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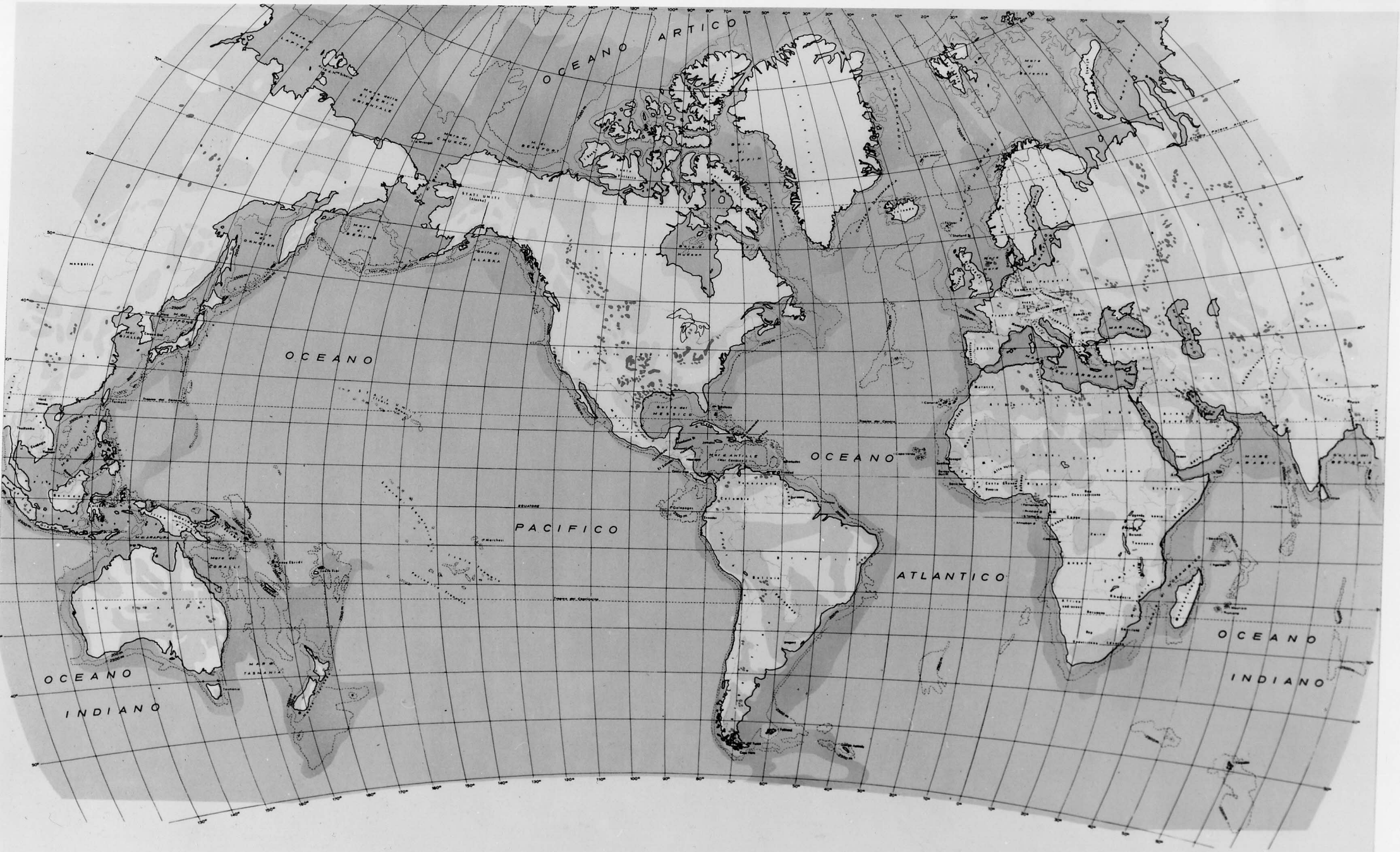

fields

main sedimentary basins

This book is used as a basic manual for courses on economics organized by AGIP for its own personnel as well as for associated companies'. Therefore it is not expected to be an exhaustive study of the subjects dealt with.

The topics, which are only briefly described in this volume, will be thoroughly discussed during the courses, according to the different needs of the attendees.

This second edition is practically a reprint of the first one, published in January 1978. Some chapters, having general and/or illustrative purposes, were neither reviewed nor revised.

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Chapter 1

ECONOMIC POLICY IN THE OIL INDUSTRY

(by M. A. Granata)

INTRODUCTION

By inventing the steam engine, James Watt set off the «Industrial Revolution», providing mankind with a new way of producing goods.
The revolutionary fact of this event consisted in the possibility, proven outside the narrow confines of the laboratory, of transferring energy to machines, without limitations of space. It was no longer necessary to install machinery at the sources of energy (winds, waterways), but it became possible to bring energy to the machine.
Not only was it clear that the role of machinery in the productive enterprise was assuming greater proportions, but it also became a proven fact that economic development is connected strictly and irreversibly with the availability of energy.
This first observation gave rise immediately to a second consideration that has continuously characterized the modern age: the availability of goods for investment or finished goods, presupposes a prior availability of the energy source necessary for their production.

* * *

It is said that *the value of a produced good is defined as the sum of the cost of the work incorporated*. By now this formulation has been accepted by all those involved in economic matters.
Now, *if work* (taken in the broadest sense of the word) *can be considered as transformation energy, the value of goods can thus be defined as the sum of the cost of the transformation energy used in the production process*.
Therefore, considering the *type of energy utilized in industry*, it is possible to realize that *the cost of producing such energy determines the cost of production*, and thus the *price of the final product*.
Among the various costs for the production of energy, the ones pertaining to risks (costs borne without any results) assumes more and more weight. Consequently, *controlling risk* means *controlling production costs*, and finally *containing the prices of goods*. The following pages attempt to list, in order of importance, the elements which define the range of risk involved in a petroleum venture. This is only a tentative summary, and does not aim to be absolute especially because, in this field, there are numerous ways of interpreting historical phenomena; these different interpretations can be partly, or completely, influenced by personal ideologies.

The short history of events connected with the exploration and production of hydrocarbons is to be considered in this light: it provides observations and points to ponder on the understanding of the logic governing the decisions of the protagonists involved.

1. ROLE OF HYDROCARBONS IN THE WORLDWIDE ENERGY BALANCE

It can be virtually affirmed, in relation to what was previously stated (that is, that the cost of production for a good is the sum of the cost of the transformation energy incorporated therein), that the quantity of produced goods depends on the quantity of transformation energy utilized. As proof of this, it is only necessary to take a look at a statistical survey, which shows that economic and industrial development has been particularly accelerated in the past decades; this has involved a parallel development in the demand for and the production of energy, and the pace has been just about as fast (if not faster) as the increase in gross national products in most countries.
In fact in the last 20 years, the average annual rate of increase in energy consumption has been equal to 4.6% versus an increase of worldwide gross products ranging from 4% and 5%.
The starting up and/or development of industrialization - which is based on «basic high energy consumption industries» - has led to a significant increase in the demand for sources of energy. The increase in the need for energy has been spectacular: in the past 50 years the total world consumption has risen from 1.5 to about 8 billion tons equivalent of petroleum (TEP).

This rise has not, however, been at the same pace for all energy sources. From 1950 to 1974, oil and natural gas doubled their percentage in world energy demand, passing from 36% to 64%; such an increase surpassed the demand for solid fuels (which dropped from 59% to 30%) and it is due to the fact that hydrocarbons resulted to be more economical, especially in view of their low cost (until 1973), their greater heat potential (for equal volumes) and their easy treatment (*).
In 1973, the year when the «energy crisis» began, petroleum alone accounted for 48% of the worldwide demand for energy, versus 19% for natural gas, 29% for coal and 4% for hydro-geo-nuclear electric sources of energy.

In the years 1950-73, the average increase in overall hydrocarbon consumption was about 7.5% (7.7% for petroleum, 7.4% for natural gas) whereas the consumption of solid fuels increased by only 1.8% per year. Hydro-geo-nuclear-electric energy levelled off at average value in the development of energy consumption, with a value of 5.1%; particular importance is shown by the fact that nuclear fuels by then maintained a more consistent percentage (12.6% of the electricity total for 1973).

(*) Whereas electrical energy has maintained its place in the ranks of primary energy sources, more and more coal has been substituted by petroleum for energy needs. This substitution has been taking place since World War II, and it has become more and more remarkable. In the economy of Western Europe, for example, coal was the outstanding primary energy source, with petroleum and natural gas in a much lesser position. During the war, the entire coal industry underwent severe damage and was largely abandoned due to either the direct consequences of war (West Germany, Belgium, and France) or the obsolescence of plants (Great Britain). The European countries thus found themselves facing a severe shortage of energy necessary for their reconstruction. Then the path was opened up for petroleum, being the easiest and most immediate energy source, and large quantities began to arrive in Europe from both the USA and the Middle East.

In recent years, it appears possible to note a reverse tendency in the breakdown of energy consumption. The short prospectus below demonstates this phenomenon:

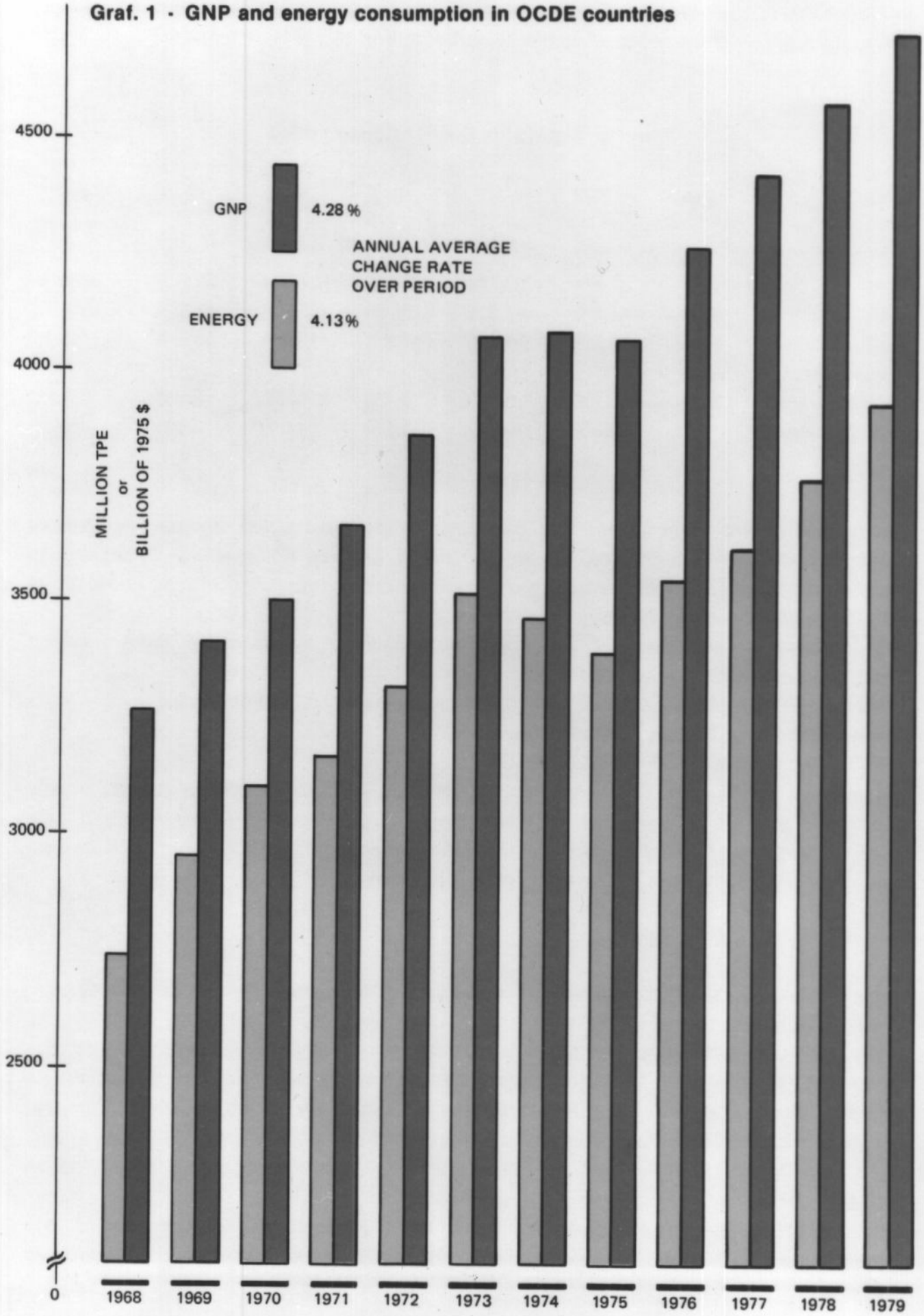
Trend of Worldwide Energy Consumption

Year	*1910*	*1970*	*1973*	*1974*	*1975*	*1979*	*1985 (forecast)*
Coal	91 %	32.9%	29.7%	30 %	30.2%	29.6%	26%
Oil	5%	44.6%	47.2%	46 %	45.5%	45.6%	45%
Natural Gas	1.5%	16.5%	16.9%	17.2%	17.1%	16.7%	17%
Electricity:							
Hydraulic	2.5%	5.7%	5.4%	5.7%	5.8%	5.8%	3%
Nuclear		0,3%	0.8%	1.1%	1.4%	2.3%	9%

The causes of this reverse tendency can be attributed to the tremendous increase of production costs which reached so high a level that once again it was necessary to evaluate the profitability of producing energy from other sources, at prices competitive with those of oil and natural gas.
The increase of production costs was influenced by macroscopic factors which simultaneously burst on the scene:
a) the serious deficit in the energy balance of most industrialized countries;
b) the necessity of finding new oil reserves;
c) the role played by Producing Countries.
Any attempt to measure the weight played by each of these individual factors in this situation would be arbitrary; all of them played a part in the development of new methodologies (technological and commercial) aimed at containing the risks of new ventures, risks which were becoming greater every day.

a) *Deficit in the energy balance*

In the 50's and 60's the ready availability of low cost oil encouraged industrial development in many countries.
At the same time high production costs, anti-pollution laws and strong emotional reactions triggered by a series of mining disasters had caused a sharp decline in coal production. As regards natural gas, various difficulties related especially to high liquefaction and distribution costs, had slowed down wide-scale use of this energy source; nuclear energy had run into trouble everywhere due to both the high production costs and the ecological problems connected with nuclear power plants.
In this situation there was a stepped up demand for oil products with a subsequent jump in prices, setting off a crisis in the more industrialized countries; naturally, there was an increase in production costs too.


Graf. 1 - GNP and energy consumption in OCDE countries
GNP
4.28 %
ENERGY
4.13 %
ANNUAL AVERAGE
CHANGE RATE
OVER PERIOD
MILLION TPE
or
BILLION OF 1975 $
4500
4000
3500
3000
2500
0
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979

2. ROLE OF PRODUCER COUNTRIES

The producer countries now have unquestioned control over their oil and gas resources. They reached this objective due to two major developments:

— the formation and subsequent action of OPEC;
— the ever-growing increase in the producer countries' share of participating interests.

2.1. Events prior to the «Energy Crisis»

At the begenning of the early 60's, the petroleum situation was characterized by a availability of oil at cheap prices: the reserves discovered between 1950 and 1960 had quadrupled, from 11 to 41 billion tons, whereas production doubled (1092 million tons in 1960 versus 521 million in 1950).
This abundance necessarily led to a general elasticity in the market prices, with discounts as high as 20% on the official prices set by the oil companies who then pledged to use these discounts as a basis for selling oil to any buyer. It was also inevitable that the posted prices should follow the trend: for example, in 1960 the price of a barrel of «Arabian Light» oil, 34° API, was $ 1.80, whereas in 1958 it had been sold at $2.08. This market situation could not but influence the profits of the major producer countries and they banded together in 1960 to form an organization called OPEC (Organization of Petroleum Exporting Countries) (*).
In 1960 the oil produced by the 5 founding members of OPEC accounted for 43% of the world production (excluding Socialist countries), estimated at 924.5 million tons; on the other hand, their reserves amounted to 27.4 billion tons, equal to 74% of the worldwide total.
As time went on, OPEC's policy evolved along two basic lines: new formulas of taxation and control of production.

A) Fiscal Policy

One of the major objectives of OPEC was to turn around in their favor the current distribution ratio of the returns on petroleum products; this ratio was largerly in favor of the consumer countries.
In fact, in the 50's these taxes had been based on the formula of «fifty-fifty» so that the total amount of Income Tax, Royalties and other fiscal charges accounted for 50% of the taxable income determined on the basis of sale proceeds. In the 1960's the so-called

(*) The original signers of The Pact instituting OPEC on September 24, 1960 were Iran, Iraq, Kuwait, Saudi Arabia and Venezuela.
It was afterwards joined by the following countries: Qatar (1961), Indonesia and Libya (1962), Abu Dhabi (1967), Algeria (1969), Nigeria (1971), Equador (1973) and Gabon (1975).

«OPEC Formula» was introduced; with this formula, heavy taxation was applied to Posted Prices and the tax rate was unified and brought up to 50%. Another important aspect of this formula was the Royalty (a rate of about 12.5%) which was no longer considered as a tax advance, but as a fiscally deductible expense (paid Royalty as an operating cost). During the period 1960-1970 the total revenues of the OPEC countries (except Algeria and Indonesia) more than doubled, rising from 2318 to 6610 million dollars; at the same time the yield per unit of exported crude increased by 11% (from $0.816 to $0.906/barrel). In the same time period production had risen to 1154 million tons (59% of worldwide production excluding Communist countries), whereas the recoverable reserves (48 billion tons at the end of 1970) accounted for 81% of the world total.
However, the increase in profits could not be ascribed to the rise in prices, which were frozen in that 10 year period, but rather to the changes in demand for oil on the part of the main consumer countries and the variations in systems of taxation.
In the 10 year period from 1960 to 1970, world energy consumption had in fact increased by 61%, from 3190 to 5148 million TEP; and petroleum was playing an increasingly important role in satisfying the stepped up demand for energy: worldwide petroleum consumption underwent a 113% increase, rising from 1065 million tons in 1960 to 2273 million in 1970.

B) Control of Production

All the steps taken in this direction were guided by the OPEC philosophy in which the producer countries claimed absolute sovereignty over exploration areas and discovered reserves. The principal measures taken consisted of a series of imposed conditions:

- all explored areas, where no commercial reservoirs had been located, were to be given up according to a definite timetable and well defined percentages;
- after suitable training, local personnel were to be placed at all management levels;
- the new agreements were no longer stipulated according to the traditional «Concession Contract» but on the basis of service contracts.

These contracts have a common characteristic in that the oil company acts as an operator working on the government's behalf.
That is, the operator takes on the responsibility for exploration, paying in advance all (or most) of the investments for development and production. In return, he gests the right to a portion (usually up to 35-40%) of the oil which is produced annually as repayment of expenses borne («Cost Oil»); he also has the right to receive a share of the residual profits (Profit Sharing Contract) or the remaining crude (Production Sharing Contract) as compensation for risks and know-how.

2.2. The Crisis and its Consequences

Control over the oil companies was accompanied by the price fixing of oil products, this time decided by the OPEC countries. After a 10 year freeze, the Posted price of «Arabian

Light». which served as the basis on which the prices of other Persian Gulf crudes were calculated, rose quickly from $1.80/barrel (1970) to $11.251 (1974) and to $12.09 (1977), a total increase of more than 650%.
Along with the increases in the Posted Prices, the OPEC countries sharply stiffened taxes -in the Teheran agreements of February 1971 - raising the Royalty from 12.50% to 20% and the Income Tax from 50% to 85%.

The principal measures taken by OPEC after the Teheran Conference (and in practice sustained also by non members) can be thus summarized:

— the Geneva Agreements (January '72): a 8.49% increase in Posted Prices:
— the New York agreements (October '72): the producer countries progressively acquired a 51% share (initially 25%) of the exploitation of their own hydrocarbons:
— the Geneva Agreements (June '73) which meant a further 11.85% increase in the Posted Prices.

This first set of agreements was followed by a series of measures adopted unilaterally by the individual OPEC member countries, and also by other countries.

— October '73 - Kuwait Conference - the Persian Gulf countries decided on a 70 - 100% increase in the Posted Prices.
— December '73 - Teheran - For 34° API Arabian Light, taken on the basis of quotations, the Posted Price increased from $5.032 to $11.651/barrel.
— June '74 - the OPEC Conference decided on a 2% increase in royalties.
— September '74 - Vienna - a series of measures was decided upon which was to cause a further increase of 9% on petroleum revenues to take effect as of December of that year.
— December '74 - Meeting of 6 OPEC countries at Abu Dhabi: royalties and income tax rates were brought up to their present - levels.

The combination of the price increase and new tax rates enabled the producer countries to increase their total and unitary oil profits. Total earnings went from $7,729 million in 1970 to $88,800 million in 1974 (*), and the unit take went from $0.95 to $8.34 per barrel.
The transfer of more than 145 billion dollars to the producer countries in a period of 5 years caused enormous problems in the industrialized countries. In addition to the upsets in the balance of payments, western economy collided with the «new course» begun by the OPEC countries who had proven the vulnerability of the consumer countries with the oil embargo adopted in 1973 following the War of Yom Kippur.

The changes in the petroleum market have been bringing countries to seek new formulas of international cooperation.

The OECD (Organization for Economic Cooperation and Development) countries, formed IEA (International Energy Agency) with a 25 billion dollar fund, to protect the balance of payments in those countries most severely hit by the crisis.

(*) Excluding revenues from Ecuador and Gabon.

POSTED PRICE PER BARREL OF PETROLEUM BY MAJOR EXPORTING COUNTRIES

YEAR END PRICES

YEAR	*Iran (1)* Light, ex Kharg Is. 34.0° - 34.9°	*Iraq* Basrah, ex Fao 35.0° - 35.9°	*Kuwait* ex Mena al Ahmadi 31.0° - 31.9°	*Libya* ex Marsa el Brega 40.0° - 40.9°	*Nigeria* Light, ex Bonny 34.0° - 34.9°	*Saudi Arabia (2)* ex Ras Tanura 34.0° - 34.9°
1950	$ ...	$ ...	$ ...	$ ...	$ ...	$ 1.750
1951	...	1.670	...	...	...	1.750
1952	...	1.670	...	...	...	1.750
1953	...	1.920	1.720	...	...	1.970
1954	1.910	1.920	1.720	...	...	1.970
1955	1.910	1.920	1.720	...	...	1.970
1956	1.910	1.870	1.720	...	...	1.970
1957	2.040	1.980	1.850	...	...	2.080
1958	2.040	1.980	1.850	...	...	2.080
1959	1.860	1.800	1.670	...	...	1.900
1960	1.780	1.720	1.590	...	...	1.800
1961	1.780	1.720	1.590	2.230	...	1.800
1962	1.780	1.720	1.590	2.230	...	1.800
1963	1.780	1.720	1.590	2.230	...	1.800
1964	1.780	1.720	1.590	2.230	...	1.800
1965	1.780	1.720	1.590	2.230	...	1.800
1966	1.790	1.720	1.590	2.230	...	1.800
1967	1.790	1.720	1.590	2.230	2.170	1.800
1968	1.790	1.720	1.590	2.230	2.170	1.800
1969	1.790	1.720	1.590	2.230	2.170	1.800
1970	1.790	1.720	1.680	2.550	2.420	1.800
1971	2.274	2.259(3)	2.187	3.399	3.178	2.285
1972	2.467	2.451(3)	2.373	3.620	3.409	2.479
1973	5.254	4.978(3)	4.822	9.061	8.404	5.036
1974	11.475	11.272(3)	11.145	15.768	14.691	11.251
1975	12.495	12.400	12.151	16.060	13.070	12.376
1976(4)	11.620	11.500	11.230	12.620	13.160	11.510
1977(4)	12.810	12.600	12.270	14.200	14.570	12.700

(1) Prior to 1966 port of export was Bandar Mashur.
(2) A.P.I. gravity for crude is 36.0° - 36.9° from 1950-1956.
(3) Ex. Khor-al-Amaya.
(4) State sales price.

AUTHORITY: "PETROLEUM ECONOMIST"

20th Century Petroleum Stats., 1978

Moreover, the most important initiative of IEA was the North-South Conference held in Paris in December '75.
The conference, which was originally supposed to be only a meeting on energy problems, broadened its scope to become a conference on international cooperation between consumers and producers.

THE LATEST DEVELOPMENTS

During the months following the 1973-1974 oil crisis, observers from many parts of the world forecast that, within a decade or so, OECD countries would reach such a degree of autonomy in energy supply, to enable them to reduce sharply oil imports from oil producing countries.

The "autonomy plan", worked out by the Nixon administration, should have been put into effect in 1985. But studies carried out later, showed that 1985 would be the year of the second crisis. Historical events showed that experts' forecasts were too optimistic. The threatened second crisis has come foreward with more than five-year advance.

Why? There are manifold reasons but most of them have a common characteristic: the pernicious over optimistic view which drove industrialized countries to consider the oil crisis as a problem to be tackled with in the long term.

— In spite of annual summits, OECD countries did not succeed in working out and putting into effect far-reaching energy strategies. IEA proved to be unable to cope with energy problems and lost a great deal of its reliability at political level.

— Since no monetary policy aimed to curb inflation was achieved, the increase in production costs inevitably eroded the profit margins obtained by oil producing countries after the sharp increase of oil prices during the years 1973-1974.

— Developed countries underrated the role played by countries belonging to the Third World (neither oil producing nor industrialized countries) in the economical and political balance. It is common knowledge that these countries are poor, indebted and vulnerable; thus, they are subject to political and social turmoils.

— Developed countries adopted as a yardstick the development and cultural patterns pertaining to the Western World.

— The revolution which took place in the Muslim World.

Since OECD countries stubbornly continued to consider the developments of the energy crisis as a long term problem, they did not adopt medium or short term economic patterns. Instead of fostering production from new energy sources, within the framework of an emergency economic policy, the developed countries prefered to follow competition-based standards, waiting for the expected increase in oil prices as an incentive to develop other energy sources.

The attached diagram clearly shows how projects for natural gas liquefaction are affected by oil prices.
Oil prices, which increased moderately and gradually during the years 1977-1978, rocketed up abruptly when, at the end of 1978, the Iranian political crisis created the favourable conditions for further increases imposed by OPEC countries.

CONCLUSIONS

In the harsh light of reality, the 1973-1974 oil crisis showed the demand inelasticity in front of a steady drop in supply.

Since the energy problem has always been considered as a question to be settled in the long term, the oil market - at least throughout the eighties - will be characterized by recurring structural tensions. There might be short truce periods due to occasional surplus during the early eighties, but the general trend will be quite different.

We think that the outstanding elements characterizing the situation at hand - which shall be taken into serious consideration - are mainly linked to the following considerations:

— The oil production from most OPEC countries has now reached the top levels. Thus, there could be an estimated 3-4 million barrels a day to reach the maximum capacity level in terms of production. As a consequence of this, OPEC countries might set up a policy based on production cuts aimed on one hand to safeguard their energy stock, and on the other to curb inflationary trends due to internal as well as to foreign causes.

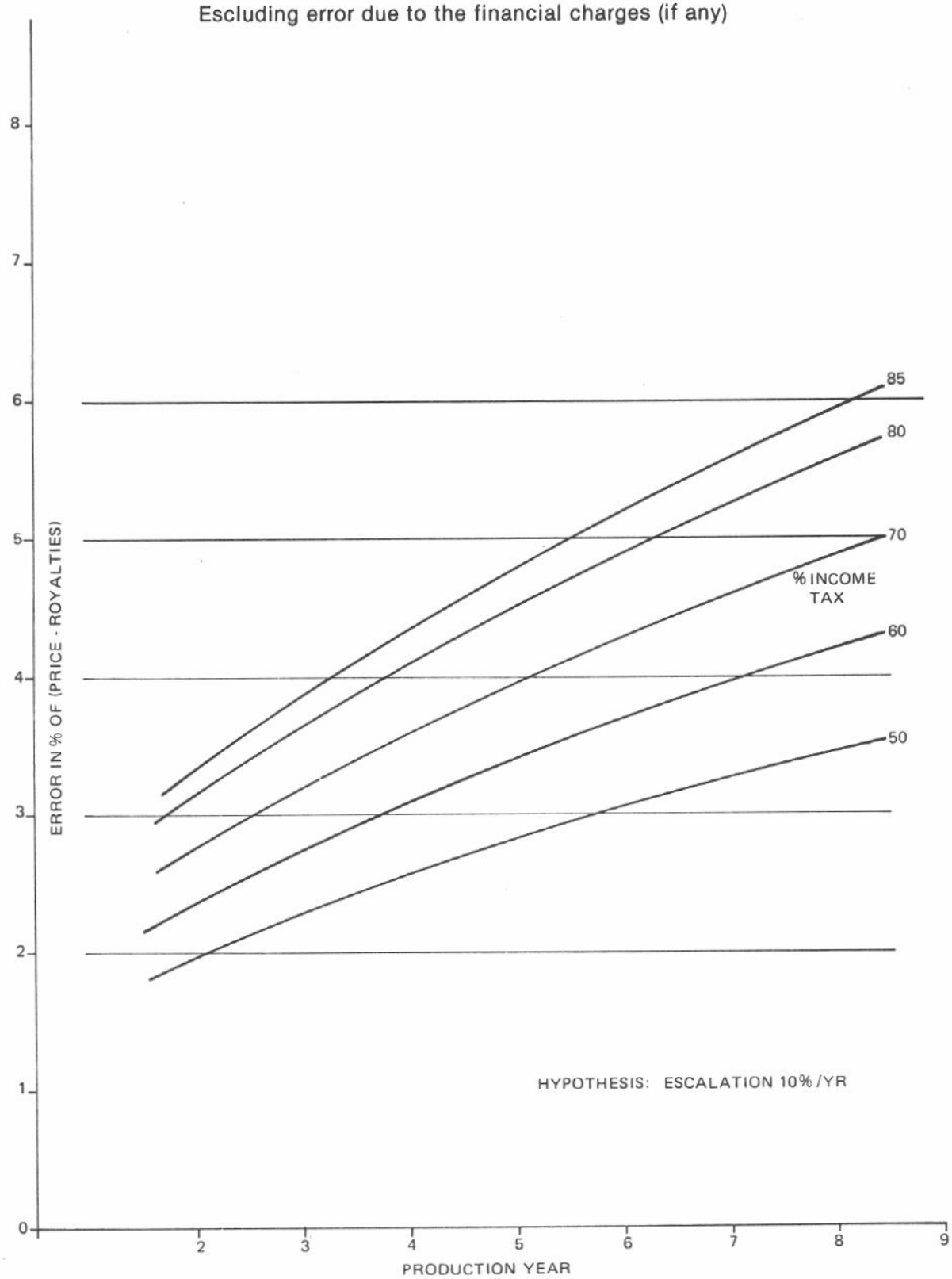
— Non OPEC countries. The USA and the USSR are going to face a rapid and relentless drop in production. Oil production from the North Sea cannot but cover, for a few years, the increasing demand of the European market. Other countries, such as Mexico, India, Malaysia and perhaps Brazil too, might boost their production which, however, will be allotted to meet the internal demand, since these countries are undergoing a steady development and therefore will be in need of constant energy supply. Thus, they will give only a small contribution to the industrialized countries' demand for oil.

— Oil as a political weapon. Since the Western World willfully disregarded or at least belittled, for too long a time, the economic cultural and social needs and conditioning of developing countries, oil producing countries are going to use oil as a political weapon to safeguard their rights to development and to claim their identity as nations.

This attitude was clearly and dramatically shown by the Islamic revolution which brought about unexpected outcomes - at least in the eye of Western standards.

If the industrialized countries continue to leave out of view this reality and to believe that the oil problem merely depends on prices and/or political and strategical retaliation, the future will bear dreadful consequences for everybody.

Graf. 15 · Underestimated amount of income tax to be paid when economics in constant costs and prices
Escluding error due to the financial charges (if any)



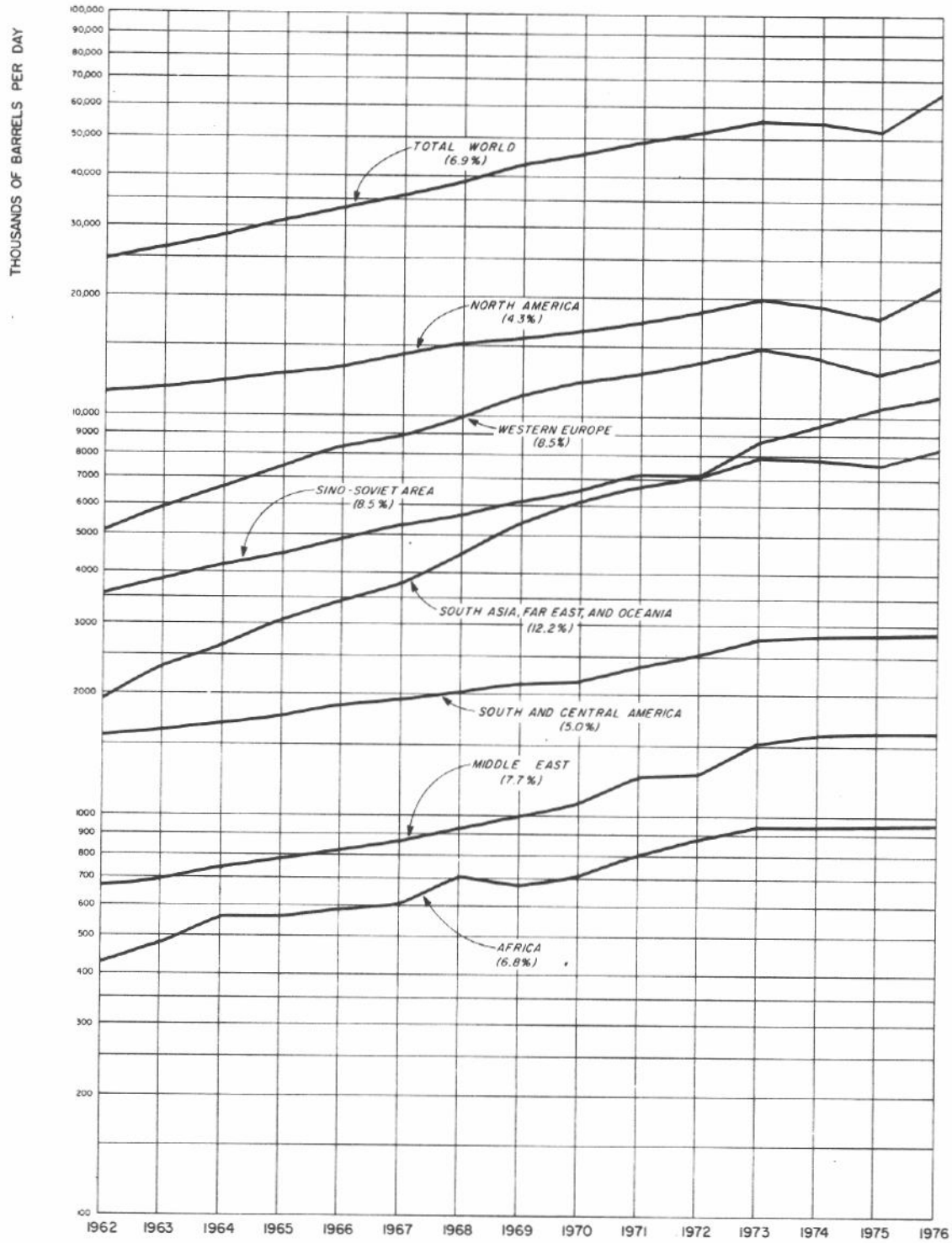
ACCUMULATIVE CRUDE OIL PRODUCTION OF UNITED STATES AND WORLD TO JANUARY 1

(THOUSANDS OF BARRELS)

Year	World	United States	Percentage Provided by United States
1918	6,990,481	4,252,644	60.8
1919	7,493,996	4,608,572	61.5
1920	8,049,871	4,986,939	62.0
1921	8,738,755	5,429,868	62.1
1922	9,504,757	5,902,051	62.1
1923	10,363,655	6,549,582	62.3
1924	11,379,391	7,191,989	63.2
1925	12,393,709	7,905,929	63.8
1926	13,462,642	8,669,672	64.4
1927	14,559,465	9,440,546	64.8
1928	15,822,047	10,341,675	65.4
1929	17,146,821	11,243,149	65.6
1930	18,632,688	12,250,472	65.7
1931	20,042,725	13,148,483	65.6
1932	21,415,257	13,999,564	65.4
1933	22,724,934	14,784,723	65.1
1934	24,167,080	15,690,379	64.9
1935	25,689,368	16,598,444	64.6
1936	27,343,863	17,595,040	64.3
1937	29,135,403	18,694,727	64.2
1938	31,174,634	19,973,887	64.1
1939	33,162,675	21,188,242	63.8
1940	35,248,835	22,453,204	63.7
1941	37,398,656	23,806,418	63.7
1942	39,169,313	25,208,646	63.6
1943	41,712,413	26,595,291	63.8
1944	43,969,050	28,100,904	63.9
1945	46,561,339	29,778,808	64.0
1946	49,156,036	31,492,463	64.1
1947	51,901,466	33,226,402	64.0
1948	54,923,605	35,083,389	63.9
1949	58,356,830	37,103,574	63.6
1950	61,760,972	38,945,514	63.1
1951	65,563,967	40,919,088	62.4
1952	69,846,697	43,166,799	61.8
1953	74,351,405	45,456,635	61.1
1954	79,149,460	47,813,717	60.4
1955	84,166,303	50,128,705	59.6
1956	89,792,186	52,613,133	58.6
1957	95,916,862	55,230,416	57.6
1958	102,355,306	57,847,317	56.5
1959	108,963,056	60,296,304	55.3
1960	116,096,294	62,870,894	54.1
1961	123,770,754	65,445,827	52.9
1962	131,956,967	68,067,585	51.6
1963	140,838,825	70,743,774	50.2
1964	150,377,171	73,496,497	48.9
1965	160,686,815	76,283,319	47.5
1966	171,749,330	79,131,833	46.1
1967	183,771,116	82,159,596	44.7
1968	196,685,456	85,375,338	43.4
1969	210,831,774	88,704,380	42.1
1970	226,054,285	92,076,131	40.7
1971	242,772,993	95,593,581	39.4
1972	260,435,786	99,047,495	38.0
1973	279,036,287	102,502,863	36.7
1974	299,404,268	105,863,766	35.4
1975	319,941,995	109,066,351	34.1
1976	339,439,599	112,118,399	33.0
1977	360,631,139	115,094,579	31.9
1978	382,457,388	118,079,939	30.9

AUTHORITY: UNITED STATES DEPARTMENT OF ENERGY

Graf. 13 · World demand for refined products
Average annual growth rate 1962-1974 = ( )



From: TWENTIETH CENTURY PETROLEUM STATISTICS 1976

Chapter 2

INVESTMENT POLICY

(by M. A. Granata)

The major difference between a purely scientific research and research with industrial purposes lies in the type of results expected.
1) In the first case, the result is predominantly scientific.
2) In the second the result is economic.
Thus in industry the investment policy is of utmost importance.

