ER-2421

OPTIMIZATION OF INVESTMENT IN AN OFFSHORE OIL FIELD DEVELOPMENT

by
Ney Tadeu Araujo Machado

ERRATA

Two typographical errors were discovered in equations 12 and 13 of this text. Rearranging, here are the equations in the correct form:

$$CNDP = \frac{q_1 (1-R) P \left[1-(XY)^T\right]}{(1-XY)} - \frac{365 A_i (1-Y^T)}{(1-Y)} \qquad (12)$$

$$DPIR = \frac{\dfrac{q_1(1-R) P \left[1-(XY)^T\right]}{(1-XY)} - \dfrac{365 A_i (1-Y^T)}{(1-Y)}}{INVESTMENT} \qquad (13)$$

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Golden, Colorado

Date January 19, 1981

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ABSTRACT

This report presents a method to determine the drainage area of wells which will optimize the discounted profit to investment ratio when developing an offshore oil field. The objective of the method is to plan the field development to improve the economic results, based on geological and geophysical information and data obtained from exploratory wells.

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INTRODUCTION

One of the most perplexing and difficult challenges in the petroleum industry today is deciding which of the many developing and producing schemes for a new offshore field is the most profitable.

The objective of the study presented in this report is to determine which among several development alternatives provides the highest discounted profit to investment ratio and the best economic results. Each alternative design is based on an assumed drainage area per well. Depending on the drainage area chosen, a different number of wells can be drilled and platforms and subsea systems are defined. Relying on these data, the method allows an economic analysis of the alternative designs. If the number of platforms and wells to be drilled, as well as the number of subsea completions are known, it is possible to evaluate the investment to develop the oil field for each alternative. Production equipment costs have to be included in these evaluations.

This economic analysis considers the reservoir volume of oil-in-place, the estimated recovery factor, the oil price, royalties to be paid, the required investment, operating costs, production decline, and the oil production rate. To determine the discounted profit:investment ratio

(DPIR), the net present value of the discounted profit for each development alternative is used, as well as the net present value of the investment. The highest discounted profit to investment ratio is assumed to be the optimal value and identifies the best option to be adopted.

The model presented here comprises graphical studies for the development plans, cost evaluations and the production decline study for the oilfield. The graphical studies take into account the boundaries of the reservoir, the number of vertical and deviated wells to be drilled, platforms and subsea systems which are to be installed according to each scheme.

LITERATURE SURVEY

The exploration and development of offshore oil fields is experiencing an unprecedented boom. The technology for drilling and producing in deep waters and in hostile environments is rapidly expanding. Since the end of the 1960's and the beginning of the 1970's a large number of papers have been written, reflecting the growth of the oil industry and it's courageous and imaginative solutions to the new problems and challenges that it has faced in the search for offshore oil.

(a) PLATFORM ECONOMICS

The selection of a conventional platform system to develop and produce an offshore hydrocarbon discovery is governed as much by the size and rate of the project's investment as it is by the reservoir characteristics, water depth, environmental conditions and location.

According to Le Blanc (1978), the variables involved in the choice between two or more platform systems lie in three major areas: the rate of investment in the field, the rate of return-on-investment and the timing of initial and full production. Earlier initial and full production will require a larger initial investment and quite frequently a larger ultimate payout. A portrait of field development in most cases shows that the size of the initial investment is

inversely proportional to the time interval between discovery and initial production, or the larger the initial investment, the sooner the initial production will begin.

(b) SHALLOW WATER AND DEEP WATER CONCEPTS

Lee (1978) describes shallow water and deep water platform features. He suggests that the design of platforms for deep water is related to shallower depths. The same problems are encountered, although they may be more severe. As the water depth increases, the dynamic response of the structure to wave loading becomes increasingly important. In addition, installation planning becomes more critical. The definition of what constitutes "deep water" has been a variable parameter, gradually increasing with the progress of the offshore industry. Traditionally, deep water has been considered as that depth just beyond the deepest existing platform. "Deep water" is certainly within the industry's current operating capabilities. Deep water platform designs are dominated by factors that are of less importance in shallow water structures. The deeper water platform is more slender and therefore more susceptible to stress amplification due to wave dynamics, which is usually ignored in shallow water. This fact also increases the significance of fatirue assessment.

Another difference between deep and shallow water

platforms is the complexity of installation. Because of the weight involved, it is no longer practical to rely on "brute strength", since the capacity of even the newest and largest derrick barge tends to be inadequate. The number of wells has to be increased to justify the large structural investment. All production equipment would be located on the structure, since the cost of a separate production platform would be prohibitive. With the increased deck size, equipment modules are frequently used to facilitate installation since the deck with equipment already installed may be too heavy to be installed conveniently as an integrated unit. As the structure is extended into 700 foot to 900 foot depths, it is necessary to separate the jacket into more than one section to facilitate handling.

(c) EARLY PRODUCTION SYSTEMS AND SUBSEA WELL DEVELOPMENT

Reeds and Trammel (1976) recommended obtaining early revenues from subsea wells, since the conventional fixed platform approach frequently involves excessive delays with resulting economic penalties. Reinforcing their arguments, they state that delays can be magnified by hostile weather, increasing water depth and locations far removed from support facilities.

According to Behar and Milton (1978) an operator's responsibility in developing an offshore field is to

generate the maximum cash surplus consistent with personnel and environmental safety. This objective can be achieved if the following criteria are observed:

* A positive cash flow is achieved at the earliest possible date.
* The oilfield equipment installed is compatible with the reservoir conditions for the life of the field.

Unfortunately, these two requirements tend to be in conflict. On the one hand, the rapid installation of production equipment that later proves inadequate to deplete the reservoir in an optimum fashion will result in lost reserves. Alternately, the installation of equipment capable of handling the actual production conditions will be both unnecessarily expensive and time consuming to install resulting in delays in commencement of production. Their conclusion was that to achieve both objectives, the production system must not only be initially capable of rapid and economic installation, but also capable of being expanded to include production from development wells, and later on, to include reservoir pressure maintenance or secondary recovery facilities. In other words, the system must be progressive.

These arguments are applicable to any field, of course, but become especially true when the reservoir size or the

water depth at the location are such that the overall economics of the field are marginal. Behar and Milton (1978) add that, until recently, the normal procedure after discovery of a field was to drill a number of step-out or appraisal wells, to obtain further reservoir information. Together with seismic results, this information was used to develop a production facilities design in which there was an acceptable level of confidence. With the increasing costs of drilling offshore wells (wells in the North Sea can now cost up to U.S. $20 million), the expenditure to obtain adequate reservoir information is often unacceptably high, particulary if the wells are abandoned.

(d) MARGINAL FIELD DEVELOPMENT

According to Cozens (1978), given the variables of field location, country and time, there is no such thing as a "general" marginal field. The factors which determine whether a field is marginal include the obvious characteristics such as reservoir size, shape, and depth; well producing rates, oil and/or gas quality, the existence of production problems such as H_2S or CO_2 and sand production. The status of technology required for development, availability of competent and efficient construction facilities in the area, nearness to market, and environmental problems such as earthquakes and hurricanes must also be taken into ac-

count. Equally real financial concerns include political and financial stability, leasing, royalty and tax terms, interest rates, oil and gas prices, and alternative opportunities for which the producing company might use its money and manpower resources.

In evaluating reserves located offshore, these factors are amplified by the normally higher cost and inaccessibility. Water depth, bottom terrain, soil condition and weather also become very important. Cozens (1978) also adds that one of the most flexible economic packages for marginal field development in the recent years is subsea completion, because the variety of surface production equipment, the lower cost of completing exploration or development wells at the seafloor and sequantially bringing each of the completed wells on stream provides for a comparatively lower front-end investment and a quick cash flow.

(e) WELL SPACING

According to Craze and Glanville (1955), the development of a new oil reservoir presents a challenging problem to the operator in adopting early in the life of the pool a sound spacing that will achieve the maximum efficiency in recovery with minimum investment in the wells. The need of adequate information on the productive horizon, it's contents, the type of drive mechanism and it's probable be-

havior offers a serious problem during the early development period. They suggest that many clues to the probable behavior of the new reservoir may be evidenced by comparison with similar reservoirs, particularly if the new reservoir is in an area where the geology is reasonably well known and where developed fields can be used as reference. Important additional information can be obtained from logs and cores on early wells, long term tests and subsurface samples of oil from the first well. They also suggest that it would be prudent to employ wide initial spacing in the development of a new reservoir, to permit early determination of the areal extent and geological characteristics of the pool, the amount of gas and oil reserves, the properties of the reservoir rock, and its contained fluids, and the nature of the producing mechanism.

DETERMINATION OF WELL SPACING

The study done by Craze and Glanville emphasizes two main considerations:

1. A sufficient number of wells must be drilled to provide adequate geologic information concerning the structural configuration of the reservoir, the continuity and characteristics of the reservoir rock and their distribution, both laterally and vertically, and the total volumes of oil and gas contained in the reservoir.

The specific number of wells required to provide such information cannot be expressed by any general rule. It is realized that highly faulted and segmented producing formations on the flanks of a piercement salt dome may require a proportionately higher density of wells to identify each reservoir segment and to define the reservoir rock characteristics. On the other hand, a small number of wells may be adequate to provide the necessary information on a reservoir comprising uniformly deposited blanket sands, without evidence of structural irregularities.

2. Sufficient wells must be drilled to drain the reservoir adequately under the type of drive mechanism. This fact suggests that there is a geometric dependence of recovery on well spacing. It is obvious that structural location of wells is important.

(a) WATER AND GAS CAP DRIVE RESERVOIRS VS SPACING

The specific location of the wells with respect to the geometry of the reservoir will ultimately govern the efficiency with which oil is recovered for both water and gas cap reservoir drive mechanisms, not the number of wells.

(b) DISSOLVED GAS DRIVE RESERVOIR VS SPACING

The relation between production rate per well and time introduces economic factors as the prime consideration in determining the well spacing for a dissolved gas drive

reservoir. In the absence of significant gravity segregation, the geometric dependence of recovery on the spacing ceases to exist, and location of wells with respect to reservoir geometry becomes of little concern.

THEORY

DISCUSSION OF THE METHOD

This method to optimize investments in offshore oil field development comprises several steps. This is a discussion of the steps and the sequence for performing the calculation in a logical way.

1. VOLUME OF OIL-IN-PLACE

(1.a) If enough data is available from the well logs run previously in the exploratory wells (Spontaneous Potential, Resistivity, CNL, Density, etc.), the Isovolume Map can be made and the volume of oil-in-place determined.

(1.b) Depending on the information available from the exploratory wells and considering relatively homogeneous and continuous reservoirs, a more simple Isovolume Map can be made. The reservoir external boundary is drawn, and the average values for porosity, pay zone thickness and water saturation are determined. According to Hilchie (1978), these formulas may be used:

$$h_{AVERAGE} = \frac{\sum_{j=1}^{n} h_j}{n} \qquad (1)$$

$$\phi_{AVERAGE} = \frac{\sum_{j=1}^{n} \phi_j \times h_j}{\Sigma h_j} \quad (2)$$

$$Sw_{AVERAGE} = \frac{\sum_{j=1}^{n} Sw_j \times h_j}{\Sigma h_j} \quad (3)$$

where

h_j = average net pay thickness of the jth productive formation (ft)

ϕ_j = average porosity of the jth productive formation (fraction)

Sw_j = average water saturation of the jth productive formation (fraction)

Using Eq. 4, the total recoverable oil reserves can be determined for primary recovery:

$$RESERVES = 7758 \frac{[\phi \times h \times (1 - Sw)]}{B_o} \times A_{TOTAL} \times RF \quad (4)$$

where

A_{TOTAL} = total reservoir area (acres)

RF = recovery factor (fraction)

B_o = formation volume factor (bbl/STB)

2. Assume several drainage areas to work with, for example 80, 160, 240, 320, 480, 640 acres, etc. Each of these drainage areas corresponds to a different spacing grid, according to which the oil field development will be studied. On transparent overlays, the several spacing grids (square grids) have to be drawn. The scales used to draw the map and the spacing grids must be the same (see Fig. 1).

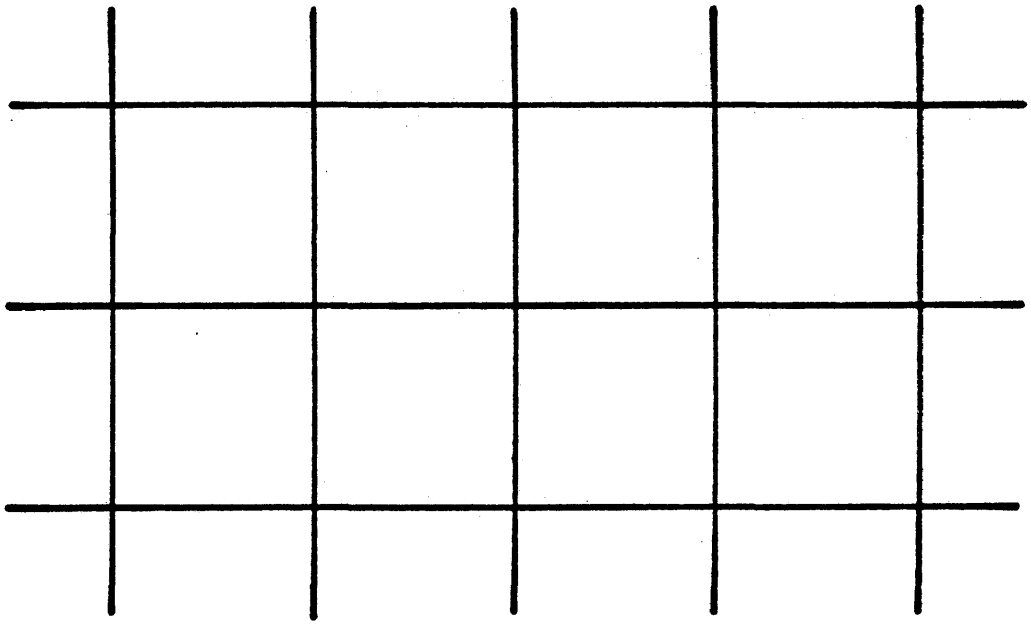


FIGURE 1 : Spacing grid to be drawn on a transparent overlay

Determination of the spacing grid: as an example, the case of developing the field with a drainage area of 320 acres per well will be used. Thus, each square has an area equivalent to 320 acres. This area corresponds to 13,939,200 sq. ft., with each side equal to 3,733.52 ft. (0.7071 miles).

The wells are plotted in the center of the square grids, as shown by Figure 2.

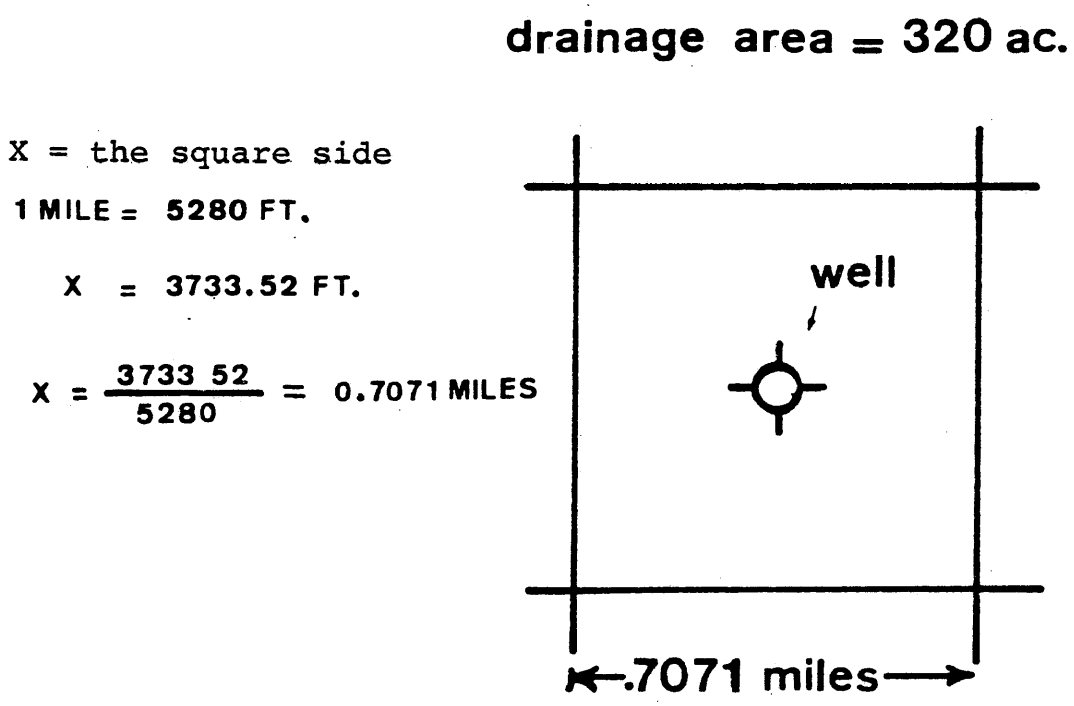


FIGURE 2 : The Square Drainage Area

3. The next step is to adjust the transparent overlay and the square grids over the reservoir map (Isovolume Map) in such a way to allow the best drainage of the reservoir. If an isopach or isovolume map is available, preference should be given to the parts of the field which have more oil. The wells have to drain the reservoir area as completely as possible in order to maximize the oil recovery. One has to avoid planning wells extremely close to the edge of the field, whose drainage areas are not totally included inside the boundaries of the field, as shown by figure 3. Be sure that at least 80% of the square is considered part of the reservoir.

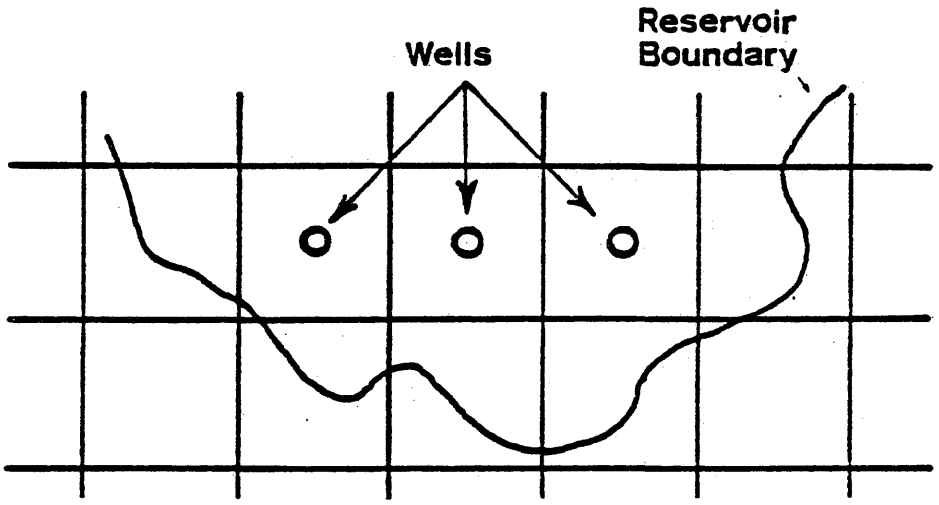


FIGURE 3: Avoid planning wells close to the edge of the reservoir.

