The Policy, Fiscal and Legal aspects relating to Oil Exploration in South Africa

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ERNEST BOSWARVA

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SUMMARY

This thesis is a textual analysis of the fiscal and legal aspects relating to the exploration and exploitation for oil and gas. The need for promotion of the exploration and exploitation of oil and gas and the fiscal and legal aspects relating thereto. The different types of legal agreements commonly found in transactions between the State and the private international investor are cited as are the implications of the different types of taxes levied by the State in order to collect its 'take' in the national resource. The method of taxation of oil in South Africa is examined with special reference to the prospecting lease OP26 granted by the State to SOEKOR (Pty) Limited.

- CHAPTER I -

This chapter considers those matters which a country needs to consider in establishing its general petroleum policy. In doing so, the country needs to take cognisance of e.g. the countries prospectivity, technical competence and impact on the environment.

1. General Petroleum Policy

The countries political and future goals normally form the basis for the choice of framework of petroleum policy. Setting these initial objectives is inherently difficult as one does not know the potential at the outset. Before any country can decide the way it should organise its energy sector it must establish the objectives of this sector. Before setting up objectives, there are individual premises that are present in each country that have to be considered. Such premises include:

- Political conditions
- Economic / legal conditions
- Administrative conditions
- Technical competence

The internal energy situation must also be considered. This includes the geological prospectivity, energy balance and general energy policy within the country.

After having identified these premises, the country must set up certain objectives for the petroleum sector. Examples of such objectives are that the petroleum sector shall:

- Contribute to State income
- Contribute to energy supply
- Contribute to increased national technical and administrative competence

Concommitant considerations would include:

- Macro-economic effects
- Regional effects
- Impact of petroleum activity on environment

There are certain mechanisms that are available to assist in achieving the stated objectives. The most important of which are:

- Fiscal terms
- Legal framework
- International participation
- Contractual framework
- National / State participation

Risks associated with exploration and production can be significant but so too the rewards. The fiscal terms are, therefore, very important for maximisation of the state income and at the same time must ensure acceptable returns to the international investor.

The fiscal terms are dependent on which contractual framework is selected. The typical taxes / provisions in the petroleum agreements include:

- Corporate Tax
- Petroleum Tax
- Royalty
- Ring fencing rules

The matter of depreciation and 'uplift' is of special importance, especially when it comes to offshore production where the investments are very high.

Other economic factors relevant in the governmental income are:

- Carrying of State company in the exploration phase
- Division between private and state oil company on profit oil
- Price of oil in risk contracts
- Rental Charges / Area fees

2. Legal Framework

A contractual framework as opposed to a legal framework consists of a less extensive petroleum act with more emphasis being placed on agreements with the government. (See Chapter III for greater detail). Under this kind of system, the law does not regulate the petroleum activity in detail, but provides wide authorisation to enter into contracts. This system gives the authorities the possibility of changing both content and conditions to changing political objectives, without the need to change the petroleum act that may have been too inflexible to the changing circumstances. This sort of framework provides the petroleum industry with a flexible system allowing changes to be introduced easily and expeditiously.

A contractual system also offers the possibility of including different elements in different licenses variable in time, or in prospectivity of the acreage, as it permits negotiation between the authorities and the licensees.

An extensive legal framework on the other hand will be more predictable to the participants, as it assumes a more thoroughly regulated petroleum act, and will also be able to prevent arbitrariness and differential treatment.

3. **International Participation (Investment Finance)**

Amongst other things, energy project finance is concerned with the development of oil and gas resources, including extraction, movement, refining and other forms of processing. Energy Project Finance is a tried and tested method of financing oil and gas projects in the developed world. The techniques are increasingly being applied in other parts of the world, such as Asia, Africa and, to a more limited extent, the new independent states of the former Soviet Union. In such countries, not only are the techniques unfamiliar to host governments, but the risks are greater. In many of these countries the legal system is developing, often from an unsophisticated base, and political risks are perceived to be higher.

Two Critical Factors

Countries choose to develop their oil and gas resources using the project techniques of the private sector, as opposed to developing the resources in the public sector, for two key reasons.

An exploration and development programme may cost hundreds of millions of dollars for a discovery of any significance. Many countries are not able to afford such costs and may in any event not have the technological sophistication to conduct an exploration and development programme without foreign assistance. Thus, foreign oil companies are invited to participate in exploration and/or production, possibly by way of a joint venture with the state oil company.

Risks associated with exploration and production can be significant. Countries with little or no gross national product may be reluctant to gamble their limited financial reserves on a high risk venture. Further, some rich countries also do not wish to assume a high level risk. Such is the case with the UK, for example, which has developed a highly regulated regime to

protect the nation's interests while the oil companies operate at their own risk and expense.

How are the factors balanced

The host nation balances these factors by inviting foreign oil companies to participate. A Petroleum Exploration and Exploitation Agreement is entered into between the foreign oil company and the host nation.

Three principal types of agreement are commonly used:

- Concession Agreement
- Production Sharing Agreement
- Risk Service Contract

However, hybrids are sometimes seen. Pakistan uses a Production Sharing Agreement but with royalty and tax provisions normally thought of a being characteristic of a Concession Agreement.

Conflicting Interests

When negotiating the Exploration and Exploitation Agreement, the interests of the foreign oil company and the host nation can differ.

The objectives of the oil company may include:

- a desire to maximise its profits;
- a desire to receive high return on its investment as quickly as possible; and
- a high degree of autonomy over the operation of the project.

On the other hand, the aims of the host government may include:

- seeking to ensure a comprehensive and efficient exploration programme;

- maximising profits received by the host government;
- asserting as much control as possible over operational activity;
- maximising the benefit to the host country, for example by training of local personnel; and
- procuring irrevocable transfers of technology to boost the industrial base of the host country.

4. **Contractual Framework**

Each type of exploration and exploitation agreement has its own characteristics, advantages and disadvantages.

1. **The Concession Agreement** (also known as the Permit Licence or Lease) give the exclusive right to explore and develop petroleum and the agreed area.

It has the advantage that the oil company will acquire rights which may, depending on the jurisdiction, be of a proprietary rather than merely of a contractual nature. This may provide extra protection should it ever prove necessary to go to court over the Agreement

2. It has the disadvantage that all operations will be at the sole risk of the Company. Payments from the oil company will include:

- rentals on the area of the concessions;
- royalties (in cash or kind, often depending upon the election of the host government); and/or
- tax

2. **A Production Sharing Agreement** differs from a Concession Agreement in certain ways.

It has the disadvantage that the legal right to explore and exploit the oil will be vested in a national oil company or

retained by the host government. It is not, as is the case with a Concession Agreement, conferred on the oil company.

As with a Concession, the oil company takes the risk of oil not being discovered. However, the oil company is remunerated in a different way. No rent is payable and the contractor, as well as being allowed to recover costs, takes a portion of the oil as its profit.

3. **Risk Service Contract** is similar to a Production Sharing Agreement but the oil company generally recovers both expenses and profit in the form of cash rather than oil. Sometimes the oil company is given the option of purchasing a proportion of the production at an agreed price as it s profit.

Which Contract

The essential differences between the three types of contract are to be found in:

1. The legal nature of the interest held by the oil company; and
2. Remuneration.

With a Concession the oil company has a right which may place it in a stronger position in the host country. In all three types of contract the oil company bears the risk of oil not being discovered, but it can be rewarded in one of three ways:

- by taking all the oil but paying sums to the host government as rent, tax and/or royalties (as in the Concession Agreement);- being paid costs and fixed profit in cash, possibly with the option of taking the profit in the form of oil (as in the Risk Service contract).

The choice of agreement will largely depend on the attitude of the host government to its natural resources. A Production Sharing Agreement or Risk Service Contract is particularly likely to be chosen

if the host government is strongly protective of its natural resources.

4. Aspects of License Negotiation

Before allocation of license or contracts, the authorities have to decide the size of each license or contracts. The size of licenses varies considerably around the world. The English licenses consist usually of one block which is about 250 square kilometres, while in Africa, a license may be 5000-10000 square kilometres or even more.

There are advantages and disadvantages with both small and large licenses. The main advantages of large licenses are that;

- They give the licensee more freedom and therefore very attractive to the companies if the geological potential is uncertain.

- Planning of development is easier.

On the other hand the advantages of smaller licenses are:

- They give the authorities more influence and flexibility. This is especially important in a more mature area like the North Sea.

- In mature areas with smaller licenses, the spread of information will usually be easier, and ideas for new exploration models will emerge much quicker.

Some of the same arguments can be made with regard to the question of the length of concessions or contracts. Longer terms give the licensees more freedom, but less control for the authorities.

The licenses may be given for both exploration and production as it is done in Norway, or the host country can choose to give one license for exploration and a separate license for the

development and production period. The advantage with one license is that it leads to automatic relinquishment at the end of the exploration period of all acreage not converted into a production license. The main advantage of only one license is that the licensees will have the right to exploit this.

The allocation of blocks or areas, can take place in rounds, through separate announcement and allocation of one block or area, or by allocating licenses whenever the companies apply for them. This third option is for obvious reasons applicable only in less attractive areas.

The two main systems for allocation of licensees are the discretionary system which can be divided into group applications and company by company applications and the auction system.

The discretionary system implies that the host country's authorities allocate licenses after applications from the companies and following negotiations.

The negotiating part of this system may include several issues, such as work program, fixed increased interest or sliding scales in bonuses.

The auction system implies, as the name indicates, that the company or group of companies that offers the highest price gets the area. The host country usually uses a pre-qualification system to limit the number of bidders.

The main advantages of the discretionary system, is that it secures direct control for the government, for instance to allocate licenses to companies from several different countries, and also to give credit to companies that for example contribute to the strengthening of the host country's economy. It also encourages exploration of what is thought to be less attractive areas more than the auction system. The

discretionary system thus makes it easier to ensure national preferences.

The main disadvantage is that it "gives away" the best areas at the same price as the less attractive areas. There are however other ways to "increase the price" of an attractive area than the auction system, the sliding scale probably being the most obvious way.

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- CHAPTER II -

This chapter examines the need for oil importing developing countries to promote oil exploration activity in their regions and mentions those factors necessary to achieve this.

PROMOTION OF OIL EXPLORATION IN SOUTH AFRICA

1. Introduction

At the present time there is no shortage of oil. Despite this apparent abundance of oil, the world reserves are being depleted faster than they are being found. Oil consumption began barely one hundred years ago and despite world wide exploration efforts we are already approaching the point where known oil is half gone.

Moreover the large consumers are rapidly depleting their domestic resources. Known reserves in the USA, USSR, and most European countries will be largely depleted by the end of this century. This grim outlook is offset by the huge reserves in the OPEC countries, particularly in the Middle East, which hold more reserves than the rest of the world together.

The industrialised countries rely on oil and gas for 65% of their total energy consumption. Unless oil is continuously discovered, it is quite possible that oil shortages will occur not many years from now, and in the long term, scarcity and high prices seem inevitable.

In this perspective one would expect petroleum exploration to promote itself. However, from a South African perspective the question is how to achieve this. South Africa can readily be described as an oil developing country (OIDC). On a more macro scale one could argue for the need to divert oil exploration activity to all OIDCs. Some 100 OIDCs represent about 40% of the world population, but account for only 10% of the world oil consumption of which most must be imported .

In South Africa this figure has as a result of the secrecy laws surrounding inter-alia crude oil imports not been easy to determine but would represent a significant percentage of our imports. Indigenous production from Sasol accounts for approximately 45% of local consumption. Mossgas at full production will add approximately another 7%.

This does not necessarily mean that the OIDC's have poor petroleum potential. More often it means that they are under explored, (this statement is not necessarily true for South Africa which has had a relatively active program of exploration both on and offshore primarily through Soekor (Pty) Ltd, a wholly owned company of the State). The intensification of exploration in developed countries which started after the oil crisis in 1973, has so far only had a scattered impact in the OIDCs, and particularly little in the yet non producing countries.

2. National Exploration Incentive

The incentive for a state to undertake petroleum exploration will vary from country to country. Oil and gas make up only 10% total energy consumed in SADCC (South African Development Co-ordination Conference) where traditional fuels like wood and charcoal dominate the picture. In the industrialised countries the oil and gas share is around 65%.

Conservation and alternative energy development is not likely to change the role of petroleum as the predominant source of energy of the commercial sector; development means increasing demand for oil products.