1) Definitions

An evaluation of the economic profitability of starting an exploration, development and production program has to take into account the investment policy of each industrial firm. An attempt has been made to provide some definitions regarding several notations used on the following pages; these definitions are necessary for a correct interpretation of both the text and, in a more general sense, of the results of the economic evaluations.

Investments:
these consist of those portions of the firm's capital (in durable goods) which can contribute to the firm's income.
Specifically: by investment we mean the whole series of plants, structures and infrastructures necessary to produce a good. All of this is locked up capital which is continuously being used to create profit for the firm. Investments are thus goods which are not destined to be rapidly used up.

Operating Costs:
these are costs which use up capital for an individual financial period, usually equal to one year.

Income of the Enterprise:
this is the increase in capital occurring in a certain time period (financial period) due to management of this capital. This term must be considered in the broadest sense: it includes both the positive and negative changes occurring in the capital. In technical language «income» is called profit or earning power if it is positive increase; it is called loss if there is a negative increase (decrease).

Two subjects can be distinguished in a company:
Economic:
this consists of the person or group of people who control the company and in whose interest the company is managed.

Chapter 2

INVESTMENT POLICY

(by M. A. Granata)

The major difference between a purely scientific research and research with industrial purposes lies in the type of results expected.
1) In the first case, the result is predominantly scientific.
2) In the second the result is economic.
Thus in industry the investment policy is of utmost importance.

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Two subjects can be distinguished in a company:
Economic:
this consists of the person or group of people who control the company and in whose interest the company is managed.

The expected rate of return (to be calculated beforehand) represents the real parameter for expressing a judgement on the economic convenience of going ahead with the investment program under study.
It is defined by a combination of various factors:

a) the relationship between the borrowed capital (mortgaged from investment banks, or from any third party outside the company) and equity capital (that is, the capital which is directly available from the company's finances): C_b/C_e

b) interest rate on borrowed capital: r_b

c) interest rate on equity capital: r_e

d) rate of risk correlated to the probability of success: p

e) expected inflation rate: s

It is to be noted that an initial judgement on the viability of the project is implicit in the value of parameters a) and b).
This value is, at least in good part, free from the planner's favor or disfavor towards the project because it is influenced by the neutrality of the third parties involved in the venture.

Reference to points "d" and "e". While for the rate of risk "p" it is very easy to understand the economic meaning of the results which can be obtained in terms of mathematical hope, "s" entails a deeper analysis.
If economics are carried out at constant prices and costs, the economic indicators resulting from calculations are scarcely reliable.

There are two essential reasons for this:

— financial burdens, as far as they come in, are often comprehensive of the inflation rate. The outcome is that an element is introduced which affects anomalously both the tax incidence and the final results;

— when the tax burden is calculated, it is inevitably under estimated. The two diagrams attached emphasize the occurring error rate (expressed in price percentage, net of royalties).

For instance, if we consider that a 5% error on a 35 $ × 0.8 price (net of royalties) corresponds to 1.4 $/barrel, we realize the importance of the error, above all if it is related to the producer's current margin of profit.

If economics are calculated taking into consideration the inflation rate and if indicators are seeked on the Deflated Net Cash Flow, the error may drop to negligible values. This means that the percentage is the same but it is related to the difference between the theoretical escalation rate and the real escalation rate.

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when $K = 0, t =$ 1 year (fiscal period), dR_t, A_t and R_n accrued or expensed during the whole year t, the previous formula can be rewritten as follows:

$$P.W.V._1 = \sum_{t=1}^{n} A_t (1 + r)^{-t+0.5} + dR_1 (1 + r)^{-t+0.5} + R_n (1 + r)^{-n+0.5}$$

That is the generalized formula normally used.
If, for the purposes of the evaluation, the inflation rates is also considered, then:

$$P.W.V._1 \frac{1}{(1 + s)} = P.W.V._2$$

where $\frac{1}{(1 + s)}$ is the "deflator".

If the total rate of risk is also considered, then:

$$P.W.V._2 \frac{1}{p} = P.W.V._3$$

Expressed in this manner the formula is valid for the first calculation method (Present Worth Value Method). If the second method is to be applied (Internal Rate of Return aimed at calculating the Average Annual Rate of Return), then it is necessary that:

$$P.W.V. = 0$$

The unknown will then be represented by the discount rate «r» which is to be determined by iteration method.

7) Economic Profitability Evaluation

The project under study will appear more or less advantageous, from an economic standpoint, according to the increase (or decrease) of the P.W.V. (first method) or of the A.A.R.R. (in the second), given by the value «r» for which the result of the equation is zero. However, both methods immediately reveal (the first explicitly, the second implicitly) whether the invested capital allows any margin of profit.

The necessary conditions are that:

a) $P.W.V. > 0$
b) $A.A.R.R. > r_e$
where r_e is the interest rate on equity capital.

The greater the difference between the two terms, the more profitable will be the project under study.
The following two graphs summarize the logic underlying the two methods.

Recommandations

a) If economics are carried out without taking into consideration the inflation rate, they can provide a merely expeditious examination.
The combination of computing elements can nullify the meaning of the indicators found.(1)

b) The profitability rate AARR *is only one* of the possible indicators and in some cases it is not significant. Experience together with the skill in appraising the computing elements and methods used, can give a better understanding of AARR reliability and can suggest the most meaningful economic indicators, among others, for decision making purposes.

(1) Compare, for instance, what said in chapter 5.2.

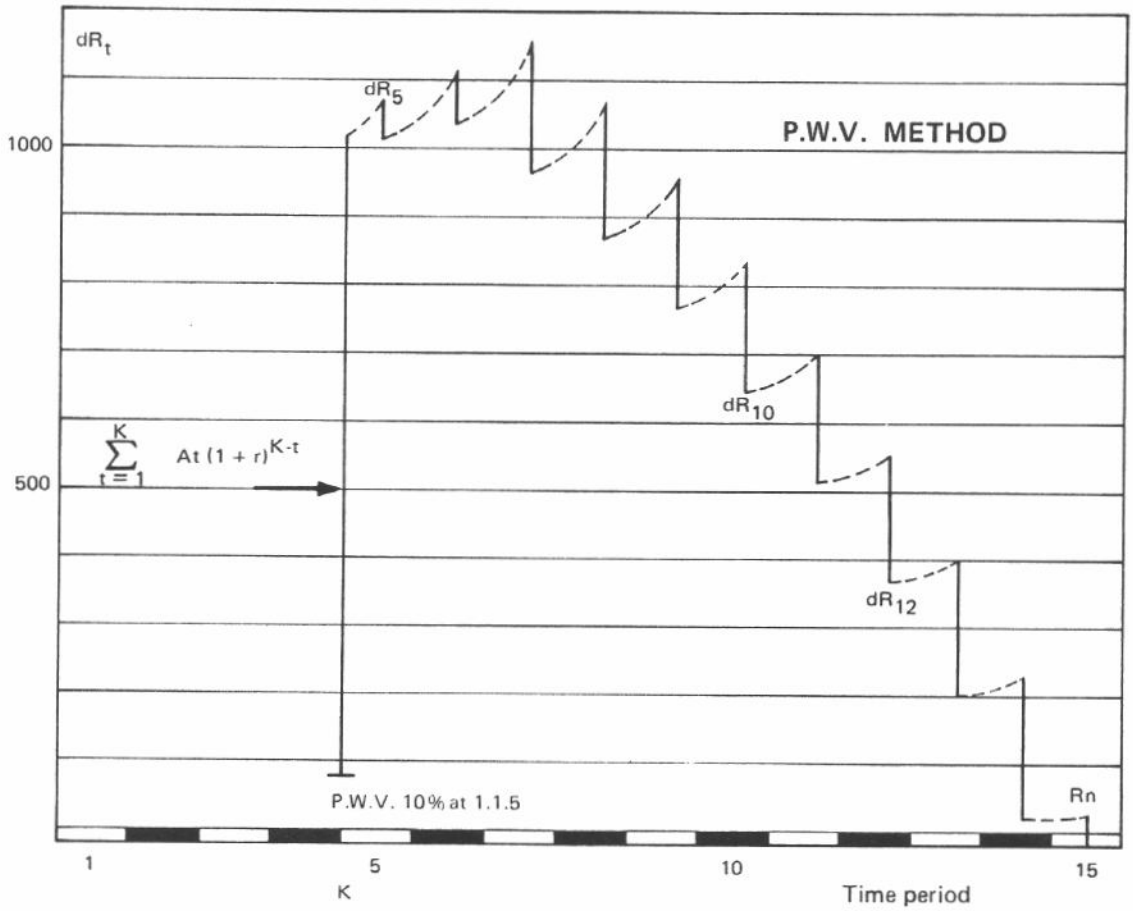
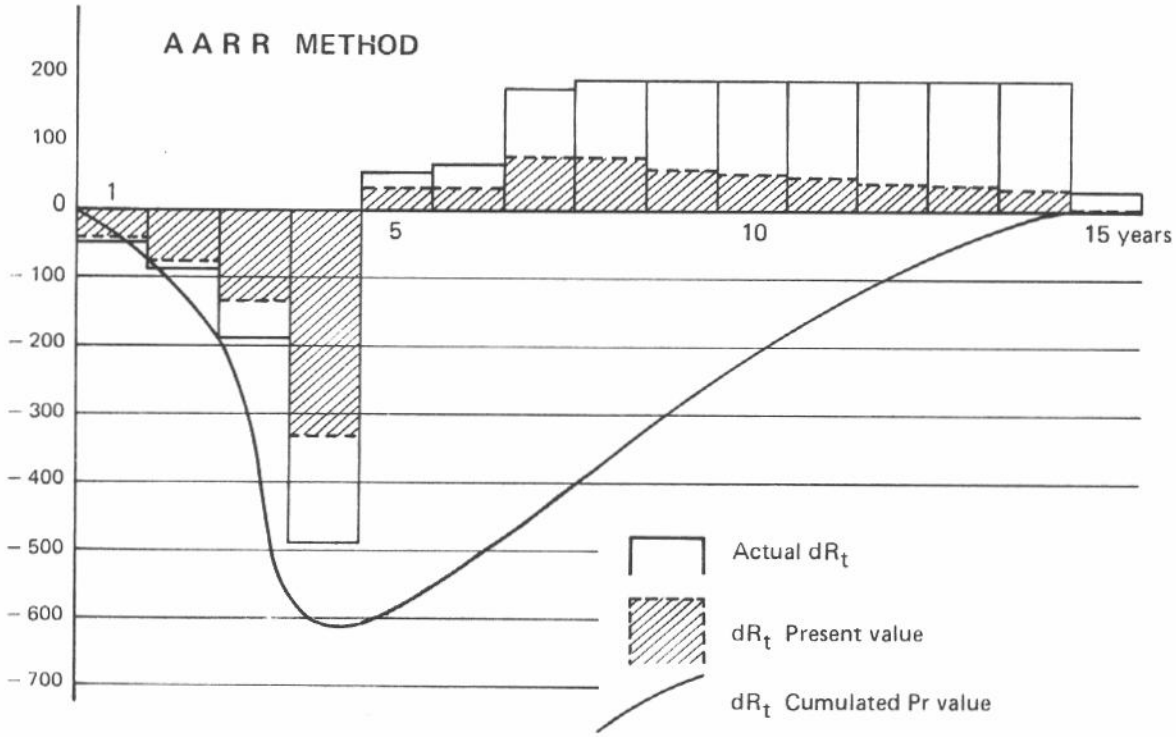

dR_t
P.W.V. METHOD
1000
500
dR5
dR10
dR12
Rn
$\sum_{t=1}^{K} At(1+r)^{K-t}$
P.W.V. 10% at 1.1.5
1
5
10
15
K
Time period

Fig. 1


AARR METHOD
200
100
0
- 100
- 200
- 300
- 400
- 500
- 600
- 700
1
5
10
15 years
Actual dR_t
dR_t Present value
dR_t Cumulated Pr value

Chapter 3

OUTLINE OF FINANCIAL MATHEMATICS

(by R. Lambri, A. Pasutti, M.A. Granata)

Nomenclature and symbols

P = value of principal sum, at a specified time
I = value of the interest yield of principal sum at the end of «n» years
A = amount (sum of the principal and interest at the end of «n» years)
i = effective annual interest rate
j = nominal annual interest rate
i_k = equivalent interest rate
n = number of years
k = number of periods considered in a year
r = $(1 + i)$ growth factor

$v = \frac{1}{(1 + i)}$ discount factor

$a_{\overline{n}|i}$ = present worth value of an annuity
$s_{\overline{n}|i}$ = amount of an annuity
z = deferred time

In financial transactions it is customary to pay compensation for the loan of a sum of money; this depends on the amount of money borrowed and on the time and is called «*interest*».

Rate of interest

The *percentage rate of interest «i»* states that for every $ 100, an interest of $ 1 in one year is obtained.
A sum of money, or *Principal* $ «P» contains P/100 times $ 100, and thus earns in 1 year interest of $ (P/100) i, and in n years $ I, where:

$$I = \frac{P.i.n.}{100}$$ which is to say:

$$\text{Interest} = \frac{\text{Principal} \times \text{rate of interest} \times \text{no. of years}}{100}$$

From the previous equation we can obtain the following formulae:

Interest formulae for	n years	m months	d days
Interest	$I = \frac{P.i.n}{100}$	$I = \frac{P.i.m.}{12 \times 100}$	$I = \frac{P.i.d}{365 \times 100}$
Principal	$P = \frac{100 \times I}{i \times n}$	$P = \frac{1\,200 \times I}{i \times m}$	$P = \frac{36\,500 \times I}{i \times d}$
Rate of interest	$i = \frac{100 \times I}{P \times n}$	$i = \frac{1\,200 \times I}{P \times m}$	$i = \frac{36\,500 \times I}{P \times d}$
Time	$n = \frac{100 \times I}{P \times i}$	$m = \frac{1\,200 \times I}{P \times i}$	$d = \frac{36\,500 \times I}{P \times i}$

Example: the interest I on a principal P = 400$ in 5 months at interest rate i = 9% is:

$$I = \frac{400 \times 9 \times 5}{12 \times 100} = 15$$

Compound Interest

Saving banks add the interest accrued at the end of a year to the principal; hence in the following year interest is also calculated on this interest.
This method of calculation is called *compound interest*.
Annuities are sums of money paid at fixed intervals of time, for example year, semester, quarter etc.
An initial sum (at the moment «O»), i.e. a principal P_o yields interest of:

$$I_o = P_o \times \frac{i}{100} \text{ in one year}$$

At the end of the first year (or at the beginning of the 2nd year) the new principal will become:

$$P_1 = P_o + I_o = P_o + P_o \frac{i}{100}$$

$$= P_o\left(1 + \frac{i}{100}\right)$$

Assuming that:

$$(1 + \frac{i}{100}) = r$$

where r is the *growth factor*, the previous formula can be rewritten:

$$P_1 = P_o \cdot r$$

From the beginning of the second year, the principal P_1 will earn interest. In one year this increases by

$$P_1 \frac{i}{100} \quad \text{to:}$$

$$P_2 = P_1 + P_1 \frac{i}{100}$$

$$P_2 = P_1 (1 + \frac{i}{100}) = P_1 \cdot r$$

but, since $P_1 = P_o \cdot r$, then the total amount at the end of the second year will be:

$$P_2 = P_o \cdot r \cdot r = P_o r^2$$

The same argument holds for the 3rd, 4th ... nth year.
At the end of the nth year, the principal P_o has been increased by compound interests and reaches the sum which is called the *amount*,

$$A = P_n = P_o r^n$$

Example. At 6% year by compound interest rate, a principal P_o = 1500 $ grows to the amount $ 2007.33 in 5 years; the interests for the individual years are shown on the following table:

Year	Principal $ at beginning of the year	Interest $ at the end of the year	Amount $ at the end of the year
1	1 500	90	1 590
2	1 590	95.40	1 685.40
3	1 685.4	101.12	1 786.52
4	1 786.52	107.19	1 893.71
5	1 893.71	113.62	2 007.33

If the interest had been simple, the principal would have grown to the amount:

$$P_o = 1\,500$$
$$\text{Interest } 0.06 \times 5 \times 1500 = 450$$
$$\text{Amount A} = 1\,950$$

Present value

For a known amount $A = P_n$ and a growth factor r, the initial principal P_o can be calculated from the compound interest formula:

$$P_o = \frac{P_n}{r^n} \qquad \text{or, generally}$$

$$P_o = \frac{A}{r^n}$$

Assuming $\frac{1}{r} = v$ (discount factor)

we thus have

$$P_o = A\,v^n$$

Annuities

The most important form of income from investments is the annuity, that is a sequence of payments made at previously determined times over a certain number of years.
Each payment of an agreed amount, called «*instalment*», is usually paid at the end of each of the time intervals considered (*instalment paid in arrears*) and, seldom, at the beginning (*instalment paid in advance*).
If the instalment had been invested at *i*% compound interest, gradually as they were received, then at the end of a certain period they would accumulate to a certain sum called the «*amount*» of an annuity.
The present value is the sum of money that has to be paid at the beginning of the period if the amount of the annuity is to be effectuated in a single payment.

Annuity payable in arrears

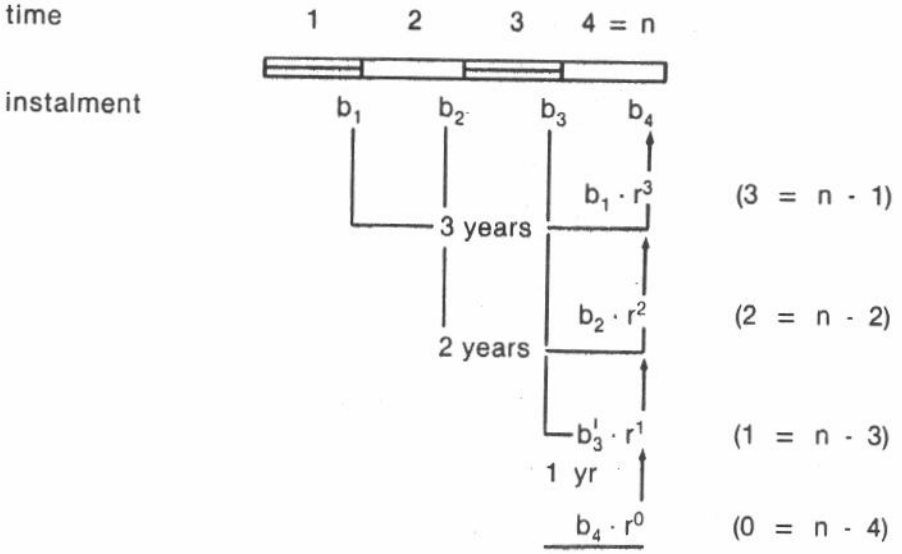
The instalments *b* payable at the end of each year accumulate to a total amount S_n (at the end of the nth year) which is the sum of a geometric series.
In fact: after n years, the first instalment *b* has the value

$$b \cdot r^{n-1}$$

the second, the value

$$b \cdot r^{n-2}$$

and so on; the latest instalment *b* has just been paid.
Example: n = 4



The total amount S_n of an annuity payable in arrears in then the sum of the geometric series:

$$S_n = b + b \cdot r + b \cdot r^2 + b \cdot r^3 + \ldots\ldots + b \cdot r^{n-2} + b \cdot r^{n-1}$$

$$S_n = b \frac{r^n - 1}{r - 1}$$

and, generalizing:

$$S_{\overline{n}|i} = b \frac{r^n - 1}{r - 1}$$ amount of an annuity payable in arrears.

To calculate the present value *a* of an annuity, the amount S_n has to be discounted at the time zero by the discount factor $v^n = 1/r^n$.

The present value becomes

$$a = S_n \cdot v^n \qquad \text{or}$$

$$a = \frac{r^n - 1}{i} \cdot v^n \cdot b$$

developing this formula, we obtain

$$a = \frac{(1 + i)^n - 1}{i} \cdot \frac{1}{(1 + i)^n} b = \frac{(1 + i)^{n-n} - (1 + i)^{-n}}{i} \cdot b$$

and finally:

$$a_{\overline{n}|i} = \frac{1 - v^n}{i} \cdot b$$ Present value of an annuity payable in arrears.

Annuity payable in advance

If the annuity is paid in advance, i.e. at the beginning of the year, each instalment *b* will be subject to interest for one year longer.
From the compound interest formula, the amount S_n of the annuity is therefore r times as much as the annuity payable in arrears:

$$\overline{S}_{\overline{n}|i} = r \frac{r^n - 1}{r - 1} b \qquad \text{or}$$

$$\overline{S}_{\overline{n}|i} = r \frac{r^n - 1}{r - 1} b$$ Amount of an annuity payable in advance.

$$\overline{a}_{\overline{n}|i} = \overline{S}_{\overline{n}|i} \cdot v^n \cdot b \qquad \text{or}$$

$$a_{\overline{n}|i} = r \frac{r^n - 1}{i} \frac{1}{r^n} \cdot b$$ and finally

$$\bar{a}_{\overline{n}|i} = \frac{1 - v^n}{1 - v} \cdot b$$ Present value of an annuity payable in advance.

Annuity payable after «z» years

If agreed, the payment of the annuity can start after a certain number of years «z». This means that:

— the amount $S_{\overline{n}|i}$ yields compound interest for z years

— the present value $a_{\overline{n}|i}$ has to be discounted for z years

where *z* is the year in which the first payment will be made. In brief:

1) If the annuity is payable in advance:

$$z/a_{\overline{n}|i} = v^z \frac{1 - v^n}{i} \cdot b$$ Present value

$$z/S_{\overline{n}|i} = r^z \frac{r^n - 1}{i} \cdot b$$ Amount

2) If the annuity is payable in arrears:

$$z / a_{\overline{n}|i} = v^{z+1} \frac{1 - v^n}{1 - v} \cdot b$$ Present value

$$z / S_{\overline{n}|i} = r^{z+1} \frac{r^n - 1}{i} \cdot b$$ Amount

Equivalent and Nominal Interest Rate

A) Equivalent interest rate «i_k»

$$i_k = (1 + i)^{1/k} - 1$$ that is, the rate «i_k» regarding 1/k of a year is equivalent to the annual interest rate «i».

B) Annual nominal interest rate

(B_1) annual interest rate «j_k» convertible k time during the year corresponding to the annual (effective) rate «i»

$$j_k = k \left[(1 + i)^{1/k} - 1 \right]$$

(B_2) annual effective rate corresponding to the nominal convertible rate «j_k»

$$i = \left[i + \frac{j_k}{k} \right]^k - 1$$

Chapter 4

GENERAL ASPECTS OF EXPLORATION AND PRODUCTION IN THE OIL INDUSTRY

(by M. A. Granata)

1. THE NATURE OF THE OPERATIONS

1.1. An analysis of the risk involved in an enterprise must necessarily cover the following:

a) the type of risk: the range of risk the company is willing to run;
b) the extent of the risk: the amount of capital involved;
c) the duration, that is, the period necessary to recover the invested capital.

The general characteristics of the gas and oil industry - in particular, the composition, formation and location of hydrocarbons and the techniques required for their exploration and production - involve highly complex problems.
In order to be sufficiently aware of the proportions of the stakes involved (investments, types of operations, etc.), the overall picture, even if only the broad outlines, must be examined.
As a rule, hydrocarbons are only found in sedimentary rocks; exploration is therefore limited to the one third of the earth's surface which is composed of these rocks (see map on the following page).

The methods used to explore for both oil and gas are the same. Exploration aims to localize possible hydrocarbon reservoirs underneath the earth's surface. The location of these «hydrocarbon traps», which have widely varying shapes and sizes, is determined by investigations carried out on the surface, and corroborated by drilling which may reach depths up to several thousand meters.
It is easy to see from this brief outline that the series of operations to be carried out has to be carefully planned.
This is especially true in view of the fact that explorational zones are assigned on a licence basis (exclusive or not) for limited periods of time. This means that programs have to be formulated in accordance with the plants and technologies which are owned or to be purchased.

In general the logical sequence of operations to be followed in an explorational venture is the following:

— Study of the areas which may be of geological interest.
— Negotations with the Governments in order to acquire a licence.

— Surface studies and geological surveys.
— Preliminary (large grid) geophysical survey (i.e. shooting and processing).
— Study of the geological and geophysical surveys.
— Detailed seismic surveys in the areas of greatest interest; these areas had been selected on the basis of the results of the previous studies and surveys.
— Survey interpretation aimed at reconstructing the morphology of the subsurface and selecting those structural elements which, for a combination of several factors, may be classified as «possible hydrocarbon reservoirs».
— Drilling of wildcat wells.
— In the event of a hydrocarbon discovery, determination of the extent of the reservoir by drilling appraisal wells.
— Development.
— Production and marketing.

Even a cursory evaluation of the extent of risk connected with petroleum operations cannot ignore the time periods and amount of investments required.

1.2. Time periods for carrying out operations

These vary considerably depending on environmental conditions. For example, high seas, ice, equatorial rains, etc. limit the number of operational days, especially in the phases regarding exploration, transport and building up plants, laying sealines, etc.

In standard situations, the average time periods (indicative) fall within the following ranges:

— The phase prior to acquisition of areas: impossible to measure.
— Exploration: 4-10 years.
— Drilling, appraisal and developent: from 3-4 years (land) to 5-6 years (off-shore).
— Production: 16-25 years.

In brief, the average overall time periods cover about 30 years, a third of which is taken up by the phases preceding production.

1.3. Investments required

There are also variations in investments depending on the various factors involved. Costs in the explorational phase may normally fluctuate between 30 and 60 million dollars (excluding signature bonuses).
As regards the development and production of new fields, the possible range of (technical) costs required to produce one barrel of oil is much wider: from a little less than one dollar (under ideal conditions on land) to values of about 7 dollars in the North Sea, or under similar conditions.
In the case of a discovery of gas, where it is necessary to equip liquefaction plants and procure a fleet of tankers, the total investments for production and marketing come to, at least, 2-3 billion dollars.

2. RISK

2.1. Mining Risk

Mining risk is usually referred to as the risk the company runs during exploration, and it is strictly tied to the probability of success.
In order to give an idea of the extent of this type of risk, let us consider two important areas: the North Sea and Nigeria.

The North Sea: in the ten year period from 1964 to 1974, a total of 514 wildcat wells were drilled, with a success rate of 25%. In spite of this, there were only 75 viable oil discoveries. This means that only one well drilled out of 7 hit a reservoir capable of being produced, and only 1 discovery out of 5 revealed a reservoir containing at least 15 million tons. The actual probabilities of commercial success in the North Sea exploration program are thus equal to only 3%, that is, one well out of 36.
And this is an area where there is a certain degree of knowledge regarding both the hydrocarbon bearing belt, and the types of hydrocarbons within this belt.

Nigeria: this oil zone is characterized by a dense concentration of small reservoirs located in a rather limited area.
The rate of success is about 18%.

As regards the type of hydrocarbons discovered, it must be observed that:

— 48% is oil
— 42% is oil and gas
— 10% is gas

However, due to governmental regulations those pools having a high gas/oil ratio (GOR) cannot be produced; therefore, the rate of success in terms of marketable oil, falls to about 10%.
The ability to predict the probable rate of successful discoveries is one of the fundamental objectives of the oil company in formulating a correct investment policy.
However, the rate of success does not only pertain to the mere discovery of hydrocarbons, but is directly dependent on the type and volume of the discovery.
In other words, the fact must be emphasized that, if the enterprise exploration concerns offshore areas and/or onshore areas at very great depths, then there will be a risk of making discoveries which, even though having the same volume as other discoveries, are not commercially feasible.
From this consideration it stems that, before undertaking an explorational venture, the exploration team must select those areas where hydrocarbon accumulations having certain minimum dimensions are likely to be found; in the long run, this determines a reduction in the rate of probability of success(*).

(*) This subject will be dealt with in greater detail in chapter 8.

The overall risk may be further increased by the everpresent possibility of discovering hydrocarbons in a different state than expected; this involves all the unknowns (and thus risks) that such a situation brings, and we will now try to present a brief outline.

2.2. Market Risk

The changed political and institutional picture which emerged during the energy crisis on the one had, and the depletion of possibilities of discoveries in «traditional areas» (**) on the other, contributed to the policy of «risk sharing» by means of the joint venture.
The fact of having several partners in the same operational venture means that there are more possibilities for conflicts of interest.
These conflicts become evident after a discovery has been made and the type of hydrocarbon bearing zone does not allow easy division of the product.
In fact, if the product has chemical-physical characteristics which make it unfit for the company's markets (those markets on which the company has based its vertical integration), then the oil company has to adopt a policy of exchange or sell its own share of production.
The risk of finding oneself with the lesser share of the agreements is obvious.
This type of risk can be illustrated in a macroscopic way: for example, let us suppose that quantities of natural gas are discovered in areas which logistically require a whole series of new plants for liquefaction, transport, re-gassification and distribution.

At this point the oil industry must face a set of problems due to:

— Lack of capital to finance new plants;
— Necessity of finding financial partners and/or long term, low interests loans.

Now, a third party agrees to become a partner if it is interested in being supplied with those amounts of gas necessary for its marketing set up.
Furthermore, the third party would be able to negotiate loans backed up by guarantees from its own country's government who would then be able to set up facilitations in return for the right to import all the produced gas.
In this type of situation the risk, described above, becomes obvious.

2.3. Financial Risk

This is proportional to the extent of the investments necessary for financing the planned operation.
The duration of financial risk is equal to the company's financial exposure, and starts from the date of the first investment until the Pay Out Time is reached for values discounted at a figurative interest rate.

(**) This term more correctly means the volume of rock to be explored.

Thus there is a need for stability of the conditions which determine the validity of all inputs utilized in evaluating the project, at least for the period of profits up to Pay Out.
Stability of conditions is tied to a set of factors, some of which are dependent on, or controlled by, the company; other more significant factors cannot be attributed to the company but are to be included in the category of political risk.

As far as the first set of factors is concerned, let us only mention:

1) the financial capacity of the company to absorb a possible loss of all the capital risked;
2) the capacity to finance development and production operations (investments in the range of several hundred million dollars), using its own capital or loans;
3) the operational structure which, due to its influence on the financial situation, must be able to get the project going within the forecasted time periods.

In our opinion, a more correct evaluation of this kind of risk should also take into account the existing or predicted inflation rate.
The financial results of a project, as seen by the cash-flows (discounted or not) and calculated on the basis of investments made with the company's own capital, must be evaluated in terms of their actual purchasing power. In fact, the cash flow should be related to the cost of future investments and, more generally, to future technical production costs.

2.4. Currency Risk

By currency risk we do not refer to the risk depending on present or future inflation or deflation but rather to that risk pertaining to «exchange controls» in force in the various countries.

In brief: if the government in the host country uses its option to become a partner in the joint venture, it could reimburse its shares of investment and/or running costs in local currency, money which may have practically no other purchasing power elsewhere.

Another risk could lie in the obligation to import into the host country all the sale revenues from abroad for conversion into local currency.

In this case the foreign bills would be subject to commisions and exchange taxes unilaterally fixed by the Central Bank of the country.

The treasury of the country could then set a limit to the exportation of profits.

2.5. Political Risk

When an oil enterprise makes a careful analysis of the political risk, from the standpoint of predictions and forecasts, generalizations cannot be made; such an analysis has to be carried out in strict reference to the particular country where the company is operating or

intends to set up operations and to the various tensions, on the surface or latent, which could go off there. Any conclusions or decisions about whether or not to start up the project have to be based on a foreseeable political stability in the area.
The most strongly feared and widespread risk is the danger of nationalization.
One conclusion which may be drawn from recent events is that the more a producer country feels independent from the consumer countries (also in terms of autonomy in enterprises), the more it will tend to reap the maximum benefit from the operations underway within its boundaries.
Governments can achieve this objective in two ways.

a) through stiffer taxation and the right to claim participating shares in the operations;
b) by resorting to actual nationalization.

The first strategy has already been discussed in the preceding pages; we will now attempt to examine the economic aspects for the involved company as far as the second one, nationalization, is concerned.
When, as in the case of British Petroleum in Libya, a government issues a decree to nationalize and declares that all the property of an oil company belongs to the state, the act is formally correct. Hydrocarbon reserves are property of the state.
The state claims the right, after adequately compensating the licencee, to produce its own oil. It is the formal, legitimate act of a government who intends to exert its own sovereignty, especially in view of the fact that the act includes reimbursement of all the «book value» costs borne by the licencee; book value corresponds to the account balance of the company. As a matter of fact, the oil company involved is actually an agency created exclusively to develop and produce from one or more mining concessions.
Its balance sheet, on the basis of which the compensation is calculated, only takes account into the costs and proceeds pertaining to the operations underway in that particular concession area (s).
Nationalization procedures completely ignore the fact that the profits obtained by the company are largely used to finance exploration ventures in other parts of the world.
An oil company facing several decrees of nationalization would then be deprived of its financial funds for exploration, and may have difficulty in surviving and sometimes the total failure is inevitable.
Another aspect of the risks connected with nationalization is that the product is no longer available to the company; this provokes immediate, serious repercussions in its commercial organization (transformation, sales, etc.).
A situation of this kind can also be determined by a form of hidden nationalization (the government imposes and increases its participating interest up to 80-90%).
Therefore, the company has to replace its production losses either from the nationalizing government or from the market of spots which will be then influenced by the new demand.
In either case, the danger of having to pay much higher prices is quite significant.

