Second Draft

PETROLEUM REVENUE MANAGEMENT
AN OVERVIEW

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EXECUTIVE SUMMARY

Oil wealth has come to be seen more often as a curse than as a blessing. This paper covers principles, measures and techniques that might allow better petroleum revenue management in future.

Petroleum resource rent is the value of the product of a petroleum resource minus all the necessary costs of production. A petroleum tax system with rent as the tax base interferes least with pre-tax decisions on investment and production. Competition in petroleum investment allows the "price" of a resource to be identified and a tax system design to capture it. Stability in fiscal terms reduces investor risk and allows states to tax more of the rent. The petroleum tax system cannot move too far out of line with those countries with similar prospectivity. It can be structured to reduce investor risk and secure higher government revenue. A petroleum tax system can differ from the general tax system and remain "neutral". A petroleum fiscal system can use production sharing, taxes and royalty or degrees of state ownership each to equivalent fiscal effect. The broader the tax base the better in each case.

Flow of funds analysis helps to check that the fiscal system delivers what it should. This and effective fiscal administration rely upon reconciliations of flows at each point in the chain, supported by an audit strategy.

Governments in petroleum economies seek to maximize revenue receipts and then confront the consequences of uncertainty and instability in actual flows. A revenue boom has somehow to be absorbed: by saving abroad, raising imports, reducing savings or increasing investment. A slump requires the reverse processes. Are there rules for keeping medium term stability in the face of booms and slumps? First, keep spending within the sustainable growth path and save excess revenues abroad. Second, use conservative (below median) forecasts of future revenues. Third, allow the foreign asset position to swing while keeping domestic absorption steady. If in doubt, save the money.

Permanent income means the amount of petroleum wealth that can be safely consumed while maintaining financial wealth for future generations. Calculation of permanent income offers a yardstick for sustainable petroleum revenue management. It has political appeal in that its use shows a leadership concerned about equity among generations.

Special funds to store and manage petroleum revenues (non-renewable resource funds or NRFs) may have three broad motives: stabilization, savings or precautionary. The integration of any fund with overall fiscal management is vital. There should be a consolidated budget framework (domestic expenditure only through the budget), a liquidity constraint on the general budget (no borrowing that offsets savings in the fund) and strict limits on domestic investment by the fund. The timing of petroleum revenues does not follow a known path; fiscal management, perhaps supported by a NRF, can shift the path of absorption and reduce the effects of uncertainty.

Hedging offers an alternative solution for the stabilization role of NRFs. A futures strategy reduces price uncertainty without initial cost; an options strategy operates like insurance and carries an initial premium cost. Because these strategies require direct access to markets an over-the-counter (OTC) arrangement with a financial institution may better suit developing country governments; it could provide for longer-term instruments but with credit risk to both parties. Hedging carries political difficulties, especially if spot prices exceed the hedged prices. Institutional capacity for hedging may be weaker than required. Over time hedging could form part of a revenue management strategy and because companies engage in it anyway governments should address the revenue consequences of private hedging.

Petroleum revenues, like any other funds, need expenditure management rules for effective use. These rules cover adequacy of data, budget preparation, budget execution and cash management arrangements. Earmarking for specific expenditures and disbursement through extra-budgetary funds may, exceptionally, have a role but are usually best avoided. In many countries, the balance between local (resource producing area) and national distribution of petroleum revenues is highly sensitive. In appropriate distributions can soon undermine the integrity of the fiscal system but a programme for decentralization and revenue sharing is important. Contractual arrangements between different levels of government over specific resource developments offer a way forward.

1. INTRODUCTION

A. Relevance of the Topic

1. Very few developing or transitional economies with a rich petroleum endowment have become success stories in development and poverty elimination. Oil wealth has come to be seen more often as a curse than as a blessing. Research on the topic has spawned a rich literature of case studies and theoretical frameworks for analysis of the problems that rise. Yet petroleum revenue could, in principle, unlock the constraints of foreign exchange, savings and public finance and underpin a path of growth, development and poverty elimination. This paper moves on from diagnosis of the disease to principles, measures and techniques that might allow better petroleum revenue management in future. These ideas have emerged from international experience, from research and from the policy work of international institutions such as the World Bank.

2. Petroleum revenue management concerns the use of vast sums of money. Figure 1 shows estimated annual oil rents in a range of non - Middle Eastern countries[1]:

Figure 1: Estimated Annual Oil Rents in Selected Countries ($ billion)

Country	@ $10/bbl	@ $20/bbl	@ $30/bbl
Nigeria	5.6	13.6	21.7
Norway	2.3	13.6	24.9
Indonesia	2.4	7.1	11.9
Algeria	1.8	6.1	10.5
Venezuela	8.2	19.1	30.1
Mexico	9.8	22.4	35.1

3. Unfortunately, inflows of this size do not cause the countries in the sample – and others – to have a path of growth and development better than countries that are resource-poor. Quite the opposite in fact. Research has repeatedly identified that resource-poor countries, whether large or small, significantly outperformed resource-rich countries in terms of *per capita* GDP growth[2]. In terms of a wider variety of development or social indicators the outcomes are often worse. As if these afflictions were insufficient, petroleum-dependent economies (beyond the Middle East) appear to have records of political instability and high levels of corruption.

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[1] Figures from Charles P McPherson, *Petroleum Revenue Management in Developing Countries*, draft, World Bank, 2001. Rents are calculated as revenue per barrel less estimated cost of extraction.

[2] For example, Richard Auty and Raymond F Mikesell, *Sustainable Development in Mineral Economies*, Oxford University Press, 2000.

4. The failure of petroleum wealth to lead to development has been blamed on many things: the so-called "Dutch Disease" – the syndrome of rising real exchange rate and wages driving out the pre-existing export and import-competing industries; rent-seeking by elites and those would otherwise put their energies into profit-making activities; volatility of prices and the "asymmetry of adjustment" (it is easier to ramp up public expenditure than to wind it down again); inflexibility in labour, product and asset markets; tensions between oil-producing and non-oil producing regions within countries. A common thread in all the explanations, however, is the central role of government behaviour: how does government collect, manage and distribute petroleum revenue? That question is the focus of this paper.

B. Structure of the paper

5. The paper begins with a simplified account of the economics of petroleum revenue (Section 2) covering the value of the resource, the concept of rent and the concept of "tax neutrality". Section 3 then covers the principles of tax design for the petroleum sector. Section 4 addresses the monitoring of the flow of petroleum revenues, or the problem of establishing whether the correct amounts have been collected; this is combined with a brief review of fiscal administration questions. In Section 5 the interaction of petroleum revenue flows with macroeconomic management is examined, including the mechanisms by which an economy responds to shocks and the possibility of rules for maintaining stability; the Section also addresses the concept of sustainable spending out of petroleum revenues or "permanent income". This leads on to Section 6 in which the design of funds for accumulation of petroleum revenues is addressed ("Non-renewable Resource Funds" or NRFs). The possibility of hedging strategies as an alternative approach to revenue stabilization is outlined in Section 7. Finally, Section 8 reviews expenditure management principles, extra-budgetary funds and local / national distribution of revenues. The paper is about petroleum revenue management, it does not prescribe an investment strategy for petroleum economies or deal comprehensively with how to convert petroleum wealth into other types of physical, social and human capital. The central sections do, however, outline some principles through which economic management in petroleum economies can support such a strategy.

2. ECONOMICS OF PETROLEUM REVENUE

A. Resource Rent

6. Petroleum resource rent is defined as the value of the product of a petroleum resource minus all the necessary costs of production, including the minimum returns to capital required, prior to the investment decision, to induce investment. It is thus the value of the resource to its owner (in most, though not all, countries the owner is the State). Since petroleum rent is generated only after all the necessary costs of production have been met then designing a tax system with rent as the tax base will tend to cause the least possible interference with the investment and production decisions that would have been made if no taxes were imposed (the principle of "tax neutrality" - see below)[3].

7. With given petroleum prices, the total amount of rent generated by a petroleum deposit over its life will vary according to its technical characteristics (reserves, reservoir characteristics, recovery rates, quality of oil or gas) and other physical factors such as its location (onshore or offshore: if onshore, ease of access and proximity to infrastructure, environmental costs and ease of disposal of petroleum; if offshore, water depth and proximity to markets). The fluctuation of petroleum prices will affect the distribution of rents over time. The uncertainty of costs and prices means that rent actually generated may turn out to be much higher or lower than initially expected (and sometimes non-existent). Petroleum fields in operation may be generating rent in one period and not in another. Aiming to tax petroleum rent, rather than the normal rewards to factors of production, is thus not a straightforward matter.