Most analysts believe that throughout this century petroleum demand will grow more rapidly in the developing countries than in the industrialised world. Indeed, access to convenient forms of energy at affordable prices is a prerequisite for economic development. Many developing countries import all their petroleum. The rise in real price for oil over the last 15 years has lead to a sizeable increase in the oil import bills, and a corresponding drain of foreign exchange earnings in these countries. The price drop in 1986 changed this situation for the better, but the petroleum bill is still a constraint for development. In the SADCC countries for example, oil imports consume an average of 20% of the foreign exchange earnings, with individual countries spending more than 50% of the export earnings on petroleum product import. With a medium to long term expectation of significant price increases for oil, the situation is serious. It is widely accepted, therefore, that increasing indigenous supplies of petroleum in the OIDCs is an imperative goal. It may be the only way for some countries to reduce their financial deficits without slowing down their economic growth. Oil exploration, therefore, needs to be intensified without slowing down their economic growth.

Most of the exploration activity however takes place outside the OIDC's.

Lack of potential is in general not the reason for low exploration activity in the OIDCs. Indeed in the late 1960's through to today the real reason for the lack of interest in South Africa has been political uncertainty surrounding any investment. However, from the results achieved after 20 years of prospecting by Soekor, the prospectivity of the area as a whole must be in some doubt.

It should be noted, that many OIDCs have a comparatively low consumption, and one single discovery may make them net exporters. This total consumption of the SADCC countries for example is less than the output of the recently discovered Palanca/Pacassa field in Angola.

The host country will therefore consider petroleum development as a foreign exchange earner beyond the domestic energy demand. Petroleum activity, when properly controlled, will also have a positive effect on other national sectors such as employment, transport and communication, training and education, trade and general infrastructure development.

3. National Sovereignty

State sovereignty over national resources is an established doctrine of international law. It is imperative that the State realise this valuable asset. Control can be exercised by a strong technically skilled State company or through transnationals - the latter course of action, however, should not result in abdication on the part of the State. Historically the transnational oil companies have had the leading initiative in the search for petroleum.

Some countries which opted for complete and exclusive State control in the outset, have later decided to open for participation of foreign companies. These companies' risk capital and technology is a positive supplement to the national effort to locate and develop petroleum resources.

Considering the importance of increasing exploration in the OIDCs, and the vast unexplored areas in many of these countries, co-operation with the international oil industry seem to be appropriate. The question then is how to achieve maximum public revenue and maintain control with the oil company participation. Recognising that the objectives of the State and those of the oil companies are not necessarily the same, the common goal to discover and develop petroleum resources should be a sufficient base for a long term partnership. Appropriate legislation and petroleum agreements will serve to maintain sovereignty over the resources.

4. Exploration Promotion

Assuming that international oil company participation is wanted in the national petroleum resources development, exploration promotion may be defined as an effort to attract commercial exploration on acceptable terms. The host country will require effective exploration of all prospective areas. Promotion may, therefore, be necessary also for countries with existing production.

Individual countries will compete to attract a finite amount of exploration dollars. Up to now the oil importing developing countries have lost in this competition even if their geological potential appears to be attractive.

5. Oil Company Exploration Incentive

The incentive for international oil companies to invest in petroleum exploration is in principle very simple. An investment is analysed in terms of rate return to the company. The return on investment over its life should equal or better the average cost of capital.

Underlying the rate of return analyses is the assumption that there are alternative exploration investments competing for the limited financial resources of the company. These resources are allocated to the investment yielding the highest rate of return for their perceived risk level.

The principal investment criteria are, however, highest return and least risk. Risk has many facets, e.g. geological risk and political risk.

6. Determining Factors in Exploration Investment

When an oil company is looking to make up a portfolio of exploration ventures, regard is had to several key questions namely;

- How promising is the geological prospect?
- What constitutes the legal and fiscal regime?
- How developed is the infrastructure?
- What is the political risk?

Geological Prospectivity

The occurrence of petroleum is linked to the deep sedimentary basins. Commercial accumulations require adequate source beds, reservoirs, and structure for entrapment and accumulation. Oil and gas, as other natural resources, have a very uneven distribution around the world, and the quantity of undiscovered oil remains an uncertain estimate. It is in this environment of risk and uncertainty that exploration investment decisions are made. Geological risk declines with increasing knowledge of a basin. Existing production in the same basin, or seismic data which demonstrate prospectivity, will greatly reduce geological risk. The expected size distribution of discoveries is also likely to influence activity level.

Exploration cost per barrel declines as field sizes increases, and investments are likely to be greater in areas with potentially large fields.

Today most countries recognise the advantage of a resource assessment before commercial licensing of a given area. In this way geological risk and the number of unknowns about exploration potential may be reduced.

Legal and Fiscal Regime

Another risk factor is the price of oil and the price of alternative fuels. The oil companies will expect the reward of investment, to at least match the risk involved.

The allocation of risk in exploration investment between the host government and the oil company is governed by the tax regime and the petroleum contract. The taxation schemes in most developing countries include signature bonuses, royalties and profit taxes. The two former parts, signature bonuses and royalties tend to allocate most of the risk to the company, because they come into effect considerably before the company starts making a profit. Profit taxes which are determined not by revenue but by profit, tend to result in greater risk sharing.

A tax scheme which involves higher tax rates of the oil company's profit when the rate of return exceeds a specific level has become common. Such tax systems allow the host government to capture windfall profits without greatly distorting the oil company's incentive to explore for both large and small fields. This last element is important as the majority of the petroleum resources will be found in small deposits which will in part be costly to develop.

Model Contracts

There are a number of contract types in effect in the developing countries:

- Concessions
- Production sharing contract
- Risk - or non risk service contracts
- Joint Ventures

These contracts represent varying systems for the allocation of risk and reward of an exploration project, and determine the distribution of operational and management responsibility between the oil company and the government. See chapter III for an analysis of the different types of agreements.

Over the last two decades the developing countries have shifted from the reliance on concessions to production sharing contracts. The service contracts are mainly restricted to countries with existing production or proven reserves. The recent trend is for greater government participation in petroleum investment activity in the developing countries. Governments now seem to be ready to assume more risk, and participate more actively in management and operations of petroleum development activities. This can only serve to increase exploration activity.

Infrastructure

A lack of infrastructure in terms of harbours, roads, railways, pipelines, communication systems and general supply may reduce the incentive to explore in otherwise geologically attractive areas. This is a common problem in many developing countries, and is indeed not limited to petroleum investment. In an effort to promote exploration

activity certain critical public sector investments may be required. In this regard South Africa is very well served.

Political Risk

Political risk is difficult to define in as much as it is perceived differently by different companies. It reflects the uncertainty that the business environment may change due to political events. At present South African political risk is high and hopefully will reduce after the general elections scheduled for next year.

In terms of promotion there is little one can do about this investment criteria. It is important, however, that contracts and negotiations with the oil companies have broad political support, as they may result in long term business relationships of critical importance to both the State and the company.

7. National Preparations for Commercial Exploration

As shown, there are a variety of factors which determine whether or not the oil companies will invest in exploration. To effectively compete for the limited risk capital available, and to obtain exploration investment on acceptable terms, the country needs to be well prepared. The preparations should be performed in parallel in two main activity areas:

- Resource assessment
- Institutional development

The exploration terms, the size and scope of the national organisation, and the financial and economic scenarios all depend on the undiscovered oil in the ground. The natural starting point therefore, is the resource assessment. In countries where exploration has been going on for some time, the assessment may be based on existing data. In previously unexplored areas, the host country is well advised to do geophysical- and geological reconnaissance

surveys prior to licensing. The geophysical work may include gravity measurements, aeromagnetic- and regional seismic surveys. In onshore basins the geophysical work will be complemented by geological field mapping and sampling. In the event that the composition of the sedimentary rock sequence is unknown or disputed, stratigraphic wells in key locations may be considered.

All available data should go into the resources evaluation, which will give an indication of the hydrocarbon potential of the respective basins:

- Has oil been generated?
- What are the realistic play concepts?
- Where are the prospective trends?
- What may be the nature and the potential size range of the accumulations?
- What is the relative ranking of the prospective areas?

It is worth noting that geological provinces and sedimentary basins are often shared between two or more countries. The most effective evaluation of such basins may be done through exchange of data and regional co-operation.

The resource evaluation is a critical input in defining an exploration strategy:

- What is the appropriate size of the licence areas?
- What work obligations should apply?
- What may be the appropriate licensing schedule?
- Operational and environmental considerations.
- Appropriate level of government participation.

Just as the resource evaluation may form basis for the government's strategic planning, it may constitute the basis for the oil companies analysis of possible exploration investment. In the past, host governments were mostly at a disadvantage in the negotiations with oil companies, because the companies knew more about the resource potential.

Today this is changing, and ideally the government agency which controls all available data, should have a leading role in the evaluation of national resources. They are thereby in a better position to promote activity.

On the institutional side, the terms of the model agreement need to be matched to the apparent prospectivity and geological risk as received after the resource assessment.

In accordance with the expected level of activity, the government will develop appropriate organisations and administrative systems to look after its interests. In a promotion context, a good data base and data retrieval systems are imperative.

8. The Mechanism of Promotion

Exploration terms will in most cases be determined beforehand through the Petroleum Law and Model Agreement. The key issue in the promotion campaign therefore, is to demonstrate the geological promise of the areas offered for licensing and to show that it is worth the price. This may be done through the preparation of an evaluation report.

The oil companies are very professional and the interpretations and evaluation offered must be equally professional. At the same time the underlying raw data must be available for control and independent interpretations by the companies. This may be done by preparing data packages and offering them for sale to the

oil companies. This is a mechanism frequently used to recover cost of data acquisition.

The promotion reports, however, should not be given a price that discourages interested companies to have a first look at the exploration potential. Ideally the promotion campaign should not be prohibited by a requirement to make money in the process. This has often proved to be counterproductive.

Before addressing the industry, the following items should be prepared in a presentable form:

- Relevant legislation
- Model agreement
- Listing and price schedule for available data
- A technical evaluation report
- Definition of areas offered for licensing
- A time schedule of licensing
- A review of infrastructure, political, and institutional issues as required.

The way of addressing the industry may vary. The more attractive countries may prepare joint presentations to the industry in key locations such as London and Houston. More important are the bilateral follow up meetings after these presentations. Those countries who do not have professionals who may enter into concrete discussions with the oil companies, technically or otherwise, should contract such services during the promotion campaign.

Conveying your message to an audience of oil companies scattered around the world, is a practical problem. One method is to give the promotion brochures and technical reports a large circulation. Promotion articles may also be filed with the large periodicals.

Promotion, however, is not a one time exercise. Once the hydrocarbon potential has been established and made known, companies may visit at any time according to their internal strategies. The host countries should have resources available internally or by external arrangement, to discuss technical or contractual issues as required on such occasions.

9. Financial Considerations

Exploration promotion in the wider sense include all national efforts to prepare for and attract investment in exploration. It is quite common to experience what may be called 'thresholds' in exploration activity; points where commercial investment halts, and a national effort is required to prove new incentives. Effective promotion may therefore require substantial human and financial resources. Seismic for example, which is the key tool in exploration, will cost in the range of 1.000 USD per kilometre offshore and 10.000 USD per kilometre onshore, including processing. Even a reconnaissance coverage may therefore amount to many millions of dollars.

Integrated basin studies and resource assessments require the joint effort of geologists geophysicists, geochemists and stratigraphers, often with a high degree of specialisation.

10. Conclusion

As the petroleum resources in parts of North America and Europe are being depleted, operators in this areas have started to look for new investment opportunities elsewhere. Possible future increases in the real price for petroleum, will give further incentive to explore new areas.

A large share of the oil to be discovered in the future exists in developing countries. With proper preparation in terms of resource assessment to demonstrate the

hydrocarbon potential and institutional framework, to facilitate petroleum exploration and development, the oil companies will be attracted to these areas.

The burden of petroleum imports represent a major constraint for development in the oil importing developing countries. It is essential that those countries with a domestic potential including South Africa recognize this opportunity and set about realising it as soon as possible.

Although the results of SOEKOR's efforts have proved thus far to be discouraging its activity should not be entirely stopped. Progress at a reduced level of investment should be considered with a promotional campaign as set out above being vigorously pursued.

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- CHAPTER III -

This chapter cursorily examines the various types of oil agreements found in oil exploration transactions.

