

## **Revenue from the Oil and Gas Sector: Issues and Country Experience**

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### **I. INTRODUCTION**

Oil and gas extraction plays a dominant role as a source of export earnings and, to a lesser extent, employment in many developing countries. But the most important benefit for a country from development of the oil and gas sector is likely to be its fiscal role in generating tax and other revenue for the government. To ensure that the state as resource-owner receives an appropriate share of the economic rent generated from extraction of oil and gas, the fiscal regime must be appropriately designed.

The government, as resource owner, has a valuable asset in the ground. This asset—a crude oil or natural gas deposit—can only be exploited once. In order to convert this asset into financial resources, the government must attract capital on terms that ensure it gets the greatest possible value for its resources—under uncertainty about what the value of the resources will turn out to be.

There is a fundamental conflict between oil and gas companies and the government over the division of risk and reward from a petroleum project. Both want to maximize rewards and shift as much risk as possible to the other party. Nevertheless, the right choice of fiscal regime can improve the trade-off between each party's interests—a small sacrifice from one side may be a big gain for the other. Oil and gas agreements and the associated fiscal rules establish the “price” of the resource in terms of the bonuses, royalties, taxes or other payments the investor will make to the government over the life of the project. Designing fiscal arrangements that encourage a stable fiscal environment and efficient resource development maximizes the magnitude of the revenues to be divided.

In designing fiscal instruments, the government will need to weigh its desire to maximize short-term revenue against any deterrent effects this may have on investment. This will require a balanced sharing of risk and reward between the investor and the government. The aim should be for fair and rising government share of the resource rent, without scaring off potential investors.

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<sup>1</sup> Background paper prepared for the IMF conference on fiscal policy formulation and implementation in oil producing countries, June 5-6, 2002. This paper draws on previous work undertaken in FAD, including more recently Sunley and Baunsgaard (2001) and Baunsgaard (2001)

## **II. REVENUE ISSUES**

The government can collect revenue from the oil and gas sector by a variety of tax and nontax instruments. Most countries collect the government share of economic rent primarily through production-based or profit-based instruments. In some countries, the government participates more directly in project by taking an equity interest.<sup>2</sup> Policymakers will also have to decide on the treatment of indirect taxes such as VAT and customs duties.

Multiple fiscal instruments may be needed to create an identity of interest between the government and the oil and gas companies over the life of the agreement. Production-based instruments, such as royalties, can ensure the government receives at least a minimum payment for its mineral resources. Profit-based instruments allow the government to share in the upside of highly profitable projects, but they also increase the government's share in the project's risk inasmuch as the government may receive no revenue if the project turns out to be unprofitable.

In addition to product-based and profit-based instruments, there may be bonuses and rental payments of various types. Bonuses can ensure some up-front revenue for the government and may encourage companies to explore and develop contract areas more rapidly. They are usually suitable only in highly prospective areas where there is strong competition among investors for petroleum rights. Annual rental payments typically are not a significant source of revenue but can be designed to encourage companies to explore and develop contract areas or to relinquish their rights.

In many countries with petroleum resources, revenues from different instruments accrue to different parties; for example, royalty payments may be made to local units of government, landowners or the petroleum ministry.

### **A. Tax/Royalty Regimes**

A common way of taxing the oil and gas sector involves a combination of tax and royalty payments. A tax/royalty regime may involve three levies: (1) a royalty to secure a minimum payment, (2) the regular income tax that is applicable to all companies, and (3) a resource rent tax to capture a larger share of the profits of the most profitable projects.

#### **Royalties**

Royalties are attractive to the government, as the revenue is received as soon as production commences and they are easier to administer than many other fiscal instruments, at least for simple royalty regimes. Furthermore, they ensure that companies make a minimum payment

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<sup>2</sup> While this paper will address some issues relating to state equity participation in a project, the role of state-owned oil companies as active participants (operators) is discussed in the paper by Charles McPherson.

for the minerals they extract. Royalties are typically either specific levies (based on the *volume* of oil and gas extracted) or ad valorem levies (based on the *value* of oil and gas extracted). Some countries have introduced a profit element in royalties by having them depend on the level of production (e.g., Chile, Ecuador, Norway, and Thailand) or on a measure of nominal return such as the R factor (e.g., Peru, and Kazakhstan).<sup>3</sup>

As royalties raise the marginal cost of extracting oil, they can deter investors if imposed at too high a level. They may also discourage development of any marginal reserves that have been discovered and lead to early abandonment of productive oil and gas wells. Investors are resistant to the use of royalties, even on potentially rich deposits, partly on the grounds that royalty payments are only a deductible expense in determining taxable income in the home country and are not allowed as a foreign tax credit against the home country's income tax.

A key issue for policymakers is to determine an appropriate method for the valuation of the extracted oil and gas used as a base for royalties and other taxes. Ad valorem royalties are generally levied on the sales price or the f.o.b. export price, at times after netting back certain costs.<sup>4</sup> An overriding concern should be the use of an observable price. When using a generally quoted market price (e.g. North Sea Oil), it should be adjusted to reflect differences in gas and crude oil quality and the wellhead value should be established by netting back transportation and other costs.<sup>5</sup>

## **Income Tax**

The income tax should be levied on oil and gas companies, as on all other companies. It is not unusual for the profit tax rate for oil companies to be higher than the general rate for other companies. This is one way to capture a share of the resource rents from the project.

Many countries provide an incentive for exploration and project development by allowing exploration costs to be recovered immediately and allowing accelerated recovery of development costs, for example, over five years. Accelerated cost recovery brings forward payback for the investor and, possibly, retirement of debt. It can therefore reduce both

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<sup>3</sup> The R factor equals cumulative revenues, net of royalties, divided by cumulative costs.

<sup>4</sup> Some countries (e.g. OPEC countries until 1974 and Nigeria until 1986) have historically used government-set prices, which were often independent from market prices. This practice is disappearing. In contrast, Norway introduced in 1974 a government-set price for oil defined as the real market price of the same type of crude over a given period.

<sup>5</sup> Governments can exercise a considerable amount of discretion in determining price adjustments. For instance, in order to establish gross revenue at the wellhead, the UK inland revenue allowed as deductions from the landed price not only transport costs from North Sea fields but also around 70 percent of production platform costs. This practice was abandoned by the end of the 1970s (Kemp, 1987).

investor risk and tax-deductible interest costs; it also facilitates project financing. Some countries offer special incentives to encourage exploration in particular regions.

To protect the tax base, countries may place limits on the use of debt financing to limit “earning stripping” through the payment of interest abroad.<sup>6</sup> To limit abusive transfer pricing between related companies, the tax authority should have the power to adjust income and expenses where under- or overpricing between related companies has resulted in a lowering of taxable profit (see Box 1).

#### **Box 1. Transfer Pricing**

Through transfer pricing, a taxpayer seeks to minimize income and maximize deductible expenditures in high-tax jurisdictions and vice versa in low-tax jurisdictions.

A transfer pricing mechanism that could affect revenue in the oil and gas sector is:

- The creative use by firms of price hedging mechanisms perhaps involving transactions between related parties, causing great difficulty in assessing whether hedging instruments are used for transfer pricing purposes rather than to reduce risk.

More common measures to maximize expenditure deductions include:

- The provision by related parties of highly leveraged debt finance at above-market interest rates.
- Claiming excessive management fees, deductions for headquarter costs, or consultancy charges paid to related parties.
- The provision of capital goods and machinery in leasing arrangements at above-market costs charged by a related-party lessor.
- If the petroleum tax rate is above the standard tax rate, there may be an incentive to establish a domestic shell firm that will on-lend financing capital from related parties to the oil company giving rise to an interest deduction at a higher tax rate than is charged on the interest earnings in the shell company.

