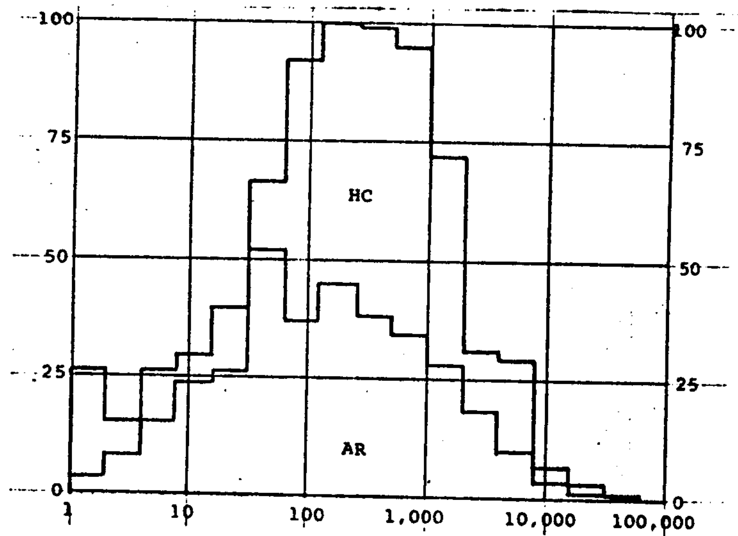
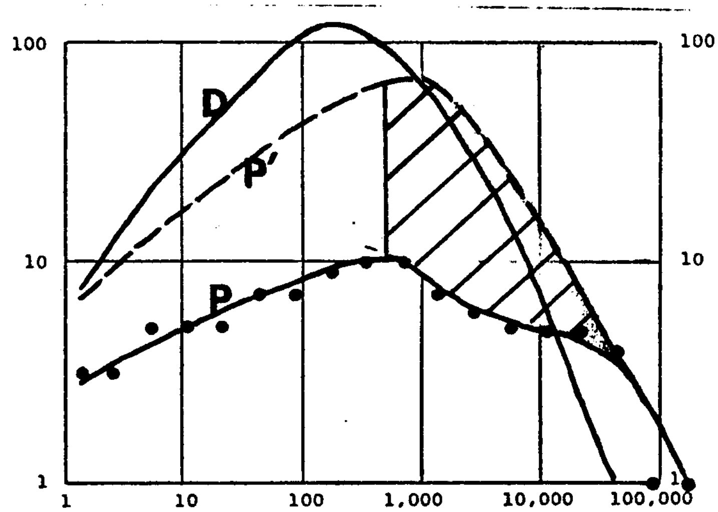


Fig. 4.--Number of fields (vertical scale) versus ultimate production (M bbls, horizontal scale), 11-county sample area (737 fields). AR = Arps and Roberts sample (1958, 338 fields); HC = this study



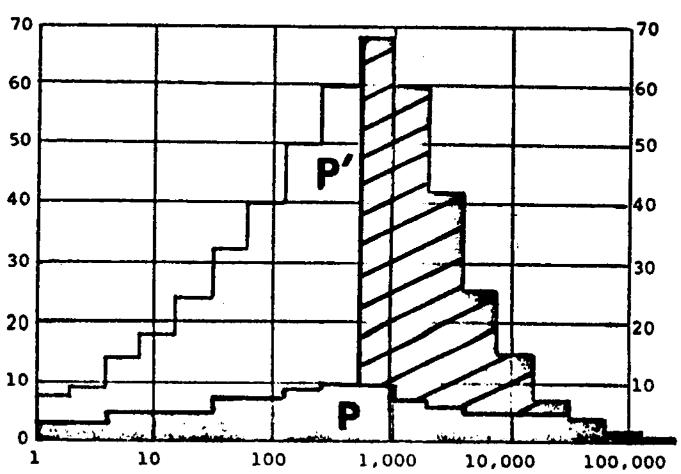


Fig. 5.--Muddy fields, Powder River basin. Upper chart, smoothed log-log distribution of numbers of fields (vertical scale) versus ultimate production (M bbls, horizontal scale); P = discoveries prior to 1/1/71; P'= predicted future distribution; D = approximate distribution of Denver basin fields; shaded area, economically attractive potential fields. Lower chart, same smoothed data as histograms.

RECONNAISSANCE EXPLORATION BY APPLICATION OF GEOSTATISTICS TO WELL LOG DATA

Gerald E. Henderson
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Denver, Colorado

Introduction

The rising costs and collapsed time frames now being experienced for exploration drilling have made it more important now than ever before that all available exploration information be extracted from raw measurements. No longer can only the easy or obvious interpretation suffice for continuing exploration success. The importance of extracting all information is easily evidenced by examination of the increased portions of exploration budgets now allocated for geophysical processing and geological analysis, as well as the obvious demand for professional explorationists. Further evidence is present in the manner in which the development of exploration technology has responded to budget availability and management interest.

A great deal of stratigraphic information may be derived by review and analysis of various electric logs, sample logs, core analyses and test results that might be available in a particular exploration area. Certainly the combination of these data will ultimately describe the structure, thickness, and areal representation of geologic units and perhaps indicate the presence of potentially productive areas. However, it is commonly accepted that only a portion of the total information available from these measurements is utilized by the explorationist in the development of drilling and play prospects.

The problem to be considered in this presentation is the reduction of the electric log data and other measurements to a form suitable for analysis and subsequent interpretation.

A significant effort has been expended in many sectors of the petroleum industry in seeking a practical solution to the extraction of stratigraphic information from electric log data. Many results and interim reports have been published, each claiming a particular measure of success and each merely pointing the way toward the need for additional study. The purpose of this presentation is to examine the theory and application of a process which affords the extraction, reduction, and presentation of structuro-stratigraphic information from digital petrophysical, geological and geophysical measurements. The specific application considered includes only petrophysical measurements, although the other two data forms apply equally well to the process.

The problem may be simply stated:

"Use of well logs as a source of mappable information for the structure, thickness and areal distribution of correlatable rock units in the area under consideration has not led to consistent exploration success. How can further mappable information be derived from the logs and subsequently analyzed?".

The process which is applied in solution of this problem may be, and has been, applied in many geologic provinces and to many stratigraphic problems. Due to the confidential nature of the results of the application of the process, a particular area considered by this presentation is the only one which may be discussed and examined in detail. The particular process considered is hereinafter referred to as "RECON"*.

Geologic Setting and Model

The area considered by this study is that surrounding the Walker Creek field in southern Arkansas and northern Louisiana. The area includes other fields in addition to Walker Creek which also produce from carbonates of the Smackover (Jurassic) formation. These other fields are Welcome, Lick Creek and Chalybeate Springs fields.

Although the geology of the Smackover carbonates in this area have been well described in the literature, an understanding may be derived from several sources.[1,2] A brief description of the geologic problem is as follows:

> "Walker Creek, Lick Creek and Chalybeate Springs Fields are interpreted as near classic examples of stratigraphic traps. The production is limited along the updip edge by a loss of porosity and along the downdip edge by a water level. Welcome Field has been interpreted as a predominantly structural trap, although there are stratigraphic implications which may be observed by analysis of the well logs of and surrounding the Welcome Field reservoir."

A generalized structural interpretation of the area reveals a simple south dip from contours placed on the top of the Smackover carbonates. A slight terracing and dip reversal at the northern edge of the field may be considered due in part to irregularity on the top of the Smackover carbonates and in part to minor local structure.

The updip stratigraphic pinch-out may be easily interpreted as follows; the reservoir rock in the uppermost Smackover is oolitic limestone with intergranular porosity. The oolite facies pinches out to the north into the anhydritic Buckner shale. The Buckner also seals the top of the reservoir. The base of the Smackover reservoirs is sealed by older limestone of the Smackover formation. Inasmuch as a detailed geologic analysis of the area and trapping mechanism is not the objective of this discussion (nor the application of the RECON process), the foregoing and the interpretations presented by others will suffice.

*Proprietary to Scientific Software Corporation, Denver, Colorado.

Of particular importance in the RECON process is the ability of the geologist working with the process to "ask the right geologic questions" of the available digitized data. Based on many years experience with the process, an identical or even greater geologic effort is required for a study of this type than that required for a "traditional" subsurface exploration analysis. In addition to all of the geologic models which might be envisioned by the more traditional approach, the RECON project geologists may propose other detailed quantitative models which would be impossible to investigate by conventional stratigraphic analysis. These RECON geologic models must be based on a sound understanding of the regional geology and of the particular depositional problem considered.

In a RECON project, a variety of geologic features may be related to stratigraphic parameters. A partial list of significant geologic features that may be considered in a RECON project would include detection of reservoir quality variations, proximity of stratigraphic parameters to hydrocarbon deposits based on anomalous geochemical changes in reservoir seals, and perhaps proximity to a paleostructural high. It cannot be overstated that the effective geologic analysis which follows the processing of the digital information cannot succeed without the development of a valid geologic model (S) for the area under consideration. In simple terms, the RECON analysis succeeds only when accompanied or preceded by stratigraphic analysis.

The specific model to be discussed in this presentation was designed to investigate the question, "Is there information in the Buckner shale which can be related to the proximity to a zone of Smackover porosity?".

The reason for the Buckner geologic model is that the change from the downdip oolite reservoir facies into the updip anhydritic Buckner shales may be interpreted as a paleographic change from shoal-water oolite bars into a sebka environment of hypersaline mud flats. This setting is one in which certain systematic changes in the characteristics of the Buckner shale could reflect distance from porous Smackover oolite ridges. Several other geologic interpretations could also reflect similar changes in the Buckner. For example the Buckner may not be immediately equivalent to the Smackover, but would behave as stated if the interval records later infilling of depositional and/or erosional topography on the Smackover.