TYPES OF MAJOR PETROLEUM ARRANGEMENTS

Despite the wide diversity of international usage, all arrangements may be classified into a half-dozen systems.

Types of Petroleum Arrangements

Petroleum arrangements fall into the following:

1. **Concession**

   The concession is generally known as a 'Permit', 'License' or 'Lease'. It is the oldest and still most widely used petroleum agreement.

2. **Production Sharing Contract**

   This concept originated in the early 1960's and is increasingly used around the world.

3. **Risk Service Contract**

   This is a relatively new concept. Its first appearance was during the 1970's.

4. **Service Contract**

   This is an old form of petroleum arrangement which is used principally for risk-free operations and, therefore, is of lesser importance in exploration.

5. **Joint Venture**

Overlying all these arrangements is the joint venture. The joint venture is not a type of petroleum arrangement but only a partnership between a company having a concession or contract and another company (frequently a government company) by which they agree to jointly operate the venture. They do this under their agreed partnership rules, the 'operating agreement.' Such a joint venture and operating agreement exists between the State owned oil company, SOEKOR (Pty) Ltd and Engen Ltd a South African company listed on the Johannesburg Stock Exchange.

6. **Nationalisation**

As a final category in the types of world petroleum arrangements there is the option of complete nationalisation of the domestic petroleum industry and its operations by the national government without participation by international companies. In many instances, however, it has been necessary to enter into petroleum concessions or contracts with international companies following nationalisation in order to have access to their expertise or for financial reasons.

The basic aspects of a petroleum arrangement between an international company (be it public of private) and a government are:

1. **Risk & Financing**

It is common to all forms of petroleum agreements to place the risk on the international company. As professional risk-takers, international oil companies are willing to provide financial and technical resources for exploration and to assume the risk of failure. They expect to receive, in the event of success, compensation in the form of recovery of their initial investment, and profit in cash or in oil and gas.

2. **Economic Return (Profit)**

In the event of success, the international partner expects to earn a profit commensurate with risk. The same economic return can be achieved through the use of concession, production sharing contract, or risk service contract through varying taxation rates, the financial aspects of production sharing, depreciation rules, equity shares, oil purchase prices, and fees. Given a sufficient number of such parameters, and considering exposure to risk as a factor to be considered separately, it is possible to achieve the same financial outcome with different forms of petroleum arrangements.

3. **Management**

This is the amount of influence and direction that the international company is allowed to exercise in the conduct of its operations and on the planning of its development and exploration investment schedules. The degree of freedom in management allowed the international company is closely defined in the petroleum law or contract. It may be very wide or very restricted with regard to one or every stage of an operation. In practice, however, the international company is generally designated the operator of the venture and, subject to supervision by government inspectors and a management committee with government representatives, exercises **de facto** control over activities. The amount of control varies with the capabilities of the international company and of the government or its National Oil Company (NOC) and the amount of confidence which the government or its NOC place in their partner.

4. **Division of Production**

The division of oil or gas production is the fundamental difference between the various types of petroleum arrangements. By this is meant the physical quantity of realised petroleum (oil and gas) production to which the international company is given access to in one form or other; i.e. the manner in which the quantity of petroleum produced is physically divided between the government and the international company. In the concession the total production typically accrues to the international company, subject to payment of tax and other obligations. In the production sharing contract, production is divided, after cost recovery in stated proportions between the government and the international oil company. In the risk service contract, production accrues to the government and the company is compensated only by payment.

BASIC ELEMENTS OF A PETROLEUM GRANT

Duration

The concession (or contract) is divided into three major phases: (1) reconnaissance phase; (2) exploration phase; and (3) the exploitation phase.

1. **Reconnaissance**

Some concessions have a preliminary phase called the Reconnaissance License (or permit). This is a non-exclusive permit of short duration, usually one to two years, which gives the right to conduct surface work only such as geological or geophysical, but does not include exploratory wells except for shallow 'core holes' drilled for geological information. This phase is sometimes replaced by the 'Geophysical Option', the right to do geophysical work and, depending upon the results, the drilling of exploration wells.

2. Exploration

The duration of an exclusive license to explore for oil and gas, including drilling, varies from one country to another. The length of the exploration period must be sufficient to enable a prudent operator to carry out an efficient and adequate exploration program, but not so long as to permit the licensee to remain passive. The exploration period is normally between three and six years, in some cases even longer.

Exploration duration is subject to renewal or extension under special conditions or expiration if production is not found.

Exploration rights can usually be renewed for specified periods. Such renewal is subject to the holder's satisfactory performance of his exploration obligations, such as required investment having been made, the wells specified having been drilled, etc.

Many countries offer renewals of the original term for a specified number of times. Thus the original maximum duration of, say, four years, can be renewed for four years several times. How many times it can be renewed is up to the government involved. Usually two renewals can be given, with an extension available at the end of any one of them in case a well is drilling as the period ends. In this case an additional six-month period is usually given to enable completion of the well and assessment of the area.

On expiration of the exploration period without commercial discovery having been made the contract automatically expires in the majority of countries.

The exploration agreement / licence should include the right to exploit oil found in commercial quantities and there should exist clarity on the basis this is to be done. See Chapter V when the prospecting lease (OP26) granted to SOEKOR is discussed in this regard.

3. Exploitation

Exploitation duration is usually twenty and thirty years. The original Middle East durations were very long but most of those concessions have been nationalised.

Relinquishment

There is a normal requirement in almost all countries to relinquish a certain portion of the of the exploration area within stated time limits. Generally, these obligations are more strict in proven oil countries than in countries with a lower potential for oil production.

Conservation

For the host government it is important to ensure that, in any given operation, maximum technical efficiency is achieved in extraction. A government should therefore, on the one hand, in its legislation or agreements have the necessary powers to regulate production based on sound conservation principles and, on the other hand, should acquire the necessary expertise to ensure that operations are conducted in conformity with the government's regulations and decisions.

Provisions to avoid pollution can be incorporated with conservation requirements.

Flaring of natural gas may be necessary since associated gas is unavoidably produced with the oil. Secondary recovery may make use of the major portion of this gas if there is no other economic use. In any case, the decision as to whether to allow flaring should be left to competent technical authorities.

Crude Oil Marketing

In many countries the oil company is obliged, at the request of the government, to purchase the state's share of the production or market it as an agent on behalf of the government.

It is important to have clearly defined contractual provisions to determine the price, terms of payment, notification periods for exercise of options, etc. If the price is to be agreed between the parties based on the market value or, failing that, by arbitration, it will be important to have mechanisms which ensure that discussions or disputes do not disturb the regular marketing of the oil, e.g., by providing that payments will be based on the last agreed or stipulated price, subject to later adjustment.

Title To Assets

Under some legislative and contractual relationships, title to assets imported by the company for operations passes to the host country at the moment of importation. This does not include leased assets, such as contract drilling rigs. The company is given the right to the use of such assets until the expiration of its rights.

Where an oil company owns the production facilities, the legislation or agreement will often provide that the ownership of these assets will revert to the state upon expiry or termination of the license or agreement. It may be necessary, for environmental or other reasons, to remove the facilities which may in some cases be extremely expensive. Therefore, it will often be useful if the legislation provides the State with an option to either take possession of the assets or to request that they should be removed by the oil company.

Guarantees of Performance

A frequently found provision in legislation or contracts is a requirement that the oil company must provide guarantees for its performance under a license or agreement, including its fulfilment of the work obligations. Such guarantees may also comprise any liability

which the oil company may incur in respect of its activities, for example, for pollution damage.

Domestic Demand

Most contracts and legislation contain a requirement to meet the national demand for oil and gas out of local production. Such provisions are more important the less the government's royalty in kind or share of production is.

Normally, the requirement to supply oil or gas will be shared among the producing companies pro rata to their production. If the oil company has domestic refining capacity, it will be useful to also add a requirement to refine the crude oil which has been placed at the disposal of the government, on reasonable terms.

The price at which the petroleum supplied for national demand is crucial and varies widely. Most often it is based on the international price, however,, there are many examples of countries that oblige produces to supply their pro-rata share of crude for national demand at prices much lower than the marketplace.

Refining Obligation

The grant of a license or contract to explore for and produce petroleum can be made subject to a requirement that the oil company must establish a refinery or other plants to process petroleum.

It is, however, often difficult to negotiate very specific obligations in this regard, for example, because the viability of such ventures may depend upon the size of any discoveries which may be made, and particularly depends on the size of the domestic market since refineries must be large scale to be economic.

Preference For Use of Domestic Goods and Services

Generally the legislation obliges the oil companies to purchase domestically produced goods and services, normally subject to the

proviso that such goods and services are available on competitive terms. World Bank financed projects allow a cost differential of up to 15 percent in favour of local suppliers. The Mining lease granted to Mossgas (Pty) Ltd contains such a requirement.

Training

Most legislation or contracts today contain provisions obliging the oil companies to provide training of nationals of the host country. It is important for a government that these obligations are as specific as possible, and such obligations should comprise both training of personnel for the oil company's own operations and training of personnel from the national oil company, the government and relevant government agencies.

It is essential that training should be of both a theoretical and practical nature and comprise all aspects of the petroleum industry.

Other Taxes and Fees

It is generally true that the agreements between companies and governments for oil exploration and development specify income tax, royalty, occasionally a surface tax, and sometimes a stamp tax. They generally, however, specifically exempt the companies from payment of taxes other than those specified in the agreement or in the petroleum legislation. Export taxes are rarely levied, nor are import or export duties. (See Chapter V for a discussion of this aspect in the context of prospecting least (OP26) granted to SOEKOR (Pty) Ltd.)

Income Tax

For a number of reasons an income tax is generally paid on production. For one, an obligation to pay a relatively high rate of tax on realised profits appears less burdensome to an oil company than an obligation to pay a heavy royalty, (the different types of tax and royalties and their affects are recorded in Chapter IV).

Minimum Investment

The minimum investment program usually refers to the exploratory period. There is no feasible means of estimating what development and production expenditure will be needed. It may not always be presumed that the oil company will, in its own interest, proceed as rapidly as it can to develop production, therefore, control must be exercised during development as well.

When an exclusive exploration ("drilling") license is granted, either as the first step or following upon a non-exclusive reconnaissance permit, it becomes important to obtain firm commitments from the license holder or contractor.

Supply of Information

An obligation to submit on a current basis all information obtained during the exploratory work is normally contained in the legislation or contracts. It is important for the government to ensure that this obligation comprises all relevant data (e.g., geological maps and structural maps, logs, samples, and cores, etc.) and that the obligations are implemented.

PETROLEUM CONCESSION

The concession was the original system used in world petroleum arrangements, and it is still the most widely used today. Where legislation has been enacted to govern petroleum it may be called a license or permit (exploration) or a lease (exploration).

The concession is an arrangement whereby the oil company received the right, in exchange for its payment of all costs and specified taxes, to explore for petroleum and, if production is found, to produce, and market the oil or gas. The right to transport hydrocarbons discovered is usually included.

In exchange, the company pays, in addition to the costs, (1) royalty and (2) income tax; some minor taxes may be levied as well.

The company is usually given export right to crude oil or gas produced subject to various obligations. Such obligations are extensive.

Other

The basic difference between concession and a petroleum contract, be it production sharing or a risk service type, is that all the production is acquired by the concessionaire.

PRODUCTION SHARING CONTRACT

The three basic elements of a production sharing contract are: cost recovery a production 'split' between the government and the oil company and income tax.

The concept of production sharing originated in Indonesia where it was first used in agriculture. It was later adapted for petroleum and first used in the IIAPCO contract of 1966. The concept in now also used in Peru, Malaysia, Guatemala, Libya, Egypt, Syria, Jordan, Bangladesh, and the Philippines, among others.

Production sharing is carried out with the government, usually through its state oil company. This would appear to give a greater degree of control over operations of the private contractor, but in fact production sharing contracts generally operate under the management of the risk-taking private partner.

Participation

The state may participate in the production sharing contract in a joint venture. Many countries, in contracts signed with private companies, have reserved the option to participate upon notice of commercial discovery. This effectively 'carries' the State through exploration.

Cost Recovery

The concept of cost recovery also originated in Indonesia, where the first 40% of production went to the contractor to cover costs. The percentage varies in other countries, generally between 20% and 40%. One country (Peru) structured production sharing contracts to exclude cost recovery, compensating by giving the oil company a higher (50%) share of production, with tax paid by Petroperu, the State company.

