THE SUPPLY OF NORTH SEA OIL

by

Paul Leo Eckbo

M.I.T. World Oil Project
Working Paper No. 77-015 WP

July 1977

THE SUPPLY OF NORTH SEA OIL

by

Paul Leo Eckbo

M.I.T. World Oil Project

Working Paper No. 77-015 WP

July 1977

This paper represents a collective effort by the Supply Analysis Group of the M.I.T. World Oil Project. Included in the group are Professors M.A. Adelman, H.D. Jacoby, and G. Kaufmann (M.I.T.) and E. Barouch (Clarkson College); and Research Assistants J. Paddock, J. Smith, and Arlie Sterling. The work was supported by the Norwegian School of Economics and Business Administration, the Norwegian Research Council for Science and the Humanities, and by the U.S. National Science Foundation under Grant No. SIA75-00739. However, any opinions, findings, conclusions, or recommendations expressed herein are those of the author and do not necessarily reflect the views of the sponsoring institutions.

THE SUPPLY OF NORTH SEA OIL

The North Sea is one of the most important non-OPEC-dominated regions both in terms of its supply potential and in providing a laboratory for testing of analytical tools. In the North Sea region, we include the British and the Norwegian sectors between 56° and 62° North latitudes, the boundary between Norway and Denmark, and the zero paleocene depth contour. This area covers the "oil area" of the North Sea as seen by most industry writers [4]. The North Sea sectors of Denmark, Germany, Holland, and France are hence not included.

Exploration in the UK sector of the North Sea started as early as 1964. The first oil discoveries were made in late 1969. Table 1 shows current assessment (June 1976) of recoverable reserves in the area of study, along with order of discovery, field names, and spud dates. Gas reserves have been converted to oil-equivalent values using a conversion factor of 1 billion cubic feet of gas equal to 178 million barrels of oil.

Table 1. Northern North Sea Discoveries, Recoverable Reserves - Oil and Gas Oil Equivalent (Millions of Barrels)

Order (j)	Name or Location	Spud Date	Size (r_j)	Order (j)	Name or Location	Spud Date	Size (r_j)
1	Cod	2/68	156	31	Ninian	9/73	1000
2	Montrose	4/69	180	32	Statfjord	12/73	4960
3	Ekofisk	9/69	1713	33	Odin	12/73	178
4	Josephine	6/70	100	34	Bruce	3/74	450
5	Tor	8/70	243	35	Magnus	4/74	800
6	Eldfisk	8/70	910	36	N.E. Frigg	4/74	71
7	Forties	8/70	1800	37	Balder	4/74	100
8	W. Ekofisk	8/70	490	38	Andrew	4/74	300
9	Auk	9/70	50	39	Claymore	4/74	375
10	Frigg	4/71	1325	40	E. Magnus	6/74	250
11	Brent	5/71	2500	41	9/13-4	6/74	220
12	Argyll	6/71	70	42	15/6-1	9/74	150
13	Bream	12/71	75	43	Brae	9/74	800
14	Lomond	2/72	500	44	Sleipner	11/74	50
15	S.E. Tor	4/72	34	45	Hod	11/74	75
16	Beryl	5/72	525	46	211/27-3	11/74	450
17	Cormorant	6/72	165	47	Gudrun	11/74	450
18	Edda	6/72	98	48	2/10-1	11/74	100
19	Heimdal	7/72	300	49	3/4-4	12/74	100
20	Albuskjell	7/72	357	50	14/20-1	1/75	75
21	Thistle	7/72	375	51	Crawford	1/75	150
22	Piper	11/72	638	52	9/13-7	1/75	350
23	Maureen	11/72	500	53	3/8-3	1/75	100
24	Dunlin	4/73	435	54	Tern	2/75	175
25	3/15-2	4/73	150	55	21/2-1	2/75	175
26	Hutton	7/73	250	56	3/2-1A	3/75	200
27	Alwyn	7/73	350	57	Valhalla	4/75	50
28	E. Frigg	8/73	623	58	3/4-6&3/9-1		200
29	Heather	8/73	150	59	15/13-2		200
30	Brisling	8/73	75	60	211/26-4		175

Source: Beall [4], and estimates by the M.I.T. World Oil Supply Group as of June 1976.

Fourteen oil fields in the UK sector and two major oil fields in the Norwegian sector have been declared commercial. Another fifteen fields are expected to be declared commercial over the coming three years [11]. Current industry expectations, as indicated by Wood, Mackenzie & Co., investment advisers of Edinburgh, Scotland, who have been computing and updating appraisals of North Sea fields since early 1973, are that oil production from these existing fields as well as those most likely to be declared commercial over the next three years, will peak in 1982 at about 4.2 million barrels a day (MMB/D) as indicated in Table 2 below. The recoverable oil reserves of the commercial fields are estimated at 14.6 billion barrels and, of the "probable" fields, at 5.6 billion barrels.

Table 2

EXPECTED NORTH SEA OIL PRODUCTION

(Production Level '000 B/D)

	1977	1978	1979	1980	1981	1982	1983	1984	1985
UK Existing Fields	875	1385	1776	2017	2090	2026	1800	1627	1446
UK Probable Fields		15	105	318	743	1247	1440	1509	1431
TOTAL UK Production	875	1400	1881	2335	2833	3273	3240	3136	2877
TOTAL Norwegian Production	415	577	747	870	939	918	911	931	940
TOTAL NORTH SEA	1290	1977	2628	3205	3772	4191	4151	4067	3817

Source: Martin Lovegrove of Wood, Mackenzie & Co. [11].