3. PROCEDURES FOR FACING RISKS

The higher forms of risk have obviously had a great influence on the development of the oil industry, and have made oil men look for instruments and strategies capable of minimizing their impact.

The action taken in pursuit of this objective mainly regards: the geographical diversification of explorational operations, the partecipation in explorational ventures, development and production by means of «joint ventures», the development of vertical integration and exchange agreements.
Whereas the first way of facing risk is quite clear, the other approach must be briefly explained.
The «joint venture» is a form of organization which is common to both exploration and production, where after having borne its own share of costs, each partner (*) has the right to claim a proportional share of the production.
This form of participation allows the individual companies to diversify investments, distributing their resources into various projects and into diverse possible production zones according to the principle of «risk sharing».
Vertical integration is the expansion of the venture in the downstream phases (transport, refining and marketing in the petroleum cycle). From the point of view of «industrial organization», this type of development provides substantial advantages for the oil venture, in that:

— it permits exploitation of the complementary techniques of the industrial processes connected with the various phases (for example, projecting refineries versus the type of crude);
— it guarantees a greater degree of certainty in carrying out company plans because all the phases of the process are controlled by the same enterprise;
— the improved coordination of the cycle provides significant savings in both transport and capital costs;
— it reduces the costs of information needed for decision-making in the various phases, and it minimizes marketing costs because the transfer of the products occurs within the enterprise itself.

Finally, vertical integration has served to reduce the risks of a political nature: in the first place, the control of outlet markets increases the marketing power of the enterprise as far as the producer state is concerned; in the second place, throughout history, vertical integration has enabled refineries to be located near consumer markets; this minimized the effects on any possible act of nationalization, and thus any interruptions in supply since the enterprise could turn to other states or production zones.
In the past few years a third method of facing risk has been developed: the exchange relationships among the companies during the phases of transport and marketing.
Certain types and quantities of the final product are interchangeable in accordance with the vertical integration of the individual companies and with the aim of cutting down rental expenses in the total final production cost.
All of this boils down to the possibility of taking advantage of the whole transport, refining and marketing organization which, in actual fact, is at an international, intercompany level.

(*) (Which preserves its own legal identity)

Chapter 5

PRINCIPAL TYPES OF AGREEMENTS

(by R. Lambri, A. Pasutti, M.A. Granata)

The principal forms of agreements used in the oil industry are (*):

1) Concession Contract
2) Production Sharing Contract
3) Service Contract
4) Participation of the producer country through shares of local companies
5) Joint Venture

The following pages will deal with these forms of agreements, but only from an economic point of view.

1) Concession Contract

Under this type of contract the oil company bears all the exploration costs (at its own risk) and, as a general rule, all the costs of development, starting up production and managing the commercial reservoirs.
The company has the right to take in kind all oil produced, less a percentage of such oil (or, as the case may be, an equivalent value of money) as royalty, which is generally imposed by law.
Furthermore, the company is subject to pay taxes established by law (income tax and other customary fiscal charges).
The major drawbacks are the risk of being nationalized and the obligation of being continually subject to possible legislation controlling and imposing the reinvestment of dividends.
The advantages lie in the immediate availability of the produced oil regardless of its price or market value.

2) Production Sharing Contract

Under this type of contract the oil company bears all the exploration costs (at its own risk) and, as a general rule, all the costs for development, starting up production and managing the commercial reservoirs.

(*) Obviously there are many other types of contracts.

In return, the producer country's government gives the company a share of oil as compensation for (1) operating costs and capital investments (2). The available production is then divided up between the producer country (goverment or its designee) and the operating company. The oil company's share is the «profit oil» to compensate for the exploration risk and know-how.
Furthermore, the state assumes responsibility for all taxes. The advantages of such a contract, however, are only apparent because, when the company finds itself operating under an economically inflationary regime, the amount of equity oil is less than it would be if the regime were economically stable.

In practice, however, the governments of the producer countries tend to leave to the oil companies amounts of oil products which provide a return based on historical rather than actual values. This lack or a re-evaluation of the investments translates immediately into (in terms of purchasing power) a loss of the cost oil value. The amount of cost oil, in fact, suffers a decrease which is directly proportional to the inflation rate existing between the time the expenses were borne and recovered. (3)
The increase in profit (which is equal to the proportion of cost oil) is never enough to compensate the loss sustained in terms of «cost oil». Furthermore, since the nominal revenue taxes tend to rise as a function of the inflation rate, the governments reduce the profit share so as to keep the nominal rate of return constant. Therefore the contractor runs the risk of seeing all his profits vanish into thin air.

3) Service Contract

The conditions are usually the same as those in the Production Sharing Contract.
The only major variation consists in the fact that:

a) re-payments are made in cash;
b) in recognition of the risk borne by the contractor and as compensation of his know-how, the contractor has the right to purchase a proportion of the product at a discount price.

4) Participation of the producer country through shares of local companies

This kind of participation is used within the framework of a concession, granted to a Limited Liability Co. which is formed by two or more oil companies.
Usually the Ltd. company is originally formed by oil companies; the government reserves the right to take a portion of the stock capital in the case of a commercial discovery. Therefore the oil companies undertake oil exploration at their own risk whereas costs for development and production of fields are borne by the Ltd. company which includes the state designee.

(1) Generally this never exceeds 35-40% of the production. In some countries this share may reach 100% of the production: this is in order to act as an incentive to exploration.

(2) In the form of depreciation shares. The relative taxes are not always recognized as costs for the company.

(3) See Chapter 2: Investment Policy.

The companies get back their investment (if exploration has been successful) through the depreciation allowance and receive dividends from the sales of petroleum products.
The oil companies usually purchase oil through «Buy Back» contracts with the Ltd. company.
The major drawbacks are those described for the Concession Contract. In addition, the buy back price is determined by negotiation.

5) Joint Venture

In the strict sense of the term, a joint venture consists of two or more companies which form an association in a specific enterprise even though they maintain their legal identity (that is, they do not form a new company) (1).
The joint venture scheme may be used both within the framework of a Concession or of a Production Sharing or Service Contract.
The costs for exploration, development and production are put up by the individual partners, according to their «participating interest» percentages. In turn, they have the right to share, in the same proportion, all benefits deriving from the contract stipulated with the producer country (as described under 1,2 and 3 above).

(1) As a rule, one of the partners acts as operator, leaving the other (s) the role of financial partner (s).

Chapter 6

DEPRECIATION OR AMORTIZATION OF PLANT ASSETS

(by M. A. Granata)

The principle on which basis investments are depreciated arises from the need to make them contribute to the determination of the production cost of the outputs produced.
Since the company is liable for tax on net income, and such net income being in turn given by the difference: Sale Proceeds-Production Costs, it is self-evident that depreciation must be included in the deductible allowable costs for determining such taxable income.
The allowable depreciation methods vary, in general, in accordance with applicable law regulations in the various countries and according to the kind of activity.
Sometimes, as a deviation from law regulations, a depreciation method is agreed upon, which is more favorable for the company, when this falls for example into the «pioneer status».

The depreciation methods, which are most widely used in the petroleum industry, are:

1) Annuity Method;
2) Declining Balance Method (and double D.B.M.);
3) Straight line Method;
4) Production Method.

1) Annuity Method

It is the same method as the one shown in loan repayment (see chapter «Outline on Financial Mathematics»).

2) Declining Balance Method

The book value of the assets at the start of depreciation period is multiplied by a certain percentage «r», and the resulting figure represents the depreciation for year 1.
Such percentage «r» may be single or composite. In the latter case it consist of two items:

p = «initial» : is applied to the book value of the assets to be depreciated for the first time;
q = «annual» : is applied to total value allowed to be depreciated in a given year.

The total value allowed to be depreciated year after year is equal to:

$$\sum_{t=1}^{t} \text{INV}(t) - \sum_{t=1}^{t-1} \text{AMM}(t)$$

If K is the first year the company noted sale proceeds, depreciation «M» will be calculated according to the following equations:

for t = K

$$M(t) = (p + q) \sum_{t=1}^{K} INV(t)$$

for K < t > n

$$M(t) = q \left[\sum_{t=1}^{t-1} INV(t) - \sum_{t=K}^{t-1} M(t) \right] + (p + q)\, INV(t)$$

for t = n

$$M(t) = \sum_{t=1}^{n} INV(1) - \sum_{t=1}^{n-1} M(t)$$

In double declining balance method the percentage r = 2 r = 2 (p + q)

3) Straight Line Method

If the depreciable life is n periods, then the periodic depreciation charge is 1/n of the depreciable costs, according to the following equation:

$$M(t) = r. \sum_{t=1}^{K} INV(t)$$

When also investments for enlargement, optimization and/or replacement will have to be depreciated, we will have as many depreciable lives as there are years in which such investments have been made.
As a result, each set of assets will be depreciated according to a percentage r_t obtained from the ratio

$$r_t = \frac{1}{n - t + 1}$$

Where:

t is the year the enlargement and/or replacement investment is made;

n is the last year of depreciable life.

4) Production Method

The depreciable asset (given a depreciable life) is measured not in elapsed time, but in units of outputs.
Then the *depreciation charge* for a period is defined as the function of depreciable cost equal to the fraction of the expected total output produced during the period.
In other words, by this method the investments affect equally the technical production cost of each output which, it is estimated, they will contribute to obtain.

The following equation will be used:

$$M(t) = \frac{\sum_{t=1}^{t-1} \left[INV(t) - M(t) \right]}{\sum_{t=n}^{t} P(t)} P(t)$$

where:

M (t) : is the total amount of depreciation for year t
INV (t) : investment to be depreciated
P (t) : output produced in year t.

Chapter 7

REPAYMENT OF A LOAN

(by M. A. Granata)

The repayment of credits and mortgages «P» (e.g. for investments or new buildings) is usually arranged in such a way that a prefixed «n» number of instalments $A_1, A_2, \ldots\ldots A_n$ are paid at agreed time periods t_h (with $h = 1,2,3 \ldots\ldots n$):
As a general rule a debt is fully paid when:

$$P.r^n = \sum_{h=1}^{n} A_h \cdot r^{n-h}$$

at time n, the amount of the loan is equal to the sum of the amount of the instalments

or:

$$P = \sum_{h=1}^{n} A_h \cdot v^h$$

the sum of instalment present values, at time zero, is equal to the amount of the loan

Many methods of loan repayment have been elaborated on this basic principle.
The two methods normally used in this field, will be analyzed in the following pages.

A) Repayment of a loan in «n» constant instalments in «n» times.

According to this method, at the end of each period $t_1, t_2 \ldots\ldots t_n$ a constant instalment «A» is paid to the creditor; this constant instalment pays off a portion of the debt (principal), and the interests accrued up to that moment are paid, That is:

$$A = \frac{\text{Principal}}{a_{\overline{n}|\, i}}$$

periods for repaying a loan in constant instalments

$$A = \text{Principal} \times \frac{j/k(1 + j/k)^{kn}}{(1 + j/k)^{kn} - 1}$$

This is the generalized formula for calculating an instalment where:

i = annual effective interest rate
j = annual nominal interest rate
k = fraction of a year

If the repayment of a loan, is made, for example, in annual or semi-annual constant instalments, the preceding formula becomes:

$$\text{annual repayment} = \text{Principal} \frac{i(1+i)^n}{(1+i)^n - 1}$$

$$\text{semiannual repayment} = \text{Principal} \frac{j/2\,(1+j/2)^{2n}}{(1+j/2)^{2n} - 1}$$

If the repayment of a loan takes place after a certain number of years (and/or fraction of a year) from the date when the draw-down loan of the period has expired, during this «grace period» obviously only the accrued interests will be paid at the end of each year.
Whenever it is necessary to indicate this share of capital and the share of interests which, at a moment «h», form the instalment, just like the total of the paid off and residual debt, the formulas to be applied are as follows:

$$C_h = \text{Principal} \frac{r^{h-1}}{s_{\overline{n}|1}} \qquad \text{capital share}$$

$$I_h = \text{Principal} \frac{a_{\overline{n-h+1}|i}}{a_{\overline{n}|i}} \cdot i \qquad \text{share of interests}$$

$$E_h = \text{Principal} \frac{s_{\overline{h}|i}}{s_{\overline{n}|i}} \qquad \text{paid off debt}$$

$$R_h = \text{Principal} \frac{a_{\overline{n}|-h\,i}}{a_{\overline{n}|i}} \qquad \text{residual debt to be paid}$$

For example, suppose we want to calculate the constant annual instalment necessary to amortize a 2 million Lire debt at 6% in 8 years.

$$\text{The instalment} = \frac{2{,}000{,}000}{a_{\overline{8}|\,0.06}} = 2{,}000{,}000 \times 0.16103594 = 322071.88$$

The plan for amortization of the debt will thus be:

year h	instalment	interest payment	principal repayment	debt paid off at the end of the year	residual debt at the beginning of the year
0	—	—	—	—	2 000 000.00
1	322 071.88	120 000.00	202 071.88	202 071.88	1 797 928.12
2	322 071 88	107 875.69	214 196.19	416 268.07	1 583 731.93
3	322 071.88	95 023.91	227 047.37	643 316.04	1 356 683.96
4	322 071.88	81 401.03	240 670.85	883 986.89	1 116 013.11
5	322 071.88	66 960.78	255 111.10	1 139 097.99	860 902.01
6	322 071.88	51 654.12	270 417.76	1 409 515.75	590 484.25
7	322 071.88	35 429.04	286 642.84	1 696 158.59	303 841.41
8	322 071.88	18 230.47	303 841.41	2 000 000.00	—

B) Amortization of a loan in «n» years at constant capital shares.

According to this method, at the end of each period «h» a constant fraction of the principal is paid, in addition to the interests matured on the residual debt.

The formulas to be applied are as follows:

$$C_h = \frac{\text{Principal}}{n} \qquad \text{capital share}$$

$$I_h = (\text{Principal}) \times i \times \left(1 - \frac{h-1}{n}\right) \qquad \text{interest share}$$

adding the two together, we get:

$$A_h = \text{Principal} \left[\frac{1}{n} + i\left(1 - \frac{h-1}{n}\right)\right] \qquad \text{instalment}$$

$$E_h = \frac{\text{Principal}}{n} \cdot h \qquad \text{paid off debt}$$

$$R_h = \text{Principal}\left(1 - \frac{h}{n}\right)$$ residual debt

Example: it is necessary to repay a 2 million Lire loan in 8 years at a rate of 8% in constant capital shares.

	Principal repayment	Interest paid	Annual payment	Residual
0	—	—	—	2 000 000
1	250 000	160 000	410 000	1 750 000
2	250 000	140 000	390 000	1 500 000
3	250 000	120 000	370 000	1 250 000
4	250 000	100 000	350 000	1 000 000
5	250 000	80 000	330 000	750 000
6	250 000	60 000	310 000	500 000
7	250 000	40 000	290 000	250 000
8	250 000	20 000	270 000	250 000
Tot.	2 000 000	720 000	2 720 000	0

Chapter 8

DECISION METHODS: STATISTICAL AND MATHEMATICAL MODELS

1. THE DECISION TREE METHOD

(by M.A. Granata, D. Gravino)

This method consists of finding the optimum sequence of the activities to be performed. It seems to be the ideal method for making selections which are theoretically based.
To check the reliability of the results, they should be compared with the real operating times, possibilities and conditions under which the company must operate.

1.1. Definition

Before commencing the analysis of the Decision Tree, we think it advisable to define a few concepts and notes:

The Expected Monetary Value or EMV is the mathematical expectation that a determined profit will ensue.
The EMV is, therefore, determined by the product of the probability «e», that a given event will take place, and the profit «p» which would be obtained once the expected results is achieved.

$$EMV = e \cdot p$$

In the face of two or more decisional alternatives, the resulting EMV is given by the sum of the EMVs relevant to each of the possible results connected with the alternative itself.
Lacking outside influences, the role of the EMV as an economic indicator, is considerable; it presupposes that, given several alternatives, the choice should fall upon the one offering the highest positive value among those obtained.

It has been indeed shown statistically «a posteriori» that the whole of the choices, made systematically on the basis of the maximization of EMV, determine a higher total net profit than that obtainable when following any other decisional strategy.
In the determination of the mathematical expectation, the input data may be considered as present or actual value. In the first case, results in terms of Expected Present Worth Value (EPWV) will be obtained, whilst Expected Monetary Value (EMV) will be obtained in the second case.

In considering the EMV or EPWV, it is necessary to remember that a negative value does not correspond to a capital loss (as occurs in the case of total failure) but may only indicate that the AARR obtainable from the project will be less than the discount factor considered.

A positive value must be interpreted as an extra profit compared with the one contained in the cost price (*), which is determined on the basis of the expected AARR and assumed to be equal to the discount factor (or discount rate) used.
Finally, a zero value, will indicate that the AARR offered by the cash flow is equal to the discount rate.

1.2. Application

This is done on the basis of a number of assumptions. A group of experts has set up a «decision tree», made up for set of operational alternatives, which includes all the necessary information (both technical and economic) and the amount of risk correlated to the same.
The economic results (discounted at 12%) have been drawn from the preliminary economic evaluation (**).

1.2.1. The probabilistic values used are those given to the economists by the concerned technical departments which have proposed the venture in the area. In this respect, it should be noted that the probability of a successful outcome of the first exploration well (equal to 20%) does not necessarily imply the identification of a commercially exploitable field (this probability being obviously lower). The discovery of a subcommercial field (or at the extreme limit, containing only one barrel of petroleum) is only a proof that the assumed probability level was correct.
The minimum, average (or more probable) and maximum values of recoverable reserves and respective probabilities have been indicated on the basis of geological and regional considerations on the basin, extrapolated from the available results of exploration activities.
The reliability levels for reserves, and daily production rates per well, are given in the two recapitulating charts hereinafter.

SUMMARY OF INPUTS AND OUTPUTS FOR DECISION TREE PATTERN

I PROBABILISTIC DATA (***)

a) Probability of successful results (Pre-acquisition) = 20%
   Probability of successful results (After first Well) = 40%

(*) «Cost price» means the price resulting from the sum: production cost + profit margin; where the profit margin is the one calculated (according to the Discounted Cash Flow Method) on the basis of the expected AARR of the project.

(**) In the event of unsuccessful drilling results, the anticipated financial losses are relative to the general studies carried out, to the cost of the aeromagnetic survey acquired, to the acquisition bonus, cost of negotiations, and expenses incurred during the various phases of exploration (seismic surveys and well drilling).

(***) Furnished by technical departments.

b) *Recoverable reserves* (Petroleum)

Probability of discovering 100 million bls. = 30%
Probability of discovering 500 million bls. = 50%
Probability of discovering 1000 million bls. = 20%

c) *Potential productivity per Well*

Probability of obtaining 1000 BOPD = 10%
Probability of obtaining 5000 BOPD = 60%
Probability of obtaining 10000 BOPD = 30%

RESULTS (Present value discounted at end of 197 ...):

RESERVES (Million bls.)	*FLOW-RATES* (BOPD/well)	*PROFIT at 12%* Million $	*AARR*
330	1750	—23.7	8.5%
	2500	— 7.1	10.9%
	3500	+ 5.7	13.0%
470	2500	+ 10.9	13.4%
	3500	+ 28.6	16.1%
	5000	+ 41.9	18.3%
670	3500	+ 56.2	18.3%
	5000	+ 81.3	21.8%
	7000	+ 90.4	23.6%

II EXPLORATION AND ACQUISITION EXPENSES

(million $, 12% P. value end of 197 ...)

Branch «A»		*Absolute values*	*Cum. values*
Acquisition bonus		1.50	1.50
Other pre-acquisition costs		0.14	1.64
1st seismic		0.54	2.18
2nd seismic		0.38	2.56
1st exploration well		4.21	6.77
2nd exploration well		3.03	9.80
	Total	9.80	

Branch «B»

Acquisition bonus	1.50	1.50
Other pre-acquisition costs	0.14	1.64
1st seismic	0.54	2.18
1st exploration well	4.40	6.58
2nd seismic	0.36	6.94
2nd exploration well	3.65	10.59
Total	10.59	

*III PROBABILITIES CONSIDERED IN THE TREE (VALUES > X)**

		(cum. < X)	(cum. > X)	(Prob. > X)	
Reserves	330	0.64	0.36	0.53	(= 0.36 : 0.68)
	470	0.77	0.23	0.34	
	670	0.91	0.09	0.13	
			0.68		1.00
Production rates (BOPD/W)	1750	0.185	0.815	0.39	
	2500	0.285	0.715	0.30	
	3500	0.440	0.560	0.27	
					1.00
	2500	0.285	0.715	0.45	
	3500	0.440	0.560	0.36	
	5000	0.700	0.300	0.19	
					1.00
	3500	0.440	0.560	0.58	
	5000	0.700	0.300	0.31	
	7000	0.890	0.110	0.11	
					1.00

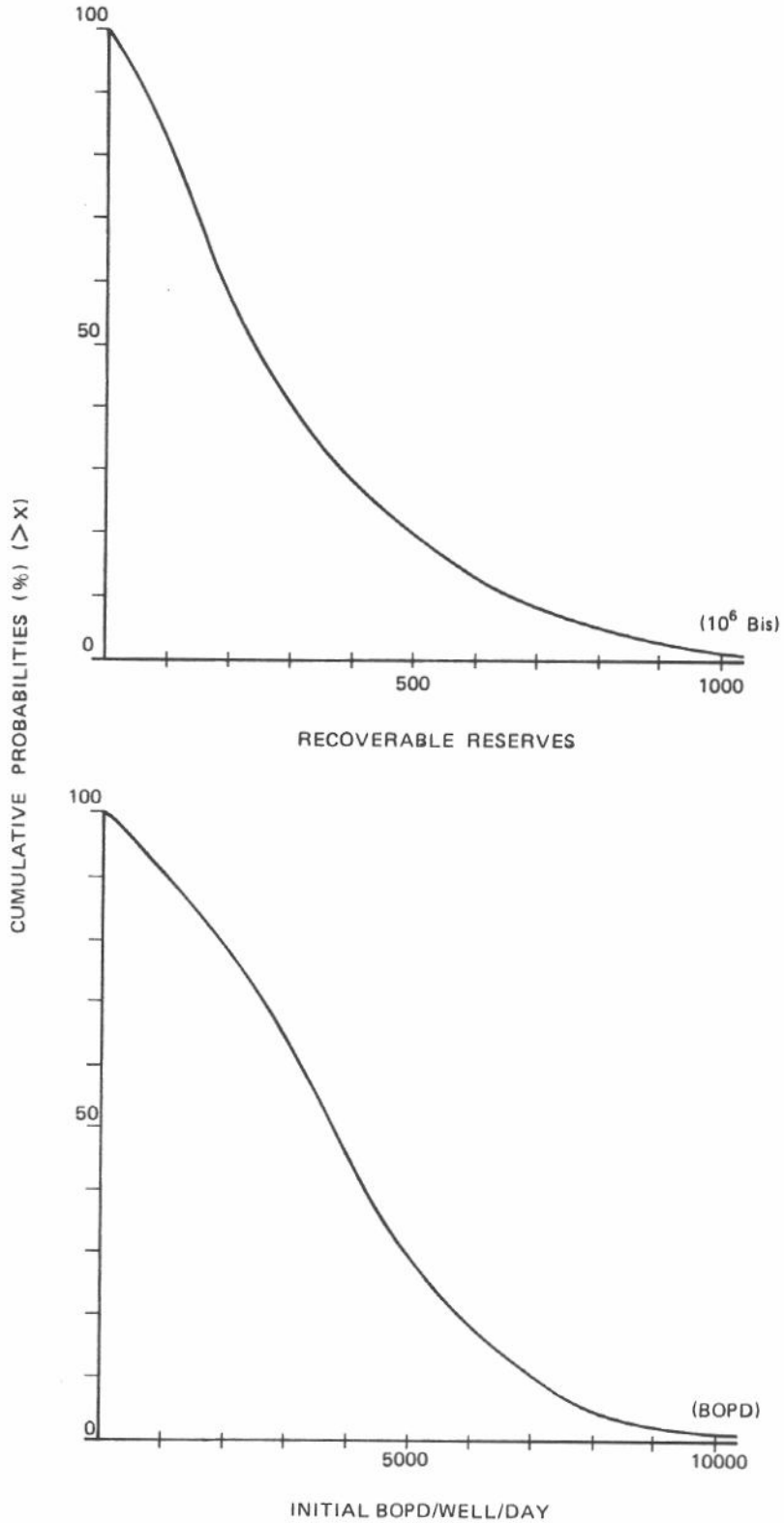
1.2.2. In Figure 3 are clearly identified two major branches (branch A and B) set up as a function of two possible operational strategies.
The values of recoverable reserves (330, 470 and 670 Million barrels) have been chosen as a function of:

(a) the capacity of the structure (identified by airborne magnetometric survey and delineated by large grid seismic survey),

(b) the possible stratigraphic series. Similar considerations have been made for the daily flow-rates, ranging from 1750 to 7000 barrels per well.

* see fig. 2.

Fig. 2 - Probability of discovering recoverable reserves "THE LEAST"



The first decision point (A) puts the management under the condition to elect whether to go ahead with the venture or reject it. If the latter decision were made, it is obvious that there would be neither profits nor losses (excluding the loss for the cost of the aquired geophysical survey, to be expensed as «cost for general studies» in the parent company's balance sheet).

If the management's decision is to go ahead with the project, all costs for feasibility studies, area acquisition, signature bonuses, if any, and first detail seismic survey will have to be charged to the item «exploration investments» in an extra-accounting analysis while awaiting to be included in the «Assets and Liabilities» of the joint venture company to be set up.

In case the decision is negative, upon completion of the seismic survey, the Management is faced with two alternatives: either to drill the first exploration well (branch A) immediately, or to perform a second, more detailed, seismic survey to better select the well location (branch B). At this point (b) the «a priori» success probabilities are still equally distributed (*).

Going through branch B, which differs from the other only in the different sequence of exploration operations, a new alternative point (c) arises, after drilling the first well. If the well turns out to be a producer (20% probability), the exploration is considered over: the recoverable reserves, with respective flowrates per well, are those assumed in the preparation of the forecasted cash flows: the probabilities, as inferred from fig. 2, are indicated in the preceding summary III.

But if the first well is dry (80% probability), this result determines a new decision point (d). In fact, one must decide among the following possible decisions:

1) *either abandon the area*, if the well is judget to be correctly drilled on the basis of reliable seismic interpretation; or

2) *continue* alone over a further exploration period. In this case the well drilled has shown that either the hole was wrongly located on a structure delineated by a correctly interpreted seismic survey, or it was located correctly, but on a structure revealed by a survey which was too approximative, or the interpretation of which was wrong (**); or

3) *assign a participating interest in the venture to another company (under a farmout agreement)*, which would bear at its own risk, all subsequent exploration expenses (second seismic survey and well).

Clearly in the latter two alternatives the expectation of a successful discovery must be greater than assumed before the beginning of the drilling, to justify continuing exploration alone, or to attract the participation of another company. The probability of success for the second exploration well has been thus raised to 40%.

(*) The judgement elements are identical: in both cases only the data emerging from the first survey phase (seismic 1) are known.

(**) There are various possible reasons for error here. The most common is due to the application of a wrong law of velocity. It should be noted that the exact velocity law is only that obtained experimentally in the area. A well must be available for its determination.

To continue exploration alone entails as said before the carrying out of a second, more detailed, seismic survey. The results of this survey will make it possible to decide whether to abandon the area or drill the second exploratory well. Even if considered in the «tree», the probability that the second seismic survey will confirm the studies and motivations for drilling the first well seems remote; in the affirmative case (i.e., if the previous overall picture is confirmed), the area should be abandoned.

The outcome of the second well will be definitively determining for the purpose of judging whether to continue or not operations.
Should the well be a dry hole, the area would be abandoned; if a producer (*), green light would be given for the development and production project.
If the Management should decide on a farm-out agreement, the cost of the second seismic survey and exploration well would be completely or partly borne by the joining company, against acquisition of an X% participating interest. In this case, the possibility of abandoning the area after the seismic survey will no longer exist.

1.2.3. Having positioned the probabilities as descibed in the various sections of the tree (fig. 3) and the profits and losses resulting from the economics prepared for each of the assumption made (fig. 4), it is now possible to go back to the calculation of the overall EPWV of the venture, and hence determine the best operational strategy to follow.

In fact, by proceeding backwards and multiplying the economic results by the respective probabilities, it is possible to determine the EPWV for each alternative point. A decision point d), for example, the three confluent strategies are characterized by the following values (see figs. 3 and 5).

a) farm-out (50%)	— 0.9 million $
b) area surrender	— 6.6 million $
c) continuation of operations (100%)	— 2.3 million $

Thus, these are three negative EPVW values.

However, because the target of the method is to maximize profits and, at least, minimize losses (in terms of mathematical expectation) the best operational strategy will be the first: farm-out against transfer of a 50% participating interest.

1.2.4. In conclusion, if the methodology described is adopted for the analysis of the two branches A and B of the tree, the following quantification of the EPWVs for venture points c) and e) (2.4 million $ for the former; 1.5 million $ for the latter) can be done.

(*) From a commercial point of view.

Fig. 3

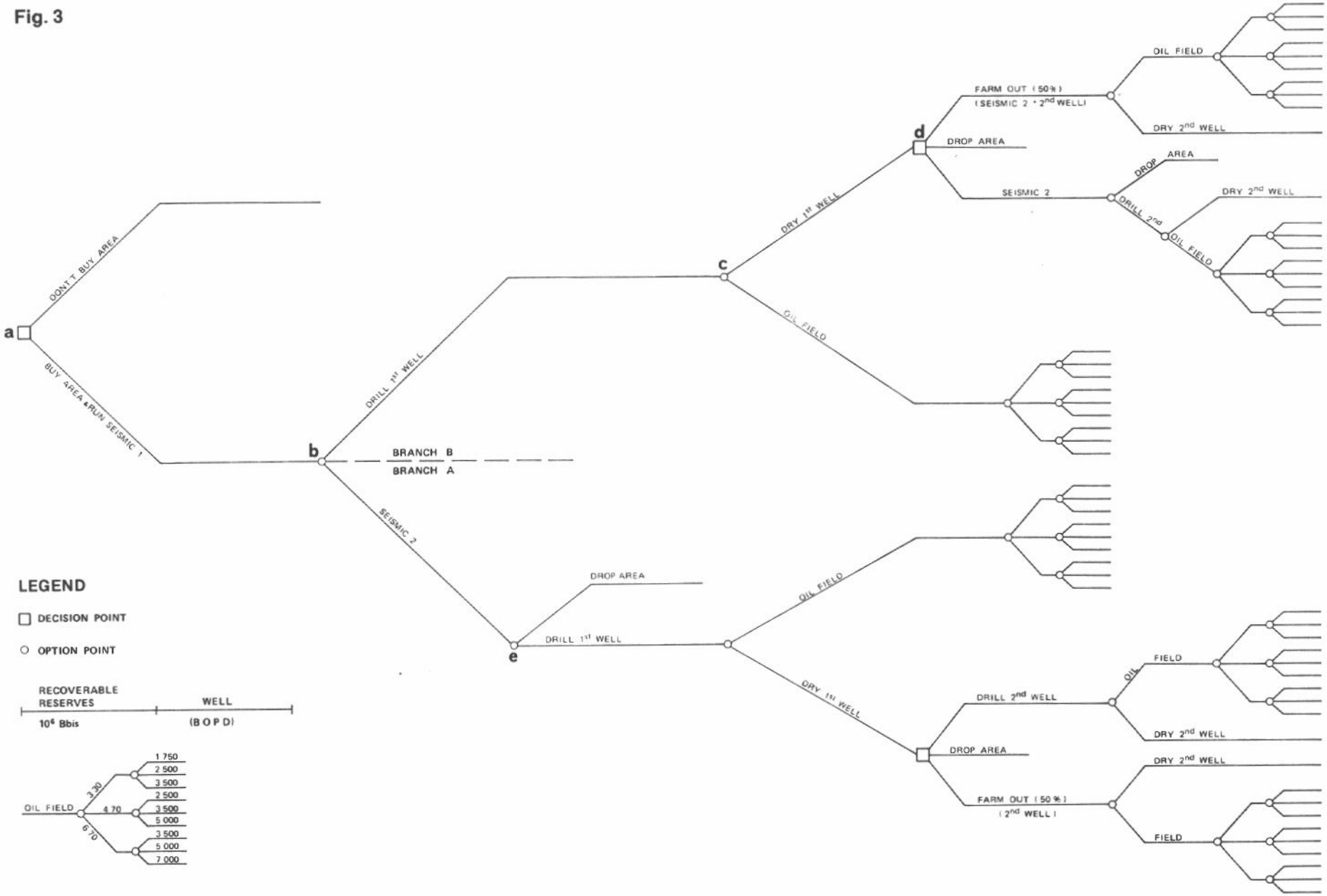

a
DON'T BUY AREA
BUY AREA & RUN SEISMIC 1
b
DRILL 1st WELL
SEISMIC 2
BRANCH B
BRANCH A
c
DRY 1st WELL
OIL FIELD
d
FARM OUT (50%)
(SEISMIC 2 + 2nd WELL)
DROP AREA
SEISMIC 2
OIL FIELD
DRY 2nd WELL
DROP AREA
DRILL 2nd
DRY 2nd WELL
OIL FIELD
e
DROP AREA
DRILL 1st WELL
OIL FIELD
DRY 1st WELL
DRILL 2nd WELL
OIL FIELD
DRY 2nd WELL
DROP AREA
FARM OUT (50%)
(2nd WELL)
DRY 2nd WELL
FIELD
LEGEND
DECISION POINT
OPTION POINT
RECOVERABLE RESERVES
10⁶ Bbls
WELL
(BOPD)
OIL FIELD
3 30
4 70
6 70
1 750
2 500
3 500
2 500
3 500
5 000
3 500
5 000
7 000