Recon Process Technology

A generalized flow chart for the RECON process includes the following items:

1. Determine the type of information to be used and reduce it to digital form.

2. Normalize or calibrate the digitized information.

3. Complete the necessary geologic studies to determine the trapping mechanisms prevalent in the area.

4. Establish a detailed correlation net for the geologic intervals required.

5. Select the geologic models which are most appropriate for the area.

6. Determine the variables that are to be calculated from the digitized information.

7. Reduce the calculated variables to those which may be mapped to indicate established production.

8. Apply the results to the exploration or nonproductive portion of the area.

Conclusions

The RECON exploration technique may be employed to provide insights in geologic studies which are not commonly available to the stratigrapher. The statistical and calculated-variable results have been shown to easily map the likelihood of the presence of Smackover porosity using data only from the sealing Buckner shales. The technique certainly supplements existing methods, and in some cases may supplant existing efforts. It has been easily shown, however, that no revolutionary geologic thinking is applied, just sound geologic thinking with more data.

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1. Chimene, Calvin A., "Arkansas' Walker Creek Area Should Grow At Both Ends", Oil and Gas Journal, September 9, 1974, pp 122-128.

2. Bishop, William S., "Petrology of Upper Smackover Limestone in North Haynesville Field, Clayborne Parrish Louisiana", Bulletin AAPG, January 1968, Vol. 52 - No. 1.

G ROGGE MARSH

FORECASTING SUPPLY AND THE TIMING OF PRODUCTION IN THE OFFSHORE FRONTIERS

Industry and government daily make decisions that could be better if they were grounded in an awareness of reasonable forecasts of future domestic oil and gas supplies. The most uncertain and perhaps the largest variable in future domestic supply is the undrilled offshore areas of the Atlantic and Pacific Coast states and Alaska. The frontiers where industry is uncertain not only of the potential but also of its ability to produce the potential due to hostile environments.

Forecasting begins where geologic assessment ends. Our concern is the translation of the geologist's and geophysicist's best estimates of undiscovered potential in undrilled areas into a reasonable preview of when we might expect production.

It is largely a matter of simulating the real-world process of leasing, exploring, discovering, developing, and producing offshore reserves...aligning a series of judgments on how the future will happen. A key prerequisite is familiarity with industry history and the process by which we turn the explorationists' ideas ultimately into oil and gas production.

Figure 1 shows a probability distribution of the risk-weighted, attainable, undiscovered potential for a hypothetical basin. This assessment has been made by a team of explorationists, pooling their knowledge, experience, and opinions.

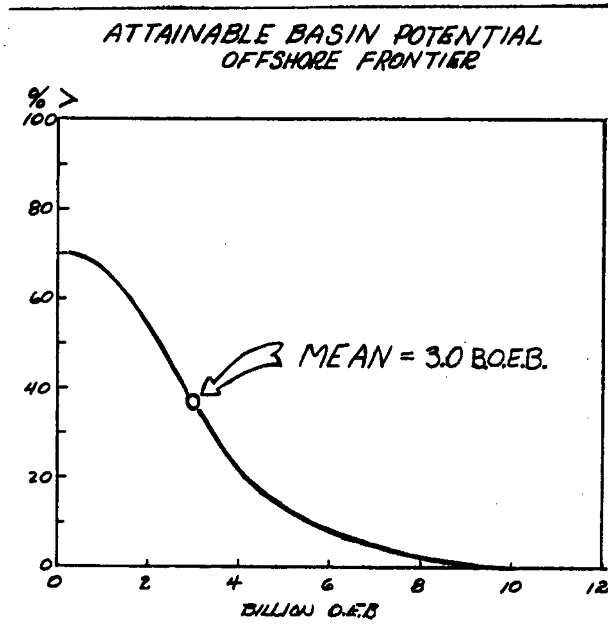

Figure 1

They began by estimating the total undiscovered potential based on the calculated sediment volume and a reasonable range of hydrocarbon yields from look-alike basins elsewhere. Or, if their reconnaisance geophysics coverage was good enough, they may have based their assessment on estimates of the number of structures, the percentage of dry structures, the ratio of stratigraphic to structural reserves, and field-size distributions either made up or taken from look-alike basins.

The next step was to estimate how much of this potential was attainable. Attainable potential is the amount of recoverable hydrocarbons in reservoirs and accumulations whose productivity and size will make their development economically feasible in the foreseeable future. Also, the technology necessary for development would be achievable within a reasonable length of time. Environmental or political constraints may have been considered too.

Finally the exploration team reached a consensus that there was a 30% chance the basin would be dry. Either nothing would be found or the discoveries would be too small to warrant development. This is illustrated by the top 30% of the curve reading zero.

Future exploration of our offshore frontiers will produce a range of results. Some areas will contain giant fields; others will be non-productive, with all grades in between. A forecast for a large area such as the United States must be the sum of the forecasts of the risk-weighted means of all the different areas. This accounts for the inevitable dry basins.

We will use the mean of the curve - 3 billion oil equivalent barrels - as the foundation for the forecast. Oil and gas should be treated separately, since timing, economics, and the procedure of development are often quite different.

In the absence of any other information, we assume oil is 50% of the total hydrocarbons (U.S. average). In remote areas, such as Alaska, delay may be much longer for gas than for oil production due to lack of a ready market close by. Aside from this, the process for forecasting gas is much the same as for oil. So the reduce complexity, we will develop a forecast only for the 1.5 billion-barrel oil potential.

A sale schedule must be designed that eventually leases all prospective areas. Published government schedules can indicate a reasonable beginning date. Rig availability, sales in other offshore areas, the number and nature of the structures, are some of the factors determining the frequency of sales. At the same time, we must estimate the percent of the potential that will be leased in each sale. Usually the large and easily found structures are leased in the initial sales. The smaller, more obscure accumulations tend to be nominated in later sales when basin knowledge has increased and economic threshold size has been lowered. For our example, the sale schedule is:

Sale Number	Date	Potential Leased	
1	1978	40%	600 MMBO
2	1981	30%	450 MMBO
3	1984	20%	300 MMBO
4	1988	10%	150 MMBO

Each sale potential is then discovered over an assumed five-year primary term of the leases. For this example, we will use a reasonable discovery schedule, similar to Gulf of Mexico experience. First year, 25% of the leased potential is discovered, then 40, 20, 10, and 5% in subsequent years. Applying the schedule to each sale, a basin discovery forecast is built up, as shown in Figure 2.

In reality, we don't know how much we have found at the time of discovery. Definition wells must be drilled. Platforms must be ordered, then installed. Development wells are drilled. As knowledge of the field increases, the

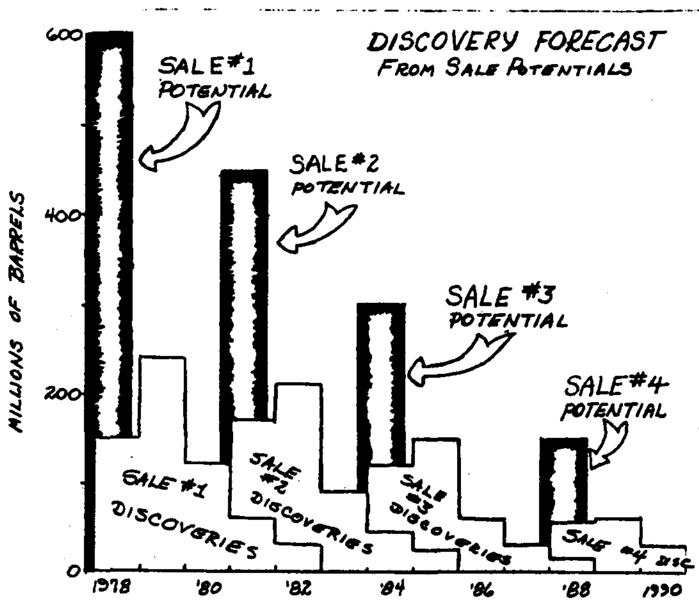

Figure 2

estimates of proved reserves increase through annual reserve additions, or "bookings." Later, production history further improves the accuracy of our estimates.

Many factors influence the rate at which reserve estimates grow and the number of years required to approximate the ultimate size of a recent discovery -- field size, structure type, relative geologic complexity, etc. Figure 3 shows the effective booking rate for recent oil discoveries in the Gulf of Mexico. This curve was derived by analysis of API data on oil discovery estimates. It implies that 50% of a discovery's ultimate reserve will be booked three years after discovery. But an accurate estimate of true size requires 15 to 20 years of bookings.

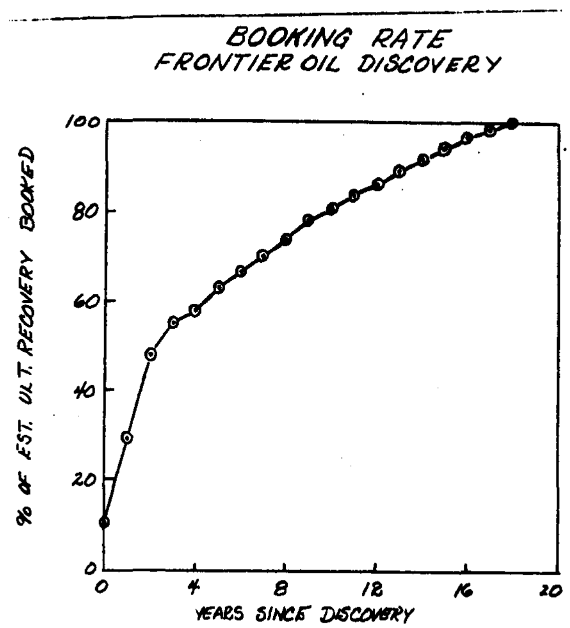

Figure 3

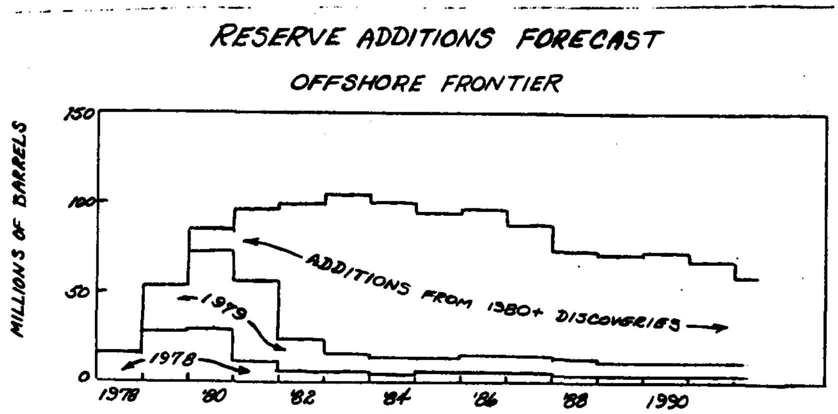

Figure 4

If we apply this booking schedule to the offshore frontier example, we get the reserve addition forecast shown in Figure 4. Each year's discoveries have been booked over an 18-year period. Reserve bookings for the first two years of discovery - 1978 and 1979 - are shown to illustrate how the bookings are spread out in time.

