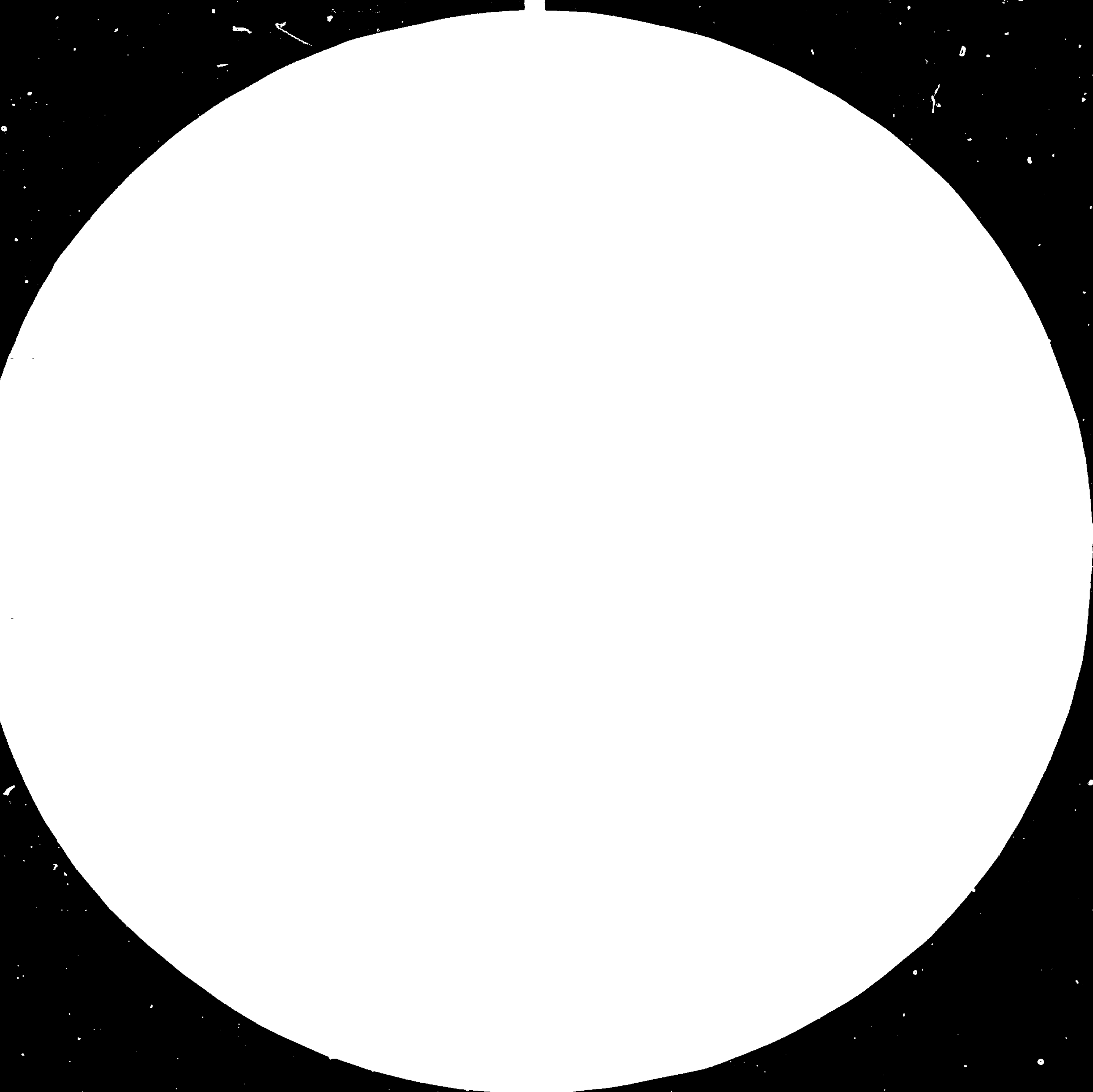

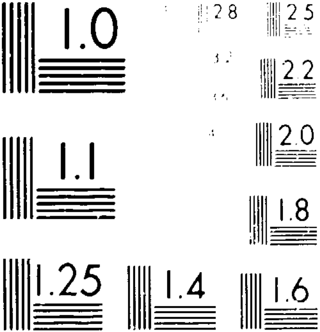
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Distr.
LIMITED

ID/WG.337/3
24 April 1981

ENGLISH

United Nations Industrial Development Organization

Second meeting of the *Ad hoc* UNCTAD/UNIDO Group of Experts on Trade and Trade-related Aspects of Industrial Collaboration Arrangements

Vienna, Austria, 1-12 June 1981

MAJOR FEATURES AND TRENDS IN CONTRACTS AND AGREEMENTS IN THE INTERNATIONAL PETROLEUM INDUSTRY *

Prepared by

The Secretariat of the
United Nations Centre on
Transnational Corporations

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* The paper has been prepared as a special contribution of the Secretariat of the United Nations Centre on Transnational Corporations for the second meeting of the *Ad hoc* UNCTAD/UNIDO Group of Experts on Trade and Trade-related Aspects of Industrial Collaboration Arrangements.

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V.81-24452

TABLE OF CONTENTS

I INTRODUCTION TO PETROLEUM CONTRACTS

Before we examine selected representative contracts and agreements, especially those covering the years 1973-1980, in order to assess the unifying elements and innovative trends which may be relevant to developing countries, it would be useful to consider the evolutionary context of the changes in the terms of petroleum contracts and agreements that have occurred since the granting of the first concession to D'Arcy in Iran in 1901. These can be grouped into three major periods. They are (1) the years 1901-1957, (2) 1957-1966, and (3) the years 1966-1980.

1. The Period 1901-1957

This period was characterized by the granting of concessions to the major oil companies which resulted in effective control by the companies of the entire range of petroleum activities. The State exercised no real voice in either the management or conduct of petroleum operations and could not participate in the company's profits either inside or outside the country, aside from a set royalty paid by the company on production tonnage. Some of the principal conditions of the original concession agreements were as follows:

a. Large areas with no relinquishment provisions;
b. Long concession periods of up to 99 years;
c. No State participation in management;
d. Royalty paid on production tonnage;
e. Exclusive rights granted to the company to all facets of petroleum activities;
f. Contractual provisions guaranteed for duration of concession period.

A cursory review of the extensive and far-reaching nature of the rights exercised by the oil companies would indicate that it was inevitable that disputes should arise. The traditional concession was by its nature a State within a State, and it was a matter of time before the State would assert its legislative and executive powers to which it was entitled. One such culmination of this process was the attempted nationalisation by Iran in 1951 of the Anglo-Iranian Oil Company. At the same time, the concession system played a necessary role in providing the incentive and capital to undertake the particularly risky and expensive business of petroleum exploration in what were then remote areas of the world.

Except for the Aminoil agreement in the Kuwaiti portion of the Neutral Zone (1948) and the Getty agreement in the Saudi Arabian portion of the Neutral Zone (1949), the original concessions in the Middle East were held by the eight major international oil companies, they were: BP (previously Anglo-Persian and subsequently the Anglo-Iranian Oil Company), CFP (Compagnie Française des Petroles), Shell, Esso (Standard Oil of New Jersey), Mobil, Texaco, Socal (Standard Oil of California), and Gulf.

It is not intended, however, to discount the importance of the Agreement of December 30, 1950 between Saudi Arabia and Aramco, which for the first time introduced the concept of equal profit-sharing to the Middle East, after its adoption by Venezuela in 1948. In fact, 50/50 profit sharing is a misnomer, as all royalty, rentals and other payments could be treated as credits against tax receivable on net profits. However, the true nature of the concessionary relationship could only change when the State is ready to assert its right to participate in the management and conduct of the petroleum operations, which is evidenced in the signing of the first joint venture agreements, and the more significant act of retaining full ownership of the concession and the oil and contracting out to the oil companies the technical services, by replacing it with the service contract. The process of change was economic and, increasingly, political in nature.

The two basic elements of concession agreements today are royalty and net income tax. Concession agreements had evolved by 1957 to include royalty, which was generally set at 12-1/2% of gross production and which was either credited or expensed against a net income tax of 50%, a shorter exploration period of 5-6 years with renewal rights, a shorter exploitation period of 25-30 years, a minimum exploration expenditure, stricter relinquishment provisions, and the training and employment of national personnel. Increasingly, the tendency was to calculate royalty and tax on the basis of a posted price, with royalty deductible as a cost item (i.e., expensed).

2. The Period 1957-1966

This period marks the signing of the first joint venture agreements and the first production-sharing contracts, and is characterized by an increasingly active State role in the conduct of oil company operations. The joint venture agreement signed in 1957 by the NIOC (National Iranian Oil Company) and AGIP (the Italian State company), and that between NIOC and Pan American (a wholly-owned subsidiary of the Standard Oil Company of Indiana, otherwise known as Amoco) in 1958, followed the Iranian Petroleum Act of 1957 which authorized the NIOC to enter into joint venture agreements. The principal conditions were as follows:

a. NIOC and AGIP were both represented on the Board of Directors, with NIOC appointing the Chairman and AGIP appointing the Vice-Chairman;

b. The duration of the agreement was limited to 25 years;

c. AGIP obligated itself to a firm spending commitment during the exploration period, with reimbursement only in the event of a commercial discovery;

d. All development and exploitation costs would be equally borne by NIOC and AGIP; and

e. AGIP was subject to 12-1/2% royalty calculated on the posted price, and 50% tax on net income after deduction of the royalty paid.

In assessing the major advances of this agreement, it should be noted that NIOC acquired the right to appoint half of the members sitting on the Board of Directors, and that the company committed itself for the first time to a firm minimum exploration expenditure. The revenue collected by the State comprised not only 50% of the net income of the joint venture partner, i.e., 25%. but also the 50% equity interest held by NIOC in the venture, i.e., a total Government take of up to 75%. The State company became an important instrument in increasing the host country's equity position. The NIOC was established by Iran in 1951. Mexico had already set up its State oil company, PEMEX (Petroleos Mexicanos) in 1938. Italy's ENI (Ente Nazionale Idrocarburi) was formed in 1953. Egypt set up its State oil company EGPC (Egyptian General Petroleum Corporation) in 1956. Venezuela established CVP (Corporacion Venezolana del Petroleo) in 1960, as was the Kuwait National Petroleum Company (KNPC). Petromin (General Petroleum and Mineral Organization) of Saudi Arabia was organized in 1962. Algeria's Société Nationale pour le Transport et la Commercialisation des Hydrocarbures (Sonatrach) was formed in 1963 and the Iraq National Oil Company (INOC) in the following year in 1964. ERAP (Entreprise de Recherches et d'Activités Pétrolières) was set up by France in 1965. The Abu Dhabi National Oil Company (ADNOC) and the Nigerian National Oil Corporation (NNOC) were both established in 1971. Norway organized Statoil in 1972, while Britain's BNOC (British National Oil Corporation) dates from 1975. The State oil companies played an increasingly active and dominant role as the vehicle for the implementation of State oil policy by direct participation in all petroleum operations. Today, all OPEC members have their individual State oil companies.

It should be kept in mind that this period coincided with the active and aggressive entry into international petroleum operations of the so-called "independent" oil companies. Companies such as Amoco, Phillips, Conoco, Union, Amerada, Getty, Marathon, Tenneco and Atlantic Richfield all had already established themselves with solid bases in the United States. The explosive growth of oil demand, the availability of virgin or relinquished unexplored areas, the promise of cheap oil combined with a strong dollar currency were all factors in the huge investments made by these companies outside the United States. It was also at this time that certain European State oil companies began to compete aggressively with the established major oil companies. Prominent among them were ERAP of France and ENI of Italy. The independent oil companies and the European State oil companies were able to offer terms which the majors were unwilling to consider because they feared the repercussions and precedents on their existing concessions.

The first petroleum production-sharing contract dates from the IIAPCO (Independent Indonesian-American Petroleum Company) agreement of 1966. The Indonesian Government's position rested on two basic premises. Firstly, that it would retain ownership of the oil and be responsible for overall management of operations and, secondly, that a division of the production would replace the pricing basis of profit-sharing. The companies would be exempt from payment of income tax and would receive up to 40% of the production for reimbursement of exploration, development and production costs, with 65%-70% of the remaining production taken by the Government. The first production-sharing contract with an international oil company was signed in 1967 with Conoco followed by contracts with the other major oil companies in 1968.

3. The Period 1966-1980

This most recent period, which can be further subdivided into 1966-1973 and 1973-1980 sections, was marked by the emergence of the oil-producing States as fully active and controlling actors. The principal device through which such control has been exercised has been the service contract, pioneered by ERAP and the National Iranian Oil Company in 1966 and brought into use in many oil-producing countries since then. But even in those countries where other forms of contracts were used, the period since 1966 has seen a marked advance in the extent to which the host government can control the petroleum sector and in the revenues accruing to the host country from petroleum production.

The service contract, which has become steadily more prevalent since 1966, not only confirms the State's legal title to oil and gas (which is also the case in most other contract forms) but also gives the State at least the possibility of asserting direct control over development and production strategy. The oil company acts merely as a contractor, providing technical services and in many cases assuming the exploration risk. In return, the company usually receives some cash remuneration as well as the right to buy an agreed portion of the oil output at a discounted price. The details of various representative service contracts are discussed below.

Throughout the 1966-1980 period, there has been a steady advance in the terms and conditions of arrangements between oil-producing states and the oil industry TNCs. At the same time, the arrangements that will prevail between a particular country and an oil company at any moment will reflect the particular bargaining power of that country. Thus, for example, a country without any oil production and with only moderate geological prospects would unlikely be able to negotiate as good a contract as a country with already proven oil reserves.

The following sections of this study illustrate the range of agreements negotiated during the 1966-1973 and 1973-1980 periods. It should be kept in mind, however, that the pattern of contractual development cannot be broken down into such precise periods. In a sense, there has been a continuity of development since 1966, and even, to a certain extent, since 1957.

II REPRESENTATIVE AGREEMENTS: 1966-1973

As a preface to the discussion of the dominant trends in the terms of the contracts and agreements of the period 1973-1980, it will be useful to examine the period immediately preceding it which, as has been suggested, covers the years 1966-1973 and represents the emergence of the producing countries as the arbiters of their petroleum resources. For the purposes of this study, a detailed review of the period 1901-1966 will therefore not be undertaken.

In this section, three major forms of contracts will be studied: concession agreements, production-sharing contracts, and service contracts. The service contracts and production-sharing contracts will be studied because they are innovative agreements. The later-type concession agreement, on the other hand, will be studied to determine its applicability for countries with no oil and its further development, such as in Madagascar, as opposed to the traditional-type concession agreements.

Concession Agreements

The traditional early type of Middle Eastern concession agreement was negotiated and agreed between the parties. As was often the case, there was no petroleum legislation and the Ruler granted the concession and guaranteed the stability of its rights and obligations for the duration of the concession. This was usually done by the issuance of a law or decree having the force of law or in the name of the Ruler.

A second type of concession agreement was based on existing petroleum legislation. Thus, in French-speaking Africa, France promulgated a number of statutes and decrees, only three or four years prior to the granting of independence to the Francophone states in the early 1960s, which set out not only petroleum laws but also model conventions (agreements). Thus, for example, Statute No. 58-1111 was promulgated by France on November 22, 1958 to regulate petroleum activities within the Organisation Commune des Regions Sahariennes. By Decree No. 61-8 of January 6, 1961, France also adopted a Model Convention governing petroleum operations in the O.C.R.S. It is therefore not surprising that the Petroleum Codes of countries as diverse as Madagascar and Chad should have had similar petroleum laws.

Although the concession-type agreement has serious shortcomings, there are cases in which it may meet the immediate needs of certain host countries—for example, countries with unproven petroleum potential, geographically isolated exploration areas, and little indigenous expertise and capital. In such a case, a concession-type agreement may be a useful device for attracting foreign oil companies to undertake exploration.