4. It's a good policy to include the exploratory wells already drilled in the field development program to reduce the high costs of offshore drilling.

5. After locating the wells, the drilling-production platform's location must be chosen. To do this, two parameters are very important: the maximum deviation angle for the deviated wells and the departure. Mitchell (1979) recommends deviation angles between 15 and 40 degrees as optimal; therefore 45^{o} or 50^{o} may be taken as maximum deviation. Target departure is the horizontal distance between the wellhead and the point where the reservoir (target) is reached by the deviated well (see fig. 4 and fig. 5). Thus, a maximum deviation angle has to be established according to the techniques developed by the company which will drill the wells. The target departure depends on the maximum deviation angle and on the depth of the producing horizon. One has to be sure that all targets in the reservoir can be reached from the platforms with a deviation angle less than the maximum angle. If there is any target not reached from one of the platforms, the need for a subsea completed well should be studied. The costs of the subsea completed wells are much higher than for directionally drilled wells from a platform. Also the

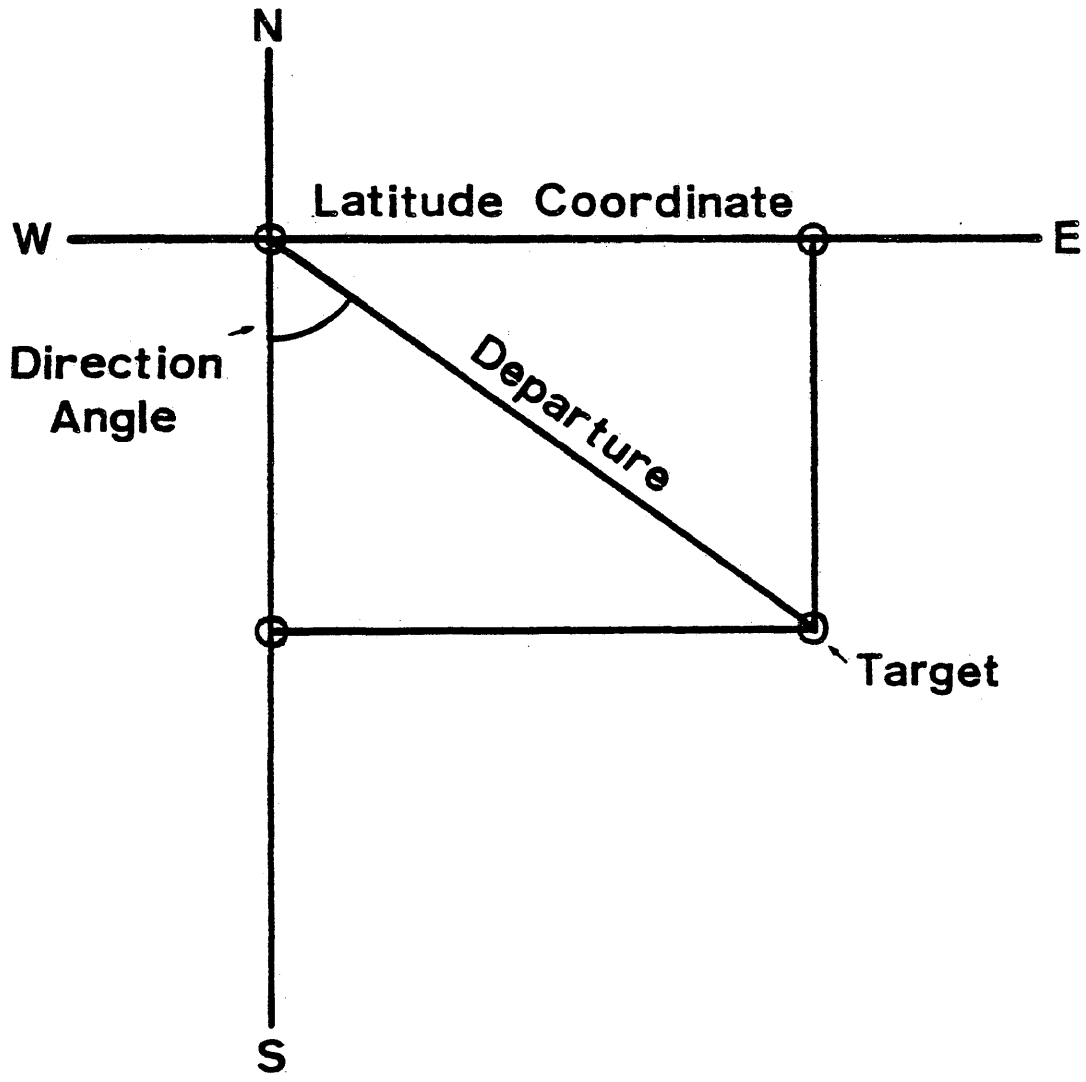


FIGURE 4: Well Deviation
(horizontal section)

AFTER B. J. MITCHELL

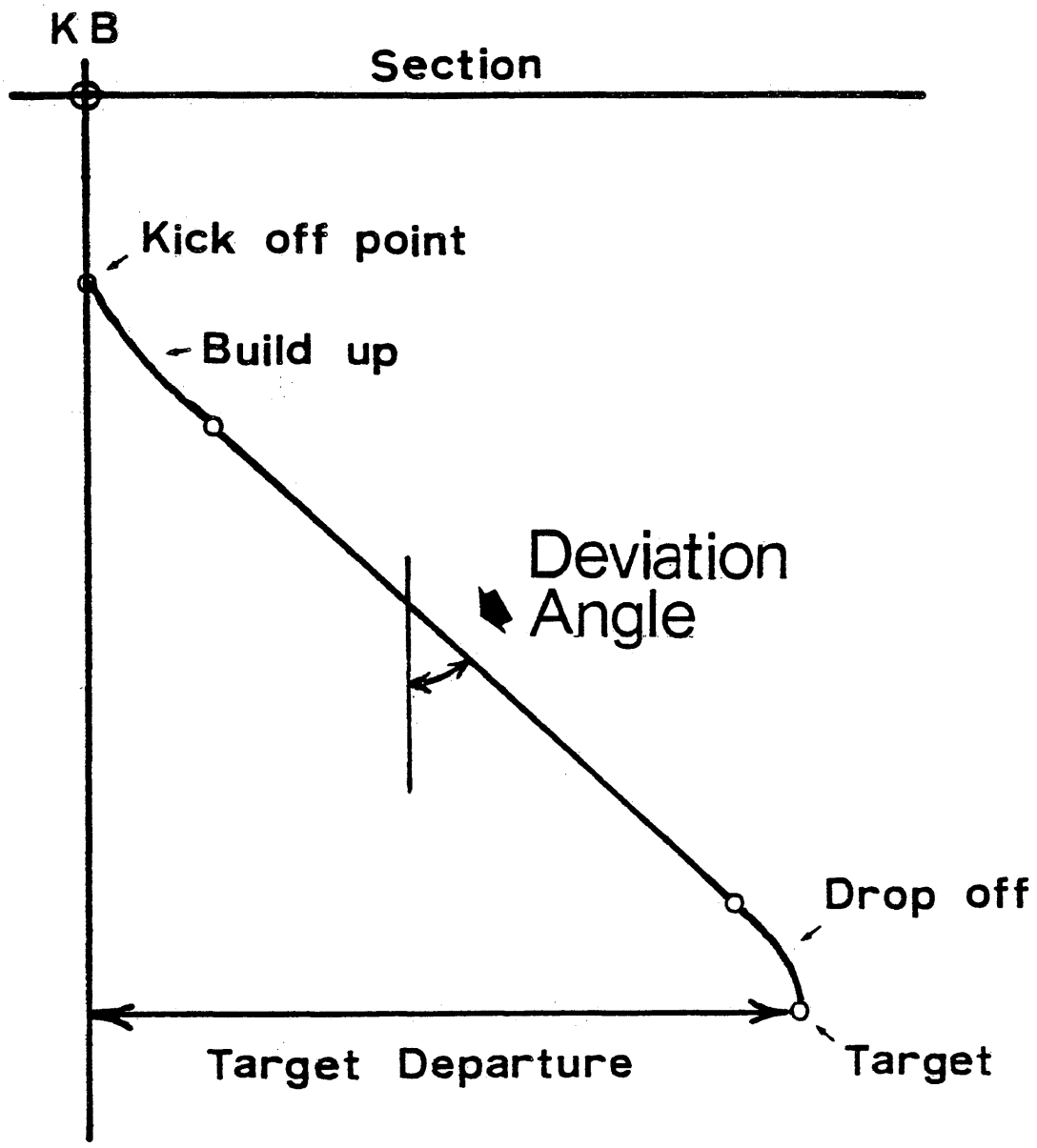


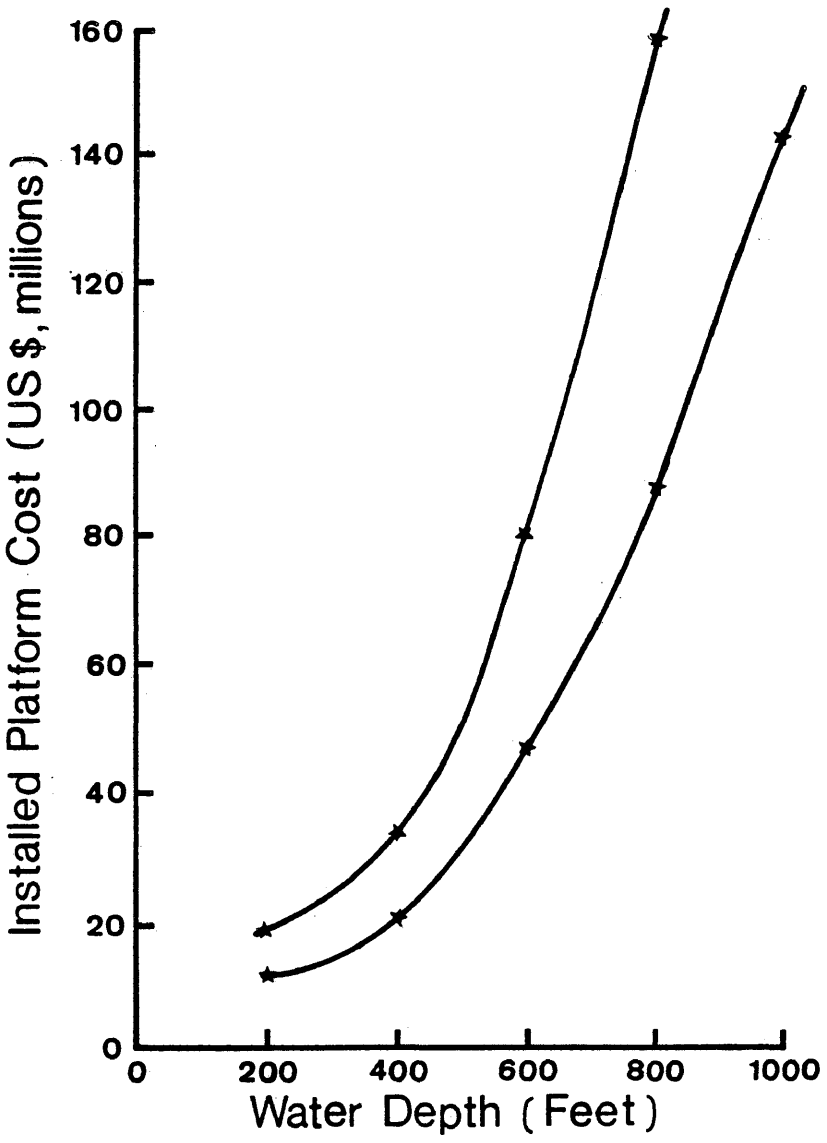
FIGURE 5: Well Deviation
(vertical section)

AFTER B.J. MITCHELL

maintenance of subsea completed wells is more difficult and expensive. This is particularly true in areas where the environment is hostile (storms, etc.).

6. For each spacing grid, the number of wells to be drilled, platforms and subsea completions necessary to develop the offshore oil field can be determined. Figures 14 to 21 (see 'Application with a Model') show the alternative development plans for the particular case of a reservoir. With update costs of platforms, subsea completions plus vertical and deviated wells drilling costs, part of the investment can be determined. Figures 6 (from Offshore Operating Committee presentation to the Marine Board of the National Research Committee, 4-23-76) and 7 (anonymous source) give the installed platform cost range. The production equipment costs can be estimated through Figure 8 (anonymous source) as a function of the oil production (bbl/day). For subsea completed wells, according to Cozens (1978), about 40% of the cost is the primary drilling. The remainder is completion, about 30%, and tie-in, also 30%. According to this same source, tie-in occupies a much more expensive share of the cost when the well is not a satellite unit, but part of a subsea collection system.

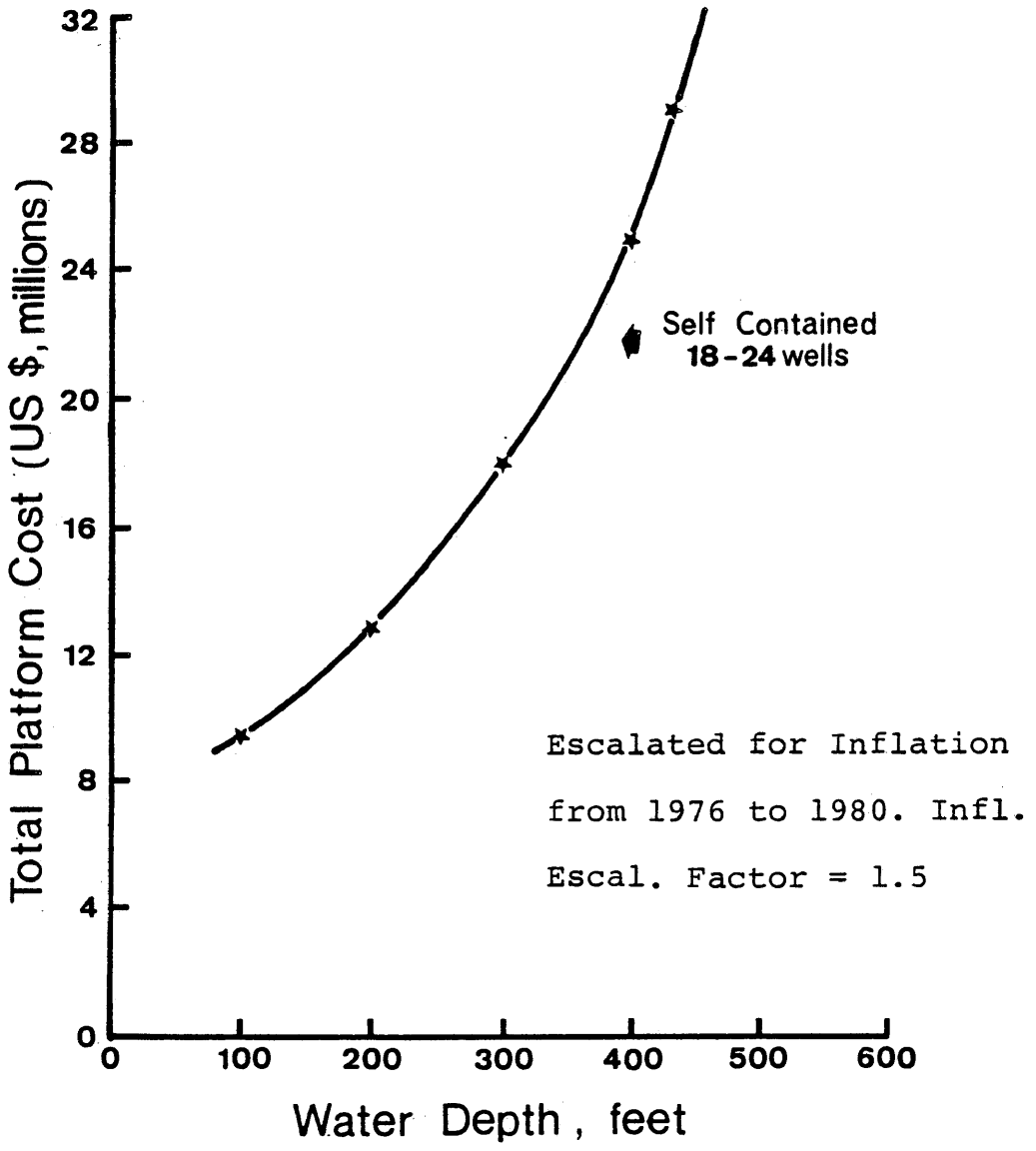
FIGURE 6
Gulf of Mexico Installed
Platform Cost Range



From Offshore Operating Committee presentation to the Marine Board of the National Research Committee 4-23-76, Escalated for Inflation, 1980. (Infla. Escal. Factor = 1.5)