To "produce" this reserve, the first consideration should be delay. This is the time required after discovery to order, build and install platforms and production facilities. There is more delay associated with offshore frontier production than any other. And the more hostile the environment, the greater the delay. In an industry survey sponsored by the BLM recently, opinions on the time required from first discovery to the beginning of production in the United States offshore ranged from two-to-four years in the Gulf of Mexico to three-to-ten years in the Beaufort Sea. For the example here, four years was used.

Since each year's discovered reserve represents a group of fields that were all found in the same 12-month period, production scheduling should be done separately for each discovery year, then summed by production years to develop a forecast for the entire area.

Annual production can be calculated by subtracting cumulative production from the cumulative additions, then dividing the result by a reasonable reserves-to-production ratio. For this example 8:1 was the ratio used. This is the ratio many large United States fields exhibit.

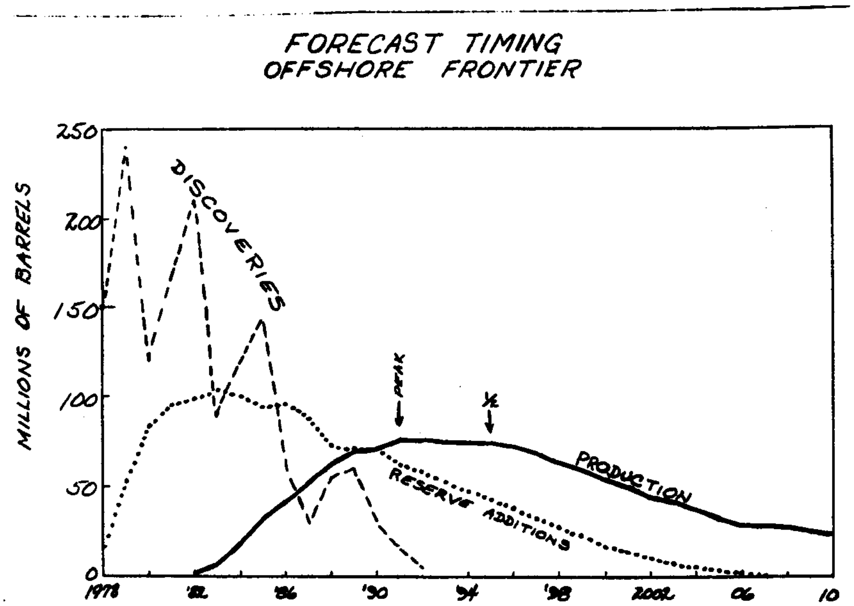

Figure 5

Figure 5 summarizes the timing of the discovery, reserve addition and production forecasts. One half of the 1500 million barrel potential has been discovered by 1982. However, due to the normal delays of reserve booking and installing production facilities, peak production is not reached until 1991. And half of the potential is not produced until 1995.

G. Rogge Marsh
Exxon Company, U.S.A.
June 27, 1975

AAPG Research Conference
Stanford University
August 20-22, 1975

EXPLORATION PROFITABILITY ANALYSIS USING MONTE CARLO SIMULATION

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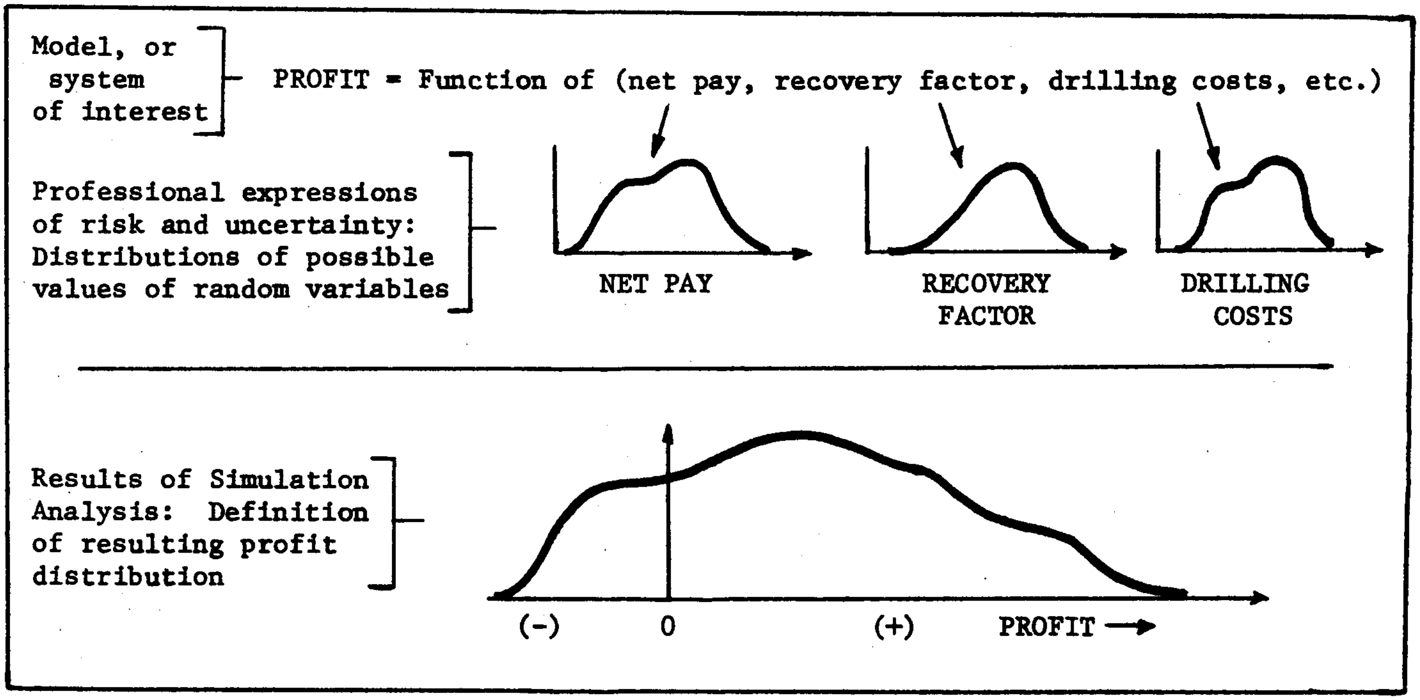
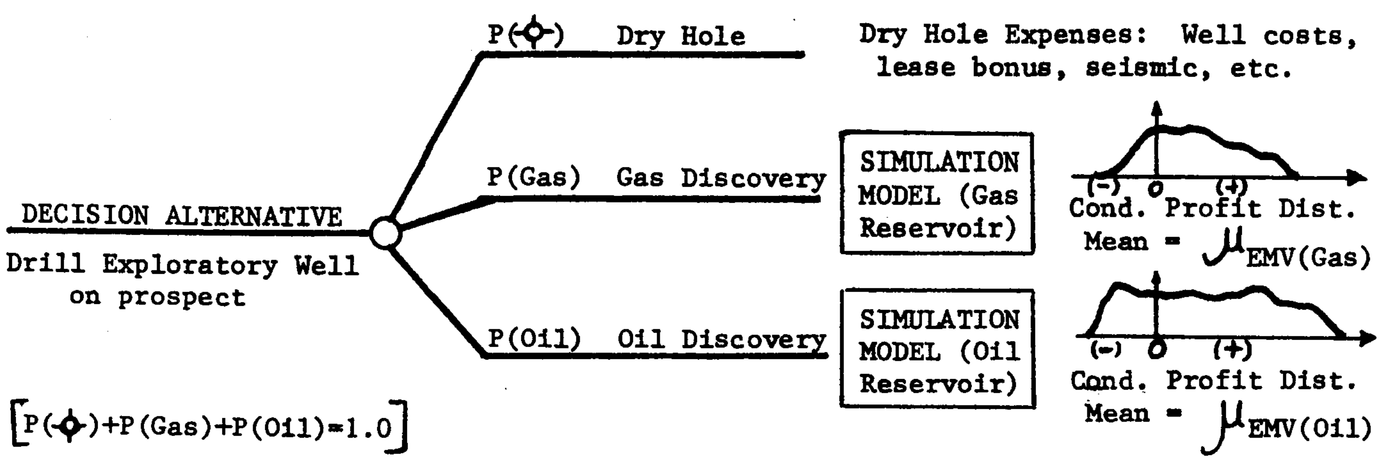
INTRODUCTION

A new approach for quantifying the degree of risk and uncertainty in drilling prospects. Introduced in late 1960's. Considered by many to be the most significant new idea in risk analysis and quantitative methods of decision analysis in many years. Permits explorationist to compute realistic expected value criteria for evaluating and comparing drilling prospects. Method is a continuous outcome model, rather than a discrete outcome model (such as dry hole or producer). Used for major decisions by virtually all major oil companies and, as more of their staff become conversant with simulation, to an increasing extent in day-to-day decisions.