Abusive transfer pricing can be very difficult to detect and prevent. Properly designing the tax code, though, is an important first step. At a minimum, the tax legislation should include safeguards requiring that transactions between related parties be assessed on an arms-length basis, or perhaps that certain deductions be capped as a share of total costs. Some countries also impose a limit on the allowable (for tax purposes) debt-leverage of a project. It is also advisable to seek close cooperation with the tax authorities in the home countries of the more important investors.

A related issue for the taxpayer is the treatment of tax credits. Many multinational companies expect to be subject to an income tax in the producing country, as this tax will be creditable against the income tax levied in the home country. Absent an income tax in the producing country, the multinational may be subject to higher tax payments in the home country.

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<sup>6</sup> For instance, in Norway, liberal rules (the current limit on external financing is 80 percent) for the deduction of financial costs from both the corporate income tax and the Special Tax has been identified as one of the basic problems of the Norwegian petroleum taxation (Noreng, 2002).

Whether or not a tax is creditable depends on the particular tax law in the home country and on any tax treaties in place.<sup>7</sup> However, a tax paid in the producing country that in nature resembles a home country tax is most likely to qualify for a tax credit. Some specialized mineral taxes, such as a resource rent tax, may be deemed to differ in nature from a standard corporate tax and, therefore, could face difficulties in qualifying for a tax credit.

It is important to determine the extent of “ring-fencing” of tax accounts. Ring fencing means a limitation on consolidation of income and deductions for tax purposes across different activities, or different projects, undertaken by the same taxpayer. Some countries ring-fence oil and gas activities, others ring-fence individual contract areas or projects. This can become complex if a project incorporates extraction, processing and transportation activities. If the oil and gas tax regime is more onerous than the standard tax regime, the taxpayer could seek to have certain project-related activities treated as down-stream activities outside the ring fence. If they are treated as a separate activity, the taxpayer through transfer pricing may attempt to shift profits to the lightly taxed downstream activities.

Ring-fencing rules matter for two main reasons:

- Absence of ring fencing can postpone government tax revenue because a company that undertakes a series of projects will be able to deduct exploration or development expenditures from each new project against the income of projects that are already generating taxable income.
- As an oil and gas area matures, absence of ring fencing may discriminate against new entrants that have no income against which to deduct exploration or development expenditures.

Despite these points a very restrictive ring-fence is not necessarily in the government’s interest.<sup>8</sup> More exploration and development activities may occur if taxpayers can obtain a deduction against current income, generating more government revenue over time by increasing the taxable base. The right choice is again a matter of balance within the fiscal regime, the degree of government’s preference for (modest) early revenues over (greater) revenues later on and the extent of the government’s bargaining power with oil and gas companies.

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<sup>7</sup> Unless foreign sourced income is exempt in the home country.

<sup>8</sup> Oil and gas companies see this provision as a major disincentive. For instance, they have proposed repeatedly that the Indonesian government relax its restriction on transferring expenses from one contract area to another. However, the government maintained its ring-fencing provision (Gao, 1994). Indonesia’s relatively tough fiscal arrangements (Barrows, 1988) are compensated by its attractive oil and gas potential.

## Resource Rent Tax

An innovative attempt both to provide the government with an appropriate share of economic rent *and* to make the tax system less distortive to investors is the resource rent tax (RRT). The RRT (such as is applied for example in Australia and Papua New Guinea) is imposed only if the accumulated cash flow from the project is positive. The net negative cash flow (in the early years of a project) is accumulated at an interest rate that, in theory, is equal to the company's opportunity cost of capital (adjusted for risk).<sup>9</sup>

The RRT takes a share of returns once the company has earned this hurdle rate of return. If the only tax imposed is the RRT, the government's revenue stream becomes back-loaded, and for less profitable projects, the government may not receive any revenue at all. Therefore, a resource rent tax is usually combined with royalties and a standard profit tax to provide some early revenue.<sup>10</sup> Only for very profitable projects will the resource rent tax then apply.

Conceptually, a RRT has strong economic features. Properly designed, a RRT captures a share of the natural resource rent, which is the return over and above the company's opportunity cost of capital. Proponents argue that the RRT can enhance contract stability because it automatically increases the government share in highly profitable projects. For the RRT to be efficient, each contract area needs to be ring-fenced. That is, costs incurred in one contract area cannot be used to offset the revenues in another contract area. One exception to this rule may be to allow unrecovered costs from an abandoned contract area to carryover to a contract area that remains active. This helps to prevent an RRT from discriminating against exploration.

While the resource rent tax has much theoretical appeal, it has not been a significant revenue raiser in practice. There may be many reasons for this. It could reflect the difficulty of designing the tax, particularly the choice of the discount (or hurdle) rate and tax rate. If the hurdle rate is set too high, chances are that the resource rent tax will never apply; if it is set too low, the tax may become a major deterrent to investment.<sup>11</sup> If either the hurdle rate of return is too low or the tax rate too high, the RRT will also increase the incentives for oil

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<sup>9</sup> The "opportunity cost of capital", which is equal to the discount rate, means the expected return on the best alternative use of available funds.

<sup>10</sup> Palmer recommends that the resource rent tax be combined with a traditional company profits tax (Palmer, 1980).

<sup>11</sup> A weakness of a tax based on rates of return is that it does not take geological risks into account (Van Meurs, 1988, p. 72).

companies to engage in tax avoidance, which in countries with a weak tax administration may be very difficult to detect and control.<sup>12</sup>

## **B. Production Sharing**

An alternative to a tax/royalty regime is production sharing.

Under a production sharing arrangement the ownership of the resource remains with the state and the oil and gas company is contracted to extract and develop the resource in return for a share of the production. The government retains the right to petroleum reserves in the ground but appoints the investor as “contractor” to assist the government in developing the resources. Instead of paying the contractor a fee for this service, while the government bears the risk, cost and expense, the parties agree that the contractor will meet the exploration and development costs in return for a share of any production that may result. The contractor will have no right to be paid in the event that discovery and development does not occur. In principle, the government retains and disposes of its own share of petroleum extracted, though joint-marketing arrangements may be made with the contractor.

The mechanics of production sharing in principle is quite straightforward. The production sharing contract (PSC) will usually specify a portion of total production, which can be retained by the contractor to recover costs (“cost oil”). The remaining oil (including any surplus of cost oil over the amount needed for cost recovery) is termed “profit oil” and is divided between the government and the contractor according to some formula set out in the PSC.

Royalties can also be introduced into the production sharing regime. In some PSCs there is an explicit royalty payment that is paid to the government before the remaining production is split between cost and profit oil. An alternative to a royalty is to have a limit on cost oil (e.g., 60 percent of production), which ensures there is profit oil, as soon as production commences. Where a cap is imposed on the deduction of costs and costs are at this limit, the cap will have a similar economic impact as a royalty, with the government receiving revenue—its share of profit oil—as soon as production commences.

Unrecovered costs in any year are carried forward to subsequent years, but some PSCs allow these costs to be uplifted by an interest factor to compensate for the delay in cost recovery. Interest expense is generally not a recoverable cost. If interest expense is allowed to be recovered, then there should be no uplift for unrecovered costs as this would involve a double counting to the extent unrecovered costs are debt financed.