The major determinants of the supply of oil are the resource base, development costs, government policies, and current and expected prices. The activity in the North Sea has generated an unprecedented wealth of information on these determinants of supply. The major reason for this is that the North Sea developments are being financed mostly by external funds and on a project-by-project basis. Banks and other sources of funds are furnished the estimates of reserves and the schedules of expenditures and outputs, which normally are confidential. Wood, Mackenzie & Co. have compiled and published these estimates in a uniform format.

The controversy over taxes and government participation has also generated more public debate and hence also more information than normally has been the case elsewhere. This wealth of information has allowed us to experiment with various analytical tools that have been designed to represent the process of oil exploration, development, and production [1, 2, 3, 4, 6, 7, 12]. Here we will discuss the application of the disaggregated process model [2,3,7,12] to forecasting the supply of North Sea oil.

Overly simplified, the disaggregated process model consists of a discovery model which tells us how a sequence of reservoir discoveries is being produced by some exploratory effort, and a reservoir model that tells which of the reservoirs discovered will be produced and at what rate. Structural relationships which relate factor inputs and outputs at each stage of the supply process, exploration, reservoir development, and production, are specified and estimated (where possible). Contingent on prices, factor costs, the tax regime, and miscellaneous public policy constraints, activity levels are determined which optimize the economic return to petroleum operators. A forecast of the process output (additions to reserves and petroleum production) is determined along with associated input levels. The need to carry out the supply analysis on a disaggregated, reservoir level is accentuated by the heterogeneous nature of the stock of resource deposits.

The economic viability of a reservoir is determined by the cost of the input factors required to develop and produce the reservoir, the fiscal costs or the government take, and the price of petroleum. In Section 1 we discuss the cost of the input factors and how development costs may be related to the characteristics of a reservoir. The combined effect of development and fiscal costs is discussed in Section 2 and summarized in a relationship between the minimum economic reservoir size (MERS) and the price of oil. How government policy affects the rate and the sequence of discoveries is also discussed in Section 2. In Section 3, we discuss the distinction between the geologic and economic resource base and show how the discovery model and the reservoir model may be used to estimate the annual additions to the productive resource base resulting from drilling up the North Sea. Finally, in Section 4, we summarize the analysis in terms of the implications for future oil production in the North Sea. We also discuss some of the empirical elements that we have not dealt with in a satisfactory fashion and that we expect will influence the supply potential of the Norwegian and British sectors of the North Sea.

1. DEVELOPMENT COSTS

The high cost escalation in the North Sea confirms "Cheops' Law" that nothing ever gets built within the initial cost and time estimates. This "law" seems to characterize the introduction of new technologies in severe operating areas. The trans-Alaskan pipeline (TAPS) is the best known example of this phenomenon. The TAPS costs doubled every three years during 1970-1975, or at a rate of about 26% a year [8]. In an official UK study of the cost escalation in the development of North Sea oil and gas reserves [13], the cost escalation is estimated in sterling terms at about 140% between autumn 1973 and spring 1975, equivalent to an annual rate of 80%. Cost escalation is defined as the difference between the originally estimated cost of a project and the actual cost or the latest estimate of final cost.

Expressed in U.S. dollars, however, Wood, Mackenzie & Co. estimated that the development costs of all the fields under development in the North Sea by May 1976, had escalated by 57% since the time the original cost estimates were made [15]. The most significant factor contributing to this escalation seems to have been the inadequate technical knowledge in manufacturing and installing complex structures in an extremely hostile environment. There are signs, however, of the maturing of the learning curve as development has progressed.

In late 1973, shortages in raw materials and components developed. The companies were bidding for a limited and fixed supply of materials and components, and their prices "went through the ceiling." The suppliers of these products were able to capture some of the economic rent the companies expected from their field development projects. This "boom" period lasted for about 12 to 15 months. Today, the situation has reversed itself. Excess capacity characterizes many of the input factor markets today.

The inadequate technical experience, the input factor shortages, and, most significantly, the bad weather of the North Sea also caused costly delays. The high fixed back-up costs of the North Sea activity make any delay a costly experience. In addition to these direct costs, delays make the project further exposed to the general rate of inflation. The general rate of inflation contributed significiantly to the cost escalation in the North Sea. In 1974/75, the consumer price annual rate of inflation was about 9% in the U.S., 24% in the UK and 12% in Norway.

Only two North Sea fields so far are fully developed. An analysis of North Sea development costs will therefore have to be based upon the planned development schedules of the oil companies or directly on engineering-type cost analysis. The recent experience of the North Sea indicates that an analysis of the input factor markets as well as the learning curve phenomenon should be included when projecting likely frontier area development costs. Given the maturing of the offshore supply industry in Western Europe and the maturing of the learning curve, a detailed factor market analysis was considered unnecessary. We adopted what seems to be the industry consensus, namely that the cost level of input factors to the activity in the North Sea will most likely increase at a general rate of inflation of about 6% in the years to come.

The development and production schedules published by Wood, Mackenzie & Co. are limited to the individual fields. Development costs and production potential are a function of the characteristics of the individual fields of a supply region. The individual field is therefore a natural unit of analysis. For convenience, we assume that each field in the North Sea consists of only one reservoir (i.e., that each field is one hydrodynamic system). Therefore, we label the micro-unit of analysis a reservoir. A reservoir is characterized for our purposes by a set of physical attributes as listed in Table 3.