The Agreement (Convention) signed in Chad in 1970 is similar to those signed by American oil companies in Madagascar (1968), in Niger (1971) and in the Central African Republic (1973). In fact, serious French exploration efforts were concentrated in the maritime nations, such as Algeria, Tunisia, Gabon, Cameroon, all of which provided easier access to the oil for eventual export to metropolitan France. The net result was that it was largely the American oil companies which directed their attention to the more virgin interior areas of central Africa. The main terms of the Exploration Permit H granted Conoco by Chad in 1969 and the Convention, which is based on the

Petroleum Code of February 3, 1962, area as follows:

Duration	Exploration 5 years + 2 renewals of 3-5 years each
Surface Area	465,000 square kilometers
Relinquishment	25% after 2 years 50% of remaining area after 5 years 25% of remaining area after 10 years
Bonus	$250,000 signature bonus $1,000,000 upon commercial discovery $2,000,000 at 100,000 B/D $2,000,000 at 200,000 B/D
Exploration Obligation	Minimum of $5,667,000 for first 5 years Minimum of $5,667,000 for second 5 years
Royalty	12-1/2% on well-head price. Deductible against taxable income but also treated as credit to determine tax due
Tax	50% net income tax on basis of realization on the portion of taxable income which is in excess of the royalty paid
Management	Conoco to be operator in all phases of petroleum operations
State Participation	None
Depletion Allowance	27-1/2% but not to exceed 50% of net income
Internal Consumption	Shall have priority over other production
Exploitation for the State	In return for a 5% profit margin to the company free of all burdens

It is important to note that Chad was not ignorant of the advance made by producing countries during the course of negotiations between 1968 and 1970. However, Chad was aware that oil had to be discovered before it could obtain more advantageous terms, and therefore accepted the need to provide the necessary incentives to induce oil companies to undertake the costly exploration of its country.

A review of the basic terms of the Convention show many of the characteristic conditions of the early concessions, i.e., very large concession area, long exploration and exploitation periods, liberal tax regime and a depletion allowance. But it also includes, unlike traditional concession agreements, bonus payments, accelerated relinquishment schedule, provision for the employment of nationals, a minimum exploration expenditure and 50% tax. Chad was also granted the right to require the concessionaire to operate "uneconomic", i.e., marginal discoveries by assuring the company a minimum profit margin of 5% free of all burdens. Similar concession-type agreements were signed in the 1960s and the 1970s by Niger, Madagascar, the Central African Republic, Mali and Mauritania, with companies which included Esso, Shell, Texaco, Conoco, AGIP, Chevron, Tenneco and CFP (Compagnie Française des Pétroles).

This approach appears justified when it is considered that in the ten years since the signing of the Convention with Chad in 1970, some $130 million have been spent on exploration alone in Chad by Conoco and its partners, Shell, Chevron and Esso. The actual minimum expenditure obligation specified by the Convention over ten years amounted to only $11,334,000. Although major oil reserves have not yet been discovered to justify the building of a pipeline for sales outside Chad, a request for the construction of a mini-refinery of 2,000 B/D capacity was made by the Chad Government in 1976 to meet the needs of internal consumption from the small discoveries already made. A financing plan was finally agreed whereby the companies and the World Bank would jointly advance the necessary funds for a small refinery in N'Djamena, as well as a small gauge pipeline to transport the crude to the refinery. The importance of mini-refineries to developing countries, such as Chad and Sudan, and the role of financing by international institutions will be considered later in this study. It is noteworthy that Chad and the oil companies operating under a later-type concession-type agreement, were able to agree on a refinery project to meet the internal needs of the country and alleviate the economic burden of imported oil. It is particularly so as there is no provision in the Chad Convention calling for the construction of a refinery.

Concession agreements were also signed in Malaysia in 1967 and 1968, by Esso, Shell and Conoco. The Conoco Agreement of 1968 will be examined insofar as it is of interest in the ensuing developments emanating from the adoption by Malaysia of the Petroleum Development Act of 1974, replacing the 1966 Petroleum Mining Act, which stipulated that the companies negotiate production-sharing contracts in place of their existing agreements. The terms of the concession agreement granted to Conoco in 1968, and which was subsequently partially farmed out to Broken Hill 25% and El Paso 25% in 1973, were as follows:

Duration:	Exploration 10 years + 5 year renewal Exploitation 40 years including exploration period
Area:	62,160 sq. kms.
Relinquishment:	50% at the end of 5 years 25% of original area at the end of 10 years
Minimum Expenditure:	$7,364,600 for first 5 years calculated on basis of yearly rates and surface area payments. Expenditure obligations are set out annually.
Royalty:	12-1/2% on posted price, expensed
Tax:	50% of net profits based on posted price, subject to certain discounts and allowances
Bonus:	$3,000,000 at 60,000 B/D $3,000,000 at 100,000 B/D

In matter of fact, the bonus payments were burdens added to the original agreement in 1973 as one of the conditions of the Government for the approval of the Conoco farmout to Broken Hill and El Paso. A second condition was the negotiation of a production-sharing contract to replace the original concession agreement, and it is the consequence of this condition set by the Government that we will consider in the next section of this study. It is not uncommon that Governments take advantage of the opening offered by a proposed farmout to secure more favourable terms to themselves as a condition of their approval. This practice is not limited to developing countries. It is especially prevalent in countries such as Norway and the United Kingdom.

Production-Sharing Contracts

Indonesia promulgated Law No.44 in 1960 which stipulated that contracts entered into by the State with foreign companies should provide for production-sharing arrangements. The first such contract was signed on April 17, 1960 by Permina, a State entity, and Kobayashi, a Japanese consortium which was interested in a liquefied petroleum gas project. Indonesia signed its first petroleum production-sharing contract in 1966 with IIAPCO (Independent Indonesia-American Petroleum Company). Conoco became the first important international oil company to sign a production-sharing contract in 1967 and Union Oil, also an "independent", signed in January 1968. Thereafter 13 other production-sharing contracts were concluded in 1968, including those of the major oil companies operating in Indonesia. It is a measure of its success, that production-sharing has been widely adopted by the new producing countries as well as those with no traditional petroleum industry. Outside Indonesia, production sharing has been adopted in countries as diverse as Egypt, Chile, Libya, Nigeria, Angola and India.

As already mentioned, the basic elements of the production-sharing contract are:

(1) Overall management of petroleum operations by the State;

(2) Cost recovery by the company of all exploration, development and production costs from a portion of the production; and

(3) A "profit" split of the remaining production between the State and the oil company.

Although the State legally retains overall management control, in practice, the oil company ("the contractor") exercises day-to-day control.

Under the terms of the production-sharing contract, the oil company bears all the exploration risk and is reimbursed only in the event of a commercial discovery out of a portion reserved for that purpose called "cost oil". The ownership and mining of oil and gas was vested in State oil companies by Law No. 44 of 1960. At the time, there were three such companies designated State Enterprises. They were Permina, which was operated by the Army; Permigan, which was the State National Oil and Gas Mining Company; Pertamina, which was the Indonesian State Oil Mining Company. Pertamina was to emerge as the dominant State company for oil and gas matters by 1968. Law No.8 of 1971 accorded Pertamina the right to enter into production-sharing contracts with foreign companies.

The principal terms of two 1968 offshore production-sharing contracts are summarized in Table 1.

A similar contract was signed in 1969 with Total Indonesia (a subsidiary of CFP) in South Central Sumatra, with the same profit split of 65/35 in favour of the State company for production up to 75,000 B/D and a 67.5/32.5 split for production in excess of 75,000 B/D. But already, in the 1971 Pertamina/Conoco contract (West Irian onshore) the production was split 65/35 in favour of Pertamina up to 60,000 B/D, 67.5/32.5 when the output was between 60,000 B/D and 100,000 B/D and 70/30 in excess of 100,000 B/D. Costs could still be recovered from up to 40% of the production. An added provision required Conoco to assign 5% of its interest to an Indonesian Participant nominated by Pertamina. In the 1972 offshore contract between Pertamina and Indonesia Offshore Operators, Inc., the production split is identical with the 1971 contract, but the contractor is obligated to offer up to 10% of its interest to an Indonesian Participant comprised of Indonesian nationals or corporations.

TABLE 1

COMPARISON BETWEEN PERTAMINA/AGIP AND PERTAMINA/CONOCO CONTRACTS

	PERTAMINA/AGIP	PERTAMINA/CONOCO
Area	West Irian (Offshore)	Block B (South China Sea)
Effective Date	10 October 1968	16 October 1968
Duration	Exploration 6 yrs + 2 yrs + 2 yrs Exploitation to 1998	Exploration 6 yrs + 2 yrs Exploitation to 1998
Relinquishment	25% at the end of 3 yrs 25% at the end of 6 yrs 10% at the end of 8 yrs	30% at the end of 3 yrs 30% at the end of 6 yrs
Signature Bonus	$1.5 million	$7 million
Production Bonus	$0.5 million at 50,000 B/D $1.5 million at 100,000 B/D $2 million at 200,000 B/D	$3 million at 50,000 B/D $3 million at 100,000 B/D
Minimum Expenditure	Firm $1.5 million first 2 yrs Option $14.5 million next 6 yrs	Firm $3.5 million first 2 yrs Option $10.5 million next 4 yrs

TABLE 1 Continued

COMPARISON BETWEEN PERTAMINA/AGIP AND PERTAMINA/CONOCO CONTRACTS

	PERTAMINA/AGIP	PERTAMINA/CONOCO
Production Sharing	65/35 up to 75,000 B/D 67.5/32.5 above 75,000 B/D - after cost recovery from up to 40% of production	65/35 up to 75,000 B/D 67.5/32.5 above 75,000 B/D - after cost recovery from up to 40% of production
Taxation	Pertamina to pay all taxes out of its share of production	Pertamina to pay all taxes out of its share of production

Service Contracts

Although Venezuela signed a limited service contract with Mobil in 1962, it was not until 1966 that the basic conditions of service contracts were developed and submitted to the Venezuelan Congress, which, in turn, adopted the amendments of 1967 to the Hydrocarbon Law authorizing service-type contracts. Venezuela had earlier indicated in 1958 that it would no longer sign concession-type agreements, but it appears likely that the ERAP service contracts with NIOC in Iran in 1966 and with INOC in Iraq in 1968, especially the former, provided the impetus for the legislation of 1967. In fact the exercise was not entirely successful for Venezuela due to a real or perceived impression by the oil companies of too much being asked for too little and with insufficient guarantees of satisfactory economic returns. CVP, published its Minimum Terms for Service Contracts in 1968, which inter alia, provided the following conditions:

a. The Contractor shall advance all funds for exploration, development and exploitation, with reimbursement only upon start of commercial production.

b. The Contractor shall receive up to 90% of the production from CVP to recover its investment, earn a profit and pay tax on net income, i.e., the difference between international market price and cost. Market price would be agreed jointly by CVP and the contractor.

c. The exploitation period shall be 20 years, with an exploration period of 3 years.

d. CVP shall participate in all development and exploitation programs through committees equally comprised of representatives of both CVP and the Contractors.

e. CVP retains the right to acquire equity interest in the event of commercial discovery on terms to be agreed.

The perception by the Oil Industry that a number of clauses were open-ended, such as the terms of CVP's equity participation right in commercial discoveries, the somewhat imprecise formula for recoupment of the contractor's investment, as well as the provision for additional payments to CVP calculated on the basis of the Contractor's "profitability", resulted in little interest on the part of oil companies. It is in two Middle Eastern countries, Iran and Iraq, that the definitive service contracts are obtained.

The service contract, as it is commonly understood, was pioneered by France's ERAP (now called Elf-Aquitaine) and Iran's NIOC in 1966. It was followed in Iraq by the 1968 contract between ERAP and INOC. Because of the importance of the two contracts, a comparison of its principal provisions is set out in Table 2.

In 1969, Iran signed a service contract along the lines of the ERAP contract with Continental Oil Company (Conoco) and, also in the same year, a similar agreement was signed with a five-member consortium composed of ERAP, ENI, HISPANOIL, PETROFINA, and the Austrian OMV. Iraq signed a service contract with Brazil's Petrobras in 1972 which contained certain clauses more advantageous to Petrobras, perhaps reflecting the priority Iraq attached to its relations with Brazil. Thus, the exploration period is 7 years, there is no provision for National Reserve, and the relinquishment and management clauses are somewhat more

TABLE 2

COMPARISON BETWEEN NIOC-ERAP AND INOC-ERAP CONTRACTS

	NIOC-ERAP	INOC-ERAP
Duration	Exploration 6 + 2 years (onshore) 3 + 3 + 3 years (offshore) Exploitation 25 years	Exploration 3 + 2 + 1 years Exploitation 20 years
Relinquishment	50% after 1 year; 1/3 of remaining area after 3 years and after 6 years (offshore) 50% after 4 years, 25% after 6 years (onshore)	50% after 3 years; 25% after 5 years
Management	ERAP to act as Operator throughout	INOC to become Operator 5 years after start of production
Bonus	None	$15 million upon commercial discovery over 10 years
National Reserve	50% of recoverable reserves after reimbursement of past exploration costs is assured	50% of recoverable reserves once daily production is 75,000 B/D
Guaranteed sales to contractor	ERAP entitled to purchase 35%-75% of production at half-way price between realization and cost	ERAP entitled to purchase 30% of production, of which 59% will be at a price of (a) production cost + (b) 13½% royalty on posted price + ½ of difference of a + b and posted price, and 41% will be at a + b

Cont'd/...

TABLE 2 Continued

COMPARISON BETWEEN NIOC-ERAP AND INOC-ERAP CONTRACTS

	NIOC-ERAP	INOC-ERAP
Marketing Assistance	ERAP to market for NIOC 60,000 B/D for 1st 5 years and 80,000 B/D for 2nd 5 years on realized price minus commission	ERAP to market up to 200,000 B/D of INOC share at world market price minus commission
Repayment of Loans	Exploration loans over 15 years with no interest. Development/exploitation loans over 5 years with interest	Exploration loans over 15 years with no interest. Exploitation loans over 5 years with interest
Tax	Effective rate 50% on realized price, with no royalty	Effective rate 50% on posted price, with 13½% royalty on posted price

lenient, but the exploitation loans are recovered by Petrobras over 7 years instead of 5 years.

If there are disagreements concerning the true economic benefits of the service contract for Iran and Iraq, there is little question of its immense political significance in putting the final seal on the host country's full ownership of its oil and all assets. Stauffer (1967), for example, argued that the 90-10 effective split in the economic return then claimed by Iran was overstated, primarily because of the effect of tax discounting, and that the actual economic return was closer to that of the conventional OPEC-type concession with tax and royalty calculated on the basis of posted price. However, some of the assumptions used by Stauffer have been questioned by Rouhani (1971), the first Secretary-General of OPEC, among others. It is fair to point out that a half-way price between realization and cost, as well as the repayment of development loans with interest over 5 years, were not unattractive to ERAP. From the point of view of the oil company, of course, even a 90-10 split in favour of the government could, if development and production costs are sufficiently low, produce a discounted cash flow rate of return for the company of 25%, 30%, or even 40% or more.

Although the economic analysis of service contracts may have some validity, it tends to obscure the political significance of the new legal arrangements. Service contracts undoubtedly emphasized the status of host state as owner of the oil even after recovery, relegating TNC to the role of a general contractor providing technical services in return for the right to purchase an agreed portion of the production at a discounted price. Although in practice, the control of the petroleum operations tended to remain in the hands of the contractor, the ownership factor was not without significance: for example, it enables the State to set aside half of the recoverable reserves as part of the National Reserve.

TABLE 3

COMPARATIVE STRUCTURE OF PETROLEUM CONTRACTS

I Concession Joint Venture Norway	II Production-Sharing Indonesia	III Service (Agency) Iran
	A. Ownership	
	1. Contractual Authority	
The Royal Decree of 8 December 1972 authorises the Ministry of Industry to grant, to both the Norwegian State Oil Company (Statoil) and the private company, a Production License for the "exclusive right to exploration and exploitation of petroleum deposits".	a) Pertamina is granted exclusive "authority to mine" for oil and gas by Law No. 44 of 1960. b) Pertamina has authority to negotiate and execute contracts with private company (contractor). c) Cabinet and President ratify such agreement by decree.	a) The Petroleum Act of 1957 grants NIOC exclusive authority to explore for and exploit petroleum in Iran. b) NIOC has exclusive authority to negotiate service contracts with private company (contractor). c) Service contracts negotiated by NIOC must be approved by Council of Ministers, Majlis and Head of State.
	2. Relationship of Parties	
a) Statoil is a Norwegian corporate entity whose shares are held by the Ministry of Industry on behalf of the State. The Board of Directors of Statoil is responsible to the Minister of Industry. b) The license is awarded directly to Statoil and the private company. Statoil is a participant in the license under the same terms and conditions, except with regard to exploration costs (see C.1 below)	a) Pertamina is a corporation owned by Indonesian Government. Pertamina reports to Cabinet through Minister. b) Pertamina has authority to enter into co-operative agreements with contractor which authorised contractor to carry out exploration and exploitation operations for Pertamina. c) Pertamina or other government or private company nominated by Pertamina can acquire part of the rights and obligations (presently limited to 10% undivided interest) of the contractor with the mutual agreement of the contractor regarding compensation to be paid.	a) NIOC is a corporation owned by the State. b) NIOC owns assets and "mineral rights". Private company is general contractor with sole right to carry out operations. Contract has force of law.