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<sup>12</sup> Although in this respect a properly designed RRT is probably less distortionary than the regular corporate income tax, since normal CIT postpones the achievement of a desired rate of return (particularly if slow depreciation rates are specified) and therefore encourages other behavior likely to increase current deductions.

The split of profit oil is often fixed—60 percent for the government and 40 percent for the investor, for example. It may vary by level of production, the price of crude oil, or the internal rate of return earned on the project. Contractors often pay income tax on their share of production. This tax could be paid out of the government’s share, but then the government’s share should be increased, all other things equal.<sup>13</sup> A significant advantage of this approach is that the contractors would have fiscal stability—any future changes in the tax rules would affect only the allocation of the government’s share between tax and non-tax oil. The assurance of fiscal stability is an important investment incentive, carrying the cost of reduced flexibility for the government to increase tax on a given project in future (see Box 2 on explicit fiscal stability clauses).

### **Box 2. Fiscal Stability Clauses**

Given the nature of investment in oil and gas extraction—long term, large-scale and up-front—a particular concern for investors is to guard themselves against unforeseen changes to the financial premises of the project. One safeguard mechanism that is often sought by investors is the inclusion of a fiscal stability clause in the project agreement. While this to the government can seem an attractive and, in the short run, inexpensive way of minimizing investor risk, it does limit the government’s flexibility to set tax policy, potentially resulting in a revenue loss and increased administrative costs.

Fiscal stability clauses come in different forms. One approach is to “freeze” the tax system at the time of the project agreement. If the tax system is later changed, this will imply a special treatment of a particular taxpayer, adding to the administrative burden, especially if several projects are operating under different tax systems. Another approach is to guarantee the total investor take. If one tax is increased, this will be offset by a reduction in another tax (or in principle by paying a compensatory subsidy), which perhaps better preserves the integrity of the tax system. Still, it may be quite difficult in practice to agree on compensatory measures that can satisfy both government and investor. There are also some stability clauses that are asymmetric: protecting the investor from adverse changes to the fiscal terms but passing on benefits of economy-wide reductions in tax rates.

Fiscal stability clauses are widespread in the oil and gas sector. Of 109 countries surveyed in 1997, a majority (63 percent) provided fiscal stability clauses for all fiscal terms (see annex Table 3). A small group (14 percent) had partial fiscal stability clauses excluding income tax. Finally, a minority (23 percent) did not provide any fiscal stability clauses in project agreements (at least up until 1997). However, this does of course not prevent an investor from seeking to renegotiate fiscal terms in response to policy changes. A recent example of a country, which repealed its tax stability clause for contracts signed from 2002 onwards, is that of Kazakhstan (Page (2002)). Tax conditions set in contracts may now be adjusted in compliance with amendments to tax laws, by the mutual consent of the government and the contractor.

A versatile production sharing framework can be attractive to both the contractor and government since it can be adjusted to suit particular project circumstances without changing the overarching fiscal framework. However, it might include design and administrative complexities causing a PSC to be as complex to administer as profit-based taxes. Difficulties

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<sup>13</sup> As an example, see the Indonesian case, as detailed in Appendix I.

relate particularly to the determination of allowable costs. Moreover, it is possible that the ex ante agreement becomes quite inappropriate as the real profitability of a project becomes known.

### C. The Choice between Tax/Royalty and Production Sharing Regimes

There is no intrinsic reason to prefer a tax/royalty regime to a PSC regime, since the fiscal terms of a tax/royalty regime can be replicated in a PSC regime, and vice versa (Table 1). For example, the PSC may have an explicit royalty, or there may be a limit on cost oil that function as an implicit royalty. In a PSC regime, the contractor can be subject to the same income tax as other companies. The split of profit oil can mimic a resource rent tax. This is especially true if unrecovered costs are uplifted by an interest factor that approximates the contractor’s opportunity cost of capital. In such cases, there would be no profit oil to be split, other than the profit oil representing the implicit royalty, until the project has earned the hurdle rate of return.

Table 1. Comparison of Tax/Royalty and PSC Regimes

Risk/Reward Trade-off	Tax/Royalty Regime	Production Sharing
Low risk to government	Royalty	There may be an explicit royalty; or there may be a limit on cost oil that functions as an implicit royalty
Medium risk	Income tax	Income tax, which may be paid out of the government’s share of production
High risk	Resource Rent Tax	The determination of the amount of profit oil can mimic a resource rent tax

PSCs permit the conditions governing petroleum exploration and development to be consolidated in one document. They may be particularly helpful to newcomers, not familiar with the operating environment, since the necessary provisions (including fiscal stabilization) can be consolidated in the PSC and the way in which the law will be applied can be clarified. The PSC is a straightforward way in which *contractual* assurances, additional to statutory rights, can be offered to investors.

### D. State Equity

A government may also participate more directly in an oil and gas project by taking equity in the project. State equity can take several forms, including: (i) a full working interest—paid-up equity on commercial terms, which places the government on a par with a private investor; (ii) paid-up equity on concessional terms, where the government acquires its equity share at a below-market price, possibly being able to buy into the project after a commercial discovery has been made; (iii) a carried interest, where the government pays for its equity share out of production proceeds, including an interest charge; (iv) tax swapped for equity, where the government’s equity share is offset against a reduced tax liability; (v) equity in exchange for a non-cash contribution, for example by the government providing infrastructure facilities; and (vi) so-called “free” equity, which is a bit misleading since even

the non-cash provision of equity usually results in some, more or less transparent, off-setting reduction in other taxes.<sup>14</sup>

State equity participation is mainly motivated by a desire to share in any upside of a project, but can also reflect non-economic reasons. These can relate to nationalistic sentiment, to facilitate transfer of technology and know-how, or to provide more direct control over project development. But full equity participation can become a costly option when consideration is given to the resulting cash-calls.<sup>15</sup> There are also possible conflicts of interest arising from the government's role as regulator overseeing the environmental or social impact of a project, which may differ from its objectives as a shareholder. In many instances, the government may be better off by focusing on taxing and regulating a project rather than being directly involved as an equity participant. It should also be kept in mind that tax instruments can replicate the economic impact of an equity share. For example, a carried interest is equivalent to a resource rent tax with the equity share equal to the tax rate and the interest rate on the carry equal to the threshold discount rate.<sup>16</sup>

### **E. Indirect Taxes**

The imposition of indirect taxes, such as customs duties and VAT, though often ignored in discussions of petroleum taxation, play an important role in the fiscal regime. In principle, oil and gas projects should be treated similarly to other economic activities when it comes to indirect taxation. In practice, however, the oil and gas sector is often treated differently either due to its special nature or as a fiscal incentive to attract investors.

#### **Import duties**

If there were no special treatment for import duties, these would be an attractive way for the government to secure an up-front revenue stream. Given the very substantial import needs, particularly during project development, this revenue is typically even more front-loaded than royalty payments. For the same reason, duty exemptions are highly attractive to investors to improve project economics. Duty exemptions can also be sought as a way to minimize dealings with customs officials, where foreign enterprises with substantial import needs can be an easy target for rent-seeking behavior.

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<sup>14</sup> See Daniel (1995) for a comprehensive discussion. Furthermore, in some transition economies, the government's inability to honor its financial commitments under a joint partnership has led to numerous tax concessions to oil and gas companies due to its weakened bargaining position.

<sup>15</sup> Cash advances required to be paid by each joint venture company to meet the net cash requirement of the joint venture.

<sup>16</sup> See Nellor and Sunley (1994) for an illustration of this point.