A.) AN OVERVIEW OF THE METHOD



B.) HOW SIMULATION IS USED IN DRILLING PROSPECT ANALYSIS



$[P(-⌖-)+P(Gas)+P(Oil)=1.0]$

C.) FINAL EXPECTED VALUE (EV) COMPUTATION

$$EV_{\substack{\text{Drill Expl.}\\ \text{Well}}} = \left[\left(P(\text{-}\!\diamond\!\text{-}) \times \begin{smallmatrix}\text{Dry Hole}\\ \text{Expenses}\end{smallmatrix}\right) + \left(P(\text{Gas}) \times \mu_{EMV(\text{Gas})}\right) + \left(P(\text{Oil}) \times \mu_{EMV(\text{Oil})}\right)\right]$$

D.) COMPONENTS OF SIMULATION MODEL (See next page)

E.) ADVANTAGES OF SIMULATION

1. Method is completely general. Can be used to analyze any system of uncertainty.
2. Explorationist can describe variability (uncertainty) of factors affecting profit as a range and distribution, rather than having to rely on a single "average" value of each parameter.
3. No limit to number of distributions which can be included. Distributions can be of any shape or range, discrete or continuous. Analyst does not have to be able to identify the distributions as to whether they are normal, lognormal, etc. - if he can draw a picture of it that's all that is needed.
4. Effective for blending expertise of firm. One person does not have to describe all of the distributions.
5. Resulting profit distribution describes all possible levels of profitability, as well as their likelihoods of occurrence. (A distinct advantage over just a single "average" or "most probable" profit plus a dry hole cost)
6. Costs of analyses are minimal. Easy to program. Takes only a matter of seconds of computer time to run.
7. Method lends itself to sensitivity analysis. Different distributions can be used for random variables to see resulting effect on profit distribution. By successive runs analyst can identify to decision maker the two or three critical variables.

F.) STATE-OF-THE-ART, AND GENERAL COMMENTS

1. We're still in learning process. Many explorationists are still unfamiliar with statistical considerations of method, and how to think in terms of describing variability (uncertainty) as ranges, rather than average values. Also, there still exists much misunderstanding on part of decision makers as to how to interpret simulation results and the meaning of expected value criteria. We are making progress - but it's a slow process.
2. Most analysts fail to account for dependencies between random variables. Most references omit this topic, so many seem to conclude there is no need to consider dependencies. A simple procedure to do this is described on pages 4 and 5.
3. Most beginners with simulation will describe distributions for parameters used to compute reserves, generate a reserve distribution, then treat costs, crude prices, operating expenses, etc. as deterministic. Also, many fail to see the need for, and benefits of making a sensitivity analysis.
4. Some explorationists feel method is only useful in areas of much drilling, where large amounts of statistical data are available so as to be able to describe realistic distributions. They claim method can't be used in virgin new areas because there are no data upon which to base distributions. Proponents counter that in new areas uncertainty is greatest - and simulation is most useful (and necessary). In absence of data many explorationists will use a single value for each random variable - but this implies a certainty which may not exist!
5. Some managers feel professional judgment expressed as a distribution is weaker than stating a single value. Viewpoint usually reflects their dislike and/or lack of understanding of method. Most feel a range and distribution is a more realistic (honest?) appraisal of uncertainty.

DETERMINE RECOVERABLE OIL (OR GAS) RESERVES

1) Sample from distributions of factors affecting recoverable reserves

2) Compute recoverable reserves. (This equation will normally be a pore volume reserve equation, but may, in certain instances, consist of other computations for reserves.)

FACTORS WHICH MAY BE CONSIDERED AS RANDOM VARIABLES IN RESERVE COMPUTATIONS:

- -Productive drainage area
- -Net pay thickness
- -Proportion of structure filled with oil or gas
- -Porosity, Water saturation
- -Oil formation volume factor (or gas FVF)
- -Recovery factor (fraction of oil or gas in place recoverable)
- -Bbls./Acre-foot, or MCF/Acre-ft.
- -Secondary recovery factors (if applicable)

DETERMINE DEVELOPMENT WELL PROGRAM, INITIAL AND FUTURE PRODUCTION SCHEDULES

1) Determine number of development wells to be drilled

2) Determine initial field productivity and future production schedule (by years) from field

3) Determine size (and number) of production facilities such as platforms, pipelines, etc.

(Note: These steps will no doubt include dependency relationships between random variables.)

RANDOM VARIABLES TO CONSIDER:

- -Recovery per well
- -Initial potential per well, or per field
- -Decline rates, patterns
- -Abandonment rates
- -Drilling time per well
- -Development dry holes
- -No. of wells per platform
- -Crude storage limitations (if applicable)
- -Pressure maintenance programs and schedules

ACCOUNTING FOR COSTS, DISCOUNTING REVENUES, COMPUTING PROFITABILITY

1) Determine total drilling costs and costs for surface facilities (platforms, pipelines, etc.)

2) Convert production schedule to net revenues after taxes, royalties, operating expenses

3) Compute discounted net present value of all cash flows using i_o discount rate. Find algebraic sum (NPV Profit)

4) Store the value of NPV Profit. Return to beginning to make another pass.

End of Pass

RANDOM VARIABLES TO CONSIDER:

- -All cost factors (wells, platforms, etc.)
- -Crude prices, taxes, royalties
- -Operating expenses

Schematic of principal components of simulation model. (Figure taken from Decision Analysis For Petroleum Exploration, by Paul D. Newendorp, The Petroleum Publishing Company, Tulsa, Oklahoma, 1975)

DATA PREPARATION TO ACCOUNT FOR PARTIAL DEPENDENCIES BETWEEN RANDOM VARIABLES IN SIMULATION ANALYSES

1.) Prepare a cross-plot of available numerical X-Y data.

2.) Draw a boundary, or envelope around the observed set of X-Y data points. This boundary defines the limits within which X and Y can vary. Any combination of values of X and Y outside the boundary will be excluded and considered as having zero probability of occurrence.

3.) Determine the variation of Y within the boundary as a function of X, and define a normalized distribution of Y which represents the observed variation. The limits of this normalized distribution are 0 and 1.0, where 0 corresponds to the minimum possible value of Y for a given value of X and 1.0 corresponds to the maximum possible value of Y for the given value of X. The dimensionless, normalized distribution is given the symbol YNORM on its random variable axis. The distribution can be of any form.

4.) The input to the simulation model are:

a.) The X distribution cumulative frequency

b.) The cumulative frequency of the normalized Y distribution, YNORM

c.) The following equation used to compute the value of Y for each pass:

$$\boxed{Y = YMIN_x + (YMAX_x - YMIN_x)(YNORM)}$$

where: $YMIN_x$ = Minimum possible value of Y, given a sampled value of X

$YMAX_x$ = Maximum possible value of Y, given a sampled value of X

YNORM = Value of the dimensionless normalized Y distribution that is sampled each pass

Y = Computed value of random variable Y to use for the pass.

(This table is taken from Decision Analysis For Petroleum Exploration, by Paul D. Newendorp, The Petroleum Publishing Company, Tulsa, Okla., 1975)

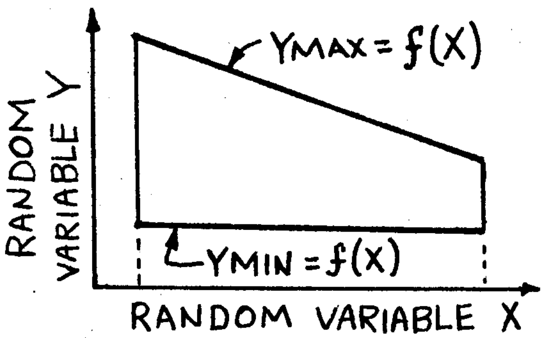
STEPS TO SAMPLE VALUES OF TWO PARTIALLY DEPENDENT RANDOM VARIABLES X AND Y ON A COMPUTER

METHOD #1

(Equations of the boundaries on the X-Y plot are known)

Step 1.) Input to computer:

a.) Cumulative frequency distribution of random variable X
b.) Cumulative frequency distribution of normalized Y distribution, YNORM
c.) Equation for Y (from page 4)
d.) Equations of upper and lower boundaries as functions of X



Step 2.) Sample values of X and YNORM in usual manner

Step 3.) Substitute sampled value of X into equations for YMIN and YMAX to compute $YMIN_x$ and $YMAX_x$

Step 4.) Substitute computed values of $YMIN_x$ and $YMAX_x$, and sampled value of YNORM into equation for Y and solve for Y.

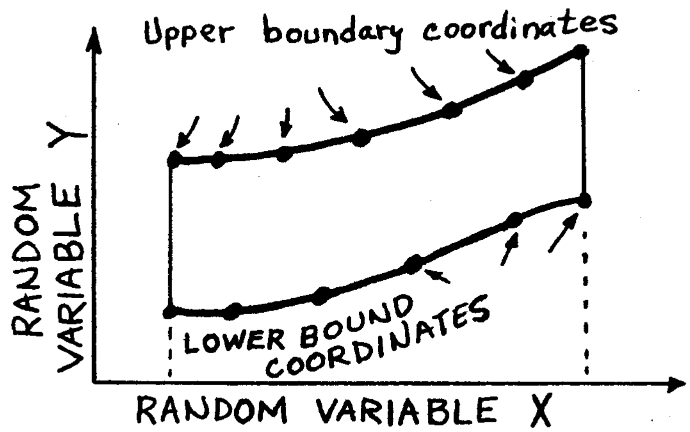
Note: Step 1.) is done only once. Steps 2.), 3.), and 4.) are repeated for each pass.

METHOD #2

(Equations of the boundaries on the X-Y plot are not known)

Step 1.) Input to computer:

a.) Cumulative frequency distribution of random variable X
b.) Cumulative frequency distribution of normalized Y distribution, YNORM
c.) Equation for Y (from page 4)
d.) Four to eight X-Y coordinate points from the upper and lower bounds.



Step 2.) Using coordinate X-Y values from lower bound have computer fit a polynomial equation through the points of the form YMIN = f(X). Repeat for upper boundary points to derive polynomial equation of upper bound, YMAX = f(X).

Step 3.) Sample values of X and YNORM in usual manner.

Step 4.) Substitute sampled value of X into equations for YMIN and YMAX to compute $YMIN_x$ and $YMAX_x$.

Step 5.) Substitute computed values of $YMIN_x$ and $YMAX_x$, and sampled value of YNORM into equation for Y and solve for Y.

Note: Steps 1.) and 2.) are done only once. Steps 3.), 4.), and 5.) are repeated for each pass.