3. Assets

Joint venture assets are owned by the participants in relation to their participating interests. Upon termination of the license, the assets revert to the State.	Equipment purchased by contractor becomes the property of Pertamina when landed, and is subject to a rental charge (equipment leased from third party is excluded).	NIOC owns all assets except movable assets which revert to NIOC after fully depreciated.

4. Entitlement

a) Statoil and the private company entitled to their participating interest shares of production. b) Statoil may require that the private company purchase all or part of its production at a mutually agreed price less a nominal discount.	a) Contractor agrees to take 100% of production (including production to cover costs and production sharing) and market Pertamina's share. b) Pertamina has option to take its share of production in kind (65.9091%; see D.1)	a) NIOC takes all production b) NIOC obligated to sell to Contractor at "halfway" price (based on realized or posted price) an agreed percentage (30-45%) depending on production levels, or up to 50% (as agreed) of all production at market price minus discount (e.g. 5%). c) Contractor must market agreed quantities of NIOC crude at NIOC's request. Contractor receives commission over realized price. d) 50% of reserves is set aside as national reserve.

B. Control

1. Conduct of operations

a) Work obligations are prescribed in the license. b) Statoil or private company is Operator. Statoil may assume operatorship years after a commercial discovery has been declared. Statoil can require the formation of a non-profit company to take over operatorship. Operating company would be Norwegian corporation with chairman appointed by Statoil.	a) Work obligations are prescribed in contract. b) Contractor is operator for life of agreement. c) Contractor prepares and submits proposed work program and budget for ensuing year for approval of Pertamina. Pertamina may suggest revisions but its approval of program and budget will not be unreasonably withheld.	a) Work obligation is prescribed in contract. b) Contractor may be operator for life of contract, or for shorter period as negotiated (e.g. 5 years). c) Contractor prepares work program and budget and consults with NIOC.

c) Statoil and private company jointly determine operations, such as approval of work programs and budgets, in accordance with voting procedure of Participation Agreement, which in effect is a joint operating agreement. Statoil has 50% interest but does not control vote.	d) Contractor hires sub-contractors. Contractor must have authorized representative in the country.	d) NIOC has power of approval over major sub-contractor selection.
d) Operator may hire sub-contractors subject to normal restrictions, and subject to an obligation to utilize Norwegian goods and service as long as they are competitive with regard to quality, service, schedule and price. Operator must have sufficient staff in Norway to direct activities from Norway.		e) Upon commercial production, Executive Committee is established, NIOC and contractor each appointing 2 members. Contractor appoints Managing Director and NIOC appoints Manager Operations who supervises production operations. Executive Committee supervises preparation and implementation of programs and budgets, but contractor retains control of both.

2. Corporate

a) The private company must be a Norwegian company, although passthrough agreements (to pass economic interest to the U.S. subsidiary) are recognized for American corporations in view of US tax laws.	Contractor need not be an Indonesian corporation.	a) Contractor need not be an Iranian corporation.
b) The parent company guarantees the performance of the private company.		b) Parent company signs agreement with NIOC and assigns to operating subsidiary.

3. Treatment of Data

a) All parties, including Statoil, are required to contribute any data they have to the joint venture, except that data which is bound by confidentiality limitations.	a) Pertamina must provide contractor with all data held by it or any other government agency which relates to the contract area.	a) Contractor must provide NIOC with all data and must keep NIOC continuously informed by written report.
b) Statoil has an equal right to all data acquired over the license area during the life of the license.	b) Contractor must provide Pertamina with copies of all data acquired in contract area, including activity reports.	b) Contractor must keep all data confidential except with permission of NIOC.
c) All license area data must be kept confidential for a period of 5 years after the expiration of the license or as may otherwise be agreed by the participants.	c) Pertamina may not disclose such data to third parties without first discussing such disclosure with contractor.	

4. Goods and Services - Training Programs

a) Separate agreement is required for training of petroleum personnel of Directorate and Ministry.	a) Contractor shall carry out training programs. b) Contractor shall give preference to Indonesian goods and services subject to equal quality, price, availability.	a) Contractor to minimize employment of foreign personnel on basis of requisite qualifications.

5. Relinquishment

a) 50% of the license area must be relinquished before the end of six years.	a) The areas to be surrendered are negotiable: 30% of original area - end of 3 years 30% - 6 10% - 8 Retained area at end of 10th year should not exceed 40% of original area. b) Contractor selects areas to be surrendered.	a) The following areas must be relinquished: 50% of original area - end of 5 years 50% of remaining area - end of 7 years All remaining area except commercial fields - end of 9 years b) Contractor selects areas to be surrendered.

6. Disputes

a) Any disputes are subject to arbitration in Norway in accordance with Norwegian arbitral procedures. b) Norwegian law applies.	a) Deciding arbitrator is selected by the President of the International Chamber of Commerce in event Pertamina and contractor cannot agree. b) If arbitrators are unable to reach decision, dispute shall be referred to Indonesian Courts of Law.	a) Deciding arbitrator is selected by president of highest court of Denmark. b) Contract itself has force of Iranian law.

C. Financing

1. Exploration

a) Private company bears all exploration expenses on behalf of Statoil.	a) Contractor bears all exploration costs.	a) Contractor bears all exploration costs.

b) Such expenses are not reimbursible.	b) Such costs are recoverable on a current basis out of production.	b) Such costs are considered a loan to NIOC and are recovered by contractor over 15 years after commercial discovery.

2. Exploitation

a) When a commercial discovery is declared, (after at least 2 wells), Statoil has 12 months to decide whether or not to participate in its development. (At least two companies must declare commercial discovery. Statoil may be one of these. b) Statoil bears it share of exploitation costs from the time it accepts such participation. c) Costs borne on behalf of Statoil between the declaration and acceptance dates (12 months maximum) are repaid by Statoil to the private company in cash with 30 days of acceptance date. d) Statoil or private company may participate in commercial discovery later than 12 and 3 months respectively after declaration date by paying 50% of the costs incurred on the deposit to that point.	a) Contractor bears all exploitation costs. b) Contractor recovers all investments on a current basis out of production.	a) Contractor bears all exploitation costs. b) Such costs are considered a loan to NIOC and are repaid to contractor by NIOC in 5 years plus interest.

D. Fiscal

1. Income Tax

a) 50.8% of taxable income assessed on "norm price". b) Special Tax of 35% which is assessed in addition to royalty and corporate tax.	a) Contractor recovers investments out of production on current basis. b) Remaining production is shared as follows. Pertamina - 65.9091% Contractor - 34.0909% c. Contractor pays 66% income tax on its share of production.	a) 85% of taxable income.

	2. Royalty	
a) Sliding-scale 8%-16% beginning with 8% at less than 40,000 B/D to 16% over 350,000 B/D. b) Valued on "norm price" stipulated for taxation purposes which is based on other country crude sales prices and North Sea realizations. c) Royalty may be taken in kind by the State.	None	None
	3. Rental	
a) An area fee is payable covering years 1-6 of $150/km^2$. b) For years 7-16, fees escalate from $360/km^2$ to $3,500/km^2$. Annual fee beginning year 17 is $7,000/km^2$. c) Fees may be credited against royalty. d) Statoil does not pay area fee prior to its participation in a commercial discovery.	None	None
	4. Bonus and Other Payments	
Examples of bonus payments are: a) $5 million at 250,000 B/D b) $10million at 400,000 B/D c) Statoil pays it share of producton bonuses.	Examples of bonus payments are: a) Signature bonus: $2million - $7million b) Production bonuses: $1million-$3million at 50,000 B/D $1million-$3million at 100,000 B/D $1million-$3million at 150,000 B/D	Examples of bonus payments are: a) Signature bonus: $1million b) Annual payments: $1million at end of each year 1-4 c) Discovery bonus: $1million d) Production bonuses: $2million at 100,000 B/D $2million at 150,000 B/D

III CONTRACTUAL DEVELOPMENTS DURING PERIOD 1973-1980

With the preceding review of the major types of contracts and agreements during the period 1966-1973, this section will be devoted to an examination of contractual terms as they have been adopted and applied by representative countries in South-East Asia, Africa, Europe and South and Central America. Special attention will be devoted to recent oil producers, such as the United Kingdom and Norway, to illustrate the rapid pace of the development of national petroleum policy and the maximization of State revenue. Indonesia, Peru, Malaysia and Sudan all represent diverse applications of the production-sharing contracts. Of particular interest is the case of Madagascar, which recently, with the help of the World Bank, has evolved the concession system into one which includes 51% ownership by the State and a form of excess-profits tax called supplementary payments.

United Kingdom and Norway

The first allocation of blocks in the North Sea took place in 1967 in the United Kingdom and, in 1965, in Norway. By 1969, commercial quantities of oil were established in Norwegian waters by the Ekofisk discovery, and in 1970, the Forties oilfield was discovered in the British sector of the North Sea. The agreements signed with the oil companies in both the United Kingdom and Norway were based on the "Joint Operating Agreement" of American oil practice with concession terms of 12-1/2% royalty and a corporation tax on net profits which was near 50%.

With the discovery of oil, both countries embarked on their separate but very similar negotiations with the oil companies in order to, firstly, increase the share of revenue to the State and, secondly, to assert the control of the State in the management and conduct of operations. The former was rapidly accomplished by virtue of the frequent allocation of blocks accompanied by increasingly favourable financial terms for the State. The significance of the enormous advantage stemming from the available acreage, from which both the United Kingdom and Norway could periodically award blocks and receive more favourable terms, can be grasped when the average block surface area of 200-500 square kilometers in the North Sea is compared with the traditional concessions with measured upwards of 100,000 to 500,000 square kilometers and covered entire countries. The latter objective was accomplished by the establishment of the Norwegian State Oil Company, Statoil, in 1972 and the establishment of the British National Oil Corporation, BNOC, in 1975.

Since its inception in 1972, Statoil has participated in all new blocks issued in Norway on a sliding scale of participation which, starting from 50%, may be as high as 80% depending on production levels. It participates actively and aggressively in the preparation and conduct of work programs and, as it has gained in experience, it has been named Operator of some of the more recent blocks awarded. In exchange for favourable consideration as future partners of Statoil, companies have been encouraged to organize programs for the transfer of know-how from the oil companies to Statoil. These include all aspects of the petroleum industry, ranging from seminars on contracts to production utilization programs.

BNOC, for its part, has acquired a majority participatory interest in virtually all the blocks in the United Kingdom and has the right to purchase 51% or more of all the oil produced at market price. In quick succession after the events of 1973 and the ensuing quadrupling of crude prices, both the United Kingdom and Norway enacted tax laws to tax so-called excess profits by the oil companies. This resulted initially in an effective Government take that could vary between 56% and 75% in both Norway and the United Kingdom. With recent increases in the rates of these taxes as a result of the steep rise in crude oil prices, the effective Government take in both countries can approach 85%. Table 4 illustrates the complex nature of tax calculations in the United Kingdom today, whereas Table 5 shows the division of the gross revenue in a hypothetical barrel of crude oil between the oil company and the British Government.

It is interesting to note that the British and Norwegian concessionary systems have evolved in the short span of the last ten years into a highly sophisticated mechanism to maximise Government revenue. Thus, in quick succession after the events of October 1973, the United Kingdom passed the Oil Taxation Act on May 8, 1975 (otherwise known as PRT, for Petroleum Revenue Tax) and the Petroleum and Submarine Pipelines Act on November 12, 1975. Amongst other provisions, they provided for the setting up of BNOC, tighter Government controls over exploration and development, as well as implementing controls on pipeline construction and refineries.

In Norway, the Act of June 13, 1975, relating to the Taxation of Submarine Petroleum Resources, provided for a special tax which is closer to the true meaning of an excess profits tax than the PRT, and taxation to be based on a "norm" price to be determined from time to time by a Price Commission in reference to existing North Sea market prices. This Special Tax is legislated each year and may vary, as does the corporate tax rate. Tax in Norway is assessed according to the following general formula:

$$\text{Total Tax} = 0.508\,(Y - R) + 0.35\,(Y - 0.30K)$$

Where Y = Taxable net income for Corporation Tax
R = Deductible distribution profits/dividends
and K = Depreciated accumulated investments plus accumulated losses carried forward

Table 6 illustrates the basic components of the British and Norwegian tax systems. Whereas originally the PRT rate was 45% it was raised to 60% in 1979 and to 70%

TABLE 4

COMPONENTS OF GOVERNMENT TAX TAKE
FOR A NORTH SEA FIELD - UNITED KINGDOM[1]
(Totals over life of field)

REVENUE	
1. Production (mm tons)	60
2. Price per ton (£)	110
3. Gross Revenue (1 x 2)	6,600
EXPENSES	
4. Royalty (12.5% x 3)	825
5. Operating Costs	1,500
6. Capital Expenditure	750
Total Expenses (4 + 5 + 6)	3,075
PRT LIABILITY	
7. Allowances for PRT (4 + 5 + 135% of 6)	3,338
8. Oil Allowance = 0.5mm tons/yr x 10 yrs (2 x 8)	550
9. Total PRT Allowances (7 + 8)	3,888
10. Taxable Base for PRT (3 - 9)	2,712
11. PRT at 70%	1,898

1. Brownlow, 1980

CORPORATION TAX LIABILITY

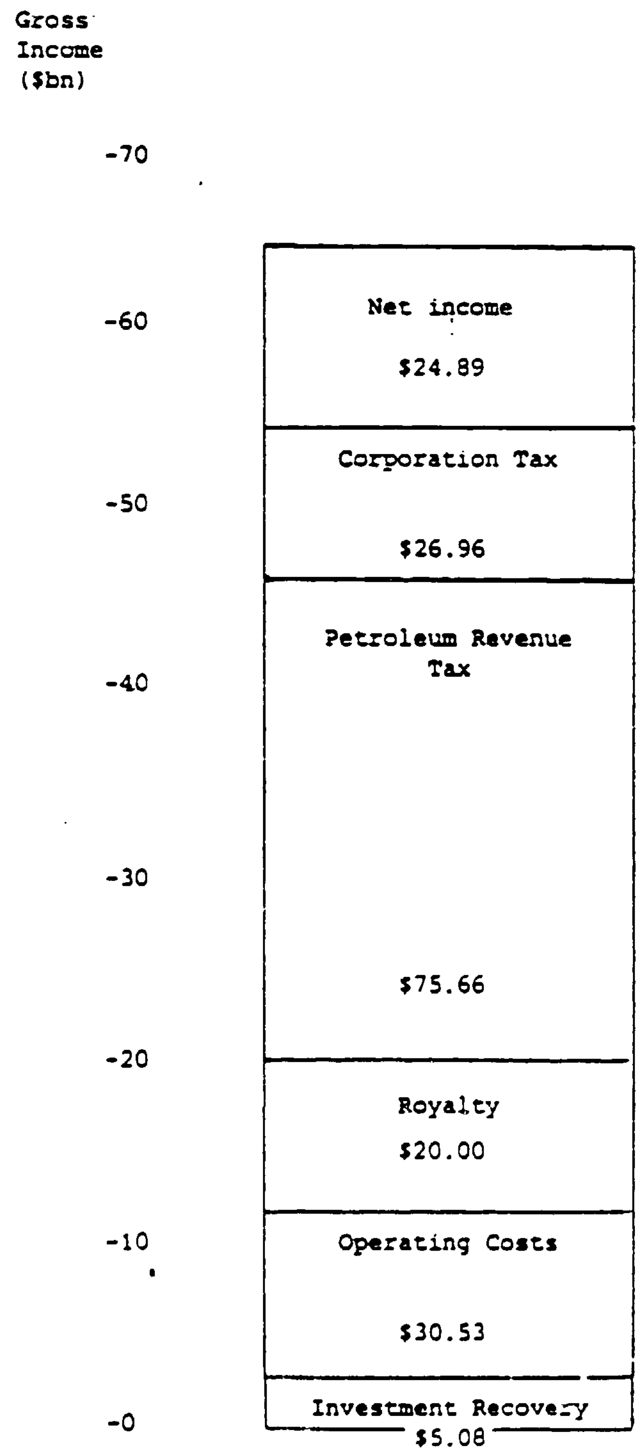
12. Allowances for Corporation Tax (4 + 5 + 6 + 11)	4,973
13. Taxable Base for Corporation Tax (3 - 12)	1,627
14. Corporation Tax at 52%	846
15. New pre-Tax Revenues [3 - (5 + 6)]	4,350
16. Total Government Take (4 + 11 + 14)	3,569
17. Percentage Government Take (16 ÷ 15)	82%

TABLE 5

DISTRIBUTION OF GROSS INCOME ON A PER BARREL BASIS

U.K. NORTH SEA[2]

Reserves	350MM Barrels
Duration	23 years as of 1980. First production 1986.
Average price	$183.12/barrel
Rate of maximum production	115M B/D for 1 year
Rate of inflation	15% per year



2. Brownlow, 1980

in 1980. The oil allowance has been reduced from the original 10 million tons to 5 million tons. In Norway the 25% Special Tax rate was raised to 35% in 1980.