FIGURE 7

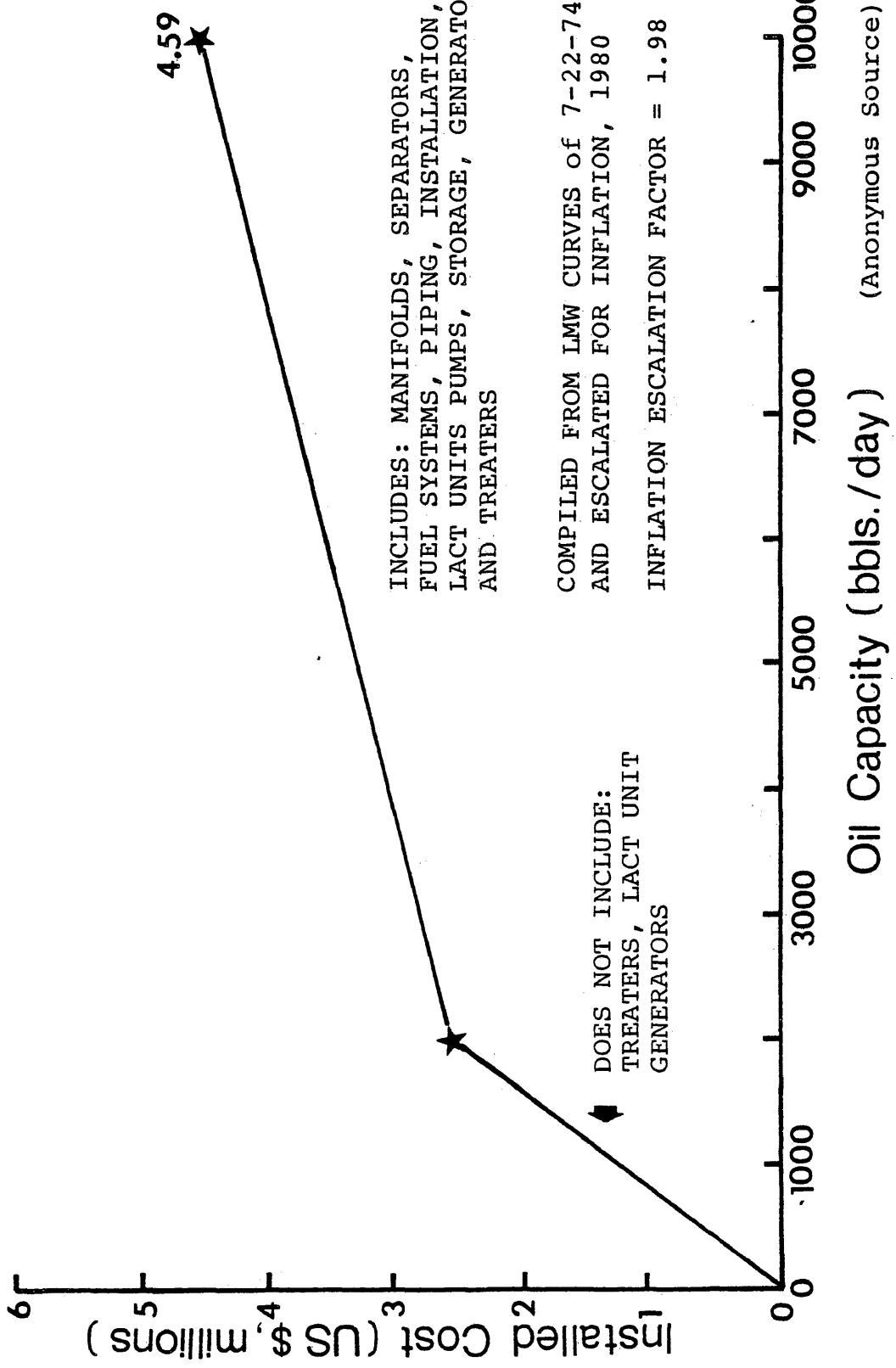
Total Platform Costs
Vs. Water Depth



Anonymous Source

FIGURE 8

Oil Production Equipment

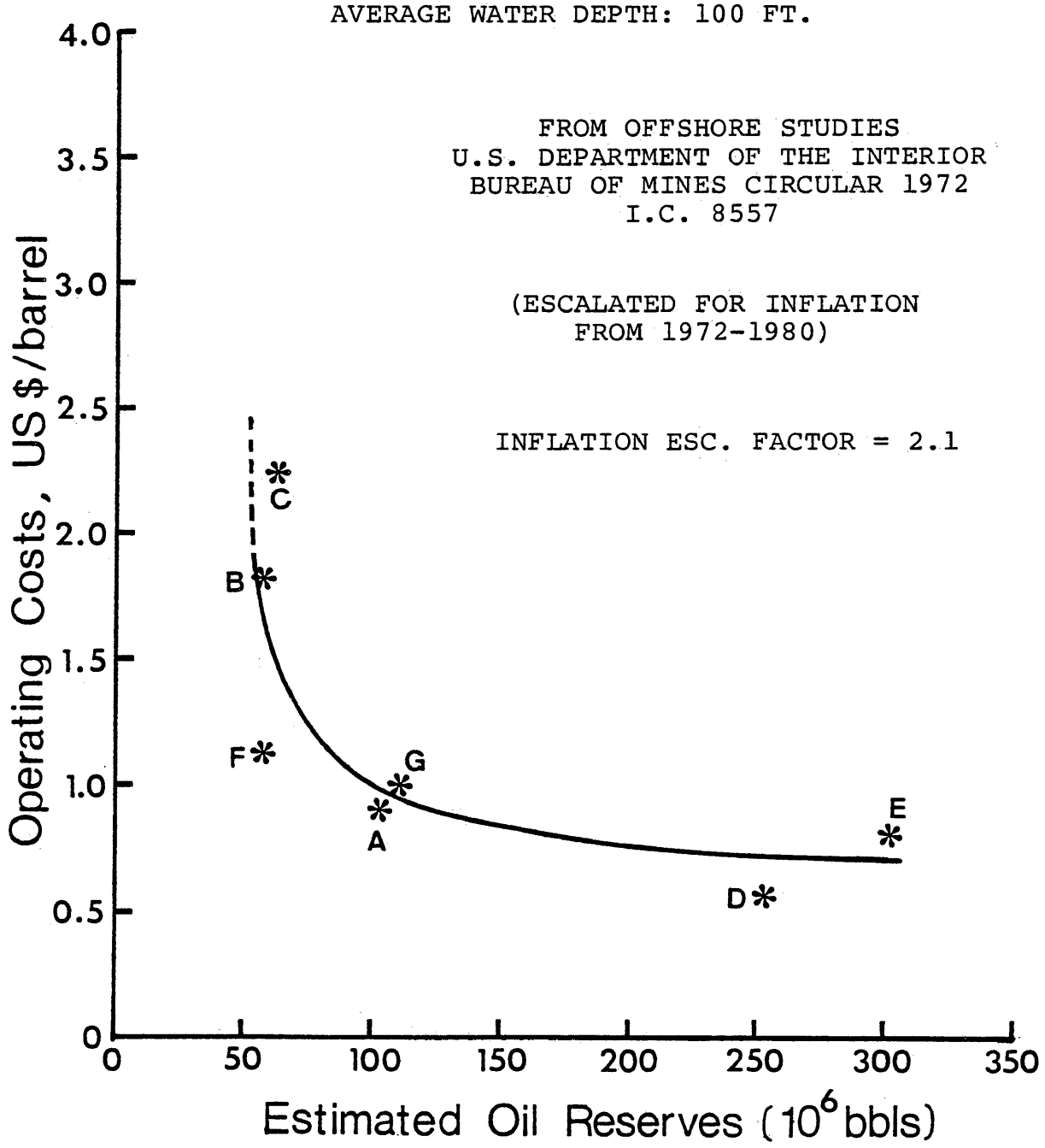


7. The overall investment must be calculated for each development design. As discussed previously, it comprises the drilling and completion costs for wells from platforms, installed platform costs (Figs. 6 and 7), and subsea completed well costs, if any. Production equipment including separators, manifolds, piping, pumps and others are important and must be included. Figure 8 presents an evaluation for this cost as a function of the oil rate.

8. During the producing life of an oilfield, there are operating expenses that occur daily in the production of oil. Due to intensive competitive bidding for offshore leases, costs and operational details are confidential and are not released to the public. Figure 9 presents data from Weaver (1972), Bureau of Mines Information Circular, IC-8557. These operational costs for producing petroleum represents many offshore fields, and the model studied by this publication considers development wells drilled directionally from platforms, with the oil and gas production being processed on the main platform and moved to shore via pipeline. The wells studied by this publication are in the depth range of 30 to 130 ft. Figure 9 shows that the operational costs per bbl of oil produced from an offshore

FIGURE 9

OPERATIONAL COSTS OF PRODUCING PETROLEUM
(REPRESENTS MANY OFFSHORE FIELDS)
AVERAGE WATER DEPTH: 100 FT.



oil field are dependent on the reserves. Reserves smaller than 50×10^6 bbl of oil have very high costs per unit of production (the curve is exponential at this point). Reserves greater than 50×10^6 bbl have lower costs, around or less than U.S. $1.00 per barrel.

According to Garland (1971), Bureau of Mines Information Circular IC-8561, "one of the facts that distinguishes the petroleum industry from most other types of industry is that in the petroleum industry annual production is destined to decline, thereby causing diminishing income and increasing cost per unit output."

In this report the operational cost for the first productive day of the field is calculated through Eq. 5. Knowing the cost/bbl of the oil and the initial daily production rate,

$$Ai = a \times Q_D \tag{5}$$

where

a = operational cost per barrel (U.S. $/bbl)

Q_D = production of the first day of the entire field (bbl)

9. The economic limit is that production rate at which the net revenue before income taxes is equal to the operational costs, according to Campbell (1965). The economic rate will be calculated based on the first day operational costs:

$$Q_{ECON} = \frac{A_i}{(1-R)(P)} \tag{6}$$

where

A_i = operational costs for the first productive day (U.S. $)

R = royalty (Fraction of the revenue)

P = price of the crude (U.S. $/bbl)

10. DECLINE PER DAY. The initial capacity of a well to produce may be established by formation evaluation production tests of the exploratory wells. The final production rate may be determined for the economic limit. Three quantities, the producible reserves, the initial production rate and the final production rate must be known to determine the characteristics of the decline. From Campbell (1965),

$$d = \frac{Q_D - Q_{ECON}}{RESERVES} \tag{7}$$

The above relation states that 'd', the percent decline in daily production divided by 100 is the reciprocal of the barrels of oil produced per barrel decline in daily production rate.

11. ANNUAL PERCENT DECLINE. The decline in production from one year to the next is given as a percent, and is customarily defined by the following relationship, from Campbell (1965),

$$\frac{q_2}{q_1} = \frac{q_{n+1}}{q_n} = r = \frac{1}{1+D} \qquad (8)$$

where 'q' is the production (bbl) for the particular year, 'r' is the ratio of successive yearly productions (less than unity), and 'D' is the percent annual decline divided by 100. According to Campbell (1965), the annual per cent decline may then be found by the relation

$$D = (1 + d)^{365} - 1 \qquad (9)$$

where d = fraction decline in daily production

12. PRODUCTION OF THE FIRST FULL YEAR

The rate of production at the beginning of the year is known (Q_D), and it is necessary to calculate the production of the first full year. According to Campbell (1965),

$$q_1 = Q_D \left(\frac{D}{d}\right) \left(\frac{1+d}{1+D}\right) \tag{10}$$

where q_1 = production of the first full year (bbl)

Q_D = production of the first day (bbl)

d = percent daily decline divided by 100

D = percent yearly decline divided by 100

13. TIME PRODUCING ON DECLINE

According to Campbell (1965),

$$T = \left(\frac{1}{365}\right) \left(\frac{\text{RESERVES}}{Q_D - Q_{ECON}}\right) \ln \frac{Q_D}{Q_{ECON}} \tag{11}$$

where 'T' is time on decline in years, ln = log to base e, 'Q_D' is the production of the first day and 'Q_{ECON}' is the production of the field at the economic limit.

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$$CNDP = \frac{q_1 (1-R) P \left[1-(XY)^T\right]}{(1-XY)} - \frac{365 A_i (1-Y^T)}{(1-Y)} \qquad (12)$$

$$DPIR = \frac{\dfrac{q_1(1-R) P \left[1-(XY)^T\right]}{(1-XY)} - \dfrac{365 A_i (1-Y^T)}{(1-Y)}}{INVESTMENT} \qquad (13)$$

14. RATIO OF SUCCESSIVE YEARLY PRODUCTIONS

$$\frac{q_2}{q_1} = \frac{q_{n+1}}{q_n} = r = \frac{1}{1+D} \qquad (8)$$

as defined by Campbell (1965) where 'r' is the ratio of successive yearly productions (less than unity), and D is the annual percent decline.

15. DISCOUNTED PROFIT:INVESTMENT RATIO (DPIR)

The discounted profit:investment ratio (DPIR) for each development scheme can be determined. According to Glass (1975), the cumulative discounted net profit or present worth is given by

$$CNDP = \frac{q_1[(1-R)P(1-XY^T)]}{(1-XY)} - \frac{[A_i \times 365(1-Y^T)]}{(1-Y)} \qquad (12)$$

where CNDP = cumulative discounted net profit

q_1 = production of the first full year (bbl)

R = royalty (fraction of gross revenue)

P = oil price

D = annual decline fraction

$X = \frac{1}{1+D} = r$

i = interest rate (fraction)

$Y = \frac{1}{1+i}$

T = time producing on the decline (years)

A_i = operational costs (first day of production)

*Obs: The operational costs are being considered as a separate term in the equation, and this allows the use of another type of operational costs, if these costs are not given as cost/barrel.

Therefore, considering the net present value of the profit and of the investment for each development design studied, the discounted profit-to-investment ratio (DPIR) can now be determined through Eq. 13. This equation is determined by dividing Eq. 12 by the investment net present value:

$$DPIR = \frac{\frac{q_1[(1-R)P(1-\overline{XY}^{T})]}{(1-XY)} - \frac{A_i \times 365(1-Y)^{T}}{(1-Y)}}{INVESTMENT} \qquad (13)$$

16. PLOTS OF DISCOUNTED PROFIT TO INVESTMENT RATIO (DPIR) vs. DRAINAGE AREA can thus be constructed as shown by Figure 10. The designs or development schemes can be separated into groups, depending on the number of platforms needed. Each group (1 platform, 2 platforms, etc.) clearly presents the spacing (drainage area) which maximizes the discounted profit-to-investment ratio (DPIR). In the abscissa are plotted the several spacings accord-

ing to the development schemes investigated. Each one presents a different DPIR, and the value which maximizes the DPIR is considered as the optimal spacing which will bring the most attractive discounted profit-to-investment ratio. As shown by Figure 10, each curve comprises a group of designs that involves the same number of platforms.

17. CUMULATIVE DISCOUNTED PROFIT vs. DRAINAGE AREA

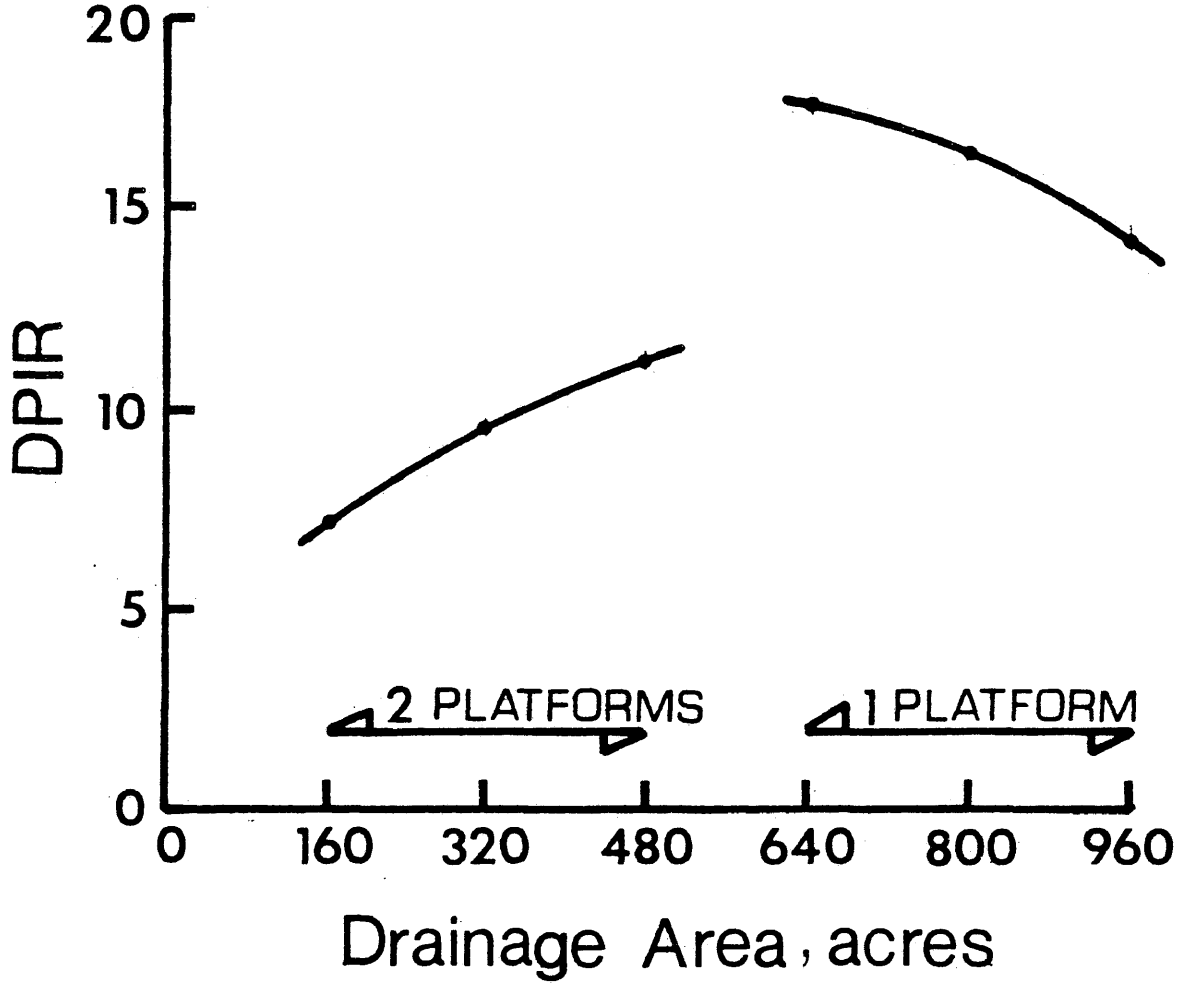
The operator may not necessarily pick the maximum value of the DPIR to develop the field. If the DPIR of a design which involves a higher density of wells is close to that maximum value or attractive enough, one may choose to develop the field according to this higher well density. The reason is that higher density of wells means a larger investment. When different development plans have a DPIR close to the maximum DPIR, or equal to, the more expensive of these development plans has the higher discounted profit. Figure 11 shows the cumulative discounted profit increasing for designs with higher density of wells.