It is quite common that specialized equipment for exploration and development is exempted from import duties. It is advisable to restrict this exemption by requiring that the equipment is re-exported after its use. In some countries, all project-related inputs (perhaps restricted to purchases that are not available locally) receive a blanket exemption. Some countries provide guarantees against discriminatory duties being imposed on oil and gas companies, for example by applying a maximum allowable duty. This can result in reverse discrimination whereby duties on imports for petroleum projects are in effect lower than for other importers.

### **Value added tax**

The treatment of the oil and gas sector for VAT purposes is often influenced more by administrative realities than by principles of good tax policy. In a developing country, typically a large share, if not all, of the output from a petroleum project will be exported. Combined with the very large investment needs, this can complicate the treatment for VAT purposes. If exports are zero-rated under a destination-based VAT regime, the taxpayer will likely be in a continuous net refund situation reclaiming VAT paid on investment goods or on inputs. While this in an economic sense is the correct treatment of an exporter, it may be difficult to pay refunds in a timely fashion if the administrative capacity is weak. This situation is further exacerbated by the magnitude of the VAT refunds, particularly during periods with large investment requirements.

Faced with this refund problem, many countries provide VAT exemptions for imported capital goods and sometimes imported inputs for oil and gas extraction. This treatment may also be sought for domestic suppliers to projects, though this can be particularly problematic since it opens a loophole for domestic firms to evade VAT. That said, if the capacity is not in place to administer a refund based system, it may be an unavoidable option to introduce a sector-specific exemption for capital goods, perhaps extended to certain specialized inputs used exclusively for oil and gas extraction. It is desirable that the exemption should not apply to inputs that can be easily used by other sectors in the economy, for this would open another loophole for tax evasion.

The standard international practice is to levy VAT on the destination basis, under which imports are taxed and exports are zero-rated. An exception to this practice was the treatment of trade between the new countries (other than the Baltics) formed after the dissolution of the Soviet Union, (hereinafter referred to as the “CIS countries”). In part because the former Soviet Union was viewed as a common economic space, the CIS countries adopted the origin basis for CIS trade, under which goods are taxed in the country in which they are produced. Non-CIS trade was taxed under the destination basis.<sup>17</sup> The CIS countries have now adopted

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<sup>17</sup> See Baer, Summers, and Sunley (1996) for a discussion of the destination VAT for CIS trade.

the destination basis for CIS trade, other than oil and natural gas.<sup>18</sup> As Russia is a large net exporter of oil and natural gas, this special rule involves a transfer of tax revenue to Russia, primarily from the Ukraine. As a matter of tax policy, applying the origin basis to trade in oil and natural gas is an unjustified poaching of the tax base.

### **Export duties**

Most export duties that countries levy are concentrated in a few products. These duties are sometimes justified as a means of taxing away windfall gains, as a substitute for income taxation (on agricultural products), and as a way to improve the terms of trade. Many countries have removed export duties as part of tariff reform programs aimed at establishing outward oriented trade regimes.

Export duties generally are not levied on oil and gas. However, Russia levies export duties on oil, natural gas, and oil products. The oil tariff is a sliding scale tied to the Ural oil price, and the rate is adjusted every two months. Below \$15 per barrel, there is no export duty. This levy, which has been justified as a revenue measure, primarily burdens producers and distorts the price of exports and domestic oil supplies. Under the current Fund program, this tax is to be removed in 2003.

### **F. Other Nontax Payments**

A number of other nontax instruments are available, though these are often of lesser importance in terms of revenue generation. Many countries require payment of various fees; either fixed or auctioned, such as license, rental or lease fees. These are commonly paid to the petroleum department and to some extent act as an incentive for the investor to carry out exploration and development work on the granted license area. Common for oil and gas projects in many countries is the requirement to pay signature, discovery and production bonuses. The attraction to the government of bonus payments is that these are received early in the project cycle;<sup>19</sup> for the same reason, they may discourage marginal investments. However, collecting bonus payments requires little administrative effort and is a desirable way to ensure some early revenue from an oil and gas project.

Auctions for exploration or development rights could in theory be a very attractive way of securing the state's share of economic rent. However, for countries where political risk is perceived to be large, or with a high level of geological uncertainty, investors will be fewer and very risk averse prior to development. The bids received will therefore be lower than the

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<sup>18</sup> However, there is one other exception to the switch to destination principle. All trade between Belarus and Russia remains on the origin principle.

<sup>19</sup> Signature and discovery bonuses are received prior to project development, whereas production bonuses are paid when production commences or reaches certain prescribed levels.

expected net present value of a mineral deposit in a situation of no uncertainty. This could lead to demands to increase the government take if a project turns out to be more profitable than the original bid would reflect. Despite this bias, an auction can be a desirable way to administer the allocation of exploration rights among oil and gas companies, as it is done in some countries, though it would be unrealistic to rely on this as a major revenue source. Empirical evidence on the effectiveness of auctioning exploration or development rights is mixed across countries.<sup>20</sup> Although auctions have performed very efficiently in the US, they were not as successful in the UK due to a much lower number of bidders. In Venezuela, the 1997 bidding round was viewed as successful in raising government revenue, though some industry sources suggest that the winning bids were at a substantial premium.

### **III. COUNTRY EXPERIENCE**

#### **A. Cross Country Evidence**

Reflecting that there is not one optimal model for taxing oil and gas projects, countries make use of a broad range of tax and non-tax instruments. To illustrate the range of fiscal regimes, Table 2 provides an overview of current practice in a wide number of developing countries.<sup>21</sup> While fiscal regimes for oil and gas exploration are strikingly diverse across countries, some general observations can be inferred.<sup>22</sup> The majority of countries in the sample apply royalties in order to secure an up-front revenue stream. Moreover, while almost all countries assess royalties on an ad valorem basis, the actual rates vary from 2 percent to 30 percent; a common range for countries with royalties would be around 5-10 percent.

The choice of tax rate reflects the typically higher economic rent in the petroleum sector. Countries without production sharing arrangements or a resource rent tax typically apply a higher income tax rate in the oil and gas sector than for other economic activities. Some countries have combined a corporate income tax with a resource rent tax, often rate-of-return based, whereas a few countries apply a higher income tax rate when oil prices exceed a certain trigger level. Some countries have provided for more lenient taxation of natural gas projects, partly reflecting lower resource rents, the typically higher investment requirement, and at times larger risk involved than under an oil project. Key issues in gas development are

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<sup>20</sup> See Frewer (2000).

<sup>21</sup> Since some countries apply special fiscal terms to individual projects, either through separate legislation or on a contractual basis, the information should only be regarded as indicative of general fiscal terms or standard contracts in the petroleum sector, whereas a particular project may actually be operating under different fiscal terms.

<sup>22</sup> A priori, one would expect that (i) countries with large proven oil reserves and relatively low exploration and development costs will be able to have a tougher fiscal regime; and (ii) high-cost countries with smaller oil reserves will have to offer more lenient fiscal terms to be successful in attracting investment.

the identification of a market for the gas and the determination of the most economic means of transporting gas to the market.

As in many other economic sectors, investment incentives are widely available. The most common are full current expensing of exploration and/or development costs, accelerated depreciation allowances, and investment tax credits. Tax holidays or reduced tax rates are less common, but some countries do offer these particularly for smaller projects or to encourage investments in less explored regions. Many countries provide exemptions from customs duties and VAT on imports, at times only for specialized equipment to be re-exported after use. Another common incentive is flexible loss carry-forward provisions, in many countries for an unlimited period of time.