The objectives pursued by Norway in its petroleum policy are well illustrated in the terms of the award of the Statfjord blocks to the Statoil/Mobil group (comprised of Statoil 50%, Mobil 15%, Shell 10%, Esso 10%, Conoco 10%, and Saga/Amoco 5%) in 1973. The surface area of the two blocks was only 580 square kilometers, but drilling on the U.K. side of the boundary and further studies by the Norwegian Directorate (the technical advisory arm of the Ministry) showed excellent prospects for a large oilfield. Today, Statfjord is the largest oilfield discovered in the North Sea. The basic terms of the award were as follows:

Term:	Exploration 6 years Exploitation 30 years
Relinquishment:	50% at the end of 6 years
Royalty:	8% at up to 40,000 B/D, escalating to 16% at 350,000 B/D Gas - 12%
Production Bonus:	$4.5 million at 250,000 B/D $9 million at 400,000 B/D
Work Program:	8 wildcat wells to be drilled by 1979. Ministry to approve all locations, with 3 wells to reach 15,000 feet.
State Participation:	50% (60% vote required in operating committee decisions). State Participation Agreement text provided by Ministry and attached to award.
General Provisions:	Includes pollution liability and safety procedures
Training:	Separate agreement for training Directorate and Ministry personnel.

What is remarkable about this award is the control exercised over the drilling program by the Directorate and the no-nonsense approach to a heavy and concentrated work program, so convinced was the Directorate, <u>because of its own independent studies,</u> of the prospectiveness of the two blocks.

TABLE 6

COMPARISON OF NORWEGIAN (SPECIAL TAX) AND BRITISH (PRT) TAX SYSTEMS

		NORWAY	UNITED KINGDOM
1.	Petroleum Revenue Tax /Special Tax (ST):	ST 35% legislated each year - in addition to royalty & corp. tax	PRT 70% legislated each year - deductible against corp. tax
2.	Corporate Tax:	50.8% legislated yearly	52% legislated yearly
3.	Royalty:	9-16% depending on production levels	12.5%
4.	PRT/ST Relief:	10% of all tangible equipment invested in preceding 15 years	No PRT payable before recovery of 135% of investment cost ("uplift"). First 5 million tons (over 10 years) of each field free from PRT. No PRT where return on original investment is less than 30% pre-tax
5.	Depreciation:	Over 6 years	Tangible investments recoverable as incurred
6.	Payment schedule:	Payable in year following taxable year	Corp. tax payable in 1 year. PRT payable as accrued
7.	Tax price ("norm"):	Set by Petroleum Price Board - provision for consultation with companies	Set equal to average U.K. North Sea market price
8.	Ring fence:	All exploration expenses, intangibles, and abortive development costs can be written off against any field or fields in Norwegian North Sea.	Ring fence allows costs anywhere in U.K. North Sea to be written off against all U.K. North Sea income for Corp. Tax purposes. Limited to field-by-field for PRT.

The announcement in April 1979 of the Fourth Round concession awards repeated the basic framework of previous awards, but added two innovative elements. As in the 1974-1975 awards, Statoil was granted an initial 50% stake in each block with a sliding scale (as negotiated individually with each group) that could raise its interest to 80% as a function of production levels. Statoil's partners are required to pay the State company's share of exploration costs. Drilling is to start in the first year and there is a compulsory work program. Additionally, in the blocks in which Statoil was named operator, oil companies were chosen to act as "technical assistants". Finally, oil companies were asked to present with their applications proposals for industrial development projects in Norway.

Indonesia

The Indonesian Production Sharing Agreements formally entrust the national petroleum company, Pertamina, with the responsibility for the management of the petroleum operations. Notwithstanding its managerial powers, Pertamina is required to assist and consult with the contractor periodically "with a view to the fact that the contractor is given the responsibility of carrying out the work programme" (e.g., Section V, Part 1.3(a) of the Phillips Agreement of 1975).

In practice, the effectiveness of Pertamina's managerial powers is undermined by its lack of managerial and technological skills which is reflected in the delegation of operational responsibility to the contractor. Despite its right to market its share of the crude, Pertamina has assigned the marketing function to the contractor. Furthermore, Pertamina has been unable to enforce effectively the contractual safeguards regarding pricing. In short, the contractor has retained effective management control despite the management clause.

It was inevitable, therefore, that in the wake of the events of 1973, certain adjustments and changes would take place. In the 1974 contract between Pertamina and Phillips/Tenneco, the following production split was agreed upon:

Cost recovery:	from 35% of the production
Profit oil:	72.5/27.5 in favour of Pertamina for production up to 50,000 B/D, 77.5/22.5 between 50,000 B/D and 150,000 B/D, 80/20 in excess of 150,000 B/D.
Excess Profits:	Pertamina to receive 85% of revenue when price exceeds \$5.83 per barrel and production output is not greater than 150,000 B/D, 90% when output is 150,000 B/D to 250,000 B/D and 95% of the revenue when output exceeds 250,000 B/D.

The division of oil revenue is structured so as to allocate progressively higher proportions of the revenue to Pertamina as a function of price and production levels.

A much more serious problem for the American oil companies operating in Indcnesia was the ruling of May 7, 1976 issued by the United States Tax Authorities which stated that the share of production retained by the Indonesian Government was in effect a royalty and therefore could not qualify as a foreign tax credit applicable to the income tax of U.S. corporations with foreign income in the United States. According to the United States Tax Authorities, both the cost-oil and profit-oil split represented fixed amounts which assured the Government its share of production, and thus were representative of a royalty, and not a tax, in the context of United States Tax Law. Furthermore, it ruled that in any event the production at all times belonged to the Government and that since the Contractor did not have legal title to the production, it could not claim foreign tax liability on production if it did not own.

In order to comply with the ruling, companies already operating in Indonesia, as well as those negotiating new contracts, have had to devise new legal structures which would qualify for foreign tax liability. One such example is the Pertamina/Conoco contract of 22nd October 1977, where both parties are joint holders of 50% participating interests in the Contract Area with obligation to jointly participate in the costs and rights under the contract. This in effect makes Pertamina and Conoco equal partners in a joint venture. The Contractor pays its share of the corporate tax. The principal provisions of the contract are summarized below:

Duration	: Exploration 6 years + 2 years + 2 years Exploitation 30 years from effective date of contract
Relinquishment	: 25% of surface area at the end of 6 years 25% of original area at the end of 6 years Such additional area at the end of 8 years so that remaining area is not greater than 40% of original area.
"Joint Operation"	: Pertamina and Contractor each hold 50% participatory interest share in the contract with the obligation to contribute to costs according to their respective interests.
Management	: Contractor to conduct operations exclusively on behalf of Pertamina.
Bonus	: Signature $3.15 million Production $1 million at 50,000 B/D and further $1 million when output reaches 150,000 B/D
Work Program	: $40.6 million over 10 years, with first 3 years commitment of $15 million firm.
Cost Recovery	: Contractor recovers its participatory interest share of all operating costs out of the sale of required quantity of Contractor's participatory interest share of oil based on the weighted average of crude sales of that year.
Disposal of Contractor's crude	: Pertamina is entitled to take 65.9091% of crude remaining to Contractor after Contractor has deducted its share of costs, and the Contractor is entitled to take 34.0909%.
Tax	: Contractor to pay corporate tax.

"Indonesian Participant"	:	5% undivided interest in contract to be offered by Contractor to Indonesian entity designated by Pertamina.
"Investment .redit"	:	An amount equal to 20% of the capital investment cost directly related to development facilities shall be deducted out of Contractor's share of production so as to allow its full recovery in 2 years.
Pertamina crude option	:	In the event Pertamina's effective entitlement to Contractor's crude is less than 50% of Contractor's share of production. Pertamina can market for the account of the Contractor a quantity of oil which together with Pertamina's entitlement equals 50% of Contractor's share of production.

A review of the contracts signed by Indonesia in 1979 and 1980 indicate that Pertamina has dropped its "joint participation" scheme as illustrated in the above-mentioned 1977 contract with Conoco. The primary objective was to gain experience and have a larger equity position in the more attractive exploration plays. The immediate reason for its suspension by Pertamina appears to be the burden of exploration expenditures it had to bear jointly with the oil companies. The oil company once again pays for all exploration and development costs, but now recovers its costs on a current basis from all production (with capital items amortized as provided). The balance of production is divided 65.9091%/34.0909% in favour of Pertamina.

As a result of the United States Internal Revenue ruling, Indonesia promulgated an income tax law similar to the United States. The Contractor pays 66% tax on its share of the production, which results in an effective calculated profit split of 85%/15% in favour of the State.

The other items regarding work programmes and bonus payments remain negotiable, although Pertamina is increasingly limiting exploration term to six years with the renewal option at the discretion of the State.

Peru

By virtue of the fiscal and contractual amendments established by Decrees No. 22774, 22775 and 22862 of 1979 and promulgated into Law in 1980, the oil companies operating in Peru were obliged to renegotiate their existing contracts. The production-sharing contracts in Peru were initially based on a 50/50 production split with no cost recovery by the Contractor and income tax paid by the State oil company, Petroperu. The new contracts eliminated the payment of tax by Petroperu on behalf of the Contractor, so that the Contractor assumes the burden of the 68.5% corporate tax on its income. The principal provisions of the two versions are briefly reviewed in Table 7.

Priority has also been given by the Government to Petroperu forming joint participations with the oil companies to develop enhanced secondary recovery programmes in the old coastal oilfields. The first contract for the Talara oilfields was signed in 1978 and involved Petroperu with 51%, and Occidental and Bridas of Argentina holding 84% and 16% respectively of the remaining 49%. The two private companies received 49% of the additional production established, free of tax burdens. In line with the tax amendments of 1980, Occidental and Bridas renegotiated their original contract. A service contract was signed in 1980, whereby Petroperu repaid the two companies their investment in the Talara project and acquired a 26% participatory interest in Petrolatina, a Peruvian Corporation jointly owned with Occidental (49%) and Bridas (25%). The companies will be paid a service fee of $17.50 per barrel on all production which will be subject to the State income tax at 68.5%.

TABLE 7

COMPARISON OF 1978 AND 1980 PETROPERU/OCCIDENTAL CONTRACTS

	Contract of 3 April 1978 - Block 1B	Contract of 30 April 1980 - Blocks 1A & 1B
Duration:	Total term is 35 years. Exploration is 7 years.	Total term is 28 years. Exploration portion is 6 years.
Relinquishment:	50% at the end of 7 years. In lieu of relinquishment, Contractor may commit to 6 additional wells between 4th year and end of 7th year.	50% at end of 6 years. In lieu of relinquishment, Contractor may commit to 4 additional wells by the end of 8th year.
Work program:	Guaranteed work program of at least 3 wells within 4 years of signing of contract	To fulfil balance of guaranteed work program
Management Committee:	2 representatives of each of the parties plus 1 observer representing the Armed Forces.	2 representatives of Petroperu, 1 representative of the Armed Forces and 3 representatives of the Contractor.
Cost Recovery:	None. Contractor will bear all costs of petroleum operations.	(As in 1978 contract)
Tax:	Petroperu to pay all corporate tax for Contractor.	Contractor to pay its share of corporate tax at 68.5%.

Table 7 (continued)

COMPARISON OF 1978 AND 1980 PETROPERU/OCCIDENTAL CONTRACTS

	Contract of 3 April 1978 - Block 1B	Contract of 30 April 1980 - Blocks 1A & 1B
Production-Sharing:	Contractor and Petroperu each to take 50% of production for oil lighter than 16° API. Of the heavy oil, Contractor takes 75% of first 12 million barrels, 70% of next 8 million barrels, 60% of following 10 million barels and 50% thereafter.	Contractor will take 50% of production up to 150,000 B/D, 48% for portion 150,000 B/D-200,000 B/D, 46% of 200,000 B/D-250,000 B/D, 44% of 250,000 B/D-300,000 B/D and 42% of production in excess of 300,000 B/D.
Assignment:	30 days preferential right to Petroperu on same terms for any assignment to non-affiliated company.	(As in 1978 contract)
Internal Consumption:	Petroperu to purchase Contractor's pro rata share for internal consumption at weighted average price of third party sales.	As in 1978 contract, but weighted average price is based on basket of crude prices (Light Arabian, Qatar Marine and Es-Sider Libya).
National Goods and Services:	To be given preference but at Contractor's sole judgment.	(As in 1978 contract)
Additional payments:	None.	Contractor will pay Petroperu 50% of excess amount received per barrel over base FOB price determined under this contract.
Joint Association:	None.	Petroperu may acquire part of Contractor's interest at a price to be mutually agreed.
Disputes:	Subject to jurisdication of laws and courts of Peru.	(As in 1978 contract)

Malaysia

The Malaysian experiences with the passing of the new Petroleum Development Act of October 1974 (to replace the Petroleum Mining Act of 1966) and subsequent amendments is illustrative of the disputes which may arise when governments attempt to change basic terms and conditions. Despite the fact that the State is entitled to exercise the prerogatives of its sovereign legislative and executive powers, the foreign oil company expects security and continuity, especially in view of the large investments required in petroleum operations.

The new Malaysia Act set up the State company, Petronas, which was to hold all oil and gas rights, thus obliging the companies to negotiate new contracts with the State entity. Following passage of the Act, there were long delays in reaching agreement on the new contracts. The Shell and Exxon production-sharing contracts were not signed until November 30, 1976 and December 8, 1976 respectively, while the Conoco Group, after increasingly bitter exchanges, rejected the terms of the proposed contract and withdrew in July 1978.

The principal provisions of the Shell and Exxon contracts were as follows:

Duration:	Exploitation 20 years + possible extension of 4 years (oil) and 14 years (gas).
Cost oil:	Recovery of costs from up to 20% of production (25% for gas).
Royalty:	Equivalent to 10% of production, deductible against income tax.
Profit oil:	70/30 in favour of Petronas.
Income tax:	45% to be paid separately by Petronas and the Contractor on their respective shares.

"Excess" profits:	70% of sale proceeds over basic price
Research/training:	0.5% of profits

The effective profit split in the Shell contract was 83.5/16.5 in favour of Petronas, while the Exxon split was materially higher in favour of the State company (92.5/7.5). Neither of these arrangements were satisfactory to the Conoco Group which argued that the proposed 83.5/16.5 split did not make the Sotong/Duyong reserves economic. When El Paso withdrew in 1977, Petronas Carigali was formed with the intention of forming a joint venture with the remaining two companies. However, no agreement was reached and Conoco withdrew in July 1978, handing over operatorship to Petronas. In the event, added weight was given to Conoco's contention that the fields were marginal when Petronas terminated the appraisal program of the oil reserves initiated in the following year by outside consultants, and re-ordered its priorities to develop the gas reserves instead.

Measures should be provided to encourage periodic consultations between the State and the private entities to foresee and rectify areas which call for modifications in the light of current industry practice and developments. This was the case notably in both Norway and the United Kingdom where the passage of the respective Taxation Acts of 1975 followed extensive consultations with the private companies that were mutually beneficial.