Table 3

RESERVOIR CHARACTERISTICS

- recoverable reserves
- average well productivity
- reservoir depth
- water depth
- distance to shore (terminal)

Our concept of a reservoir should be distinguished from the engineering concept of a reservoir. Reservoir engineers usually conceive of a reservoir as a set of geological conditions that could sustain various levels and rates of petroleum production, depending upon the level of investment, the chosen production profile, and other factors. The traditional engineering development model is designed to optimize several of the quantities we have taken as fixed reservoir attributes.

Although our simplified definition of a reservoir prevents fine-tuning of the rate of extraction from economic reserves, there are several compelling arguments for its use. To go beyond our idealized concept of a reservoir would require detailed information on hydrocarbons in place and on the geologic variables that determine the recovery factor and the rate of development and extraction (e.g., permeability, porosity, formation thickness, initial pressure, temperature, etc.). Unfortunately, we have no basis for predicting how each of these variables will behave in the exploration-discovery process. There is, however, a substantial amount of work on how the hydrocarbons in place and (with a fixed recovery factor) the recoverable reserves change as an area is drilled up. As our focus is on the intermediate- to the longer-term future, the analysis includes the discovery and development of new reservoirs. It does not make sense to try to analyze a reservoir along more dimensions than can be predicted with reasonable confidence. Our simplifying reservoir definition greatly reduces the complexity of the analysis without being very restrictive when evaluating the reservoirs of particular interest--those on the borderline of economic viability.

The cost categories that can be explained using predictive reservoir characteristics (Table 3) are also more aggregative than those of an engineering-type reservoir development model. Total development and extraction costs are divided into the categories of Table 4. From the point of view of data collection, this level of cost-disaggregation is also as ambitious as we could be in the North Sea.

Table 4

COST CATEGORIES

- development drilling
- platform structures and their installation
- platform equipment
- pipelines/tankers and offshore loading facilities
- terminals
- operating costs, platforms, and equipment
- operating costs, pipelines and terminals/ tankers and offshore loading facilities.

The North Sea data base consists of Wood, Mackenzie's estimates of planned investment and operating expenditures for 17 actual and potential crude oil producing fields. The Ekofisk complex is treated as one field. These historic and planned expenditures series were converted into mid-1976 dollars at the historic and expected North Sea cost inflation.

The small number of observations and the homogeneity of the North Sea with respect to non-size characteristics made the coefficients of these characteristics, when included as explanatory variables in the cost relationships, turn out to be not significant. Although engineering-type analysis clearly points out the significance of flow rate and water depth as determinants of total capital expenditures, our North Sea sample did not allow us to verify this. For lack of a broad enough sample, then, we differentiate among individual reservoirs on the basis of size alone. The potential error in doing so within a play (a group of similar geological configurations conceived or proven to contain hydrocarbons) is small, due to the overriding importance of reservoir size in economic calculations. But, although the Wood, Mackenzie sample reflects considerable variation in the size of recoverable reserves, the current sample size is deficiently small. This turns out to be consequential in the estimation attempts, because of our inability to reliably estimate nonlinearities that are inherent in the cost functions.

Among the fields of particular interest to this study, i.e., small fields on the borderline of economic viability, there are three categories: (1) the average isolated field; (2) the special tanker offtake/high peak-ratio field, and (3) the field discovered close to available transportation or other capacity. The first category promises average productivity, but requires complete build-up of infrastructure. The second category consists of fields which can achieve peak production through the substitution of variable expenses for the high fixed-capital costs associated with permanent infrastructure. The third category is comprised of fields that are able to take advantage of existing infrastructure--thus avoiding both high capital costs and high variable costs. The cost analysis of this study focuses on the fields of category 1. By excluding categories 2 and 3, we bias the minimum field size upwards and the level of ultimate recoverable reserves downwards, even if only slightly so.

A detailed discussion of the problems encountered when estimating the North Sea cost equations based upon our preliminary data analysis is beyond the scope of this paper. These estimation problems are discussed elsewhere [12]. To indicate the exploratory power of recoverable reserves, R, (in millions of barrels of oil) for total development expenditures, CD, (in millions of mid-1976 dollars), the following equation was estimated in an unconstrained form:

$$CE = 320 + 0.785R \qquad (R^2 = 0.8163) \tag{1.1}$$

It is also apparent from equation (1.1) that the cost of the marginal barrel increases rapidly as the size of the reservoir added declines as a function of the discovery decline process. The disaggregated process model thus allows us to identify how the supply curve will move to the left as a function of resource depletion. Because the distortive effect of the fiscal regime is also dependent on the characteristics of the marginal reservoir, a disaggregated approach is required to identify the location of, as well as the dynamics of, the supply curve. The fiscal regime is discussed as part of the government's policy in Section 2.