Fig. 4

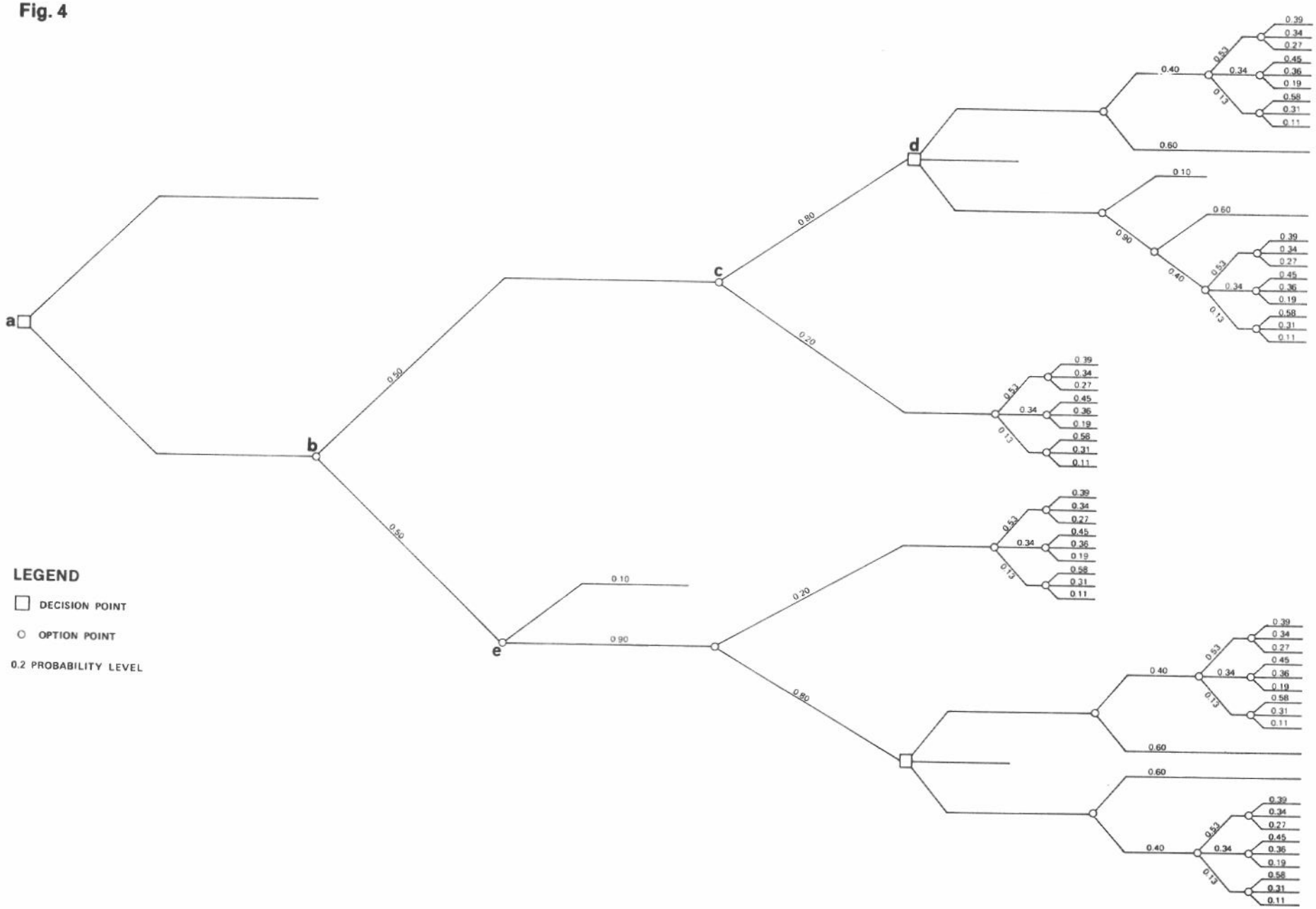
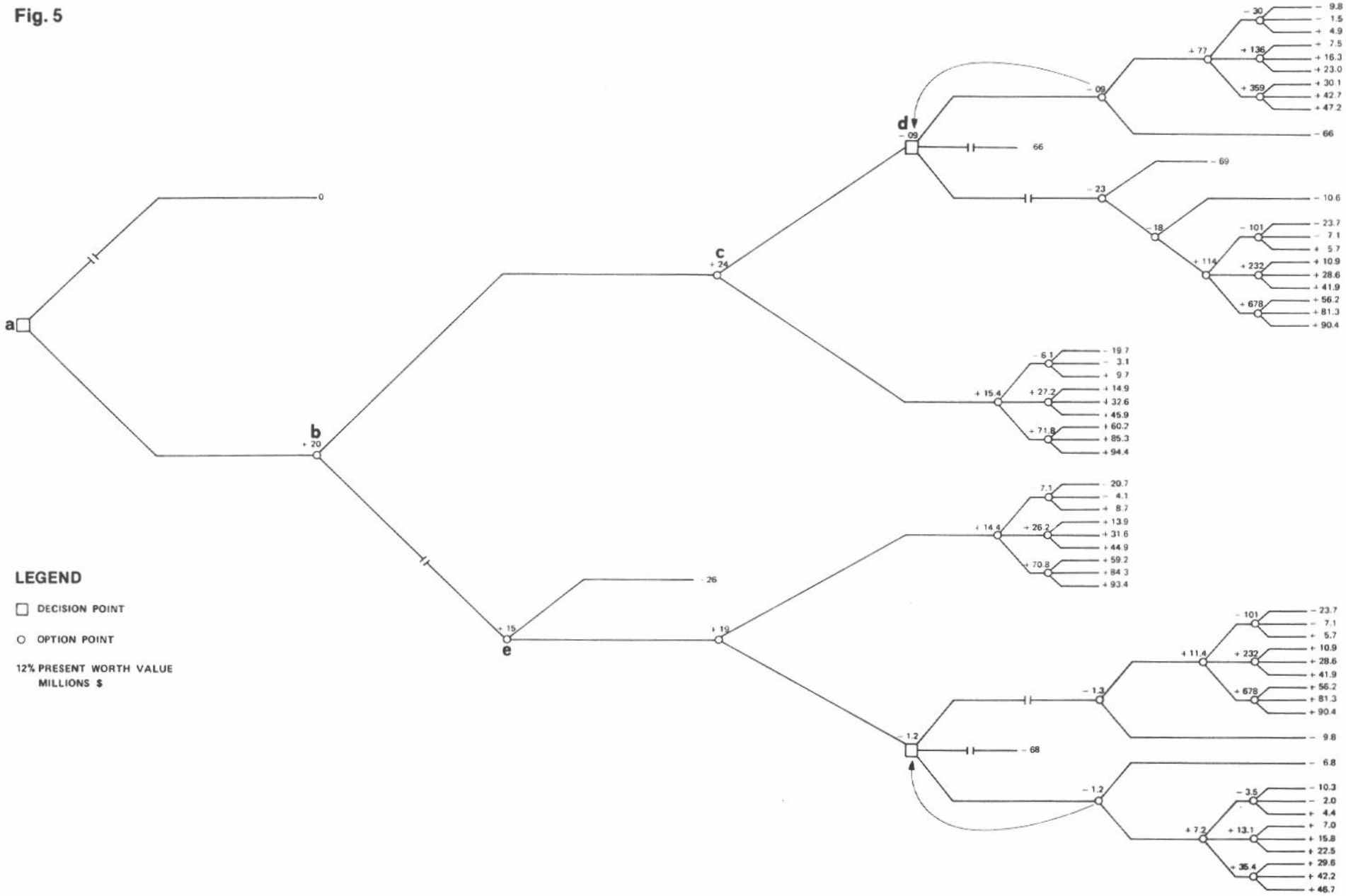

a
b
c
d
e
0.50
0.50
0.80
0.20
0.10
0.90
0.20
0.80
0.40
0.60
0.10
0.60
0.90
0.40
0.60
0.60
0.40
0.53
0.34
0.13
0.39
0.34
0.27
0.45
0.36
0.19
0.58
0.31
0.11
LEGEND
DECISION POINT
OPTION POINT
0.2 PROBABILITY LEVEL

Fig. 5



LEGEND

□ DECISION POINT

○ OPTION POINT

12% PRESENT WORTH VALUE
MILLIONS $

The strategy to be selected emerges from the comparison of the two values, and consists of:

a) acquisition of the area and first seismic survey;
b) drilling of the first wildcat;
c) in the event of unsuccessful results, assignment of an equal participating interest to the company accepting to join in operations under a farm-out agreement.

The resulting EPWV (point B) will be equal to 2 million $, a positive value representing the extra profit which can be earned, according to the definition given on page 42.

Finally, the EPWV value and the assumptions made justify the venture in the area only when there are no alternative venture plans which could offer higher EPWV values.

1.3. Checking the operational feasibility of the selected strategy.

Upon closer examination of the real possibility of performing the various exploration stages, the optimum scheme, derived from the previous analysis, may not be feasible because of three essential reasons:

a) problems connected with move in and move out of the seismic contractor. The stages of seismic survey execution, as contemplated in the scheme analyzed according to the preceding criterion, are excessively distant from one another in time;

b) unavailability of suitable Companies for a farm-out transaction, either because companies interested are not acceptable to the Government in some cases, and/or to us in others, or because they, in their turn, are not interested in the area;

c) the time necessary for negotiating a farm-out agreement would be excessive, because it is necessary to conclude an inventory of the petroleum prospects of the area before expiry of the exploration permit.

The problem is thus the optimization of the strategy outlined by the decision tree method, according to the real operations requirements.

2. FACTOR ANALYSIS

(by M.A. Granata)

The application of the «decision tree method» does not take into account the criteria and way adopted in assessing the degree of probability that the considered events occur.
Now, to apply stochastic laws in determining the probability of success, it is first necessary to *identify the scheme which supports them; this means finding out situations in which the company wants to carry on exploration and the causes which determined the formation of possible accumulations.*

From an industrial point of view, the calculation of the probability of success of an enterprise makes sense only if conducted with the specific aim of quantifying the risk and, at the same time, keeping the costs within the limits of the expected result.
The problem must therefore be solved before the series of events occurs, that is, during the planning phase, either for starting or continuing exploration.
The optimum solution to the problem under discussion is perhaps possible by continually resorting to a special statistical technique of data processing: factor analysis.
The essentials of this method are reported below.

2.1. The factor analysis (1) is a statistical technique used to reduce or simplify a composite group of data, that is a group consisting of a number of variables or samples.
Using this method one determines the degree of association, or concordance, between pairs of variables, usually indicated by the coefficient of correlation «r» (2).
The factors are composite characters or classes, mathematically defined so as to represent natural sets of samples on the basis of their similarity, or distribution of the attributes within the sample.

Let us suppose, for example, that one wants to use all the characters observed in the formations penetrated by each single well in a basin, in order to establish correlations: the study is not realistically feasible. It is thus convenient to examine only the essential data, restricting them to the smallest possible number of classes, or factors, at the same time being careful not to put aside meaningful data. In other words, one sets a certain number of samples, or key characters, and checks for their presence in each series penetrated.

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(1) For a systematic treatment of the subject, see:
— L.L. Thurstone, *Multiple factor analysis*, The University of Chicago Press, Chicago.
— Miller R.L. and Kahn J.S., «Statistical analysis in the geological sciences» - J. Wiley & Sons Inc., New York.
— M.A. Granata: La razionalizzazione delle scelte nella ricerca petrolifera
ECONOMIA INTERNAZIONALE DELLE FONTI D'ENERGIA, Anno XIII, n° 6 Nov. Dic. 1969 - A. GIUFFRE ED. MILANO

(2) The correlation coefficient «r» is the ratio of the covariance.

$$\sigma_{xy} = \frac{\sum \sum x_{ij} y_{ij} F_{ij}}{P}$$

and the geometric average of the variances

$$r = \frac{\sigma_{xy}}{\sqrt{\sigma_x^2 \, \sigma_y^2}} = \frac{\sigma_{xy}}{\sigma_x \, \sigma_y}$$

where, as known, the variance is given by the sum of the differences squared from the arithmetic average

$$\sigma^2 = \frac{\sum (a_i - A)^2}{n} F_i$$

where:
a_i : are the values measured
A : the arithmetic average of the «a_i» s
F_i : the frequency of observations per element
n : the number of observations

To determine the factors all information contained in the orgininal data is then used. They are processed in eight basic stages:

1) make up a chart, or matrix, of the raw data (3);
2) order the data so as to render the weighting coefficients homogeneous for all attributes;
3) calculate the concordance factor between each pair of attributes;
4) calculate the initial matrix of factors, that is, the matrix of «r_{ij}» coefficients, which quantify the relationship between variables and factors (4);
5) subjectively set the number of key factors deemed as suitable for the classification of the data under review;
6) on the basis of the number of selected factors, rotate the factor matrix, so as to obtain the final classification of the factors;
7) from the matrix thus rotated, select the key samples, or those most representative of each factor, and construct a raw data chart to be used in the interpretation of each factor (5);
8) prepare a map of factors, or else use the classification thus obtained as a support for the geological interpretation of the data.

(3) For example:

Well	Formation		% Sand	% Clay	% Marl	% Limestone	...
	Depth	Thickness					
1	— 1,450	200	20	15	40	10	
2	— 1,430	130	30	60	10	0	
3	— 1,478	175	15	45	30	0	
4	— 1.515	185	20	50	10	0	
.							
.							
N — 1	— 1,530	280	35	65	0	0	
N	— 1,462	250	90	10	0	0	

(4) The matrix will of the type:

Variable i	j	1	2	3	4	...	n — 1	n
1		r_{11}	r_{12}	r_{13}	r_{14}	...	$r_{1\,n-1}$	r_{1n}
2				r_{23}	r_{24}	...	$r_{2\,n-1}$	r_{2n}
3					r_{34}	...	$r_{3\,n-1}$	r_{3n}
.							.	.
.							.	.
.							.	.
N — 1							$r_{N-1\,n-1}$	$r_{N-1\,n}$
N								r_{Nn}

(5) For the techniques of extraction of factors from the universe of samples, see the cited work by Miller and Kahn, page 292 and following pages.

Stages 1,5 and 7 require manual processing, and their interpretation is subjective; thus there is no getting away from the use of human reasoning here. In the remaining stages 2, 3, 4, 6 and 8, on the other hand, electronic processing is possible using suitable machine programs for the calculations and feed-out of results.
The results emerging from the fourth stage are, in the first place, used to determine the number of factors, or partial results of each correlation, to be used in the final classification. The factor matrix, rotated and used to construct the final classification, gives the degree of concordance of each sample with each factor.

2.2. Leaving aside the mechanics of this analysis (6), we wish to point out 2 considerations, the first of which deals with the field of application of the study, and the second the result.

2.2.1. Field of application: doubtless, it is most important to perform the analysis on the basis of drilled well profiles, particularly for the useful suggestions derived regarding continuation of exploration and putting the field into production once it has been discovered. However, prospecting is carried out through a course of data finding and processing which is upstream of the drilling of a certain number of wells.

2.3. To briefly anticipate a subject which will be dealt with later, it can be said that the problem is to compare, through statistical correlations and for homogeneous terms, data collected on a known area with data emerging from the survey of an area being prospected.

2.3.1. The planning stage. On the basis of evaluation elements collected in the investigations mentioned above, the next step is the preparation of the work programme and exploration budget; keeping the total costs within the limits of the mathematical expectation.

Supposing that the area under review is given the probability «p» of finding the same quantity of hydrocarbons discovered in the key area, the first operation to be carried out is to determine the commercial value of the assumed field (s). Obviously this study must be conducted in the light of the political, economical and juridical situation of the country in which the company is to operate.

The calculation of the present worth value (P.W.V.) of the project is made by the method known as «Discount cash-flow». The desired interest rate, introduced into it, which constitutes the basis upon which to discount the set of costs and proceeds expected at the time of project formulation, will have to take into account also the following variables:

(6) For treatment of this subject, see the specialist literature. Factor analysis has already found application in geology.

— C (b) = borrowed capital
— I (b) = interest paid on C (b)
— C (e) = equity capital
— I (p) = desired income on C (e)
— Q = *1—r, risk factor. It is equal to the complement to 1 of the concordance factor «r»*
— S = expected currency devaluation rate.

The P.W.V. may even be equal to zero (in such event it would represent the «break even point»), when the attainment of a *surplus* is renounced. However, if there are no economic policy limits, the company shall have to aim at maximizing the present worth value.

This end may be achieved, in the first place, by adopting exploration techniques which are suitable as regards both type and quantity for the desired result. Particular attention must be paid to the distribution, areal size and volume of the assumed field (7).
The next problem is the verification of the assumptions made; this is the objective of the second and subsequent exploration phases.

2.3.2. Second phase: general exploration. This consists in verifying the assumptions made in the preceding phase by means of field surveys (gravimetric, magnetic, geological, large grid seismic).

What is to be done is:

a) determine the most prospective areas which should be given precedence in detail surveying in the future; areas which justify, from an economical and petroleum point of view, the extension of the survey;
b) make, according to the new picture, the factor analysis and recalculate the probability of accumulation;
c) repeat identically the set of operations illustrated in the previous phase.

Here, also, the set of operations is meant to determine: the minimum volume capacity of the field (s) necessary to justify further investment (considered in addition to those already made).

With reference to the areal size of the field (s), first determine the size of the grid of the next detail seismic survey, the number of wells to be drilled, etc.
This means the determination of all elements useful to the formulation of the new exploration budget.

(7) The prime aim of the investigation is in fact the determination of the commercial value of the reserves in the area where exploration is planned. Thus, given a successful assessment of the recoverable volume of the hydrocarbons in place and the proceeds (less taxes and operating costs) which can be expected from their sale, this amount will constitute the limit of the investments which can be made to proceed from the field to market outlet sales.
The two sets of values are understood in present value at the same discount rate and date.

The primary and most delicate objective is to set the size of the new seismic grids in view of the formulation of the new project. The sides of the grids must have the marginal length, i.e. the maximum size, suitable for evidencing the structures which have been assumed as capable of yielding the maximum present worth value of the project.
The same principle should govern the planning of the spacing of the wells to be drilled and the entire range of investments necessary to bring the assumed production into the market outlets.

2.3.3. Phases 3, 4, and 5 each, in succession, follows the series of enquires described above. Briefly:

3 - By means of a detail seismic survey, confirm or correct the structural features revealed by the gravimetric survey and/or by other types of survey performed during the second phase.
4 - By drilling a wildcat, check the assumptions made on the basis of the results which emerged during the second phase.
5 - If the fourth phase has had a favourable outcome, delimit the field.
It is clear that, at the end of each phase and before passing to the next one, the investment budget has to be reformulated, and the present worth value of the project in progress calculated from time to time.

The logic governing the series of phases discussed hereinabove is illustrated in the attached block diagram.

2.4. Final Considerations

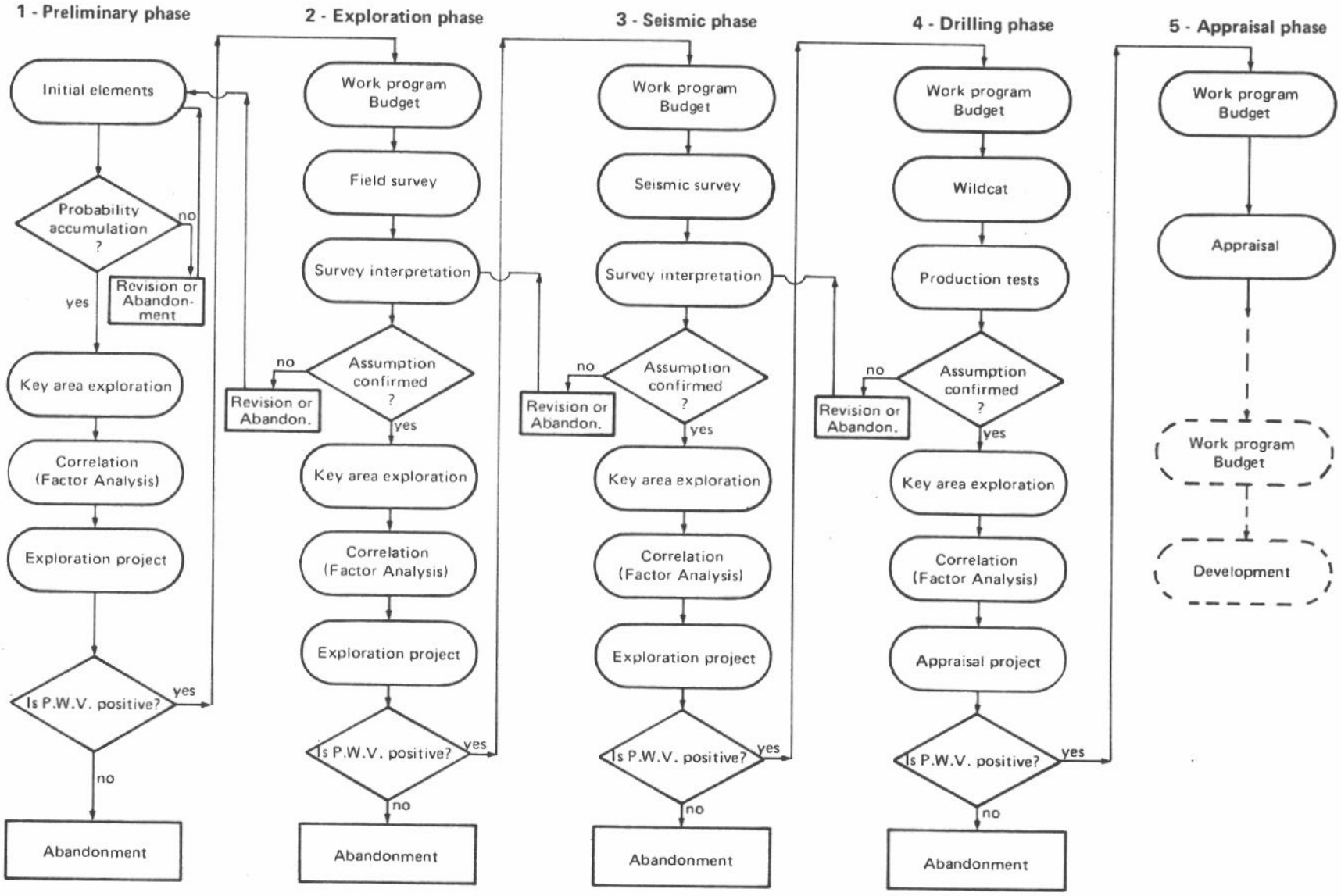
In short, the advantages deriving from the investigation techniques suggested here, consist in representing symbolically an objective basis of judgement for the preparation and updating of the work programmes and exploration budget for areas being explored or acquired.

In reality, it would appear that there are two orders of obstacle to the development of an exploration logic of the type outlined above:

1) on the one hand, the existence of standard agreements that the grantor Governments tend to impose, together with minimum expenditure commitments on companies;
2) on the other hand, the lack, sometimes total lack, of geological information concerning the area to be acquired. Companies are thus often obliged to buy blind.

The solution to the problem is postponed rather than being subject to obstacles (even if, objectively, it meets with limitations). Once the area has been acquired and exploration begun, the company will have a first amount of information available. It is at this point and on the basis of this information that it can proceed to what is called here the preliminary phase, and hence formulate a first series of assumptions and pass to a first verification of those made at the time when it was decided to undertake the venture.
The investigation will permit, at most, the verification of the existence, or not, of the essential conditions for the accumulation or hydrocarbons, and in the negative case, to abandon the venture with the smallest possible financial losses.

Fig. 6 - Exploration strategy - Block diagram



2.4.1. The same holds true for the search for the key area. When information is insufficient to enable a factor analysis to be made (or when it is decided not to make it), in the manner described above, a correlation could be made using weighted values, between the area being examined and geologically known areas.
In other words, the problem is still to identify among the known areas, the one which is most closely similar to the one being examined.
Let us suppose that the latter, A, is characterized by factors a_1, a_2, a_3, ... a_n, we must obtain similar information (from a qualitative point of view) ${}_ix_1$, ${}_ix_2$, ${}_ix_3$, ... ${}_ix_n$ from each known area iX, and determine the level of concordance between, a_j's and ${}_ix_j$'s.

Briefly, we have:

Character	1	2	3	.....	n — 1	n
Weight	P_1	P_2	P_3	.....	P_{n-1}	P_n
Area A	a_1	a_2	a_3	.....	a_{n-1}	a_n
Area B	b_1	b_2	b_3	.....	b_{n-1}	b_n

where: 1,2,3 ... n are characters in order by weight or by the factor of importance P_i attributed to them subjectively. We shall have, for example:

n — x : observed clay content
n — y : formation thickness
n — z : formation depth
etc (8)

therefore, we shall have:

a_{n-x}: average clay content observed in A
b_{n-x}: as above, observed in B
etc.

where A is the area being examined
B the area which will prove most closely associable with A (key area).

2.4.2. The duplex set of observed values must be made homogeneous. It is possible to reduce the variables to pure numbers through the ratio:

$$a_j = \frac{a_i + b_i}{a_i} \cdot P_i$$

(8) Also in this type of process, which is simpler, the geologist must pay particular attention to the attribution of weight to the qualitative elements which have to be introduced into the analysis. It would therefore be useful to process auxiliary statistics.

and

$$b_j = \frac{a_i + b_i}{b_i} \cdot P_i$$

$$i, j = 1, 2, 3, \ldots\ldots n$$

If we now call α and β respectively the differences from the average values of a_j and b_j, that is to say:

$$\alpha_i = a_j - \frac{\sum_{j=1}^{n} a_j}{n}$$

$$\beta_i = b_j - \frac{\sum_{j=1}^{n} b_j}{n}$$

the coefficient of correlation r can be calculated:

$$r = \frac{\sum_{i=1}^{n} \alpha_i \beta_i}{\sqrt{\sum_{i=1}^{n} \alpha_i^2 \sum_{i=1}^{n} \beta_i^2}}$$

2.3.4. As an example, we give below the calculation of the coefficient of correlation r between wells 3 and 4 indicated in the table given in Note 3 (cfr. para 1).

well	elevation	weight	thickness	weight	sands	weight	clay	weight	marl	weight
3	— 1,478	10	175	100	15%	60	45%	50	30%	20
4	— 1,515	10	185	100	20%	60	50%	50	10%	20
Order number	5		1		2		3		4	

i	a_j	b_j	α_i	β_i	$\alpha_i\beta_i$	α_i^2	β_i^2
1	206	195	+ 106	+ 96	+ 10,176	11,236	9,216
2	140	105	+ 40	+ 6	+ 240	1,600	36
3	106	95	+ 6	— 4	— 24	36	16
4	27	80	— 73	— 19	+ 1,387	5,329	361
5	20	20	— 80	— 79	+ 6,320	6,400	6,241
Σ	499	495			+ 18,099	24,601	15,870

$$r = \frac{18{,}099}{\sqrt{24{,}601 \cdot 15{,}870}} = 0.916$$

The value r = 0.916 represents the degree of probability f obtaining in one of the two wells under consideration the same result obtained in the other.

2.4.4. The informing criterion of the exploration project is the economic reintegration of investments. The probability of reaching this objective must be quantified «a priori» by the trial and error method, with the final aim of maximizing the present worth value of the projetc. At most, this maximization may be reached by minimizing the loss (marginal loss) (9).

In the final analysis, it is the amount of risk involved that must condition the project; this risk must be quantified «a priori», and also an estimation must be made «a priori» of the amount of the costs to be incurred in connection with the quantity of recoverable product and the sale proceeds therefrom.

Substantially, the extreme condition of being under the obligation to develop an uneconomic field under law requirements or under agreements with co-ventures must be avoided.

(9) «Marginal loss» means the minimum loss which cannot be recovered through an additional amount of investment.
That is, when necessary, one should allocate investment amount capable of causing the production of proceeds so that to recover also the maximum part of the investments made during the preceding exploration phases.

Chapter 9

MAIN ECONOMIC INDICATORS

(by R. Lambri, A. Pasutti)

As a general rule, economic indicators or yardsticks (*) should:

a) enable us to compare and classify investment project;
b) indicate whether or not the AARR deriving from a chosen investment is at least equal to the rate of interest on the borrowed capital and/or to the rate of return established beforehand by the company;
c) reflect the value of the company's equity; that is, the indicators should represent a company's equity; that is, the indicators should represent a company's earning power;
d) show up the risk connected with each investment project.

In actual fact, however, no economic indicator is able to synthesize all of above; therefore it is necessary to make very careful use of several indicators simultaneously. This can be explained by the fact that there are no mathematical relationships which connect these indicators. As best there are only some statistical connections, as can clearly be seen on the graphs shown in figure 7.

In the oil industry the economic indicators most widely used to determine the feasibility, from an economic standpoint, of one or more investment projects are as follows: (1)

— Pay out time (P.O.T.)
— Profit/investment ratio (ROI or NTIR) (2)
— Rate of return
— Present worth value of the profit (P.W.V.)

Other indicators, such as percentage gain on investments, appreciation of equity, risk weighted rate of return, etc., are seldom used since they can be derived from the present worth value of the profit and the rate of return.

Much has been written about each of these indicators but here we will only give definitions and a broad outline of their validity.

(*) Also called measures of value, decision criteria.
(1) Note that these indicators give no measurement of risk.
(2) Depending on whether the profit is net or gross as far as investments are concerned.

Pay Out Time

The pay out time of a project can be defined as the time required to completely recover the invested capital.
That is, pay out time is an indicator which only shows the «speed of recovery» of the investments, and gives no information regarding the amount of invested capital and the profit which the project is able to generate; it does not, as a general rule, consider the function «time».
Such an indicator can only be an initial basis for comparing alternative projects, with particular regard to those countries characterized by political or economic instability or in case the company's financial situation is precarious.
Small oil companies attribute more importance to this indicator than the larger ones, especially in view of the fact of credit accessibility (possibility of borrowing money).

Profit/Investment Ratio

This can be defined as the ratio between total profit and the amount of investment.
This indicator shows the profit generated for each monetary unit invested in the project.
The advantage of this indicator, in comparison to the pay out time, is that it indicates the profit, and does not necessitate a determination of the cash flow. The disadvantage of this parameter (like the pay out time) lies in the fact that it does not take the time function into consideration; in fact, several projects may have the same pay out time and profit/investment ratio, but give a different cash flow.

Present Worth Value

This is the algebraic sum of the cash flows discounted at a determined time period and at a pre-established interest rate.
The characteristic of this index are:

a) the interest rate reflects the internal yield expected by the company or, at least, the interest rate claimed by bank when analogous capitals are borrowed;
b) it reveals immediately if the project is economically feasible (when the present worth value equals zero, the interest rate is also the rate of return of the project);
c) when it is used as the only evaluational yardstick it does not allow, as in the case of the rate of return, a comparison;
d) the most critical point of this index lies in the choice of the interest rate, since the available capital is derived partly from self-financing, and partly from borrowed capital. In general, the interest rate ranges from a minimum rate (bank rate) to a maximum rate (the company internal rate yield).

Discounted Cash Flow Rate of Return

The D.C.F. Rate of Return (1) is defined as the interest rate which makes the present profit value equal to zero, that is discounted investment and profit are balanced;

$$\sum_{k=1}^{n} I_k (1 + i)^{-k} \quad \sum_{k=1}^{n} P_k (1 + i)^{-k} = o$$

I = investment
P = profit
i = interest rate

The particular characteristics of such index are as follows:

a) it takes into account the present worth value and therefore the distribution in time of cash flows;
b) it tells us whether or not the project is feasible in that it can be compared with the company internal yield rate and/or bank rate of interest on funds that can be borrowed on the financial market;
c) it is much affected by the amount of capital invested in a project and to the time necessary for plant going on stream;
d) because of its nature of indicator, it is to be meant as closely related to the investment project under consideration. In the rality, its meaning must be compared to the investment capability of the company in its dynamic organization.
   In fact, it must be stressed that in the concept of return, the implicit assumption is made that the expected cash flows are then actually reinvested by the company in operations capable of yielding «that» rate of return.
   There is the risk that rates of return calculated on a project may finally be unrealistic to the extent in which they exceed the rate of reinvestment by the company of capital thus available;
e) it does not give the extent of the risk;
f) as a general rule, it does not allow to make a comparison of the projects among them in terms of «quantitative amount of the profit»;
g) it cannot be calculated when the cash flows are either all positive or all negative;
h) it is possible to have different rates of return depending on the variations of the calculation parameters (quantity, time, etc.);
i) the AARR is calculated by the trial and error method.

Appreciation of equity rate (i_{ae})

It is the interest rate that makes the present worth value (or the Amount) of investment equal to the present worth value (or to the Amount) of cash flows (including investment), the latter being computed at an interest rate equal to the company internal yield. We have the following equation

(1) It is the index most widely used in the petroleum industry. It is also called: internal yield, internal rate of return, discounted cash flow rate of return, profitability index, margin efficiency capital, or improperly, AARR (annual average rate of return).

$$\sum_{k=1}^{n} I_k (1 + i_{ae})^k = \sum_{k=1}^{n} P_k (1 + i_o)^k$$

where I = investment
P = profit
i_o = internal yield
i_{ae} = equity appreciation rate
k = time (year)

As a matter of fact, this index is little used because it is a derivation of the rate of return and is comprised between the value of the AARR and the value of the company internal yield. It should be noted that it is affected by the duration of the cash flow.

Percentage gain on investment (i_{pg})

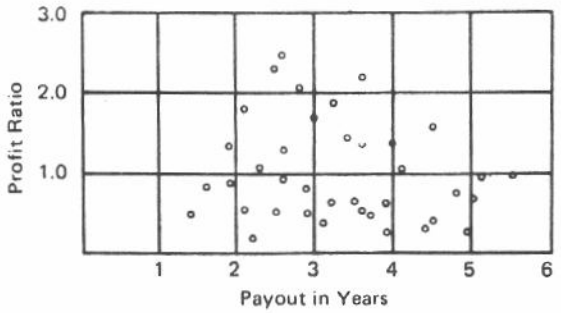
It is an index that measures a profit in excess of that (calculated at the company internal yield rate) which is normally yielded by an investment. We have the following equation:

$$i_{pg} = \frac{1}{I} \times \frac{(1 + i_o)^n \times i_o}{(1 + i_o)^n - 1} \times \text{actual profit value}$$

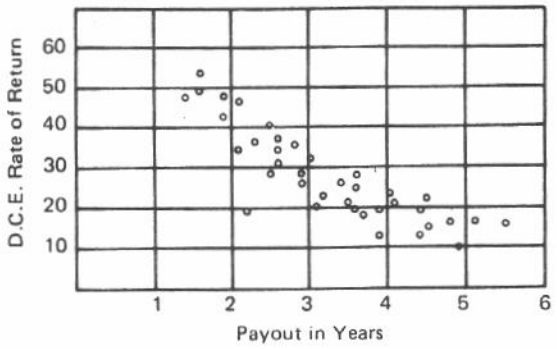
where: I = investment
i_{pg} = percentage gain on investment
i_o = internal yield rate
n = number of years of cash flow

$$\frac{(1 + i_o)^n i_o}{(1 + i_o)^n - 1}$$ = annuity paid in arrears necessary to depreciate a debt of 1 lira over n years.

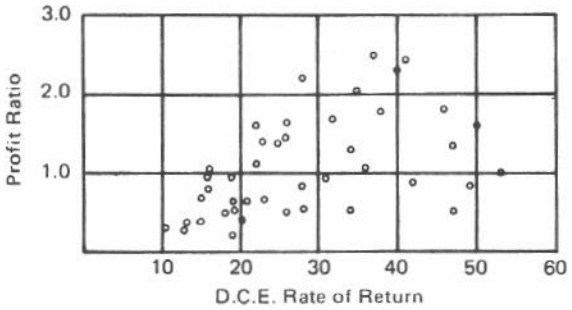
The profit is expressed as a fixed amount of liras ($I \times i_{pg}$) that can be deduced from the cash flow on a yearly basis, since the remaining balance is sufficient to recover the investment and relevant financial costs. As it is a derivation of actual worth value, said index is little used.



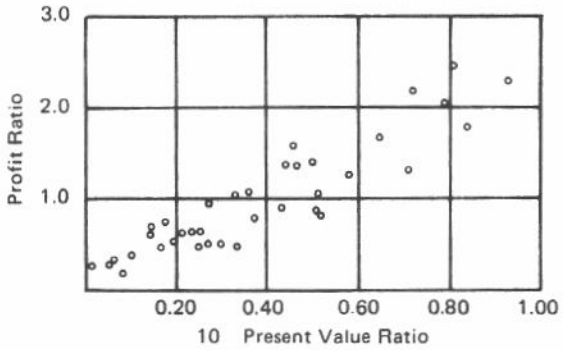
A - Individual plot-points for the 40 development ventures.



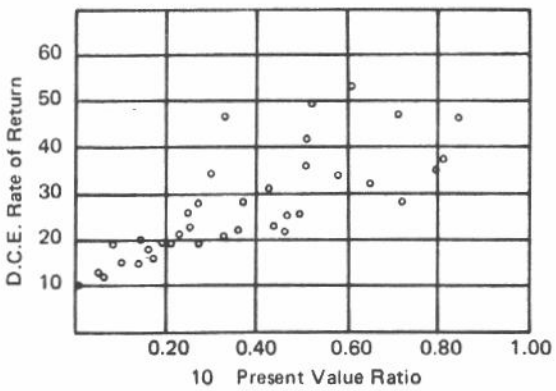
B - Individual plot-points for the 40 development ventures.



C - Individual plot-points for the 40 development ventures.