Madagascar

With the promulgation of Law No. 62-105 of 1 October 1962, Madagascar established its Petroleum Code whereby exploration permits (called Permis H) could be granted to foreign oil companies under traditional concessionary terms. Up to then, and until 1967, the only serious petroleum exploration was carried out by S.P.M. (Societe des Petroles de Madagascar) a wholly-owned subsidiary of the French State-owned petroleum enterprise (now called Elf-Aquitaine). The drilling of mostly shallow wells had been carried out in Madagascar since 1901, attracted by the surface indications of the Bemolanga tar sands. From 1968 to 1975, foreign oil companies including Total (Compagnie Francaise des Petroles), Conoco, Chevron, Agip and Tenneco were granted exploration rights and 15 wells were drilled onshore and offshore contained some gas indications but no oil shows. As a result of the unsuccessful drilling results, Industry interest in Madagascar ceased.

The present Government, faced with the ever-increasing burden of the cost of imported oil, entrusted OMNIS, l'Office Militaire National pour les Industries Strategiques, with the task of reviving oil industry interest in Madagascar. In carrying out this directive, the approach adopted by OMNIS was two-fold.

On the one hand, agreement was reached with the World Bank, within the context of its declared program (World Bank, 1979) of extending financial and technical aid to developing countries to help establish indigenous sources of petroleum. This allowed OMNIS to engage international consultants to undertake offshore and onshore geophysical studies to determine by priority the areas of maximum interest.

At the same time, cognisant of the evolvement of petroleum practice throughout the world, the Government adopted a new Petroleum Code (Law No. 80-001 of June 6, 1980). The basic concept underlying the new Petroleum Code was to outline the major lines of the petroleum regime and to have the formulation and application of regulations concerning certain key clauses, e.g. fiscality, joint venture with the State Enterprise, granting of mining concessions and training of nationals, to be decreed subsequently by the Council of Ministers. The principal provisions of the old and new Petroleum Codes are set out below:

		Old	New
1.	Concession Title	Private company or enterprise	State enterprise only
2.	State Participation	None	Minimum of 51% in any joint venture
3.	Joint venture with State Enterprise	Not applicable	Necessary as title is vested in the State company
4.	Royalty	12½% on well head price, expensed/ credited	15-20% (undecided as of this writing) on world prices-expensed
5.	Tax	50%	45%
6.	Supplementary tax	None	As a function of rates of return
7.	Training of nationals	General provision	Specific obligations - decreed
8.	Management of operations	Oil company	State Enterprise is Operator but may assign operatorship to oil company
9.	Depletion allowance	27½%	None
10.	Assignment of interest ("farmout")	Subject only to Ministry approval	State Enterprise has preemptive right to any assignment.

The three significant departures from the traditional concessionary relationship of the Petroleum Code of 1962 are: 1) Title - which is vested in the State and is exercised through a State Enterprise holding not less than 51% participatory interest in any joint venture with a private company, 2) Fiscality - where Government revenue above royalty and the 45% general tax rate is augmented by a supplementary tax assessed as a function of the rate of return enjoyed by the parties to joint venture, and 3) Management - where the State Enterprise assumes Operatorship but can "entrust" it to the oil company.

Faced with the need to strike a balance between the stated policy of encouraging oil companies to explore in Madagascar and the inclination to maximize State revenue, the supplementary tax may prove a reasonable formula.

Its flexibility renders it responsive to marginal field economics and is thus a useful tool for developing countries that do not have large petroleum reserves.

As it has already been mentioned, the Petroleum Code of 1980 implicitly presumes that the definition of the salient conditions and their regulatory application will be prescribed by the Council of Ministers by the adoption of appropriate decrees. The advantage of such a system is that it dispenses with some of the legislative rigidity inherent in most national laws and effectively allows the Council of Ministers to supplement the national law by a process of redefinition. Whereas, in the case of an amendment to the Petroleum Code, it would require the assent of the General Assembly.

Sudan

Chevron (Standard Oil of California) farmed into the Conoco concession in Chad at about the same time (October 10, 1974) that it was awarded licences in Sudan (November 23, 1974). By virtue of a Presidential Provisional Order amending the Petroleum Act of 1972, Chevron and the Sudanese Government signed a production-sharing agreement dated 12 October 1975. More commonly, Texaco and Atlantic Richfield signed straight concession agreements in 1980 which include royalty and tax. The terms of the Chevron production-sharing agreement are reviewed below:

Area:	331,500 square kilometers
Duration:	Exploration 4 years + 2 years + 2 years + 2 years.
Work programme:	$31 million over 10 years, with firm commitment of $4 million over first 2 years.
Relinquishment:	25% at end of first year, 12.5% of original area at the end of the second year, 12.5% of original area at the end of the third year, 12.5% of original area at the end of the sixth year.

Bonus:	Signature $3 million Production $1 million at 100,000 B/D $2 million at 200,000 B/D $2 million at 300,000 B/D
Cost oil:	Contractor recovers costs out of 30% of all production.
Profit oil:	Balance of crude is divided 70/30 in the Government's favour when production does not exceed 450,000 B/D, 75/25 for output between 450,000 B/D and 750,000 B/D, and 80/20 for output in excess of 750,000 B/D.
Tax:	Government shall pay all of Contractor's income tax.

The accelerated relinquishment program was adopted in view of the vast exploration area. It should be recalled that at the time, as in Chad, there was no serious interest in the remote interior basins of southern Sudan. As a direct result of the discoveries made by Chevron in its Unity and Abu Gabra fields and because of the accelerated relinquishment program, it has been able to expand the exploration pace of its southern basins by signing agreements with other companies. In November 1980, the Total group was awarded a concession over 145,000 square kilometers, covering in part the areas relinquished by Chevron. The State-owned Public Petroleum Corporation holds a 10% interest in the venture.

As is the case of Chad, the inherent difficulties of establishing commercial quantities of oil in geographically remote areas often require some incentives to induce oil companies to undertake costly exploration programs. The fields discovered to date are located at a distance of approximately 1500 kilometers to the Red Sea coast near Port Sudan, which boasts the only refinery in the country. Notwithstanding, the results of Chevron's drilling have considerably brightened the prospects of early production to meet part of Sudan's local needs. The Unity field may have reserves of 50 million barrels which could possibly sustain the required flow of 5,000-10,000 B/D for the building of a small topping unit (mini-refinery). The products of the mini-refinery will be used for the exploration needs of Chevron and the balance distributed to the internal market.

Guatemala

Decree No. 96-75 was promulgated on December 10, 1975 as the new National Petroleum Law governing production-sharing contract to replace the concessionary system of the Petroleum Law of 1974 (Decree No. 62-74). As will be seen, although the contracts are called production-sharing, in their conceptual framework they approach the Brazilian risk contracts. The principal provisions of the Petroleum Law, as further developed in the Regulations (Official Gazette of 13 January 1978) and the Call for Submission of Bids dated 28 May 1980, are summarized below:

Duration:	Exploration 6 years Exploitation 25 years
Area:	Not to exceed 200,000 hectares
Relinquishment:	50% before the end of 5 years. Contract will terminate at the end of 6 years if there is no commercial discovery.
Work Program:	Firm minimum commitment to drill 1-2 wells (depending on area) before end of 3 years to at least 3000-400 meters or geological basement.
Exploration/ Exploitation costs:	All costs are paid by Contractor
Minimum Investment:	$1.5 million for first year. Subsequent yearly minimum investments range between $3.5 - $7 million per year
Bonus:	$1 million signature bonus called for by Petroleum Law

State Participation:	55% of production up to 30,000 B/D 60% for portion 30,000 B/D-50,000 B/D 65% for portion 50,000 B/D-100,000 B/D 75% in excess of 100,000 B/D
Other Participation:	Contractor is obliged to offer Guatemalan citizens option to participate in 5% working interest.
Income Tax:	To be paid by the State.
Contractor:	The production remaining after deducting State participation is sole remuneration received by Contractor.
Contractor Cost Recovery:	Out of Contractor's remuneration.
Management:	State supervises operations through National Petroleum Commission comprised of 4 members representing Ministries of Economics, Public Finances, Public Works and Bank of Guatemala.
National Reserve:	The State retains right to determine portion of reserves to be set aside as National Reserve.
Export Tax:	All crude that is exported is subject to 2% tax based on international market price.
Training Programs:	Contractor to spend following amounts on training and scholarship: $125,000/year before production $350,000/year after production
Construction:	Contractor will build roads to exploitation area. Obligation to build a school and a hospital ($300,000).
Disputes:	All settlements of disputes and arbitration procedure governed by courts and laws of Guatemala.

Whereas, initially, about 40 companies showed interest in exploration in Guatemala following the promulgation of Decree No. 96-75 of December 10, 1975, the final response was less than encouraging. By 1977, no company had signed a contract.

Among the conditions of the new Petroleum Law were an additional "export" tax on crude sales, the right of the State to determine the requirements of a National Reserve, no cost recovery outside the remuneration paid the Contractor, the right of the National Petroleum Commission to determine petroleum operations whilst not participating in exploration or development risk, the need for the Contractor to assign a minimum of 5% working interest to Guatemalan citizens and the right of the State to require the Contractor to sell any part of the remuneration crude for internal needs.

It should be noted that the amount of the additional export tax on the Contractor's crude was not determined in the Petroleum Law of 1975. In order to correct the situation, Decree No. 66-77 was passed on December 22, 1977 and set the export tax at 2%. By 1978, only two State-owned companies, Elf-Aquitaine of France and Hispanoil of Spain, had accepted contracts, with a Texaco-Amoco group as the only private entrant. In response to the 1980 Call for Submission of Bids, just the Elf-Hispanoil-Petrobras consortium signed a contract, whereas upwards of 30 companies indicated an initial interest. There are a number of clauses in the Petroleum Law and Regulations which are "open-ended" in favour of the State. Thus, the State can determine the allocation of reserves to be set aside for the National Reserve, as well as the quantities of crude required from the Contractor for internal consumption. The National Petroleum Commission, as written, can control petroleum operations while the oil company pays all the costs and takes all the risks. The introduction of an export tax may have confused the companies as to the further intentions of the State in the crucial area of taxation.

In view of the limited response by the oil companies to the terms and conditions offered by Guatemala, it may be that the combination of risk and terms was simply too stringent from the companies' point of view.

IV PRINCIPAL CONTRACTUAL TERMS AND PROVISIONS

Prior to the presentation in the subsequent section of the final observations and conclusions of this study for the decade of the 1980s, a review is included below of the principal factors in petroleum contracts and agreements, with particular attention given to current conditions and expected developments.

Ownership and Equity Participation

Ownership of petroleum falls into two basic categories. These are: (1) the ownership by the foreign oil company in whole or in part with the State oil company in straight concessionary agreements such as by joint ventures in the Middle East and the North Sea, and (2) ownership vested in the State by legislation in the case of service/risk-type contracts as in Iran or in Brazil, and production-sharing as in Indonesia. There remain instances of quasi-concessionary systems, such as in Madagascar, where the Petroleum Law vests ownership of the concession in the State, which then arranges through its State oil company an "association" with the foreign oil company while retaining 51% equity participation. Increasingly, ownership of mineral resources will be vested in the State, especially in the less developed countries where equity participation is seen not only as an economic imbalance but also as an obstacle to sovereign aspirations. In Norway, the same practical result is accomplished by the wide participatory rights given the State oil company within the concessionary framework, where Statoil's equity interest may approach 80% for production incremental to 400,000 B/D.

Duration of Contracts

The primary exploration period can vary between 3 and 8 years, viz., Norway 6 years, United Kingdom 6 years, Tunisia 4 years, Niger 5 years, Peru 6 years, Thailand 8 years, with the right for its extension for additional period of 1-5 years each, renewed two or three times. More recently, contracts set a limit beyond which extensions will be granted only at the discretion of the host country, e.g. 4-1/2 years in Egypt, 6 years in Indonesia, 6 years in Guatemala. In Nigeria, the primary term is negotiable. Duration of the exploitation period can vary from 15 years (Brazil) to 30 years from signature date (Egypt, Indonesia), 30 years from commercial discovery (Norway), 40 years (Chad) and to 50 years (Tunisia). It is likely that exploitation periods longer than 25 years will be less common. It is particularly the case that as discoveries become smaller, most reserves today cannot support a production life of over 15 years. At the same time, desirous of accelerating the coming onstream of potential discoveries, host countries will become less disposed to grant automatic extensions to the primary exploration period of 5 or 6 years.

Relinquishment Provisions

Relinquishment of 50% of the original area at the end of the primary term of 4-6 years is called for in most contracts, with a further 25% commonly required for additional renewals of 2-5 years. In large areas, relinquishment is accelerated. The Upper Egypt block contract requires 75% relinquishment at the end of the first year, while in the Nile Delta, 40% must be given up before the end of the 4th year and 30% at the end of the 6th year, so that only 30% of the original area is retained. Relinquishment obligations within the primary term of the exploration period, e.g., 25% at the end of the 2nd year, and 25% at the end of the 4th year of a 6-year term, will become more common with the growing practice of host countries to limit contracts to the primary exploration period unless there is a commercial discovery.

Royalties, Cash Bonuses and Other Payments

The advantage of the royalty payments to the State is that it is a payment on production itself and is therefore independent of net profits on which tax is calculated. Except for some of the lower income less-developed countries, royalty as a rule is calculated on posted price, or some other "reference" price based on a weighted average of crude export prices, and is a cost-deductible item. It varies generally from 10%-20% and is increasingly being taken in kind rather than in cash. Examples are: Italy 8%, United Kingdom 12-1/2%, Gabon 20%, Nigeria 20%, Argentina 12%. Legislation in Norway provides for a sliding scale royalty increasing from 8% for production below 40,000 B/D to 16% over 350,000 B/D. Royalty for OPEC countries is now set at 20%. In addition to royalties, governments seek cash bonus payments at signature and at various levels of production. Bonus payments may be legislated (Guatemala) or negotiated (Indonesia, Iran, Sudan). Examples of signature bonuses vary between $1.5 million and $7 million in Indonesia and are indicative of the range of signature payments, although they tend to be more prevalent in the range of $1-$3 million. Examples of production bonuses are $4.5 million at 250,000 B/D and $9 million at 400,000 B/D (Norway); $1 million at 100,000 B/D, $2 million at 200,000 B/D and at 300,000 B/D (Sudan): $1 million separately at 50,000 B/D, 100,000 B/D and 150,000 B/D (Indonesia): $3 million separately at 60,000 B/D and at 100,000 B/D (Malaysia). In the West Sinai, Egypt is paid $3 million at signature, $1 million when production reaches 50,000 B/D, $2 million at 100,000 B/D and $3 million at 150,000 B/D. Rentals are another form of payment, but in most countries they are relatively low. Notable exceptions are Norway and the United Kingdom, where in the 10th year after commercial discovery the annual rental is about $5,400/km^2 and $7,200/km^2, respectively. In the latest seventh round of awards in the United Kingdom, applicants paid about $12 million per block, which is in effect a signature bonus.

Pricing

The valuation of the petroleum is crucial in determining the amount of royalty and tax receivable by the host country. Historically, crude prices have been based on either realization (actual sales price realized) or posted price, which is set by the host country and is as a rule higher than the realized price. Many countries today prefer to set the crude price as an approximate weighted average of international crude prices, allowing for transportation and quality differentials (Peru, Norway, Indonesia). Whatever basis is used, petroleum prices should be based on true arms-length third party sales to non-affiliates. Prices set by producing countries on the basis of such averaging of crude export prices are known as reference prices or norm prices. In Norway the norm price is set by the Petroleum Price Board which consults with the oil companies. The prices for OPEC-member countries are set from time to time by OPEC directives but have proven to be volatile and unreliable. National oil companies as a function of their more dominant role in crude marketing, have assumed a more central role in price determination.

Taxation

The tax rate on net income is either a special petroleum tax or a legislated corporate tax. OPEC countries apply a special income tax rate of 85%. Non-OPEC income tax rates can vary from zero to 85%. Sudan applied a special petroleum tax of 70% in concession agreements it signed in 1980. In the United Kingdom and Norway, the respective corporate income tax rates are set at 54% and 50.8% and are legislated yearly. They have been augmented by the introduction of the Petroleum Revenue Tax and the Special Tax (see below). The 45% corporate income tax rate applicable to petroleum in Madagascar is also augmented by supplementary payments as a function of profitability. In view of the rapidly rising crude prices, producing countries will continue efforts to share in the larger profits by hiking the fiscal terms. Examples of income tax rates are: Nigeria 85%, Argentina 55%, Tunisia 55%, Niger 50%, Ecuador 71.42%, Italy 48%, Peru 68.5%.