B. Tax Neutrality

8. An important economic principle in the design of taxes is that taxation should be "neutral". "Neutral" (in the economic sense) means that the tax does not alter the decisions about investment, production, consumption and trade that would be made in the absence of the tax unless the tax is deliberately intended to do so. Neutrality does not require that the same rates and types of tax should be applied to all sectors of economic activity. There are three main reasons why the use of special tax systems for the petroleum sector is appropriate - and is not a violation of the principle of neutrality.

9. Firstly, the scale of investment required in petroleum exploration and development, before any revenue is generated, may be such that the risks incurred require special measures to accelerate payback (investment recovery) if the level of investment warranted by geological conditions and market demand is to be forthcoming. Providers of both equity and loan capital are likely to be foreign and are likely to perceive some degree of political risk (risk of expropriation, of unilateral alteration of terms, of currency restrictions, or of politically-induced operating difficulties). Their sensitivity to this risk

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[3] More detailed discussion of these concepts is available in Rögnvaldur Hannesson, *Investing for Sustainability: the Management of Mineral Wealth*, Kluwer, Boston, 2001 or Ross Garnaut and Anthony Clunies Ross, *Taxation of Mineral Rents*, Oxford, 1983.

will be greater the larger the investment and the longer the time during which it is outstanding.

10. Secondly, since investors in petroleum projects are likely to be international petroleum companies (IPCs) and to be specifically interested in petroleum investment, investment is unlikely to be diverted out of other sectors into petroleum because a special tax regime is applied to the petroleum sector.

11. Thirdly, petroleum fields may generate rent in the sense of a surplus over all necessary costs, as defined above. Rent is the value of the resource itself and not, if properly identified, part of the necessary reward to providers of capital, to labour, or to suppliers of inputs; as such it can be used as the tax base by the resource owner (the state) without necessarily altering decisions about exploration, investment or production that would be made in the absence of a tax on petroleum rent.

C. The Investor's Required Rate of Return[4]

12. In the face of uncertainty, expected returns will in practice amount to the investor's assessment of the average of a range of more or less likely outcomes. The price at which investment will be forthcoming is the expected rate of return required by the least demanding investor.

13. The price at which investment capital will be supplied, on this definition, is determined on the basis of what the investor expects and requires. This point is of fundamental importance since it implies that the availability of resource rent (and of a base for taxation) is not fixed independently of government action; governments can affect the investor's perception of risk in a variety of ways and can thus affect the determination of the required rate of return.

14. The required rate of return will consist of the expected return from placing the same funds in a riskless investment ("AAA" bonds, for example) together with a premium for perceived risk in the petroleum project in question and the "political risk" of investing in the country or jurisdiction where the petroleum deposit is located. “Risk”

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[4] "Rate of return" in this paper means a <u>discounted cash flow (DCF)</u> rate of return. By <u>discounting</u> is meant the procedure of taking into a account the time-value of money by reducing costs incurred or benefits received in future years back to their <u>present value</u> (value in the year for which the calculation is being made) by applying a certain percentage <u>discount rate</u> in each year beyond the current (or base) year. The procedure is the opposite of adding interest at a compound rate to a current sum to obtain its future value if it is invested at a certain rate of interest. The DCF rate of return on a project is the discount rate which makes the present value of the stream of costs and benefits equal to zero. By definition, therefore, this is a rate of return earned over the life of a project, and although it is expressed as an annual rate of return on the cash outlays made, it is not the same as an annual measure of a rate of return on assets employed.

here is a combination of pure risk and pure uncertainty[5]. A petroleum investment prospect contains elements of both: geological and commercial risk, for example, come closer to pure risk, while political risk is closer to pure uncertainty.

15. The required rate of return can be expected to increase with both uncertainty and risk - which, in the usual case, will be greater the larger an individual investor's exposure in a project. To the extent that government action (for example, by means of participation in investment guarantee arrangements, or by imposition of taxation which minimises any increase in pre-tax risk of absolute loss) can mitigate either risk or uncertainty perceived by the investor, the required rate of return on capital will fall and the resource rent taxable in the petroleum sector will increase - both because more projects will go ahead and because investors will require fewer concessions to proceed with them.

16. A "marginal" project is one that just, but only just, yields the investor's required after-tax rate of return on outlays; a "profitable" project is one that yields returns in excess of this requirement. A project's "profitability", in this context, thus refers to the extent to which rent is generated, not to the amount of accounting profit yielded.

D. Special Factors Affecting Taxable Rent

17. The magnitude of rent and the proportion that is taxable will depend, among other things, on the degree of competition or monopoly in the supply of investment (see below). It is also possible that "quasi-rents" will have to be paid: these are returns to a factor of production the supply of which is fixed in the short run, but of which increased supply can be generated in the long run in response to the payment of the quasi-rent. The reward to specialist technical or managerial skills, such as those concentrated in large international petroleum companies, is sometimes of this nature. Such returns are not available for taxation as petroleum rent without affecting efficiency in the short or medium term.

18. The imposition of rent taxation also has to take into account the degree of risk-aversion among investing companies. Saying that a large petroleum company is "risk averse" does not mean that it is unwilling to take risks - only that the greater is the risk that it perceives in an investment, the greater will be the reward it requires. A higher degree of aversion to risk will increase the risk premium added to the required rate of return.

19. Petroleum companies will also seek to recover the costs of unsuccessful exploration and development elsewhere in the industry and in other countries. While a

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[5] Pure risk is the property of uncertain outcomes for which there are techniques of prediction available: past identical events can be used to determine a probability distribution of possible future outcomes. Pure uncertainty applies to events whose outcomes are inherently unknowable; it refers to the uncertain outcome of a unique event for which past history cannot be used as a guide to future outcome.

government could reasonably question the need for it to subsidize unsuccessful activity elsewhere from potential petroleum revenues, companies will seek some way to meet these costs and will incorporate their requirements into their criteria for each new investment decision. Companies may do it by seeking a higher rate of return across all projects, or by ensuring that they share substantially in the proceeds of any bonanza, if one is found. In either case, there is a further limitation on appropriation of rent by the government.

E. Competition in Petroleum Investment

20. A resource-owning government faces competition from other governments seeking to license petroleum deposits to investors. While the government is a monopolist over individual deposits, it is not a monopolist over close substitutes in other jurisdictions. As a prospect is explored and evaluated the owner's monopoly position becomes more effective; in attracting initial exploration, however, a government clearly faces external competition over the terms of investment from other governments. An already identified deposit may be the most attractive to a range of investors on given geological and reservoir information, but its relative attractiveness can be reduced if another deposit is expected to be subject to more generous taxation arrangements (for the investors). This too acts as a constraint in setting the rate of petroleum rent taxation.

21. The usual situation for determining the required rate of return will be one of actual or potential competition: among investors for access to promising deposits or exploration areas and among countries seeking to attract investment. Competition among investors may be limited to a few companies possessing the expertise and financial resources needed for the project in question; in this case quasi-rents of the type discussed above are likely to exist and to diminish the rent the state can aim to tax.

22. The host government is, nevertheless a monopolist with respect to rights over a particular prospect. If there is competition in the supply of investment, the owner of the resource can "sell" it for the value of its economic rent to the least-demanding investor. With competition in investment supply it is in principle possible to discover a "going rate" which investors are willing to pay for access to petroleum rights. The going rate will seldom be cast in the form of a lump-sum bid (and would be unacceptably low if it were), but will consist of expenditure commitments and conditional payments (that is, taxes or charges dependent upon outcomes). Competitive bidding for discovery of the going rate is common in the petroleum industry, but other means of access to market information are commonly found - such as that on contract terms held by industry consultants or international agencies. Discovery of the "going rate" (in fiscal terms) is similar to the establishment of a market price for a petroleum prospect where rights to petroleum are still exclusive but are privately owned. The price paid will in that case be the discounted present value (at the investor's discount rate) of the expected future earnings stream from the field. The owner will sell to the highest offering (least demanding) purchaser. The difference is that a government accepts an undertaking to pay taxes in future instead of a single cash payment at the beginning.