(This table is taken from Decision Analysis For Petroleum Exploration, by Paul D. Newendorp, The Petroleum Publishing Company, Tulsa, Okla., 1975)

HYDROCARBON ASSESSMENT USING SUBJECTIVE PROBABILITY

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The Department of Energy, Mines and Resources of Canada has developed a method of assessment designed to operate with whatever data base is available, incorporate uncertainty and answer the following questions:

- how much hydrocarbon exists?
- where is it?
- how big are the pools?
- how certain are the estimates?

A committee of nine geologists from various Canadian government agencies travels to regional offices where geologists and geophysicists have prepared data on the hydrocarbon potential of their area. The committee interrogates the specialists on the various areas and with their help makes the assessments by:

- writing an equation to describe the hydrocarbon potential;
- estimating equation parameter values given that they are non-zero or larger than some minimum value;
- estimating the probability that some of the parameters are larger than the minimum value;
- solving the equation by Monte Carlo methods;
- producing a solution to the equation in the form of a distribution of estimates and the probability of occurrence of each estimate.

Since 1970, the committee has made three estimates of Canada's hydrocarbon resources. In these estimates, proven reserves are included with undiscovered recoverable hydrocarbon potential. Undiscovered hydrocarbon potential is the quantity of oil and gas that is postulated to exist in as yet unfound pools and will be recoverable from a well bore by conventional technology. The main topic of this paper is assessment of undiscovered hydrocarbon potential, especially in frontier basins with low data availability.

An estimate of hydrocarbon potential can be expressed as an equation relating a series of variables to the potential. Two examples are shown in Figure 1. The advantage of an explicit equation is that a more rigorous scrutiny of variables and assumptions can be made. In general, specific values are unknown for most of the variables in the potential equation, and it is possible for at least some of the variables to have a wide range of possible values, so that the equation also will have a range of solutions. This range is expressed as a frequency distribution of potential estimates.

The parameters in the equation are described, where necessary, by subjectively derived cumulative distribution functions based on the opinions of the estimators. The parameters are described initially by two probability distributions (conditional and marginal). In discussing porosity for example, the question asked is - What is the average porosity in a particular unit? This is really two questions - Is there porosity in the unit? (marginal probability) and, If there is, how much? (conditional probability). The two questions require consideration of different factors and are best answered separately.

Bayes Theorem allows the probability statements concerning the two questions to be combined to provide a joint probability statement that answers the prime question - What is the average porosity in the unit?

A conditional probability curve is constructed by questioning the committee as to the chance of the average porosity exceeding a given value given that the porosity is greater than the cutoff. The distribution is anchored at the small end by the cutoff and the maximum value is in part related to the 45% porosity value of cubic packed spheres discounted to some average value over the reservoir. If there is local knowledge it takes precedence. The 5 and 95% probability values are estimated to control the tails of the distribution and the quartile values are used to establish the central part of the distribution. The committee produces the curve by a modified Delphi approach; either by concensus or an average of curves drawn by each member.

The answer to - What is the probability that the porosity is greater than the minimum cutoff? - is the marginal probability and is given as a single number after consideration of available data and the committee's experience in petroleum geology in general. Clearly the probability could have a range of values and should be entered as a distribution. We have not done this as yet.

The product of the marginal probabilities associated with each of the parameters in the equation is the probability that all of the parameters will have values larger than the minimum values (see Fig. 2). If any of the parameters have a value less than its prescribed minimum then the potential is zero. The product of the marginal probabilities - the risk - is then the expected success ratio - the chance that a given prospect will contain pooled hydrocarbon. This success ratio can be compared to the estimator's opinion of the uncertainty of the venture.

The form of the "potential" equation is related to the nature of the data being considered. Although we use several equation variations, there are two basic types: the "volumetric" type and the "exploration play" type.

The volumetric method makes use of analogues to the basin, area or rock unit under consideration, but is usually done at the basin level. Ultimate yield of recoverable hydrocarbon per unit volume of rock is determined for basins geologically similar to the basin under consideration. The yield is multiplied by the volume of the basin to be evaluated. The approach is usually inadequate because most basins have no good analogues and, if they do, the proven ultimate potential figures are not available or are unreliable. The method is, however, a useful check on the "exploration play" method and, if very little data are available, the "volumetric" method may be all that is possible to use. It is necessary, however, to describe the yield and perhaps the volume by frequency distributions and to incorporate the possibility that the basin may be barren of pooled hydrocarbons.

In the "play" method, assessment is made of individual, demonstrated or conceptual, exploration plays in an area. The "play" method requires more data than the "volumetric" method but answers the question - What are the sizes of the accumulations present, and is more specific as to where the hydrocarbon occurs. Both of these considerations are necessary for economic analysis of ventures in the region.

Plays are composed of prospects and play assessment is basically the addition of prospect assessments. It is desirable, but generally impossible, to identify all prospects and to evaluate them individually. What can be done, is to produce frequency distributions that describe the range and frequency of occurrence of values that the parameters in the prospect potential equation may have throughout all prospects in the play (see Fig. 3). These distributions, are conditional on the variables having a greater than minimum value.

The multiplication procedure (a Monte Carlo method) is as follows. On the first iteration a random selection is made of each parameter in the equation and the equation is solved. The same is done for successive iterations. We generally use 10,000 iterations. The distribution of these 10,000 solutions gives the distribution of sizes of prospects in the play or the pool size distribution in the play conditional on pooled hydrocarbon occurring in the prospects.

The conditional distribution can be "risked" by applying the product of marginal probabilities of the parameters to produce a joint distribution. This describes the probability that the pool size will be larger than a given value and incorporates the probability that pooled hydrocarbon occurs in a given prospect.

The next step in the procedure is to estimate the play potential. At this point, we have a distribution describing the amount of hydrocarbon expected in any given prospect and a distribution of estimates of number of prospects. These two distributions are combined as follows (see Fig. 4): a random number of prospects is selected and that number of pool sizes is sampled randomly. These pool sizes are summed to give the play potential for that iteration. The appropriate number of zero size pools are sampled, according to the risk. In general 2,000 iterations are done and the resultant distribution describes the play potential. The various play potentials are added to give a basin potential if required.

If the committee is not satisfied with the results after going through the assessment procedure, it can then go back to the distributions describing the variables and to the marginal probabilities. In some cases, new ideas or new data are available and rational changes can be made. Often they cannot and the committee must live with the estimates as given. The facility to critically examine the component parts is crucial in the very necessary reappraisal procedure.

CONCLUSIONS

The exploration play method of assessment does the following:

1) It incorporates uncertainty into the estimates of potential;
2) It displays the possible range of estimates;
3) It indicates the expected pool size distribution;
4) It indicates the general location of the hydrocarbon resource;
5) It breaks the assessment procedure into component parts that can be critically appriased;
6) It provides ease of revision through alteration of the components.

Useful estimates of potential can be made under conditions of great uncertainty. The key word is useful. To be useful, under conditions of minimal data, the estimate must indicate the range of possible values and the uncertainty associated with each. This can be done using "potential" equations, subjective probability and Monte Carlo methods. Resource estimates given without associated levels of certainty may be misleading. The certainty with which the estimate is held is as important as the estimate itself. Different decisions may require different levels of certainty. The coupling of uncertainty and estimate of resource makes the decision-maker's life more complex but he must take responsibility for determining an acceptable chance of success in the context of the decision to be made.

POTENTIAL EQUATIONS

VOLUMETRIC TYPE —

AREA POTENTIAL = VOLUME OF ROCK · HYDROCARBON YIELD/UNIT VOLUME

EXPLORATION PLAY TYPE —

PROSPECT POTENTIAL = AREA OF TRAP · RESERVOIR THK. · POROSITY · (1-WATER SAT.) · TRAP FILL · OIL FRACTION · RECOVERY · CONSTANT

≡ VOLUME OF PORES IN TRAP · HYDROCARBON FRAC. · ENGINEERING FACTORS

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FIGURE 1. TYPES OF POTENTIAL EQUATIONS.

PLAY/PROSPECT								DATE		
POTENTIAL EQUATION VARIABLES								"OIL" OCCURRENCE FACTORS		REMARKS
	CONDITIONAL PROBABILITY %.GT. 100	95	75	50	25	5	0	PRESENCE OR ADEQUACY	MARGINAL PROB.	
AREA OF CLOSURE	1	10	18	23	26	33	50	GEOMETRIC CLOSURE	.8	
RESERVOIR THK.	10			40			90	LITHOFACIES	1	
POROSITY	.08			.12			.16	POROSITY	.8	
TRAP FILL	.05			4			.7	SEAL	1	
RECOVERY				.35				TIMING	.5	
WATER SAT.				.25				SOURCE	.5	
SHRINKAGE				.7				PRESERVATION	1	
GAS FRACTION				.5				RECOVERY	1	
NO. OF PROSPECTS	3	8	15	20	25	40	60			
										8000 ft.
										average depth
								PRODUCT	.16	

FIGURE 2. EXAMPLE OF PLAY DOCUMENTATION SHEET. NUMBERS ARE GIVEN TO DESCRIBE THE PARAMETER DISTRIBUTIONS AND THE "RISKS".

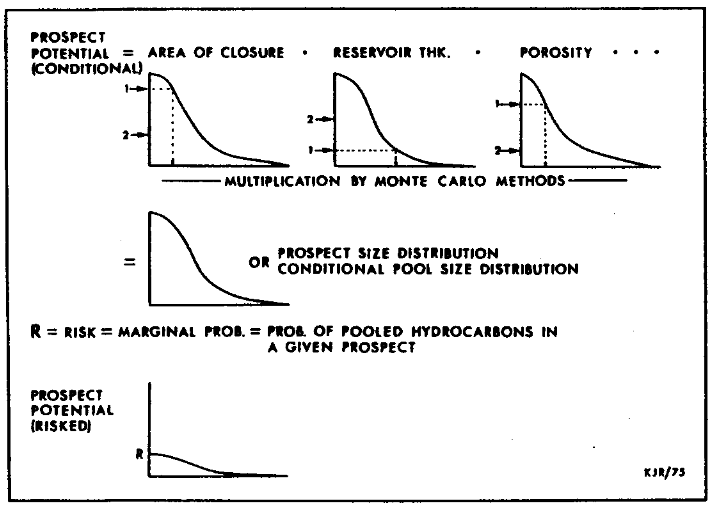

FIGURE 3. SEQUENCE OF EVENTS LEADING TO ESTIMATE OF PROSPECT POTENTIAL (1 AND 2 ARE FIRST AND SECOND ITERATIONS IN MONTE CARLO SIMULATION).