"Excess" Profits

Excess profits are applied either as supplementary payments (Norway, Madagascar) or treated as a deductible item against the taxable income as in the case of the Petroleum Revenue Tax in the United Kingdom. The measures can take the form of new tax legislation, as in the case of Norway and Madagascar, or a larger share of the production and the proceeds of crude sales which are written into contracts as in the case of Indonesia and Malaysia. The Special Tax of 35% in Norway is in addition to the corporate tax and is set so as to allow the oil company an acceptable commercial rate of return. In Madagascar, the supplementary payment is a percentage of the after-tax net cash flow paid to the Government when the real rate of return is higher than 15%, viz. 25% for a rate of 15%-20%, 50% for the range 20%-25% and 75% for a rate of return higher than 35%. Contractual arrangements can provide for payments in the form of 50% per barrel of the excess amount realized above an agreed F.O.B. sales price (Peru), or an increased share in the production (Indonesia) where production under 50,000 B/D is split 72.5/27.5 in favour of Pertamina, 77.5/22.5 for production of 50,000 B/D to 100,000 B/D and 80/20 for production in excess of 150,000 B/D. Additionally, Pertamina receives 85%-95% of the price realized in excess of an agreed sales price. In Malaysia, a new 25% profits tax is applied to profits, which are already subject to the 45% income tax and an excess profits tax based on the difference between actual realized F.O.B. prices and an agreed base price. In addition, Petronas has announced a $1 premium on all crudes.

Disputes

An increasing number of contracts stipulate that all disputes be settled according to the laws and under the jurisdiction of the courts of the host country, e.g., Brazil, Guatemala, Malaysia, Indonesia, Norway, United Kingdom, Peru. At the same time, various international arbitration procedures continue to be used. The Rules of Conciliation and Arbitration of the International Chamber of Commerce is applied by Indonesia, as it is by Egypt which stipulates that it be convened in Stockholm. Thailand refers arbitration to the I.B.R.D. (International Bank for Reconstruction and Development) as does Niger. In Chad, the parties agreed to submit all differences to The Hague.

Training and Employment of Nationals

There are two types of programs. They are: (1) programs that are left to the discretion of the oil company, and (2) programs that are clearly stipulated in the contract or by separate agreement. In the first instance are countries such as Tunisia, Chad, Indonesia, the Gulf States, Peru and Colombia, which require that training programs be jointly organized by the authorities and the company, and that preference be given to nationals in the company's hiring practice, given the necessary qualifications and subject to the judgment of the Contractor. In contrast, the requirements for national goods and services and training programs are separately decreed in Madagascar. Malaysia requires that 0.5% of profits be allocated to research and training programs. In Norway, the Licensee signs a separate agreement to train Ministry personnel, in addition to contractual requirements to train Statoil's personnel. Guatemala stipulates the amounts to be spent on scholarships and schools ($125,000/year before production and $350,000/year after production). Ecuador required 95% of the work force to be nationals, but only 65% of the technical staff. The contractual stipulation of the precise requirements of training programs and hiring practices, especially in the case of developing countries, is useful in order to establish clear guidelines for future reference and to avoid disagreements.

International Financing

In addition to the newly available sources of financing for petroleum projects from institutions such as the World Bank and the International Finance Corporation, as well as OPEC and OAPEC (Organization of Arab Petroleum Exporting Countries), government financing by petroleum-poor consumer countries, such as Japan and Germany, in return for secure access to crude supplies, should become an important source of external financing of exploration and exploitation projects. Japan has been particularly active in promoting project financing in return for crude supplies (see Segal, 1979). Loans advanced by Japan have helped finance the construction of the Transandean pipeline in Peru, in return for which Peru is to supply Japan with 153.3 million barrels of oil and 102.2 million barrels of refined products over ten years. Major investments in petrochemical projects in Saudi Arabia and Iran were undertaken in return for some 257,000 B/D and 180,000 B/D plus 400,000 B/D of products, respectively. Japan has made available loans amounting to $250 million to PEMEX of Mexico for ports and pipeline development, and has also invested in Dome Petroleum's costly Arctic exploration program. Iraq is providing some 40,000 B/D in exchange for Japanese investment under the terms of a ten-year supply agreement negotiated in 1974.

Marketing Aspects

Traditionally, the foreign oil company took all the production which it then marketed, remitting the appropriate share to the Government. Especially in the 1950s and the 1960s, with the weakening of crude prices resulting from over-supply, the marketing function of the foreign oil company was indispensable to the producing country. In spite of the steep rise of crude prices since 1973 and the actual market conditions favouring the producing countries, when Saudi Arabia formally required full ownership of Aramco in December 1980, it admitted that Aramco continued to be responsible for marketing most of the daily output of 10.5 million barrels. At the same time, Saudi Arabia is handling increasing larger crude transactions on government to government sales. In Kuwait, the national oil company, KNPC, has moved aggressively into downstream activities. Countries such as Iran and Venezuela market most of their crude on long-term contracts. BNOC, the British National Oil Corporation, which has a right to 51% of all U.K. production, markets its share of the 1.6 million barrels produced by the United Kingdom last year. More frequently, government-to-government crude sales by-pass private oil companies as well as national oil companies. National oil companies are no longer marginal suppliers, but have become major traders of State oil in their own right.

Refining and Downstream Activities

In anticipation of local petroleum discoveries, a number of countries have proceeded with the construction of refineries without securing long-term crude supplies and markets. The Government of Sierra Leone, in one such case, entered into an agreement in 1972 with a consortium of oil companies comprised of BP, Shell, Texaco, Mobil and AGIP whereby it could acquire from the Government the refinery assets previously built by Nissho. The refinery had been operating at part capacity and it was the intention of the oil companies to bring it fully onstream after discharging the Government's remaining financial obligations to Nissho. The refinery was to operate on a purchase and sale basis so that the companies could purchase the crude requirements and sell the products as needed, provided that in the event petroleum is produced in commercial quantities in Sierra Leone which is commercially competitive and of suitable quality then such petroleum will be supplied to the refinery. The Government retained the right to furnish the refinery up to 50% of the crude required for domestic processing out of its share of petroleum produced in Sierra Leone. Any petroleum produced locally by a refinery oil company would replace the supplies which would otherwise have been imported by the company. The agreement provided for an Advisory Committee comprised of 2 representatives each of the Government and the companies to decide on product prices, and a Board of Directors made up of 5 directors representing the Government and 5 directors representing the companies. An aggregate note of 80% is required for passage of resolutions. Other provisions provide for preference to be given to Sierra Leone carriers and the employment and training of nationals.

A more cautious approach is contained in the agreement signed by Ghana and Shell in 1974, wherein the oil company may be required to prepare a feasibility report on the construction of a new refinery or on the expansion of the capacities of any existing refinery facilities, once it is producing petroleum in commercial quantities. The Government can require the construction or expansion of a refinery if a reasonable profit can be assured to the oil company.

In Indonesia, the 1977 agreement with Conoco provides that 10% of the oil company's entitlement is to be refined in Indonesia and that the oil company should construct such refining capacity if no such facilities exist. The conditions are as follows:

1. The oil company's share of local production should be no less than 175,000 B/D.
2. The refinery project should be deemed economical by both parties.
3. The oil company may, in lieu of the refinery project, make an equivalent investment for a related petroleum or petrochemical industry.

It is essential that a sound economic basis be established to justify the construction of any refinery. This means that for countries with little or no industrial base, the presence of indigenous sources of petroleum is of overriding importance.

Transfer of Technology

The transfer of technology is sought not only by developing countries but by all producing and non-producing host countries. With ownership of petroleum being increasingly vested in the State, the basic strength of the multinational oil companies remains the technical and managerial services they can offer. Thus, as technical advisers to national oil companies, they have been granted participation in a number of blocks in the North Sea where Statoil is operator. It has been noted that the Aramco countries will continue to technically assist Saudi Arabia, especially in oil and gas related industries. State oil companies, such as Elf-Aquitaine, ENI and BNOC have provided new technology through exploration programs. BNOC has conducted seismic and drilling operations for Malaysia, while ENI of Italy and ERAP of France have introduced the most innovative agreements, joint venture and service contracts, to the Middle East. Saga Petroleum, a young Norwegian commercial grouping with interests in the Statfjord field and other North Sea blocks, has undertaken the development of the Seme field off Cotonou, in Benin. The field was discovered in 1974 by Union but was deemed uneconomic to develop. As a result of the large rise in oil prices, the field profitability has increased. Saga was able to convince the Norwegian government to agree to provide a financing package worth $134 million, on the condition that most of the equipment and services would be bought in Norway. Saga will manage the development project for the Government by virtue of a service contract signed in 1979. Saga will also be responsible for a comprehensive training program which will include the posting of Benin national engineers and geologists for practical training in Norway.

Outside of the multinational and the State oil companies, a number of regional and world institutions have been able to offer technical assistance. The United Nations has extended assistance in the form of technical surveys, training programs and expert personnel through its United Nations Centre for Natural Resources and its Centre on Transnational Corporations. OAPEC (Organization of Arab Petroleum Exporting Countries) has established service subsidiaries for geological, geophysical and drilling projects and, together with OPEC, is expected to be a major source of financing and technology transfer for the developing countries through the 1980s.

V OTHER ISSUES AND TRENDS

The implementation of national petroleum policy and priorities, to satisfy the divergent needs of individual developing countries, has required the establishment of State entities, as well as international institutions and programs. Certain aspects of these issues are discussed here to illustrate some of the mechanisms that have been made available to the host countries.

National Oil Companies

As of June 1979, all 13 OPEC countries had established their national oil companies. The earliest State oil companies appear to have been formed in South America, with the first recorded national oil company YFP (Yacimientos Petroliferos Fiscales), set up in 1922 by Argentina. In Italy, AGIP (Azienda Generale Italiana Petroli) was formed in 1926 and was later absorbed by ENI (Ente Nazionale Idrocarburi) in 1953. However, it was the establishment of PEMEX (Petroleos Mexicanos) in 1938 by Mexico, following the nationalisation of the foreign oil companies operating in Mexico, that was the first significant assertion of nationalist aspirations amongst the oil producing countries, in the same way that the formation of NIOC (National Iranian Oil Company) followed the nationalisation of Anglo-Iranian Oil Company in 1951.

The establishment of national oil companies flows from the doctrine of State ownership of its natural resources, which is the prevalent body of law governing mineral rights in almost all of the countries of the world. The United States is one of the small number of countries in which the practice of private ownership of mineral rights prevails. Thus, basic differences and disagreements can be traced to conceptually different approaches, on either side, arising from the question of public versus private ownership.

It is natural, therefore, for the State to intervene to protect its interests. It attempts to do this, firstly, by laying down a set of rules to regulate petroleum operations on its soil and, secondly, by establishing a national oil company to act as the instrument of national petroleum policy. The set of rules would include the following measures:

1. To supervise exploration and production programmes;
2. To ensure the technical and financial qualifications of the operator;
3. To oversee prudent exploitation practice;
4. To ensure requirements of domestic consumption;
5. To maximize oil revenue for the State;
6. To advance operator's use of national goods and services, and
7. To observe restrictions of a social or religious nature.

The main impetus to the establishment of national oil companies during the 1950s and 1960s was the growing maturity in the evolving petroleum policies of the producing countries. A non-exhaustive chronological listing of national oil companies, since their inception, highlights the major periods of accelerated growth in State participation.

YPF (Yacimientos Petroliferos Fiscales)	- 1922
AGIP (Azienda Generale Italiana Petroli)	- 1926
RAP (Régie Autonome des Pétroles)	- 1938
PEMEX (Petroleos Mexicanos)	- 1938
NIOC (National Iranian Oil Company)	- 1951
ENI (Ente Nazionale Idrocarburi)	- 1953
Petrobras (Petroleos Brasileros)	- 1953
EGPC (Egyptian General Petroleum Corporation)	- 1957
CVP (Corporation Venezolana del Petroleo)	- 1960
KNPC (Kuwait National Petroleum Company)	- 1960
Petromin (General Petroleum and Mineral Organization)	- 1962
Sonatrach (Société Nationale pour le Transport et la Commercialisation des Hydrocarbures)	- 1963
INOC (Iraq National Oil Company)	- 1964
ERAP (Entreprise de Recherches et d'Activités Pétrolières)	- 1965
Hispanoil (Hispanica de Petroleos)	- 1965
JPOC (Japan Petroleum Development Corporation)	- 1967
NNOC (Nigerian National Oil Corporation)	- 1971
ADNC (Abu Dhabi National Oil Company)	- 1971
Statoil (Den Norske Stats Oljeselskap)	- 1972
Petronas (Malaysia)	- 1974
BNOC (British National Oil Corporation)	- 1975
Akorama (Madagascar National Enterprise for Hydrocarbons)	- 1980

The national oil companies have played a central role in the expansion of the State's control over the conduct and management of petroleum operations. The growth of Statoil's and BNOC's technical expertise has already been noted, allowing both companies to assume operatorship in the North Sea. With at least 50% and 51% respectively, of the crude at their disposal, both companies will undoubtedly increase their downstream involvement and overseas investment. In their joint ventures with foreign oil companies, national oil companies indirectly play a supervisory role on behalf of the State by their presence on Boards of management. But it is in the sphere of increased State participation, i.e., increased revenues to the State, that the role of the national oil companies has been most conspicuous.

Beginning with the joint ventures in Iran in 1957 which gave the NIOC a 50% participatory stake in agreements with foreign oil companies, demands for increased State participation in the major producing countries appear to be limited only by the level of technical expertise available to the host country. Thus, demands for State participation in the Gulf States rose from 25%, agreed in 1973 by Saudi Arabia, Abu Dhabi and Qatar to an agreement in principle in 1975 for a 100% takeover of Aramco (Arabian-American Oil Company) by Saudi Arabia. By 1976, Saudi Arabia had acquired a 60% interest in the company and effective control. It was announced on December 10, 1980 that Saudi Arabia had acquired full ownership of Aramco and that it was to set up a national petroleum company to take over its assets and operations. The four companies (Exxon, Texaco, Standard of California and Mobil Oil) had been fully compensated for the remaining 40% of their holdings. Aramco will remain in a technical advisory capacity, with the right to take agreed quantities of production but at market prices. As a service company and in return for a fee, it would offer technical assistance in exploration and exploitation activities for petroleum and gas, in related industries and in marketing.

Today, Iran, Iraq, Kuwait, Qatar and Bahrain have all opted for a 100% takeover of the petroleum operations and assets in their respective countries. Oman's and Abu Dhabi's respective participatory shares are 60%. Libya which has a 51% interest in its existing concessions, now favours production sharing contracts where the production is divided 81%/19% in its favour. Nigeria's participation stake, which was 55%, has been recently raised to 60%. Statoil of Norway, with an initial interest of 50%, can increase its participation to 80% if production levels are high enough. In countries with production-sharing regimes, such as Indonesia, Pertamina has signed a number of contracts where its equity share as a "joint participant" is 50%. In Peru, Petroperu retains the option to buy at a negotiated price a part of the interest held by the Contractor. In Madagascar, which has no existing oil production, Akorama (the National Enterprise for Hydrocarbons) holds a 51% participatory interest in any joint "associations" with foreign oil companies.

It is self-evident that the role of national oil companies will progressively encompass downstream, as well as upstream activities. The growing importance of the national oil companies in crude trading and their burgeoning bargaining power may mean that non-commercial criteria, such as political factors, may prevail over market forces for the allocation of oil supplies. The parallel growth in the financial strength of the national oil companies and their assured access to crude supplies will mean downstream joint ventures with crude-deficient oil companies and foreign governments.

Petrobras is an example of the diverse and interlocking roles played by national oil companies. Braspetro (Petrobras Internacional) has participated in exploration ventures in countries such as Colombia, Iraq, Iran, Libya, Algeria and Angola. Petrobras Quimica (Petroquisa) is responsible for the petrochemical sector whilst Petrobras Comercio Internacional (Interbras) was set up in 1976 to develop export markets.