18. DISCOUNTED NET REVENUE-TO-INVESTMENT RATIO (DNRIR)

When the operational costs cannot be evaluated, or the uncertainty about the estimate is too high, the discounted net revenue-to-investment ratio can be calcu-

FIGURE 10

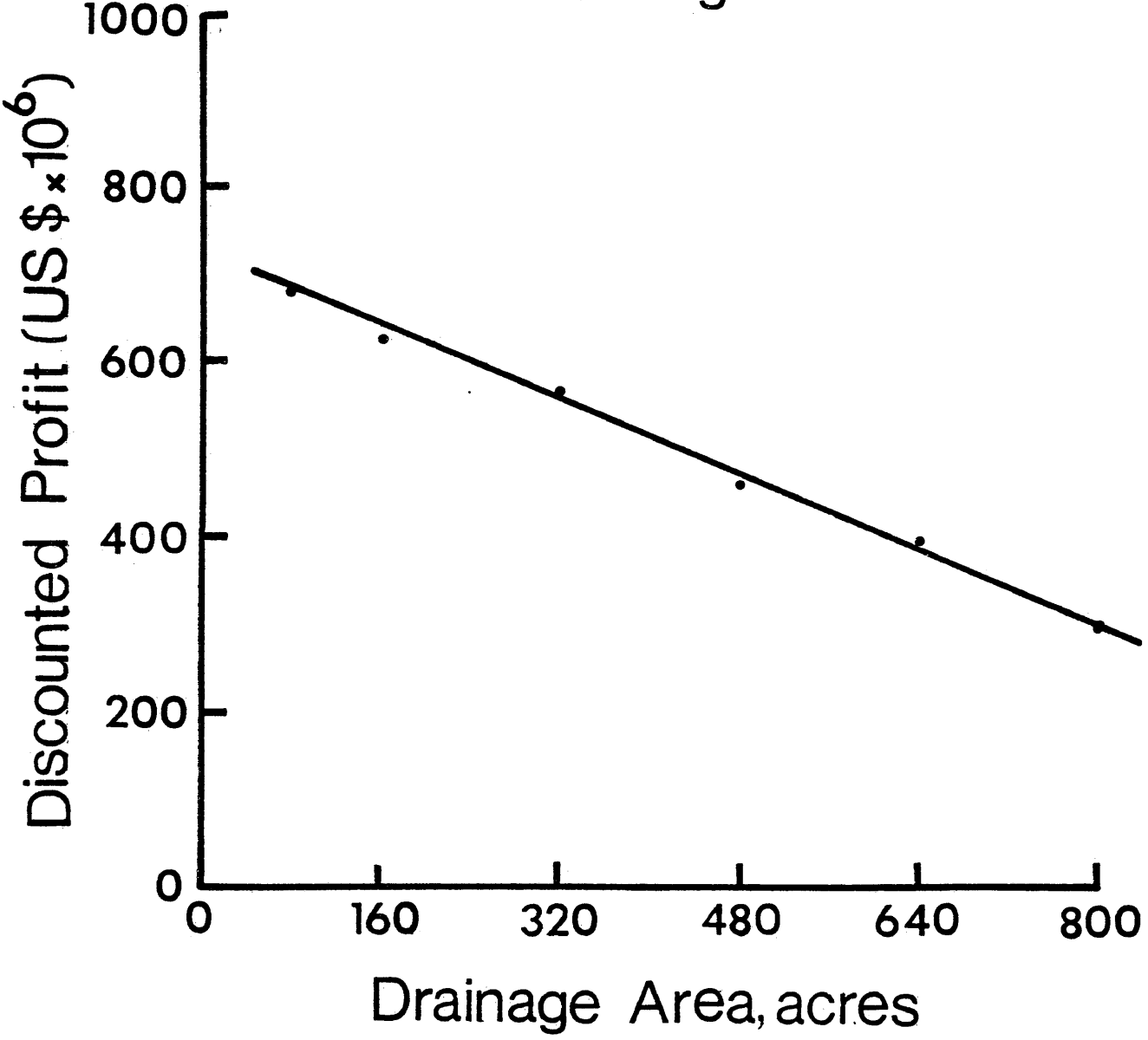
Drainage Area Vs. DPIR



The value of the drainage area which maximizes the discounted profit-to-investment ratio (DPIR) is the optimal value determined by the method presented in this report.

FIGURE 11

Cum. Discounted Profit Vs. Drainage Area



The cumulative discounted profit increases with the increasing density of wells.

lated using Eq. 14, with operational costs equal to zero. The plot of DNRIR vs. drainage area shows the same trend as the plot DPIR vs. drainage area, and the design which optimizes DNRIR is the same one that optimizes DPIR. Some small differences between both show the effect operational costs have on the evaluation. The advantage of using DPIR and not DNRIR is that DPIR includes the offshore operational costs, usually very high: this allows one to have a more realistic idea about the discounted profit and is a more complete evaluation. The important point is that, even if the operational costs are not available for any reason, the method can still be used to study the optimal drainage area for the offshore field development through the DNRIR.

19. INVESTMENT vs. DRAINAGE AREA

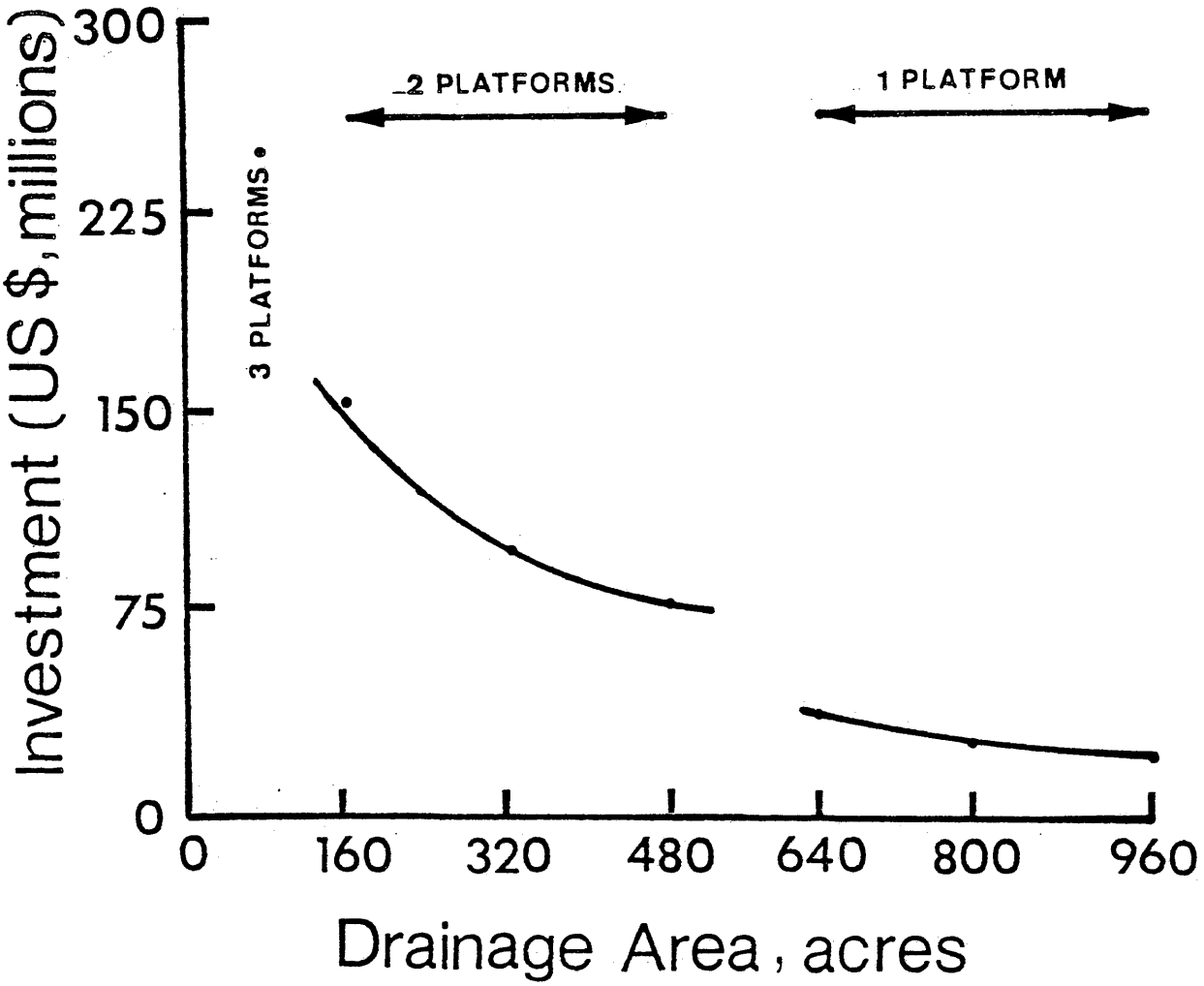
Figure 12 shows the exponential increase of investments as spacing area decreases. The designs are grouped according to the number of platforms required.

20. SENSITIVITY ANALYSIS

The pay zone thickness is not a certainty, but a probability. The accuracy of this expected value depends on the number of exploratory wells drilled, geological and geophysical data, and mainly, the homogeneity and

FIGURE 12

Investment Vs. Drainage Area



Exponential increasing of investments as spacing decreases. Wells are separated in groups, according to the number of platforms they need.

continuity of the pay zone. The author suggests that a sensitivity analysis be made considering the most probable pay zone thickness and porosity and using the minimum and the maximum expected values for these two parameters. This most probable, minimum and maximum expected values are established based on exploratory wells data. This sensitivity analysis can give the range of variation for the DPIR, depending on the reserves found to be larger or smaller than the most probable reserves, for each one of the development plans under study.

ASSUMPTIONS

(1) BEGINNING OF THE FIELD PRODUCTION

The method presented in this report assumes that all the wells will start producing at the same time, after finishing the work on drilling, well completion, platforms and production facilities installation.

(2) NET PRESENT VALUE

The method assumes that the investment is made at the end of the year which precedes the first producing year. If this is not true, the correction must be made in such a way to determine the net present value of the investment.

(3) PRODUCTION DECLINE

The exponential decline is assumed as being representative for the reservoirs in this study. Therefore, the change in the production per unit time is assumed to be a constant percentage of the production rate. Campbell (1965) is the main reference consulted as to the production decline study.

(4) PRIMARY OIL RECOVERY

Since this study is related to the primary oil production, just the ultimate primary oil recovery is computed as recoverable oil for the several alternative designs.

(5) INCREASING COST PER UNIT OUTPUT

In the petroleum industry annual production is destined to decline, thereby causing diminishing income and increasing cost per unit output, Garland (1972). To face this fact, the operational costs per day were considered constant from the first until the last day of production, and equal to the operational costs of the first day of the decline. Thus, as the production declines, the operational costs per unit output will increase until they reach the economic limit.

GENERAL DISCUSSION

1. ECONOMIC FEASIBILITY

The method presented in this report doesn't provide a means to judge the feasibility of any of the alternatives studied. The method determines the drainage area which will maximize the discounted profit-to-investment ratio (DPIR). After the drainage area has been established and the number of wells, platforms and subsea completions are known, a careful economic analysis has to be made concerning the treatment of this oil onshore, pipelines or shipment and storage of the oil, as well as taxes which have to be paid to the government, and so on.

In other words, the method chooses the best economic design for the new oilfield; the best option among several designs from the economic standpoint, but it doesn't analyze the physical feasibility. Items like political stability, earthquakes, agressive environments and policy of government taxation must be studied carefully and deeply by experts. Projects that in normal circumstances would be economically feasible, sometimes can be considered marginal, depending on other circumstances.

2. VARIABLE GRID

The method presented here can also evaluate offshore oilfields with variable grids, i.e., higher density of wells in the zones where the volume of recoverable oil is larger. Even designs without regular spacing can be evaluated according to this process.

3. CONVENTIONAL PLATFORMS AND SUBSEA COMPLETION SYSTEMS

Because of the greater efficiency and more definitive features, conventional platforms are usually recommended as the solution for the development of offshore fields. Subsea completion systems are considered good solutions for the development of marginal fields, extremely deep water, early production designs or as "satellite" wells associated with conventional platform systems.

4. RELIABILITY OF FORECASTS

As the number of exploratory wells in a field increases, the degree of confidence in the data also increases. The reliability of the forecasts related to the wells to be drilled, number of platforms and production facilities to be installed is proportional to the number of exploratory wells drilled.

APPLICATION WITH A MODEL

STATEMENT OF THE PROBLEM

Company "A" is exploring the "Y" Offshore Oil Field. Five exploratory wells were drilled in this field, four of them showing commercial production and one non commercial. The exploration-production staff, based on seismic coverage and on the data available from the wells drilled (geological and geophysical data, plus DST and Formation Evluation Tests) established the probable zero contour for the field (Fig. 13). Table 1 presents the "Y" Offshore Oilfield data.

*OBS: Comments about Table 1:

(a) Case I corresponds to the most probable pay thickness and porosity expected values. Case II considers the minimum expected value for the pay thickness and porosity values, and Case III considers the maximum expected value for both parameters. The production rates are made proportional to ϕh.

Thus:

CASE I : 'ϕ' and 'h' most probable values

CASE II : 'ϕ' and 'h' minimum expected values

CASE III: 'ϕ' and 'h' maximum expected values

TABLE 1 'Y' OFFSHORE OIL FIELD DATA

PARAMETER	UNIT	CASE I	CASE II	CASE III
ϕ	%	20	18	22
h	ft	60	50	70
Sw	%	23	25	21
Bo	bbl/STB	1.35	1.35	1.35
Q	bpd	3000	2,300	3,800
RF	%	20	20	20
K	mD	136	73	249
GAS/OIL RATIO	SCF/bbl	150	150	150
OIL GRAVITY	^{o}API	38	38	38
VISCOSITY	cp	12	12	12
WATER DEPTH	ft	225	225	225
AVERAGE FORMATION DEPTH	ft	7,750	7,750	7,750
OIL PRICE	US$/bbl	25	25	25
ROYALTY	FRACTION	1/6	1/6	1/6
DISCOUNT RATE	%	12	12	12
OPERA-TIONAL COSTS	US$/bbl	4.5	5	4

(b) According to Hilchie (1978) the permeability can be calculated using the equation

$$k_j = \frac{0.136 \times \phi_j^{4.4}}{Sw_j^2} \qquad (14)$$

where

k_j = permeability of the jth layer (md)

ϕ_j = porosity of the jth layer (fraction)

Sw_j = water saturation of the jth layer (fraction)

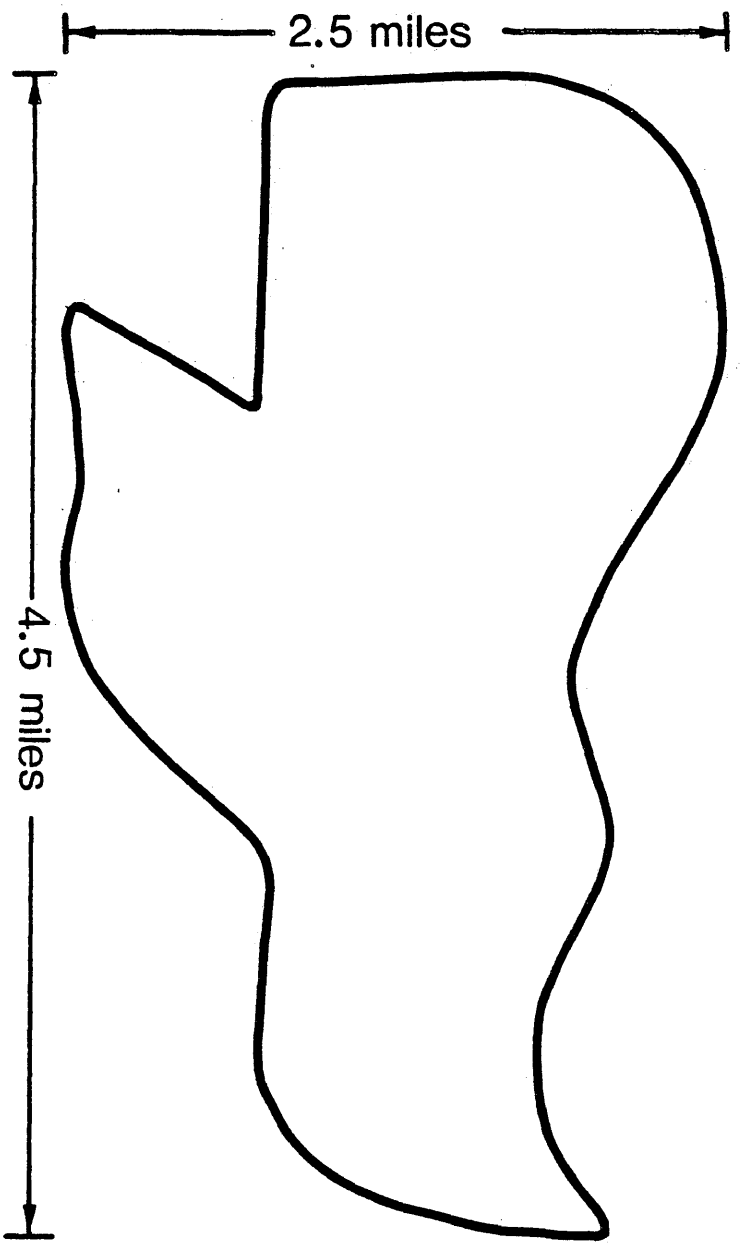
TABLE 2. DEVELOPMENT WELLS COST

(a) DRILLED FROM CONVENTIONAL PLATFORMS	
deviated well	U.S. $1,000,000.
(or more, depending on the deviation angle)	
vertical well	U.S. $ 800,000.
(b) SUBSEA COMPLETED WELLS	
wet tree	U.S. $4,000,000.

APPLICATION

1. The Iso-volume map shown in Figure 13 assumes that the pay zone thickness and porosity are uniform and homogeneous for the three cases.

FIGURE 13
Isovolume Map



2. Average values for the reservoir parameters (h, ϕ, Sw) are given in Table 1.
3. Drainage areas chosen to be studied are 80, 160, 320, 480, 640, 800, 960, and 1120 acres.
4. Spacing Grids are drawn on transparent overlays - Figures 14 to 21 - according to the guidelines given in the section 'Theory - Discussion of the Method'.
5. The wells have to drain the reservoir as completely as possible. This step defines the number of wells to be drilled according to each development plan. Figures 14 to 21 which will be commented on step #7, show the best fit for each spacing grid according to each development plan.
6. To locate the drilling-production conventional platforms the departure has to be studied according to a maximum angle. Using a maximum angle of 45^{o}, the formation depth being 7,550 feet, the kick-off point can be established at 700 feet, and the departure will be 7,000 feet. The calculations are shown at the bottom of Figure 22, that presents the sketch of the directional drilling from the conventional platforms for this offshore oil field.
7. Analyzing the development plans

   DESIGN #1: The drainage area per well is 80 acres as

shown by Figure 14. Three platforms were required to develop the oil field: Platforms #1 and #2 are to drill sixteen wells each and #3 fifteen wells, for a total of 47 wells. The production facilities will be installed on the three platforms. This plan involves a high density of wells, and therefore, a very high initial investment. These high investments are only justifiable when the reserves are large.

DESIGN #2: The drainage area per well is 160 acres (Fig. 15). Two platforms are planned, #1 with twelve wells and #2 with ten wells. The well density is still high, with a total of 22 wells being drilled. The production facilities are to be installed on platform #1.

DESIGN #3: The drainage area per well is 320 acres, (Fig. 16). Two platforms are required, both having six wells each. A total of 12 wells will be drilled according to this plan. Platform #1 will handle the oil production, with the production facilities being installed on it.