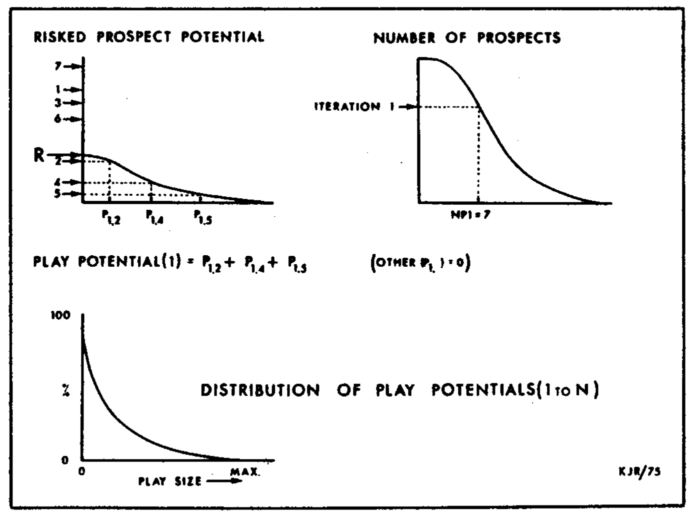

FIGURE 4. DERIVATION OF PLAY POTENTIAL (SEE TEXT FOR EXPLANATION).

The Area of Influence of an Exploratory Hole

by

Donald A. Singer

Exploration decisions must focus upon two fundamental considerations: First, estimates must be made of the probabilities that deposits having various characteristics occur in the region. Second, given these probabilities of occurrence, the probabilities that deposits will actually be discovered with various levels of exploratory effort must be estimated. The purpose of this talk is to demonstrate how the array of drill holes from previous exploration in the region of interest can be used to aid in the estimation of the first category of probabilities--the occurrence probabilities.

Prior to the drilling of the first exploratory well, a specific but unknown inventory of deposits exists (occurs) in the region. As wells are drilled in the region through time two phenomena occur. First, each exploratory well drilled whether successful or not, has some area around it where, it can be argued, resource targets could not have existed without having been found; that is each well sweeps out a portion of the total region available for exploration. Thus, as holes are drilled, areas are condemned and the area remaining to search diminishes. Second, the successful exploratory well also reduces the quantity of the undiscovered resources of the region. The chance that a point is condemned is referred to as the degree of exhaustion which is defined as the probability that a target centered at that point with orientation equally likely in all directions would have been hit by at least one of the holes drilled. The manner in which the region is exhausted during its exploration history is referred to as the physical exhaustion sequence in this talk.

The physical exhaustion sequence provides information concerning the number and sizes of deposits yet to be found and also information about the efficiency of the past exploration process. At any point in this sequence, the portion of the area searched and the spatial distribution of the exhaustion is completely determined by the area of influence of wells and the arrangement of the wells drilled to that point. The area of influence of a single well is determined by the size and shape of the resource target sought. A method whereby the area of influence of a well can be calculated is presented below.

Method of Computation

In order to determine the area of influence of a hole, it is necessary to consider the problem in terms of the variable for which the drill hole has an influence. In this examination, the variable of interest is the presence or absence of the natural resource target. A great many natural resource targets can have their shapes in plan view approximated by an ellipse or circle. If a well actually penetrates the resource target it is assumed that the target is always recognized. It is also assumed that the centers of resource targets have an equal chance of occurring everywhere in the surface projection of the region of interest. These assumptions are used below in the first of three general cases which are presented to demonstrate how the area of influence of a hole may be calculated.

Case 1: Single exploratory hole and a circular target

For this case a circular target with radius r_c and a center located somewhere within the area of interest is considered. The degree to which any given point in the region is explored is related to the distance between that point and the exploratory well and the radius, r_c, of the target interest.

The hole provides no information for points beyond the radius r_c since a target centered beyond r_c could not have been hit by the hole. Any target centered within radius r_c of the hole would have been hit with certainty, however. Thus it can be concluded that the distance of influence about a drill hole is the radius of the target and the area of influence of the hole is the area of the target, πr_c^2. In this case the probability of complete search is equal to 1.0 for all points on increasing radii away from the center of the drill hole until the radius r_c is reached beyond which the probability drops directly to zero.

Case 2: Single exploratory hole and elliptical target

The same approach can be used for targets having an elliptical shape. In this case, two circles are drawn around the drill hole centered at h; the inner circle has a radius (r_b) equal to the length of the semiminor axis (b) of the elliptical target of interest and the outer circle has a radius (r_a) equal to the length of the semimajor axis (a) of the ellipse. An elliptical target centered within radius r_b of the hole could not have been missed; therefore, all points less than radius r_b away from the hole are completely explored with respect to centers of this target. The drill hole provides no information concerning the existence of a target centered beyond the radius r_a from the hole. Between circles of radii r_b and r_a, the degree of exhaustion depends upon the distance of the point from the hole.

If it is assumed that all orientations of the target ellipse are equally likely, then the probability of the ellipse being hit by the drill hole is equal to the possible hit orientations, that is those in angle Ø, divided by all possible orientations, that is 180 degrees. The angle Ø is calculated as follows:

$$\text{Ø} = 2\mathrm{TAN}^{-1}\ \frac{b}{a}\sqrt{\frac{a^2 - r_d^2}{r_d^2 - b^2}} \qquad \text{for } a > r_d > b$$

where, a is the length of the semimajor axis of the target ellipse
b is the length of the semiminor axis of the target ellipse
and r_d is the distance between the hole and point of interest.

The degree or probability of physical exhaustion at a point of distance r_d from the hole is then Ø/180°. The mathematical derivation of the above eqqation is provided by Drew (1966). The area of influence of the exploratory hole in this case is πa^2. Thus the area influenced by the hole can be quite large, but the area exhausted is only the area of the target, that is πab.

Case 3: Multiple exploratory hole array and an elliptical target

Computation of the degree to which a point in a region has been explored by an array of exploratory holes is more complex than that for a single hole because the areas of influence of two or more holes may overlap. The solution to this condition is to consider all possible hit orientations where the target can be hit for all drill holes located within distance r_a of the point of interest.

The angle in which a target centered at some point less than r_a from two or more holes could be hit is equal to the sum of all possible hit angles minus the angles of multiple hits and the degree to which the point is explored is the new angle divided by 180 degrees. The angles are calculated with the equation for ϕ and the angle of multiple hits is obtained by an accounting procedure.

Applications

The degree to which any point in the area of interest has been explored can be determined by the methods presented above. By use of a computer it is possible to calculate the degree of exhaustion for all possible points with respect to a target of any size or shape and for any array of exploratory holes. An example in which 14 exploratory holes plus several holes outside the map area have been drilled in search for a hypothetical target is presented in figure 1. Contour lines in this figure show how the completeness of search varies across the region. Points within the 1.0 contour lines are totally explored with respect to the target; possible targets centered within these subregions could not exist without having been detected. Points located on the 0.5 contour lines are 50 percent exhausted with respect to the target, that is, targets centered on points on these lines would have been found with a probability of 0.5. Targets centered on points within the 0.0 contour lines could have any orientation without having been detected.

Maps generated by this method offer a means by which it is possible to determine how well any area within the region has been explored. If it can be assumed that the centers of targets are located with equal likelihood at every point in the region, such a map may be used directly to select favorable exploration sites. The assumption of equal likelihood of the locations of targets is however, not believed to hold in general. In regions where certain areas are more favorable locations for the centers of deposits, the information used to identify the more favorable areas could be used to make a map showing the relative favorability of areas for the occurrence of the deposit of interest. This map could then be used in conjunction with the exhaustion map to select the most favorable exploration sites. For example, if each of the values on the exhaustion map is subtracted from 1.0, the values on the new map, which would be high in unexplored areas and low in explored areas, could be multiplied by the values of the relative favorability map to make an exploration potential map for the region.

Knowing the degree to which each point has been explored in a region allows the average degree of exhaustion with respect to a given target to be estimated for the whole region. The average degree of exhaustion is calculated by summing the values used to generate the exhaustion map and dividing by the number of points used. For example, the degree of search was calculated for each 2500 points used to generate figure 1 and the average degree of exhaustion is 16 percent. In effect, the average degree of exhaustion is a measure of how much of the "room" available for exploration has been used. A variation of this procedure wherein the proportion of areas explored through time is considered, could also be used to make resource estimates.

Among the methods which have been used to make petroleum resource estimates are several which in part attempt to characterize the exploration process explicitly by employing the relationship between discovery rates and cumulative exploratory drilling footage (Zapp, 1962; Hendricks, 1965; Hubbert, 1969). From these analyses it can be shown that domestically, the rate of discovery of reserves per foot of wildcat well drilled has declined markedly during the last 25 years (1950-1974). By extrapolating this relationship to a point where it can be assumed that the region under consideration is totally explored, an estimate of the total volume of reserves which will ultimately be produced can be made. The validity of estimates made in this manner is dependent upon two assumptions: (1) the economic and technologic structures of the exploration and extractive industry are relatively stable through time, and (2) accurate estimates of the point at which regions are totally explored can be made in terms of the cumulative footage of exploratory drilling. The latter of these two assumptions may be challengeable on the basis of an observed pattern of spatial and temporal clustering of exploratory drilling (Ryan, 1973; Drew 1975). In regions which have had a large number of exploratory holes drilled, the area of influence of many holes may overlap each other, thereby implying that cumulative exploratory footage may not be reliable surrogate variable for the completeness of exploration.