23. If competitive conditions of this kind apply the rate of return expected by the investor is broadly market-determined and can be identified within a fairly narrow range. Thus although the magnitude of rent is subject to uncertainty, one of the important deductions from revenues needed to arrive at realised rent as the project proceeds can be determined. It then becomes feasible to design tax systems which more accurately tax economic rent, maximising the share of revenues to the state in given market conditions, while leaving the incentive to invest intact. The design of taxation to meet these competitive conditions also means that the tax arrangements are likely to be stable since the resource-owner cannot alter them to the detriment of the investor without deterring future investment.

F. Setting the Price of the Resource

24. The price for petroleum output and the costs of production cannot be known with certainty in advance. Accordingly, the magnitude of potential rent from a petroleum deposit cannot be determined in advance. Effective resource taxation thus requires devices in the form of conditional payments to tax realised and not forecast rent.

25. If the rent charges imposed have a significant probability of taxing returns or inputs in low or negative profitability cases, the absolute risk of loss perceived by the investor will increase and so will the risk premium added to the required rate of return. It follows that government can increase the magnitude of taxable rent across the petroleum sector as a whole by so structuring tax measures that pre-tax risk of loss to the investor is increased as little as possible. For a given tax burden, this approach is likely to call forth more investment.

26. A great deal of confusion is caused by attempts to divide petroleum rent into two parts and to argue that the two parts should be taxed by means of separate devices. Such attempts are sometimes built upon a dubious conception of "the price of the resource" on the one hand and "windfall gains" on the other.

27. This line of argument runs as follows. The resource in the ground should be treated as an input to production and a charge should be levied for it, in advance, otherwise it will be inefficiently used and the owner of the resource may not be compensated for the permanent loss of an "exhaustible" resource. Given that any such "price" has to be fixed in advance, there is still a possibility that "windfall" gains (or losses) will occur over the life of a field, usually if very high (or very low) prices prevail for a period. At this point, some will argue that "windfalls" should be taxed ad hoc using temporary measures, while others will argue that the "windfalls" should remain with the investor as a random reward for risk-taking, or even for "efficiency".

28. The argument is most often used to justify imposition of fairly high royalties on production or on gross revenue. It is fallacious. If the "price of the resource" (collected in advance by means of a royalty) is not, in the end, part of the surplus over what is needed to reward capital and labour and pay for inputs, it will distort production decisions (lead to waste of petroleum). The possibility that this payment will turn out to be part of the revenue needed to pay for inputs, labour or capital will deter investment, at

the margin, and this effect will be greater the higher is the "payment for the resource" set in the form of a royalty. For these reasons, any royalty - whether set in legislation, or by bidding, or by negotiation, - will have to be set sufficiently low to avoid the distorting and deterrent effects. If it is thus set at a low rate it will not be capable of collecting a significant share of "windfalls", or what should more accurately be termed high levels of realised rent.

29. There may be good reasons for attempting to collect part of resource rent in the form of a royalty. The Government may have a pressing need for revenue early in the life of a petroleum field, or may wish to broaden the base of tax revenue from petroleum for administrative reasons; political risk may be reduced if the petroleum field is seen to be making a payment to the Government early in its life and whenever production occurs. These reasons for use of a royalty should not be confused with the notion that a royalty set in advance properly charges an investor for the "value of an exhaustible resource".

30. The actual value of the resource can only be known after petroleum has occurred, in conditions of known prices and costs; all that can be established in advance is the basis upon which such value will be taxed if it is in fact realised by setting, auctioning or negotiating types and rates of tax (or "conditional payments" for the use of the resource, as they might more accurately be termed). The more that any tax (including royalty - which is a gross output tax) opens the possibility of taxing returns which are not rent, the lower its rate will have to be if distortionary and deterrent effects are to be avoided.

G. Stability of the Fiscal Regime

31. The balance of advantage in knowledge about the likely value of a deposit will tend to shift from the petroleum company to the government as a project proceeds. If, however, governments permit investors access to deposits on generous terms, only to impose onerous variations in taxes when high returns are actually generated, investors will tend to anticipate such changes and increase their risk premia in the face of heightened political risk.

32. Resource rent available to be taxed will thereby be reduced both because the required rate of return is higher and because some potentially economic prospects will not then be developed. There is thus a sound economic justification for Governments to offer stability of the fiscal regime for petroleum and to build in the option of taxation measures that encourage stability by responding automatically, according to parameters known in advance, to changed circumstances in costs or prices.

H. Dissipation and Diversion of Rent

33. Tax policy is not just concerned with dividing a given amount of rent between governments and investors, it is also concerned with making the rent available for division in the first place.

34. Rent can be dissipated, for example, by technical and managerial errors in petroleum field development, or by an obligation on a petroleum field to use a sub-economic transport route, or to sell to a less-than-efficient processing plant, or by

taxation that encourages poor reservoir management and thus permanent loss of otherwise economic reserves.

35. Rent can also be diverted to parties other than petroleum companies and governments: for example, by excessive wage demands, by fraud or corruption, or (in onshore activities) by excessive compensation claims by landowners for the location of pipelines or other facilities.

3. DESIGNING A PETROLEUM TAXATION SYSTEM

A. General Strategy

36. Three important principles derived from the preceding economic arguments inform our approach to the design of a petroleum fiscal regime:

a) first, a fiscal regime for petroleum cannot move to far out of line with that prevailing in countries with similar prospectivity, or else investment will be diverted;

b) second, if the government carefully structures its tax system to reduce risks faced by investors (for example the risk that high royalties or input taxes will cause losses) it can in the long run secure both more investment and higher tax revenue over the life of a petroleum field; and,

c) third, that the pursuit of "tax neutrality" with respect to petroleum activity is not a simple matter of setting the same overall taxes as are applicable to other sectors.

37. Government tax policy can influence the pace, intensity and efficiency of petroleum development, the magnitude of the tax base and the share which the government can obtain.

38. An effective tax package needs to balance two sets of considerations.

a) On the one hand the tax package should minimise the additional risk (beyond any pre-tax risk) to the investor of absolute loss; it should also aim to tax realised rent once it is known rather than a forecast of revenues which may turn out to be wrong and which may imply the taxation of legitimate costs.

b) On the other hand, the package needs to offer the prospect of stability of contract terms; thus it should lower an investor's political risk that the terms will subsequently be altered if a project turns out to be especially profitable. It will do this only if it offers the prospect of a revenue yield that is perceived by government and the public as reasonable in the context of overall fiscal conditions and policy.

39. The balance of these considerations is likely to require:

a) measures (such as accelerated depreciation or expensing of capital outlays) to facilitate early payback of initial outlays;

b) a focus on the taxation of profit (rather than inputs or gross output), and on the taxation of profit in way that allows the investor to secure the required rate of return as early as possible, given the intrinsic economics of the project, thus making petroleum rent the main base for taxation;

c) the presence of some device providing early revenue to the government, and a payment of some sort whenever production is occurring;

d) that the proportion of the value of the resource eventually taxed is high enough to outweigh any temptation to future governments to change the terms, while leaving sufficient upside potential for the investor to make the initial risk-taking and resource commitment worthwhile and to provide incentive for efficient operation;

e) there may be advantages in leaving an element of choice to the investor about the manner in which profits are taxed, provided that the government is indifferent as to the choice made; some investors will be more concerned about the risk of absolute loss, others about maintaining their share of benefits in any bonanza.

40. When the domestic tax system contains serious distortions it will be necessary to arrange that petroleum operations are given special treatment in respect of a number of taxes: input taxes (especially import duties and related taxes on capital equipment and supplies) and other taxes on domestic business transactions (withholding taxes on certain payments for services, stamp duties etc.) where these are either levied at excessive rates or in a manner that prevents them being credited against home country taxation. The basic objective is to achieve a clear tax regime where the direct taxation of petroleum income, together with reasonable taxation of inputs and outputs, represents the effective tax burden on petroleum activity.

B. Tax Burden and Tax Structure

41. In designing or appraising a fiscal regime an exclusive focus on the impact of individual tax instruments can be very misleading. Investors themselves will be interested in the overall impact of the tax regime, under a range of assumptions about output, costs and prices. This impact has two aspects: the tax burden and the tax structure.