DESIGN #4: With a drainage area per well of 480 acres, this development plan presents also two platforms, but a much smaller number of wells than the previous alternatives. Platform #1 will drill five wells and platform #2 just two wells. The production facilities will be

FIGURE 14
Development Plan No. 1
80 Acres/Well

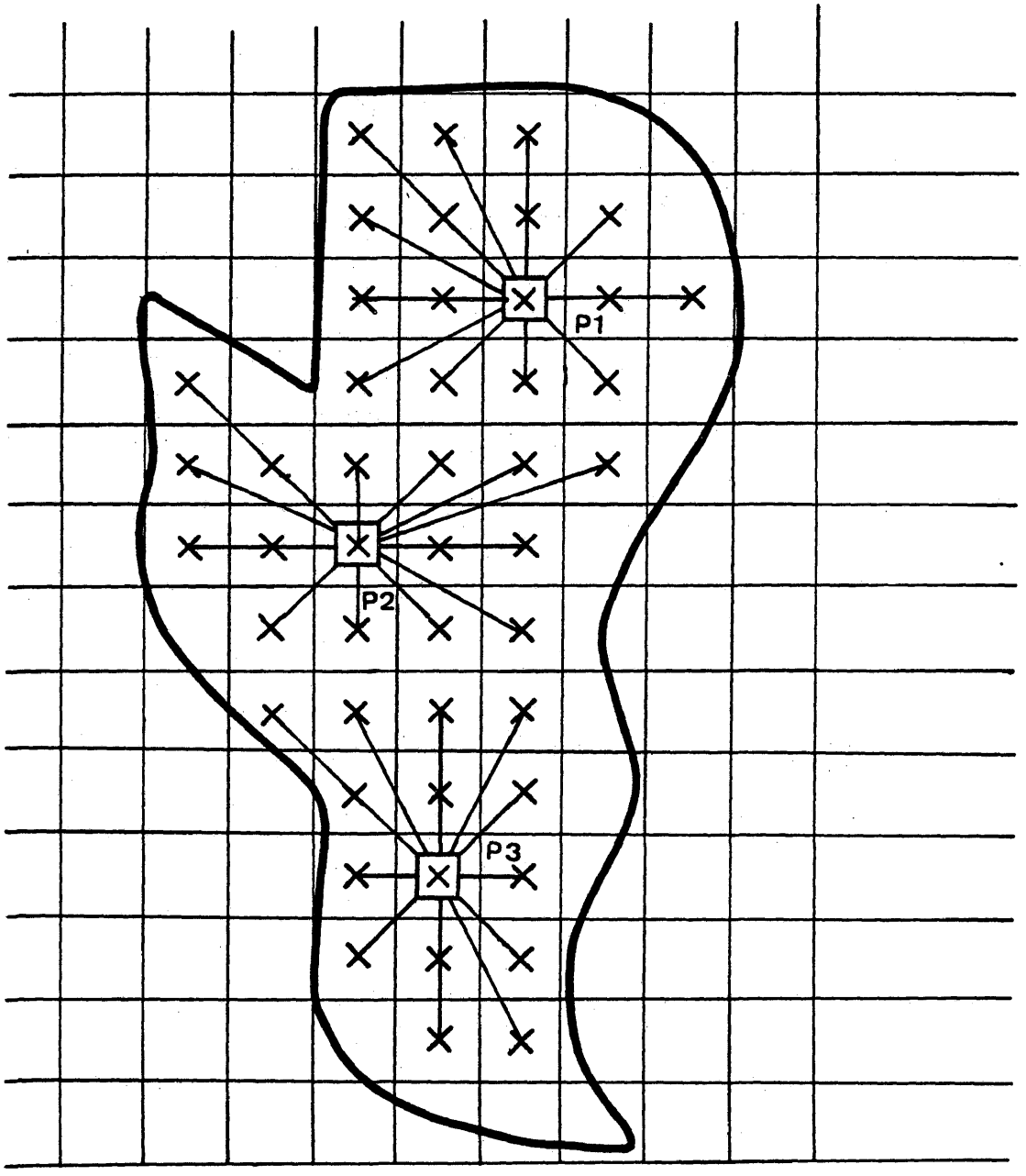


FIGURE 15
Development Plan No. 2
160 Acres/Well

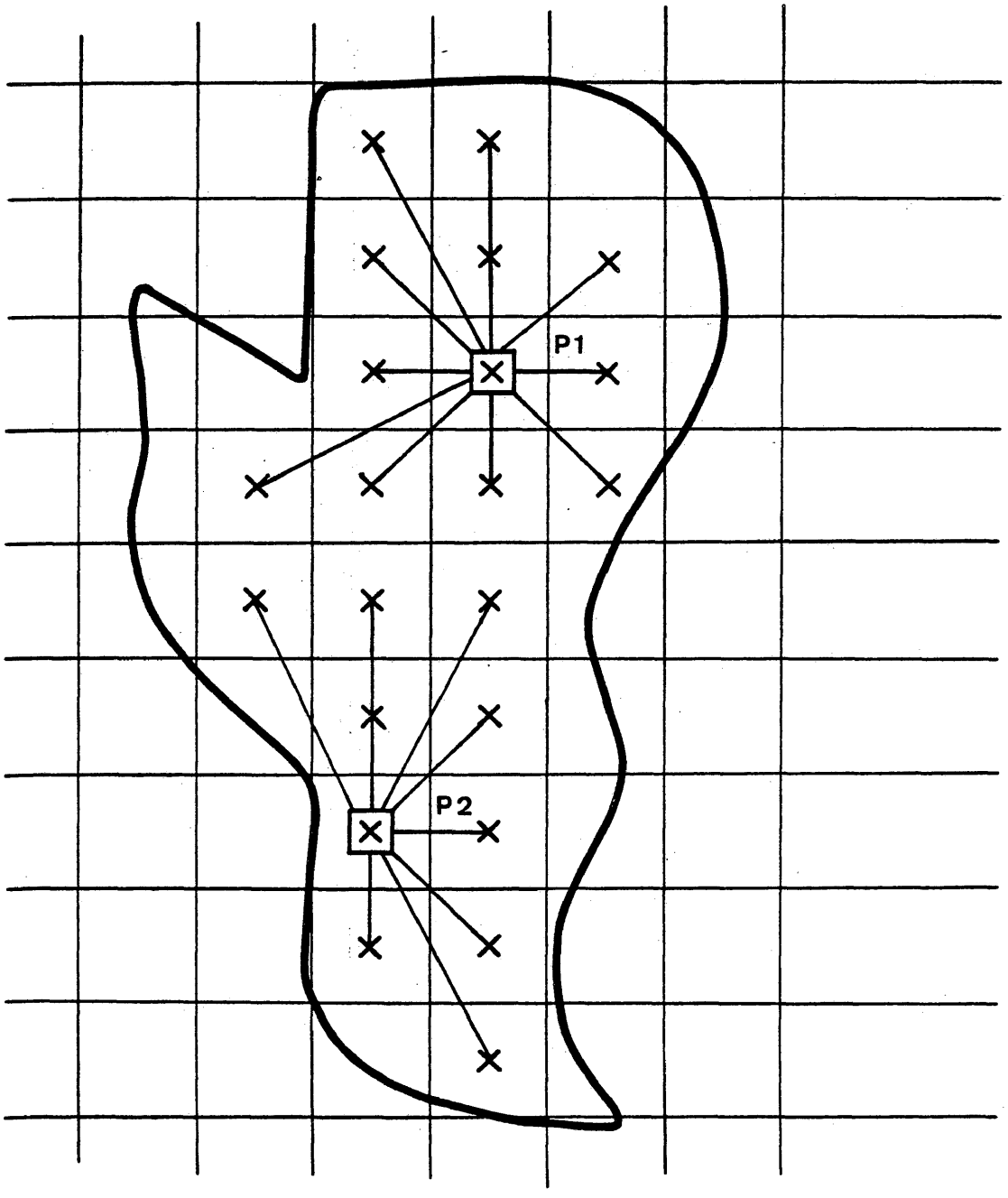


FIGURE 16
Development Plan No. 3
320 Acres/Well

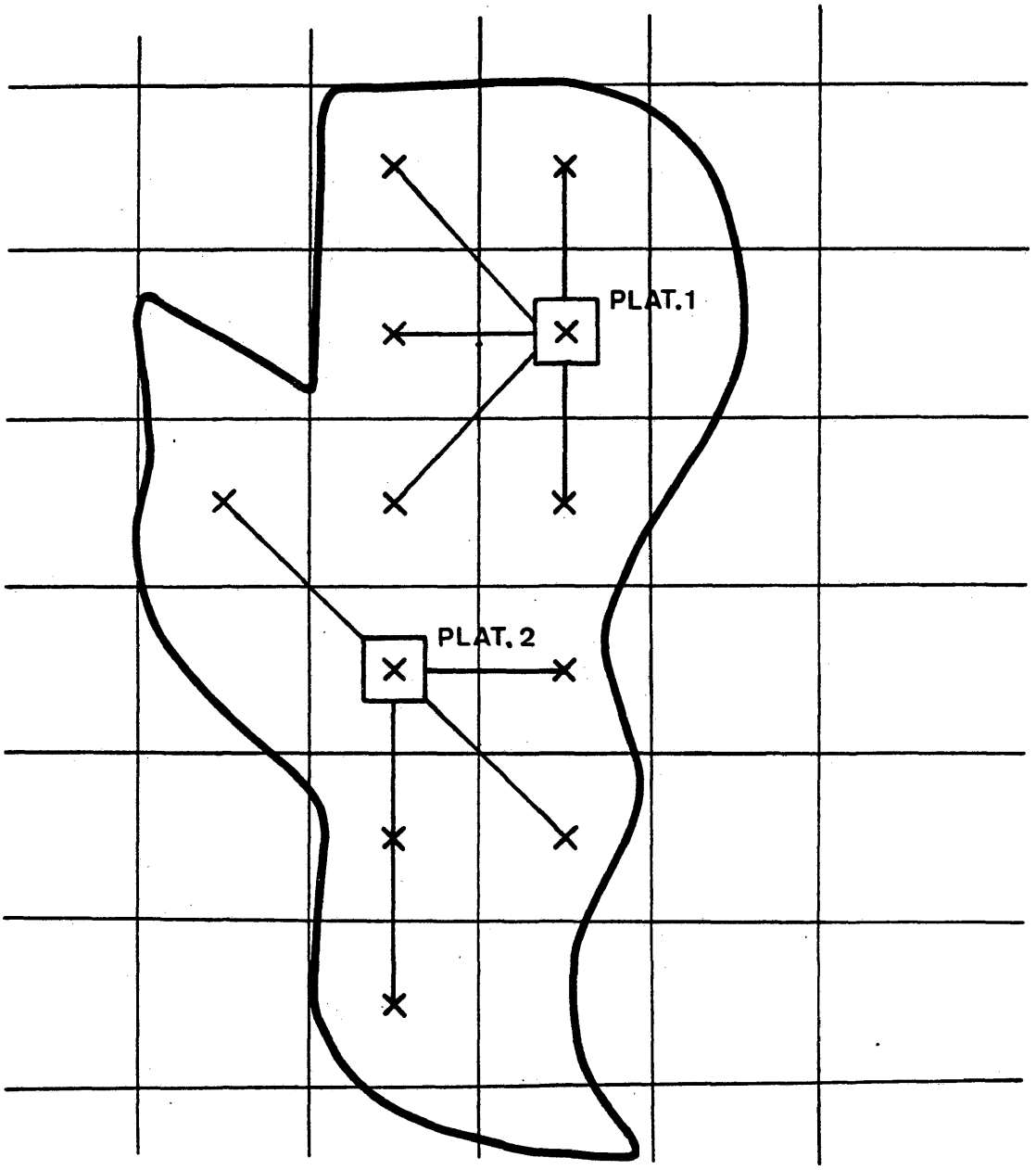
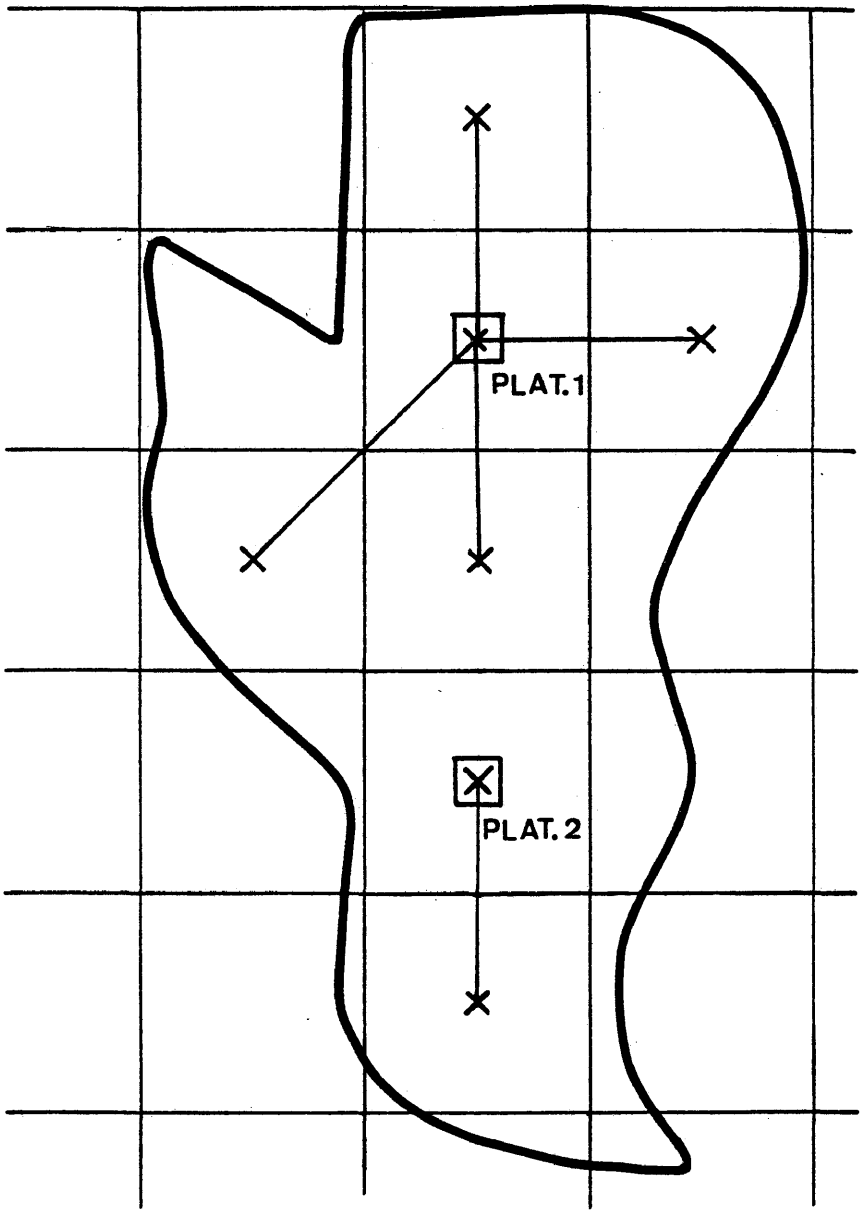


FIGURE 17
Development Plan No. 4
480 Acres/Well



installed on platform #1 (Fig. 17).

DESIGN #5: This development plan assumes a spacing of 640 acres/well, as shown on Figure 18. One platform will be required with four wells being drilled. The fifth well could not be reached from the platform since the departure for this well would be longer than the maximum departure assumed (7,000 feet, that corresponds to a 45^{o} deviation angle). The solution is to use one subsea completed satellite well. The production facilities for all wells will be installed on the platform.

DESIGN #6: The spacing for this development plan is 800 acres/well. As in the previous design just one platform will be required for the field. Three wells will be drilled. There is a satellite well (subsea completion), and the entire production will be handled by the production facilities on the platform. This development plan is shown by Figure 19.

DESIGNS #7 and #8: The spacing for both development plans are 960 and 1120 acres respectively. Both alternative designs involve the drilling of three producing wells from one platform, as shown by Figures 20 and 21.