Production sharing arrangements are widespread in the petroleum sector where about two-thirds of the countries surveyed have this as the main core of their fiscal regime. Quite common is a formula-based system with the share of profit oil linked to the volume of production. It is typical to have at least 50-60 percent of profit oil going to the state, but in some countries a higher share applies. Countries also differ regarding limits for allowable costs the operator can recover as cost oil. In some countries, even if income taxes are nominally due, these are paid out of the state's share of production.

The extent to which countries participate directly in projects as equity holders differs. Typically countries retain the right to take equity in a project. Often this is done on a carried interest basis, whereby the cost of the equity is paid back to the company out of production proceeds. However, many countries do not actually exercise their right to equity participation or at least not fully, in part due to the costly financial obligations that can arise from project participation, particularly when the equity interest requires the country to meet cash calls and to make other cash payments.

Some regional patterns are also apparent. In Africa, about one-half of the surveyed countries rely on production sharing. Of the other half with a tax/royalty regime, some apply a resource rent tax in addition to the corporate income tax. In Asia, production-sharing arrangements are widespread. Only a few countries in the Pacific use resource rent taxes. In the Western Hemisphere, production sharing is quite rare outside of the Caribbean, and very few countries apply resource rent taxes. There are also several Latin American countries that have reduced tax rates noticeably over the last couple of years—particularly Argentina, Chile and Peru—to attract investment. In the Middle East, the majority of countries rely on some form of production sharing, which is also common among the surveyed transition countries.

Table 2. Key Characteristics of Fiscal Petroleum Regimes, Selected Developing Countries

<i>Country</i>	<i>Royalties</i>	<i>Production sharing 1/</i>	<i>Income tax rate</i>	<i>Resource rent tax</i>	<i>D.W.T. (nonres)</i>	<i>Investment incentives 2/</i>	<i>State equity 3/</i>
<u>Africa:</u>							
Angola	16-20%	50-90% (V)	50%	None	...	Yes (E)	25%
Benin	12.5%	55%	None	None	...	Yes (E,U)	15% (C)
Cameroon	Negotiable	None	57.5%	None	25%	Yes (O)	50% (C)
C.A.R.	12.5%	None	50%	None	40%	None	None
Chad	12.5%	None	50%	None	20%	None	10%
Cote d'Ivoire	None	60-90% (V)	None	None	12%	Yes (O)	10-20%
Ethiopia	None	15-75% (V)	50%	None	10%	Yes (E)	10%
Gabon	10%	65-85% (V)	None	None	...	Yes (E)	15% (C)
Ghana	12.5%	None	50%	12-28%	10%	...	25%
Mozambique	15%	10-50%	None	None	...	Yes (E)	None
Namibia	12.5%	None	42%	Formula	None	Yes (E,U,I)	None
Niger	12.5%	None	50%	None	18%	Yes (E)	...
Nigeria	0-20%	20-65%	85%	None	10%	Yes (E, Cr)	Variable
Senegal	5-12.5% V	0-50% (ror)	35%	Yes	10%	...	5-20%
South Africa	2-5%	None	30%	40%	...	Yes (O,U,I)	20% (C)
Sudan	...	60-80%	None	None	None	...	None
Tanzania	20%	45-72.5%	None	25-35% rr	10%	...	15% (C)
Uganda	None	None	30%	0-80% ror	15%	Yes (E,U)	25%
Zambia	10%	0-25% (ror)	Contract	Yes ?	15%	Yes (E,I,U)	10%
<u>Asia and Pacific:</u>							
Bangladesh	None	60-70% (V)	None	None	...	Yes (I)	None
Brunei	...	None	55%	None	None	Yes (A)	50%
Cambodia	5-12.5%	40-65% (V)	30%	None	None	Yes (E)	None
Indonesia	...	80-90% (V)	35%	None	13%	Yes (I, A,Cr)	10%
Malaysia	10%	50-70%	38%	70% (Pr.)	None	Yes (A, E,U)	25%
Mongolia	12.5%	35-60%	40%	None	20%	Yes (I)	None
P.N.G.	2%	None	45%	20-25% rr	None	Yes (I, Cr)	22.5 (C)
Philippines	None	60%	32%	None	15-32%	Yes (E)	None
Thailand	12.5%	None	50%	None	10%	Yes (E)	None
Vietnam	6-25%	65-70% (V)	50%	Formula	15%	Yes (H)	15%
<u>Europe:</u>							
Bulgaria	12.5-17.5%	50%	40%	None	15%	Yes (H)	None
Turkey	12.5%	None	25%	None	20%	Yes (E)	None
<u>Middle East:</u>							
Abu Dhabi	12.5-20%	None	55-85%	Product.	...	None	60% (C)
Algeria	10-20%	50-85% (P)	None	None	20%	None	51%
Bahrain	None	70%	50%	None	...	None	None
Dubai	12.5-20%	None	55-85%	None	...	None	None
Egypt	10%	70-87% (V)	40.55%	None	None	Yes (I)	None
Libya	16.67%	Yes (P)	65%	None	...	...	...
Morocco	...	None	39.6%	Yes (ror)	20%	Yes (A,I)	35%
Oman	None	80%	55%	None	None	None	None
Qatar	...	80-90%	None	None	None	None	None
Tunisia	...	None	50%-75%	Yes (ror)	None	Yes (E,U,I)	Negotiable
Yemen	3-10%	70-80%	None	None	None	Yes (E,U)	None

See footnotes on the following page.

Table 2. Key Characteristics of Fiscal Petroleum Regimes, Selected Developing Countries  
(concluded)

<i>Country</i>	<i>Royalties</i>	<i>Production sharing 1/</i>	<i>Income tax rate</i>	<i>Resource rent tax</i>	<i>D.W.T. (nonres)</i>	<i>Investment incentives 2/</i>	<i>State equity 3/</i>
<u>Latin America:</u>							
Antigua	5%	30-50% (T)	None	None	...	None	None
Argentina	12%	None	30%	None	35%	None	None
Aruba	None	79-89.5% (V)	39%?	None	None	Yes (E,U)	None
Barbados	12.5%	50-70% (V)	None	None	15%	Yes (E,U)	None
Belize	7.5%	5-15% (V)	25%	None	15%	Yes (U)	5%
Bolivia	31%	None	25%	25%	12.5%	Yes (E,U)	None
Chile	Formula	None	15%	None	35%	Yes (A)	35%
Colombia	20%	None	12.5%	None	7%	None	50% (C)
Costa Rica	1-15%	None	30%	None	15%	None	None
Dominican Rep?	17-30%	None	25%	None	25%	Yes (I)	None
Ecuador	12.5-18.5%	None	25-44.4%	Formula	25%	...	None
Guatemala	20%	30-70% (V)	31%	None	None	Yes (E,U,I)	None
Guyana ?	None	50-70% (V)	35%	None	10%	Yes (E)	None
Honduras	1-15%	None	25%	None	10-15%	None	None
Mexico ?	None	None	35%	None	7.7%	Yes (E,I)	None
Peru	Negotiable	None	20%	None	None	Yes (E,A,I)	None
Trinidad & Tob.	...	Variable	50%	0-45% Pr	...	Yes (A,H,I)	None
Venezuela	16.7%	None	67.7%	None	None	Yes (E, Cr)	0-35%
<u>Transition econ.:</u>							
Azerbaijan	None	45-65% (P)	30%	None	15%	Yes (E,O,U)	7.5-20%
Kyrgyz Republic	None	60-80% (V)	None	None	15%	Yes (H)	None
Turkmenistan	12%	40%	25%	None	15%	...	None
Uzbekistan	Yes	Yes	33%	None	15%	...	50% (C)

Sources: Barrows (1997), Coopers & Lybrand (1998), PricewaterhouseCoopers (1999), and International Bureau of Fiscal Documentation (various).