42. The tax burden (strictly, the average tax burden) is the share the government takes in taxes, duties and royalties over the life of a petroleum field. The share could be measured as a proportion of total revenues, as a proportion of net cash flow (net benefits) or as a proportion of "total benefits" - revenues minus operating costs and replacement capital investment, i.e., the "cake" from which taxes are paid, debt is serviced and equity providers are rewarded. In projecting the likely tax burden on a new petroleum field the benefits and costs should be discounted to present values at a suitable discount rate.

43. The tax structure is the way in which the tax burden is imposed at different points in petroleum field life; it could be represented as the path over time of the marginal tax burden.

44. Two examples of differing tax structures which might be used to impose the same average tax burden follow:

a) if there are no duties on inputs of materials and equipment, no royalties, and immediate expensing of capital items for income tax purposes, the marginal tax burden during the period of investment recovery will be zero; it will then rise to the marginal rate of income tax once the accumulated losses caused by capital expenditure have been used; if there is some additional tax imposed after achievement of an agreed rate of return or some other measure of profitability the marginal tax burden will rise again once that is triggered. The tax structure under this regime imposes a substantially heavier tax burden in the later stages of project life. This tax structure will also impose a higher average tax burden as the pre-tax rate of return on a project rises, in other words it will be "progressive".

b) If, on the other hand, there are significant duties and royalties, and only life-of-petroleum field or life-of-asset capital redemption allowances against income tax, the marginal tax burden is likely to be high early in project life and may even fall as the project proceeds - it will be "regressive" with respect to changes in the pre-tax rate of return.

45. In the first, recovery of initial investment outlays is not slowed down by taxation; there can be "rapid payback" and the investor's perception of risk under such a tax structure is likely to be lower than in the second case. For this reason, and because the eventual tax burden is imposed late in project life (so that its effect on the investor's discounted present value is lower), the overall tax burden can probably be higher than it could in the second case, without deterring investment.

46. One important criterion for assessing a system of petroleum rent taxation (and individual tax devices) is therefore the maximum rate at which tax can be imposed without deterring investment or distorting production decisions. Subject to other criteria, a tax that can safely be imposed at a higher rate is to be preferred to one that can only be imposed at a lower rate.

47. In appraising a petroleum project, large companies will examine first the intrinsic economics of the project under the given tax regime. This usually involves estimation of an expected rate of return (in discounted cash flow terms) in constant prices in an all-equity (ungeared) case. This return will have to exceed a corporate threshold, adjusted for special project risks and political risk. The average tax burden will be vital to this assessment, but so will the timing of the major part of the tax burden - and thus the tax structure - the later a given tax burden is imposed the higher will be the investor's expected rate of return.

48. The assessment of risk may include the speed at which payback is achieved, the likelihood (percentage probability) on plausible assumptions of a result below the target rate of return, and (again on plausible assumptions) the dispersion or variance of possible results around the average expectation. The tax structure has a major influence on

assessment of risk by these criteria: risk will be perceived as lower with an acceptable tax burden in a tax structure that permits rapid payback and in which most of the tax burden is imposed after the recovery of investment.

Box 1: Petroleum Fiscal Modelling

Petroleum fiscal modelling is an essential tool supporting petroleum revenue collection and management. It has three main purposes:

- Simulation of outcomes during project negotiations or fiscal policy analysis;
- Flow of funds monitoring;
- Revenue forecasting and fiscal planning.

At the core of a petroleum fiscal modelling system lie project-by-project models of the kind used by IPCs. These calculate the cash flows and generate indicators of present value and rates of return for a given project annually over its expected life. Each project model incorporates assumptions about reserves, production profile, sales prices, capital and operating costs.

A sector-wide model for petroleum revenue management is an aggregate of a range of different project models, with the addition of modules for tracking the flow of funds among government petroleum sector institutions. A detailed flow of funds model may cover periods much shorter than one year (monthly, for example).

Among the agencies using a modelling system will be the Ministry of Finance and Central Bank, the Revenue Service, the Petroleum Ministry and the NOC.

In most circumstances the reserves and production forecast is generated by the investor companies, as is the forecast of costs. Over time the government agencies can accumulate expertise in checking these forecasts. Price forecasts come either from companies, commercial agencies or official international institutions. Alternatively, a "central" price forecast can use the forward market. Light sweet crude, for example, is quoted for forward contracts on NYMEX up to six years ahead. The PSC and tax framework is grafted onto pre-tax calculations, together with any financing assumptions.

Many companies are reluctant to share their own models with government agencies but will supply underlying data. It is then possible to calibrate model results by comparing outcomes for a range of cases.

C. General Terms or Case-by-Case Negotiation?

49. Administrative costs, political difficulties over individual projects, and probably the investor's perception of risk will be reduced by having established terms applicable to all petroleum projects and contained in general legislation (the alternative is to set them out in a model agreement, but this is likely to make them little more than a basis for negotiation).

50. The advantages to governments of case-by-case negotiation of fiscal terms are frequently exaggerated, requiring as they do detailed knowledge of the prospective profitability of a field which is likely to be unavailable to governments at the time of negotiations. They also require concentration of administrative effort, negotiating skills and detailed assessment of an individual investor's requirements, which in many circumstances may be difficult to achieve.

D. Setting General Terms

51. For petroleum investors the overall tax structure and burden are more important than the particular tax devices chosen. Provided that due attention is paid to considerations of foreign tax credits in the home tax jurisdiction of the investor, a production-sharing contract can be designed to have equivalent fiscal effect to a tax and royalty system. Similarly, individual devices for state participation (working interests, carried interests, free equity) each have a fiscal effect and an equivalent tax measure can, in principle, be designed. The choice among the type of fiscal system therefore depends essentially on non-financial considerations.

52. Information on the petroleum fiscal regimes of virtually all jurisdictions in the world is widely available from commercial and published sources. Not all this information, however, is easy to interpret because the interaction between petroleum-specific terms and the elements of the general tax system that may apply is often unclear from these sources. Furthermore, while fiscal regimes can be compared for their impact on a particular field example or exploration play, such a comparison does not take account of industry perceptions of the relative prospectivity of a particular area, of cost and infrastructure differences or of political risk assessments. Although a fiscal system should not move far out of line with that in another area of comparable prospectivity, an assessment of what is appropriate really requires “market-testing” to see if it is robust in a bidding round or in negotiations over a particular prospect.

53. Petroleum fiscal terms covering gas development pose particular difficulty. This is, first, because the attractiveness of a gas prospect depends critically on availability of a market for the gas and, second, once there is a market, the method for determining the price of gas at the export point from the production facilities may have as much or more impact on the returns to the state and investors as the fiscal terms themselves. Once a gas industry is mature (and has ready markets) standard fiscal terms may be feasible (as in the UK or the Netherlands, for example). In the case of “stranded” or “remote” gas case-by-case negotiation is usually the norm. This places the host government at a disadvantage since it is less likely than an investing company to possess the technical and

commercial knowledge required to assess the prospect and its market; it may be faced with demands for terms that yield a particular anticipated rate of return on conservative price and volume assumptions. In these circumstances it is important to secure external advice, to retain powers to approve gas sales contracts and to include in the fiscal system some device enabling the government to share substantially in the upside potential of the project.

54. Gas development often follows initial oil development. Nigeria, Papua New Guinea and Trinidad and Tobago are differing illustrations of this process. There is a danger that, in setting terms for gas development, continuing oil revenues provide an effective subsidy. Terms should be set so that net incremental gas production creates net additional revenues.

55. Unless there exceptional circumstances the fiscal system, or its production-sharing equivalent should be broadly based. Thus normal import duties would apply (excluded only if discriminatory or distortionary) and VAT, if any, would apply to the petroleum sector. Thereafter the likely structure includes a royalty or equivalent (though the prevalence of this has reduced in recent years), normal income tax on corporate profits and then some device for capturing a significant share of high rents for the government, while leaving investors with attractive additional profit potential.

56. The original rationale for a royalty (or regular production payment) was to charge a "price for the resource" – understandable when the petroleum rights were in private hands (as in onshore USA). Now that there is a better understanding of the concept of rent the rationale is more likely to be the political reassurance than comes from a regular payment and the predictability that it adds to government revenue flows. Investors are often resistant to the use of significant royalties on the two grounds that (1) royalties add to the cost of production and may therefore reduce total recoverable reserves and (2) that royalty is a deductible rather than a creditable item for foreign tax credit purposes.