2. GOVERNMENT POLICY

The governments of UK and Norway influence the activity through the licensing of blocks for exploration and development, through the terms of the concession agreements, and through the tax regime. The governments influence the rate of exploratory drilling through the number of blocks they make available to the oil companies and the work program specifications of the concession agreements, i.e., the minimum number of wells that the companies will have to drill on each block. The rate at which blocks are allocated is determined on the basis of what the likely effect on the aggregate economy would be as a consequence of the resulting exploration, development, and productivion activity. The Norwegians have been concerned about "over-heating" the economy and thus followed a "go-slow" policy, whereas the British have been more concerned about their balance of payments and unemployment problems and thus followed a more aggressive licensing policy. Both countries have retained certain key blocks as part of a bargaining strategy vis-a-vis the companies. The governments have thereby influenced not only the rate at which dicoveries have been made, but also the sequence of discoveries. For example, the Statfjord field in the Norwegian sector was the 32nd discovery in the North Sea as indicated in Table 1. If exploration were permitted to proceed unrestricted, rather that at the rate at which the Norwegian government chose to license its blocks, this structure would most likely have been drilled at about the same time as the Brent field which was the 11th discovery and adjacent to Statfjord. Such government-induced distortion of the discovery process itself creates problems when estimating the most likely ultimate recoverable reserves of an area as well as the rate at which these reserves will be produced. The reserve potential is usually calculated by some sort of geologic analogy as is also the case in this study as discussed below. By distorting the process by which geologic data are generated, the government will also distort the estimates of the ultimate resource base. The largest structure in the North Sea is sitting on one of the Norwegian government's key blocks. The information generated from drilling this structure is essential to more accurate evaluation of the North Sea resource base as well as to planning the appropriate development of infrastructure in the North Sea which would also affect the commerciality of smaller reservoirs that presently could not support the infrastructure associated with an average, isolated field as defined above.

In addition to directly influencing the rate and sequence of discovery of recoverable reserves through licensing and concession arrangements, the government also influences the process of adding to the recoverable reserve base through its tax regime. In the North Sea, a tax and participation system, rather than a bidding system, has been designed to capture the economic rent associated with developing and producing oil and gas. An important economic variable then becomes the government's perception of how great a rent exits. The characteristics of the oil industry in particular, and of extractive industries in general, make it more difficult to design an appropriate tax package for such industries than for non-extractive industries. The cost characteristics of each production unit in a non-extractive industry are, except for possible scale effects, relatively homogeneous across a large number of production units. In the petroleum industry, however, two reservoirs discovered in the same year may have entirely different cost characteristics due to different locations, permeability, porosity, formation thickness, etc. The heterogeneity of the reservoirs and resulting tax package design problems have left much room for misunderstanding which has created additional uncertainty and caused delays in the development and production schedules of the North Sea. The distortive effect of the present tax regimes and the complexity of the issues make revisions and further misunderstanding possible even if the learning curve also applies to government policy-making.

The ideal tax system removes economic rent only, and hence leaves investment unaffected at the margin. The actual tax systems of the North Sea depart so far from the ideal that we must try to capture the effects of that divergence [6]. For this reason, a reservoir development model has been designed to analyze the economic viability of individual reservoirs and to determine the physical characteristics of the marginal reservoir depending upon the prevailing level of economic incentives. By extension, the model also demonstrates the sensitivity of reservoir development to changing economic conditions. The rules and regulations that determine the share of total revenues that are being paid to the government are represented in a detailed fashion in the reservoir model. The fiscal variables include royalty payments, petroleum revenue tax, special tax, corporate tax, special deduction and depreciation rules such as ring fence and uplift provisions, oil allowance and maximum liability provisions, as well as withholding tax on distributed dividends and capital tax. The tax systems of UK and Norway differ in terms of their distortive effects. A discussion of the elements of the two tax systems is beyond the scope of this paper [6, 12]. For the purpose of this forecasting exercise we may assume that the Norwegian tax system represents the North Sea fiscal regime. A more detailed empirical analysis would have to distinguish between the geopolitical regions of the North Sea.

Figure 1 summarizes the economics of North Sea reservoir development as seen by the private operator, i.e., real and fiscal costs are embedded in the relationship between the minimum economic reservoir (MERS) and the price of oil. The MERS corresponding to a given price is that size which equates the net present value of the operating company's cash flow to zero (assuming a discount factor of 10%). The relationship of Figure 1 is estimated assuming size but not price-sensitive development and production profiles [12]. The cost equations entering into the relationship are those of the average, isolated field. Because the government in some cases owns directly some of the required infrastructure or controls the pricing of infrastructure (e.g., pipeline rates), the government may compensate for the distortive effect of the tax system, i.e., that the social MERS is smaller than the private MERS, by appropriate pricing of this infrastructure. Such policies may shift the curve of Figure 1 to the left.

To summarize the effect of the licensing policy and the concession/work program policy of the North Sea governments, we have relied upon estimates made by the offshore division of the Norwegian shipbroker company, R.S. Platou A/S[1] as to the number of exploratory wells to be drilled in the period 1976 to 1978. If we assume that on the average, four delineation wells will be required to determine the reserves of each discovery, then

---

[1]R.S. Platou A/S: Offshore Newsletter, January 9, 1976, p.2.