1/ Production sharing linked to physical volume of production (V), years of production (T), or realized profitability (P)

2/ Investment incentives: tax holiday (H), accelerated depreciation (A), tax credit (Cr), current expensing of exploration and/or development cost (E), exemption of imports of equipment and capital goods (I), unlimited loss-carry forward (U) and other (O).

3/ The maximum equity share that the state can select to take, often on a carried basis (C).

## B. Evolution of Selected Fiscal Regimes

The evolution of fiscal regimes for upstream oil and gas activities in four diverse countries (Norway, Kazakhstan, Indonesia and Angola), summarized in Appendix I, provide some insights into how oil and gas taxation varies over time and across countries.

There are four main features of the dynamic evolution of these fiscal regimes. First, the fiscal terms appear to have been influenced by oil prices, becoming more generous in periods of price decline and vice versa. As declining world oil prices lead to expectations of lower profitability and reduced investment activities, there is some evidence that host country governments have responded to this by offering more attractive fiscal conditions. Whether

this observation is generalized to most oil and gas producing countries in periods of sustained petroleum price changes remains to be confirmed. If so, it would imply that conservative oil and gas revenue projections should reflect an assumption of relaxed fiscal terms along with projected persistent lower oil and gas prices. Second, fiscal terms have been influenced by tax policies set in the home countries of international petroleum companies. For example, Indonesia modified the terms of its production sharing contracts in 1978 in response to the US Internal Revenue Service (IRS) that disallowed a tax credit for “income taxes paid” by the Indonesian government on behalf of American companies, and Norway raised the Special Tax rate and restricted capital depreciation provisions in 1979, following the introduction of the US windfall profits tax. Third, bonuses have become streamlined and less important over time as a method of petroleum revenue collection. Fourth, the case studies suggest that as the petroleum fiscal system matures, the revenue regime becomes more progressive. For example, in 1972, Norway moved from a single-rate royalty regime to a multiple-rate one based on the scale of production. In 1995, Kazakhstan introduced the excess profits tax with a range of rates corresponding to different rates of return brackets. In 1988, Indonesia adopted a progressive production sharing scheme where the production split between the contractor and the government depended on the nature of the field and on production volumes. In Angola, the 1988 model production sharing contract provides five different share parameters between the government and the contractor, based on different rate of return brackets.

An important explanation of the wide difference in fiscal patterns observed across countries lies in their difference in bargaining power when negotiating fiscal terms with international oil and gas companies. In turn, a country’s bargaining power is derived from its particular circumstances. The strictest fiscal regimes tend to be in countries, which offer very attractive geological prospects, combined with political and macroeconomic stability (Indonesia is a good example of such a country until recently). While it can be argued that all countries embody some degree of most forms of risk from political to commercial, certain risks tend to influence the bargaining position, and hence the fiscal terms, more so in some countries than in others.

In Norway an important risk issue concerns the competitiveness of its oil and gas in highly contested markets. Although characterized by a stable political regime and reasonably strong geological prospects, Norway must compete with several other North Sea producers (the UK, The Netherlands and Denmark) to attract international companies’ investments in North Sea exploration and production activities. The main market for North Sea oil and gas is Western Europe, a fairly saturated and competitive market. This market-based risk has likely influenced Norway to further focus on its lenient ring-fencing, interest deductibility and depreciation rules. These provisions are believed to have undermined the effectiveness of the Special Tax, which underscores the importance of combining a tax on excess rents with strict ring fencing and thin capitalization rules.

Kazakhstan is an investment location characterized by significant resource commercialization risks. Kazakhstan’s land-locked geography makes it dependent on either Russian-owned pipelines or on its ability to secure investment for, and build, alternative

routes (across other jurisdictions) in order to ship its oil and gas to international markets. Transportation fees to the pipeline companies dissipate some of its petroleum sector rents across jurisdictions, leaving fewer rents to be collected by the Kazakh government. This has weakened the government's bargaining position and has led to more relaxed fiscal terms over time, such as streamlined bonuses and the deductibility of bonuses and royalties from the income tax and the excess profits tax.

Finally, Angola—a country with strong geological prospects (Barrows, 1988)—is an investment location characterized by relatively high-perceived political risks. The fiscal regime concluded between investors and the government of Angola is specific to each production sharing contract, which includes a tax stability clause. Other terms of the contracts have become more discretionary over time. For instance, model production sharing contracts used to specify a maximum cost recovery share, an uplift factor and a depreciation rate for development expenditures. These provisions became determined on a contract-by-contract basis in 1997. Furthermore, the list of expenditures admissible (at the government's discretion) under cost recovery has been expanded.

#### IV. CONCLUSIONS

A broad range of fiscal instruments is available to policymakers to design a fiscal regime for the oil sector that will attract investment as well as secure a reasonable share of economic rent for the government. Some may favor greater reliance on production-based levies to ensure a steady stream of revenue for the government. Others would put greater emphasis on profit-based levies to minimize distortions. Most countries have both profit-based and production-based levies. Fiscal terms accepted by a country reflect the negotiating strength and experience of the country, geological prospects, and the track record of previous projects. During negotiations, potential fiscal revenue may be lowered to compensate for particular high costs of extracting oil, reflected in markets, commercial or political risk premia.

There clearly is not one optimal fiscal regime suitable for all petroleum projects in all countries. Countries differ, most importantly in regard to exploration, development and production costs; the size and quality of petroleum deposits; and investor perception of commercial and political risk. Likewise, projects may differ sufficiently that some flexibility is necessary in deriving an appropriate fiscal regime. At times, this could justify a case-by-case approach to project negotiations, though it is desirable if the chosen fiscal framework is sufficiently flexible to respond to unforeseen developments so as to minimize the need for ad hoc changes. These factors will influence the size of the government's revenue take: a country with large proven reserves and low exploration and development costs will be able to negotiate a higher revenue share than a country that has a short, and perhaps somewhat uneven, track record, particularly if there is uncertainty regarding the size, quality and extraction costs of its petroleum reserves.

Despite these qualifications, it is possible to outline some desirable features to target when designing a fiscal regime for the petroleum sector. Ideally, this should combine some up-front revenue with sufficient progressivity to provide the government with an adequate share

of economic rent under variable conditions of profitability. This can be achieved through a tax-based system combining a corporate income tax with a rate of return based resource rent tax (or a progressive income tax), and a royalty at a modest level to secure some up-front revenue. However, it could also be achieved by a production sharing arrangement with a moderately progressive government take linked to product prices or project rate of return. The latter, however, may be more difficult to negotiate for countries with few successfully developed projects. Under those circumstances, a resource rent based tax system could prove more flexible while requiring less information ex-ante about potential project profitability. Still, the capacity of a particular country to competently administer a complex taxation-based system must be taken into account when designing the fiscal regime. Attempts should be made to keep the administrative burden as low as possible, while maintaining sufficient safeguards such as ring-fencing to counter tax avoidance, particularly the risk from transfer pricing.

The case studies in this paper provide useful insights into the dynamics of fiscal terms. First, there is some evidence that these react endogenously to world petroleum prices, at least to sustained medium-term changes. Second, fiscal terms set by host countries are influenced by tax policies in the home countries of oil and gas companies. Third, there may be some tendency for revenue collection schemes to become more progressive as a country's petroleum fiscal system matures.