57. If a PSC imposes a limit on cost oil below 100% and a minimum state or NOC share of profit oil, a share of oil – akin to a royalty – flows to the state whenever production occurs. Once the investor's costs recovery requirement falls below the cost oil limit, however, the minimum profit oil share will yield more for the state than the originally equivalent royalty would have done. For example, until the 1980s a traditional rate of royalty was 12.5% of gross production. A cost oil limit of 50% coupled with a minimum profit oil share for the state of 25% would yield the same "royalty" amount while recoverable costs exceed the cost oil limit. If recoverable costs fall to, say, 30% of total production then the minimum state profit oil share at 25% will yield 17.5% of total production (70 x 25%). If the investor's income tax liability is settled from the state share then this "royalty" may be at least partly creditable, whereas a traditional royalty is only deductible.

58. A normal corporate income tax is needed to minimize transfer of revenue to the home tax jurisdictions of investor companies. This requires tax payments to be creditable, as far possible, against home tax liabilities. In the case of the USA, a foreign tax may be creditable if it meets two key criteria: (1) that it is a tax – charged under taxing powers

and not levied in return for some direct or indirect economic benefit; (2) that its character is that of an income tax in the US sense (it should tax "net gain" meaning, roughly, realized gross receipts reduced by recovery of costs and expenses attributable to generation of those gross receipts). Under production-sharing arrangements, taxes paid by the NOC on the investor's behalf out of the NOC share can still be creditable in the US. Such a method can also offer fiscal stability, by limiting tax obligations to the maximum NOC or state share. Rates of normal corporate income tax cluster around the range 30-35%. A number of countries separate petroleum income tax from normal corporate income tax and charge a higher rate (Angola, Nigeria, Papua New Guinea, for example); this seems not to affect creditability of the tax.

59. Depreciation, amortization or cost recovery rules interact with whatever rates or tax and production-sharing rates have been set. In general, slower depreciation or cost recovery increases early and regular revenue to government but correspondingly extends the payback period for an investor and reduces the internal rate of return. The appropriate balance is strongly-related to the fiscal position of the government: if the government is in a position to make savings then its discount rate will probably fall below that of the investor. In these circumstances the government maximizes both absolute and discounted returns by allowing rapid depreciation or cost recovery.

60. A large majority of production sharing arrangements and many tax systems incorporate some means by which governments can share to a greater extent in returns from fields of very high profitability. In traditional PSCs the state share rises with the average daily rate of production (Indonesia, Egypt), in a few (Nigeria) it rises with cumulative production. These arrangements are only proxies for profitability, since they ignore costs and prices. Attempts have been made to include price considerations together with the average daily rate of production (Trinidad and Tobago). Simpler in concept, however, is production-sharing calculated according to the investor's achieved rate of return (the "resource rent tax") or according to the ratio of cumulative receipts to cumulative outlays (the "R-factor"). These schemes require monitoring of costs and prices ain the same way as normal corporate income tax does.

Box 2: Rate of Return (RoR) Based Production Sharing

This method uses the principles IPCs themselves apply for project appraisal: rate of return calculated by the discounted cash flow (DCF) method. It comes closest to sharing of economic rent, defined as the excess of over all necessary costs of production including a reasonable return to capital. An interest rate is applied periodically to accumulate all the project's negative cash flows (capital outlays, operating costs and taxes) that are not offset by positive cash flows (receipts from cost recovery or profit-sharing). The interest rate should be as close as possible to the investor's discount rate - the minimum required rate of return. Using a range of accumulation rates makes the regime progressive and avoids the need for precise identification of the investor's discount rate; an account is kept for each rate of return. Sharing does not take place, or increase in the government's favour, until the accumulated cash flows become positive (including application of the interest rate); at that point the designated rate of return has been earned and sharing begins or moves to the next level. If there is re-investment (such as installation of secondary recovery techniques) negative cash flows are once again accumulated at the agreed rates until recovered.

The accumulation rate(s) could be established by competitive bidding; investors will bid the rate of return on a risk free investment (a long-term money market or high quality bond rate) plus the risk premium they wish to add for perceived technical, commercial or political risks. Where there is no bidding, the rate could be determined by bargaining with advice from international sources.

In principle, calculation of rate of return should be made after taking all other taxes into account; only thus will sharing accurately target surplus over and above the investor's required after-tax rate of return. For offshore petroleum in Australia, a before tax rate of return is used. It is possible to use an after tax return, however, at the cost of a little added complexity. The after-tax return in each account could be calculated, say, every quarter and shares in the next quarter would be apportioned according to the result (Angola and Azerbaijan use this procedure in some PSCs). Alternatively, profit shares could be calculated using an assumption of an imputed tax payment before production sharing; the resulting after-tax shares would then be grossed up to pre-tax levels by dividing by (1 - t) where "t" is the rate of tax.

Is ROR-sharing prone to unnecessary over-investment or "gold-plating"? "Gold-plating" is worthwhile only if the expected present value to the investor, after tax and production-sharing, of the additional income stream generated as a result of the new expenditure exceeds the expenditure itself. The higher the accumulation rate and the higher the State share the more likely this is to occur. The solution to the problem is to keep both the accumulation rates and the sharing rates reasonably low. As a practical matter, accumulation rates above 25% (plus inflation) and combined rates of sharing exceeding 75% of net cash flow may create gold-plating incentives.

The investor will not face more than the effective royalty (and income tax, if applicable) until the required after-tax DCF rate of return has been earned; the scheme therefore reduces investor risk. When costs change or prices rise or fall very substantially, the scheme responds automatically to adjust the production sharing without any need for renegotiation; it therefore promotes stability of the PSC.

Box 3: Payback Ratio or "R Factor" Based Sharing

This scheme is a variant of ROR sharing that is less precisely targeted to the investor's rate of return, and thus to economic rent, but may, in some circumstances, be simpler to administer. The scheme began life in Tunisia, Mozambique's PSAs use the R-factor scheme, as do the majority of PSAs in Azerbaijan.

The R-Factor or Payback Ratio is the ratio of the project's cumulative receipts in Cost and Profit Oil ("Cumulative Gross Receipts", CGR) to its cumulative total outlays under the PSA on exploration, development and operating costs ("Cumulative Gross Outlays", CGO). CGO will include payments of income tax if the calculation is to be made on an after-tax basis; CGO might also be adjusted for inflation. When the ratio of CGR to CGO is less than one then payback has not been reached; as it grows to a greater multiple of one the State's share increases.

The R Factor differs from the rate of return method in that it does not take explicit account of the time value of money; whether the ratio increases quickly or slowly does not matter in the calculation, the same share is still triggered.

This problem could, in principle, be overcome by adding an interest rate to unrecovered costs within CGO—if this is done the device becomes almost exactly the same as ROR Sharing and it is probably better then to use ROR sharing itself.

For example:

Range for R Factor	Contractor's Share of Profit Oil	State Share of Profit Oil
< 1	100%	0%
1< 2	90%	10%
2< 3	70%	30%
3< 4	50%	50%
4 & >4	40%	60%

61. Under royalty and tax schemes, as under production sharing, the average and marginal government take from net cash flow has tended to fall since the 1970s. In a few mature and highly prospective areas, states have been able to maintain a marginal take of up to 85% after cost recovery but this is now unusual with top marginal rates of 65-70% more common.

4. FISCAL ADMINISTRATION AND THE FLOW OF FUNDS

A. Crude Petroleum Output and Disposal

62. Under a tax a royalty system the concern of the taxing authorities is to ensure that petroleum production is correctly measured and that its disposal is properly reported. Together with prices, the reporting of total petroleum output and disposal enters the calculation of gross revenue for royalty and tax purposes. Production sharing, or other forms of joint venture between state companies and IPCs, also require the calculation of the entitlements of the state or state companies and those of the IPCs.

63. Output measurement rules are commonly established in Petroleum Law and Regulations or in a Production-Sharing Contract. The Accounting Procedure of a PSC requires a forecast of output against which to compare reported output. Assignment of shares to the state will either work in direct proportion to a state equity share or result from a production-sharing formula. Under a PSC the government of NOC will benefit from in-house capacity to model sharing terms. The liftings of each party require reconciliation with entitlements.