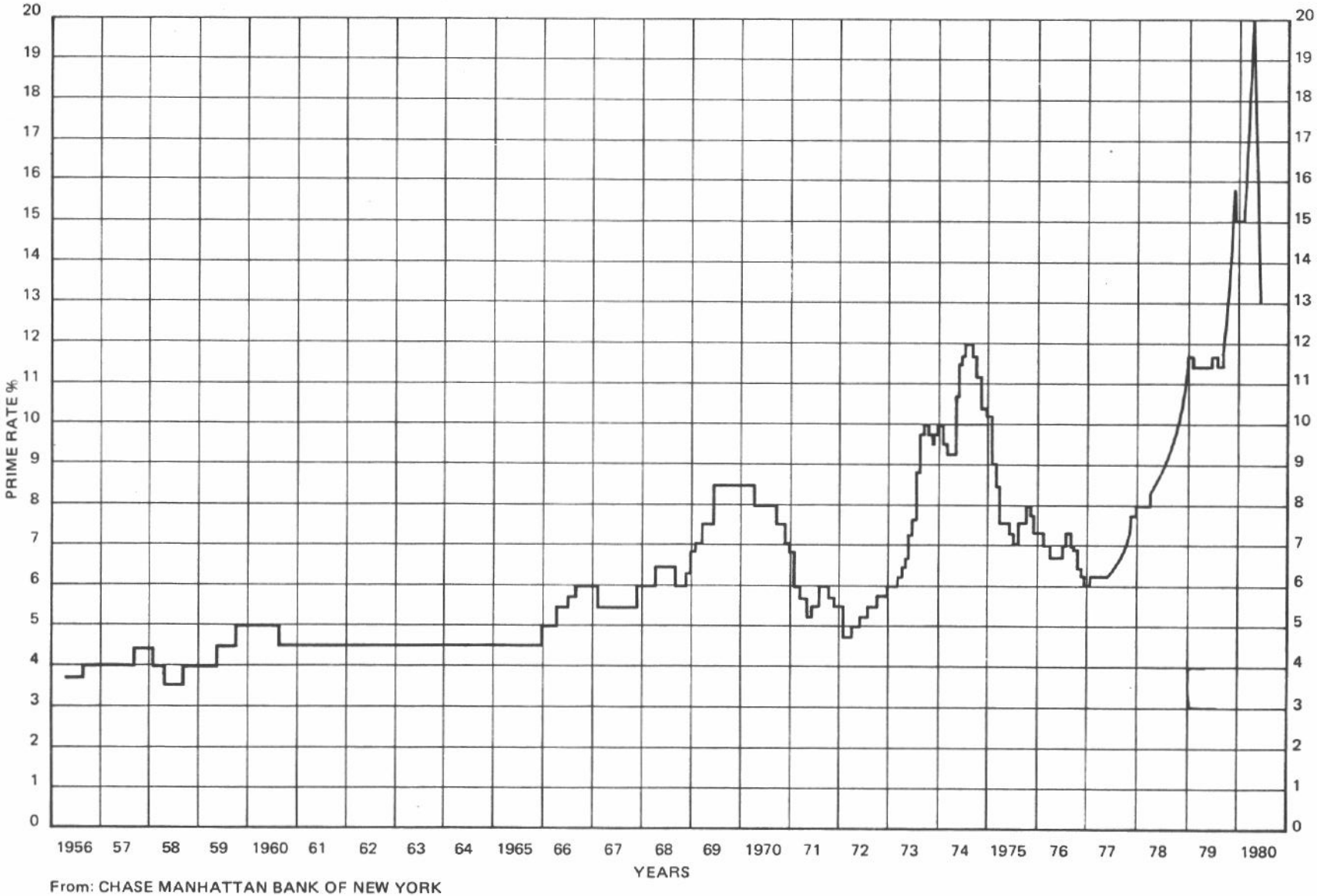
D - Individual plot-points for the 40 development ventures.



E - DCF rate of return vs 10 per cent present value profit ratio.

Fig. 7

Fig. 8 - Prime rate - VS - YEARS



From: CHASE MANHATTAN BANK OF NEW YORK

Fig. 9 · P.W.V of profit · Vs discount rate (before royalties and taxes)

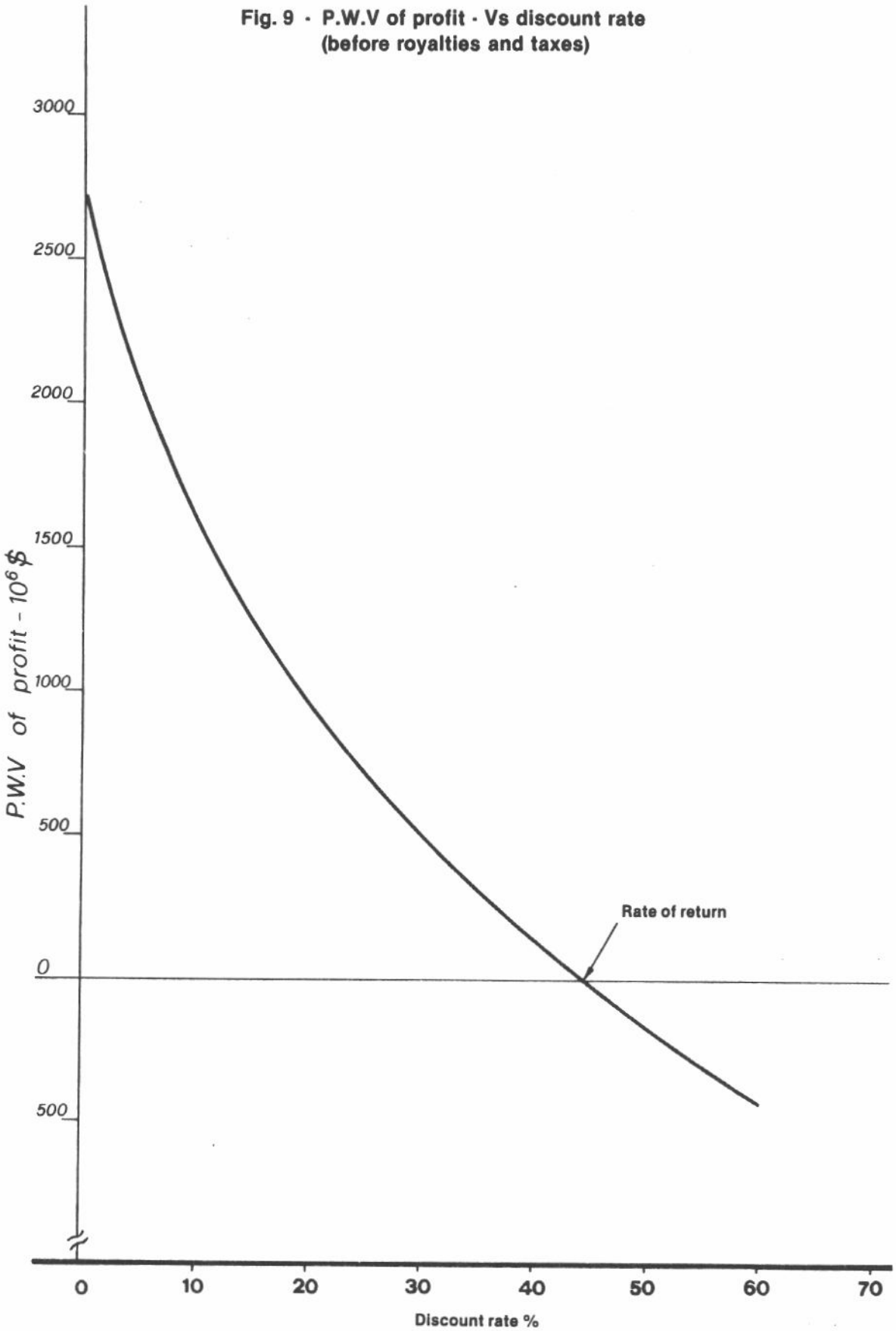


Fig. 10

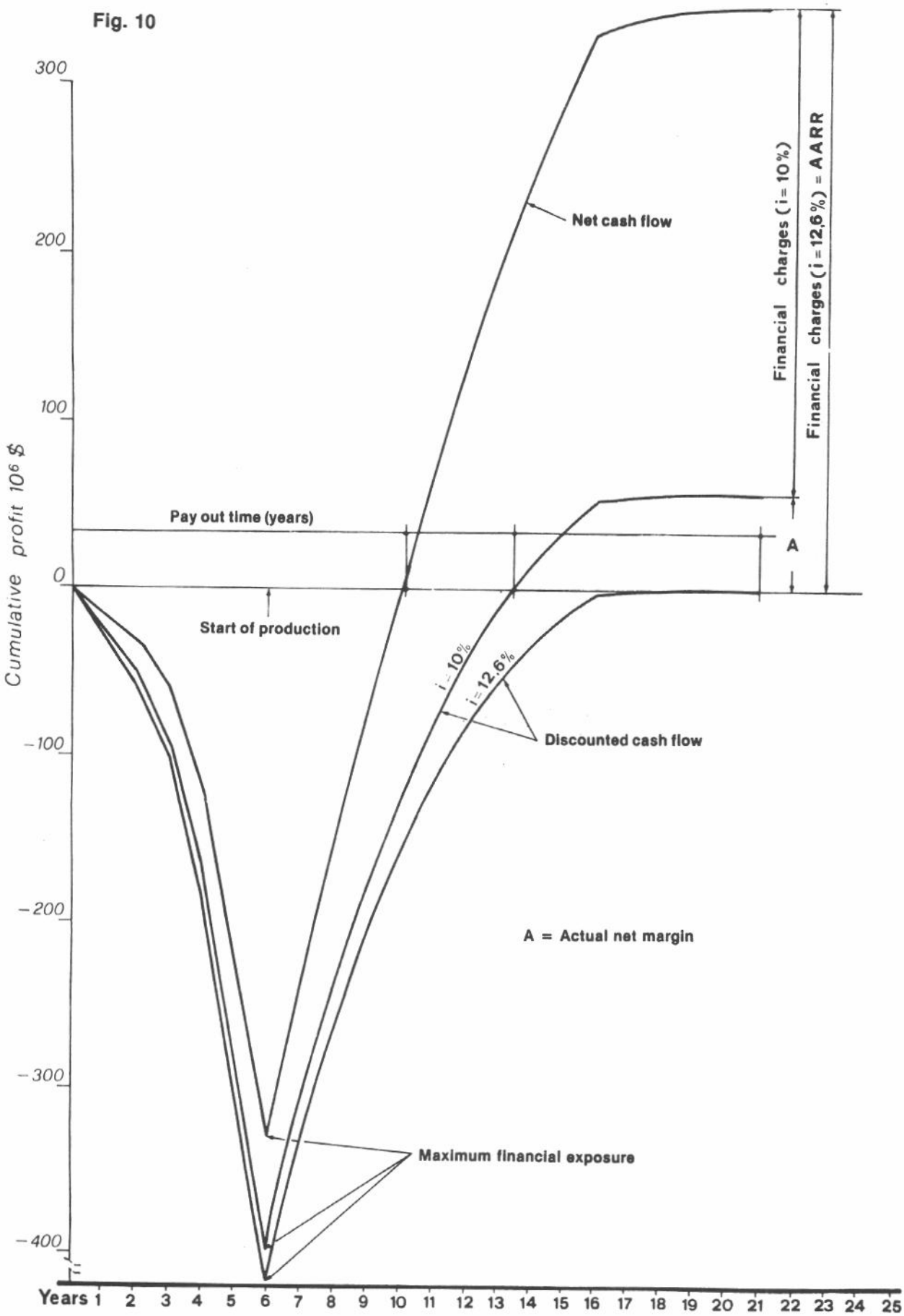

300
200
100
0
-100
-200
-300
-400
Cumulative profit 10⁶ $
Net cash flow
Financial charges (i = 10%)
Financial charges (i = 12,6%) = AARR
Pay out time (years)
A
Start of production
i = 10%
i = 12,6%
Discounted cash flow
A = Actual net margin
Maximum financial exposure
Years 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25

Table 1 - PROJECT COMPARISONS After - Tax Net Cash Flow by Year

	Project										
Year	P (dollars)	Q (dollars)	R (dollars)	S (dollars)	T (dollars)	U (dollars)	V (dollars)	W (dollars)	X (dollars)	Y (dollars)	Z (dollars)
0	- 1000	- 1000	- 1000	- 1000	- 1000	- 1000	- 1000	- 500	- 1000	- 1000	- 500
1	500	600	25	10	800	700	0	0	900	210	0
2	400	400	50	20	300	500	0	0	200	210	10
3	300	300	50	50	100	200	100	5	100	210	15
4	200	200	100	100	50	100	100	25	50	210	25
5	100	50	200	200	50	50	100	50	50	210	50
6	50	20	300	300	20	10	300	150	10	210	150
7	40	10	400	400	20	10	500	250	10	210	250
8	30	10	500	500	10	10	500	350	10	210	350
9	20	5	500	500	10	10	500	350	0	210	350
10	10	5	100	400	10	10	500	250	0	210	300
	650	600	1225	1480	370	600	1600	950	330	1100	1000
	Criteria										
Profit-to-investment ratio	0.65	0.60	1.23	1.48	0.37	0.60	1.60	1.90	0.33	1.10	2.00
Payout, years	2.3	2.0	6.7	6.8	1.7	1.6	6.8	7.0	1.5	4.8	7.0
Internal rate of return, percent	22.5	25.0	12.5	13.4	19.3	28.5	13.8	14.7	20.0	16.5	15.1
Present worth											
at 5 percent, dollars	446	423	582	724	249	448	794	487	227	622	518
at 10 percent, dollars	284	294	153	230	150	323	270	188	139	290	208
at 15 percent, dollars	153	179	- 141	- 102	66	217	- 81	- 10	64	54	3

Table 2 - PROJECT RANKINGS FOR CAPITAL ALLOCATION

Measure	Project										
	P	Q	R	S	T	U	V	W	X	Y	Z
Profit	7	8	3	2	9	8	1	6	10	4	5
Profit/investment	7	8	5	4	10	9	3	2	11	6	1
Payout	5	4	7	8	3	2	9	10	1	6	11
Internal R/R	3	2	11	10	5	1	9	8	4	6	7
Present worth at 5 percent	8	9	4	2	10	7	1	6	11	3	5
at 10 percent	4	2	9	6	10	1	5	8	11	3	7
at 15 percent	3	2	11	10	4	1	9	8	5	6	7

Chapter 10

SENSITIVITY ANALYSES

(by R. Lambri, A. Pasutti)

The aim of this type of analysis is to show, usually graphically, the incidence of variations in one or more variables on the basis of economic indices used for evaluating the feasibility of an investment.
In the oil industry this analysis is widely utilized, in view of the inherent difficulties in making «a priori» measurements of certain variables which are then used for carrying out the economic analyses.
Sensitivity analysis is carried out on those technical and economic variables which are reputed to be the most difficult to measure.
These variables are:

— recoverable reserves;
— daily rate from the field;
— daily rate from each well;
— investments;
— operating costs;
— prices;
— fiscal take.

Furthermore, the sensitivity analysis is useful in solving problems connected with:

— optimization of a field
  • optimum number of wells
— the stipulation or revision of an agreement
  • signature and/or production bonuses
  • fiscal take
  • cost oil/profit oil.

It was also considered appropriate to portray on the following graphs the various economic results which may be obtained in the different types of agreement (1).

In the specific case three types of agreement have been compared:

(1) In the various contract hypotheses, the economic calculations have been carried out on the basis of the same basic data (reserves, investments, operating costs and prices).

— OPEC fiscal take

- Royalty: 20% (on the Posted Price)
- Income Tax: 85% (on the Posted Price)
- Selling Price = 0.93 Posted Price
- Depreciations: in 10 years straight-line
- Interest: 10% fiscally deducible

— North Sea Fiscal Take (English District) (2)

- Royalty: 12.5% (on the Selling Price)
- Petroleum Revenue Tax (PRT): 45% (on the selling price basis)
- Corporation Tax: 52% on S. Price
- Depreciations: accelerated (both for PRT and CT)
- Interest: 10% fiscally deducible (for the CT)
- In order to determine PRT there is a further deduction of an oil allowance (max 10 million tons)
  and a 75% uplift of investments

— Sharing Contract

- Cost oil: max 100%
- Profit oil: 15%
- Depreciations: 7 years DDB & straight line
- Interest: 10% fiscally deducible
- Oil for domestic market: 4%

Furthermore, it is possible to compare the three results with the one pertaining to the more technical cost (investments and operating costs).
In addition to being a decision-making tool within the limits of the inherent operational difficulties, this type of analysis provides an understanding of the developments occurring in both the field of petroleum contractual negotiations and in the sphere of development policies followed by the oil companies.

(2) The total Government «take» is intended to be in the region of 70% of profits from North Sea oil development but the precise position will depend on the circumstances of each individual field.

Note on the following figures:

Figure 11: variation of the rate of return versus the variation of recoverable reserves.
Figure 12: variation of the economic indices versus the number of well (only technical costs).
Figure 13: variation of the rate of return versus the number of wells.
Figure 14: variation of the rate of return versus the time needed to put a field into production; time expressed in number of years.

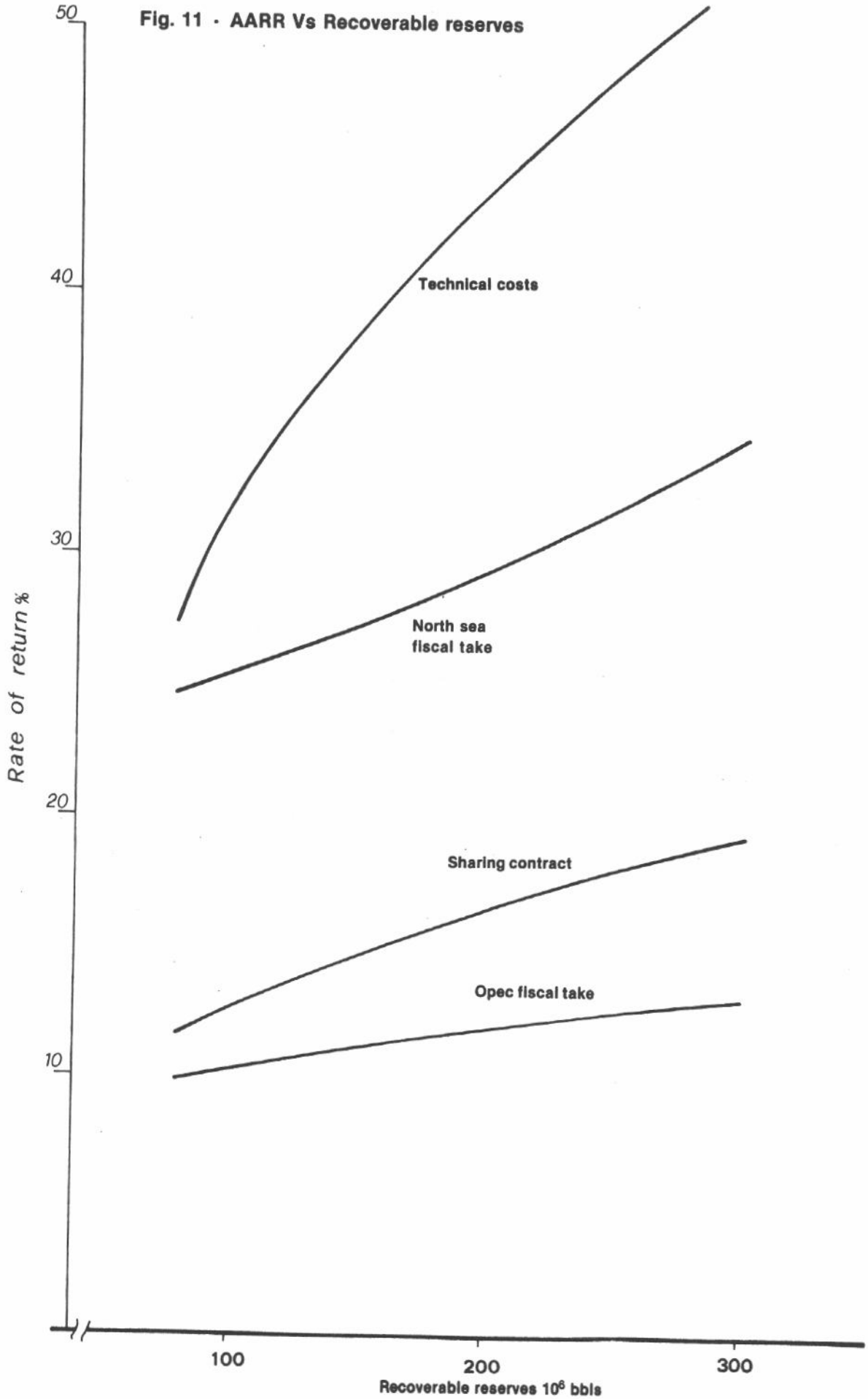


Fig. 11 · AARR Vs Recoverable reserves
50
40
30
20
10
Rate of return %
Technical costs
North sea
fiscal take
Sharing contract
Opec fiscal take
100
200
300
Recoverable reserves 10⁶ bbls

Fig. 12 - PROSPECT - C
Well optimization before fiscal take
Rate of return - Vs - No of wells

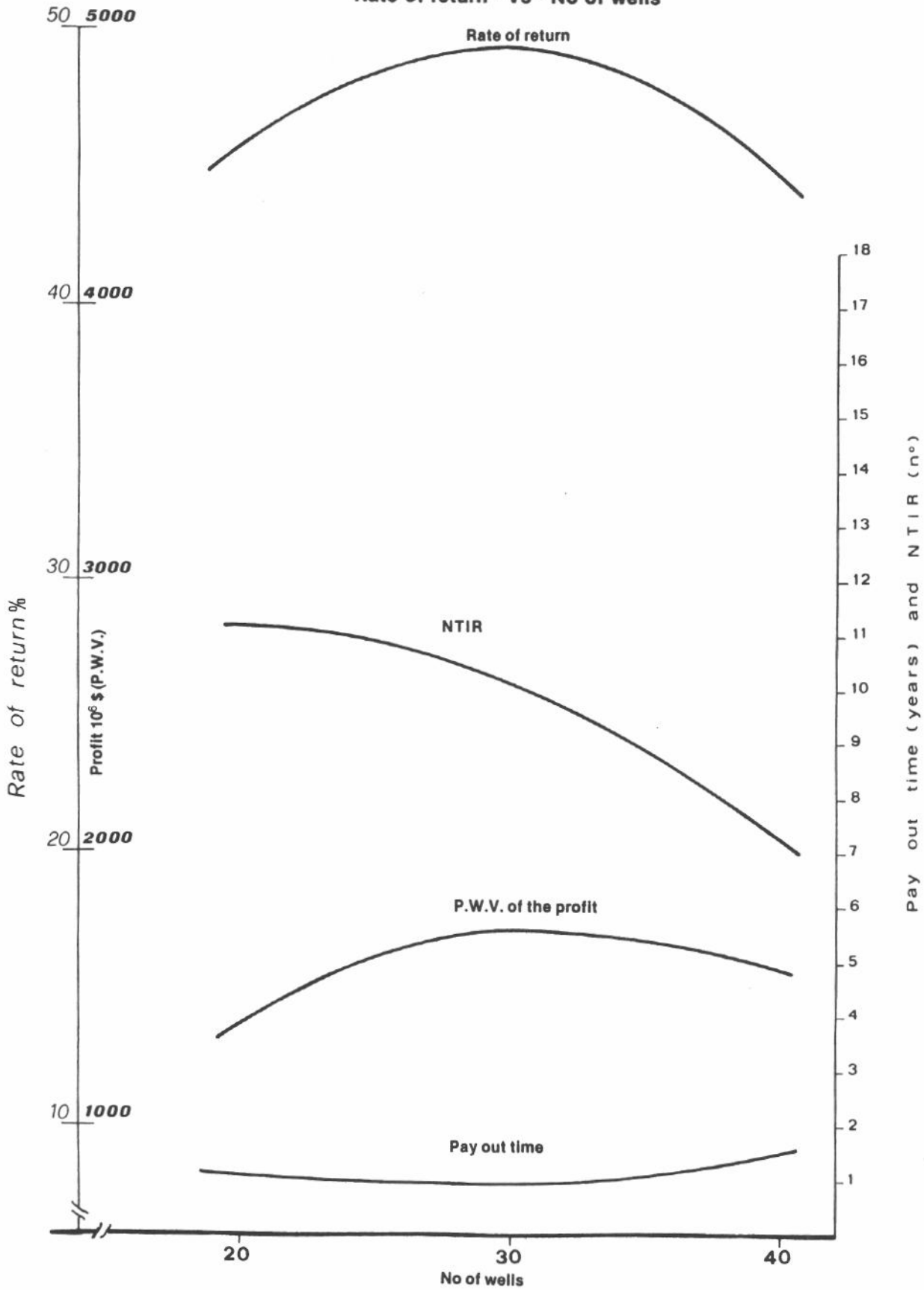


Fig. 13 · PROSPECT · C Well optimization after fiscal take
Rate of return · Vs · No of wells

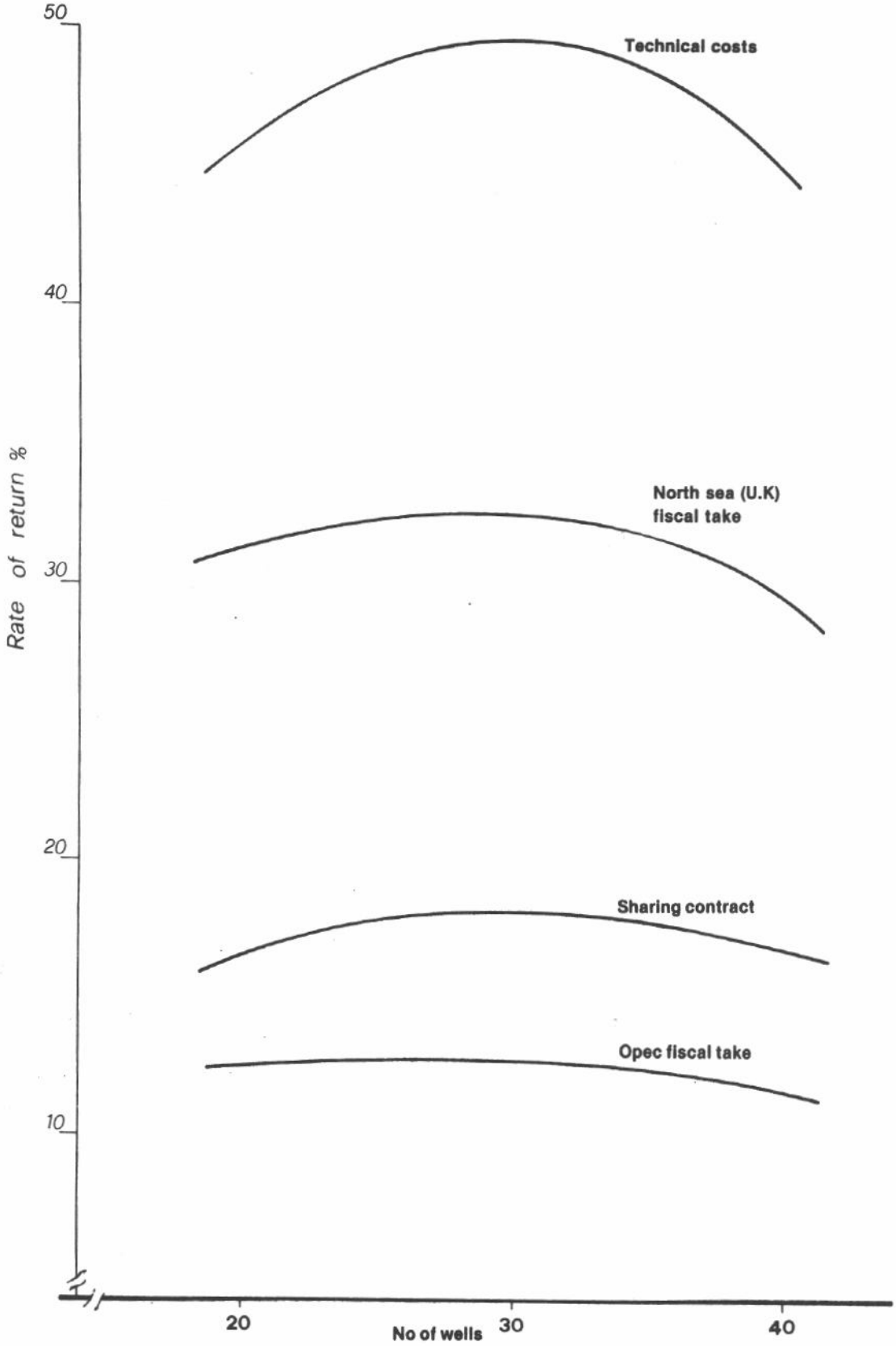
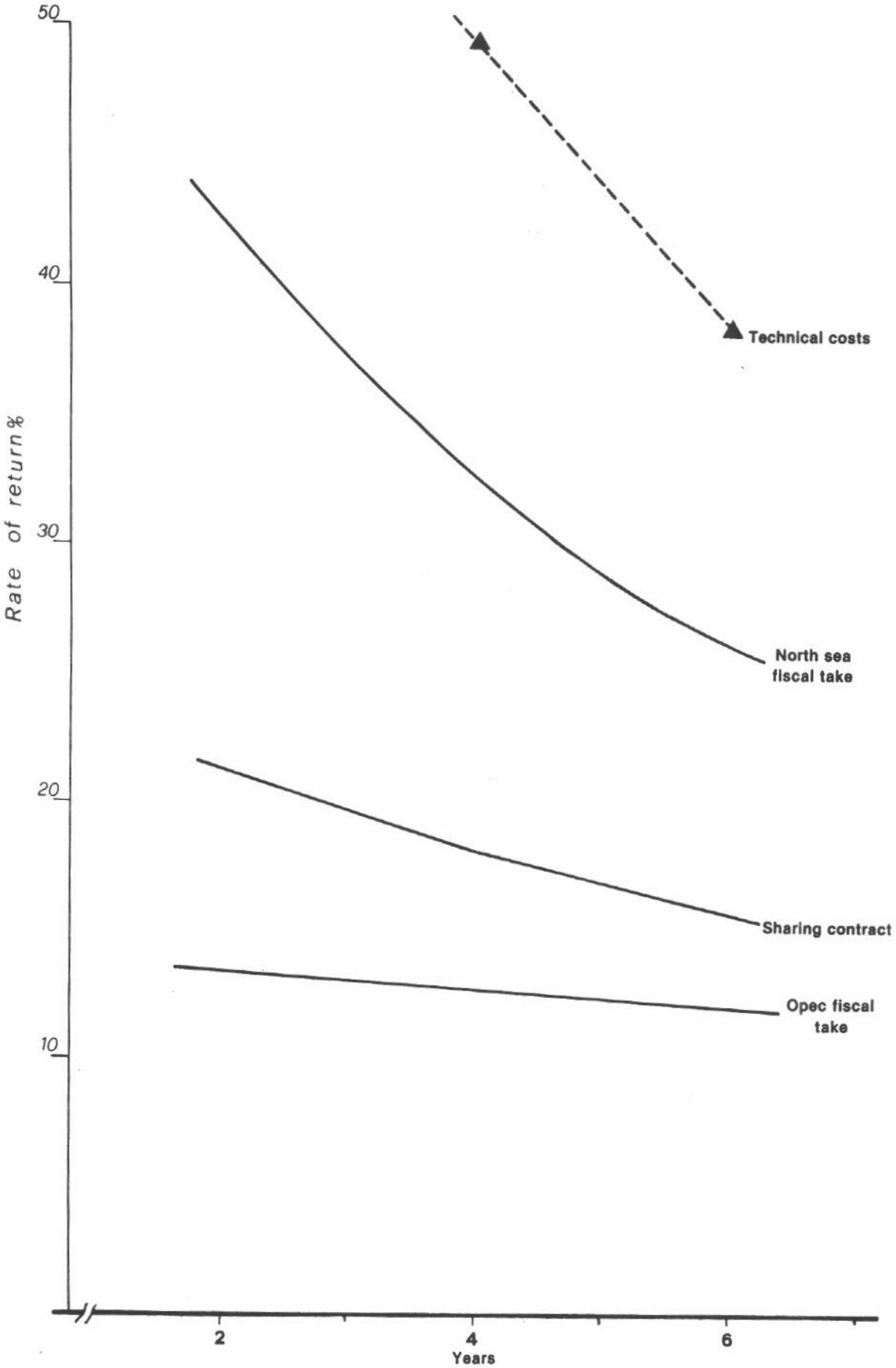


Fig. 14 · PROSPECT · C Time is money



OPEC FISCAL TAKE

Prospect		A		B		C	
Recoverable reserves	10^6bbls	88		159		262	
Economically, recoverable reserves	10^6bbls	79		150		250	
			$/bbl		$/bbl		$/bbl
Exploration investments	$10^6$$	30	0.38	30	0.20	30	0.12
Development investments	$10^6$$	180	2.27	240	1.60	300	1.20
Operating costs	$10^6$$	156	1.97	238	1.59	330	1.32
Total technical costs	$10^6$$	366	4.62	508	3.39	660	2.64
Royalty	$10^6$$	244	3.08	461	3.08	769	3.08
Taxes	$10^6$$	358	4.51	935	6.24	1810	7.25
Total Government take	$10^6$$	602	7.59	1396	9.32	2579	10.33
Total costs	$10^6$$	968	12.21	1904	12.71	3239	12.97
Gross Revenue	$10^6$$	1138	14.35	2150	14.35	3583	14.35
Profit	$10^6$$	170	2.14	246	1.64	344	1.38
P.W.V. (i = 10% as of start of production)	$10^6$$	0		21		57	
Rate of return	%	10		11.2		12.6	
Pay out time (from start of production)	years	4.7		4.4		4.1	
N.T.I.R.	n°	1.8		1.9		2.0	

Distribution of the profit after technical costs

Government	78.0%	85.0%	88.2%
Company	22.0%	15.0%	11.8%
	100.0%	100.0%	100.0%

CASE A: recoverable reserves

Prospect		A	B	C
Reserves	10^6bbls	88	159	262
Total Investments (expl. & develop.)	10^6\$	210	270	330
Profit	10^6\$	170	246	344
P.W.V. of the profit (as of start of production)	10^6\$	0	21	57
Rate of return	%	10.0	11.2	12.6
Pay out time (from start of production)	years	4.7	4.4	4.1
N.T.I.R.	n°	1.8	1.9	2.0

* * *

CASE B: well optimization

Prospect C

Number of wells	n°	20	30	40
Total investments	10^6\$	260	330	440
Profit	10^6\$	285	344	375
P.W.V. (i = 10% as of start of production)	10^6\$	46	557	40
Rate of return	%	12.5	12.6	11.5
Pay out time (from start of production)	years	4.2	4.1	4.4
N.T.I.R.	n°	2.1	2.0	1.9

* * *

CASE C: time is money

Prospect C

Years for build up:	n°	2	4	6
Total investments (expl. & develop.)	10^6\$	330	330	330
Profit	10^6\$	308	344	392
P.W.V. (i = 10% as of start of production)	10^6\$	60	57	53
Rate of return	%	13.4	12.6	11.9
Pay out time (from start of production)	years	4.4	4.1	3.8
N.T.I.R.	n°	1.9	2.0	2.2