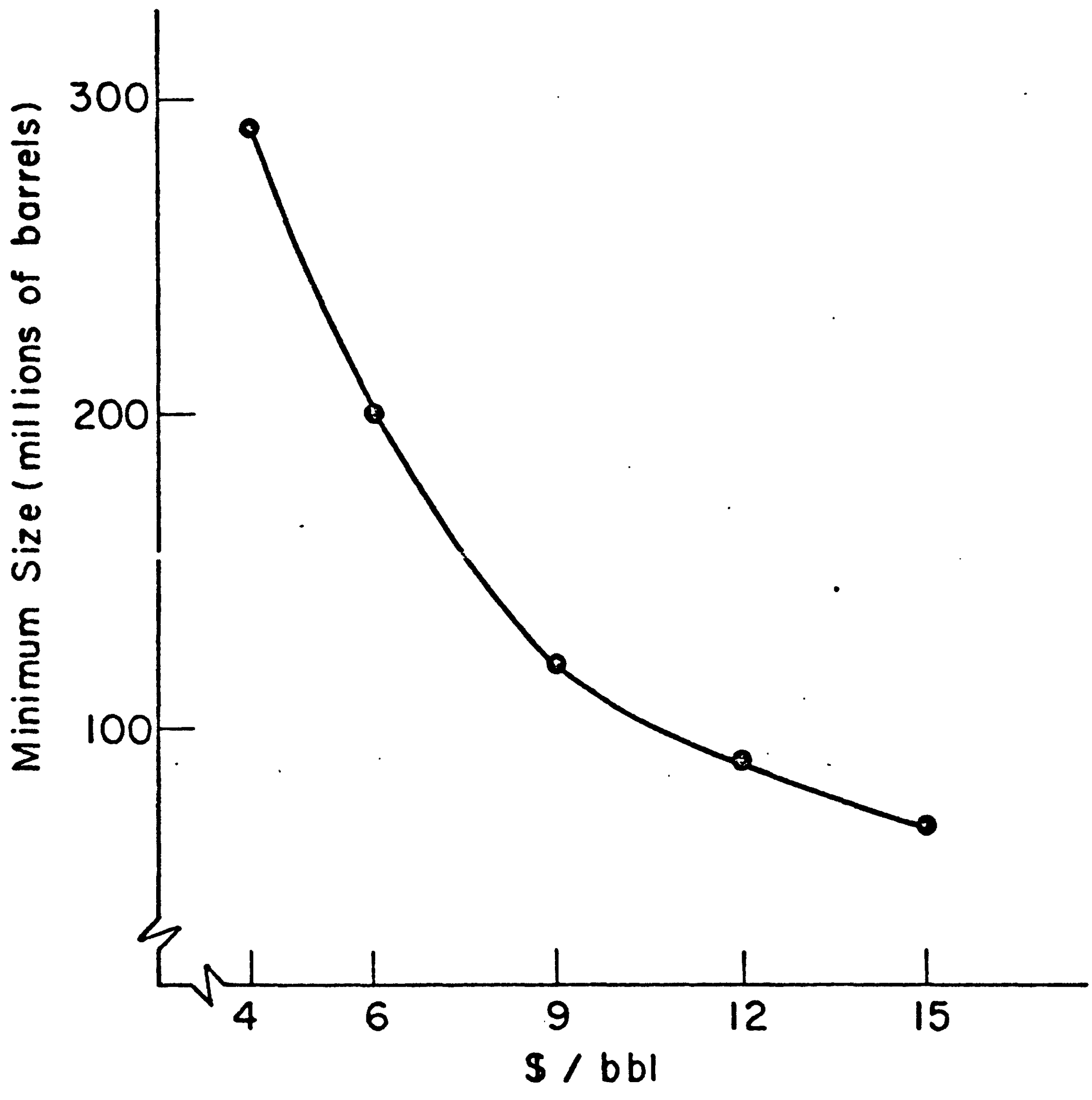

FIGURE 1. MINIMUM ECONOMIC RESERVOIR SIZE IN THE NORTH SEA AS A FUNCTION OF OIL PRICE (1976 PRICES)

the Platou estimate implies a rate of 44 exploratory wells per year in the North Sea. For the purpose of this discussion, we will assume that this level of exploratory drilling will be maintained until economic constraints are encountered as a result of the discovery decline behavior of the exploration process.

3. THE RESOURCE BASE

Viewed as an economic process, oil supply is the depletion of a stock, which is constantly being renewed by adding new reservoirs and expanding the limits of the old ones. In this section, we focus on the process of replenishing the stock of reservoirs.

The resource base may be broken down into a number of reserve categories of economic or geologic significance. We distinguish between reservoirs which have already been discovered and declared commercial ("existing" reservoirs); reservoirs which have been discovered but not yet fully evaluated ("probable" reservoirs); and reservoirs to be discovered ("discoverable" reservoirs). Existing North Sea oil reservoirs as discussed in Table 2 contain an estimated 14.6 billion barrels of recoverable reserves, i.e., 14.6 billion barrels is the sum of the annual production profiles presently planned for these reservoirs. This may be considered a conservative estimate. Through a process of extension and revision as a result of production experience and additional development, we could consider this estimate to be increased by 25 - 50%. This process of extension and revision is disregarded in our forecasting exercise, thereby biasing the future supply potential downwards.

The information available on probable reservoirs is substantially less extensive than for the commercial reservoirs. The reservoir size estimates of the probable fields as included in the Wood, Mackenzie estimates of Table 2 are all substantially larger than the MERS' of Figure 1 in the \$9 - \$15 price range (mid-1976 dollars), the price range considered relevant for this exercise. They are hence all candidates for inclusion in the productive resource base as judged by the reservoir model of this study. A number of smaller discoveries has also been made as indicated in Table 1 as well as in more recent listings of North Sea discoveries [11]. On the basis of guesstimates of the size of the smaller probable reservoirs of Table 1, each of these reservoirs were run through the reservoir model to determine the price at which these reservoirs would enter the productive reserve base. The reservoir model was hence used to estimate the supply elasticity of the probable reservoir category [12]. As we are in the process of updating our data base on the potentially probable reservoirs and a fairly extensive discussion of the assumptions entering into such probable reservoir analysis is required to be of empirical interest, we will assume that the probable fields as listed by Wood, Mackenzie exhaust the list of candidates for the probable reservoir category. This simplification biases, of course, the elasticity of supply of North Sea oil downwards. The recoverable reserves estimate of the probable reservoirs as listed in Table 2 is 5.6 billion barrels.