The government's share of economic rent can become excessively low as countries compete to attract investment capital for oil and gas extraction, particularly if the fiscal regime is used to try to compensate for an otherwise unattractive investment environment or high political, market or commercial risk. Though the pressure to provide generous fiscal terms to attract investment can be almost irresistible, the overall investment climate is more important determinant for attracting investment than tax factors.<sup>23</sup> Moreover, there must be a lower bound for the government share from oil and gas extraction below which it would be better for the country to postpone a project rather than forego a reasonable share of the economic rent.

From the perspective of the multinational oil companies, the primary concern is how attractive are the oil and gas prospects, how the fiscal terms affect their risk, what is the expected reward if petroleum is found, and how do these factors—for any particular regime—compare to investment opportunities elsewhere.

Ultimately, there is a market test for each country's fiscal regime—can the country attract investments in its oil and sector. If not, the fiscal regime may be inappropriate for the

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<sup>23</sup> Tax incentives may also be insufficient in determining a firm's location decision. In a recent survey of 75 multinational companies, including 12 firms in the energy sector, most of the energy firms identified non-tax factors, such as geology or market opportunities, as more important for the location of a foreign subsidiary (Wunder, 2001).

country, given its exploration, development and production costs; the size and quality of petroleum deposits; and investor perception of commercial and political risk.

Table 3. Petroleum Contracts: Fiscal Stability Clauses 1/

Fiscal stability clause		Fiscal stability clause, excluding corporate income tax	No fiscal stability clause
70 countries (63%)		15 countries (14%)	26 countries (23%)
Abu Dhabi	India	Albania 3/	Argentina
Algeria	Indonesia	Azerbaijan	Aruba
Angola	Jordan	Belize	Bolivia
Antigua	Kazakhstan 2/	China	Brazil
Bahamas	Kenya	Costa Rica	Czech Republic
Bahrain	Kyrgyzstan	Ecuador	Fiji
Bangladesh	Laos	Eritrea	Hungary
Barbados	Liberia	Ethiopia	Jamaica
Benin	Libya	Guatemala	Lithuania
Brunei	Madagascar	Lebanon 3/	Nicaragua
Bulgaria	Malaysia	Mauritania	Papua New Guinea
Burundi	Moldova	Namibia	Paraguay
Cambodia	Mongolia	Pakistan 3/	Poland
Cameroon	Morocco	Senegal	Russia
C.A.R.	Mozambique	Ukraine	Seychelles
Chad	Myanmar		Slovakia
Chile	Nepal		Suriname
Colombia	Niger		Thailand
Congo	Nigeria		Tonga
Cote d'Ivoire	Oman		Trinidad & Tobago
Croatia	Panama		Tunisia
Dominican Republic	Peru		Turkey
Dubai	Philippines		Uruguay
Egypt	Qatar		Uzbekistan
El Salvador	Romania		Venezuela
Equatorial Guinea	Somalia		Zambia
Gabon	South Africa		
Gambia	Sudan		
Ghana	Syria		
Guinea	Tanzania		
Guinea Bissau	Togo		
Guyana	Turkmenistan		
Honduras	Uganda		
	Vietnam		
	Yemen		

Source: Barrows (1997)

1/ Information reflects contracts in existence up until 1997, since then more countries have been offering fiscal stability assurances.

2/ repealed in 2002.

3/ Fiscal stability clauses for offshore projects.

## APPENDIX I. Evolution of Petroleum Tax Systems for Selected Countries.

### 1. Norway

1969: 35 percent compulsory state participation on a carried interest basis on all new licenses.

1972: Royalties on oil (applicable to gross revenue from a field's total production at the production point of shipment) changed from 10 percent to a range of 8 to 16 percent. Special tax relief provisions in the offshore industry were abolished.

1974-1975: period which follows a quadrupling of oil and gas prices. Introduction of an excess profits tax, the Special Tax (designed to capture the rent from offshore petroleum activities), of 25 percent on the full income net of the corporate income tax of 50.8 per cent. Introduction of a straight-line capital allowance of 6 years (effective after the beginning of production) used against the Special Tax. Capital also benefits from an annual depreciation of 10 percent over 15 years (capital uplift). Only 50 percent of losses incurred from other activities in Norway are deductible from offshore income. Introduction of a new government-set price for oil, the "norm price" defined as the real market price of the same type of crude over a given period as determined by independent traders on a free market. No ring fencing provisions other than around offshore activities.

1979-1980: Further increases in oil and gas prices (which tripled from 1978 to 1982) and introduction of the US windfall profits tax strengthen the bargaining position of the Norwegian government for North Sea projects. The Special Tax rate is raised to 35 percent. Capital annual depreciation parameter and number of years reduced.

Mid 1980s: drop in oil and gas prices combined with strong geological prospects.

1987: Special Tax rate reduced to 30 percent, royalties lifted for new fields. Depreciation calculated under the Special Tax and the income tax starts from the time the expenditure is incurred. Uplift is no longer available on capital expenditure after January 1987.

1992: Major tax reform. Corporate income tax reduced from 50.8 to 25 percent while Special Tax rate is raised to 50 percent. Deductibility of financial costs, applied to oil companies and not to individual prospects, is limited to 80 percent of external financing. 5 percent depreciation allowance over 6 years is allowed as additional depreciation under the Special tax. Deductions became more important when the Special Tax gained prominence relative to the corporate income tax, which led to a gradually declining government take.

## **2. Kazakhstan**

1991: year of the initial main contract negotiated between the Kazakh government and a major international oil company. Three types of royalties<sup>24</sup>: fixed (US\$20 million the first year, US\$30 million the second year and US\$40 million the third and the fourth year), base (18 percent after four years) and additional (25 percent if the nominal return exceeds 17 percent). Three types of bonuses (signing, commercial discovery and mining). Maximum corporate income tax of 30 percent.

1995: Tax Decree. Introduces the excess profits tax, which starts with an internal rate of return of 20 percent and comprises up to four rates applicable to thresholds stipulated in individual contracts. Introduces ring fencing.

1996: Petroleum Law. Introduces a tax stability clause.

1997: Amendments to the Tax Decree. Royalties and the signature bonus become deductible from the income tax and the excess profits tax. The commercial discovery bonus and the mining bonus are repealed. Repeal of the tax stability provision restoring economic interests of the parties if international treaties force changes in the original terms of the contract.

2002: new tax code. The entire tax stability clause is repealed for contracts signed after December 31, 2001.

## **3. Indonesia**

Production-sharing contracts (PSCs) were first used in Indonesia. They have some of the world's strictest financial and fiscal terms, which are counterbalanced by the country's great hydrocarbon potential and the generally cooperative nature of the state owned company Pertamina and the Indonesian government (Gao (1994)).

### **1960-1975: First generation PSCs.**

Cost recovery is limited to 40 percent of annual production with the remainder of the production split 65/35 in favor of the government. Carry forward of unrecovered costs allowed, but not uplift factor. Recoverable operating costs exclude interest payments on debt. In 1972, some PSCs provided a formula maintaining the 65/35 split up to a base level, beyond which it escalated when production reached certain levels. Oil price used for cost recovery and tax calculation purposes set by the government according to an OPEC-type guide price.

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<sup>24</sup> Applicable to gross proceeds at the wellhead net of transportation and marketing costs, non-well associated operating costs and depreciation of non-well facilities.

Bonuses: Bonus payments vary considerably between individual PSCs. Bonus payments are borne solely by the contractor and cannot be included in the operating costs, which are recoverable from production, but can be charged against tax liabilities once profitable operations commence. The signature bonus ranges between \$1 million and \$5 million. There may be 2 to 5 production bonuses triggered by the volume of production, from a low of 0 to 50,000 barrels per day to a high of 100,000 to 500,000 barrels per day. Total bonus commitments commonly range from \$15 million to \$50 million.