Fig. 15 · CASE A
Fiscal take : opec
Recoverable reserves

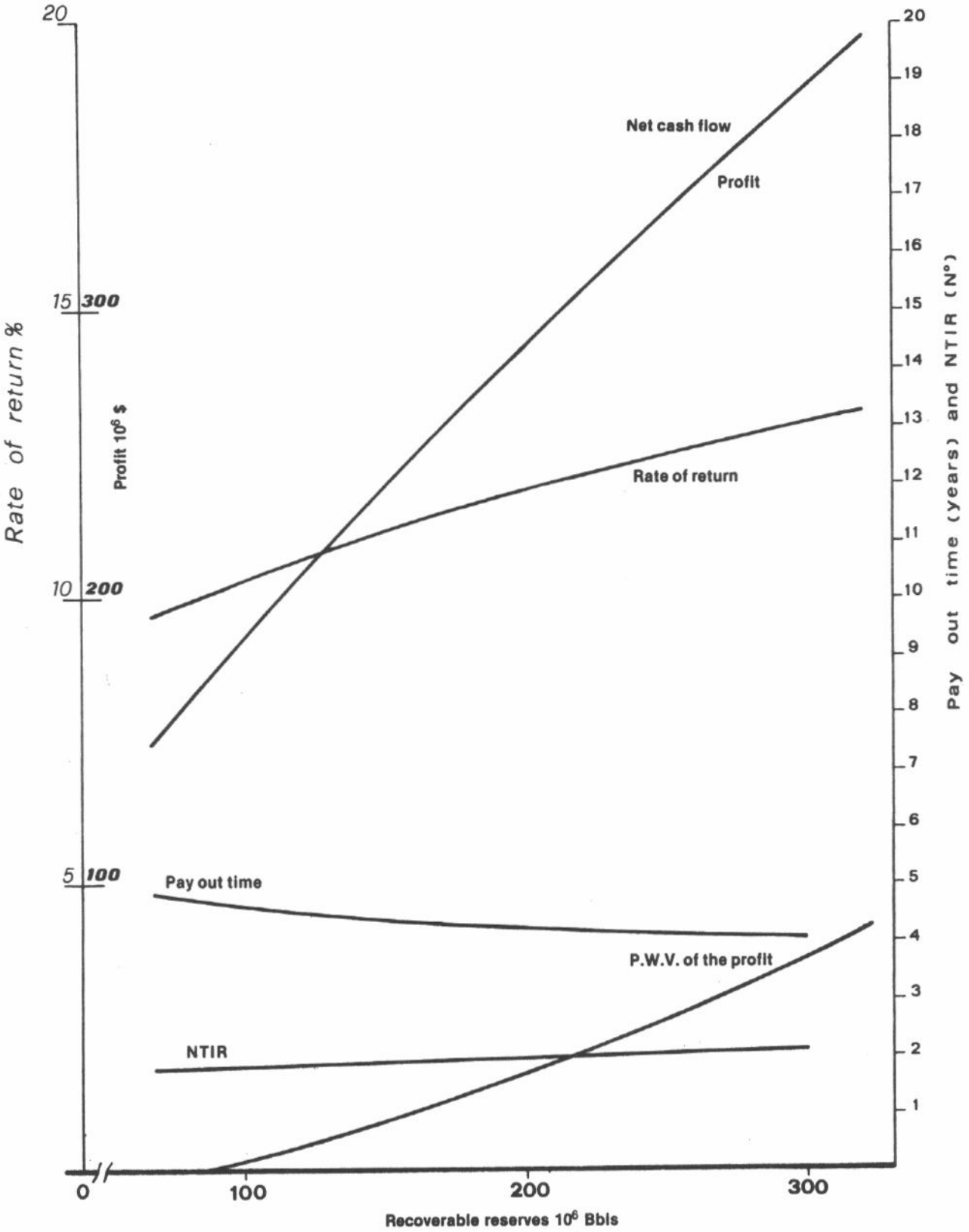


Fig. 16 - PROSPECT - C
Fiscal take : opec
Well optimization

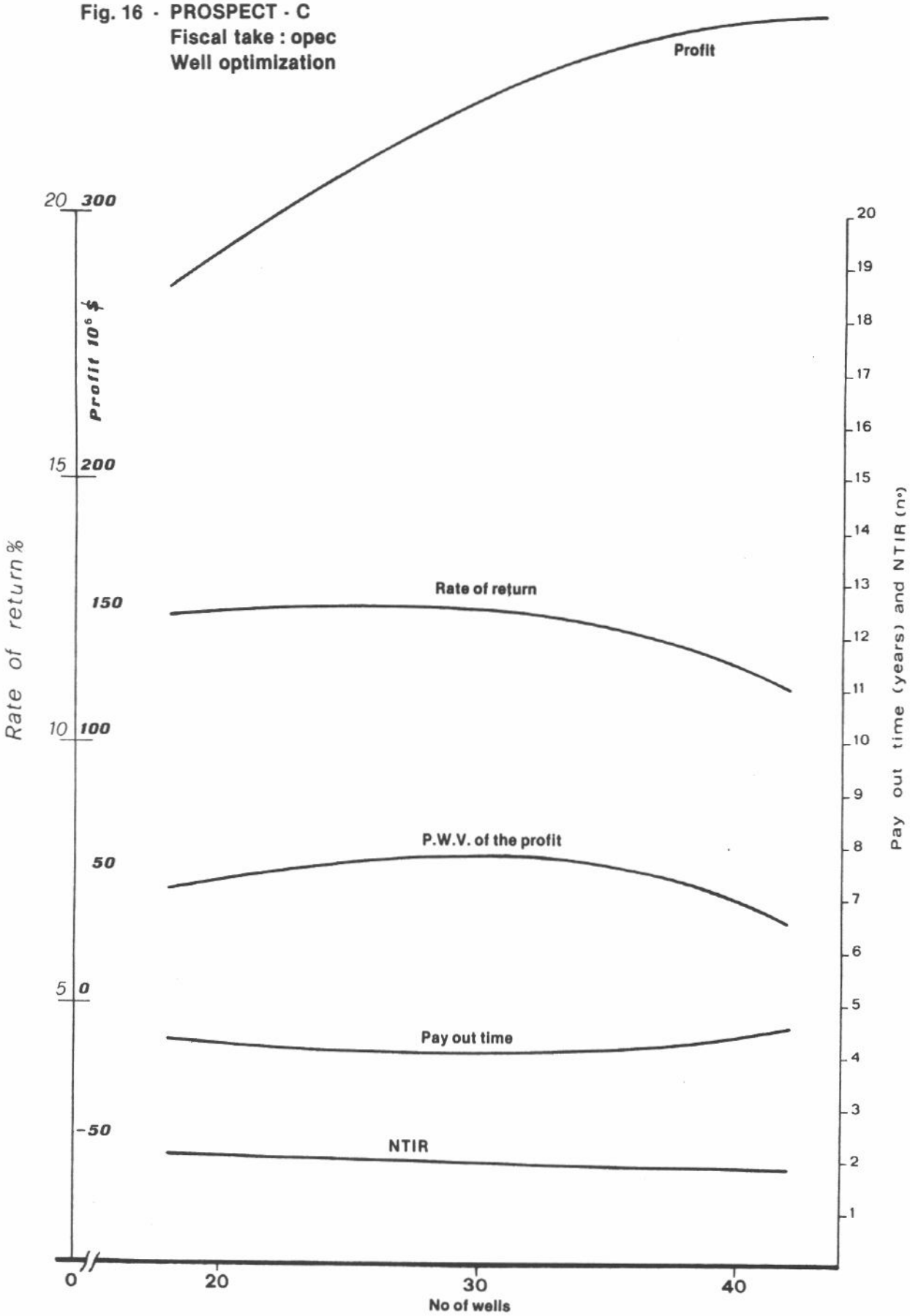


Fig. 17 · PROSPECT · C
Fiscal take : opec
Sensivity analysis

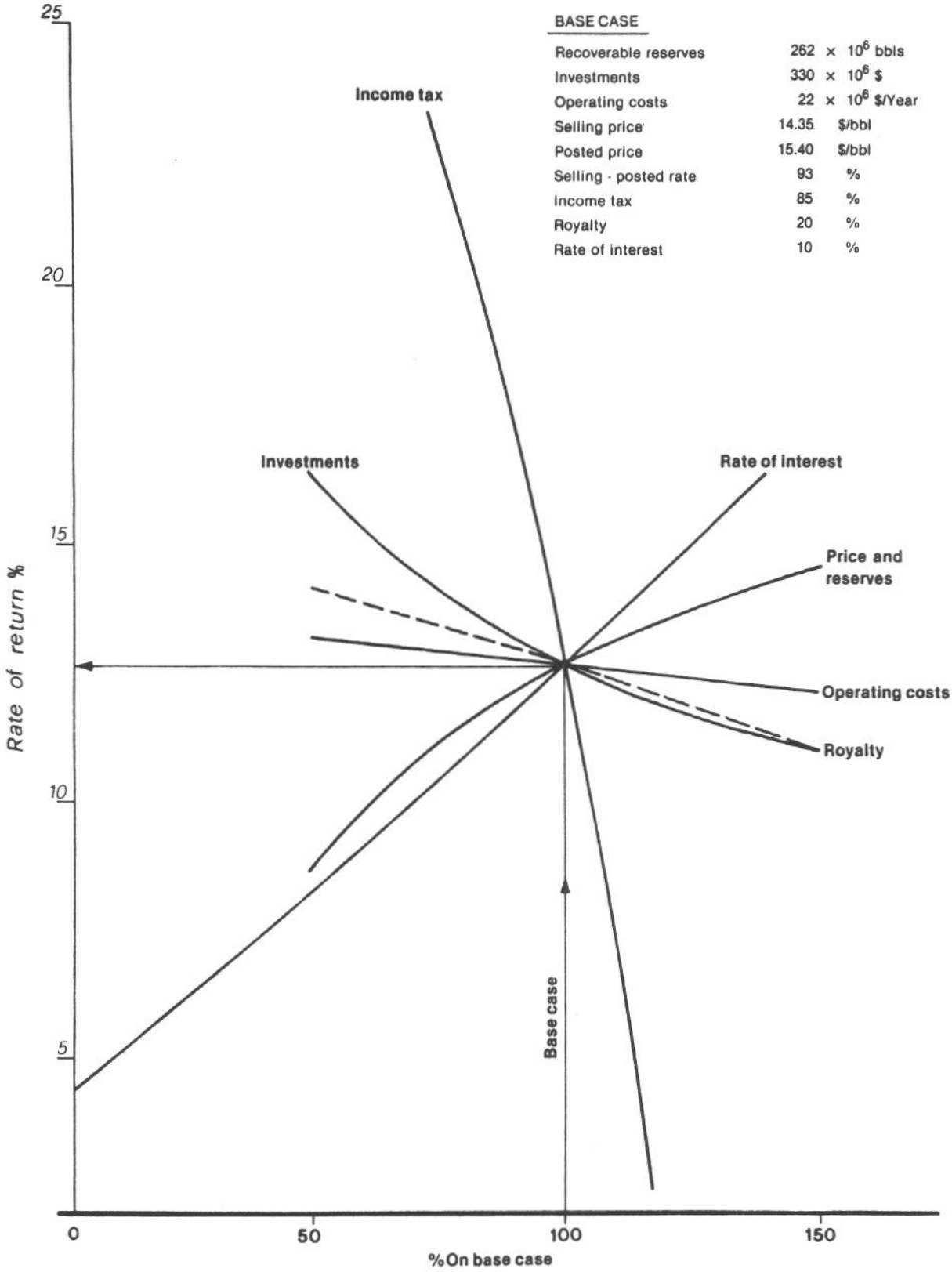
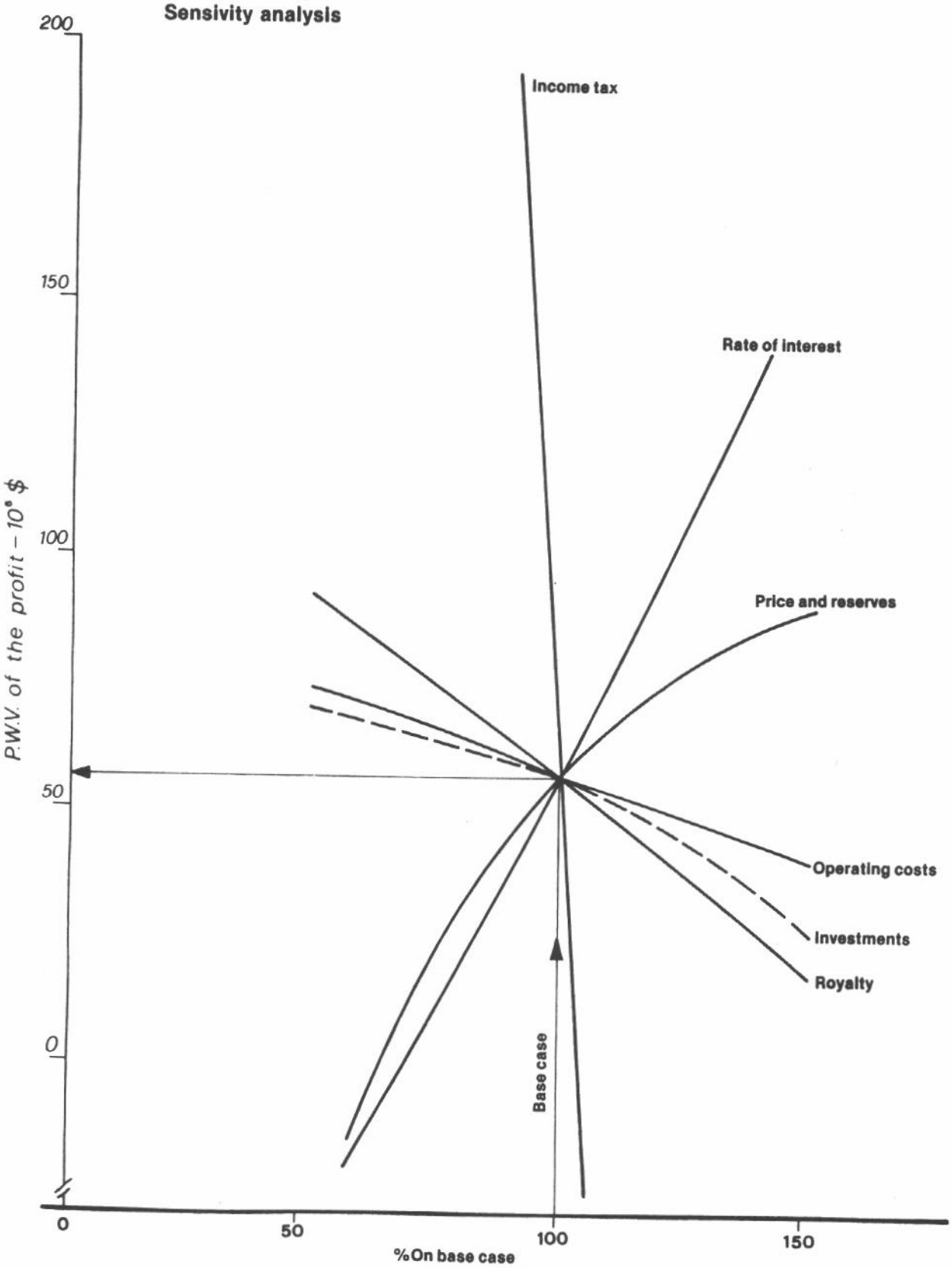


Fig. 18 - PROSPECT - C
Fiscal take : opec
Sensivity analysis



NORTH SEA FISCAL TAKE (U.K.)

Prospect		A		B		C	
Recoverable reserves	10^6bbls	88		159		262	
Economically, recoverable reserves	10^6bbls	88		159		262	
			$/bbl		$/bbl		$/bbl
Exploration investments	$10^6$$	30	0.34	30	0.19	30	0.11
Development investments	$10^6$$	180	2.05	240	1.51	300	1.15
Operating costs	$10^6$$	221	2.51	306	1.92	418	1.60
Total technical costs	$10^6$$	431	4.90	576	3.62	748	2.86
Royalty	$10^6$$	158	1.80	285	1.80	470	1.80
Petroleum Revenue Tax (P.R.T.)	$10^6$$	0	0	5	0.03	386	1.47
Corporation Tax (C.T.)	$10^6$$	315	3.58	679	4.27	1058	4.04
Total Government Take	$10^6$$	473	5.38	969	6.10	1914	7.31
Total costs	$10^6$$	904	10.28	1545	9.72	2662	10.17
Total revenue	$10^6$$	1263	14.35	2282	14.35	3760	14.35
Profit	$10^6$$	359	4.07	737	4.63	1098	4.18
P.W.V. (i = 10% as of start of production)	$10^6$$	167		369		581	
Rate of return	%	24.9		27.6		32.5	
Pay out time (from start of production)	years	2.2		1.5		1.1	
N.T.I.R.	n°	2.7		3.7		4.3	

Sharing of the profit after technical costs

Government	56.8%	56.8%	3.5%
Company	43.2%	43.2%	36.5%
	100.0%	100.0%	100.0%

NORTH SEA FISCAL TAKE (U.K.)

CASE A: recoverable reserves

Prospect		A	B	C
Reserves	10^6bbls	88	159	262
Total Investments (expl. & develop.)	10^6\$	210	270	330
Profit	10^6\$	359	737	1098
P.W.V. (i = 10% as of start of production)	10^6\$	167	369	581
Rate of return	%	24.9	27.6	32.5
Pay out time (from start of production)	years	2.2	1.5	1.1
N.T.I.R.	n°	2.7	3.7	4.3

* * *

CASE B: well optimization

Prospect C

Wells	n°	20	30	40
Total Investments (expl. & develop.)	10^6\$	260	330	440
Profit	10^6\$	1013	1097	1045
P.W.V. (i = 10% as of start of production)	10^6\$	500	580	548
Rate of return	%	31.2	32.5	29.2
Pay out time (from start of production)	years	1.3	1.1	1.6
N.T.I.R.	n°	4.9	4.3	3.4

* * *

CASE C: time is money

Prospect C

Years for build up:	n°	2	4	6
Total investments (expl. & develop.)	10^6\$	330	330	330
Profit	10^6\$	1081	1098	1121
P.W.V. (i = 10% as of start of production)	10^6\$	593	581	564
Rate of return	%	42.4	32.5	26.1
Pay out time (from start of production)	years	1.1	1.1	1.1
N.T.I.R.	n°	4.3	4.3	4.4

Fig. 19 - CASE A
North sea fiscal take (U.K)
Recoverable reserves

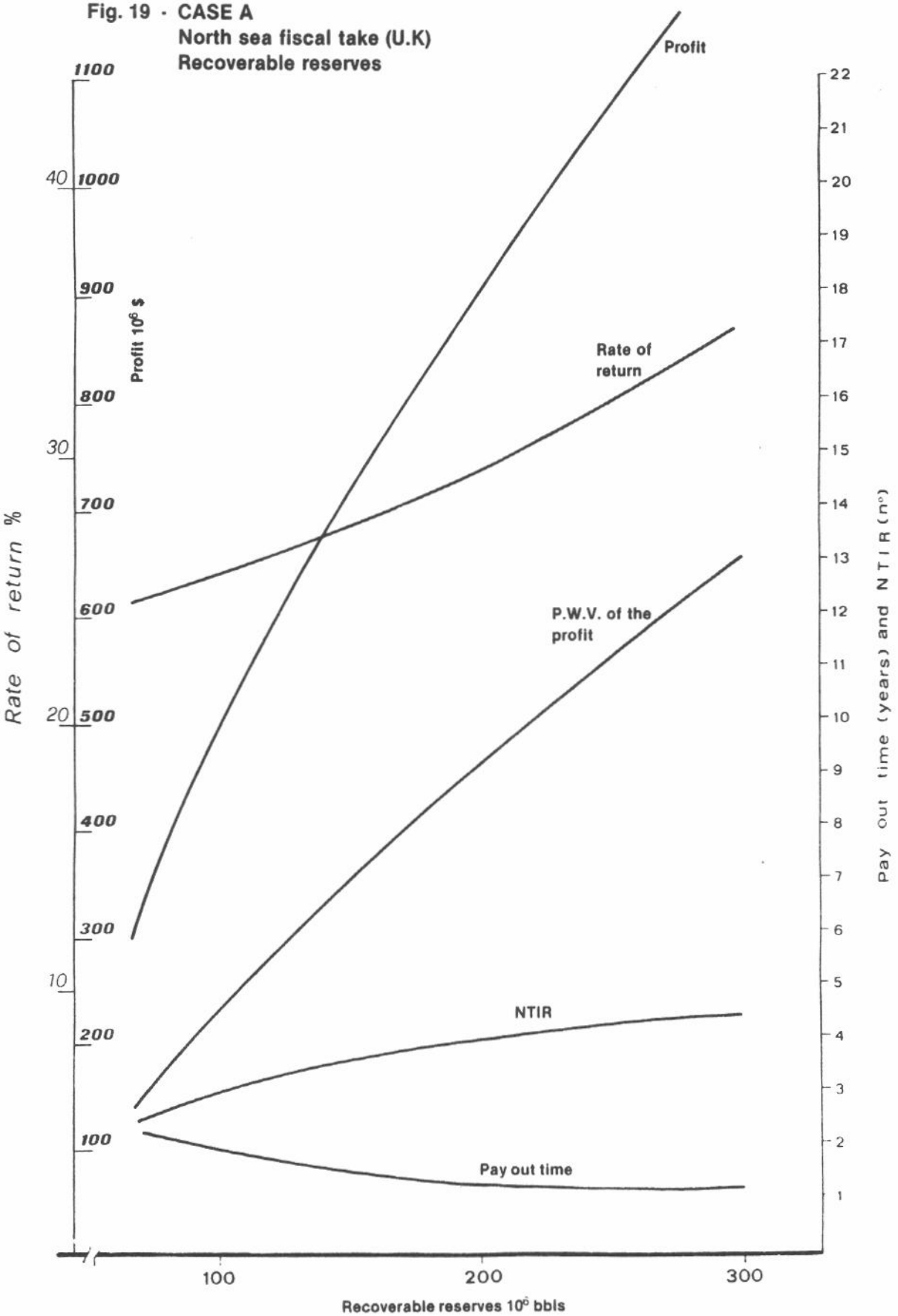


Fig. 20 - PROSPECT - C
North sea fiscal take (U.K)
Well optimization

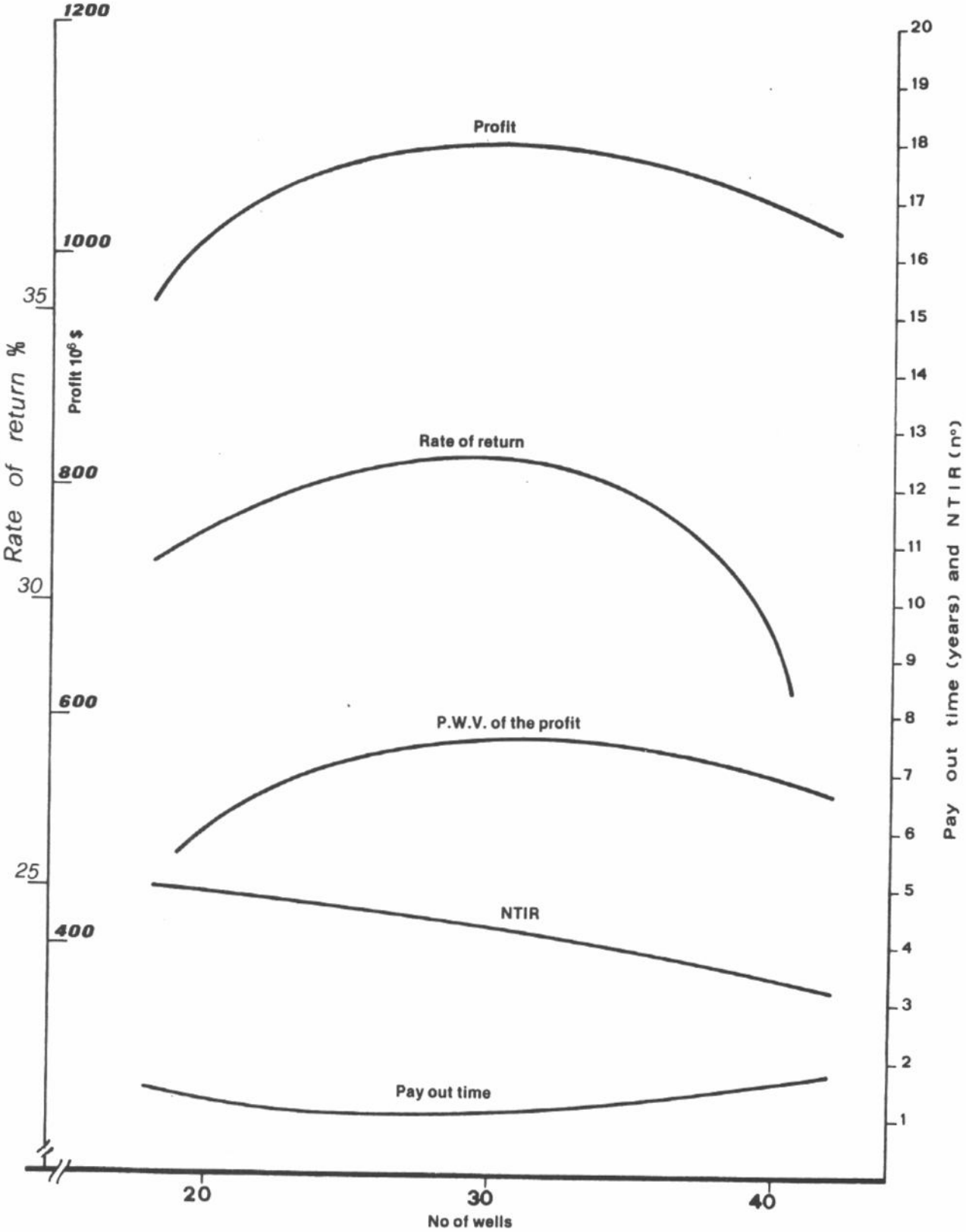


Fig. 21 · PROSPECT · C
North sea (U.K) taxation
Sensivity analysis

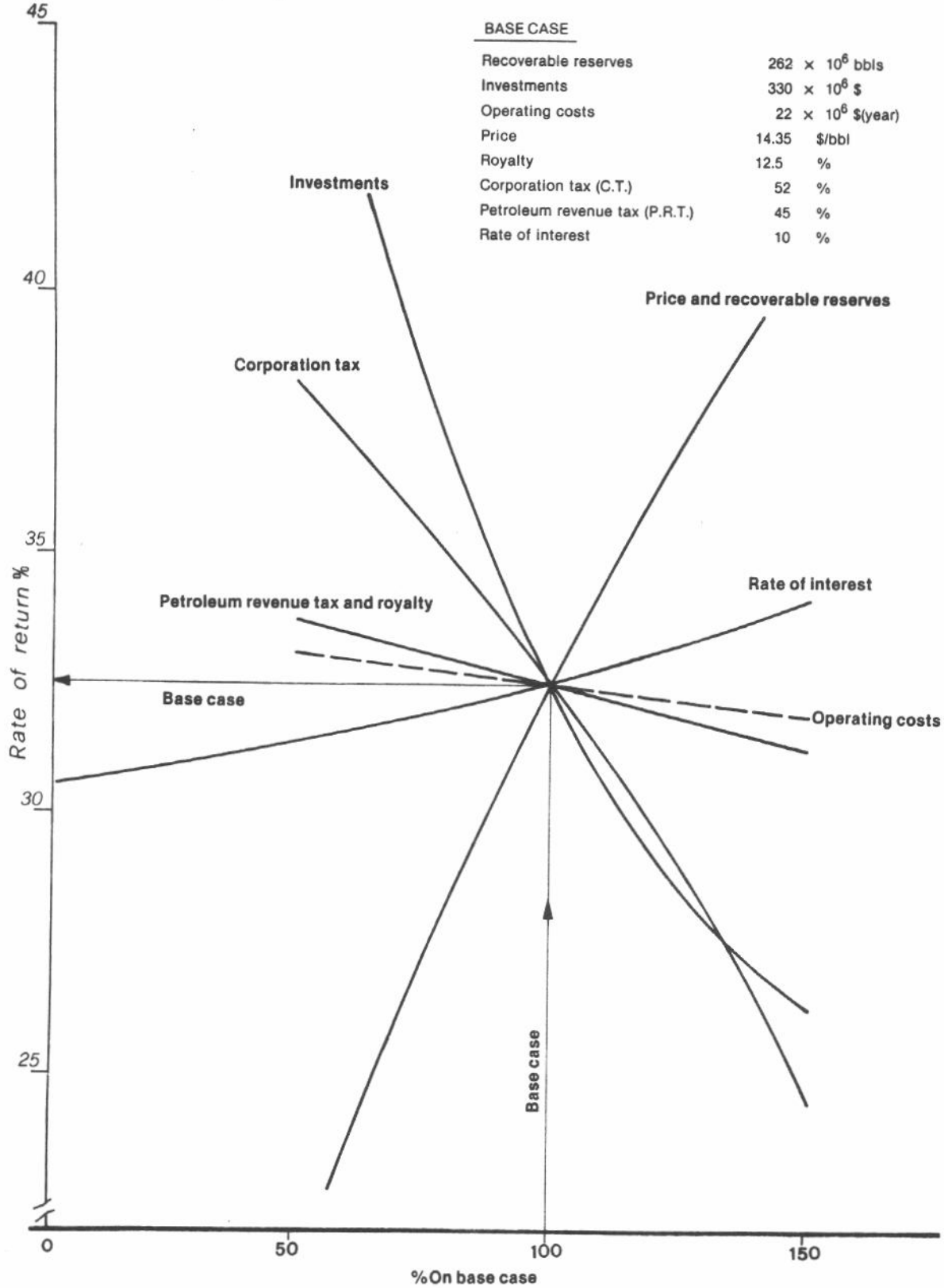
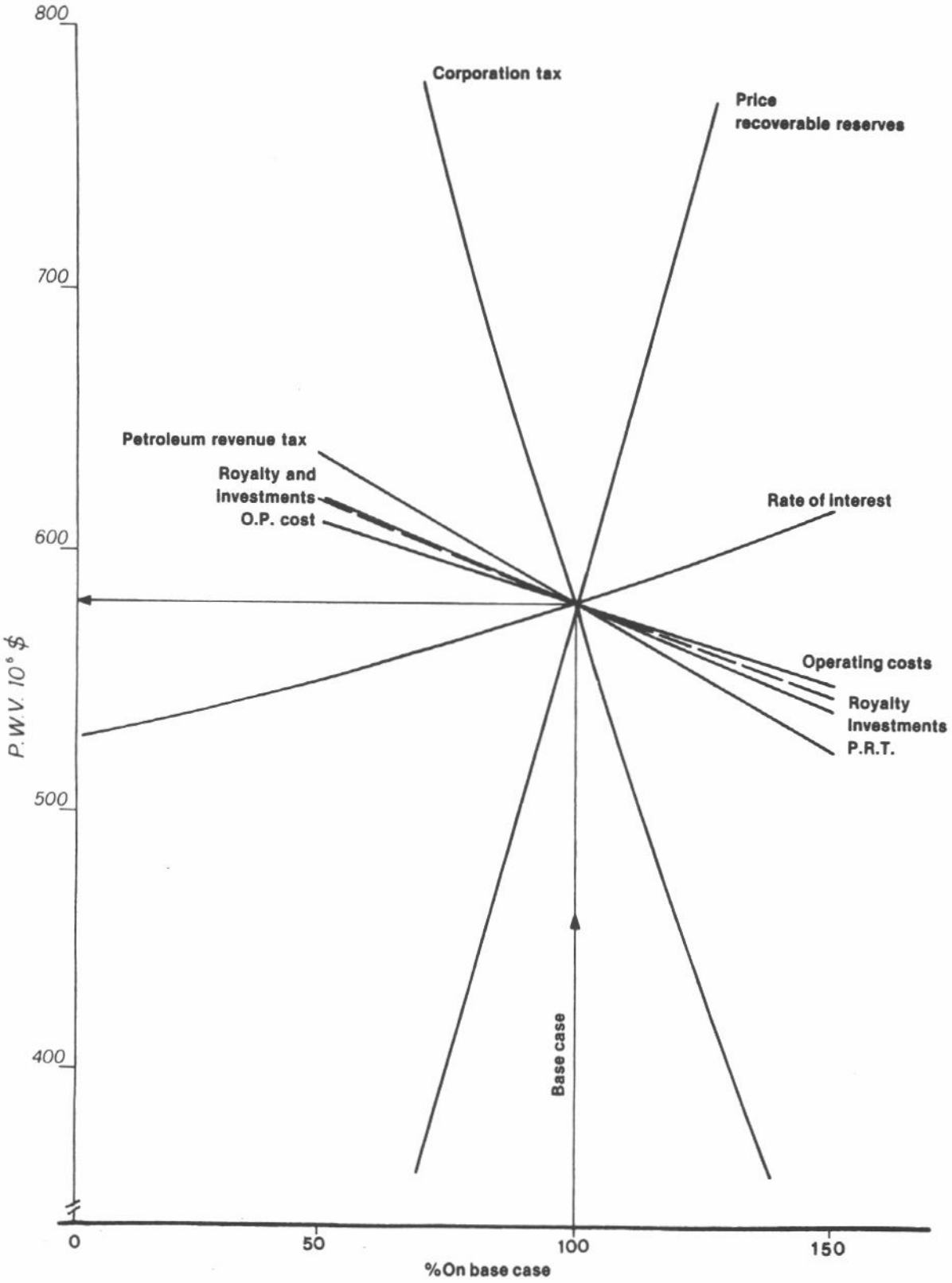


Fig. 22 - PROSPECT - C
North sea (U.K) taxation
Sensivity analysis



SHARING CONTRACT

Prospect		A		B		C	
Recoverable reserves	10^6bbls	88		159		262	
Economically, recoverable reserves	10^6bbls	88		159		262	
			$/bbl		$/bbl		$/bbl
Exploration investments	$10^6$$	30	0.34	30	0.19	30	0.11
Development investments	$10^6$$	180	2.05	240	1.51	300	1.15
Operating costs	$10^6$$	221	2.51	306	1.92	418	1.60
Total technical costs	$10^6$$	431	4.90	576	3.62	748	2.86
Profit oil	$10^6$$	626	7.11	1342	8.44	2426	9.26
Domestic market	10$	46	0.52	84	0.53	139	0.53
Total Government take	$10^6$$	672	7.63	1426	8.97	2565	9.79
Total costs	$10^6$$	1103	12.53	2002	12.59	3313	12.65
Total revenue	$10^6$$	1263	14.35	2282	14.35	3760	14.35
Profit	$10^6$$	160	1.82	280	1.76	447	1.70
P.W.V. (i = 10% as of start of production)	$10^6$$	22		78		165	
Rate of return	%	11.8		14.9		18.1	
Pay out time (from start of production)	years	3.1		2.7		2.4	
N.T.I.R.	n°	1.8		2.0		2.4	

Distribution of the profit after technical costs

Government	80.7%	83.6%	85.2%
Company	19.3%	16.4%	14.8%
	100.0%	100.0%	100.0%

SHARING CONTRACT

CASE A: recoverable reserves

Prospect		A	B	C
Reserves	10^6bbls	88	159	262
Total Investments (expl. & develop.)	10^6\$	210	270	330
Profit	10^6\$	159	279	447
P.W.V. of the profit (as of start of production)	10^6\$	21	78	165
Rate of return	%	11.8	14.9	18.1
Pay out time (from start of production)	years	3.1	2.7	2.4
N.T.I.R.	n°	1.8	2.0	2.4

* * *

CASE B: well optimization

Prospect C

Wells	n°	20	30	40
Total Investments (expl. & develop.)	10^6\$	260	330	440
Profit	10^6\$	408	447	447
P.W.V. (i = 10% as of start of production)	10^6\$	140	165	151
Rate of return	%	16.5	18.1	16.6
Pay out time (from start of production)	years	2.0	2.4	2.6
N.T.I.R.	n°	2.6	2.4	2.0

* * *

CASE C: time is money

Prospect C

Years for build up:	n°	2	4	6
Total investments (expl. & develop.)	10^6\$	330	330	330
Profit	10^6\$	426	447	476
P.W.V. (i = 10% as of start of production)	10^6\$	176	165	152
Rate of return	%	21.3	18.1	15.7
Pay out time (from start of production)	years	2.6	2.4	2.3
N.T.I.R.	n°	2.3	2.4	2.4