When proceeding to the next category of reservoirs, the discoverable reservoirs, the extent of available information is further reduced and the uncertainty surrounding the estimates is increased. To estimate the supply potential of the discoverable reservoirs, an analysis of the exploratory process is required, the process by which the geologist's list of prospects is transformed into an inventory of reservoirs to be developed, as determined by the reservoir analysis. By separating the discovery/development process in this fashion, an attempt is made to separate the geological characteristics of an area from the economic attractiveness of the area. The separation is not complete as the selection of the prospects to be drilled is influenced by the expected economics of the reservoirs to be discovered.

There is no basis for predicting how each of the geologic variables that characterize a reservoir will behave as an area is drilled up. By properly idealizing an area, however, we may learn how the most significant geological variable (which is a composite of a number of geological phenomena), the number of and size distribution of the individual reservoirs to be discovered, behaves as the exploration process matures. Such an idealization is a "play". A play is defined as a group of similar geological configurations, generated by a series of common geological events, forming a statistical population and conceived or proved to contain hydrocarbons. There is a substantial amount of work on the size-frequency distribution of reservoirs at the play level [9, 10], and we have some basis for predicting the size of discoveries to be made.

The size-frequency distribution of the discoverable reservoirs may be estimated directly from geologic and judgmental data [8, 12], or statistically as done by Kaufman and Barouch [2, 3]. The approach made here is an adaptation of the Kaufman-Barouch work. The analysis is based on two hypotheses, one about the nature of resource deposition and the other about the character of oil exploration. It is assumed that reservoir size, measured in terms of recoverable reserves r, is a random variable, and that its density function is lognormal [2, 3, 9, 10]. That is, log r is normally distributed with mean μ and variance σ^2. To this hypothesis about nature is added an hypothesis about the process by which oil operators search for and find reservoirs. Following the work of Kaufman and others [2, 3, 9, 10], the exploratory process is characterized as one of random sampling, without replacement, in proportion to reservoir size r. With these hypotheses, it is possible to predict the density functions of future discoveries conditional upon the exploratory history already experienced. The mathematics and numerical analysis techniques necessary to do these computations are beyond the scope of this paper. See the work of Barouch and Kaufman [2].

For the purpose of the analysis, the North Sea was treated as one play, whose discovery history is that of Table 1. The discoveries of Table 1 can, however, be assigned to three distinct plays. We were restricted to a "one-play" analysis by the computational resource intensity of the statistical approach. Due to improved computational algorithms, we will be able to perform the three-play analysis of the North Sea shortly. A reordering of the discovery sequence of Table 1 will also be made prior to further analysis to adjust for the effect of government licensing policy on the discovery process.

The nature of the results is shown in Figure 2, which shows predictions of the next three discoveries. For example, the figure shows the rough shape of the density function for the 61st discovery and the conditional expectation of the size of the 61st discovery which, in this case, is 258 million barrels.

Figure 2 indicates how we calculate what output from a sequence of successful discoveries might be. Given an exploratory effort determined by government licensing policy as discussed in Section 2, the number of discoveries is determined by the geologic risk. The geologic risk results from the lack