64. Crude oil disposals for export or to refineries require reconciliation with measured output figures. Some losses, or use in production processes, may occur. Gas deliveries at the export flange of a pipeline are reconciled with reported sales under the first sales and purchase agreement. Deliveries to refineries, in turn, call for reconciliation with product output from the refineries.

B. Inflow of Funds

65. Does the inflow of funds match the measured volume of production and the calculated entitlements? Where the state or NOC has petroleum entitlements there should be an audit trail following the disposal of these entitlements, receipts by the selling institution and record of deposit of the funds in the banking system. Under a tax and royalty system the trail of receipts and payments should likewise track the calculated tax obligations. At each step, the payments of one institution from petroleum revenues should match the receipts of another.

66. Export revenue should reflect available export prices. In the usual case today, the realised prices will reflect spot prices for the quality of crude, adjusted for the particular terms of any export contract. Any discrepancy may call for the use of an adjusted valuation, referring to arm's length prices. In the case of disposals to domestic refineries other prices may prevail but will be subject to the scrutiny of the NOC or taxing authority. The pricing of gas presents special problems: volumes and sales need to be related to a particular gas sales contract and to the reference pricing arrangement within it (see box).

67. In any tax or sharing system based on profit or cash flow the control and monitoring of costs becomes a central issue. Where there are joint ventures within the

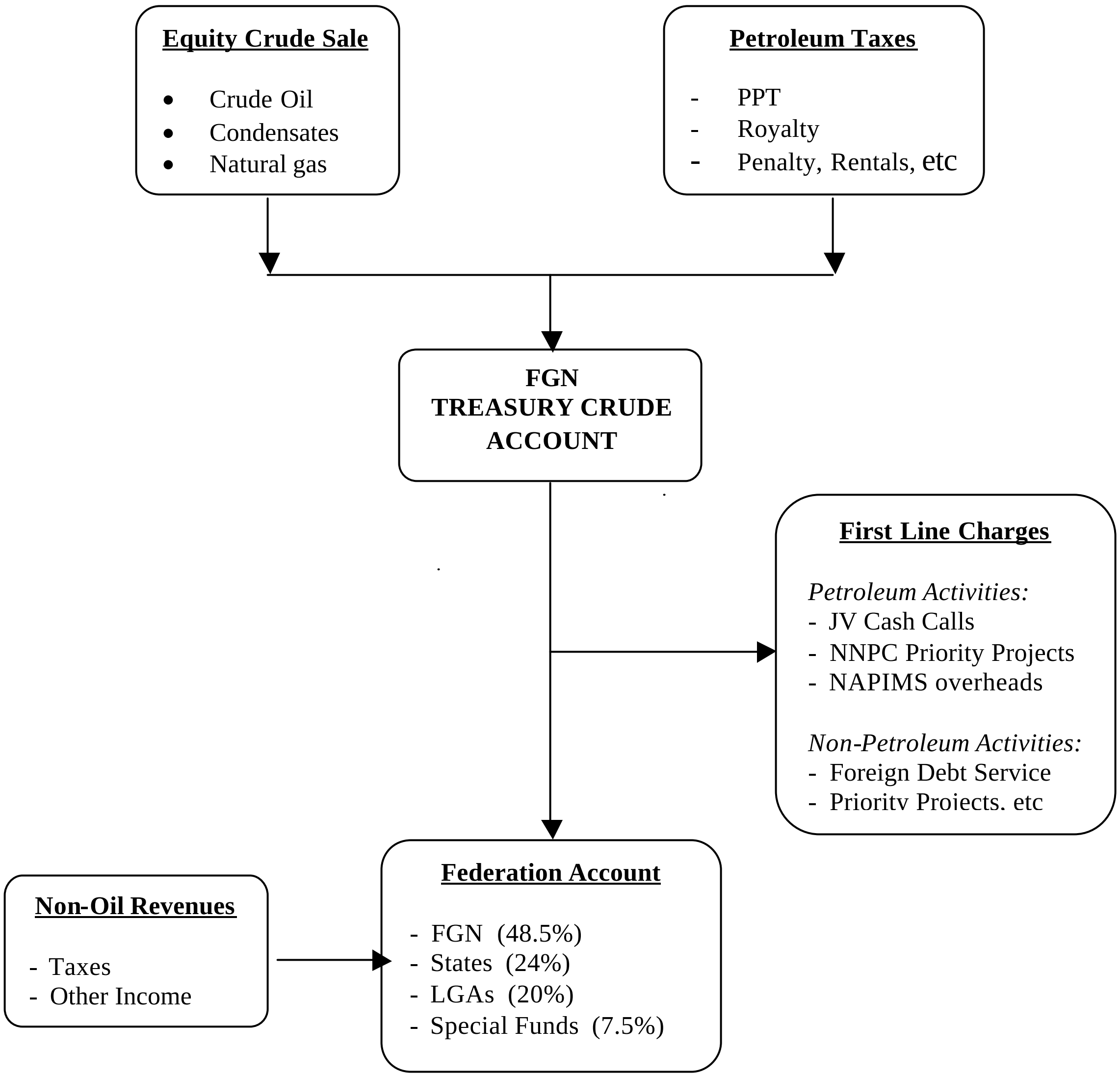
private sector, the venture partners can usually be relied upon to set in place mechanism to ensure efficient and least-cost performance by the operator. In the case of a solely owned venture, or of operations by the NOC, periodic valuation of costs by government is essential. In a tax and royalty system this function will fall to the taxation office, which must therefore be adequately skilled and resourced for the purpose. In the North Sea countries, for example, significant specialist organizations have been constructed, such as the Oil Taxation Office (OTO) of the United Kingdom.

68. In a number of developing or transition economies with NOCs (Azerbaijan or Nigeria, for example) the problem of arrears in payment has arisen. The emergence of arrears is a significant distortion of the fiscal framework and usually implies the creation of extra-budgetary subsidies. Analysis of the flow of funds provides an opportunity to identify arrears and plan for their elimination.

C. Outflow of Funds

69. Under a tax and royalty system the funding of the petroleum sector does not rely on a specific outflow from revenues received by the state. Under other systems, however, a specific outflow may occur. In these cases the government needs capacity to monitor the deployment of allocations of funds: reconciliation of allocations with the expenditure records of NOCs or joint ventures, control of costs within the recipient organizations.

Box 4: Petroleum Sector Flow of Funds in Nigeria



Box 5: Conclusions of Flow of Funds Review for Nigeria

The World Bank conducted a review of the flow of funds in the petroleum sector for the Nigerian Government, addressing the years 1995-1999. Six companies that operate under the unincorporated joint venture arrangement with Government produced about 98% of the total output. In each of the 5 review years, the Federation's share of equity crude exceeded its documented disposal by an average of 9.4 million barrels (2.1% of the Federation's annual share). In funds flow terms, the value of this apparent shortfall was an average of $152 million per year. The volume of crude oil delivered to the refineries each year was not consistent with the amount of products produced by them. Over the 5-year period, recorded deliveries were about 7.7 million barrels (or 1.5%) less than the minimum volume of input crude that was required to produce all the products that came out of the refineries. The Federation's joint venture partners' yearly crude liftings did not tally with their share of output

The Review did not find any material leakage of incoming revenues. The practice of direct cash payments into Central Bank of Nigeria (CBN) offshore accounts and the tight controls surrounding these accounts leave little room for leakage at the inflow end of the funds flow system.

During the 11 quarters from October 1996 to June 1999 the average price realized by Nigeria National Petroleum Corporation (NNPC) for the sale of the Federation's equity crude was consistently lower (by an average of $0.44 per barrel) than the weighted-average market price of Nigerian crude. The estimated Federation funds flow impairment from the lower realized prices was roughly $44 million per quarter.

CBN receipts were on average $2 million per month higher than NNPC's record of payments made for liftings. Actual oil companies' Petroleum Profits Tax (PPT) receipts by the CBN were on average $1.7 million per month less than payments reported by Federal Inland Revenue Service (FIRS). Total companies' royalty receipts by the CBN were on average $5.9 million per month less than the amount reported by Department of Petroleum Resources (DPR) as having been paid by the oil companies.

Out of the $45.4 billion realized during the review period, a total of $11.3 billion was disbursed as cash calls to operators of the joint ventures, and a further $2.1 billion (1995-1998 only) was disbursed to NNPC to cover National Petroleum Investment Management Services' (NAPIMS) overheads and to support the Corporation's operations in general.