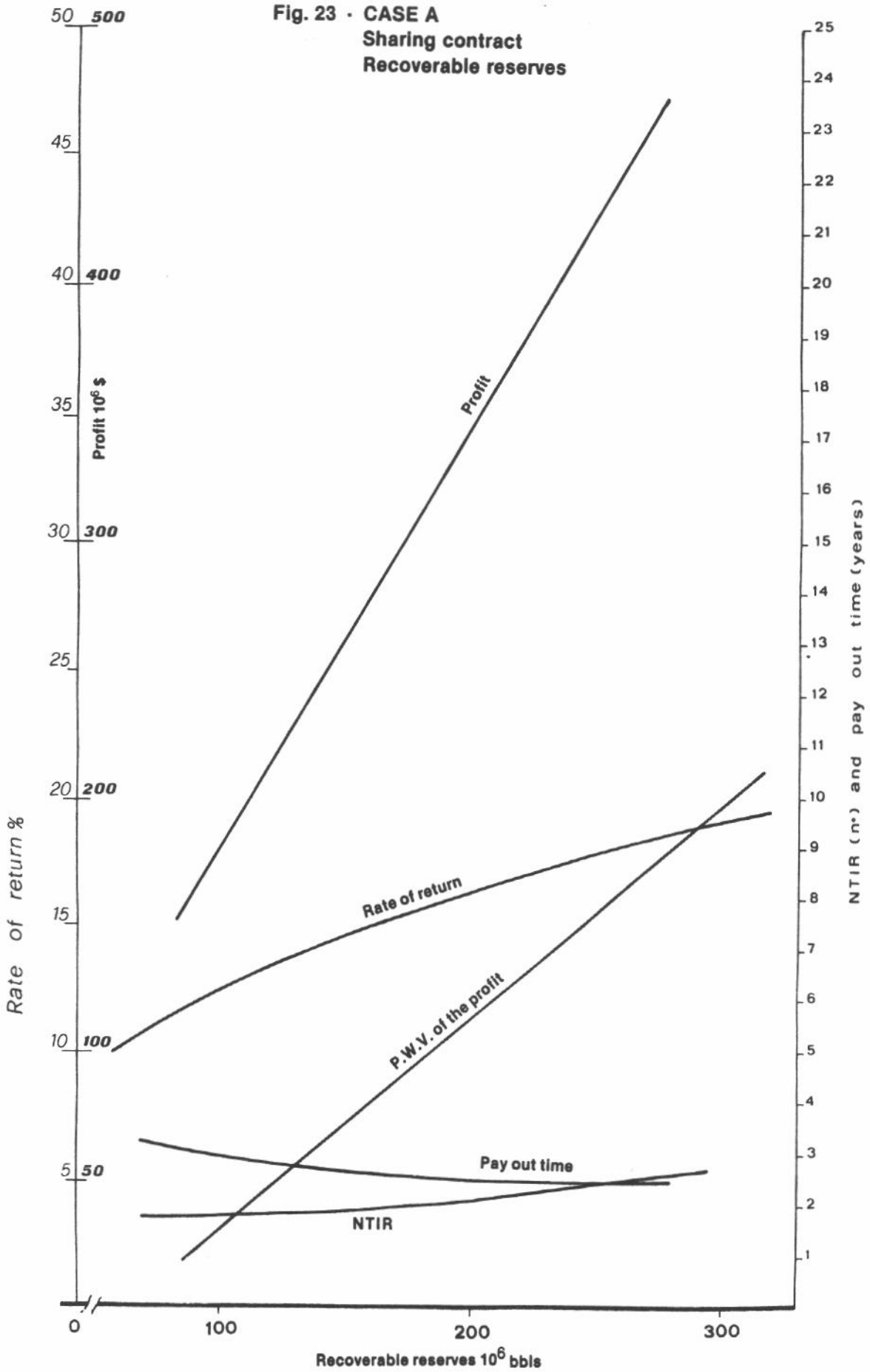


Fig. 23 · CASE A
Sharing contract
Recoverable reserves
Profit
Rate of return
P.W.V. of the profit
Pay out time
NTIR
Rate of return %
Profit 10^6 $
NTIR (n°) and pay out time (years)
Recoverable reserves 10^6 bbls
0
100
200
300
50
45
40
35
30
25
20
15
10
5
500
400
300
200
100
50
25
24
23
22
21
20
19
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1

Fig. 24 · PROSPECT · C
Sharing contract
Well optimization

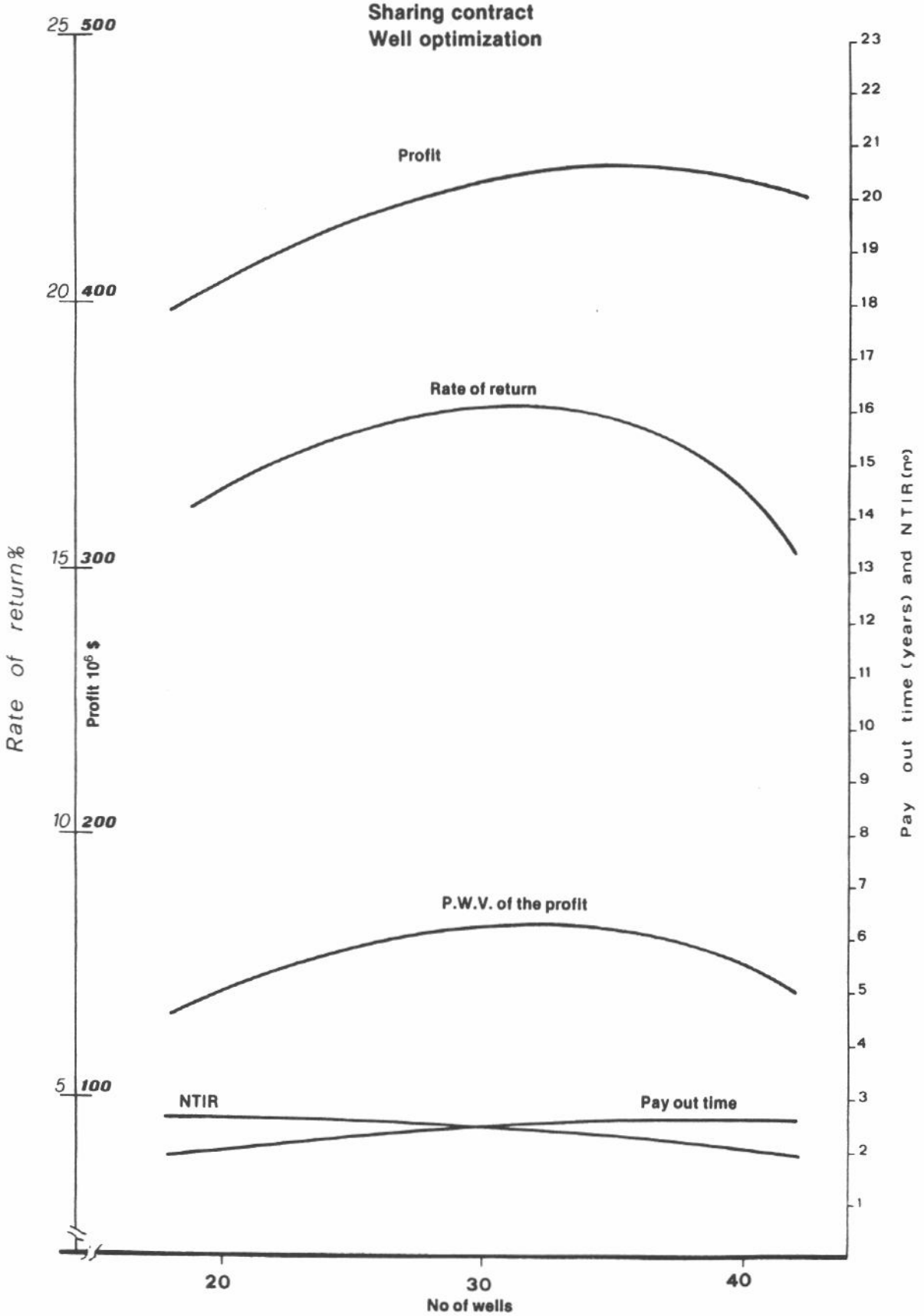


Fig. 25 · PROSPECT · C
Sharing contract
Sensivity analysis

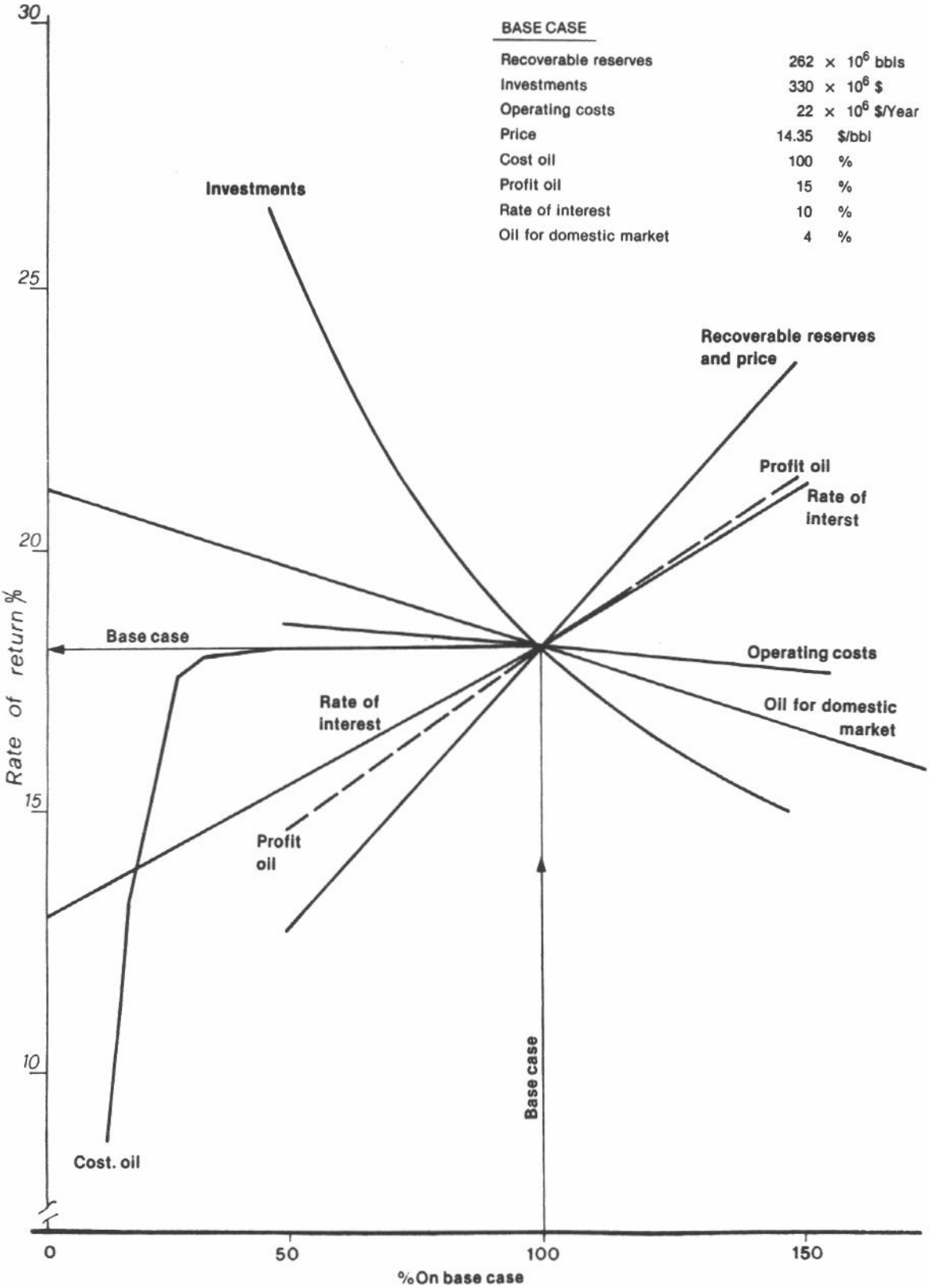
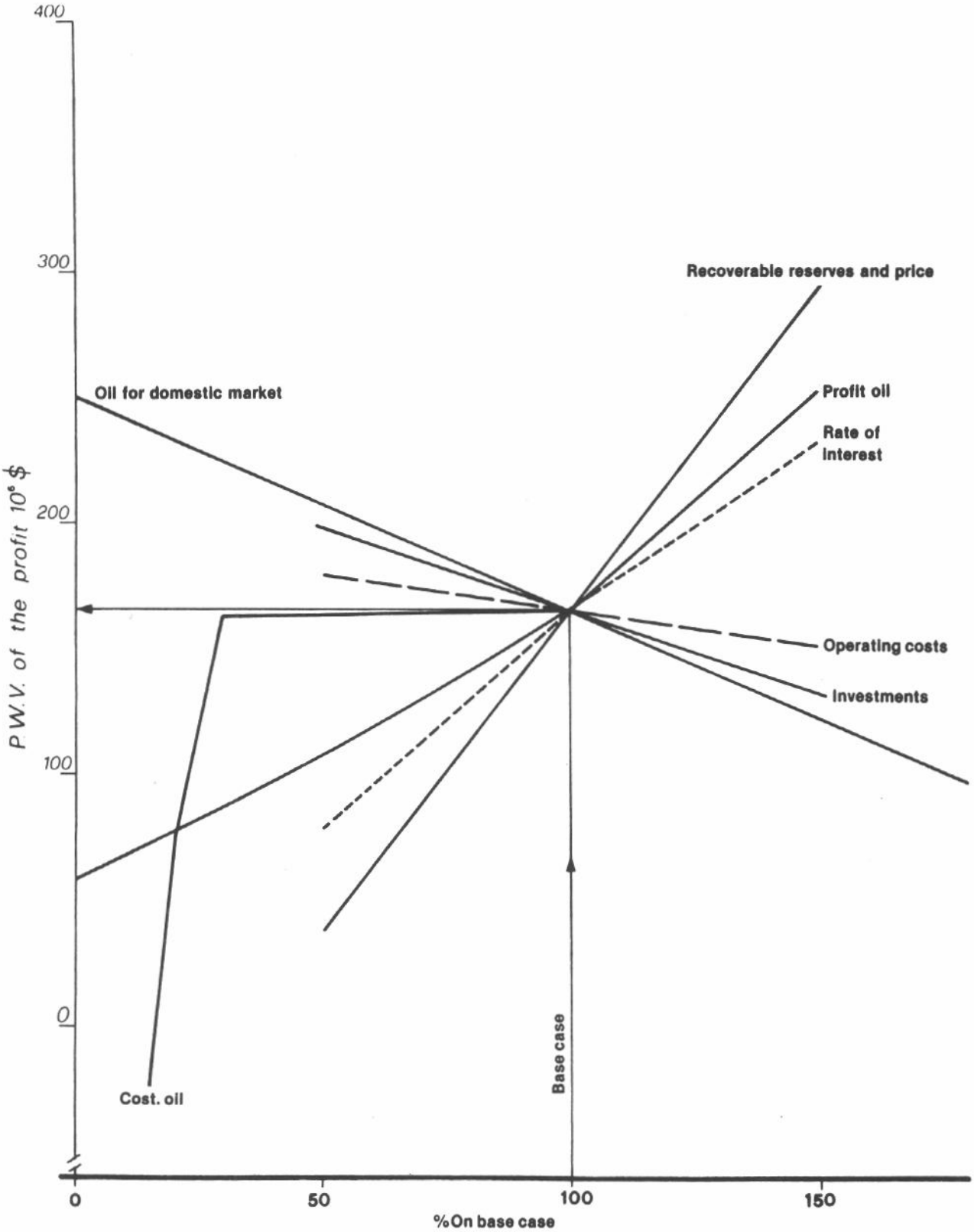
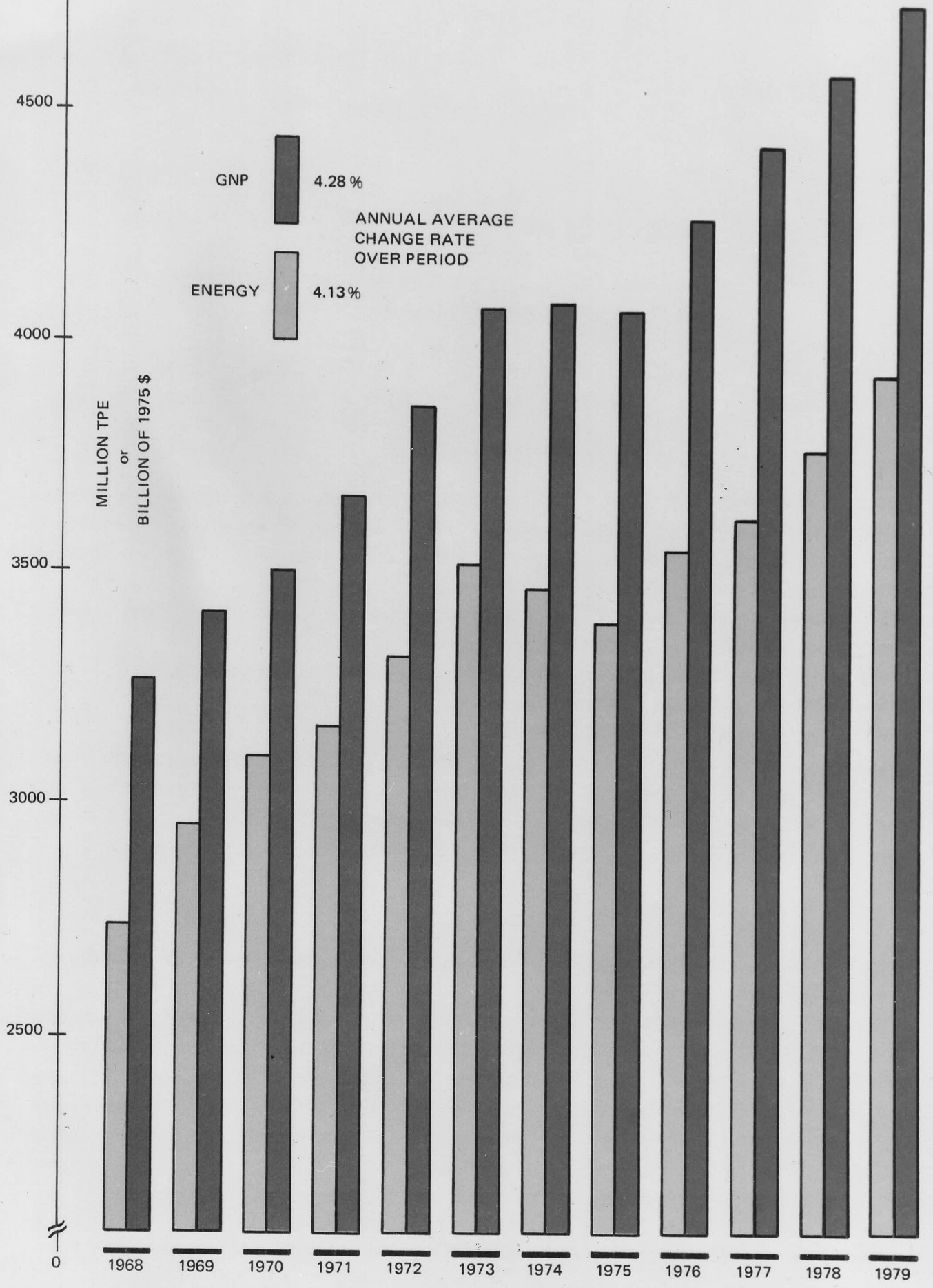


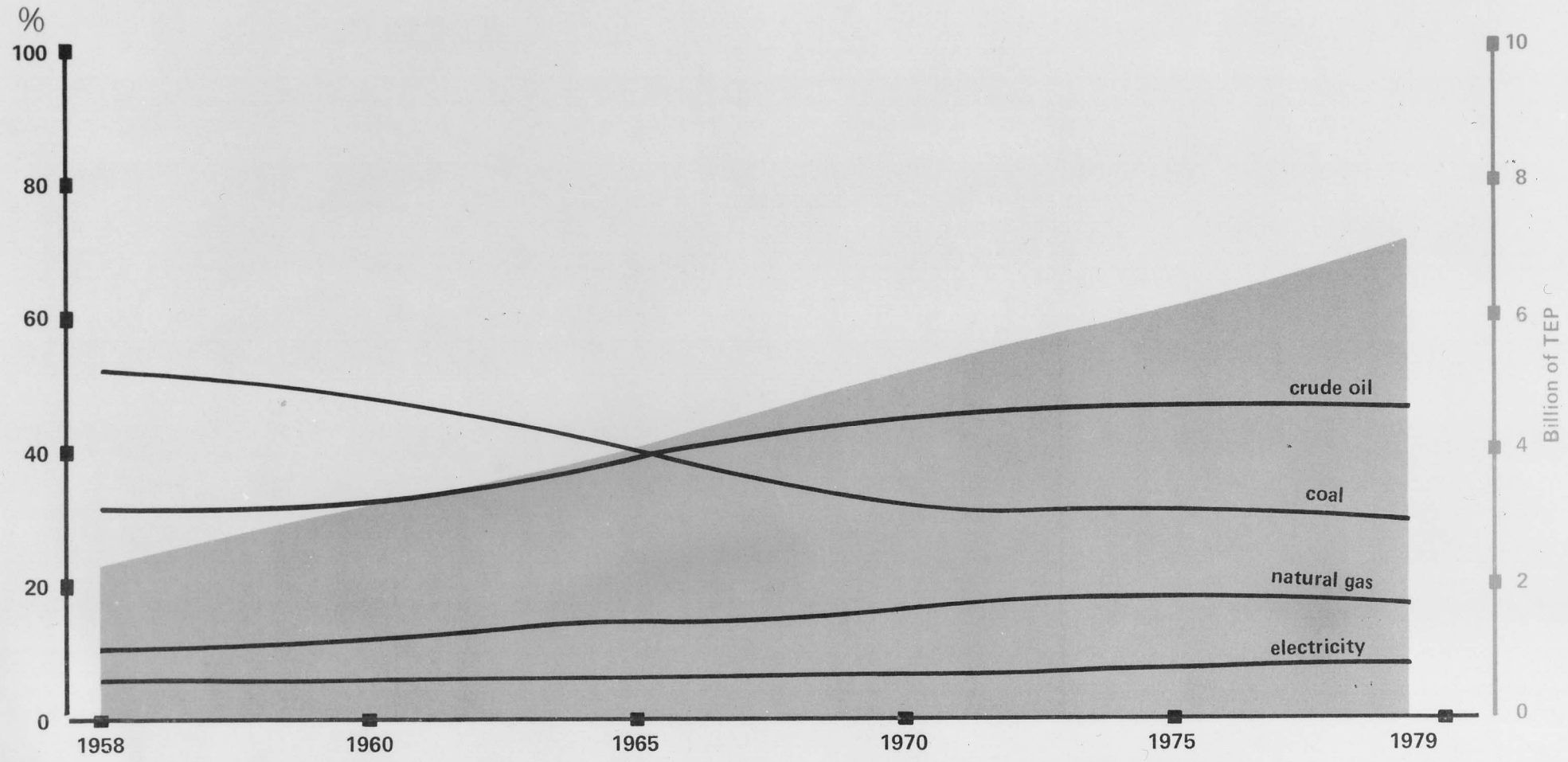
Fig. 26 · PROSPECT · C
Sharing contract
Sensivity analysis



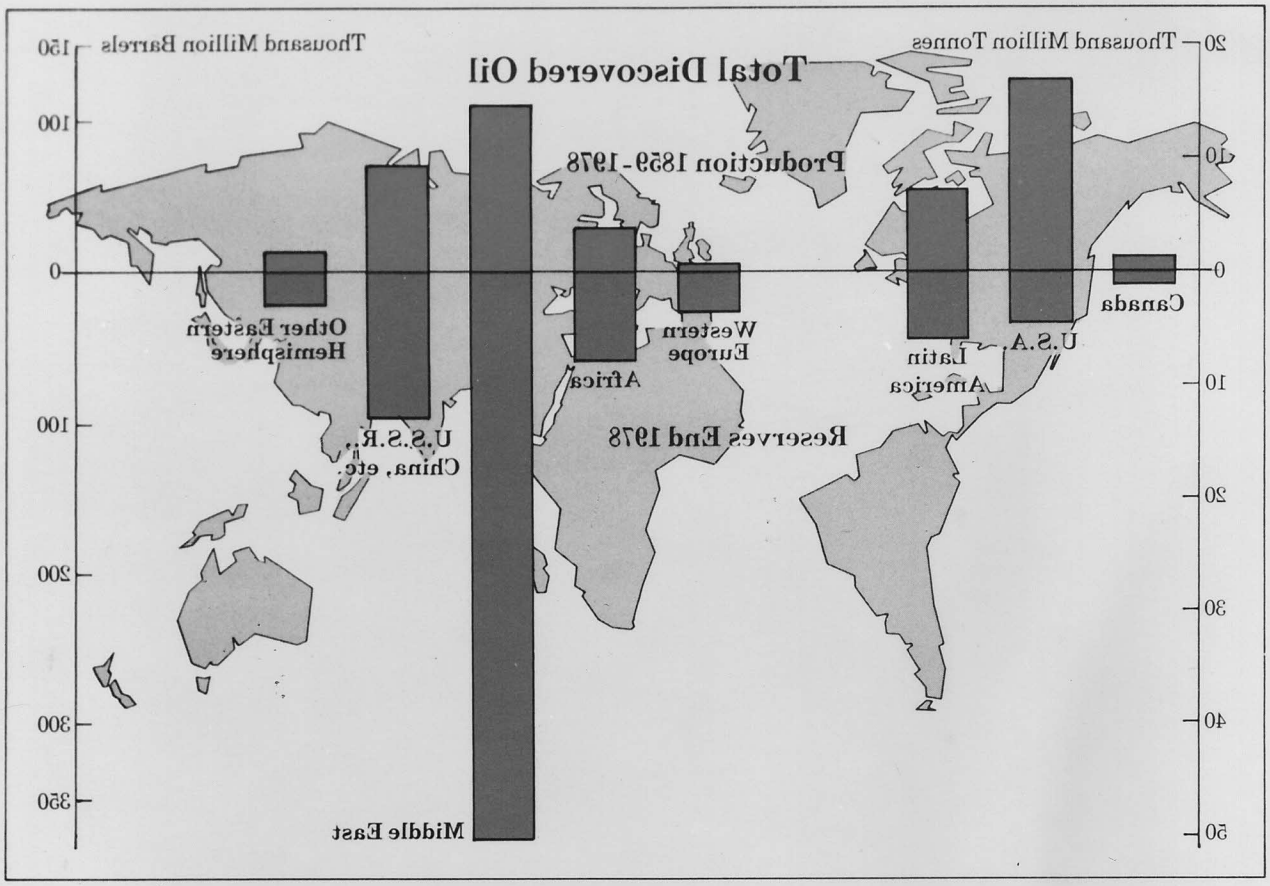
Graf. 1 · GNP and energy consumption in OCDE countries

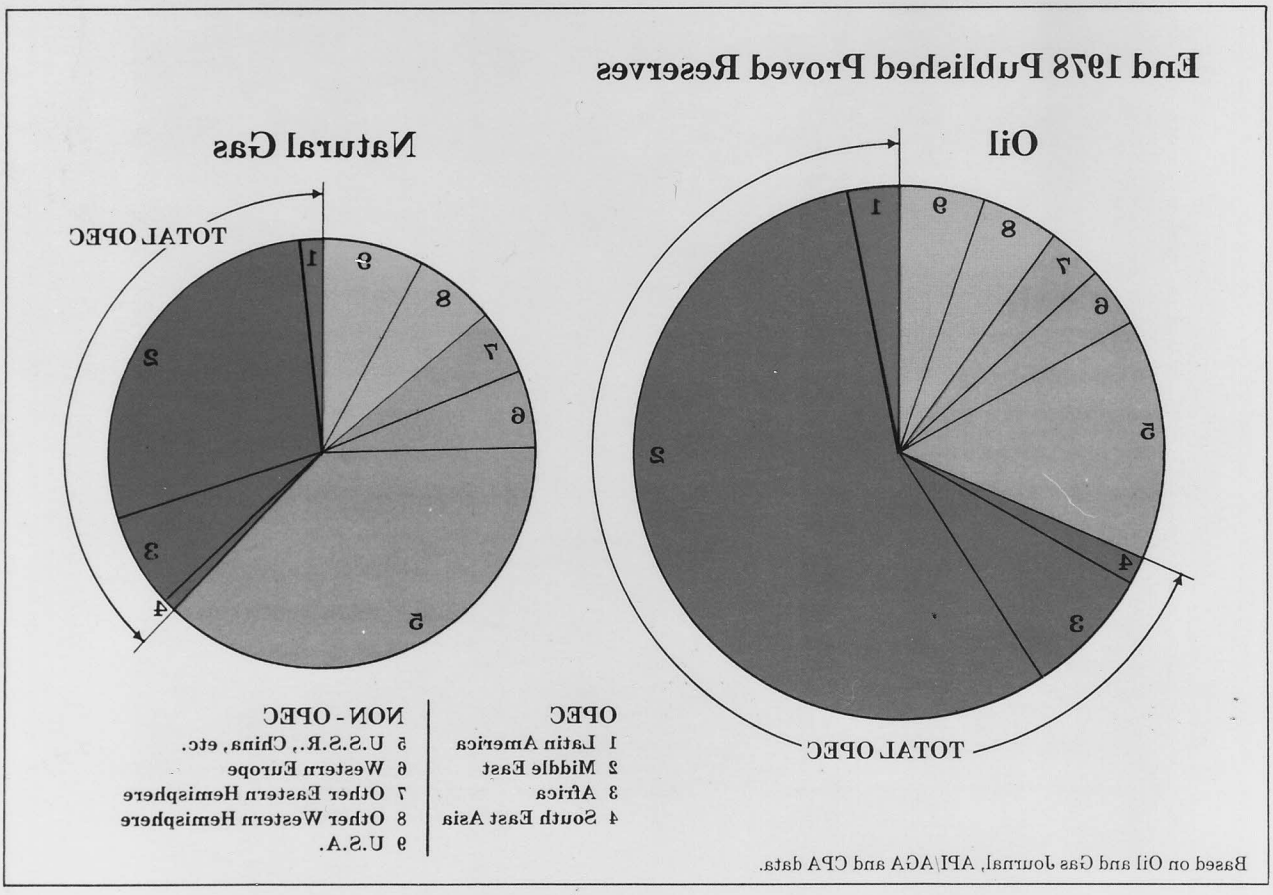


Graf. 2 · Breakdown of worldwide energy consumption

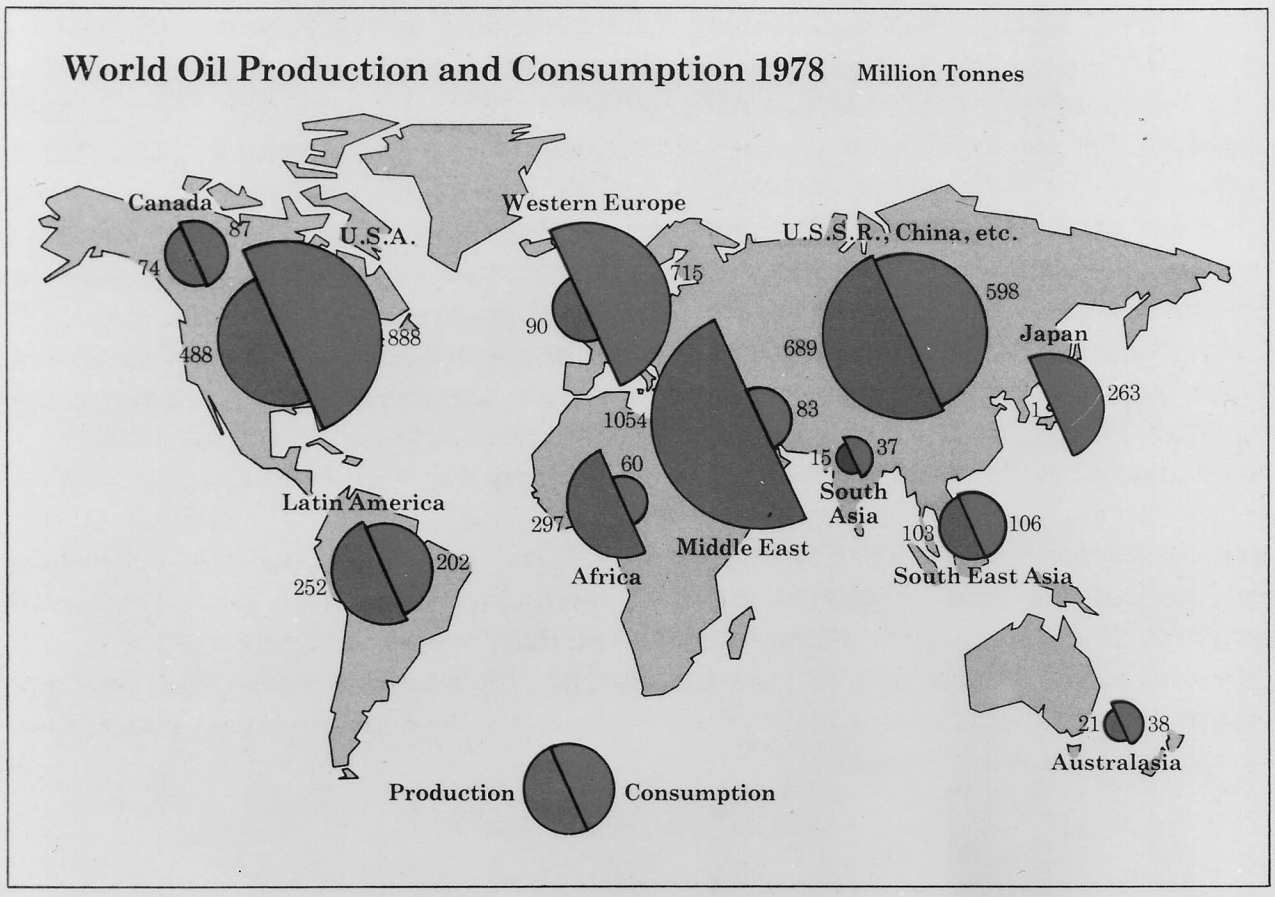


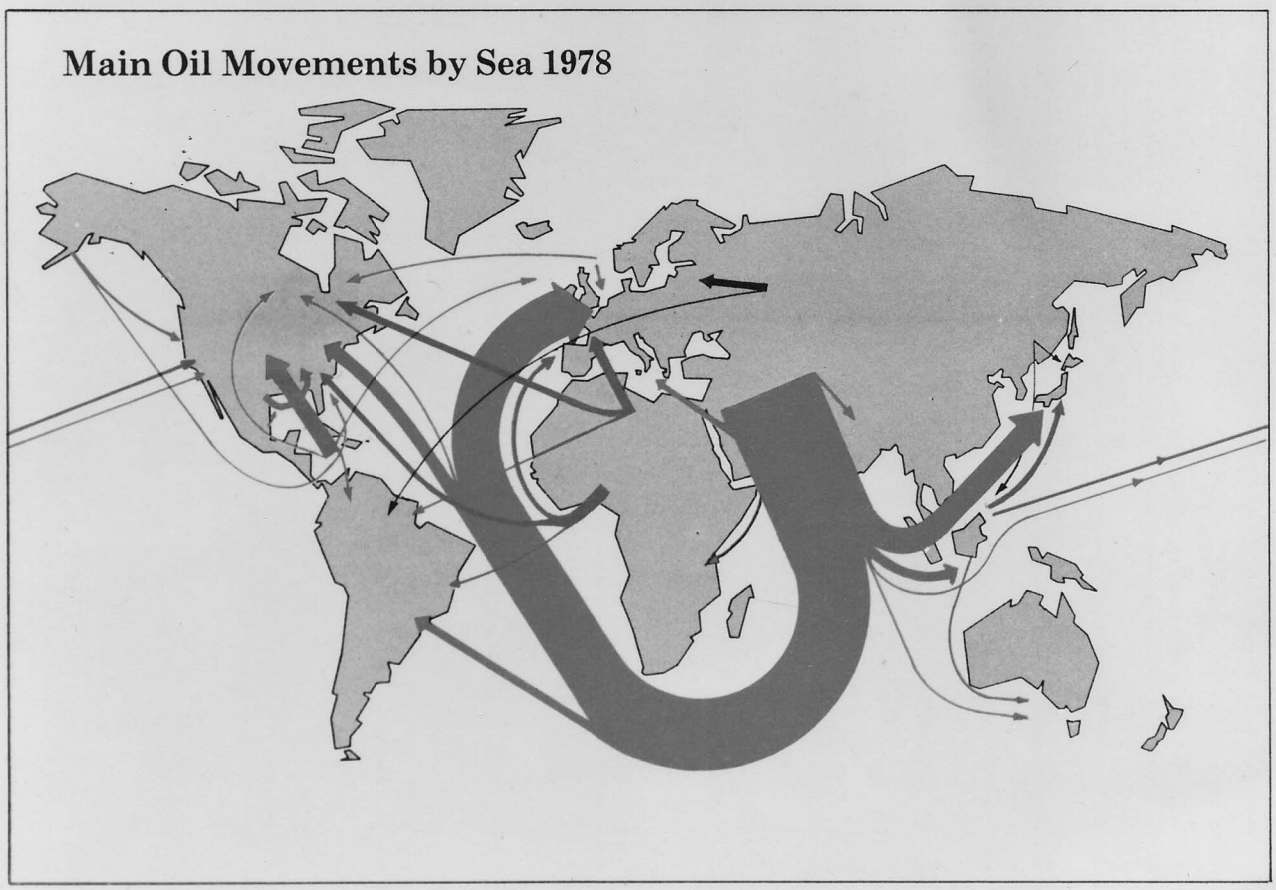
Grafi. 3


Total Discovered Oil
Production 1859-1978
Reserves End 1978
Thousand Million Barrels
Thousand Million Tonnes
150
100
0
100
200
300
350
20
10
0
10
20
30
40
50
Middle East
U.S.S.R., China, etc.
Other Eastern Hemisphere
Africa
Western Europe
Latin America
U.S.A.
Canada