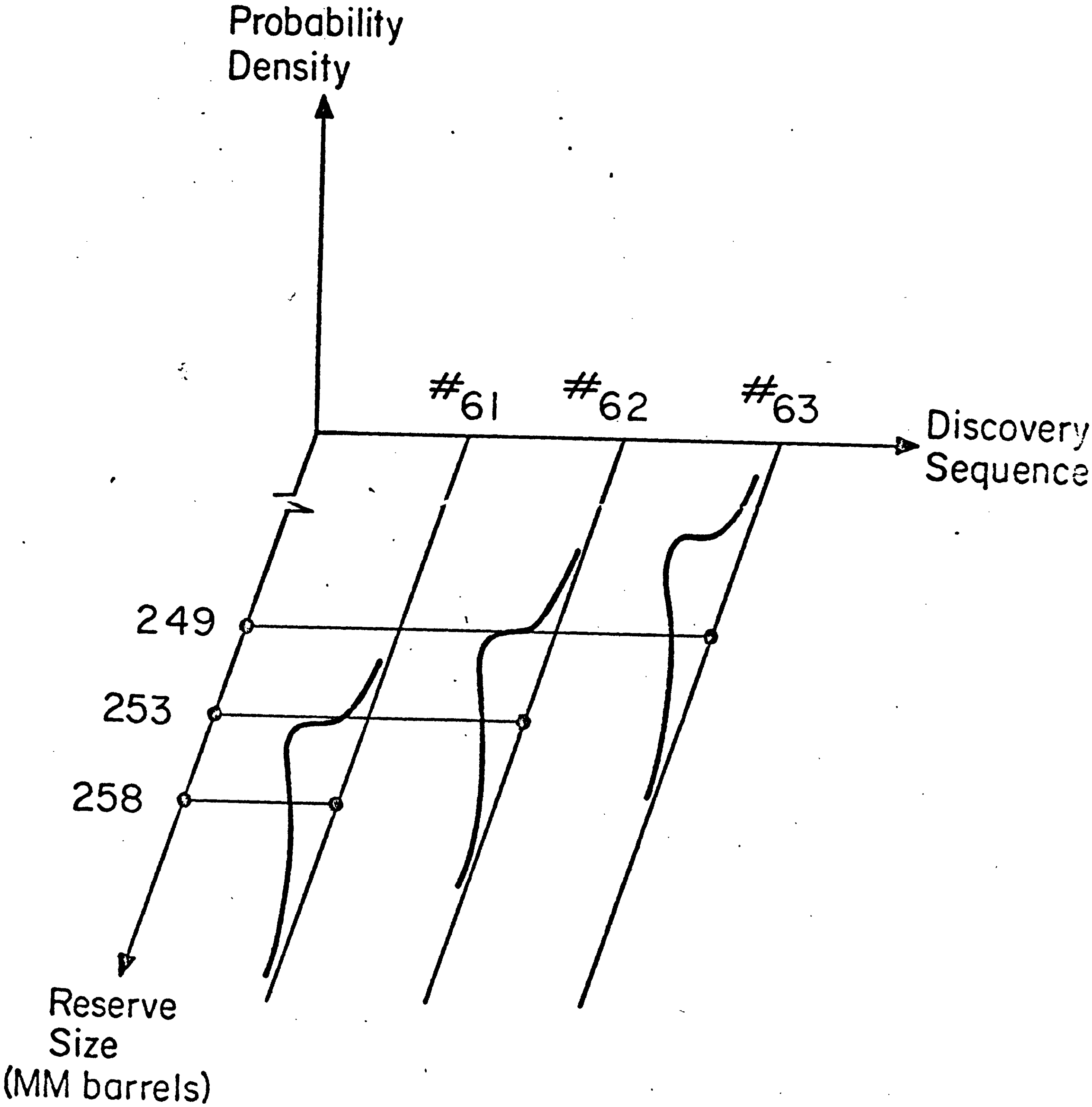

FIGURE 2. THE SEQUENCE OF PREDICTIVE DISCOVERY DISTRIBUTIONS

of technology to determine, prior to drilling, whether a prospect is in fact a reservoir (i.e., contains hydrocarbons). In the area of analysis, approximately every fourth wildcat has produced a reservoir. We have assumed that this ratio will persist over the forecast period. The government-regulated exploratory effort of Section 2 and a geologic success ratio of 0.25 imply an expected rate of 11 discoveries per year in the North Sea until the economic incentive to further drilling is removed.

The economic risk results from the fact that some of the reservoirs to be discovered may not contain hydrocarbons in commercially attractive quantitites. Therefore, recognizing the variability of actual reservoir size around the predictive mean, we need some indication of the expected number of barrels to be found in reservoirs of various sizes. Using the predictive density funcitons, we can calculate the "partial expectations" i.e., the expected number of barrels to be found in reservoirs of various sizes. In Table 4 below, four size categories have been calculated using the North Sea example. The table shows the partial expectations of the number of barrels to be discovered in each category in the next five successful exploratory wells. It is evident that most of the oil is expected to be found in larger reservoirs and that there is a process of "discovery decline" that governs the exploratory process.

The total increment of economic reserves in year t consists of all current discoveries of oil in reservoirs which satisfy the MERS criterion plus any oil from earlier discoveries which for the first time satifies this criterion. The cumulative inventory of submarginal reservoirs is thus monitored continuously as economic incentives fluctuate.

Table 4. Predictive Discovery Distributions, Oil and Gas, Millions of Barrels Oil Equivalent

Size Category, k	Limits	Partial Expectation, P_{ik}, for discovery number 61	62	63	64	65
1	125 to 250	18	18	18	17	17
2	250 to 375	26	25	25	25	24
3	375 to 500	31	31	30	30	30
4	over 500	176	173	169	166	163
Expected Value, $E(r_i)$		258	253	249	244	240

The fraction of gas in North Sea hydrocarbon reserves is about 23% [4, 12]. We assume that this ratio will stay constant and that the particular circumstances governing North Sea gas imply that gas can be disregarded in a MERS context. The results of the discovery analysis can then be summarized as done in Table 5 below under an expected $12 and $9 price scenario (mid-1976 dollars). The slow decline of the discovery decline function implies that the ultimate recoverable reserves estimate is fairly sensitive to price or MERS, i.e., the point at which the "discovery tail" is cut off.

Table 5

ESTIMATED ANNUAL DISCOVERIES OF RECOVERABLE

RESERVES OF OIL (MILLIONS OF BARRELS)

Price	Total	1976	1977	1978	1979	1980	1981
$ 9	5023	1911	1664	1448			
$12	8459	1946	1694	1475	1284	1118	942

The resource base of the North Sea can then be summarized as consisting of 14.6 billion barrels of oil in existing reservoirs, 5.6 billion barrels in probable reservoirs, and 8.5 billion barrels in discoverable reservoirs at an expected price of $12 or 5 billion barrels in discoverable reservoirs if price expectations were an average $9 per barrel of oil. When we disregard the price sensitivity of the probable reserves, the ultimate recoverable oil reserves of the North Sea, or the sum of the three reserves categories is 28.7 billion barrels at an expected price of $12 and 25.2 billion barrels at a $9 price. The elasticity of the resource base within this price range is thus about .42.

4. NORTH SEA OIL SUPPLY

The result of applying the disaggregated process model to our North Sea data base is indicated in Table 6. The result is, of course, influenced by subjective judgment and interpretation of the data base as well as of the government policy that will regulate the activity in the North Sea in the years to come.

The elasticity of supply of North Sea oil in 1985 is estimated at about .67 in the $9 to $12 price range. It is higher than the elasticity of the resource base of 0.42 because the discoverable reservoirs are smaller than the average for the existing reservoirs and are produced at a faster rate (higher rate of peak production). The elasticity of oil supply is, however, sensitive to the price range. In the $12 to $15 price range, the supply elasticity is only half as high as in the $9 to $12 range.