8. Investments. After determining the number of wells, platforms and subsea completions, the investment

FIGURE 18
Development Plan No. 5
640 Acres/Well

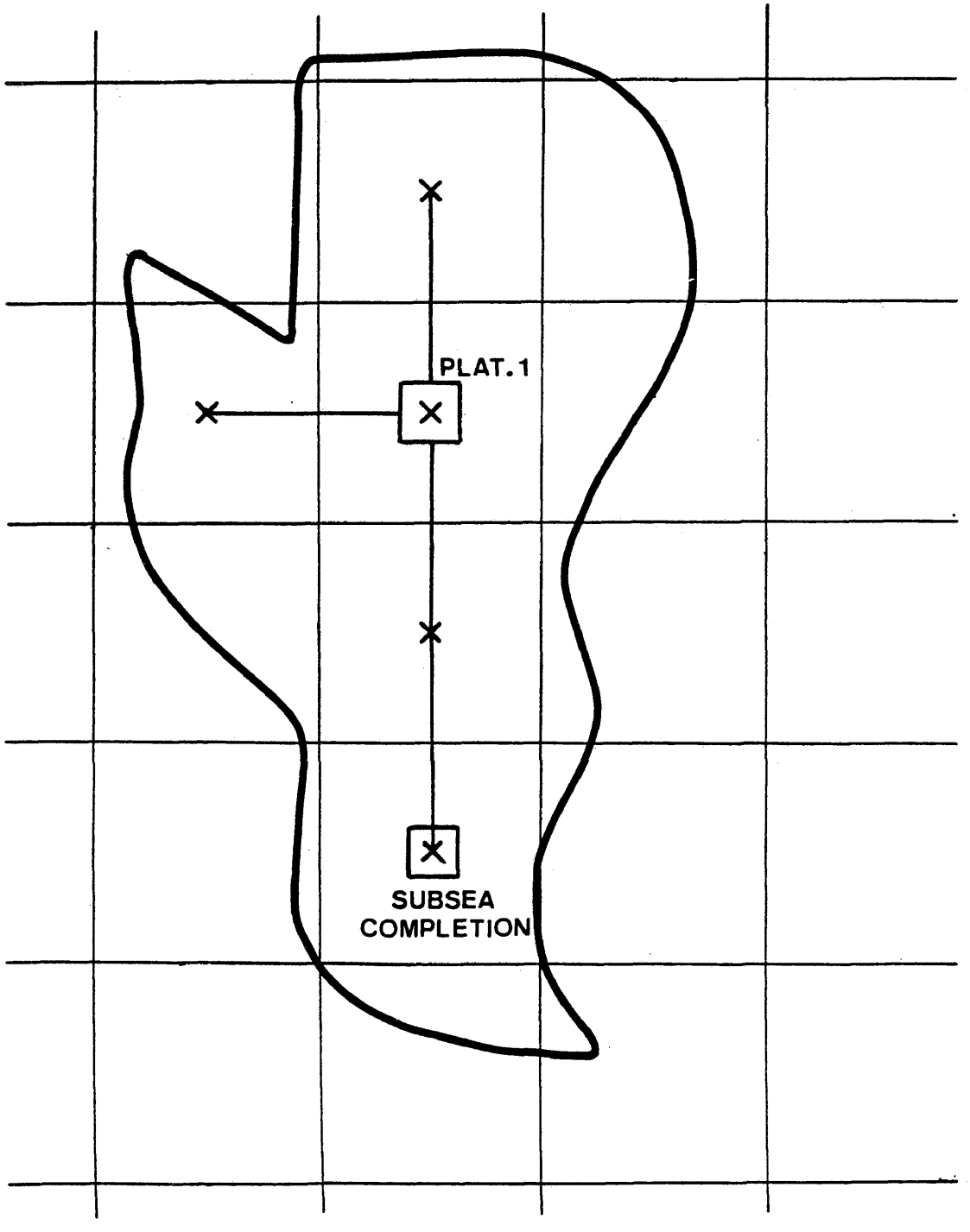


FIGURE 19
Development Plan No. 6
800 Acres/Well

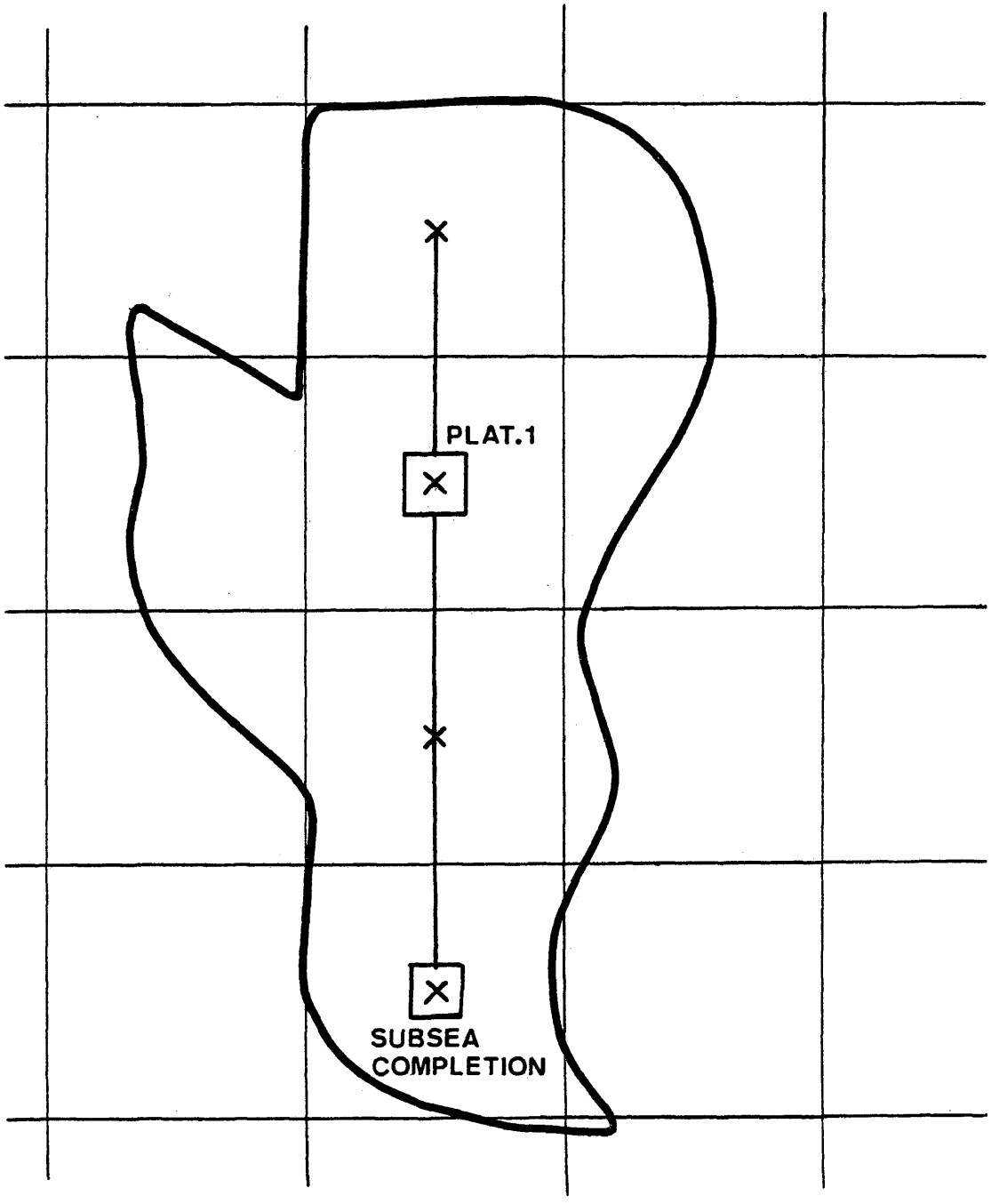


FIGURE 20
Development Plan No. 7
960 Acres / Well

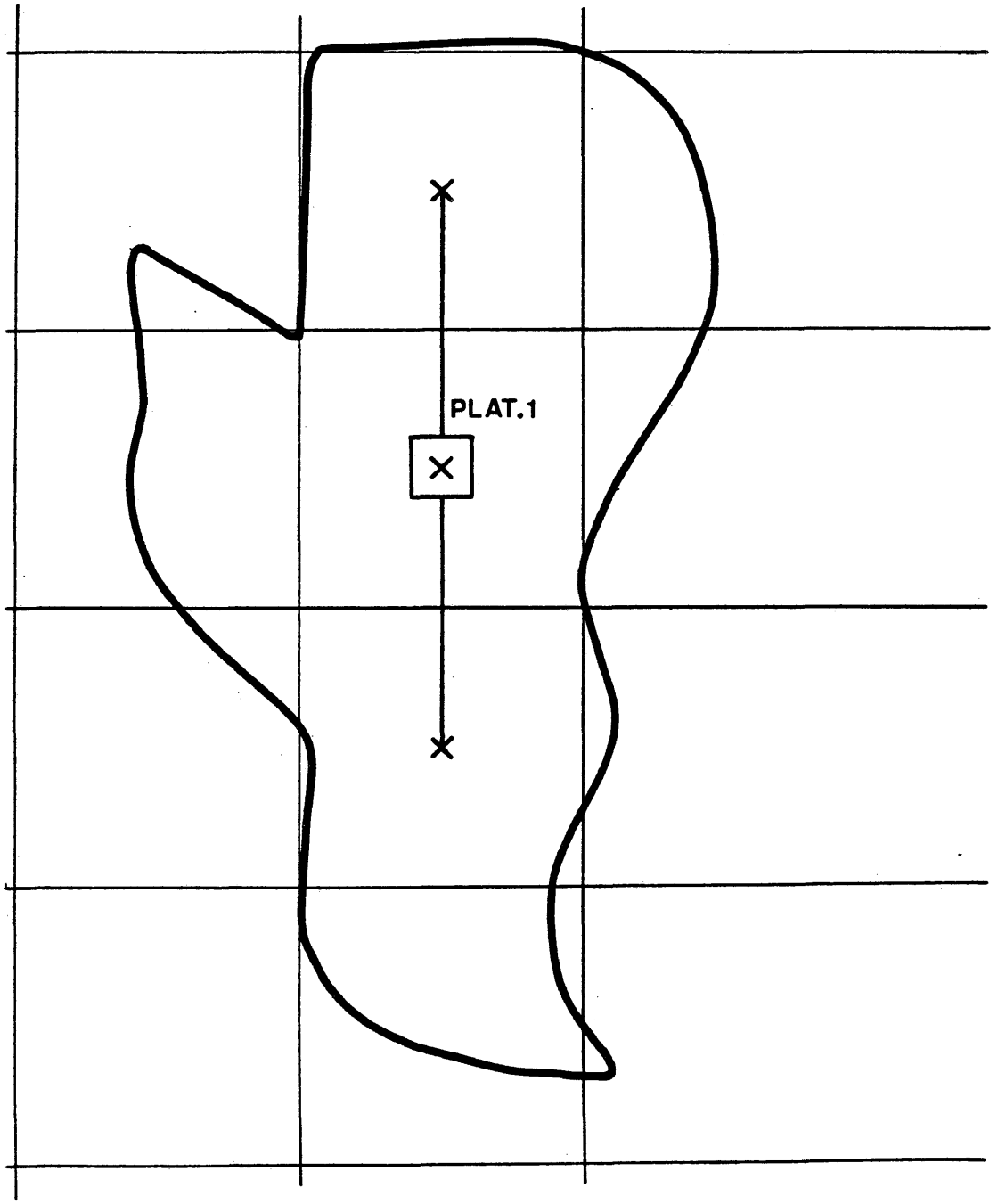


FIGURE 21
Development Plan No. 8
1120 Acres/Well

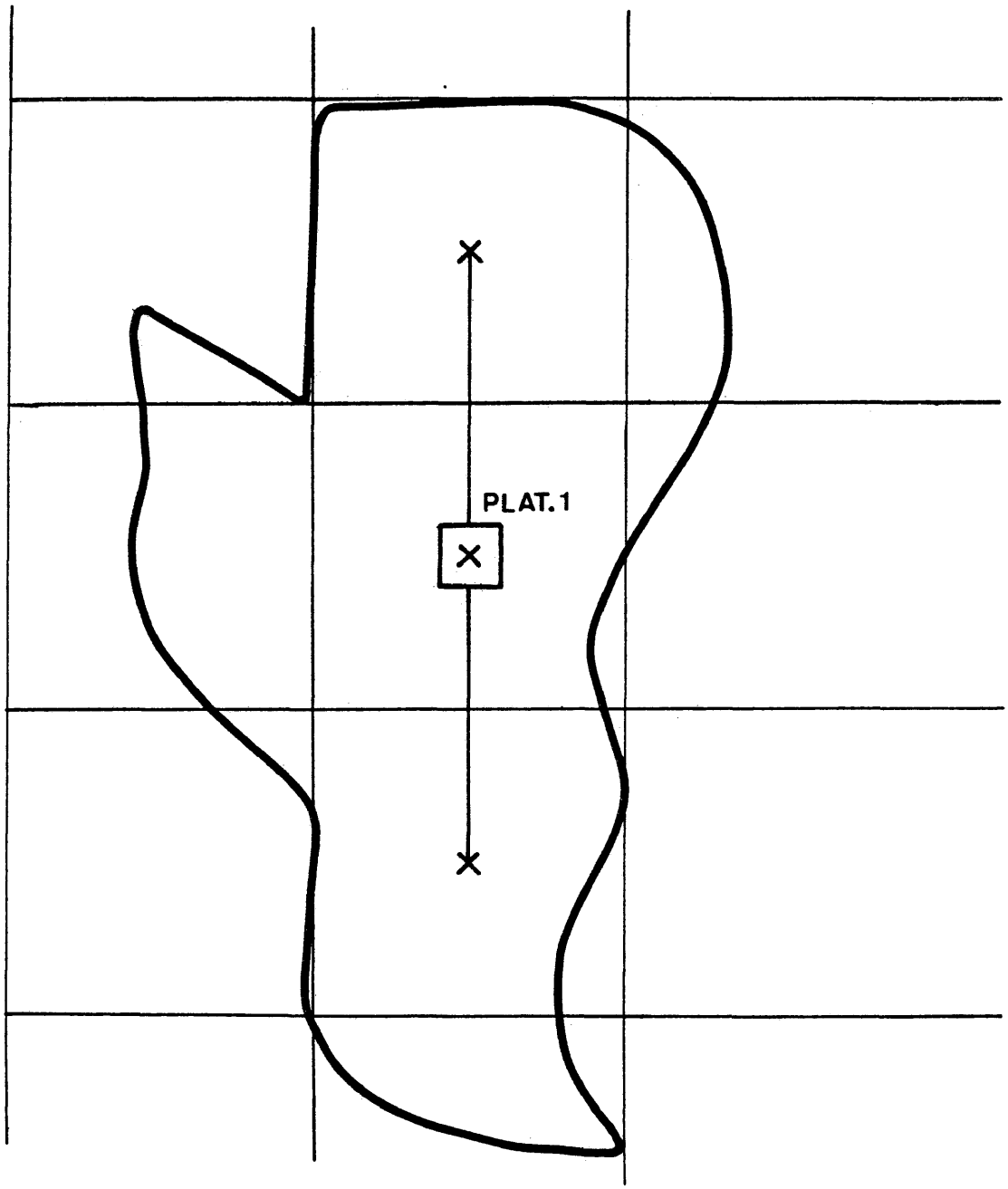
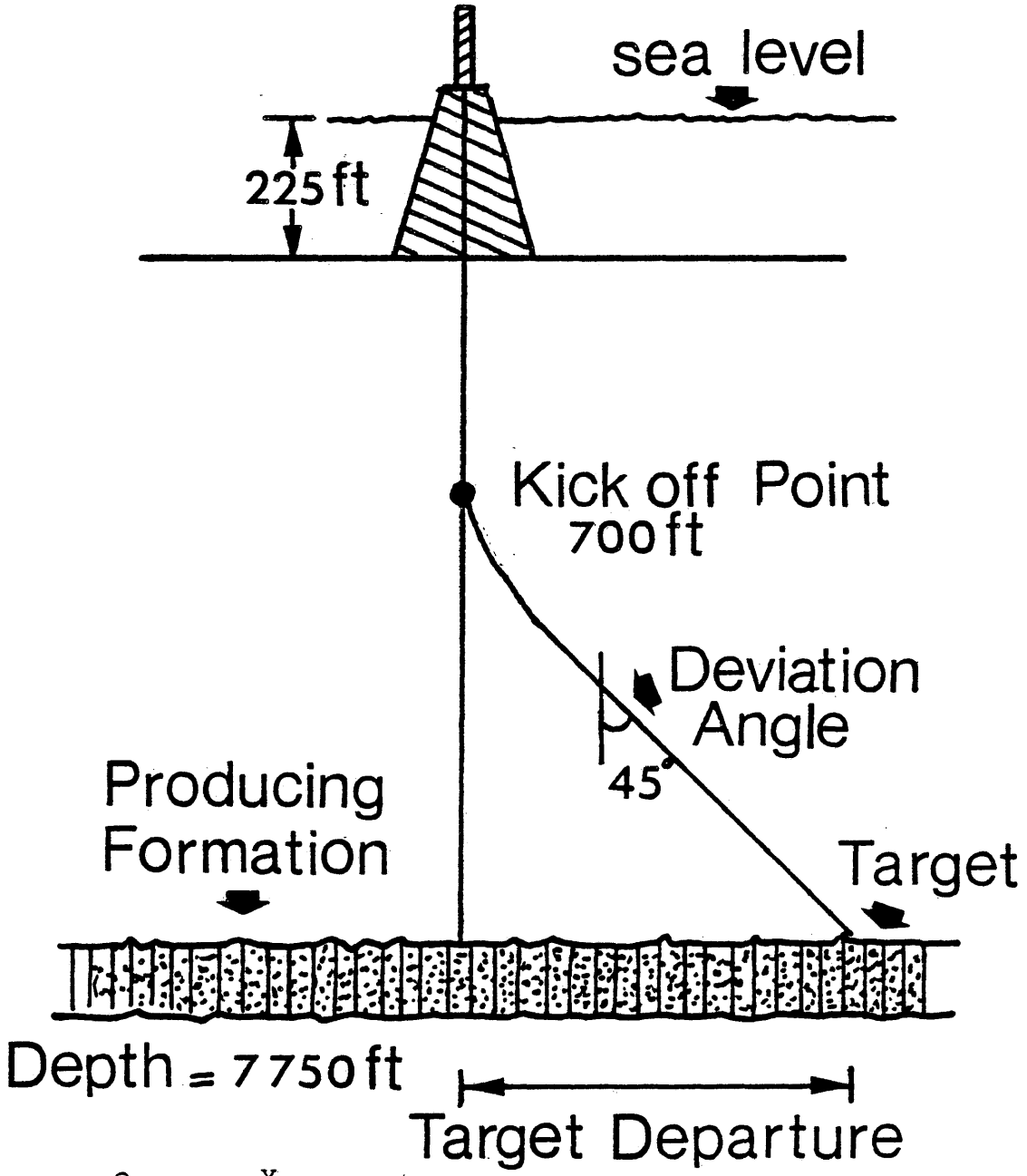


FIGURE 22

Well Deviation Diagram



$$tg\ 45^{\circ} = \frac{X}{7750-700} = d \qquad X \cong 7{,}000\ Ft.$$

Maximum Departure = 7,000 Ft.

necessary to develop the offshore oil field according to each one of the alternative plans can be calculated. The production equipment costs can be determined from Figure 8, as a function of the oil rate. The conventional platform costs can be estimated through Figures 6 and 7 as a function of water depth and size of the platform. The development well cost used for calculations are presented in Table 2.

Table 3 (page 68) presents the number of platforms to be installed, the number of wells to be drilled from each platform, and subsea well completions if any for all designs under study. The total platform costs are shown in Table 4 for each design. Table 5 presents the total drilling and completion costs: as the well spacing increases, the deviation angle increases and the cost per well is higher. Table 6 shows the Oil Production Equipment Costs for all the alternative designs, Cases I, II, and III. Oil production equipment costs are determined through Figure 8, as a function of the oil rate per day. The total investment for each design is presented by Tables 7a, 7b, and 7c.

9. Reserves determination for primary recovery are determined by using Equation 4.

$$\text{Reserves} = 7758 \frac{[\phi \times h \times (1 - Sw)]}{B_o} \times A_{TOTAL} \times RF$$

where

ϕ = porosity (fraction)

h = pay thickness (ft)

Sw = water saturation (fraction)

A_{TOTAL} = Total Reservoir Area (acres)

RF = recovery factor (fraction)

Using the data given by Table 1, the recoverable reserves for the three sets of parameters (Cases I, II, and III) are determined in order to make the sensitivity analysis:

CASE	RESERVES (bbl)
I	46, 727, 296
II	34, 135, 200
III	61, 524, 273

10. Production Decline. The production decline is studied for the three cases (I, II, and III) as shown in Tables 8a, 8b and 8c. The production rate for the first day is estimated for Case I, based on formation evaluation tests ($Q_{CASE\ I}$ = 3,000 bpd). To find the oil rate for Cases II and III, it is assumed that this expected oil rate for Case I has to be multiplied by a proportionality factor. It is assumed that the average oil rate is proportional to ϕ x h.

Thus,

$$\frac{3,000}{\phi_1 h_1} = \frac{Q_{CASE\ II}}{\phi_2 h_2} = \frac{Q_{CASE\ III}}{\phi_3 h_3}$$

And,

$$Q_{CASE\ II} = Q_{CASE\ I} \frac{^2h_2}{\phi_1 h_1} = \frac{0.18 \times 50 \times 3000}{0.20 \times 60} = 2300 \text{ bpd}$$

$$Q_{CASE\ III} = Q_{CASE\ I} \frac{^3h_3}{\phi_1 h_1} = \frac{0.22 \times 70 \times 3000}{0.20 \times 60} = 3800 \text{ bpd}$$

The economic limit (economic rate) corresponds to the oil rate where profit before taxes is equal to the operational costs, and it has to be calculated for the three cases.

$$Q_{ECON} \times (1-R)P = \text{FIRST DAY OPERATIONAL COSTS}$$

$$Q_{ECON} = \frac{\text{FIRST DAY OPERATIONAL COSTS}}{(1-R)P}$$

where

R = royalty (fraction of gross revenue)

P = oil price

The percent decline per day (d) is determined according to Equation 7, for each one of the cases, and for all alternatives. The percent decline per year (D) is determined through Equation 9. The successive yearly production ratio (r) is determined as a function of the percent decline per year (Equation 8). Equation 10 calculated the first full year's production (q_1). The production life (T) is calculated through Equation 11.