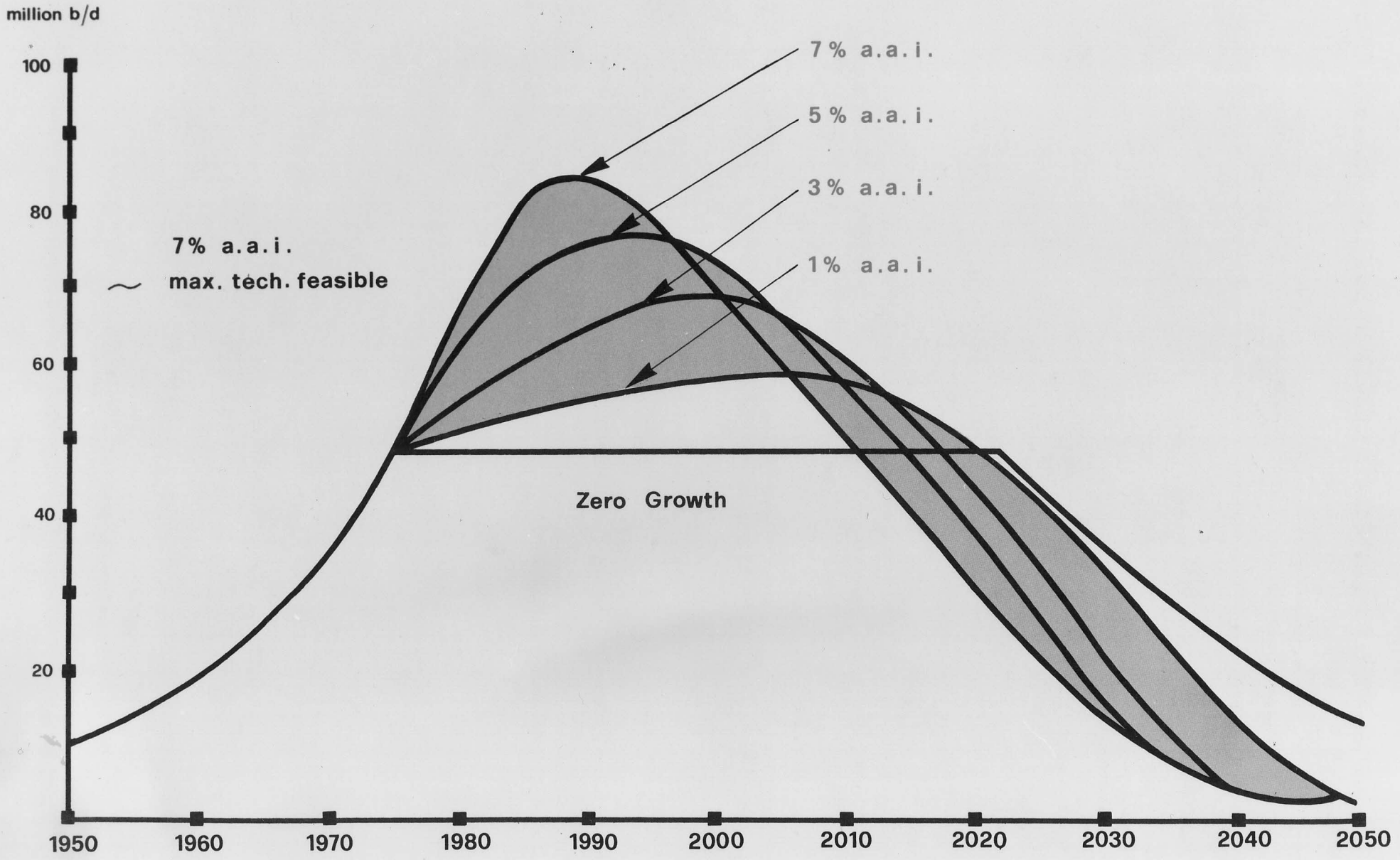

End 1978 Published Proved Reserves
Oil
Natural Gas
TOTAL OPEC
TOTAL OPEC
OPEC
1 Latin America
2 Middle East
3 Africa
4 South East Asia
NON - OPEC
5 U.S.S.R., China, etc.
6 Western Europe
7 Other Eastern Hemisphere
8 Other Western Hemisphere
9 U.S.A.
Based on Oil and Gas Journal, API/AGA and CPA data.

Graf. 4


World Oil Production and Consumption 1978
Million Tonnes
Canada
87
74
U.S.A.
488
888
Western Europe
715
90
1054
60
297
Africa
Middle East
83
15
37
South Asia
U.S.S.R., China, etc.
598
689
Japan
263
Latin America
202
252
103
106
South East Asia
21
38
Australasia
Production
Consumption


Main Oil Movements by Sea 1978

Graf. 5 · Crude oil life cycles: theoretical effect of variable rates of exponential growth

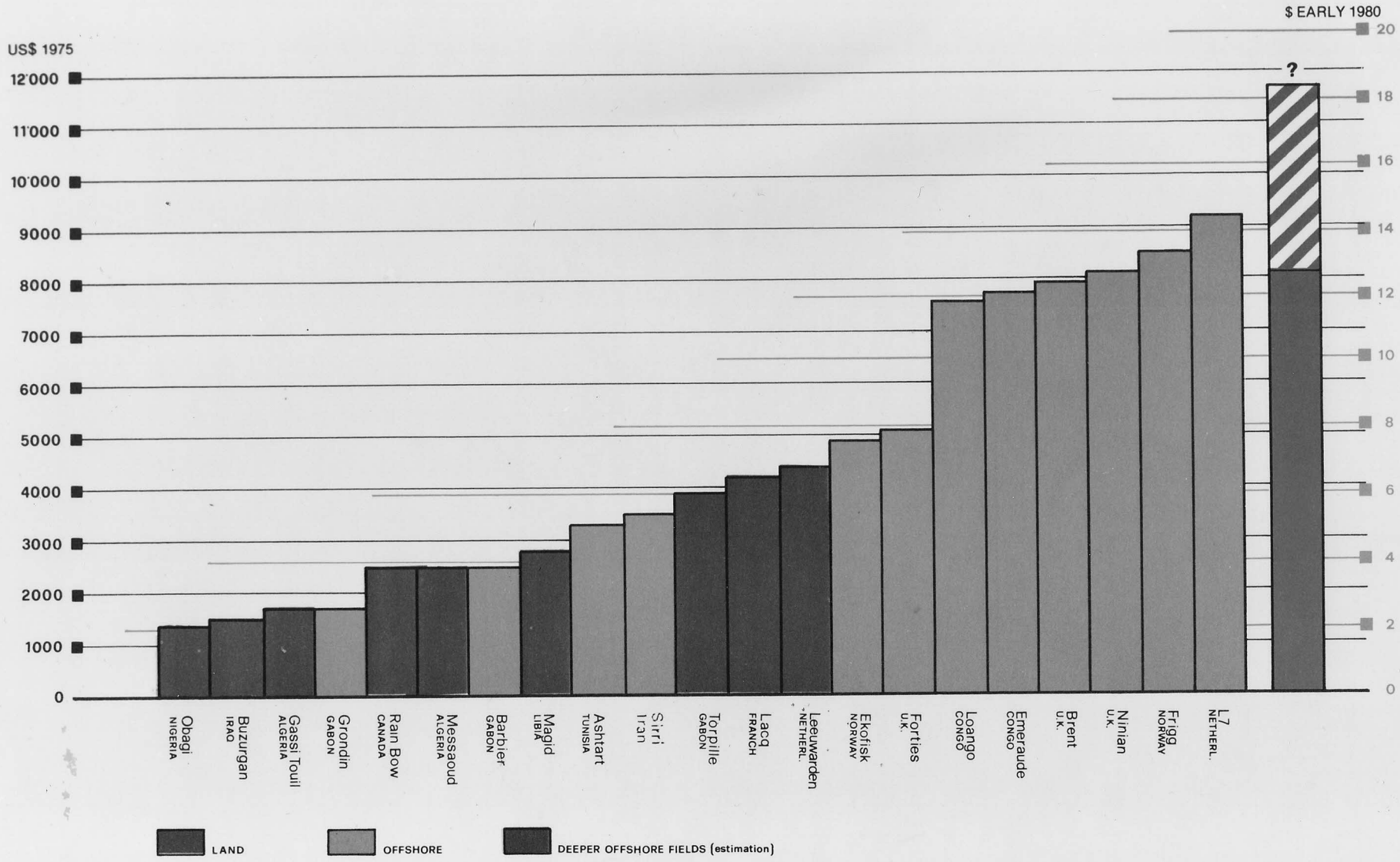


PRODUCTION COSTS $/Bbl; INVESTMENT $/BODP BY SIZE, LOCATION AND TYPE OF RESERVOIR

ENERGY	PRODUCTION COST $/b	INVESTMENTS $/b/d
Oil		
Middle East		
— land		
• old discovery	0.18 — 0.35	200 — 300
• new discovery	0.40 — 1	500 — 1 500
— offshore		
• large fields	0.60 — 1.00	800 — 1 200
• small fields	1.50 — 2	1 500 — 2 500
Africa		
— Libya	0.40 — 1.50	500 — 2 500
— Algeria	1.50 — 2	2 500 — 3 000
— offshore	1.50 — 3	1 500 — 5 000
USA		
— land	1.50 — 3	2 000 — 4 000
— offshore	3 — 5	4 000 — 8 000
— Alaska	5 — 7	8 000 — 12 000
Europe - North Sea		
North Zone	4.50 — 7	8 000 — 12 000
South Zone	2.50 — 4	3 500 — 5 000
Gas		
USA	1.20 — 4.50	2 000 — 8 000
Europe		
— land	0.70 — 2	1 000 — 3 000
— North Sea		
• far from the coast	3.50 — 6	8 000 — 12 000
• near the coast	1.50 — 2.50	2 000 — 3 500

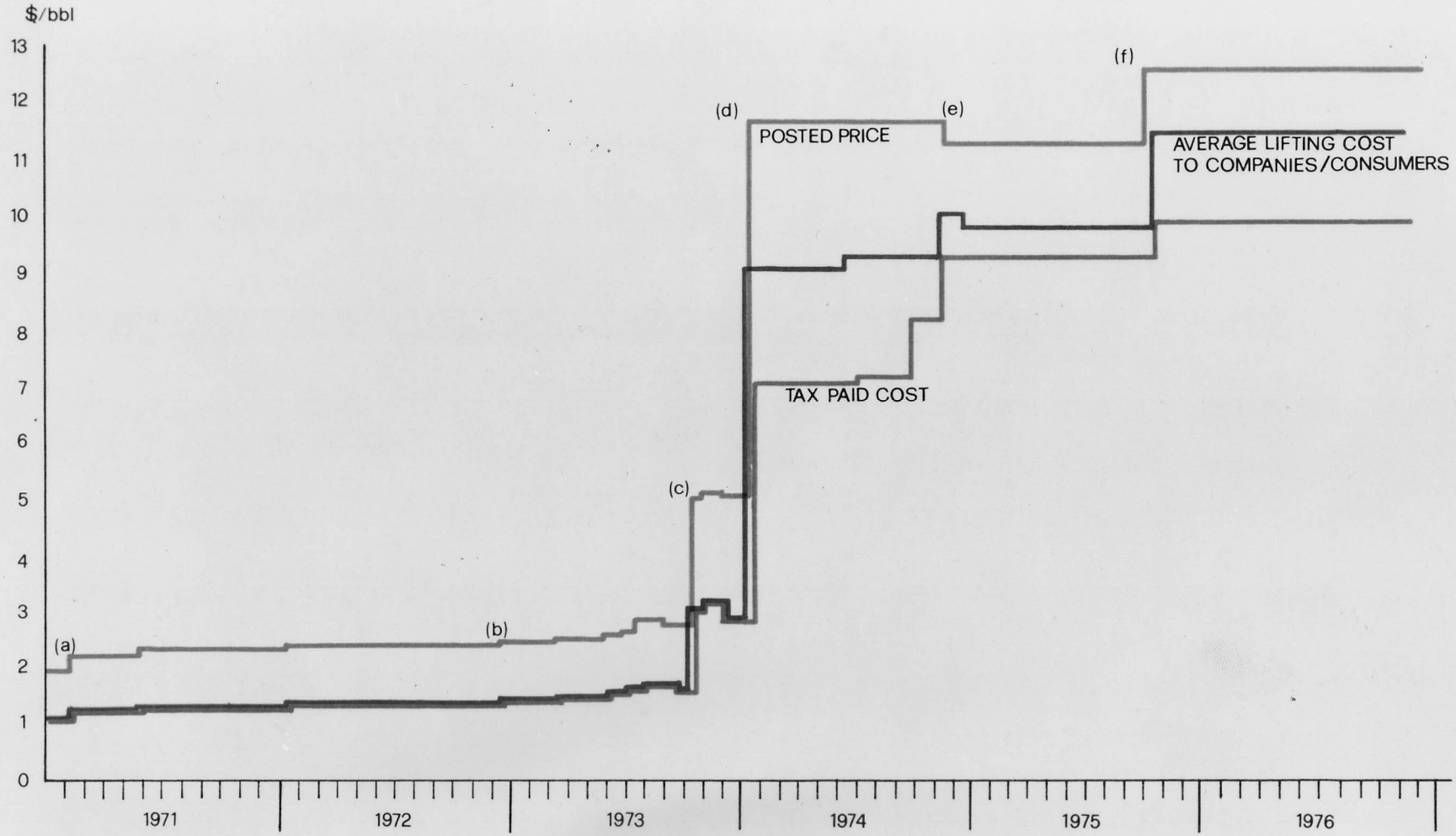
Source: Institut Française du Pétrole, 1975

Graf. 6 - Development Investiments $/BOPD



From : REVUE DE L'INSTITUT FRANCAIS DU PÉTROLE - MARS - AVR. 1976

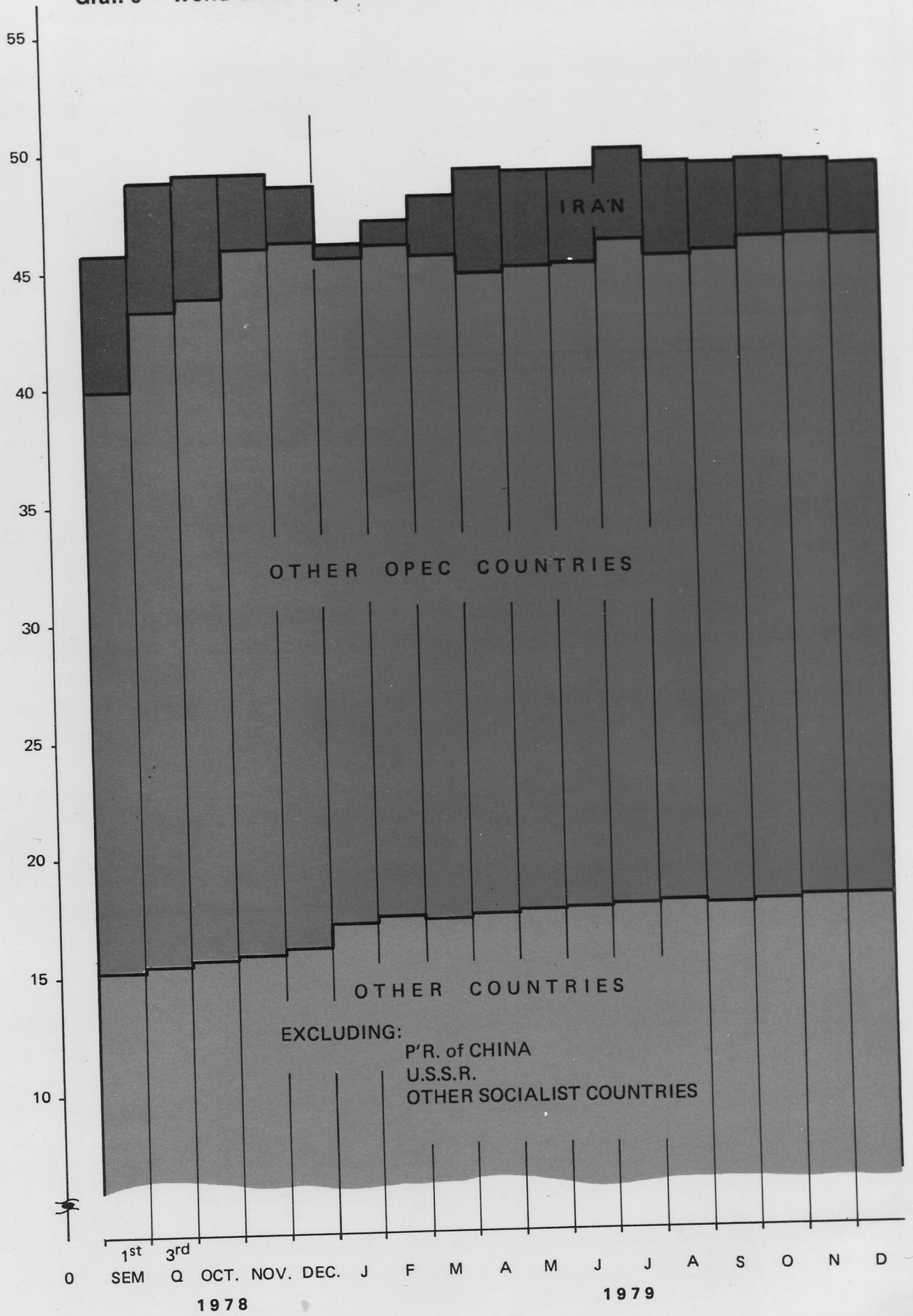
Graf. 7 · Price trends of arabian light crude oil 1971-1976



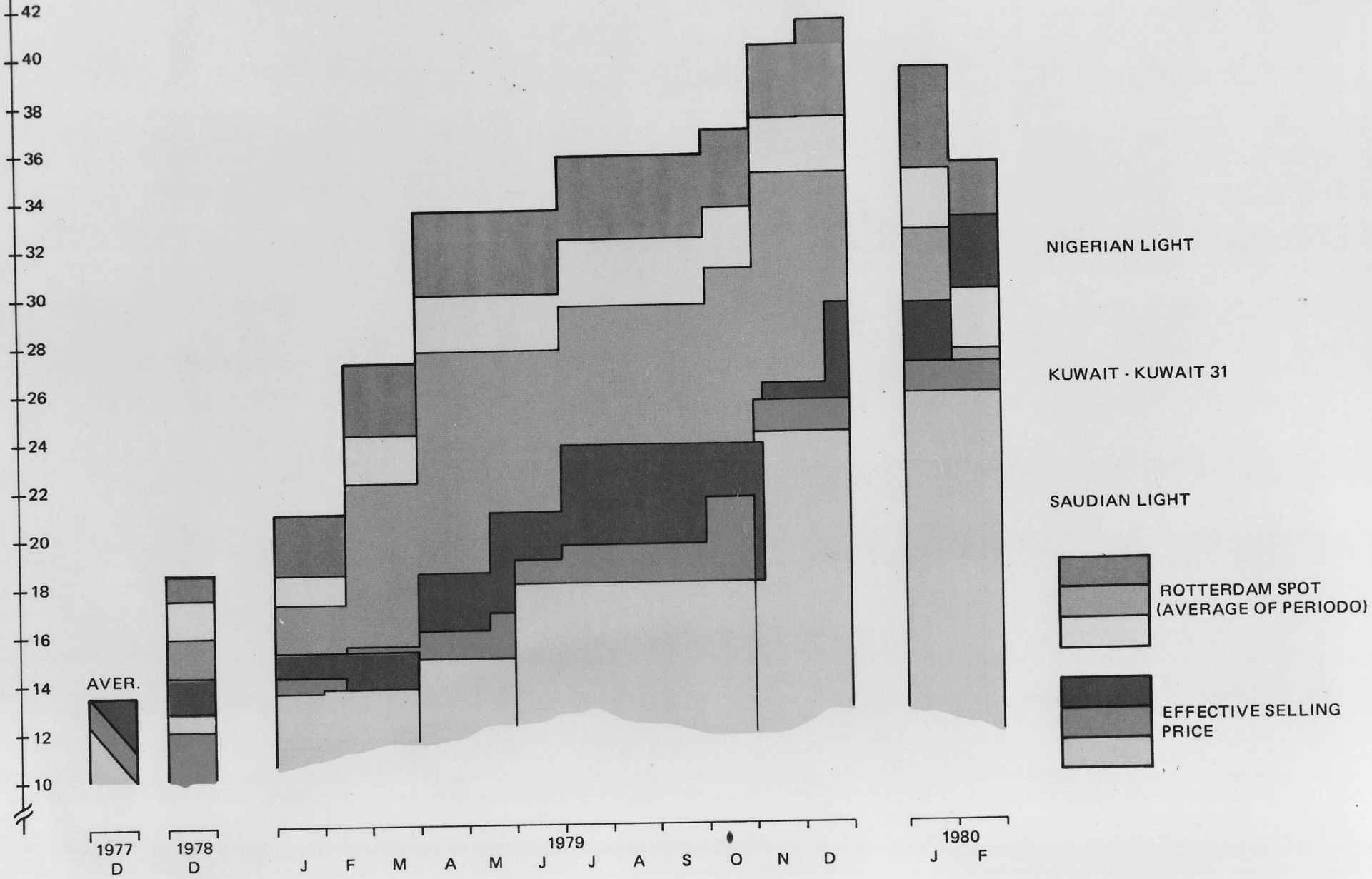
(a)	February 1971	Income tax rate raised to 55% from 50%. Posted price raised 35% per barrel.
(b)	January 1973	Government acquired a 25% interest in the producing properties.
(c)	October 1973	OPEC increased Posted Price of oil by 70%.
(d)	January 1974	OPEC more than doubled the price of crude oil, and governments acquired a 60% interest in the producing properties.
(e)	Oct/Nov. 1974	Posted Price lowered but tax rate raised to 85% and royalty to 20%.
(f)	October 1st 1975	OPEC increased price by 10%

From: TWENTIETH CENTURY PETROLEUM STATISTICS 1976

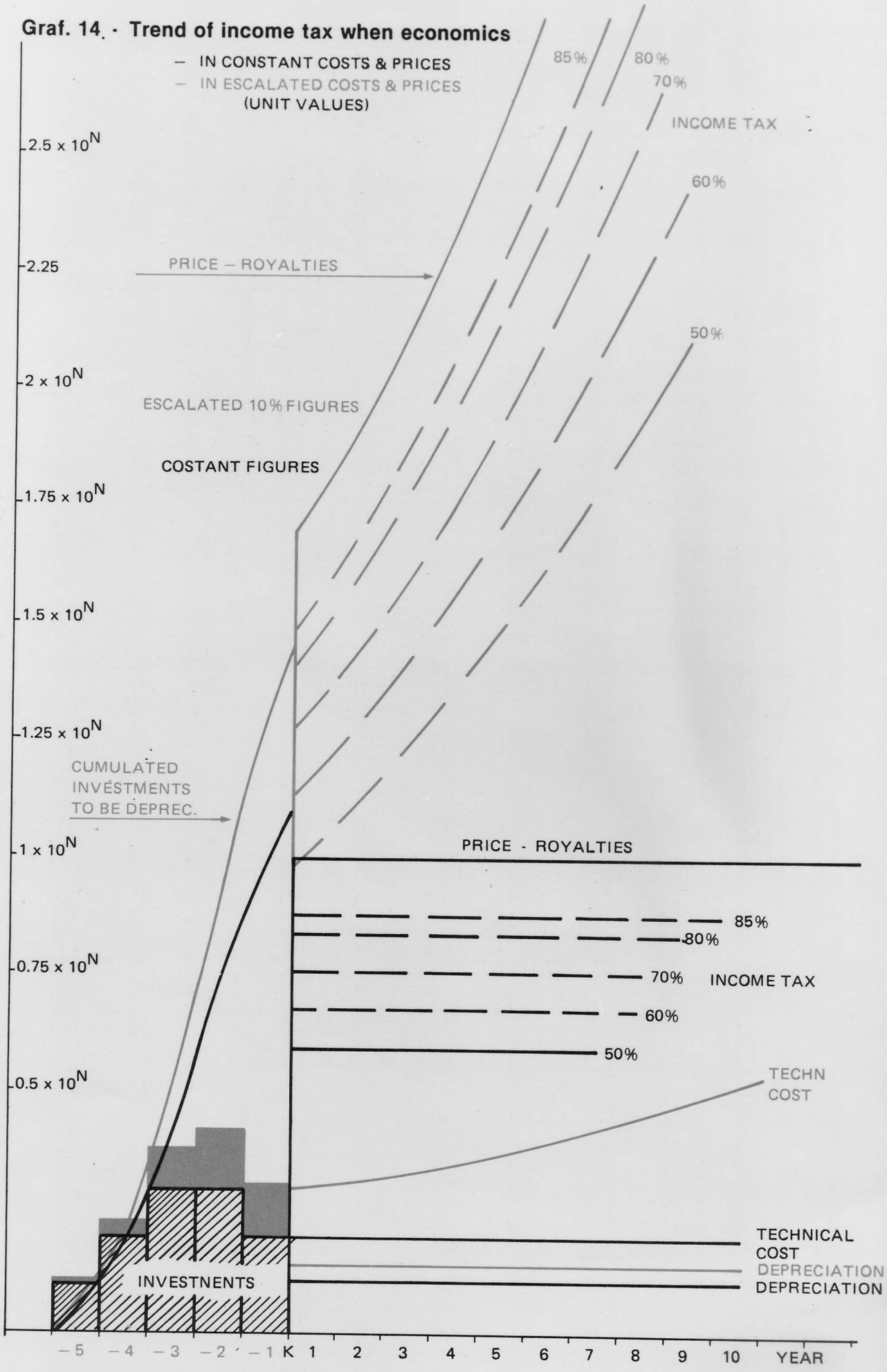
Graf. 9 - World crude oil production in mm BOPD in 1978 and 1979



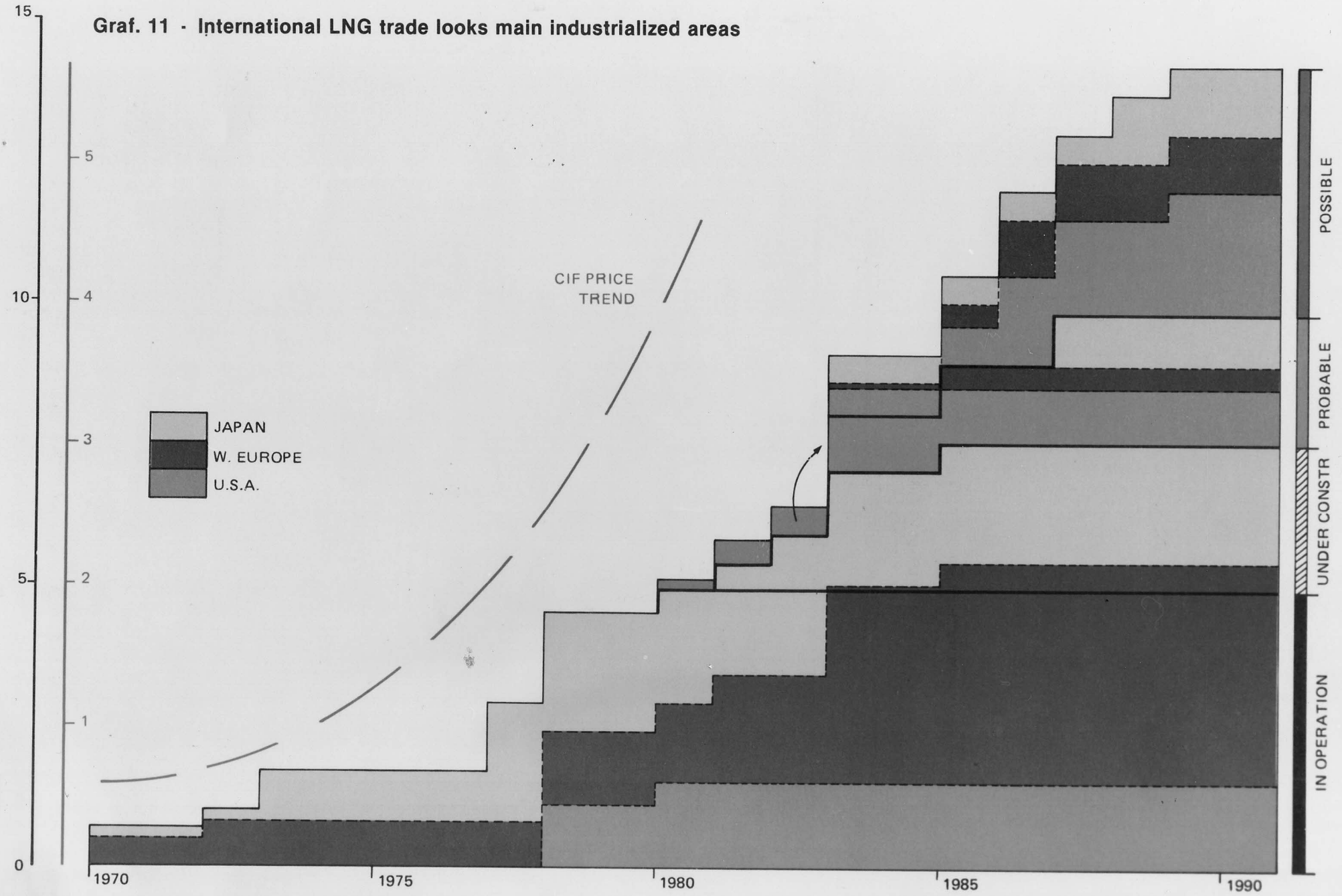
Graf. 10 - 3 key export crude prices between Dec. 1978 an Feb. 1980 u.s. $/barrel



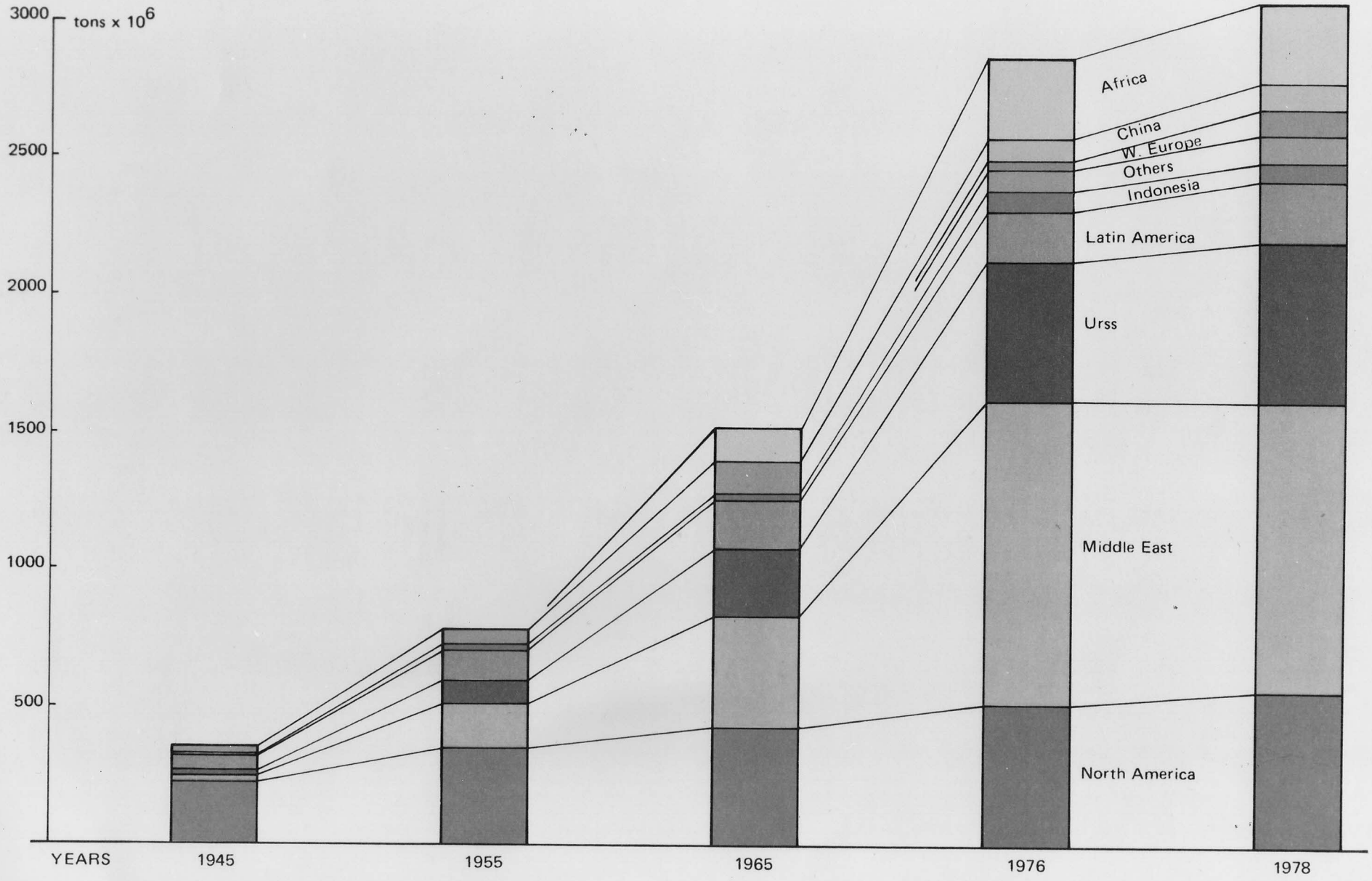
Graf. 14. · Trend of income tax when economics



Graf. 11 - International LNG trade looks main industrialized areas



Graf. 12 - World production of Crude Oil



FROM: PETROLÉ 1975 - Petroleum Economist - January 1977 - Oil and Gas Journal 27-12-1976
Note: when not specified; Africa, West Europe and China are included in "Others"
1978: after our data