The area of influence methods developed in this paper offer a possible solution to the problem of accessing, in explicit terms, the proportion of any region which has been explored at any point in time. The percentage of the region exhausted with respect to several deposit sizes and shapes can be calculated at several points in time during which an incremental number of wells have been drilled and the result plotted against the cumulative barrels found in each class of deposit. A hypothetical example of such a physical exhaustion sequence is presented in Figure 2. In this example, 1000 wells have been drilled and the region is now 40 percent explored with respect to the large targets and 20 percent explored with respect to the small targets. By fitting curves to the data from each of the three classes of deposits and extrapolating them to the points where the region is completely explored, and estimate of the total volume of the commodity remaining to be discovered in the region in each deposit class can be made. With such curves it is possible, by relating the exploratory drilling rate to the advancement in the degree of physical exhaustion, to determine the incremental value of exploratory drilling.

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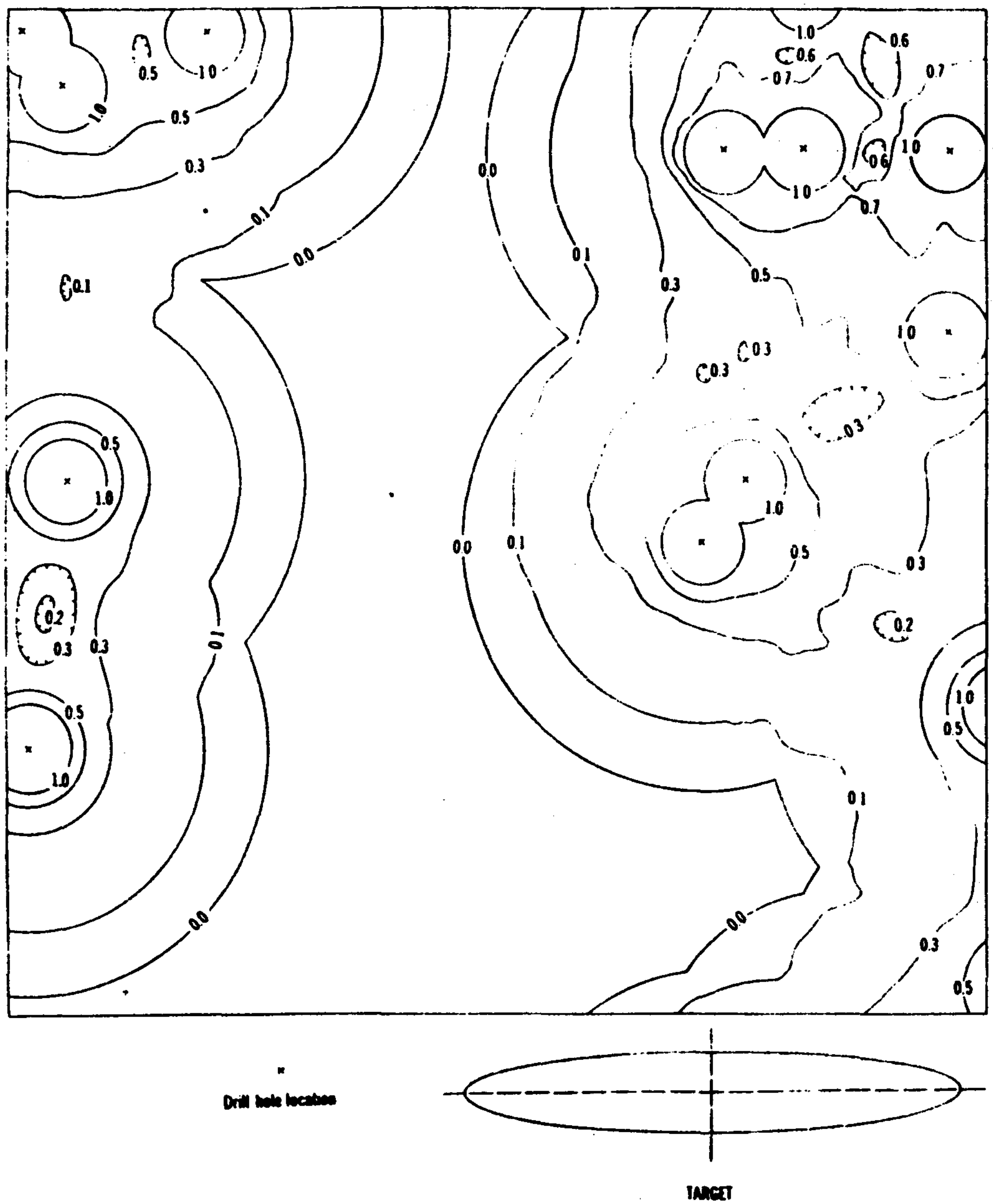

Figure 1 Physical Exhaustion Map for Target Shown

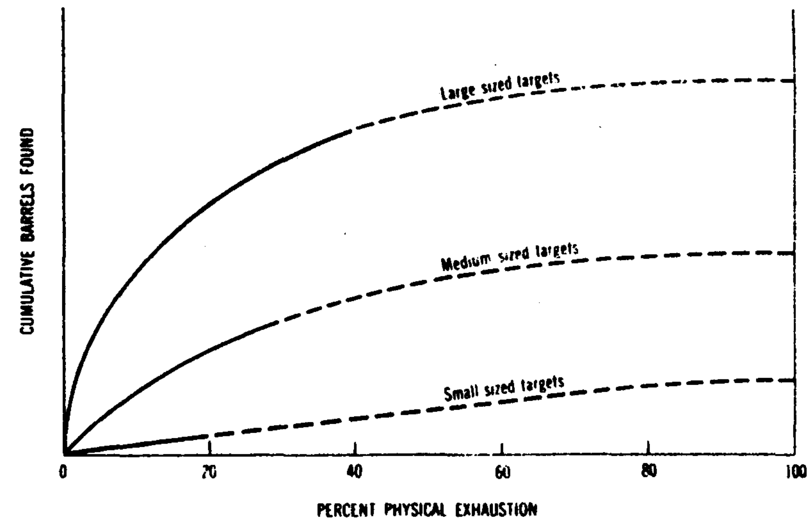

Figure 2 Hypothetical Physical Exhaustion Sequence for Large, Medium and Small Sized Targets

SEQUENTIAL SEARCH BY COMPUTER IN EXPLORATION

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ABSTRACT

A sequential search strategy for locating and delineating a hidden target in a geographic area has been designed and implemented. The digital technique developed depends on computers adequate for integrating all historical geological and geophysical data for a search area with whatever new information becomes available at each exploration step. The objective is the identification of effective search strategies instead of the determination of optimal geographic patterns for exploration sites. An information radiation model serves as a basis for computer superposition of indicators of enhancement or depression in target occurrence probabilities. The indicators are assumed to be available from interpretations of diverse types of survey and exploration measurements at an unrestricted number of points.

Simulation studies indicate that the exploration process partitions into (a) discovery, and (b) target boundary delineation phases. These phases become distinct when information on probable target characteristics is introduced. The operational search program with the arrays of values for the information and proximity maps occupy 32K and 256K characters of computer storage. With this active storage, areas may be mapped with grids as fine as 60 x 60 to be resolved into 3600 cells. The local limit of effective virtual storage 16 million characters could permit the resolution of over one million cells, however, the corresponding execution time might become prohibitive for the prototype program. Using map resolutions of a few thousand cells, search strategies have been developed for significantly enhancing the success ratio of target hits in simulated worst-case situations.

INTRODUCTION

For over two decades analytic and computational tools have been used in the exploration or geographic search problem by many for example: Bates 1959 and Bostick et. al. 1968. Search strategies are possible upon the postulation of a model for the target and some valid assumptions about areas or regions of influence surrounding the points already explored within or near the search area. Values of enhancements or depression of the probability of finding a target in the search areas may be inferred from interpretations of the data from previous surveys or explorations using conditional probability models for target occurrence [Koopmans 1957, Kauffman 1963, Griffiths 1966, Drew 1967].

In this study, a simple two-dimensional search area enclosed by a convex boundary is considered. The problem is to develop computer programs that can use all current data to isolate the less favorable areas for target occurrence from those that are more favorable. This is to be done by sequentially locating exploration sites to either intersect the target after a minimal number of steps or, at any step prior to target intersection, to minimize the probability that a profitably larget target being left undetected.

Statement of the Search Problem

The problem under study is the sequential selection and placement of exploration sites for optimizing the search for either a fixed isolated single target or a cluster of multiple targets of unknown size and shape. A non-zero probability of target presence in a designated geographic region is assumed. Selection of each subsequent site for exploration is to be based on an integrated review of all available data at each step. The search region is in general complex, since it may be composed of separate simply bounded parts. The parts of such complex search regions are assumed to be equally accessible and therefore the costs for all possible explorations are not significantly different.

It is assumed that it is possible to choose in advance an optimal strategy for search. At the same time, one assumes that it is impossible to preplan an optimal search pattern if one uses any significant new information from each additional exploration. An ideal or optimal search strategy distributes the exploration resources over the search area so that at each step maximum information is gained. All the newly acquired information is applied toward deciding which parts of a composite search region should be abandoned to reallocate remaining exploration resources for use in the more favored and yet unexplored parts.

Features of a Computer Solution of the Search Problem

Because of the vast amount of data available for a search area, it is necessary to use computer systems to store, update and retrieve all relevant information. Programs executable by these systems can integrate the data to produce completely updated maps designed to indicate a separation of the favorable and unfavorable parts of the region. The programs may select, from the favorable areas, candidate sites that might be expected to yield a maximum of new information and thereby continually enhance the probability of intersecting the target or delineating its boundary.