11. Discounted profit-to-investment ratio (DPIR). Finally, the DPIR can be determined for each one of the eight designs and the three cases studied. These several values of DPIR are calculated through Equation 13 and are shown in Tables 8a, 8b and 8c. These values of DPIR are then plotted, DPIR vs. DRAINAGE AREA (Fig. 23, page 62). In these sensitivity analysis it becomes clear that two designs are maximizing, and thus, optimizing the discounted profit-to-investment ratio for this offshore field development. This plot DPIR vs. DRAINAGE AREA (Fig. 23) will be interpreted in the next section, 'DISCUSSION OF THE ALTERNATIVE PLANS'.

12. Discounted Profit vs. Drainage Area. The discounted profit is the investment multiplied by the DPIR. The plot 'Discounted Profit vs. Drainage Area' is shown in Figure 25. The plot shows that the discounted profit increases with the increasing density of wells in the field. Tables 9a, 9b and 9c present the discounted profit determination.

13. Discounted Net Revenue to Investment Ratio. Using the same Equation 13, with operational costs equal to zero, one determines the Discounted Net Revenue to Investment Ratio, DNRIR, as shown by Table 10. The plot (Fig. 26) DNRIR vs DRAINAGE AREA follows the same trend shown in the previous plot of DPIR (Fig. 23).

FIGURE 23
DPIR Vs. Drainage Area

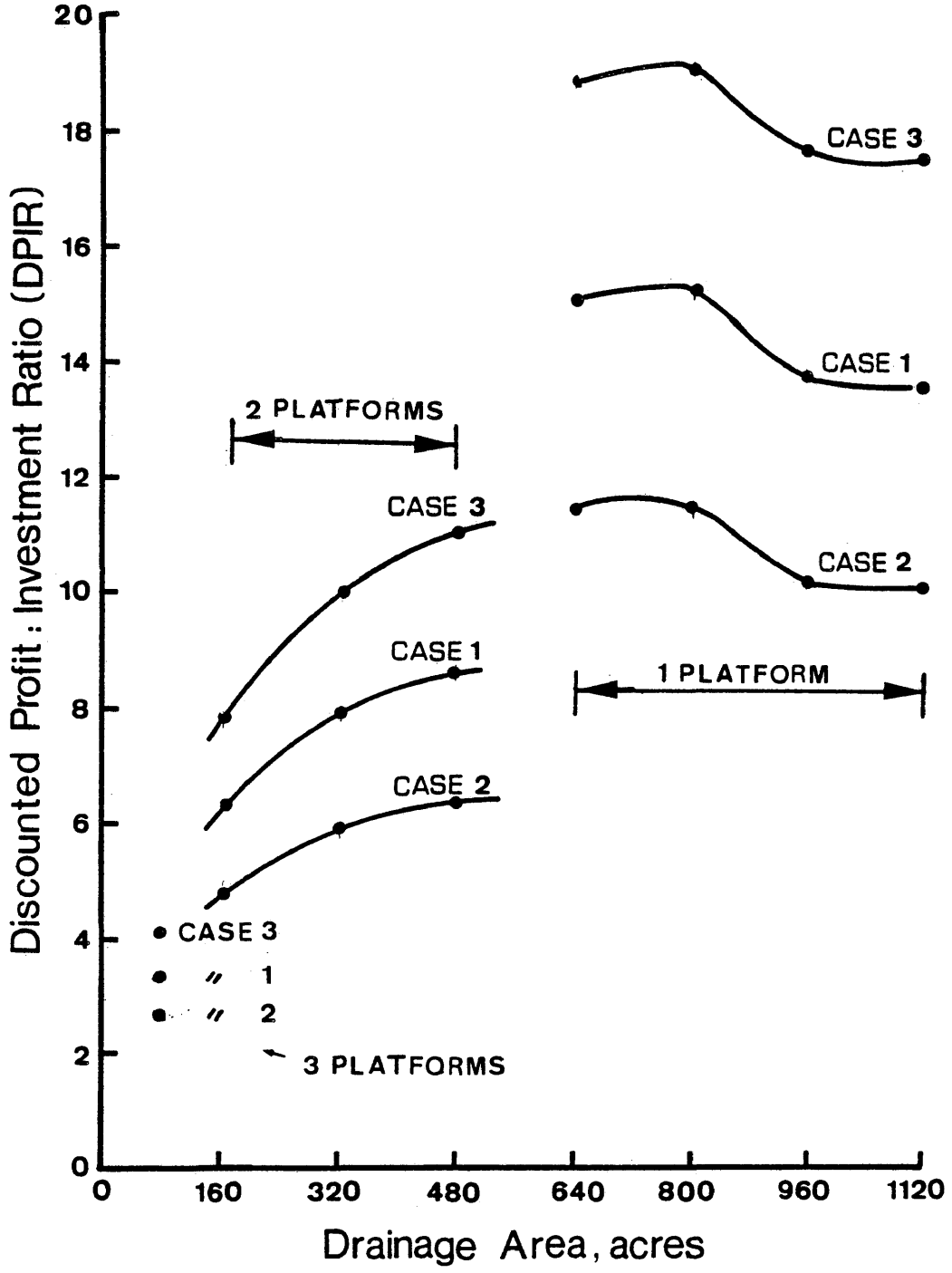


FIGURE 24

Investment Vs. Drainage Area

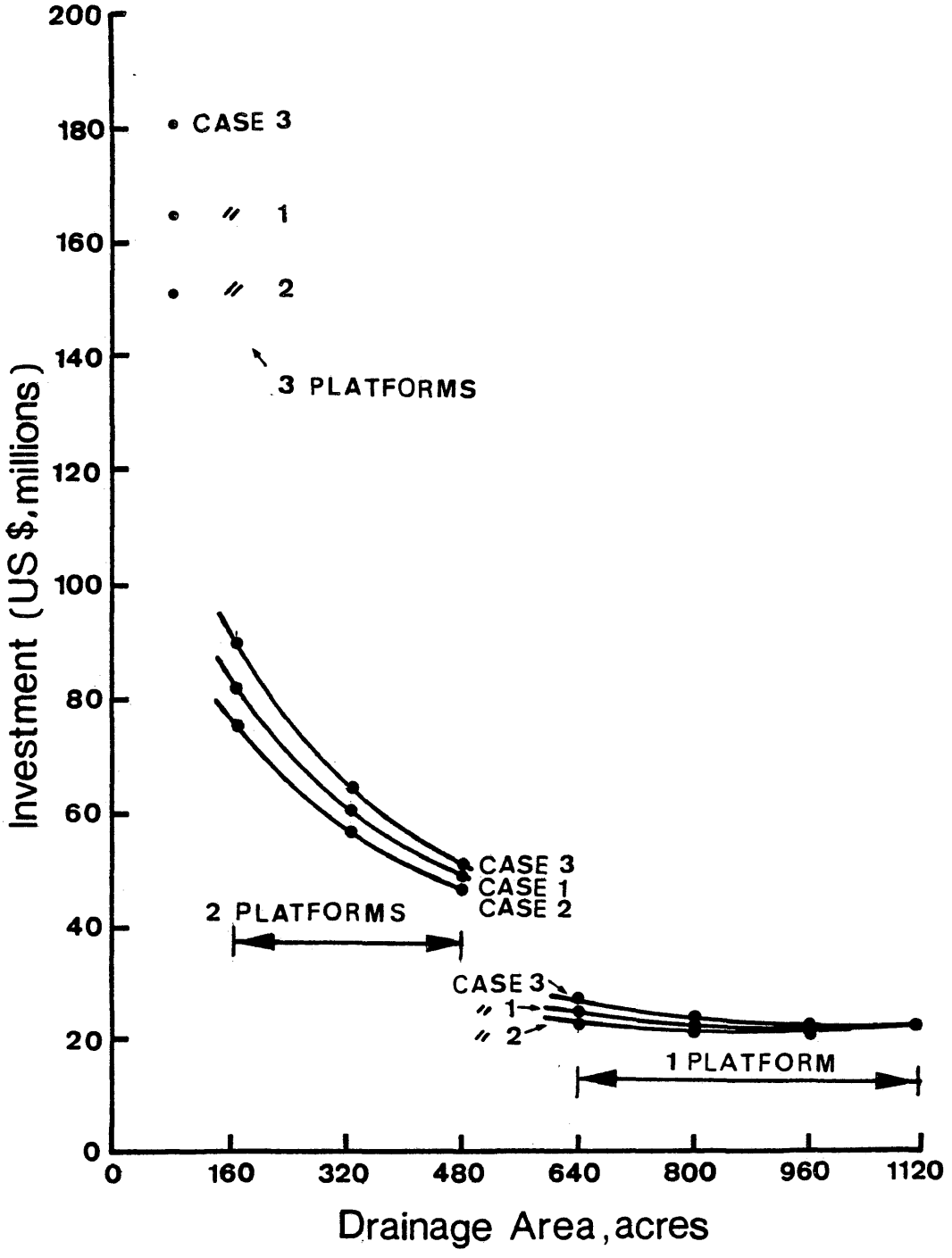


FIGURE 25

Discounted Profit vs. Drainage Area

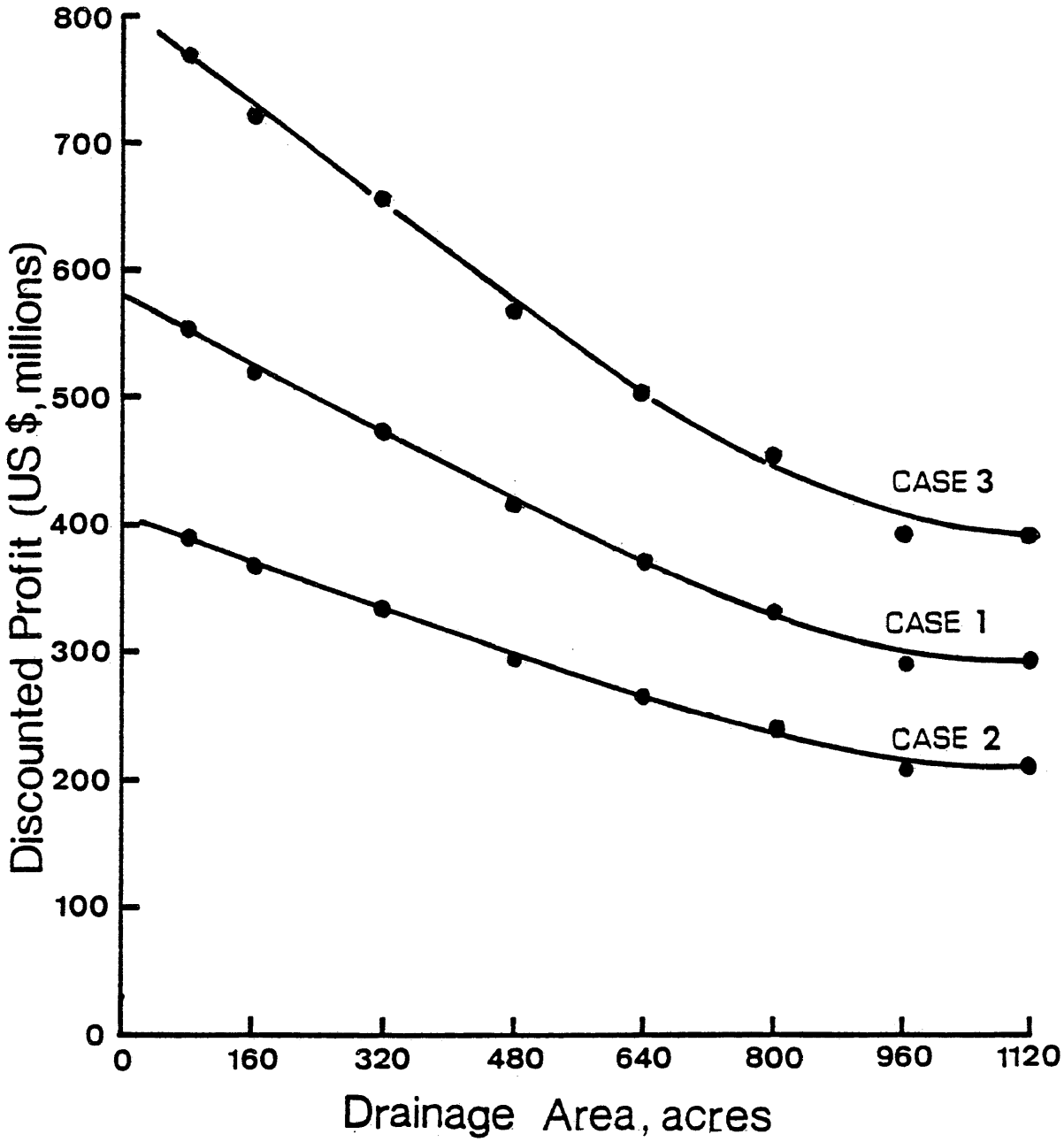
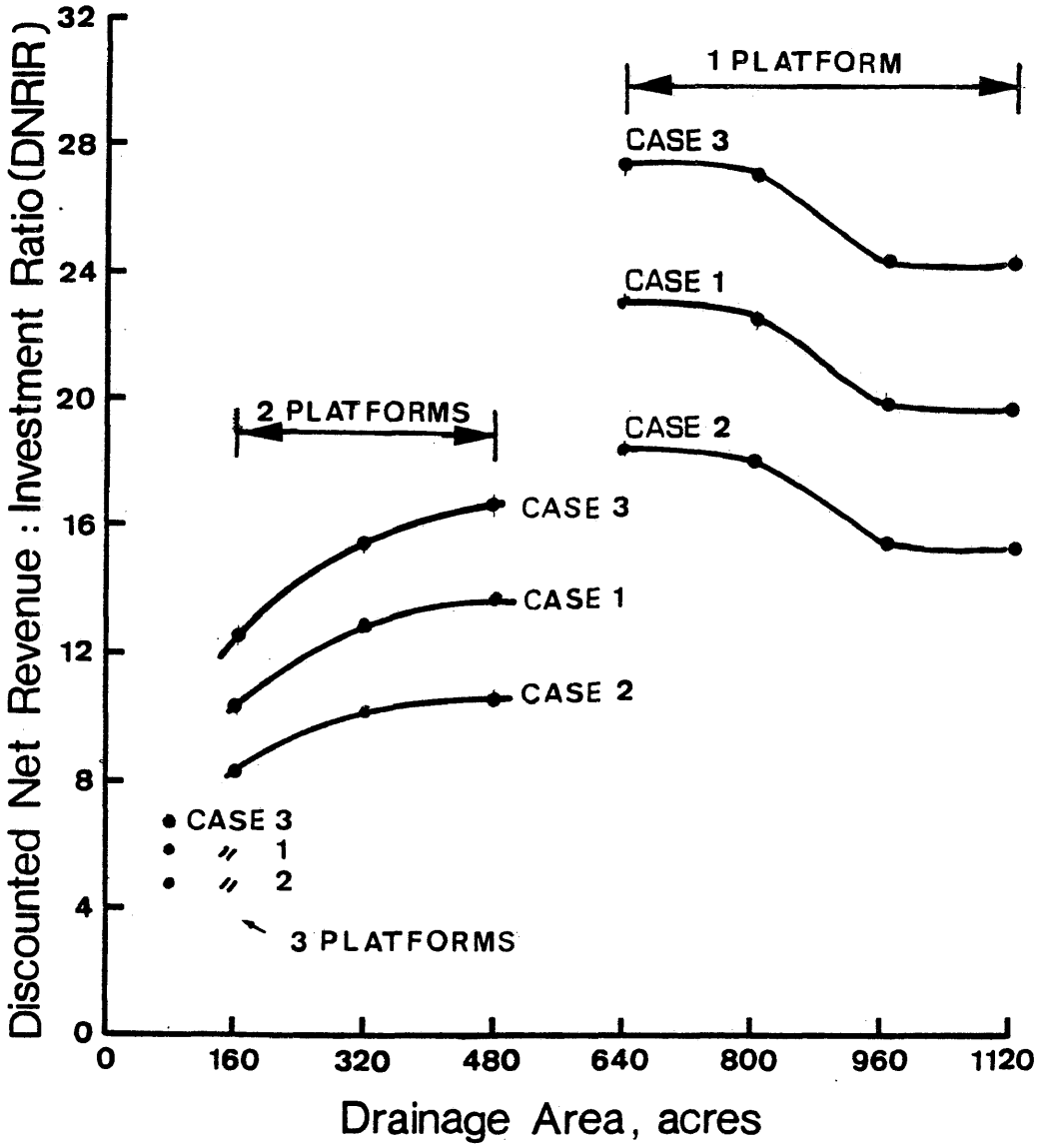


FIGURE 26
DNRIR Vs. Drainage Area



DISCUSSION OF THE ALTERNATIVES

This proposed offshore field can be considered a small field (expected reserves range from 34 x 10^6 bbl to 61 x 10^6 bbl).

(a) The production decline and profit-to-investment ratio (DPIR) study show that designs number 1, 2, 3, 7 and 8 are poor choices. Designs number 1, 2, and 3 need extremely high investments if compared to the others. They will produce the field very rapidly (1 to 7 years), with very low DPIR. Designs 7 and 8 will produce the field for a long time (25 to 30 years) with low DPIR and low investment: This means that the total discounted profit presented by these designs will be low at the end of the field producing life.

(b) Designs number 5 and 6 are the best choices: Reasonable investments, producing life in the range 15 to 22 years, high DPIR and reasonable discounted profits (the minimum expected being U.S. $ 243,570,000. for design 6/Case II, the maximum U.S. $ 502,870,000. for design 5/Case III. Both designs have one platform and one satellite well.

(c) Design number 4 is a reasonable choice. Its discounted profit is between U.S. $298,000,000. (Case II) and U.S. $ 569,030,000 (Case III). The problem is that two

platforms will be installed and, consequently, the initial investment is high. Its seven wells will produce the field in 11 to 13 years, and the DPIR is still attractive (between 6.4 for Case II and 11 for Case III). Although the DPIR is not the optimum if considering all the designs, it is the optimum among those designs which have 2 platforms. Anyway, considering the DPIR, it is not the best choice.

(d) The best choice is still between designs 5 and 6. Although they are presenting almost the same DPIR for the three cases and very similar features, to decide between them is not difficult: design #5 has five wells and design #6 has four wells. Design #5 will produce the oil much faster (16 to 18 years) as compared to design #6 (19 to 22 years). And another important point: The investment of design #5 is higher than that presented by design #6, which means that the discounted profit for design #5 (U.S. $ 266,810,000/case II to U.S. $502,870,000/Case III is much higher than for design #6 (U.S. $ 243,570,000/Case II to U.S. $ 455,155,000/Case III).

Therefore, the method points design #5 as the best choice for developing this offshore oil field.