Table 6

NORTH SEA OIL SUPPLY ESTIMATES

(Million Barrels Per Day, 1976 Prices)

	1980		1985	
	$9	$12	$9	$12
Existing Reservoirs	2.89	2.89	2.39	2.39
Probable Reservoirs	0.32	0.32	1.43	1.43
Discoverable Reservoirs	0.47	0.48	1.68	2.87
TOTAL	3.68	3.69	5.50	6.69

The estimate of a supply elasticity of 0.67 is conservative as we have assumed away any price elasticity of existing and probable reservoirs. The degree to which we will experience extensions and revisions of existing reservoirs as well as having more recently discovered reservoirs added to the list of probable reservoirs is also a function of the prevailing price expectations. We are in the process of gathering data for an analysis of the elasticity of supply of these reservoir categories.

To increase the empirical validity of the analysis, we are presently gathering data that will allow us to more fully exploit the disaggregated model's ability to handle the complexity of the process of oil supply. As reported above, reservoir size only is determining development and operating costs. Additional data and engingeering-type analysis will allow us to specify costs as a function of the five reservoir characteristics of Table 3 [5]. This is significant for the ability to explain costs as drilling is moved into deeper waters or a different environment. The rate of introduction of new technologies is also to be built into the cost equations. The emerging sub-sea completion technology may significantly affect offshore development costs in the years to come.

The discovery analysis as reported above allows us only to predict discoveries within the geographic location of a play. Prospect information is required to determine the likely location of new discoveries relative to existing discoveries and infrastructure. Prospect data would thus allow us to operate with a larger set of reservoir categories for MERS purposes.

The governments of the North Sea also have a number of participation options that affect the MERS as seen by a private operator. The British version is neutral, the Norwegian version, however, "carried interest" participation, increases the MERS.

There is some administrative freedom in the fiscal regimes as they affect the North Sea activity. Tax and royalty reimbursement and direct and indirect subsidies are possible under the present regulatory regimes. These options may be exploited as the North Sea matures and may decrease the private MERS towards the social MERS. This effect may also be obtained by changing the structure of the fiscal system itself.

A reordering of the discoveries of Table 1 to adjust for the impact of government policy on the discovery process and estimating predictive discovery density functions for three separate North Sea plays are also likely to affect our forecasts, as will more recent discovery data and the likely discovery of additional plays. As an area matures, the geologic risk or the success ratio is likely to be affected. A more sophisticated analysis of the geologic risk and the rate of exploratory drilling is presently being undertaken. The last item on the list of immediate research tasks is the assumption of a constant gas/oil ratio and the economics of North Sea gas which affects the MERS of associated gas fields and the economic incentive to drill.

The single, most important event as far as North Sea supply is concerned, would be the drilling of the largest structure in the North Sea, lying on acreage held by the Norwegian government. This structure, if not dry, might contain 5 to 15 billion barrels of recoverable reserves and thus completely change the supply potential of the region [11]. While waiting for this structure to be drilled, the estimates of Table 6 are our best guesses as to the 1980 and 1985 supply of North Sea oil.

REFERENCES

1. Adelman, M.A. and H.D. Jacoby, "Alternative Methods of Oil Supply Forecasting", prepared for the International Energy Agency Workshop on Energy Supply in Paris, France, November 15-19, 1976.

2. Barouch, E. and G.M. Kaufman, "Oil and Gas Discovery Modeled as Sampling Proportional to Random Size", M.I.T. Sloan School of Management, Working Paper WP 888-76, December 1976.

3. Barouch, E. and G.M. Kaufman, "Probabilistic Modeling of Oil and Gas Discovery", in Energy: Mathematics and Models, SIAM Institute for Mathematics and Society, 1976.

4. Beall, A.O., "Dynamics of Petroleum Industry Investment in the North Sea", M.I.T. Energy Labroatory Working Paper No. 76-007, June 1976.

5. Beck, F.M. and K. Wiig, The Economics of Offshore Oil and Gas Supply, Lexington Press, Lexington, Mass., August 1977.

6. Eckbo, P.L., "PLanning and Regulation in the North Sea", Northern Offshore, No. 9, September 1976.

7. Eckbo, P.L., H.D. Jacoby, and J.L. Smith, "Oil Supply Forecasting: A Disaggregated Process Approach", M.I.T. World Oil Project, Working Paper No. MIT-EL 77-007WP, February 1977.

8. Ivanhoe, L.F., "Economic Feasibility Appraised for Petroleum Search in Remote Regions", The Oil and Gas Journal, December 20, 1976.

9. Kaufman, G.M., "Statistical Analysis of the Size Distribution of Oil and Gas Fields", in Symposium on Petroleum Economics and Evaluation, AIME; 1965.

10. Kaufman, G., Y. Balcer and D. Kruyt, "A Probabilistic Model of Oil and Gas Discovery" in Studies in Petroleum Exploration, No. 1 AIME; 1975.

11. Lovegrove, M., "The Development of Oil and Gas Reserves on the UK and Norwegian Sectors of the Continental Shelf Off North-West Europe", Paper presented to an OECD Workshop, November 1976.

12. M.I.T., World Oil Project, Supply Analysis Group, "Supply Forecasting Using Disaggregated Pool Analysis", M.I.T. Energy Labroatory Working Paper No. 76-009WP, May 17, 1976.

13. "Petroleum Economist" August 1976, p. 316.

14. Wood, Mackenzie & Co., "Section 2 of the North Sea Service", Edinburgh, June 9, 1976.

15. Wood, Mackenzie & Co., "North Sea Report", Edinburgh, May 14, 1976.

16. Wood, Mackenzie & Co., "North Sea Report", Edinburgh, February 1977.