Brazil, unlike Mexico, shifted its stand of achieving self-sufficiency on its own and invited the participation by foreign oil companies because of the relatively disappointing results from the enormous investments it had made in exploration. Following the opening, in October 1975, of offshore exploration and development to foreign oil companies, Petrobras signed the first of its innovative risk contracts with BP in 1976, followed by contracts with Shell, Elf/AGIP and Exxon. The response, however, was not enthusiastic. A second round, announced in 1977, attracted new entrants such as Pennzoil, Marathon and Hispanoil. In 1978, Petrobras opened a third round comprising offshore and, for the first time, onshore blocks. The response by the oil companies was weak, with only 9 bids received for the 42 blocks offered. In order to stimulate interest in the 25 remaining blocks, Petrobras dropped its requirement of firm drilling obligations. The offshore contract signed by Hispanoil and Hudson's Bay Oil and Gas in 1979 provides for 3 years of seismic surveys before the companies decide whether to commit to drilling.

The principal terms of the risk contracts are as follows:

Duration:	Exploration 3 years + 1 year + 1 year Exploitation 15 years
Relinquishment:	50% at the end of 3 years
Work program:	Firm commitments vary from $8 million (Elf/AGIP) to $20 million (Shell). Recently Petrobras has offered seismic options.
Exploration and Development Costs:	At sole risk of Contractor. Exploration monies reimbursed with no interest from production; development reimbursed with interest (1% + prime U.S. rate)
Remuneration:	Petrobras shall pay Contractor service fee equal to a percentage of production calculated at market price. 35% under 42,000 B/D 30% 42,000 B/D - 84,000 B/D 20% over 84,000 B/D Percentages and production levels are negotiable.

Market price:	Determined by Petrobras on quarterly basis to be weighted average of international crude sale prices.
Royalty:	None
Tax:	No corporate tax; 25% dividend tax.
Operatorship:	Petrobras has right to become Operator upon commercial discovery
Arbitration:	Governed by the Brazilian Code of Civil Procedure

The World Bank and Exploration and Production Financing

With the steep rise of oil prices beginning in 1973, oil-importing less developed countries experienced large oil deficit accounts and a corresponding growth in their external debt. At the same time, the increase in gross national output in the lower-income oil importing LDCs barely kept abreast of population growth. Parra (1979) points out that the per capita income for these countries grew by only 0.6%/year to $140 during the period 1970-1976 and was illustrative of the widening disparity between their gross national product and the cost of imported oil which had more than quadrupled during the same period. It is estimated that the oil import bill of developing countries will rise from $50 billion in 1980 to $110 billion by 1990 (World Bank, 1980).

Several international institutions such as the Centre on Transnational Corporations and other divisions of the United Nations Department of Technical Co-operation for Development offer developing countries assistance in national energy planning and provide technical advisory missions. The World Bank has established program of loan assistance to oil-importing developing countries in order to finance the development of indigenous petroleum resources.

In 1977, the World Bank adopted a program of loans to member countries, initially for the purpose of developing and putting onstream already discovered small oil and gas fields which had been considered uneconomic by the oil companies in terms of their export potential. The World Bank share of the necessary financing generally averaging 20% of the project cost but which can vary widely frcm project to project, would also play a useful role in attracting other sources of private investment, including the oil companies. For example, in the case of Chad, a commitment to eventual participation by the World Bank became one of the oil companies' central conditions in agreeing to develop the Sedigi field for internal consumption, as the oil companies were not amenable to financing the entire project by themselves.

Whereas a few loans were made available for the far riskier exploration programmes, which would be refinanced out of eventual production or to be repaid by the foreign oil company in the event the exploration was not successful, they were primarily directed to exploration projects in which the host country was associated with a foreign oil company. However, it is frequently the case that the host country cannot find an oil company which is prepared to invest capital in petroleum exploration and therefore must bear all the risk by itself. Increasingly, the World Bank has been prepared to undertake risk financing of exploration in appropriate circumstances. The Board of Directors of the World Bank approved in 1979 the expansion of the Bank lending program to $1,500 million per year by 1984, of which 60% of the loans would be for production facilities and 40% for exploration and other pre-production activities. Loans will be made available for geological and geophysical surveys and exploratory drilling.

The World Bank has also proposed the setting of a separate lending affiliate which would invest up of $25 billion in developing countries over the next 5 years. The new facility would devote itself entirely to financing the development of energy resources. Compared to the total investment of $3.6 billion in oil and gas in 1980, the average annual investment for the years 1981-1990 would rise to $6.3 billion.

The Mini-Refinery and Producing Non-Exporting Developing Countries

A total of 17 exploratory wells had been drilled in Chad in the period 1969-1979, before the suspension of exploration activities as a result of the intensified civil war. Of these, 8 wells were discovered but none of the reserves so far found are large enough to be considered commercial insofar as export capabilities are concerned. It is estimated that the pipeline/terminal investment of some $500 million to transport Chad crude to the port of loading near Douala requires minimum threshold reserves for southern Chad of some 350 million barrels or about 100,000 B/D.

Article 9 of the Convention of 23 July 1970 signed by the Chad Government and Continental Oil Company (Conoco) stipulates that, in the event the oil company decides not to develop a discovery because it is considered uneconomic, the State shall have the right to require the company to develop the discovery on behalf of the State on the condition that the State provide all the financing for the development and exploitation costs as well as assure the company a profit margin equal to 5% of the ex-field value of the crude free of all burdens. However, the Convention contains no reference to the construction of a refinery.

As a result of the steep rise of oil prices, Chad, with a daily consumption of only some 1,251 B/D in 1976 and projected to grow to 1,342 B/D by 1980, faces an oil bill of about $20 million per year at current prices. As early as 1974, Chad indicated its interest in the feasibility of constructing a small refinery to satisfy the needs of the domestic market. The oil companies, (including Shell 50%, Conoco 25% and Chevron 25% as a result of the consecutive "farmouts" by Conoco of its interest in the exploration permit), recognizing that the construction of a small refinery would mean important savings of foreign exchange for the country, were prepared to offer technical assistance but declined to be responsible for the entire funding of the project. A feasibility report for the mini-refinery project was prepared by the oil companies and submitted to the Government in 1976. The report concluded that the processing of Sedigi crude to provide a limited range of refined products (regular gasoline, gas oil, residual fuel oil) for internal consumption was technically feasible, and that the refinery to be constructed should be a simple 1,500 B/D distillation unit on skids to be located at N'Djamena, the capital and market centre. A typical refinery run would yield by volume regular gasoline (28%), gas oil (41%), residual fuel (28%), mini-refinery fuel (2.5%) and flared gas and loss (0.5%). The report recommended the transport of the crude oil from the well-head at Sedigi to Lake Chad through a narrow-gauge pipeline, then by barge and truck to N'Djamena (this composite scheme was subsequently dropped in favour of a direct pipeline link between Sedigi and the refinery). It estimated the cost of the refinery and transportation system at $7 million.

In considering the alternative requisites for the construction and operation of the mini-refinery, the Government and the oil companies organized in 1977 a Chad company, called the Société d'Etudes et d'Exploration de la Raffinerie du Tchad (SEERAT), in which the State would have an initial stake of 20%, with Shell holding 40%, Conoco 20%, and Chevron 20%. The parties were agreed that the State interest could be increased ultimately to full ownership of the refinery.

The draft convention of February 1978, between the Chad Government and SEERAT, defined the conditions of the establishment and operation of the refinery activities and the transport of crude from the producing field to the refinery. SEERAT would be responsible for the construction of the refinery and would subsequently operate the refinery and the pipeline for a fee. The shareholders of SEERAT would be entitled to their pro rata share of the finished products at the same price as those sold to other distributors. The price ex-Sedigi at which SEERAT would purchase the crude would be governed by a separate convention to be agreed between SEERAT and the producing companies. Alternatively, the Government could take possession of the crude at an agreed purchase price when it entered the pipeline at Sedigi for delivery to the refinery, and take the refined products at the other end for sale to the distributors.

It had been made evident to the Government at the outset that the producing companies would seek outside financing for part of the project's capital requirements, which included a single 6-inch pipeline to transport the crude directly from the Sedigi field to the refinery at N'Djamena, a distance of 350 kilometers. The oil companies were prepared to advance their share of funds for the refinery ($6 million) and for production drilling and facilities ($5 million) only on condition that the Government could guarantee the financing and construction of the pipeline ($7 million). The companies held negotiations in 1976 and 1977 with a number of European and American financial institutions on behalf of the Government. At the same time, the World Bank, on the strength of its Board decision to extend its lending to the petroleum sector and, in particular, for the development of small reserves for domestic markets, indicated its interest in the Chad project and accepted in principle (subject to final Board approval) to make available to the Government the necessary financing for the construction of the pipeline and to pay for the State's 20% share of the SEERAT costs.

The minimum conditions set by the producing companies for their investment in the refinery project were the following:

1. A 5-7 year payout period.
2. A commercial rate of return.
3. A crude price adapted to world market prices.

Not surprisingly, one of the more intractable elements proved to be the agreement on the price of the crude ex-Sedigi to be charged to the Government. The companies' starting position in calculating the ex-Sedigi price was to work back from known crudes to establish a price which would be indexed to OPEC price fluctations. It soon became apparent, however, that a price adapted from world market prices was unacceptable to the Government and that, instead, it would have to be worked up from the field investment. The Government for its part, proposed a price much more in line with the incremental barrel costs in producing countries with high production rates, which was far too low to allow a commercial rate of return on a Sedigi-type one-well operation with its commensurately higher cost per barrel investment. A compromise price has been agreed by the Government and the companies, which provides for a commercial rate of return to the producing companies for the sale of the Sedigi crude, thus removing the final obstacle to the start of the refinery construction. The Chad mini-refinery project is a model that can be usefully studied by other lower income LDCs with small, "marginal" reserves.

In the Sudan, a similar project is under way, bringing together the Sudan Government, Chevron and the World Bank. Sudan with a daily consumption of some 20,000 B/D faces an oil bill of about $300 million per year. Since the signing of the contract with Chevron in 1975, a number of promising discoveries have been made although, as in the case of Chad, none of the reserves are large enough on the basis of drilling to date to justify the cost of a pipeline to the coast for export, a distance of approximately 1500 kilometers to the Red Sea. As neighbouring countries, Sudan followed with interest Chad's efforts to become self-sufficient in petroleum. It initiated talks with Chevron and the World Bank for the financing of a small refinery with a capacity of 2,000 B/D to 10,000 B/D to process crude from the Unity field. It will reportedly be located at the producing field and use the composite barge and road scheme for distribution of finished products as the field is located in southwestern Sudan. It is expected that the entire World Bank commitment will be about $75 million, to include a mini-refinery costing $7-10 million, $5 million for the river barge and storage system, $10 million for a tanker to bring in Saudi crude as a back-up to the Sudan production as well as various improvements to the transportation infrastructure of the country, viz. the Port Sudan-Khartoum pipeline, the national railway, and the Port Sudan harbour facilities. Until sufficient delineation drilling of the known reserves is accomplished, and this is a function of the geology as well as oil company's estimation of the potential of finding high-capacity oil fields based on sustained well flow rates, it will remain difficult to predict accurately the refinery through-put capacity that can be maintained by the discoveries to date.

VI CONCLUSIONS

In setting out the conditions of representative contractual term, a distinction should be made between producing and non-producing countries. However, with the rise of oil prices and the falling curve of new oil discoveries, non-producing developing countries will find oil companies increasingly willing to agree to more favourable terms for the host country. Its final form will be a function of the immediate needs and priorities of both the oil company and the host country.

The determination of the factors to be taken into account in the formulation of exploration contracts and agreements for the 1980s would include the following:

- an exploration period of 4-6 years, with no renewal except at the discretion of the host country. The contract to lapse in the absence of a commercial discovery.

- relinquishment provisions providing for the surrender of 25% of the original area at the end of each 2 years of the contract. This could be accelerated to 50% of the area at the end of 2 years in the case of large exploration areas as in Sudan and Chad.

- a firm work program setting out on a 2-year by 2-year basis the geological and geophysical objectives of the exploration program and spending obligations. The work program, including the drilling obligations to be included in the body of the contract or agreement.

- all exploration costs to be paid by the oil company. In the event of a joint venture, the State oil company to pay for its share of development costs upon commercial discovery or arrange financing by the oil company or outside bodies to be reimbursed over 5 years with interest. In a production-sharing or risk contract, exploration and exploitation cost will be paid by the contractor and recovered out of production.

- minimum State participation of 50%. Higher participation to be tied to higher production levels.

- a management committee with equal representation by both parties with full rights to review and pass on programs.

- royalty rates to be preferably lower than 20% to not penalize marginal discoveries. A sliding-scale royalty beginning at 8% or 10% can be geared to rise to 20% in increments of higher production levels.

- a fiscal regime providing mechanism to share in higher profits resulting from rapidly rising prices, either through special tax or through supplementary payments as a function of price and profitability.

- the right to "farmout" by the oil company, subject to prior approval by the State, should be retained to provide rapid additional financing of exploration or development budgets when required.

- a schedule of bonus payments upon signature, commercial discovery and higher production levels. These should be negotiated separately with each company.

- a detailed listing of the obligations assumed by the oil company in regard to the training and hiring of nationals, including minimum expenditure.

- the priority supplying of the internal market.

- recourse to international expert arbiters in the event of serious disputes not resolved by host country conciliation procedure.

In examining the advantages and disadvantages of the different contractual arrangements, it is difficult to make prior claims as to their suitability and preference. It would appear that the risk contract is the least attractive of the options open to oil companies in that despite assuming all exploration and development risk, remuneration to the company does not include access to crude. The service contract, as developed by Iran, can offer the same degree of control by the State whilst allowing the contractor assured crude supplies. It presupposes large reserves and high production levels which can offset the considerable investments required of the State. Service contracts whereby oil companies are paid a fee for their services and given access to assured supplies of oil at market prices, are becoming increasing prevalent in the established producing countries of the Middle East, such as Kuwait, Saudi Arabia and Qatar, and will set the pattern for the 1980s.

The concession system and production-sharing both offer the necessary flexibility for petroleum operations in developing countries. The concession arrangement, especially where it is legislated, offers a straightforward and well-defined system which can be adapted to any country. The disadvantages of the traditional concession system lay in the perceived view of concessions, particularly between the First and Second World Wars, by the oil companies rather than in any inherent shortcomings of the system. Thus, once joint ventures and other forms of participation were started in the 1950s, the State incorporated into the concession agreements the necessary conditions for its direct involvement in the management and conduct of operations, including work programs, budgets and the training and hiring of nationals. As has been already noted, the basic concession system is used in countries as diverse as Norway and Chad.

The joint venture marriage can be arranged just as well in production-sharing contracts as in concession agreements. The experience of Pertamina appears to have been that the burden of the participation in its share of the costs proved to be too heavy. However, as ownership and control is already formally vested in the State, production-sharing is primarily concerned with the allocation of production between the State and the contractor and tax. Unlike the fixed terms of reference in the concessionary system, production-sharing is a more flexible system where the State can structure the production split on the basis of a theoretical model which would incorporate a fair rate of return for the contractor and a fair share of increased revenue from rising prices to the State. In the final analysis, contractual systems are relevant only in terms of the national requirements of the individual countries and how well these are satisfied. Experience suggests that concession agreements and production-sharing both exhibit the necessary adaptability and flexibility to survive through the 1980s. With time, hybrid systems will also develop incorporating elements of two or more of the established contractual systems.

The assessment of the changing relationship between the multinational oil companies and the developing countries, and their respective roles, is effectively the assessment of the balance between the frequently conflicting demands of the oil company and the host country and the degree of parallelism and "mutuality" of interest that exists, or that can be brought to exist, between the two parties. Thus, whereas the concessionary relationship in Norway has been marked by a wide range of contracts and exchanges of training programs and technology which have been mutually beneficial, the development of the traditional concession system in the Middle East is one in which there has been little parallelism of interests. Until recently, it was marked by confrontation, dispute and nationalisation. They are not in themselves indicative of the strengths and weaknesses of the system, but instead reflect the product of the unequal relationship fostered by the major oil companies and the political realities of big-power intervention in the Middle East between the First and Second World Wars. It is therefore essential, if negotiations between foreign oil companies and the host country are to start on a positive note, that from the outset a partnership of common interests and views be established which can only be achieved if there is on the part of the foreign company a full understanding of the problems and needs of the host country. In order that this sensitivity to the host country's needs be properly communicated, it is necessary that the oil company be represented by an effective spokesman who is equally at home in the host country's economic and political imperatives.