TABLE 3 NUMBER OF WELLS AND PLATFORMS

DESIGN # 1 DRAINAGE AREA = 80 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	PLATFORM 3	TOTAL
DEVIATED WELLS	15	15	14	44
VERTICAL WELLS	1	1	1	3
TOTAL	16	16	15	47

DESIGN # 2 DRAINAGE AREA = 160 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	PLATFORM 3	TOTAL
DEVIATED WELLS	11	9	-	20
VERTICAL WELLS	1	1	-	2
TOTAL	12	10	-	22

DESIGN # 3 DRAINAGE AREA = 320 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	PLATFORM 3	TOTAL
DEVIATED WELLS	5	5	-	10
VERTICAL WELLS	1	1	-	2
TOTAL	6	6	-	12

TABLE 3 NUMBER OF WELLS AND PLATFORMS

DESIGN # 4 DRAINAGE AREA = 480 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	TOTAL
DEVIATED WELLS	4	1	5
VERTICAL WELLS	1	1	2
TOTAL	5	2	7

DESIGN # 5 DRAINAGE AREA = 640 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	TOTAL
DEVIATED WELLS	3	-	3
VERTICAL WELLS	1	-	1
SUBSEA COMPLETION WELL	1	-	1
TOTAL	5	-	5

DESIGN # 6 DRAINAGE AREA = 800 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	TOTAL
DEVIATED WELLS	2	-	2
VERTICAL WELLS	1	-	1
SUBSEA COMPLETION WELL	1	-	1
TOTAL	4	-	4

TABLE 3 NUMBER OF WELLS AND PLATFORMS

DESIGN # 7 DRAINAGE AREA = 960 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	TOTAL
DEVIATED WELLS	2	-	2
VERTICAL WELLS	1	-	1
TOTAL	3	-	3

DESIGN # 8 DRAINAGE AREA = 1120 ACRES

# OF WELLS	PLATFORM 1	PLATFORM 2	TOTAL
DEVIATED WELLS	2	-	2
VERTICAL WELLS	1	-	1
TOTAL	3	-	3

TABLE 4 PLATFORM COSTS

DESIGN # 1 (80 ACRES)	WATER DEPTH (Ft.)	TOTAL OF WELLS PER PLATFORM		COST (US$ MILLION)	DELIVERY TIME
PLATFORM # 1	225	16		18	10 Month
PLATFORM # 2	225	16		18	10 Month
PLATFORM # 3	225	15		18	10 Month
			TOTAL	54	
DESIGN # 2 (160 ACRES)					
PLATFORM # 1	225	12		18	10 Month
PLATFORM # 2	225	10		13	10 Month
			TOTAL	31	
DESIGN # 3 (320 ACRES)					
PLATFORM # 1	225	6		18	10 Month
PLATFORM # 2	225	6		13	10 Month
			TOTAL	31	

TABLE 4 PLATFORM COSTS

DESIGN # 4 (480 ACRES)	WATER DEPTH (Ft.)	TOTAL OF WELLS PER PLATFORM		COST (US$ MILLION)	DELIVERY Time
PLATFORM # 1	225	5		18	10 Months
PLATFORM # 2	225	2		13	10 Months
			TOTAL	31	
DESIGN # 5 (640 ACRES)	225	5		13	10 Months
PLATFORM # 1			TOTAL	13	
DESIGN # 6 (800 ACRES)					
PLATFORM # 1	225	4		13	10 Months
			TOTAL	13	
DESIGN # 7 (960 ACRES)					
PLATFORM # 1	225	3		13	10 Months
			TOTAL	13	
DESIGN # 8 (1120 ACRES)					
PLATFORM # 1	225	3		13	10 Months
			TOTAL	13	

TABLE 5 TOTAL DRILLING AND COMPLETION COST

DESIGN #	NUMBER OF WELLS DRILLED AND COMPLETED FROM PLATFORMS		COST PER WELL DRILLED AND COMPLETED FROM PLATFORMS (US$ MILLION)	DRILLING AND COMPLETION COSTS (FROM PLATFORMS) (US$ MILLION)	# OF SUBSEA COMPLETED WELLS	COST PER SUBSEA COMPLETED WELLS (US$ MILLION)	DRILLING COST (SUBSEA COMPLETED WELLS) (US$ MILLION)	TOTAL DRILLING AND COMPLETION COST (US$ MILLION)
1	DEVIATED	44	1.0	44	-	-	-	46.4
(80 ACRES)	VERTICAL	3	0.8	2.4				
2	DEVIATED	20	1.1	22	-	-	-	23.6
(160 ACRES)	VERTICAL	2	0.8	1.6				
3	DEVIATED	10	1.2	12	-	-	-	13.6
(320 ACRES)	VERTICAL	2	0.8	1.6				
4	DEVIATED	5	1.3	6.5	-	-	-	8.1
(480 ACRES)	VERTICAL	2	0.8	1.6				
5	DEVIATED	3	1.4	4.2	1	4.0	4.0	5.0
(640 ACRES)	VERTICAL	1	0.8	0.8				
6	DEVIATED	2	1.5	3.0	1	4.0	4.0	3.8
(800 ACRES)	VERTICAL	1	0.8	0.8				
7	DEVIATED	2	1.6	3.2	-	-	-	4.0
(960 ACRES	VERTICAL	1	0.8	0.8				
8	DEVIATED	2	1.7	3.4	-	-	-	4.2
(1120 ACRES)	VERTICAL	1	0.8	0.8				

TABLE 6 OIL PRODUCTION EQUIPMENT COSTS

DESIGN	CASE I		CASE II		CASE III	
	PRODUCTION RATE	TOTAL EQUIPMENT COSTS (U.S. MILLIONS)	PRODUCTION RATE	TOTAL EQUIPMENT COSTS (U.S. MILLIONS)	PRODUCTION RATE	TOTAL EQUIPMENT COSTS (U.S. MILLIONS)
1	141,000	64.71	108,100	49.62	178,600	81.98
2	66,000	30.29	50,600	23.23	83,600	38.37
3	36,000	16.52	27,600	12.69	45,600	20.93
4	21,000	9.64	16,100	7.39	26,600	12.21
5	15,000	6.89	11,500	5.29	19,000	8.72
6	12,000	5.51	9,200	4.38	15,200	6.98
7	9,000	4.38	6,900	3.83	11,400	5.23
8	9,000	4.38	6,900	3.83	11,400	5.23

The oil production equipment costs are proportional to the production rate. They can be estimated by Figure 8.

TABLE 7a TOTAL INVESTMENT CASE I

DESIGN	TOTAL DRILLING AND COMPLETION COSTS (US$ MILLION)	PRODUCTION EQUIPMENT COSTS (INSTALLED COST) (US$ MILLION)	TOTAL PLATFORM INSTALLED COST (US$ MILLION)	TOTAL INVESTMENT (US$ MILLION)
1	46.4	64.71	54.0	165.11
2	23.6	30.29	31.0	84.89
3	13.6	16.52	31.0	61.12
4	8.1	9.64	31.0	48.74
5	5.0	6.89	13.0	24.89
6	3.8	5.51	13.0	22.31
7	4.0	4.38	13.0	21.38
8	4.2	4.38	13.0	21.58

TABLE 7b TOTAL INVESTMENT CASE II

DESIGN #	TOTAL DRILLING AND COMPLETION COSTS (US$ MILLION)	PRODUCTION EQUIPMENT COSTS (INSTALLED COST) (US$ MILLION)	TOTAL PLATFORM INSTALLED COST (US$ MILLION)	TOTAL INVESTMENT (US$ MILLION)
1	46.4	49.62	54.0	150.02
2	23.6	23.23	31.0	77.83
3	13.6	12.69	31.0	57.29
4	8.1	7.39	31.0	46.49
5	5.0	5.29	13.0	23.29
6	3.8	4.38	13.0	21.18
7	4.0	3.83	13.0	20.83
8	4.2	3.83	13.0	21.03

TABLE 7c TOTAL INVESTMENT CASE III

DESIGN #	TOTAL DRILLING AND COMPLETION COSTS (US$ MILLION)	PRODUCTION EQUIPMENT COSTS (INSTALLED (US$ MILLION)	TOTAL PLATFORM INSTALLED COST (US$ MILLION)	TOTAL INVESTMENT (US$ MILLION)
1	46.4	81.98	54.0	182.38
2	23.6	38.37	31.0	92.97
3	13.6	20.93	31.0	65.53
4	8.1	12.21	31.0	51.31
5	5.0	8.72	13.0	26.72
6	3.8	6.98	13.0	23.78
7	4.0	5.23	13.0	22.23
8	4.2	5.23	13.0	22.43

THE PRODUCTION DECLINE STUDY AND THE DISCOUNTED PROFIT:INVESTMENT RATIO DETERMINATION

TABLES 8a, 8b and 8c

RESERVES DETERMINATION

FIRST DAY PRODUCTION RATE (Q_D)

ECONOMIC LIMIT (Q_{ECON})

PERCENT DECLINE PER DAY (d)

PERCENT DECLINE PER YEAR (D)

SUCCESSIVE YEARLY PRODUCTIONS RATIO (r)

NUMBER OF DAYS AND YEARS PRODUCING ON DECLINE

OIL PRODUCTION (FIRST FULL YEAR) (q_1)

DISCOUNTED PROFIT:INVESTMENT RATIO (DPIR)

TABLE 8a THE PRODUCTION DECLINE STUDY AND THE DISCOUNTED PROFIT TO INVESTMENT RATIO DETERMINATION CASE I

	Q_D 1st DAY RATE (bpd)	A 1st DAY OPERATIONAL COSTS (US$)	Q_{ECON} (bpd)	d PERCENT DECLINE PER DAY	D PERCENT DECLINE PER YEAR	r X	NUMBER OF DAYS AND YEARS PRODUCING ON DECLINE DAYS	YEARS	q_1 (bbl) OIL PRODUCTION FIRST YEAR	DPIR
1	47x3000 141,000	634,500	30.456.	0.00236573	1.369005	0.4221807	647.7828	1.774747	34,523,849	3.36
2	22x3000	297,000	14,256.	0.00110736	0.49774874	0.66766873	1,383.8996	3.791506	19,829,281	6.19
3	12x3000 36,000	162,000	7,776	0.00060402	0.24657391	0.80219872	2,537.1493	6.951094	11,796,211	7.86
4	7x3000 21,000	94,500	4,536.	0.00035234	0.13721487	0.8793413	4,349.3987	11.916161	7,193,976	8.61
5	5x3000 15,000	67,500	3,240.	0.00025167	0.09619938	0.91224281	6,089.1582	16.68263	5,231,808	15.00
6	4x3000 12,000	54,000	2,592.	0.00020134	0.07624806	0.92915382	7,611.4477	20.85328	4,223,330	15.20
7	3x3000 9,000	40,500	1,944	0.00015100	0.05665927	0.94637886	10,148.59699	27.80437	3,196,444	13.72
8	3x3000 9,000	40,500	1,944	0.00015100	0.05665927	0.94637886	10,148.89699	27.80437	3,196,444	13.60

OBS: $r = X = \frac{1}{1+D}$

TABLE 8b THE PRODUCTION DECLINE STUDY AND THE DISCOUNTED PROFIT TO INVESTMENT RATIO DETERMINATION CASE II

	Q_D 1st DAY RATE (bpd)	A 1st DAY OPERATIONAL COSTS (US$)	Q_{ECON} (bpd)	d PERCENT DECLINE PER DAY	D PERCENT DECLINE PER YEAR	r X	NUMBER OF DAYS AND YEARS PRODUCING ON DECLINE DAYS	YEARS	q_1(bbl) OIL PRODUCTION FIRST YEAR	DPIR
1	47x2300 108,100	540,500	25,944.	0.00240678	1.40468754	0.41585444	592.95611	1.624537	26,299,917.	2.58
2	22,2300 50,600	253,000	12,144.	0.00112658	0.50827993	0.66300690	1,266.769873	3,470602	15,152,995.	4.72
3	12x2300 27,600	138,000	6,624.	0.00061450	0.25134990	0.79913700	2,322.411434	6.362771	9,027,218	5.90
4	7x2300 16,100	80,500	3,864.	0.00035846	0.13975504	0.87738151	3,981.276745	10.907607	5,509,305.	6.41
5	5x2300 11,500	57,500	2,760	0.00025604	0.09794802	0.91078993	5,573.787443	15.270065	4,007,883	11.45
6	4x2300 9,200	46,000	2,208.	0.00020483	0.07762160	0.92796952	6,967.234300	19.088313	3,235,933	11.50
7	3x2300 6,900	34,500	1,656.	0.00015362	0.05767008	0.94547441	9,289.645737	25.451084	2,449,449	10.18
8	3x2300 6,900	34,500	1,656.	0.00015362	0.05767008	0.94547441	9,289.645737	25.451084	2,449,449	10.08

OBS: $r = X = \frac{1}{1+D}$

TABLE 8c THE PRODUCTION DECLINE STUDY AND THE DISCOUNTED PROFIT TO INVESTMENT RATIO DETERMINATION CASE III

	Q_D 1st DAY RATE (bpd)	A 1st DAY OPERATIONAL COSTS (US$)	Q_{ECON} (bpd)	d PERCENT DECLINE PER DAY	D PERCENT DECLINE PER YEAR	r X	NUMBER OF DAYS AND YEARS PRODUCING ON DECLINE DAYS	YEARS	q_1 (bbl) OIL PRODUCTION FIRST YEAR	DPIR
1	47x3800 178,600	714,400	34,291.200	0.00234556	1.351672	0.42522937	703.5679118	1.927583	43,867,910.	4.21
2	22x3800 83,600	334,400	16,051.200	0.00109792	0.49260264	0.66997068	1,503.076902	4.1180189	25,157,337.	7.77
3	12x3800 45,600	182,400	8,755.2000	0.00059887	0.24423473	0.80370687	2,755.640987	7.549701	14,955,378.	10.00
4	7x3800 26,600	106,400	5,107.200	0.00034934	0.13596950	0.88030533	4,723.955976	12.942345	9,117,166.	11.09
5	5x3800 19,000	76,000	3,648.000	0.00024953	0.09534169	0.91295713	6,613.538368	18.1192832	6,629,372.	18.82
6	4x3800 15,200	60,800	2,918.4000	0.00019962	0.07557431	0.92973586	8,266.922960	22.6491040	5,351,309	19.14
7	3x3800 11,400	45,600	2,188.8000	0.00014972	0.05616309	0.94682347	11,022.56395	30.1988053	4,049,581	17.63
8	3x3800 11,400	45,600	2,188.8000	0.00014972	0.05616309	0.94682347	11,022.56395	30.1988053	4,049,581	17.47

OBS: $r = X = \frac{1}{1+D}$

DISCOUNTED PROFIT

TABLES 9a, 9b and 9c

TABLE 9a DISCOUNTED PROFIT DETERMINATION CASE I

DESIGN #	INVESTMENT (US$ MILLION)	RETURN (DPIR)	DISCOUNTED PROFIT (US$ MILLION)
1 (80 ACRES)	165.11	3.36	554.77
2 (160 ACRES)	84.89	6.19	525.47
3 (320 ACRES)	61.12	7.86	480.40
4 (480 ACRES)	48.74	8.61	419.65
5 (640 ACRES)	24.89	15.00	373.35
6 (800 ACRES)	22.31	15.2	339.112
7 (960 ACRES)	21.38	13.72	293.54
8 (1120 ACRES)	21.58	13.60	293.49

TABLE 9b DISCOUNTED PROFIT DETERMINATION CASE II

DESIGN #	INVESTMENT (US$ MILLION)	RETURN (DPIR)	DISCOUNTED PROFIT (US$ MILLION)
1 (80 ACRES)	150.02	2.58	387.05
2 (160 ACRES)	77.83	4.72	367.36
3 (320 ACRES)	57.29	5.90	338.01
4 (480 ACRES)	46.49	6.41	298.00
5 (640 ACRES)	23.29	11.45	266.81
6 (800 ACRES)	21.18	11.50	243.57
7 (960 ACRES)	20.83	10.18	212.05
8 (1120 ACRES)	21.03	10.08	211.98

TABLE 9c DISCOUNTED PROFIT DETERMINATION CASE III

DESIGN #	INVESTMENT (US$ MILLION)	RETURN (DPIR)	DISCOUNTED PROFIT (US$ MILLION)
1 (80 ACRES)	182.38	4.21	767.82
2 (160 ACRES)	92.97	7.77	722.38
3 (320 ACRES)	65.53	10.00	655.30
4 (480 ACRES)	51.31	11.09	569.03
5 (640 ACRES)	26.72	18.82	502.87
6 (800 ACRES)	23.78	19.14	455.15
7 (960 ACRES)	22.23	17.63	391.92
8 (1120 ACRES)	22.43	17.47	391.85

TABLE 10 DISCOUNTED NET REVENUE: INVESTMENT RATIO

	DISCOUNTED NET REVENUE: INVESTMENT RATIO DNRIR		
DESIGN #	CASE I	CASE II	CASE III
1 (80 ACRES)	5.75	4.64	6.83
2 (160 ACRES)	10.35	8.33	12.34
3 (320 ACRES)	12.77	10.12	15.46
4 (480 ACRES)	13.51	10.60	16.53
5 (640 ACRES)	22.83	18.73	27.27
6 (800 ACRES)	22.67	18.05	27.19
7 (960 ACRES)	19.90	15.51	24.39
8 (1120 ACRES)	19.72	15.36	24.17

CONCLUSIONS

(1) For a given crude oil price schedule, the maximization of the discounted profit-to-investment ratio (DPIR) basically depends upon the size of the initial investment, the producing life of the oil field and the production rate of the field.

(2) As shown by the model herein presented, designs which involve a high well density and consequently large investments will result in low and unattractive discounted profit-to-investment ratio (DPIR), even though the reserves are produced rapidly.

(3) Spreading the oil revenue over a very long period of time (30 to 40 years) makes the alternative of developing the field on large spacing unattractive. Companies usually prefer to have producing life for oil fields between 10 and 20 years.

(4) As shown by the model, the profit-to-investment ratio (DPIR) doesn't depend much on the reservoir geometry. The initial investment is the single most important factor in determining the optimum well spacing.

(5) The sensitivity analysis made in the model shows that for increasing values of pay zone thickness (and consequently, reserves), the discounted profit-to-

investment ratio (DPIR) increases for all the alternative designs. The one which maximizes the DPIR remains the same, independent of the increasing thickness.

(6) It can happen that two or more development plans maximize the discounted profit-to-investment ratio (DPIR), with the same or very close DPIR. The best alternative is the one which achieves the highest discounted profit. This best design will produce the reserves faster, using more development wells and, therefore, having a larger investment.

(7) The model shows that spacing patterns of equal surface acreage are not always the best solution for offshore oil well developments. The recommended pattern is an irregular spacing in which all wells drain comparable areas or the same volume of reservoir. In this case the productive life of the development wells will be approximately the same.

FUTURE WORK

The author of this report suggests these investigations:

(1) Optimization of investments in offshore oil field development for staggered production and investments done in more than one year.

(2) Optimization of investments in offshore oil field developments associating the risk and the uncertainty to the oil reserves which can be found.

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