Peru's 1980 tax amendments eliminated the tax payment by Petroperu but still provide no cost recovery.

Production Split

Following deduction of cost recovery, production is divided between the oil company and the State. This is known as the production "split", and it varies widely. Some countries vary the production split with production levels.

The variation between production splits around the world is not as striking as it may seem, for the oil company is subject to income tax on its share and regardless of the split the rate of return to the oil company can be controlled by varying tax rates.

Tax

Around the world oil companies are generally subject to national corporate income taxes on their share of production. The 85% OPEC income tax does not apply to production sharing contracts but only to production under the old style concessions. One OPEC country, Libya, does not impose income tax on production sharing contracts at all, but divides production 81% government 19% company free of tax.

Other provisions of the production sharing contract dealing with exploration and exploitation duration, size of area, relinquishment,

employment of nationals and training, etc are similar to those contained in concessions, as previously reviewed.

PRODUCTION SHARING AGREEMENT - SUMMARY OF PRINCIPAL CHARACTERISTICS

Subsoil Rights:

Exclusive title to subsoil and to conduct petroleum operations is given to the NOC. The latter has the authority to conclude agreements with oil companies who are then considered Contractor to the NOC.

Management

Contractor is operator and works under the supervision of the NOC.

Risk

Contractor provides all the funds for the operations and carries all the risks involved.

Title of Assets

All assets accrue to the NOC, either immediately upon acquisition or gradually with or after depreciation.

Cost Recovery

When the ventures reaches the producing stage the Contractor will recover its 'allowable' costs out of the production. Sometimes the volumes available for cost recovery is limited by stipulating either a maximum or a fixed percentage of the available production.

Allowable costs are defined in a manner similar to those usually applied for taxation purposes, i.e. using depreciation and amortisation rules.

A combination of both restrictions, by way of volume and of depreciation rules, is also possible.

The part of production that is used for cost recovery is called 'Cost Oil' or 'Cost Recovery Crude Oil.'

The agreement will contain rules for the determination of the value of the oil for cost recovery purposes.

Production Split

The balance of the available production, normally called "Profit Oil", which is what remains of the production after deduction of the Cost Oil, is shared between the NOC and the Contractor in agreed proportions usually dependent on production levels achieved; i.e. at higher production levels, frequently on an incremental (sliding scale) basis, Profit Oil is split in proportions more favourable to the NOC.

There are agreements where there is no Cost Oil, all being treated as Profit Oil. Under such agreements there is no need to establish rules for determination of the value of the oil.

Taxation

Contractor is either exempt from all taxes on income or remains subject to such taxation. In the later case such taxes are either paid by the NOC on behalf of the Contractor or will be paid by the Contractor himself. Where the Contractor is exempt from taxation or where the NOC pays the taxes on his behalf the Contractor receives his share of the Profit Oil free from any fiscal burden and in the latter case is put in a position to show to the fiscal authorities of his home country that the local taxes on income have been paid - in order to obtain a tax credit against local taxes.

RISK SERVICE CONTRACT

The risk service contract shares the usual elements of duration, work obligations, etc, with concession and production sharing contracts, but differs in important aspects. Its basic distinctive feature is that is pays the oil company in cash, not in crude oil (although it may have provisions permitting the company to buy back an amount of crude at international prices from established production).

Risk

The risk contract typically places all risk and investment on the Contractor, who provides capital for exploration and production. If no discovery is made the contract ceases to exist. If discovery is made, the contractor places it on stream. Thereafter it may be operated by the State or, in some cases, by the Contractor. Capital is reimbursed with interest and a risk fee.

Taxation

Contractors are subject to taxation usually at general corporate rates. Here again taxation is of lesser importance, since the service contract 'fee' or production payment also determines profits: the higher the fee the higher the tax.

The risk contract generally has the same specifications as the concession as regards area, size of contract area, relinquishments, etc.

SERVICE CONTRACT (NON-RISK)

The pure service contract is a simple contract of work wherein the contractor is paid a flat fee for his services. An example of importance is the Aramco contract in Saudi Arabia. Aramco, the major oil company in the country, carries on production operations for the Saudi government for a net fee of about 15 cents per barrel (plus inflation), after tax. Exploration is also carried out, and risk is

rewarded with additional crude from reserves found plus an additional 6 cents per barrel on new oil.

Another example of a pure service contract is the Total contract in Abu Dhabi where the government's offshore field (Zakum) is operated by Total for a per-barrel fee, plus the right to buy part of its production.

Tax

Service contracts are subject to general corporate taxation, but not to higher special petroleum taxes.

In effect, these contracts operate without profit to the company. Since there is little incentive, their efficiency is yet to be proved.

Types of Contracts

There are two categories:

1) The Service Contract running parallel, but contractually unconnected, with a purchase contract for part of the oil being produced from the area or operations to which the Service Contract, relates or;

2) The Service Contract not accompanied by any access to the oil being produced under such Contract.

JOINT VENTURE

The joint venture has been widely misunderstood as being a separate type of petroleum agreement. It is not. It is a partnership arrangement wherein the State, either directly or through its national oil company (NOC), received an equity or ownership interest in the rights and obligations of a contract or a concession. The State may achieve this through 'participation', or nationalisation, as in the partial nationalisations or enforced participations throughout the world e.g. Libya, Nigeria, United Kingdom, Norway. It may originate in the

structure of the arrangement from the first. As a partner, the State shares in the production from the contract or concession in proportion to its interest; thus 25% joint venture interest would accord right to 25% or production. In addition, the associated oil company pays taxes and/or production sharing on its share of production, so the benefits to the State are two-fold.

Costs

The State or its NOC shares in the costs in equity's proportion. Frequently, however, the arrangement provides that the private partner assume part of the government's risk, State to assume its share of costs only after production is discovered. This arrangement is called a 'carry.' The State's share of costs is repaid either directly by the State, or through allocation of part of the State's share of the joint venture production to the oil company.

Cost Reimbursement

Exploration costs may not be reimbursable to the oil company, i.e. as they are not in Norway and Libya. Once production begins, however, the State normally pays its share of operating costs. The State may be 'carried through development', in which case the State or its NOC will be carried to the point of production. It then becomes essential to have a clear definition of when commercial production begins, since from that point on the State will share in costs.

The farther the State is carried, the lower the return it must expect to obtain. Thus the State when 'carried through development' would normally receive a lower share in the joint venture or the production split than if carried only through exploration. The advantage to the State in both arrangements is that it takes no share of risk exploration and may elect to put little money in development since arrangements can frequently be made to have the State share repaid out of its share of production.

Interest

In some cases, interest is paid on exploration and development costs advanced by the oil company. In Brazil, development moneys advanced are repaid plus interest from production.

Participation

The government's participation amount in production is not determined by the oil company's estimate of the potential size of discoveries, costs of development, political risk, and other factors. The final production split may vary with these factors, but the State must decide on the amount of its participation on the basis of its own financial and technical capabilities.

Taxes

Provision can be made in the joint venture concessions or contract to accommodate changes in production levels, with the State tax or royalty on a sliding scale basis rising with production. This can be done with prices as well, with the State share rising with crude oil price.

Advantages

The State may find advantages in the joint venture approach. The greatest risks exist in the exploration phase, and all this is assumed by the oil company. Once a commercial discovery has been made three may still be some risk but it is normally not difficult to obtain financing. Major financial institutions such as the World Bank lend to governments at advantageous interest rates, and other international and regional development in situations may make financing available.

Operating Agreement

Joint ventures require mutual agreement on procedures, such as meeting costs of operations in a timely manner. The agreement to determine these procedures is knows as an 'operating agreement' or a

'joint venture operating agreement'. It contains detailed specifications on who is to be the operator, what operations can be performed without special permission, etc. A joint management committee may be established to pass on important decisions and to decide the future course of operations, and other essential details. Voting on the management committee is usually proportionate to interests held. Often the State holds the post of president of the management committee, with the oil company acting as operator.

Incorporated Vs Unincorporated Status

The joint venture can be a incorporated or non-incorporated vehicle. In the latter case participation shares are held in undivided interest, i.e. the NOC and the oil company each own an undivided interest in the venture embodied by a mining title and a concession contract with the government (in its capacity as grantor of the mining title). Each acquires its own share of the production and is responsible for paying taxes on his share. The assets used in the ventures are jointly owned.

The NOC and the oil company jointly supervise the operations. Usually there exists a joint management or operating committee for this purpose. In such committee decisions are taken unanimously or by qualified majority, providing that a 51% to 60% government participation will not automatically lead to a power of veto for the NOC. In most cases the oil company is the operator of the venture. Sometimes, however, the operations are entrusted to the NOC or to a non-profit making and no assets owning operating company which is jointly owned by the NOC and the oil company in proportion to their participating interests. The funding of the operating company takes place in accordance with the rules of financial participation agreed in the joint venture agreement.

Participation may also be implemented on a corporate basis. The government or its NOC and the oil company each own its percentage interest share of the shares of a company holding a concession contract. This will the be a profit making company selling all the crude oil produced by the venture and owning all the assets. This

form has been chosen in very few cases and then only when a joint venture has been introduced at a mature stage of the venture (e.g. Brunei).

The joint company is subject to the fiscal legislation and is responsible for the payment of taxes.

The corporate profits after taxes are divided between the two shareholders, viz. the oil company and the government, and paid to them in the form of dividends.

The disadvantages of the incorporated Joint Venture compared to a non-incorporated Joint Venture are:

1) All crude oil is sold by the joint company, which means that prices and customers have to be agreed between the shareholders. Under an undivided interest set-up each Participant acquires its own share of the production and is free in the disposal of this share, subject of course to the requirements of the applicable legislation and the concession contract.

2) Under the corporate route the participants get their shares of the benefits of the venture in the form of dividends. The dividend policy is thus a matter that has to be settled in mutual agreement.

   The disadvantages are of such importance that where an incorporated joint venture is unavoidable the shareholders usually make arrangements among themselves allowing direct access to the crude oil, thereby, reducing the joint venture to a mere operating organisation.

Buy Back

In many countries joint venture arrangements have been supplemented by buy back provisions, i.e. the oil company has the option to buy part of the NOC's share of production. This can also

take the form of the oil company selling on behalf of the NOC such part of the NOC's share as the latter is unable to sell itself.

Assistance In NOC Financing

In many instances the oil company will make interest bearing loans to the NOC in order to enable the latter to fulfil its financing obligations under the joint venture contract.

The repayment of loan and interest is usually tied to the NOC's income from the venture and may be effected by the oil company lifting a certain percentage (say 60% or 70%), of the crude oil accruing to the NOC. Such a link between repayment and production introduces another complication for the oil companies and NOC.

Participation

In some contracts it has been agreed that upon making a commercial discovery the government or its NOC (i.e. the state partner) has the option to acquire a minority interest, say 15% to 25%. The participation may embrace the whole venture or only the discovery concerned. Sometimes the state partner's proportions share of the exploration expenditure incurred up to the option date is reimbursed to the company, sometimes it is not.

At increasing levels of production from the venture or from the field concerned the state partner may have the option to increase its percentage interest in the venture or in the field concerned in stages up to a previously agreed maximum percentage. In some contracts it has been agreed that as compensation for the increase in participation the state partner will pay to the oil company a corresponding share of the undepreciated/unamortised portion of the expenditure incurred up the time of the increases. The reimbursements due are either effected in monthly cash instalments or in kind for which purpose a certain percentage of the crude oil share of the state partner will be lifted by the oil company.

When a discovery has been declared commercial the NOC when joining in such declaration will immediately receive a 51% interest in such discovery and it will have the right to demand a further increase as soon as the production profile for the field has been approved by the government in accordance with an agreed scale, linking estimated peak production levels with participation interest. If a new commercial deposit is found the NOC may demand a further increase of participation interest (in all then current development and production) in accordance with the same scale.

The final participation interest in development and production may be in the order of 70 to 75% but will only occur if substantial volumes are being produced.

Comparison

In summary, each petroleum arrangement has its distinctive advantages and drawbacks. While all are risk-free so far as the government is concerned, the concession has the advantage of being clear and in a familiar form that works. Where a law exists under which concessions are given, the guidelines are present and government negotiators can stand on the basis of the law to press for additional advantages. It has the disadvantage of lack of flexibility.

In this respect the production sharing contract, with its two-edged sword of production split and tax, has the advantage. Its disadvantage is that unless correctly structured to accommodate changes in oil price, its original intent may be lost and the oil company either rewarded beyond the original intent or penalised.