There were substantial disparities among the unit production costs of operators, including those operating in similar environments. The average unit cost in the sector grew at an annual rate of 7% over the review period, in contrast to a declining worldwide industry trend that resulted from recent technological advances

Despite institutional weaknesses the basic system that put in place to monitor crude petroleum production and collect related revenues proved fairly robust.

D. Fiscal administration

70. The skills and resources available to the various institutions managing the flow of funds, together with the transparency and accountability of their operations, mainly determine the efficiency of the system. Nevertheless, a number of fairly straightforward measures can radically simplify effective fiscal administration.

71. Most countries use a provisional tax payment system. Instead of relying upon estimates from the previous year's tax return, companies should be required to make forward estimates upon which to base provisional payments. Where there is adequate forecasting capacity in government institutions these estimates are checked and possibly revised. Companies and the tax authorities should operate under a general objective to make the provisional tax paid approximate as closely as possible the tax that will eventually be due under a final assessment using actual results. This system prevails, for example, in Indonesian tax law.

72. In the final returns themselves and in payment obligations, the use of self-assessment can markedly reduce delays resulting from capacity problems in government.

73. Calculation of tax depreciation (capital allowances) is a complicated and time-consuming part of the tax system where individual asset registers are required. Use of the "pool" depreciation system (most conveniently combined with reducing-balance depreciation) offers much greater simplicity. The pool system (now adopted widely in OECD countries) requires only the calculation of additions to the pool for each asset class each year and the subtraction of depreciation allowed from each asset class pool as a whole. Asset sales proceeds either reduce the pool or add to income.

74. Taxpayers should be required to provide a reconciliation of corporate accounts with their tax computation. Since "projects" often consist of several "taxpayers" it assists tax administration if joint venture operators have an obligation to reconcile the partners' accounts for tax purposes, giving the authorities a composite view of the tax position of a project as a whole.

75. Tax authorities require a field audit strategy rather than use of audit only in response to disputed items. Occasional targeted audit works well with self-assessment. In some countries, out-sourcing of certain assessment and audit functions could be appropriate. Suitably regulated private firms and public sector entities with consulting arms from petroleum jurisdictions around the world are available to strengthen national capacity. Incentive contracts can sometimes be used in pursuit of value for money.

5. PETROLEUM REVENUE MANAGEMENT

A. Economic Issues

76. The government of a petroleum-producing country seeks to maximize resource rent receipts from petroleum exports and then confronts the economic consequences of risk and uncertainty about the magnitude of these receipts[6].

77. The taxation problem is to establish in the face of uncertainty a system of revenue sharing between IPCs and the government that maximizes the flow of government revenues over time. A fiscal system that efficiently taxes petroleum rent may maximize revenue flows but shift the risk of instability to the government. A government that organizes macroeconomic management to enable it to bear this risk will probably do better in revenue terms over time and set in place a macroeconomic framework leading to efficient use of petroleum revenues.

78. The macroeconomic task is to maintain the targets of internal and external balance. Internal balance means a combination of full employment of resources and price stability. Evidence for internal imbalance in developing countries often comes as excess migration from rural to urban areas. Full employment and price stability make greater contributions to welfare than their absence. External balance means a sustainable external debt position relative to the servicing capacity of the economy and adequate foreign exchange reserves for external payments throughout any economic cycle. Absence of external balance implies a reduction in consumption and welfare of future generations. It may also lead to imposition of controls on external trade and payments thus raising the cost of investment. Maintenance of internal and external balance – meaning general economic stability – reduces the risk premiums investors may attach to decisions, avoids disruption of major projects (public and private) and strengthens a country's position in trading or negotiating with the rest of the world.

79. Economic stability is vital to poverty reduction. Those without assets and skills tend to be damaged by instability, controls or rent-seeking behaviour. Fiscal and monetary instability jeopardizes any programme of social transformation or redistribution. Sound macroeconomic management is a necessary but not sufficient condition for growth and poverty reduction.

B. Responses to Shocks

80. Whether temporary booms and slumps in petroleum revenue or major secular shocks are at issue, the extremes of possible responses emerge from simple national accounting identities. Where income equals expenditure, then:

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[6] This chapter draws upon Philip Daniel, "Economic Policy in Mineral-Exporting Countries: What Have We Learned?", in John E Tilton (ed.), *Mineral Wealth and EconomicDevelopment*, Resources for the Future, Washington DC, 1992 and on Alan Gelb and Associates, *Oil Windfalls: Blessing or Curse?*, Oxford University Press for the World Bank, 1988.

$$Y = C + I + G + X - M$$
$$= A + B$$

Y is national income, A is total domestic expenditure (absorption) consisting of private consumption (C), investment (I) and government consumption (G); B is the trade balance of exports (X) minus imports (M). When a shock lowers national income, Y, then either absorption, A, or the trade surplus, B, must fall. Either domestic expenditure must be cut or a trade deficit must be financed. A petroleum revenue boom requires either that absorption is increased or that a trade surplus leads to accumulation of foreign financial assets.

81. In the face of a revenue boom there are four broad paths of adjustment:

a) Constant Absorption: this requires saving abroad (accumulation of foreign financial assets);

b) Trade Adjustment: raising the import-propensity of the economy or cutting exports;

c) Reduced domestic savings: an excess of income over expenditure means an excess of saving over investment. Reduction in saving requires increase in private consumption or an increase in the government deficit (or some combination of the two) as a proportion of GDP;

d) Increased investment: a rise in investment as a proportion of GDP restores external balance through the same mechanism as path "c".

82. Paths "c" and "d" would be strongly expansionary. Path "d" would accelerate growth if the investment were to be efficient. Path "a" would be the least expansionary if saving abroad proved complete and sustainable. Path "b" could prove still prove expansionary if the increased imports go to investment rather than consumption or if a cut in exports releases resources for investment in home goods or services.

83. In the face of a boom and without an adjustment strategy relative prices will change to restore external balance. This is the driving force of the so-called "Dutch Disease". Prices of non-traded domestic goods and services will go up while the prices of imports and exports remain as determined on world markets. Resources may also move out of pre-existing agriculture and manufacturing into the petroleum sector and possible into domestic goods and services. The impact varies with ease with which skills and other resources can switch from one industry to another, with the flexibility of wages and prices, and with the existing extent of unemployment.

C. Rules for Medium Term Stability

84. If the pace of absorption exceeds the sustainable rate of capacity growth in the economy inflationary pressure will follow. This pressure will exacerbate the relative price changes required in response to an increase in petroleum revenues. Such inflation has its

counterpart in physical supply bottlenecks, competing and leapfrogging wage claims – with possible strikes – and generation of rents for owners of land and housing and even for skilled workers. A key task is therefore to frame a realistic estimate of sustainable medium-term capacity growth in the economy and to restrict the public sector's contribution to demand to a level consistent with this rate of growth. By implication, a monetary policy geared to an inflation target will influence private sector consumption and investment in the same direction.

85. Consumption and investment in excess of the sustainable growth rate will further distort the economy and will fail to produce acceptable investment and welfare returns. The portion of petroleum revenues than cannot be used is better saved abroad for use when the range of profitable investment opportunities at home has expanded and the returns exceed the returns on saving abroad. Alan Gelb's 1988 study of six "high-absorbing" oil exporters concluded that economic performance would have been better than experienced if as much as two-thirds of the 1973-74 and 1979-80 petroleum revenue windfalls had been saved abroad.

86. A judgment about the sustainable growth rate is not sufficient for a decision on how much to save and how much to spend. Uncertainty about the forecast of petroleum revenues and possible fluctuations must also be taken into account. Any forecast implies a probability distribution of outcomes: the most likely outcome is clustered around the middle of the distribution with the tails of the typical "bell curve" on either side. The mean or "central" forecast implies an equal chance that revenues will be higher or lower than forecast. Maintaining a safety margin in the face of uncertainty requires selection of a forecast where the chance of a better outcome is greater than the chance of a worse outcome. If this is not done then the problem of "asymmetry of adjustment" (it is much harder to cut expenditure than to ramp it up) presents when revenues turn out to be lower than expected.