The program for computer guided site selection that has been implemented has the following features: (1) it accepts as input, for an unlimited number of points, values from some linear scale for the enhancement or depression of target occurrence favorability as available from the interpretations of a variety of types of geological and geophysical surveys, (2) Some numerical estimates of the relative quality or accuracy of the interpretations of the different types of surveys for indicating the favorability for the particular type of target being located, (3) both the results of interpretation and locations of explored sites are combined for isolating those areas that are simultaneously remote from established unfavorable localities and from points that can yield little new information, (4) each explored point is assumed to be surrounded by a circle or sphere of influence which is modeled as a scalar field that influences the probabilities in accordance with a radiation pattern that decays as a function of an inverse power of distance. (5) Areas of influence may be elongated or distorted to reflect any known anisotropic geologic controls, (6) the isolation of favorable zones is performed by an algorithm that determines a threshold interval on the information map constructed from all the data given for the area, (7) completeness of coverage for possible large targets depends on dynamically updating the information map, and (8) a computer program isolates the favorable areas from the information map. The result is then combined with the constraints of the proximity map to select the coordinates of specific sites that are to be candidates for subsequent exploration.

The relationships between functional blocks of the sequential site selection program are shown in Figure 1.

Results of Simulated Search Experiments

Figure 2 shows the locations of 25 sequentially located exploration sites and the convergence of the isolated favorable area about the target area.

The effectiveness of the computer-guided search strategy as implemented in an APL program was evaluated in terms of performance measures simulated for worst case situations. The simulations use randomly sized and located targets in a grid of uniformly distributed values used to represent the indices of favorability. The indices have opposite signs inside and outside of the target. Computer experiments indicate that for this worst case, success ratios for hitting a single target are approximately double the value expected in the absence of a sequential search strategy or with some rigidly preplanned search pattern. This is true in both the initial discovery and delineation phases of search in the absence of target size information. If target size information is available at the time of the first target intersection success ratio for delineation of the target boundary can approach one out of two.

Summary and Conclusions

Before and after the target is intersected, two distinct pahses of the search are distinguishable only if external information on probable target size distribution is introduced and if it can be assumed that a single convex-bounded target was intersected. Depending on the objectives of the exploration, the discovery phase of the search may either be continued by withholding target information to maximally cover the area for possibly remaining large targets, or alternatively upon introducing target size information, the boundary delineation phase may be evoked to concentrate on delineating the known target instead of search for other possible targets.

Information field and geometric considerations can be used in designing efficient strategies for delineating the boundaries of single targets of known probable size. There is little promise of developing techniques for efficiently delineating the perimeter of composite targets comprised of closely neighboring components immersed in highly unfavorable surroundings.

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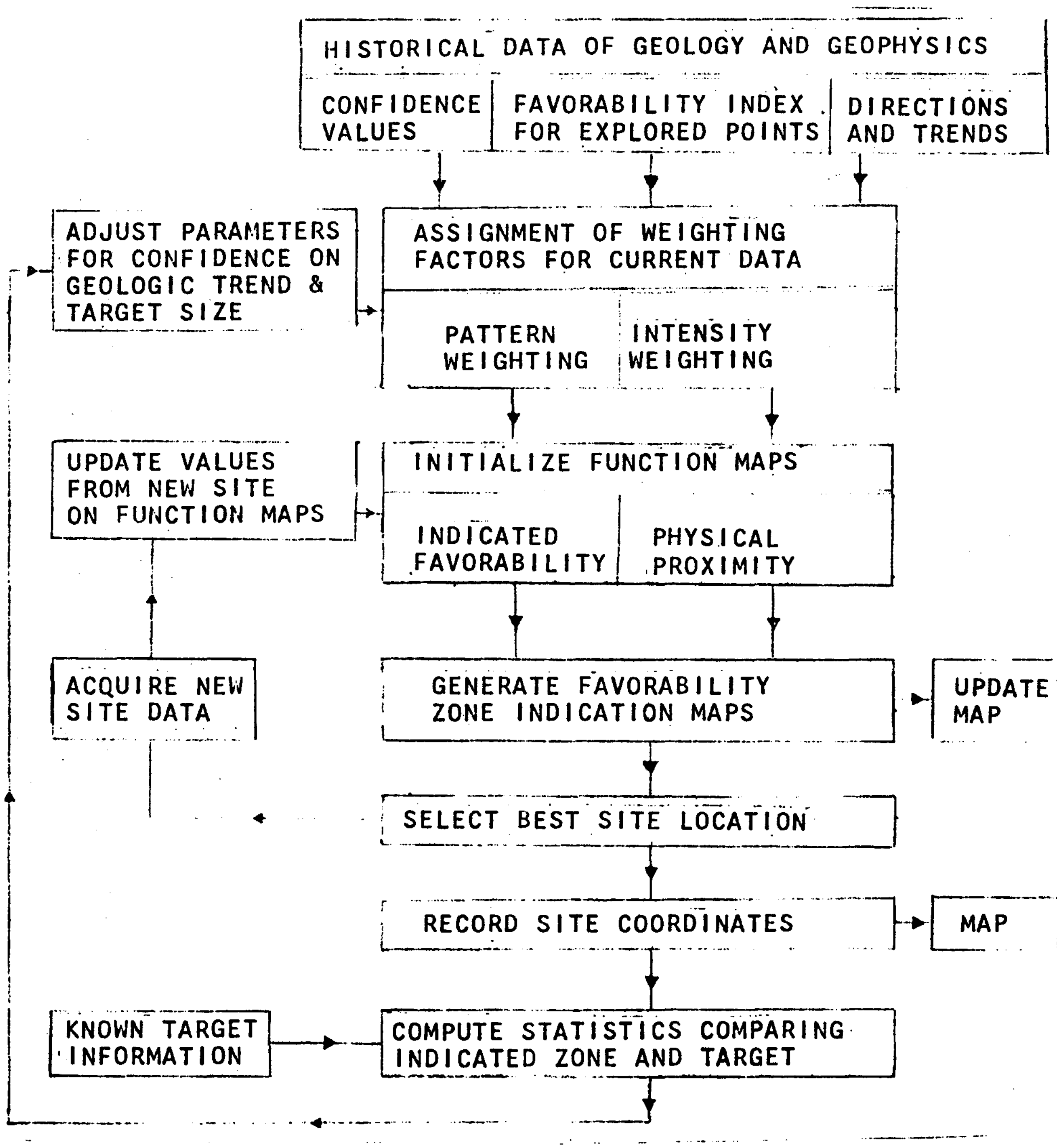
Figure 1.



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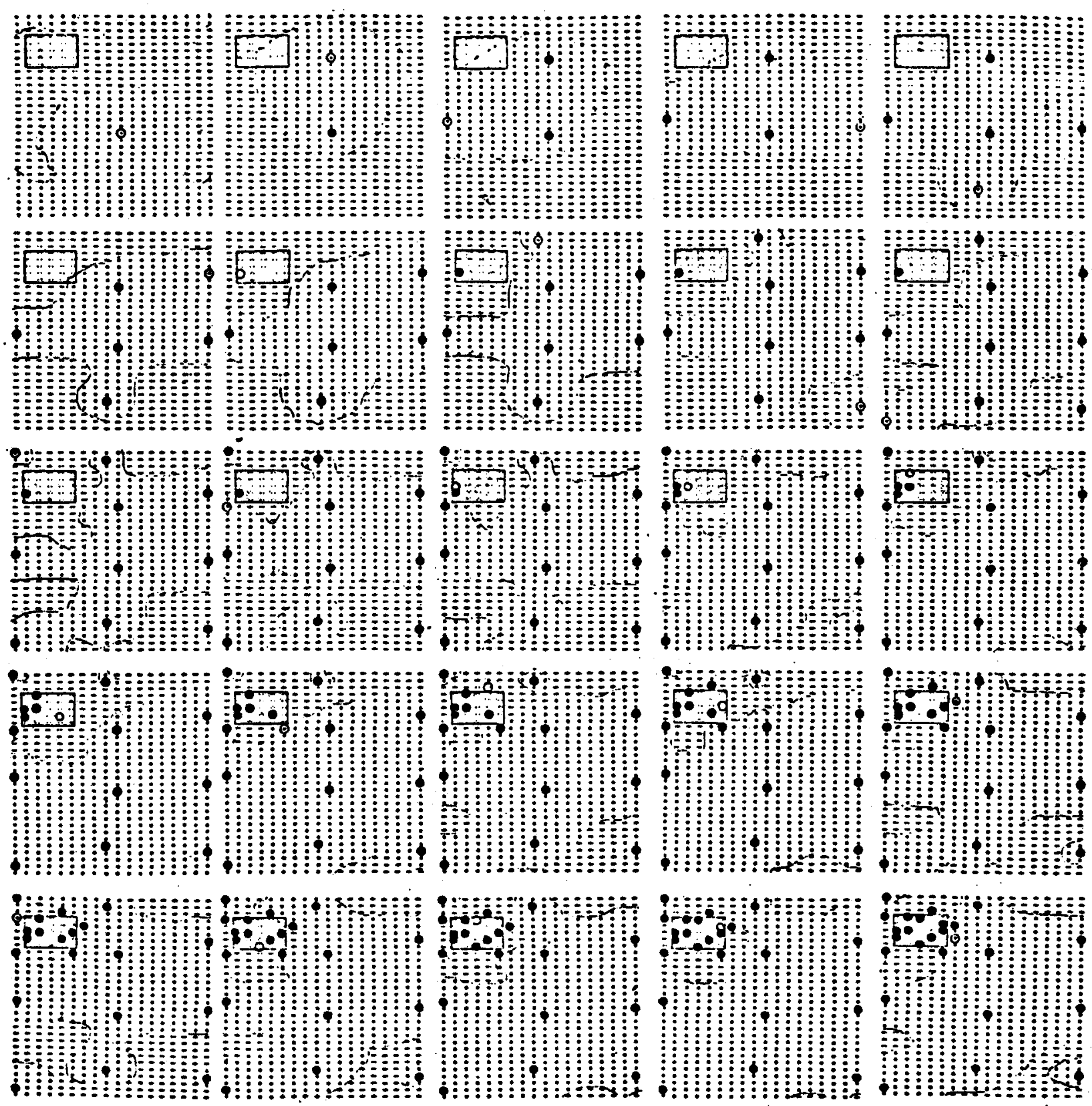

Figure 2. Exploration of an 18 x 18 area containing a 5 x 5 target showing the locations of 20 sites and the indicated favorable zones after 25 explorations.