The risk service contract has the advantage of seeming to establish production such as secondary recovery projects, or to countries where production levels have risen so high that the national treasury can afford the huge reinvestment necessary to maintain output, such as Saudi Arabia.

Each government, it seems, must find that arrangement, or mixture of arrangements, which best suits its national picture.

- CHAPTER IV -

This chapter examines the object of petroleum taxation and the different types of taxes employed by the State(s) to extract their 'take' and the effects thereof on investment.

PETROLEUM TAXATION

In most countries of the world petroleum rights are owned by governments, and in disposing of their rights governments normally have a number of objectives. The collection of a high share of the economic rents is certainly a major objective in all producing countries. Other common objectives are to regulate the pace of exploration and development, to ensure security of supply for the domestic market, to influence the domestic price of petroleum, to obtain significant local ownership of an important resource, and to enhance local participation in employment and provision of supplies and equipment. It is clear that the maximisation of revenues from petroleum exploitation is likely to be inconsistent with some of these other objectives. For example ,domestic price controls or the imposition of requirements to purchase supplies of equipment locally will reduce the revenue base below the level it would otherwise have been.

A main objective of a petroleum taxation system is to collect the economic rent of oil and gas production. The rent refers to all returns to input factors, which exceeds opportunity costs; i.e. returns accruing to a production factor in excess of its return in next most valuable alternative use. The supply price of a factor reflects the necessary costs and return in order to bring it into use. In order to allocate capital and labour they must be paid a sum sufficient to bid them away from their alternative use. The rent refers to the difference between the total revenue and the supply price.

A desired feature of any fiscal system is to have a built-in flexibility in relation to different field sizes and cost conditions in a geological province, as well as changes in our prices. Ideally the rent should be collected in different situations, without having to introduce discretionary changes in order to obtain rent-skimming. Discretionary tax changes is likely to introduce uncertainty to the investor.

The fiscal system should raise revenue without causing any distortions. A key question to any fiscal system is to what extent it will have adverse influence on the investment decision and resource recovery decision with respect to reaching optimal decisions for the society. One has to examine the impact of the total fiscal package applied to petroleum exploration and exploitation as compared with the pre-tax situation. A fiscal system is considered neutral if the after-tax decisions in relation to exploration, development, production and abandonment are identical to the pre-tax decisions. The fiscal system should not produce disincentives to explore for new reserves, develop new fields and marginal reserves within each single field.

It is crucial to relate a fiscal system to the geological basis in a petroleum province and the position of the exploration province on the geological learning curve. It might be directly misleading to make comparative studies between different countries without carefully taking into consideration the different geological basis.

An efficient fiscal package is a balance avoiding both a too liberal approach, which will result in revenue loss, and a too restrictive approach, which will result in fewer projects and thus also revenue loss. The challenge is to develop a petroleum taxation system which will gather the economic rent while encouraging the efficient exploitation of exhaustible resources

WHO SHOULD RECEIVE ECONOMIC RENT

The Beneficiaries Can Be Investors, Oil Consumers And Governments.

In the absence of legislation it is natural to assume that investors would receive the total amount of the economic rent.

In some oil- producing countries oil consumers receive a share of the economic rent in the form of reduced prices.

The exploitation of petroleum normally requires the provision of a relevant infrastructure and government will usually be involved in the financing of this infrastructure. It is argued therefore that the tier of government that is responsible for providing the infrastructure has a corresponding claim to the reserves. Also ,petroleum is a depleting resource and as production diminishes, the local population could become less able to sustain the burden of providing local public goods. If the state had to provide the infrastructure relating to the exploitation of the resource, the government is entitled to a share of the economic rent.

TYPES OF RENT/TAX COLLECTING SYSTEMS

The Marais technical committee on mining taxation reported on the effects of different taxing systems as follows;

Royalties and Productions Taxes

- The conventional fiscal devices imposed on oil exploitation activities can produce various types of distortions. The most traditional form of impost has been the royalty; this has traditionally constituted the reward of the landlord for allowing exploitation of a resource which he owns.

- In a situation where the investor has no control over the market price of his product, conventional royalties and other production-

based levies can cause marginal fields to be uneconomic, and can also lead to fields being prematurely abandoned. Conventional royalties and production levies are obviously not well related to profits and so the danger of such distortions emerges.

- As profitability of exploitation falls due to lower oil prices or higher exploitation costs, a traditional flat-rate royalty of production tax will take an increasing share of gross profits. In an extreme situation payments have to be made when zero or negative profits are being earned.

- Because obligation to pay royalties or production tax commences with first production, the burden of these imposts in present-value terms is increased compared with other taxes, liability for which does not commence so early in field life. It follows that in present-value terms the burden of production-based levies is higher than for payments of total comparable size which commence later in field life. The early commencement of liability also increases the share of such payments in the economic rents from field production. When a field becomes marginal the burden of front-end royalty or production-tax payments can readily make a project sub-marginal.

- When profitability of exploitation increases due to rising oil prices or unexpectedly low costs, the share of a flat-rate royalty or production tax in gross profits falls. Similarly, the share of economic rents extracted falls. Traditional royalties are thus crude devices which are comparatively insensitive to changes in realised economic rents emanating from oil-price movements or cost variations. In other words flat-rate royalties and production taxes are not efficient instruments with which to collect economic rents.

- Investor will generally cease production from a field when net profits turn negative, and the existence of production-based levies can accelerate the timing of this decision. As production falls, exploitation costs eventually exceed revenues; the field is abandoned when marginal cost exceeds marginal revenue. Production-based levies form a wedge between gross revenues and exploitation costs. The requirement of an additional payment based on revenues means that marginal cost exceeds the net price at a higher level of output.

- The field will be abandoned earlier than would otherwise be the case and resources, the exploitation of which is in the national interest, will remain in the ground. For this reason provisions for royalty relief exists in the regulations of many countries.

- From the point of view of host governments, royalties and production taxes have some obvious advantages. Early revenues are attractive to all governments, and the likelihood of these continuing throughout field life is also appealing. The costs of monitoring and administering royalties are also less than those for other fiscal devices.

Corporate Income Tax

- The effects of conventional income taxes on petroleum investments depend upon the rate of tax and the provisions regarding depreciation, loss offsetting, and any other allowances in the system. The timing of the recovery of investment costs affects the effective burden of the tax because the present value of tax liability is reduced.

- The facility to offset the costs of new exploration and development against other existing income by postponing payments of tax reduces the effective costs of developing new fields. In most countries income tax is levied on a company's nationwide activities; so if the legislation permits allowances to be utilised as soon as expenditure is incurred, the investor obtains a useful incentive.

- In some jurisdictions ring-fence provisions prevail whereby income-tax assessments are made on a field-by-field or contract-area basis. Indonesia is such a case - a separate company is required for each contract area and no group relief is permitted. This increases the net cost of undertaking new exploration and development work.

- The legislation concerning utilisation of allowances reflects the extent to which government is sharing in the investment risks. When exploration and development allowances can be set against other income as soon as expenditure is incurred, the government is sharing in the investment risks to a considerable extent. This is

the main example of loss offsetting being permitted. If the new expenditure does not generate taxable profits, the government will have lost revenue in absolute terms; if the new expenditure is successful, the government will be suffering a postponement of revenue compared with the situation under ring-fence arrangement or one where allowances cannot be claimed until the asset is placed in service.

Special Profits-related Taxes

- In the main North Sea producing countries (the United Kingdom, Norway, Denmark, and the Netherlands) the governments have imposed special profits-related taxes which are not income taxes in the conventional sense. In the case of the first three countries they are levied on a field-by-field basis. This limits the government's investment risks. At the same time devices such as the 'uplift' or extra relief for field capital expenditure are included, in order to relate the government take to field profitability.

- While in general such imposts are less likely to cause disincentives than are production taxes or royalties, they do carry inherent risks of creating distortions. The presence of an 'uplift' on capital outlays can ensure that the tax burden is progressively related to profits in money-of-the-day terms, but it may not do so in present-value terms. Also, the provision of investment relieves exceeding 100% of the outlays, combined with high marginal rates of tax, can result in a lack of cost-consciousness or the encouragement of 'gold-plating' expenditures.

- The given objectives of this type of tax is to collect a high share of economic rents while maintaining investment incentives. However, the tax is not directly related to field profitability (in present-value terms). Use of the indirect mechanism, certainly introduces the risk that the scheme will not ensure that disincentives do not emerge or that government's share of economic rents will be 'adequate.'

- These schemes have also been found to be insufficiently flexible to changing oil prices to fulfil their given objectives; and discretionary changes have had to be made by governments. This increases the uncertainty of the investment environment.

Special Excise Taxes

- As a device to collect economic rents from rising oil prices, several governments have introduced excise-type taxes based on the difference between a base price and the market value. The most famous of these is the Windfall Profits Tax in the United States but others - such as the Excess Proceeds Tax in Malaysia; some forms of levies employed in Australia over the last decade; and one element of the royalty scheme in Alberta - all fall into the same general category.

- The basic idea behind this type of levy is that oil price increases confer windfall gains on produces, and at least a part of these gains can legitimately be extracted by the state. The tax may commence as soon as production from a field starts if the base price is less than the market price at the same time. This type of levy has several problems associated with it. There is a danger that incentives to develop marginal fields will be impaired, while at the same time the burden on highly profitable projects will be comparatively light.

- The scheme could be made more complex or sophisticated in an attempt to deal with these problems. This is certainly the case with the Windfall Profits Tax in the United States, where the rate of tax and the base price vary according to when the fields were discovered; the base price is higher for 'new' oil and the tax rate lower. Also, very small projects are exempt from the tax. These modifications can obviously provide incentives to explore, but the mechanism is still crude and could well not achieve its objectives.

- From the point of view of risk sharing, this type of tax leaves the exploration and field development risks with the investor, while the oil price risks are shared between the investor and the government when the market price exceeds the base price. The fact that the tax is reduced to zero when the price falls to the base level gives more 'downside' protection to the investor compared with a straight production tax.

- In sum, it is unlikely that the excise duty levied on the difference between a base and market price can extract economic rents from petroleum exploitation without introducing distorting effects.

Production-Sharing Agreements

- Though legally quite different in concept, production-sharing schemes have some economic features in common with an income-tax system. Provisions for cost recovery (both regarding any ceilings on the amount of oil available for this purpose and regarding the speed at which costs can be recovered) are akin to allowances for exploration, development, and operating costs. The effects of different rates of recovery are essentially the same as those discussed for depreciation under the income tax.

- The overall effect of a production-sharing scheme depends on the share of profit oil taken by government as well as on the cost-recovery terms. For example, 'faster' cost recovery can compensate for 'high' profit oil share accruing to government. To obtain neutrality between different petroleum projects, the pace of cost recovery should be same as for economic depreciation under the income tax. If the ceiling on the share of production is set very low, the investor may not recover all his costs over the lifetime of the field; such a situation would be akin to the imposition of a royalty or production tax.

- An incremental production-share scheme is akin to a progressive income tax to the extent that differences in government income accrue from differences in field size. The fact that the progressive scale is on an incremental basis ensures that the marginal rate of 'tax' on the investor does not exceed 100%. This reduces the scope for depletion decisions' being distorted by the fiscal package but, if marginal rates rise very steeply, situations could emerge where it would pay the investor to deplete fields more slowly.

- The production-sharing system is not geared to deal well with the situation of unexpected changes in economic rents emanating from oil price changes. If the price of oil doubles, the profitability to the investor of a given share of oil would increase considerably; but the fiscal package would not react automatically in such a way as to give the government a large share of such a windfall.

- If a government adopts a standard form of production-sharing contract throughout its jurisdiction, it might well find that a given structure is appropriate for one area but not for another. A government could vary the terms from one part of the country to another, but this increases the complexity of the regulatory package and probably increases the uncertainty of the investment environment.

- Production-sharing contracts are normally designed effectively on a ring-fence basis though the term as such may not be employed. Typically, the exploration and development costs incurred in a contract area may be set against revenues only from the same area.

- Production-sharing contracts leave the contractor to take the risks at the exploration and development phases. The government does, however, have an interest in ensuring that these costs are kept to a minimum, because the lower they are the more oil will be available for sharing purposes. When production commences the risks are shared between the two parties.