Ring fence provision.

Domestic market obligations: since 1968, compulsory for all foreign companies. The quantity supplied by each company varies according to its own production volume and inversely to overall Indonesian production, providing that the pro-rata quantity does not exceed 25 percent of total production from its contract area. The oil price for domestic supply is determined as follows: for the first five years of production, it equals the price received by the contractor for the recovery of operations costs (export price). After the first five years of production, the price is the cost plus \$0.20 per barrel.

**1976-1988: Second generation PSCs**, which terms are affected by the oil price crisis of 1973 and the US IRS ruling disallowing tax credits for Indonesian corporate taxes paid by Pertamina, on behalf of US oil companies, out of the government's share of production.<sup>25</sup> Abolition of cost oil, increase in government share from 65 to 85 percent of production after cost recovery, introduction of a tax on foreign companies and of a number of investment incentives.

1976: Stricter terms for the new cost recovery feature based on a double-declining balance depreciation method. Cost recovery period extended from 7 to 14 years. Interest expenditures are treated as a recoverable operating costs subject to the following limitations: financing must be with non-affiliates, loans should be obtained at rates not exceeding prevailing commercial rates, financing plans and amounts must be included in each year's budget of operating costs for the prior approval of Pertamina.

1977: Investment credit of 20 percent of production subject to a guarantee to the government of a 49 percent share of gross revenue over the life of the field.

1978: contractors' pre-tax profit share of 34.0909 becomes subject to the corporate income tax rate of 45 percent and a 20 percent tax on interest, dividends and royalties after deducting the corporate tax. PSC set a new pre-tax split at 65.9091 for Pertamina and 34.0909 for

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<sup>25</sup> Rev. Ruling 76-215 , which characterized the government's share of production as a royalty.

contractors.<sup>26</sup> The net effect of the tax change resulted in a post-tax split of 85/15 in favor of Pertamina.

1984: PSCs concluded thereafter are subject to a new income tax of 35 percent of taxable income and a dividend tax of 20 percent on the balance. Profit split is reset at 71.1853 for Pertamina and 28.8642 for the contractor in order to compensate for the lower tax rate and keep the post-tax split unchanged at 85/15. Investment credit decreases to 17 percent subject to a guarantee to the government of a 25 percent share of gross revenue over the life of the field.

**1988 onwards: Third generation PSCs.** Decreasing petroleum prices, increasing production costs and tightened international competition for scarce investment funds influenced modifications to the PSCs. First Tranche Petroleum (FTP), increased investment credit, progressive sharing splits, deregulation in certain areas and investment promotion.

1988: Introduction of First Tranche Petroleum (FTP), a portion of oil/gas production amounting to 20 percent to be split between Pertamina and the contractor every year on the basis of the applicable profit split ratio before any deduction of cost recovery. The FTP constitutes, in effect, a royalty in kind which varied according to the volume of production and the applicable sharing ratios. Introduction of new pricing formula under which the governments sets the oil price on the basis of monthly average spot prices for a basket of five internationally traded crude oils.

Domestic production requirement. Nominal payment for the old oil was increased in 1989 to 10 percent, and in 1992, to 15 percent of the export price for both new and old oil for all PSCs. It was raised again in 1993 to 25 percent of the export price for old oil from frontier and deep-water fields.

Profit oil shares restructured by the 1988, 1989, 1992 and 1993 incentive packages. Progressiveness in production sharing replaces the previous fixed split. For contracts signed after 1988, the production split may slide between 75/25 and 90/10 depending on the nature of the fields and the production volumes. Nevertheless, the original 85/15 split seems to remain predominant over other ratios.

Requirements for bonus payments have been declining sharply over the years. Total bonus payments reported in the 46 PSCs concluded in the first peak years of signing 1979-82, \$306 million, are much higher than the total of \$60 million from the 45 PSCs concluded in 1987-1990.

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<sup>26</sup> Rev. Ruling 78-222 concluded that the new fiscal arrangements resulted in a creditable income tax for US taxpayers. In 1983, the United States Treasury issued new regulations under section 901 of the Internal Revenue Code that allows a credit for tax obligations paid by another party, provided the tax is otherwise creditable.

#### 4. Angola

Main modifications in the model PSC contract from 1988 to 1997 include relaxing the profit sharing parameter which becomes determined on a contractual basis, increasing the range of admissible expenses for cost recovery purposes, eliminating the price cap excess fee provision and increasing the rate of straight line depreciation of development expenses prior to leaving their uplift factor and depreciation rate determined on a contractual basis.

**Bonus:** Signature bonus, to be determined on a contractual basis. Not recovered or amortized for cost recovery purposes.

**Development area rental:** \$300 per km<sup>2</sup>.

**Purchase rights:** State company has the right to purchase the contractor's oil, for an amount equivalent in value to the petroleum income tax due by the contractor to the Ministry of Finance.

**Fiscal regime:** not specified in the model PSA. To be established by concession decree. Contractor is responsible for all taxes except the petroleum income tax.

**Tax stability clause:** government is open to revisions subject to the fact that it does not impact negatively on either party's economic benefit. SONANGOL reimburses the contractor for increases in clearance, stamp duty and/or the statistical levy applicable to imports.

**Cost recovery:** Maximum of 50 per cent per year as cost recovery crude oil (provision, which was in the 1988 model contract, stayed throughout until 1997 when it was replaced by an unspecified parameter). **Ring fencing** for development expenditures. **Uplift factor** of 1.4 to development expenditures, which are then depreciated linearly (on an equal annual installment basis) at 20 percent per year starting in the year where the expenditure is incurred (in 1991, the uplift is same as before but the resulting amount is recoverable at the rate of 25 percent in annual installments, for offshore agreements). The uplift and depreciation parameters are no longer specified in the model PSA agreement of 1997.

No ring fencing for exploration expenditure. Recoverable from unused balance of cost recovery crude oil existing from each development area after recovery of development expenditures and production expenditures, up to 50 percent. In each year, exploration expenditures shall be recoverable first from any cost recovery crude oil balance having the most recent date of commercial discovery and then any balance of total exploration expenditure not already recovered shall be recoverable in sequence from development areas with the next most recent dates of commercial discovery.

**Nonadmissible expenditures:** signature bonus, petroleum income tax, contributions and taxes on salaries and wages of workers employed by the operator.

**Loss carryover:** unchanged throughout the considered period. 5 years for development expenditures, after which contractor's share of crude oil is increased to allow for cost recovery. Indefinite carry forward with no change in cost recovery parameter for other types of expenditure.

**Admissible costs:** between 1991 and 1997, the list of admissible expenditures under cost recovery widens. Many technical health, safety and environmental audits items (provided by affiliates of operator or SONANGOL) as well as communication studies. Range of items falling under costs recoverable only with prior approval of SONANGOL has increased. Element of discretion (includes costs incurred before the effective date of the agreement, promotional and advertising expenses, cost for renewal of contracts without prior authorization).

**Production sharing:** crude oil produced and saved in a quarter from each commercial discovery and its development area and not used in petroleum operations less cost recovery crude oil from the same area is referred to as "development area profit oil" and shared between SONANGOL and contractor according to the after tax nominal rate of return achieved in the preceding quarter. Model PSA has 5 different rates of return brackets with different share parameters between SONANGOL and the contractor. Parameters not specified in the model PSA.

Rate of return is determined on the basis of the accumulated compounded net cash flow for each development area.

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