Reconciling the primary objectives of the oil company, which are a commercial return on investment, secure crude supplies and juridical stability, with those of the developing country, which are the assertion of national sovereignty over natural resources, the meeting of internal consumption needs, the maximization of revenue, the rapid development of resources, and the training of technical personnel, can be accomplished on a number of levels. They are most usefully dealt with at company-government and company-national oil company-level programs organized to service those areas in which the government and the national oil company require assistance, with appropriate seminars, conferences and visits by experts. There have been substantive developments in fiscality as a result of such interchanges. The definition of an acceptable fair rate of return which forms the basis of the evolving concept or excess profits has meant the sharing of heretofore "confidential" information. It has been seen earlier in this study that the concessionary system did not preclude the establishment of a climate of mutual trust and frank discussions which led to the agreement of the mini-refinery concept in central Africa. It is the further expansion of this dialogue that provides the best basis for further petroleum relations between multinational oil companies and developing countries.

ANNEX 1

ROYALTY AND TAX

"A State that grants an oil concession to a concessionnaire subjects him to financial obligations other than royalties. There is the cash bonus which is usually a one-time payment. There is surface rent, payable annually, which is assessed on the basis of the area of the concession, and which is deducted from royalty as soon as commercial exploitation begins. And there is, of course, income tax, which derives from the common law fiscal system. It goes without saying that the fact that the concessionnaire pays royalty to the State as Owner of the oil in the ground does not relieve him of the obligation of paying the statutory income tax to the Treasury."[1]

Royalty and tax are calculated either on the basis of realized price or posted price.

Realized price is the actual price at which arms length transaction takes place with third parties. That is to say, it is the actual price realized by the oil company in the sale of one barrel of oil. The realized price as a basis of royalty and tax computation has been discontinued except in those countries with little or no production.

Beginning in the 1950s, royalty and tax began to be paid on the basis of posted price. Posted price can be defined as the price that each company set for the sale of its crude F.O.B. its oil terminal, and was so set as not to disrupt the price of domestic oil sold in the United States on its eastern seaboard. Because of the high productivity of its well and over-production, Middle Eastern oil in the late 1950s became cheaper than U.S. oil, leading the United States to impose import quotas on foreign oil. This had the effect of further weakening of oil prices outside the United States and resulted in a lowering of the posted prices. This fall in posted prices, over which the producing countries had no control, was the main factor leading to the formation of OPEC, the Organization of the Petroleum Exporting Countries, in 1960,

1. Rouhani, p.219

comprised of Iraq, Iran, Kuwait, Saudi Arabia and Venezuela. Thereafter royalty and tax were paid at a posted price agreed with the producing country, which as a rule was higher than the realized price. It thus became a notional price set by the producing country for calculation of tax.

Historically, royalty was either "credited" or "expensed" in computing income tax. In the former case, royalty payment was directly subtracted from the income tax due. In the latter case, the royalty payment was one of the deductible cost items in arriving at taxable income. In 1964, OPEC adopted the expensing of royalties as the basis of computing total tax. Examples 1 and 2 below illustrate each of the basic calculations.

	1. Credited	2. Expensed
Posted Price	$ 2.00	$ 2.00
Costs	0.20	0.20
Royalty at 12½%	-	0.25
Taxable income	1.80	1.55
Tax at 50%	0.90	0.775
Royalty at 12½%	0.25	-
Net tax payable	0.65	0.775
Total Government take per barrel	$ 0.90	$ 1.025
Per cent Government take	50%	66%

ANNEX II

PETROLEUM CHRONOLOGY : 1901-1973

1859	UNITED STATES	First oil well.
1972	IRAN	First petroleum rights granted to Baron Julius de Reuter.
1888	OTTOMAN EMPIRE	Sultan grants mining rights to Deutsche Bank.
1889	IRAN	Second concession awarded to de Reuter, three wells drilled without success, rights cancelled in 1899
1901	IRAN	Concession granted to D'Arcy.
1901	UNITED STATES	Beginning of major U.S. production in Texas.
1908	IRAN	First significant oil discovery is made by D'Arcy.
1913	WORLD OIL	Principal oil producing countries are: U.S. (33 million tons), Russia (8.6), Mexico (3.8), Rumania (1.9), Dutch East Indies (1.6), Burma and India (1.1), Poland (1.1).
1913-1914	PERSIAN GULF	Great Britain gains exclusive oil rights for British subjects in Kuwait, Bahrain, the Trucial Coast emirates and Oman. Rulers of Saudi Arabia and Qatar agree to grant concessions to foreign subjects after British approval.
1914	IRAN	British Government acquired 51% of Anglo-Persian, successor to the D'Arcy concession.
1914	IRAQ	Anglo-Persian, Deutsche Bank, Royal Dutch-Shell and Gulbenkian establish Turkish Petroleum Company and agree to explore jointly the vilayets of Baghdad and Mosul. World War I prevented implementation of the agreement.
1914-1919	WORLD WAR I	Emergence of oil as a matter of supreme strategic importance to the industrialized West. Entrance of American oil companies in international exploration.
1920	IRAN	"Interpretive" agreement signed with Anglo-Persian. Payment of £1,000,000 to Persia, excluded some downstream operations in the calculation of profits.
1920	IRAQ	American Government and oil companies begin to seek participation rights with TPC which were not formalized until 1925. Britain and France sign the San Remo Agreement, by which France obtained a 25% interest formerly held by German interests in TPC.

1920	MIDDLE EAST	Middle East oil production is about 1% of total world production of 94 million tons.
1922	VENEZUELA	Major oil discovery made.
1923	IRAN	Agreement signed with Sinclair for north Persia provides 50% of profits to Persia, but Sinclair withdraws in 1925.
1925	BAHRAIN	Concession awarded to the Eastern and General Syndicate.
1925	IRAQ	Concession awarded to TPC including six American companies, covering all of Iraq except the Basra vilayet.
1927	BAHRAIN	Gulf acquires rights of Eastern and General.
1927	IRAQ	Oil discovered at Kirkuk by TPC.
1928	BAHRAIN	Standard of California (BAPCO) acquires rights of Gulf.
1928	MIDDLE EAST	TPC members sign Red Line Agreement, agreeing not to compete in Iraq or Arabian Peninsula, Kuwait excepted.
1931	IRAQ	IPC (formerly TPC) agrees new concession terms: plot system dropped, area reduced, Mediterranean pipeline project.
1932	BAHRAIN	Major oil discovery made by Standard of California.
1932	IRAQ	Mosul concession awarded to British Oil Development, providing Government with 20% of all production.
1933	IRAN	Anglo-Persian concession renegotiated and named Anglo-Iranian Oil Company: extended duration, reduced area, fiscal adjustments, training of nationals.
1933	SAUDI ARABIA	Concession awarded to Standard of California, later to be part of the Aramco group.
1934	BAHRAIN	Concession awarded to BAPCO (Standard of California).
1934	IRAQ	Pipeline to the Mediterranean is completed.
1934	KUWAIT	Concession awarded to Kuwait Oil Company (Anglo-Persian and Gulf).
1935	BAHRAIN	Texaco acquires 50% of BAPCO.
1935	QUATAR	Concession awarded to Anglo-Persian.

1936	SAUDI ARABIA	Texaco acquires half of Standard of California's interest.
1937	IRAQ	IPC acquires British Oil Development and forms Mosul Petroleum Company to operate former B.O.D. concession.
1938	KUWAIT	Major oil discovery made by KOC.
1938	SAUDI ARABIA	Major oil discovery made by Aramco.
1938	WORLD OIL	Main oil-producing countries: U.S. (162 million tons), Venezuela (28), Iran (10), Mexico (6), Iraq (4).
1939	QATAR	Major oil discovery made by IPC.
1939	IRAQ	Oil discovery made in Mosul concession.
1939	SAUDI ARABIA	Aramco concession area expanded to include additional 125,000 square miles.
1939	SAUDI ARABIA	Supplemental Agreement: concession area enlarged, term extended.
1942	VENEZUELA	Enacts income tax on foreign petroleum companies.
1945	OIL WORLD	Oil industry benefits from expansion of industrialized economies, including petrochemicals. Need for increased production. High per barrel profitability in post-war years. New independence of producing nations. Entrance of smaller "independent" oil companies.
1947	SAUDI ARABIA	Standard of New Jersey and Mobil acquire interest in Aramco.
1948	KUWAIT	Neutral Zone concession awarded to Aminoil.
1948	MIDDLE EAST	First Arab-Israeli war, State of Israel is established.
1948	MIDDLE EAST	Red Line Agreement is terminated by the companies involved.
1948	UNITED STATES	U.S. becomes a net importer of petroleum.
1948	VENEZUELA	Income tax law enacted with 50/50 profit-sharing principle.
1949	IRAN	Anglo-Iranian agreement is revised: royalty increased, income guarantee to Iran, £5 million payment.

1949	SAUDI ARABIA	Neutral Zone concession granted to Getty permitting taxation of company to the extent that such taxes can be credited against taxes to any other government.
1949	WORLD OIL	World Oil production is 475 million tons, Middle East is 70 million tons.
1950	PERSIAN GULF	Production exceeds Venezuelan production for the first time.
1950	SAUDI ARABIA	First Middle East income tax enacted: 50% of "net operating income", with limitation on all payments of 50% of gross income minus operating costs and depreciation. Other producing nations enact income tax legislation by 1952 including posted price, with the exception of Iran.
1951	IRAN	Government nationalizes Anglo-Iranian Oil Company, and forms the National Iranian Oil Company. Iran signs agreement with Consortium ending nationalization.
1955	ALGERIA	Major oil discovery made by CFP.
1955	LIBYA	New petroleum law for foreign investment.
1956	MIDDLE EAST	Israel/France/Britain attack Egypt.
1957	IRAN	NIOC and ENI sign SIRIP agreement, first "joint venture" with 75/25 profit-sharing.
1957	NEUTRAL ZONE	Japanese group acquires offshore concession, including participation for Kuwait and Saudi Arabia and share of downstream profits.
1957	UNITED STATES	Government establishes voluntary import controls.
1958	IRAN	Amoco and NIOC sign first private company joint venture agreement.
1959	ARAB WORLD	First Arab Petroleum Congress meets in Vienna.
1959	UNITED STATES	Government imposes compulsory import controls.
1960	INDONESIA	Kobayashi and Pertamina sign first production-sharing type contract.
1960	KUWAIT	Shell signs offshore agreement: first major company to accept host government partnership.
1960	OPEC	Iran, Iraq, Kuwait, Saudi Arabia and Venezuela form OPEC.
1961	IRAQ	Government enacts Law No. 80 forcing 99.5% IPC relinquishment.

1961	LIBYA	First production begins. Petroleum law modified regarding relinquishment, depletion allowance, posted prices.
1961	NETHERLANDS	Government agrees with NAM on 40% state participation option on gas fields.
1962	SAUDI ARABIA	Formation of Petromin.
1962-1963	INDONESIA	Old concessions revised to provide 60/40 profit split.
1963	SAUDI ARABIA	Aramco agrees to base payments on Sidon posted price less transportation costs.
1964	CONTRACTS	Most governments and companies adopt OPEC decision that royalty be treated as an expense item and not credited against income tax.
1964	UNITED KINGDOM	First North Sea blocks awarded.
1965	ALGERIA	Accord Petrolier signed between Algeria and France.
1965	LIBYA	Petroleum law modified regarding expensed royalties, postings, discounts.
1965	NORWAY	First offshore blocks awarded.
1965	SAUDI ARABIA	Petromin signs joint venture agreement with AUXIRAP providing 40% interest to Petromin upon commercial discovery.
1965	WORLD OIL	World oil production is 1,500 million tons Middle East is 500 million tons.
1966	IRAN	First "service contract" signed between ERAP and NIOC.
1966	INDONESIA	First definitive production-sharing contract signed with IIAPCO.
1967	INDONESIA	Production sharing contract signed with Conoco, clearing way for major oil company participation in Indonesia.
1967	MIDDLE EAST	Arab-Israeli war, Suez Canal closed.
1967	NIGERIA	Civil war breaks out, output falls from 570,000 B/D to 60,000 B/D.
1968	NETHERLANDS	Netherlands awards North Sea blocks. (April)
1968	PERU	Peru and Exxon reach agreement whereby all subsoil and surface rights are transferred to state oil company in return for which Peru drops claim for "outstanding debts" of $144 million. (August)

1968	PERU	A new regime declares the Peruvian settlement with Exxon null and void and nationalizes Exxon's assets declaring at the same time that Exxon owes $690 million in outstanding debts.	(November)
1969	NORWAY	Norway awards second round blocks.	(May)
1969	LIBYA	Libyan monarchy replaced by Revolutionary Command Council.	(September)
1969	NIGERIA	Nigerian Civil War ends. Production which had slowly increased during the war to about 500,000 B/D doubles to 1 million B/D.	(October)
1969	BOLIVIA	Gulf Oil assets nationalized by Bolivia.	(October)
1970	SYRIA	Tapline carrying 475,000 B/D of oil from Saudi Arabia to the Eastern Mediterranean is shut down by Syria.	(May)
1970	LIBYA	Libya cuts Occidental's production from 800,000 B/D to 500,000 B/D, Amoseas production cut back by 100,000 B/D and Oasis production by 150,000 B/D.	(June-July)
1970	ALGERIA	Algeria unilaterally raises posted prices on crude exported by CFP and ERAP following breakdown of posted price discussions.	(July)
1970	UNITED KINGDOM	U.K. awards second round blocks.	(August)
1970	VENEZUELA	Venezuelan Congress passes law creating "service contracts". Terms call for 80% relinquishment after 3 years, 20% carried interest for CVP and 10% crude offtake right for CVP.	(August)
1970	EGYPT	Death of President Nasser of Egypt.	(September)
1970	IRAN	Iran increases tax rate from 50% to 55%. Other Persian Gulf producing countries follow suit.	(November)
1970	NORWAY	Oil discovered in Norway.	(December)
1970	VENEZUELA	Venezuela raises tax rate to 60% and declares the right to raise posted prices unilaterally.	(December)
1970	OPEC	At Venezuelan urging, OPEC conference in Caracas decides to pursue uniformly higher postings, starting with an increase in the Persian Gulf.	(December)
1971	SYRIA	Syria allows Tapline to reopen following an agreement for increased tariffs to Syria and Lebanon.	(January)

1973	IRAN	Iran declares it cannot continue the existing consortium arrangement past 1979 and demands full participation by 1973.	(January)
1973	LIBYA	Oasis offers Libya a Persian Gulf type participation settlement.	(February)
1973	IRAN	Iran and Consortium representatives agree on new arrangement on pattern of service contracts.	(February)
1973	SAUDI ARABIA	Saudi Arabia warns U.S. of its policy of support toward Israel.	(April)
1973	NIGERIA	Shell and BP accept 35% participation by Nigeria.	(May)
1973	OPEC	New agreement to protect OPEC postings against currency fluctuations.	(June)
1973	LIBYA	Libya nationalizes Bunker Hunt, the remaining half of the original BP-Bunker Hunt concession.	(June)
1973	KUWAIT	Kuwait asks for renegotiation of participation agreement, the Kuwaiti assembly never having ratified the agreement signed on January 8.	(June)
1973	IRAN	Iranian agreement with consortium ratified in detail by Majlis, the Iranian Parliament.	(July)
1973	LIBYA	Occidental agrees to 51% Libya participation demand with buy back, followed by Oasis with exception of Shell, follows suit.	(August)
1973	ECUADOR	Ecuador and Texaco/Gulf reach model agreement whereby Ecuador may buy 25% of operation by 1977, and may lift up to 51% of oil produced.	(August)
1973	NORWAY	Blocks awarded in Norway in which Statfjord, the largest North Sea oil field, was later to be discovered.	(August)
1973	OPEC	OPEC calls for higher posted prices and revision of 1971 Tehran agreement.	(September)
1973	MIDDLE EAST	New Arab-Israeli war. Arab oil cut-backs of 5% to 10% and an embargo on oil to the U.S. Iraq nationalizes Mobil and Exxon.	(October)

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