- In sum, production-sharing contracts, especially those incorporating incremental arrangements for profit oil splitting, have some advantages over traditional schemes of royalty and income tax. A given scheme can ensure that governments automatically obtain a high share of the economic rents accruing from fields of many different sizes. If a government is risk-averse, the production-sharing scheme also has attractions.

- On the other hand this form of agreement cannot ensure that changes in economic rents emanating from changes in the oil price (either upward or downward) will automatically be reflected in changes in government take.

- Further, a given, single scheme may not be appropriate for fields with large differences in costs.

The Brown Tax

- Because of the imperfections of all the conventional fiscal devices discussed above, economists have proposed the use of other fiscal instruments in an attempt to obtain a distortion-free mechanism by which economic rents can be collected. The two which have found most favour are the 'Brown Tax' and the resource rent tax.

- The 'Brown Tax' is based on corporation net cash flows. All exploration, development, and operating costs are recoverable on 100% first-year basis. There are no ring-fence provisions and so all expenditures on new activities can immediately be set against existing income.

- In effect the government subsidises exploration and development activities (entailing negative cash flows) at the same (flat) rate that is subsequently applied to positive cash flows from petroleum exploitation. Where the investor has no existing income against which to set off expenditures it incurs, the government actually pays a share of the costs to the extent of the tax rate.

- This tax, very simple in concept, is neutral in the sense that the post tax rate of return is not less than the pre-tax one (though post-tax net present values will generally be less than pre-tax values).

- The scheme shares project risks with government to such a large extent that, statistically, the dispersion of the distribution of outcomes facing investors from new projects is actually reduced. This major 'shifting' of investment risk may well be unacceptable to some governments.

- No tax would be payable if no commercial discovery were made or if exploitation were unprofitable, and the financing of the government's share of costs may prove difficult, especially in Third World countries.

- In general the tax has many attractions, not only because of its neutrality, but also because of the comparative ease of obtaining a distortion-free scheme which is automatically adaptable to changing circumstances in the operating environment.

- The scheme taxes only economic rents, but there is no complicated procedure required by legislators to determine or define rents; for example, no knowledge is required of the investor's discount rate.

Resource Rent Tax

- Probably because of the requirement on governments to become full sharers in the front-end investment risks, the 'Brown Tax' has not been popular among governments.

- The resource rent tax has been found more acceptable to legislators. In essence this tax allows the investor to achieve a specified (discounted) threshold rate of return on a project before tax becomes payable. The threshold rate of interest is used to compound forward the investor's net cash flow, commencing with initial exploration; the accumulated total becomes a larger and larger negative figure until production commences; and the compounding process continues until the accumulated total becomes positive. The resource rent tax is then levied and continues to be levied on positive annual net cash flows.

- In principle the threshold rate should represent the investor's discount rate. If this rate is employed, then the tax should not discourage investment in fields which have already been discovered. Unfortunately, different investors may employ different rates, and any one investor could legitimately employ several, with the chosen one depending on the perceived risks of the project in question.

- Further, investors will generally not reveal their discount rates to governments. Governments will therefore have to estimate discount rates. If they use rates that are below those employed by investors, projects will be discouraged; if they employ rates higher than those employed by investors, governments would end up with a lower share of the economic rents than could have been obtained with full knowledge.

- If investors' threshold rates are accurately reflected in those enacted in legislation, then economic rents from discovered fields can be collected without disincentives emerging.

- Marginal field developments, too, would not be impaired. The system would be highly sensitive to fluctuations in oil prices and to ranges of exploitation costs and field sizes. It would automatically react in such a way as to increase government take when profitability increases, from whatever source, and to reduce government take when profitability falls. The sensitivity would be strong enough to ensure that government would always obtain an 'adequate' share of the economic rents while field developments would never be deterred when they were viable on a pre-tax basis.

- From the investor's view point the resource rent tax has the advantage that capital investment risks are shared with government to a greater extent than under conventional tax systems: until the threshold rate of return is attained no tax is payable; this does not happen with conventional taxes.

- Risk sharing is unlikely to be as great as it is with the 'Brown Tax,' however, because the resource rent tax is likely to be levied on a contract-area or project basis, not on a company-wide basis. Thus, the investor still has to bear all the initial exploration and development risks prior to production from the project in question.

- Resource rent tax schemes can have one or more tiers with positive tax rates. Under a multi-tier scheme the system is progressively related to rates of return. When several tiers exist, care has to be taken to ensure that over investment or 'gold-plating' incentives are not introduced. In general the danger of such distortions emerging is greater the jump from one threshold rate to the next and the greater the increase in tax rates from one tier to the next.

- When exploration risks are brought into the picture, it becomes clear that a resource rent tax could produce disincentive effects at the exploration stage of petroleum exploitation activities. Investors base exploration decisions on calculations of expected monetary values which take into account the probability of discoveries being

made. A resource rent tax system, while it might not deter the development of discovered fields that were viable on a pre-tax basis, could still deter exploration. Expected monetary values could be positive on a pre-tax basis and negative post-tax.

- The danger of this occurring increases as the probability of making discoveries falls, because the resource rent tax as normally specified does not share in the risks of failure to make commercial discoveries. If the scheme is on a project or contract-are basis, there is no provision for write-off of unsuccessful exploration. It has thus to be recognised that a resource rent tax could reduce exploration. It should be emphasised, however, that this type of disincentive is present with all conventional tax and royalty schemes.

Bidding Systems

- Bidding systems can take various forms, Cash bonus bids are the most common in the United States and Alberta. They are lump-sum payments made at the time the leases are offered. Other possible forms include royalty bidding, and work-program bidding.

- The competitive bonus-bidding system favoured in the United States and Canada is frequently advocated because it should not produce any distortions. It is argued that, if there is a high degree of competition in bidding for the rights to exploit petroleum, the size of the bonus bids should reflect the expected economic rents. In effect the interested investors will estimate the Expected Monetary Value (EMV) from the prospect on offer, discount future costs and revenues at their own discount rates, and make their own estimates of the probability of success at the exploration phase. The bids thus reflect the investors' perception of the prospects and their own discount rates, rather than the perceptions of outside parties such as host governments.

- Despite the obvious attractions there are problems associated with the widespread application of a bonus-bidding system. A high degree of competition among bidders is required; collusion among investors could thwart the effective operation of the system. The dangers of collusion are less the greater the number of bidders, but in many countries the number of investors interested in acquiring blocs put on offer can be very small. In some Third World countries they have been many cases of only one investor (or two investors forming a joint venture) interested in acquiring rights to particular blocs.

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- CHAPTER V -

In the previous chapters we have examined the need for inter-alia South Africa to promote the exploration and subsequent exploitation of its potential reserves the establishment of a general petroleum policy and different contractual basis to achieve its petroleum objectives. In this chapter we will examine the contractural basis that South Africa has chosen for the exploration of its natural oil as well as the income tax on the income earned from such activities.

Introduction

SOEKOR was formed in 1965 by the State which it wholly owns with the purpose of exploring the potential of South Africa's natural oil resources and to exploit them either on their own or preferably in conjunction with private investors.

SOEKOR was given the legal right to do the prospecting for natural oil both onshore of South Africa and within the territorial waters of South Africa. Since its conception the accent switched from the land to the sea and in spite of some known oil occurrences on land it is clear that if we are to make a substantial oil discovery it will be offshore. So far over eighty-three holes have been drilled offshore and an amount of excess of R450 million has been spent by SOEKOR and an amount of in excess of R110 million by other companies. These numbers exclude the costs of developing the Mossgas Project. This figure is estimated to be in the sum of R15 billion.

Legal Mechanism for the Granting of Exploration Rights in South Africa

The granting of prospecting and mining leases at the time that SOEKOR received its prospecting rights was regulated in terms of the Mining Rights Act, No 20 of 1967. That act has since been repealed and substituted by Act 50 of 1991 the Mining Rights Act. The effect of certain portions, which are relevant to the Prospecting Lease granted to SOEKOR and the Mining Lease granted to Mossgas, are

however unaffected by it as a consequence of an amendment made to the 1991 Act which was specifically introduced to preserve the rights contained in the prospecting lease granted to SOEKOR and the mining lease granted to Mossgas.

The Mining Act provides for the award of a prospecting lease which entitles the grantee thereof the right to prospect for natural oil and in the event of a successful find the subsequent right to apply for and the grant of a mining lease for that area. In essence then a prospecting lease contains a) the right to prospect and b) the subsequent right to mining should a quantity of oil be found which justifies exploitation.

SOEKOR was in terms of the Mining Act granted a prospecting lease which covered the area consisting of the whole of the land of the Republic of South Africa, commonly referred to as OP29 and a prospecting lease for the exploration of oil within the territorial waters of South Africa - commonly referred to as OP26.

Clause 14 of the Mining Rights Act of 1967 in terms of which OP26 was granted to SOEKOR (a similar clause is contained in the 1991 Act) provides;

"Prospecting leases for natural oil.

1. The Minister may -

   a) by notice in the Gazette and in one or more newspapers circulating in the area in which any land is situated call for tenders for a prospecting lease over such land in respect of natural oil, and may grant such a prospecting lease on such conditions as he may subject to the succeeding provisions of this section determine to any tenderer who satisfies him -

      (i) that the scheme according to which the tenderer proposes to prospect for natural oil upon such land is satisfactory; and

(ii) either that his financial resources are adequate for proper prospecting under such a lease or that the arrangements by which he proposes to obtain capital for the purpose are satisfactory; or

b) without calling for such tenders grant such a prospecting lease on such conditions as he may subject to the provisions of this section determine over any such land in respect of natural oil to any person applying therefor who so satisfies him.

2. The minister shall, before granting or refusing any lease under subsection (1), submit every tender or application for the lease to the Board for its report."

An interesting provision is contained in article 14 (3) of the mining Rights Act of 1967 - which was not in turn incorporated into the 1991 Act, which reads -

3. "Any lease under subsection (1) may embody any terms and conditions agreed upon in consultation with any other Minister on matters falling within the purview of a department of State administered by such other Minister and shall provide -

a) for the scale on which and the manner in which prospecting operations shall be carried on;

b) for the supply to the Minister, at such times as may be specified in the lease, of full statements describing the nature of the prospecting operations which have been carried out and the site and depth of any borehole and the formations penetrated, and containing such other information as the Minister may require;

c) for the keeping by the prospector of records relating to the operations;

d) or the inspection or examination by the Minister, or any person authorised thereto by him, of such records and of the lease area and of any substance (including borehole cores) brought to the surface in the course of such operations; and

e) or the payment by the holder of the lease to the owner and any person entitled to use the surface of any land included in the lease area, who suffers any surface damage or any damage to crops or improvements on such land caused by the exercise by the holder of the lease of his rights under the lease, or by any act or omission incidental thereto, of compensation for such damage.

and may further embody any or all of the terms and conditions (including terms and conditions agreed upon in the manner aforesaid) which will be applicable to any mining lease to which the tender or applicant for the prospecting lease may become entitled under section 25 (1) (g) on the land in question, and any terms and conditions shall for the purposes of this act be deemed to have been recommended by the board and **shall not withstanding anything in any law contained be binding upon the State."**

It is believed that the insertion of this clause which enables the Minister of Mines to agree with any other Minister on matters which in effect, would if any agreement is reached between them override any other legislation pertaining to the particular portfolios for which they are Ministers responsible for, was regarded as necessary in order to develop a prospecting lease which could be packaged in such a way as to encourage investment in this important energy sector of the country. Such an approach gave the prospecting lease a degree of flexibility, and the prospective investor certainty as to the fiscal and other parameters affecting his investment. This attribute is desirable when one considers the high degree of risk that is inherent in prospecting for oil.

In practice it has been shown that even greater flexibility exists than what is stated above. At the time of the granting of Mossgas Lease, SOEKOR after having prospected in terms of OP26 for twenty years were of the view that the circumstances had changed in various respects and also that there were certain unsatisfactory elements within the wording of OP26 which justified amendment. The Minister of Mines and the Minister of Finance both showed a willingness to re-negotiate certain of the terms of the prospecting lease and the mining lease to accommodate those issues which they believed had merit. In essence, therefore, the prospecting lease should be regarded as the complete framework against which the investor can make his decision but sight must not be lost of the fact that the Minister of Mines and the Minister of Finance have shown a willingness to accommodate investors by altering the terms of the prospecting lease.

As was stated above the Mining Right Act of 1991 did not include a clause equivalent to Section 14 (3) which immediately raised the question of whether those provisions which conflicted with any existing legislation were valid in law. This resulted in the amendment to that act which in effect preserved the position of the Mossgas lease and the SOEKOR OP26 by virtue of the amendment to Section 44 of Act 50 of 1991, which reads as follows - "Section 44 of the Principal Act is hereby amended by the addition of the following subsection:

"(8) (a) The provision of the Mining Rights Act, 1967, in relation to the granting of a mining lease for natural oil in terms of section 25 (1) (g) of the said Act and any other matter in connection therewith shall, notwithstanding the repeal of the said Act by section 68(1), remain in force until the last existing prospecting lease granted in terms of section 14 mentioned in subsection (a) (a) (ii) has lapsed in accordance with subsection (1)(b).

b) Any mining right granted or acquired by virtue of paragraph (a) or any share in such right shall, notwithstanding the repeal of the Mining Rights Act, 1967, by section 68 (1), remain in force subject to the

terms and conditions under which it was granted or acquired or deemed to have been granted or acquired and which are contained in the document concerned.

c) The provisions of Section 47(1)(f) and (2) shall apply *mutatis mutandis* to a mining right referred to in paragraph (b).

d) Notwithstanding anything to the contrary contained in any law, agreement, authorisation or approval, no mining right referred to in paragraph (b) shall be ceded, transferred, let, sublet, tributed, subdivided, amended or mortgaged, either wholly or as to a part of parts, without the approval of the Minister granted in terms of this paragraph.

e) For the purposes of this act the holder of any mining right referred to in paragraph (b) or his successor in title shall, in relation to such mining right, be deemed to be the holder of - (i) the right to the mineral concerned in respect of the land concerned; and (ii) a mining authorisation".

Mining Tax Provisions Of The Income Tax Act

Before examining the fiscal provisions of the OP26 the taxation provisions of the Income Tax Act will be set out briefly this will be useful when one examines the provisions of OP26 to see how the provisions of the Mining Act have been deviated from in order to provide a more favourable result for the investor exploring for oil within the territorial waters of South Africa.

Taxable income derived from the carrying on of mining operations must be determined in accordance with the ordinary provisions of the Act, subject, in particular, to the special provisions contained in subsection 1 5 (2A), 15,36 and 37 of the Act. These special provisions provide for:

- Excess recoupments of capital expenditure (para (j) of the definition of the terms "gross income" in s 1).

- Section 5 (2A) provides for the basic rate plus the maximum levy of 40% as well as for the reduction of the levy to or by such an amount and on such conditions, as the Minister of Mineral and Energy Affairs in consultation with the Minister of Finance may determine.

- The deduction of contributions to a qualifying institution carrying out the environmental rehabilitation of mining land by a taxpayer engaged in mining, prospecting, quarrying or similar operations (11(hA)).

- The deduction of capital expenditure from income derived by the taxpayer from mining operations (subsection 15 (a) and 36).

- The deduction of expenditure incurred on prospecting operations from income derived by the taxpayer from mining operations (Section 15 (b)).

- In certain circumstances dividends declared by companies mining for natural oil are exempt from the non-resident shareholders' tax in terms of Section 42 (2) (e).

Other special provisions relating to mining operations are contained in:

- Section 9 (1) (cA), which provides that an amount will be deemed to have accrued from a source within the Republic if it has been received by or has accrued to or in favour of a person by virtue of a contract made by that person for the disposal of any mineral (including natural oil) won by him in the course of mining operations carried on by him under a mining lease granted under the Mining Rights Act 20 of 1967, wherever the contract was made or the mining operations were carried on.

- Section 9 (1) (fA), which provides that an amount will be deemed to have accrued form a source within the Republic if it has been received by or has accrued to or in favour of a person by virtue of any services rendered by that person to - or work or labour done by that person for - any other person upon, beneath or above the continental shelf referred to in Section 7 of the Territorial Waters Act 87 of 1963 in the course of operations connected with operations carried on by any person under a prospecting or mining lease granted or that may be granted under the Mining Rights Act or under any sublease granted or that may be granted under any such lease, wherever payment for the services or work or labour is or is to be made Section 18A, which provides a special basis for the deduction of qualifying donations made to universities, colleges or educational funds of the Bible Society of South Africa by companies carrying on mining operations.

  Mining operations are eligible for most of the appropriate deductions provided for by the Act. Nevertheless, the no longer available initial and the still current annual allowances on industrial buildings may not be claimed for buildings used in the course of the trade of mining (subsection 13 (1) and (7); the now terminated "50/30/20" depreciation is unavailable on machinery and plant used for the purposes of the trade of mining (Section 12B) and so is its replacement, "20/20/20/20/20" depreciation (Section 12C); and the benefaction allowance may not be claimed in the context of mining operations or operations normally carried on in the course of such operations.

- In terms of Section 42 (2) (E) of the Income Tax Act non-resident shareholders tax on dividends distributed out of taxable income from natural oil mining is not subject to NRST.

Although not relevant for the purposes of comparing the provisions of the Income Tax Act with the provision of OP26 it may be useful to distinguish between a speculator in mineral rights and a miner of mineral rights.

A speculator is one who engages on exploration in order to earn income from the disposal of any rights to mining for the oil which he may receive on discovering the oil. A miner earns income from the disposal of the oil itself.

Exploration Expenses Incurred by a Speculator

Exploration expenses incurred by a speculator will be deductible in terms of Section 11 (a) as it is expenditure incurred for the purposes of producing income from the disposal of the Oil Mining Rights which may result from the exploration. Such income will of course be taxable falling within the definition of gross income.

Strictly speaking, because the speculator regards his mineral rights as trading stock (see Section 22), this trading stock must valued and the value brought into income at the close of each year.

If there is no income from the disposal of mineral rights in the tax year that the exploration expenditure is incurred, then an assessed loss is created which can be carried forward to a future year or years where income is earned.

Exploration Expenses Incurred by a Miner

Exploration cost incurred prior to a mining lease being granted are deductible. However, it is only deductible from mining income, therefore, the deduction would have to wait until income is derived from mining. The expenditure cannot be offset against other non-mining income.

Exploration costs incurred in an area where a mining lease has been granted are not deductible as it does not fall within the ambit of Section (15) (b) nor does it fall within the definition of capital expenditure in Section 36. The expenditure can therefore only be deducted in terms Section 11 (a) this is considered unlikely. Capital expenditure is not deductible in terms of Section 11 (a) and, in view of the enduring benefits test, the expenditure in seeking further

mineral deposits would probably be regarded as capital expenditure that is more closely associated with the income earning structure rather than an expense incurred in the income earning operation.

The disadvantage of this is that the exploration expenditure can be incurred over a lengthily period and in the interim, until a commercial deposit is discovered and income is derived therefrom, there is no deduction. If no commercial discovery is ever made the expenditure will never be deductible.

A payment to compensate a predecessor in title for past exploration expenditure ought to acquire Mineral Rights is not deductible from mining income.

For this reason companies seek to deduct the expenditure under Section 11 (a) of the Income Tax Act rather than under section 15 (b). They do this by classifying themselves as traders in mineral rights. Mineral rights are stock in trade, the sale of which give rise to a non-mining income. The expenditure in acquiring those rights is therefore incurred for the purposes of producing income and is thus deductible in terms of section 11(a). The advantage of having the deduction in terms of Section 11 (a) rather than Section 15 (b) is that the expenditure can be settled against any income and not mining income.

If there is no discovery the exploration costs will have been deducted from other income and the objective has been achieved.

If there is a discovery the mineral rights must be sold to another group company which will exploit those rights. The income from the sale will constitute income which will be taxable as a recoupment thus effectively wiping out the effect of deducting the expenses ignoring (the time value of money). The purchaser will be allowed in terms of Section 37 (1) to deduct the cost of these so called development assets by virtue of them forming part of the capital expenditure incurred in Section 36 (11).

Should, therefore, a mining lease be issued to a tax payer it would be imperative, in determining his tax status, what his intention was. Is he a trader in natural oil Mining rights or a miner under those rights.

We shall now turn to examine the fiscal conditions of OP26.

Fiscal Provisions of OP26

An examination will now be had of the fiscal provisions of OP26. It is not the purpose of this minor dissertation to examine the contents of OP26 in its entirety.

This prospecting lease which also includes the terms of the mining lease was granted to SOEKOR on 23 June 1967 but has just prior to the granting of a mining lease to Mossgas (Pty) Ltd in 1990 been amended after negotiations between SOEKOR and the relevant Ministers. The principal clause dealing with taxation and the calculation thereof is contained in Clause 23, which is re-stated here for ease of reference purposes;

"23. Except to the extent exempted, SOEKOR shall throughout the term of this Mining Lease be liable for income tax payments to the State on the annual taxable income derived by it from the mining of natural oil in accordance with the Income Tax Act of the Republic of South Africa as amended from time to time but such tax, however, shall not exceed in respect of taxable income derived during any year of assessment from the mining of natural oil in the mining block, the sum of -

23.1 an amount of tax (hereinafter called the 'basic tax') calculated on the full amount of such taxable income at the rates applicable under the Income Tax Act to taxable income derived by a company from mining.

23.2 an amount of tax calculated on the balance of such taxable income remaining after the deduction therefrom the 'basic tax', at the rate of -

23.2.1 20% (twenty percent) if the total amount of the taxable income derived by SOEKOR from the mining of natural oil in the mining block during the years of assessment preceding the year of assessment in respect of which the income tax is payable, does not exceed an amount equal to the direct capital development costs incurred by SOEKOR in respect of the mining block, as determined in terms of sub-clause 23.3 hereof, or if SOEKOR has not derived any such taxable income during the said preceding years of assessment; or

23.2.2 30% (thirty percent) if the said total amount of taxable income exceeds an amount equal to the said direct capital development costs, but does not exceed an amount equal to twice direct capital development costs; or

23.2.3 40% (forty percent) if the said total amount of taxable income exceeds an amount equal to twice the said direct capital development costs.

23.3. For the purposes of this Clause 23 the direct capital development costs incurred by SOEKOR in respect of the mining block shall be deemed to be the sum of -

23.3.1 any expenditure actually incurred by SOEKOR itself in prospecting for natural oil in the mining block as well as in transactions in connection therewith excluding the costs of mineral or mining rights and land prior to the commencement of mining operations therein ; and

23.3.2 such expenditure actually incurred by SOEKOR itself in developing the mining block prior to the date of completing the development programme

for the production of natural oil from the mining block on a commercial sale, as in terms of the Income Tax Act is included in capital expenditure ranking for deduction from income derived by SOEKOR itself from mining for natural oil in the mining block.

23.4 The date referred to in sub-clause 23.3.2 hereof shall be such date as may be agreed upon between SOEKOR and the Commissioner for Inland Revenue or, in the absence of such agreement, as may be fixed by the Government Mining Engineer having regard to the circumstances.

23.5 SOEKOR shall maintain a permanent establishment in the Republic of South Africa and arrange its affairs in such a manner that all the profits from mining for natural oil under this Mining Lease will be attributable to that establishment.

23.6 Any payments to the State in terms of Clause 23 hereof, shall constitute SOEKOR's only commitment to the State, or any political sub-division thereof, for taxes or levies on the income derived by SOEKOR from the mining of natural oil and SOEKOR shall not be liable for:

23.6.1 any other taxes or levies of a similar nature, calculated in relation to taxable income; profits or turnover arising out of SOEKOR's operations in the mining and disposal of natural oil under this Mining Lease;

23.6.2 any share of profit by the State, any royalty or any other form of lease consideration in respect of the activities performed by it pursuant to this Mining Lease;

23.6.3 non-resident shareholders' tax or any other dividend withholding tax, in respect of dividends declared or paid in favour of shareholders who are not resident in the Republic of South Africa out of profits derived from the mining of natural oil, or any tax on the remittance outside the Republic of South Africa of profits derived from the mining of natural oil; or

23.6.4 undistributed profits tax in respect of profits derived from mining for natural oil.

23.7 In calculating the taxable income referred to in Clause 23 hereof, the deductions from income shall be as laid down in the Income Tax Act, provided that such deductions shall not be less favourable that those allowed under the Income Tax Act, as at the date on which the 1977 amendments thereto were promulgated, and shall in any event include -

23.7.1 under current working costs, also the cost of transportation of natural oil from the mining block to the marine terminal or the local refinery, as the case may be; and

23.7.2 as capital expenditure ranking for redemption -

a) the costs of laying pipelines from the mining block to the points referred to in sub-sub-clause 23.7.1 above or to the onshore processing facility of SOEKOR contemplated in sub-clause 13.5 hereof;

b) the costs expended by SOEKOR itself on prospecting operations within the area covered by the mining block in any tax year or part thereof prior to the date of granting of this Mining Lease;

c) the costs incurred by SOEKOR itself in connection with the viability of the relevant undertaking and the design, procurement, management (including also project management), transport and construction of the constituent parts (from and after raw material stage and including also the piles and other foundations) of any marine or onshore receiving installations erected or to be erected on the mining block or onshore with a view to exploitation of the natural oil discovered or found in the mining block, including also the costs of training of personnel for any purpose in connection with such installation, at any time prior to the successful commissioning of such installations but excluding any assets belonging to another taxpayer; and

d) a capital allowance equal to 12% (twelve percent) compound interest per annum on the total amount of unredeemed capital expenditure, ranking for redemption, calculated from the end of the month during which such cost was incurred, until it be redeemed and calculated, as far as this can be done, according to the provisions of section 26(3) and (4) of the Mining Rights Act, 1967, an example of which is attached hereto as Annexure I.

23.8 Expenditure shall not be disallowed as a deduction from income for income tax purposes merely because it has been incurred by SOEKOR outside the Republic of South Africa.

23.9 Mining activities taking place in or in connection with an area or areas covered by one Mining Lease and its associated pipelines and onshore receiving installations up to the boundary of the local refinery, if any, shall be deemed to have taken place in respect of a single mine provided that assets belonging to another taxpayer will be disregarded.

23.10 In the event of SOEKOR making a discovery of natural oil or a discovery in workable quantities and this Mining Lease being granted in respect thereof, there shall be deducted in each year of assessment throughout the continuation of this Mining Lease from the amount of tax calculated in accordance with the foregoing provisions of this Clause 23, an amount equal to 50% of so much of such tax as is relatable to taxable income derived from the disposal of natural oil from the mining block, provided that this deduction shall apply only with regard to the first Mining Lease granted in respect of waters up to 200 metres in depth and another two with regard to the first two Mining Leases granted in respect of waters of more than 200 metres in depth.

23.11 The amount of tax payable in terms of the preceding sub-clause of this Clause 23 shall be reduced to or by such an amount and subject to such provisions as the Minister of Economic Affairs and Technology, in consultation with the Minister of Finance, may determine.

23.12 In determining the taxable income in respect of the block, the prospecting, development and exploitation activities shall be taxed as set out in this Clause 23.

23.13 Should SOEKOR's offshore facilities be linked to an onshore plant also belonging to SOEKOR, the offshore facilities and pipelines as well as the onshore receiving facilities and pipelines (as well as all related structures and foundations) up to the boundary of the onshore plant

will be regarded as a mine and the income there from taxed as herein set out, while the rest of the onshore facilities will be regarded as a factory and the income there from taxed in accordance with the income tax laws of the Republic of South Africa as amended from time to time, the gross income of SOEKOR from the combined mine and factory being deemed to have originated from the mine and the factory respectively being in such proportion as SOEKOR and the Commissioner for Inland Revenue agree or, failing such agreement, as determined by any of the firms or entities referred to in Annexure 2 hereof at the request of the Commissioner, unless SOEKOR and the said Commissioner agree on another firm or entity.

23.14 Should SOEKOR (Eiendoms) Beperk be exempted from paying normal income tax, it shall exercise its rights herein through an affiliate, nominee, cessionary or assignee which is subject to such tax, which affiliate, nominee, cessionary or assignee shall be taxed in accordance with the Clause 23."

It may be felt that the wording of Clause 23 speaks for itself but I will make comments on each of the clauses ad seriatem;

- Section 23 in its entirety sets an upper limit on the tax that SOEKOR is to pay.

- Section 23.1 through to Section 23.2.3 provides a reduction to the provisional normal tax that is provided in Section 5 (2) (A) (a) of the Tax Act cited above by substituting it depending on the extent to which the taxable income exceeds the direct capital development costs and could be either 20%, 30% or 40%.

- In effect the Mining Operations of SOEKOR will be taxed on the taxable income from natural oil (which include crude oil and gas) at the rates applicable to mining income. To this however, will be added the special levy which is similar to the additional normal tax

referred to in Section 5 (2A) (a) but at rates which are capable of being less than 40% described in the aforesaid Section 5 (2A) (a) in that it can be 40%, 30% or 20% depending on the extent that taxable income exceeds the direct capital costs incurred by SOEKOR. This, therefore, represents a fiscal advantage that is not available outside of the lease (i.e. it is not catered for in the Tax Act to such an extent).

. Although Section 23 reads that SOEKOR will be liable for income tax payments to the State on the annual taxable income derived by it from the mining of natural oil in accordance with Income Tax Act of the Republic of South Africa as amended from time to time...." One must read this together with Section 32.1 which reads;

"The Mining Lease throughout the period of its existence, shall be governed by and interpreted in accordance with the laws of the Republic of South Africa respectively in force on the date the 1977 amendments to the Income Tax Act, 1962 (Act 58 of 1962), as promulgated, and by such further laws as maybe passed in addition to or in substitution of them, provided such further laws shall not adversely affect the rights and obligations of SOEKOR."

. When taking into account the provisions of this Clause 32, it is clear that although Clause 23 subjects one to tax in accordance with the Income Tax Act as amended of the day, should the results thereof be less favourable than those as existed at the date of the 1977 amendments and they will not be effective. Clearly an obligation of SOEKOR includes and obligation to pay tax.

. Clause 23.3 defines what the direct capital development cost would be and would seem to have been included in order to be used specifically for the purposes of being able to calculate the special levies referred to in 23.2 above.

. Clause 23.5 which requires SOEKOR to maintain a permanent establishment in the Republic so as to ensure that all profits arising from the Mining Lease are attributable to that establishment is clearly directed at ensuring that SOEKOR does not structure itself

in such a way that it could be argued that the profits were sourced outside of South Africa. If such were the case then that income would not be subject to tax by virtue of it not falling into the definition of "gross income" of the Tax Act which requires inter-alia that the amount received in order for it to fall within the definition of "gross income" must have originated from a "source within or deemed to be within the Republic."

One would have thought that this provision would be unnecessary in the light of **Rhodesian Metals Limited (in liquidation) versus C O T 1938 AD 282**, as it would be very hard for SOEKOR to create a set of facts such that it could argue that the originating cause was something other than the mine itself. However, the Minister of Mines was probably being cautious and wanted to establish certainty that income would be regarded as falling within "gross income" by virtue of this provision.

- Clause 23.6 is that clause which endeavours to limit the taxes payable to the State to that sum which is specified in the lease. However, if one looks at the wording of this clause it would seem that certain taxes could be argued not to fall within the ambit of this clause and therefore do not rank for exemption.

The reason for the statement that not all taxes are caught by these provisions is that it could be argued that VAT is not "a tax or levy of a similar nature, " nor is it "a profit on turnover" - as per 23.6.1.

It is recommended that as it is a desirable feature of leases of this kind to bring clarity to the liabilities of the investor that this uncertainty be eradicated by way of an appropriate amendment to the lease.

- Paragraph 23.7, is a capping provision in that the deductions from income although required to be those as laid down in the Income Tax Act have the proviso that "such deductions shall not be less favourable than those allowed under the Income Tax Act, as at the date on which the 1977 amendments thereto were promulgated..."

As we have seen, Clause 23.1 refers to SOEKOR's liability for income tax payment to the State on their annual taxable income derived from the mining of natural oil in accordance with the Income Tax Act.

The provisions of this clause must be considered in relation to section 36 (7E) and section 36 (7F). Section 36 (7E) was introduced by way of section 25 (C) Income Tax Act 1983 effective as from the commencement of years of assessment ending on or after the 1 January 1984 and Section 36 (7F) was inserted by Section 6 (1) of the Income Tax Act 1985 effective as from the commencement of years of assessment ended on or after 5 December 1984.

Section 36(7E) of the Act restricts any deduction available by reference to mining capital expenditure to mining income, any capital expenditure in access of that income being carried forward and deemed incurred in the following year. It is important to note that this deduction is limited to mining income and may not be offset against any other tax base that a taxpayer may have. In the absence of OP26 if SOEKOR were to make available mining income base then the provisions of Section 36 (7F) would still ring fence the capital expenditure. Section 36 (7F) has the effect that the expenditure in excess of income from a particular mine cannot be offset against any other income including any other mining income but must be carried forward and deemed to be capital expenditure and incurred by that mine in the future year or years.

As can be seen from the date that each of these subsections were introduced they were not in effect on the date 1977 amendments to the Income Tax Act were promulgated. The application of Clause 23.7 has the effect of removing the ring fencing applied by Sections 36 (7E) and 36 (7F) so that SOEKOR and or any party mining in terms of this lease will be able to offset mining capex in excess of its mining income against its other income.

I would argue that the amendments introduced in 1983 result in a lesser deduction against mining income than before 1983. Accordingly Section 38.6 (7E) and 36 (7F) produce a less favourable result and would therefore not apply. In essence, therefore, the ring fencing provided by those two sections would not be applicable in terms of this lease.

This is a tremendous advantage to SOEKOR and or Mossgas (and or any co-venturer).

If one looks at the Mossgas situation for one moment which has spent approximately R7 billion on building a refinery to process the natural oil derived from the offshore mine then it would be able to offset the capital expenditure of the mining against the income derived from the mining and manufacturing activities.

It has been assumed that any joint venturer with SOEKOR would have access not only to the industrial capex as well as the mining capex and further would be able to use mining as well as non-mining income base. Mossgas will by virtue of its onshore refinery being a process of manufacture also enjoy the deductions allowed in terms of Section 12 of the Act. If one considers the size of the project the amount of tax base that could be taken out of the Commissioner pockets may be of real concern. However, it appears that the Mossgas venture does not have the potential profits to entice a private participant to participate notwithstanding those tax allowances.

- The rest of Clause 23 really defines capital expenditure ranking for redemption and goes beyond Section 36 of the Income Tax 1962 in certain respects.

- Clause 23.8 promotes the deduction from income of expenditure that may have been disallowed by virtue of it having been incurred outside South Africa.

This clause may have been of more relevance when Section 11 (b) allowed the deduction of expenditure incurred outside the Republic only at the discretion of the Commissioner of Taxes. This latter requirement has since fallen away.

- Section 23.10 provides for a permanent rebate of 50% of so much of the annual tax payable in respect of the taxable income relating to the lease area in the event of SOEKOR making a first discovery of natural oil. Provision is made for one such discovery in respective waters of up to 200m in depth and two such discoveries in respect of waters of more than 200m in depth. (This rebate has no equivalent in the Tax Act).

- Clause 23.11 provides for a reduction of the amount of tax payable in terms of this Clause 23, should the Minister of Economic Affairs and Technology in consultation with the Minister of Finance so determine. (A similar provision is found in the Tax Act - Section 5 (2A) (b)).

  Having such a clause is always advisable as it empowers the respective Ministers to make amendments in order to take into account the exigencies at any given time.

- Clause 23.14 is interesting but probably takes cognisance of the fact that SOEKOR as a parastatal may be capable of being exempted from tax.

- One further clause in the lease which has an important application on the fiscal provisions is that contained in Clause 30, which reads as follows

  > "the Minister by his execution of this Mining Lease hereby approves and adopts the terms and conditions thereof on behalf of the State of the Republic of South Africa and undertakes on behalf of the State of Republic of South Africa and the Minister to do and perform all acts and things which are or maybe required to be done or performed to give full effect to this mining lease in accordance with its provisions terms and

conditions and guarantees that the rights and obligations especially created hereby **shall not be altered without the consent of SOEKOR."**

Clearly, therefore, before any changes can be effected SOEKOR consent will be required and one cannot envisage a situation of greater liabilities being accepted by SOEKOR. This is an example of further protection being afforded the investor.

CONCLUSION

It would seem that in many respects that the prospecting lease (OP26) and the concomitant Mining Lease go a long way to providing an investor with the degree of certainty as to the fiscal terms that one would expect in contracts of this nature. It has the desirable features of flexibility in changing circumstances and always to the benefit of the investor. Bearing in mind that the prospectivity of South African waters are doubtful every reasonable aspect which encourages participation to explore for oil should be considered and where possible implemented. However, from what has been stated above there are certain areas which require clarification and or amendment to achieve what one would regard as a more satisfactory result.

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