87. After the capacity growth rate and the cautious forecast of revenues the third pillar of fiscal strategy is constant absorption to dampen short-term fluctuations. Simply put this will involve saving of foreign assets in the upswing and spending from the accumulated balances in the downswing. Borrowing in the downswing against repayment in the upstream achieves the same effect but, evidently, with greater exposure to risk from mis-forecasting. The constant absorption strategy is difficult. Strong domestic and external pressures may act against tolerance of the necessarily wide swings in holdings of foreign assets. Short-term accumulations often create great pressure to spend – from bankers and donors as well as domestic interest groups.

88. The constant absorption strategy does not mean "fine-tuning" by counter-cyclical fiscal and monetary policy. This is a hazardous undertaking largely abandoned by the major world economies. In any case, frequent changes in tax provisions or interest rates may distort investment and production decisions defeating the central purpose of the strategy. The strategy must centre on saving and dissaving. In economies without sophisticated financial markets automatic stabilizers play an important part. In boom times companies remit profits removing a source of domestic demand, lower export earnings mean lower import capacity, banks may conserve liquidity in good times and

allow it to fall in bad times. Some countries have chosen to buttress the absorption strategy by using some type of non-renewable resource fund (NRF). The next section takes up the design of such funds.

89. The implementation of the strategy described here requires judgements that may turn out to be wrong. That is not, however, a good reason to avoid the judgments or the strategy. A medium-term fiscal framework for any country, whether a petroleum producer or not, requires a set of medium-term judgments about uncertain economic variables. The vital rule is to err on the side of caution. Some of the economic judgements required may appear sophisticated but –

"No sophistication is needed for the wise decision to deposit fast-growing mineral income in the bank, pending the emergence of sensible opportunities to spend the money. On the other hand, even a financially sophisticated government can squander the public income if it is unwise or dishonest or not concerned with social and economic development." (Marian Radetzki, 1992[7]).

D. Permanent Income and Sustainable Long-Term Use of Petroleum Revenues

90. Permanent income means the income from petroleum production which can be safely consumed without diminishing the stock of wealth available to future generations. It implies a measure of petroleum wealth in per capita terms. The stock of petroleum wealth means remaining petroleum reserves plus financial assets accumulated to maintain the real value of wealth from the starting year. If the real value of petroleum wealth is to be maintained then only the real return on from the petroleum wealth can be consumed. If the per capita value of oil wealth is to be preserved then consumption must be limited to the real return minus the rate of population growth.

91. A permanent income estimate offers only a yardstick. The uncertainties in the estimation procedure make it unwise to rely upon this approach as the central feature of fiscal planning. It is, however, another element available to inform a prudent overall fiscal judgment. It has the political appeal that its use will show a political leadership concerned about inter-generational equity in use of petroleum wealth.

92. In order to estimate permanent income the following information is needed.

a) **Oil reserves**: an estimate of total recoverable reserves derived from the probability of discoveries and then of commercial development. Ideally this estimate would also be linked to price, though for simplicity the estimate could initially be made on the assumption of a constant recovery cost per barrel. As noted below, it may initially be realistic to set the probability of new commercial discoveries at zero.

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[7] Marian Radetzki, "Economic Development and the Timing of Mineral Exploitation", in John E Tilton (ed.), *Mineral Wealth and EconomicDevelopment*, Resources for the Future, Washington DC, 1992.

b) **Production Profile**: either a fully estimated profile to peak production and tailing off thereafter or an approximate annual rate of increase in production to a peak year, followed by an approximate annual rate of decline thereafter.

c) **Cost per barrel**: in countries where production will occur under PSCs or concessions with foreign companies, the "cost" should be the projected average Contractor take per barrel at the chosen oil price. For the state this is the full cost, including capital cost, per barrel.

d) **Oil price range**: a range of projected oil prices in real terms of the base year. If the range represents a reasonable probability distribution of price expectations it would be wise to adjust the central forecast to one where the chance that the price will turn out to be lower is no more than 25 - 35%.

e) **Real interest rate**: a conservatively estimated real rate of return on financial assets accumulated from petroleum wealth, based on investment in bonds and currency deposits. This will be used to determine the discount rate to be applied to future flows of oil revenue.

f) **Projected Population Growth Rate**: either constant or varying over time, as appropriate. This will be used to adjust the real rate of return on oil wealth.

93. The calculation then proceeds as follows:

- Net real revenue (constant price terms) to the state per year is calculated from the assumptions in (a), (b), (c) and (d) above;
- The discount rate in (e) is applied to this income stream to calculate the present value of the stream of petroleum revenues (the "petroleum wealth");
- If the population growth rate varies, then the permanent income stream should be estimated annually as the rate of interest less the population growth rate.
- This stream of "permanent returns" is also then discounted to its present value. Both results can then be expressed as percentages of base year GDP.
- If the population growth rate is constant, the permanent income stream can simply be estimated as the appropriate percentage of oil wealth.

94. This calculation aims to set a limit only on current consumption out of oil revenues (and even then it is only one possible criterion); it does not preclude capital investment or retirement of debt. It does imply, however, that any investment made will yield a financial return on oil wealth equal, at minimum, to the discount rate while maintaining the real value of the capital stock invested.

95. In countries commencing the petroleum development phase (East Timor, Azerbaijan, Chad, for example) there is particular difficulty with the estimate of recoverable reserves. If there are uncertainties about export routes or markets (a

particular issue with gas) or about future discoveries or about development concepts, there is a strong case to limit recoverable reserves initially to those proven in fields which are operating or for which a development commitment has been made. In the early stages of petroleum production the permanent income estimate would, in any case, be subject to regular (probably annual) revision.

6. ISSUES IN ESTABLISHING NONRENEWABLE RESOURCE FUNDS

A. Overall goals

96. Establishment of a NRF is no substitute for sound overall fiscal and economic management but in certain circumstances it may buttress the right policy mix. A separate fund is not essential to promote adequate saving out of petroleum revenues but may make the politics and management of saving easier. A NRF of itself will not prevent wasteful use of revenues where the management rules and procedures of the NRF are inadequate and corruption or rent-seeking are in any case prevalent features of fiscal affairs; a well-designed and transparently managed NRF, however, can support the battle against waste and corruption.

97. There are three broad motives for establishing a fund:

- A ***stabilization*** motive where the priority is to insulate economic activity from fluctuations in petroleum revenues.

- A ***savings*** motive where the aim is to save wealth for future use on grounds of inter-generational equity.

- A ***precautionary*** motive where great uncertainty surrounds the likely path of future petroleum revenues or the ability of the economic to absorb spending efficiently.

98. Much has been written about funds of the first two types and examples described. Country examples (successful and unsuccessful) are shown in Figure 2.

Box 6: Precautionary Funds – Azerbaijan and East Timor

From the commencement of economic stabilization in early 1995 until 2000 Azerbaijan operated no formal Oil Fund but maintained a "shadow" oil fund by limitation on the amount of bonuses paid by IPCs for petroleum rights that could be used to finance the budget deficit. In addition the State Oil Company of Azerbaijan (SOCAR) fed current consumption by transferring tax revenues directly to the budget and by accumulating arrears of payment that amounted to significant subsidy for consumption of fuels. The use of tax payments and bonuses from the oil sector was probably consistent with a "permanent income" view of sustainable consumption of petroleum revenues in Azerbaijan; susbsidization through accumulation of arrears probably was not.

Since 2000 the State has received profit oil from the Chirag field (developed by a consortium led by BP) and also further bonuses. The State Oil Fund of Azerbaijan (SOFAR) was established By Presidential Decree and further financing of the general government budget from oil bonuses ceased. Profit oil and bonus receipts have since been accumulated in the Oil Fund, reaching some US $ 630 million by September 2002. Very limited expenditures have so far been made from the Fund; it has been operated in a precautionary manner. It is possible that part of the Fund will be used to finance Azerbaijan's 25% share in the Baku-Tbilisi-Ceyhan oil export pipeline.

The SOFAR is strictly under Presidential control, although expenditures may only me made through the Treasury system and in the framework of the state budget. Parliament has a consolidated budget laid before it but cannot determine expenditures from the Oil Fund. The Fund is not used for deficit financing of the general government budget. The Fund is subject to independent external audit and independent investment managers are now being appointed. The Fund has it s own regulations and also a memorandum of understanding with the Ministry of Finance

Existence of the Fund has probably avoided wasteful expenditures and permitted greater accumulations than would otherwise have been possible. It can, however, be spent by Presidential Decree and any guidelines for expenditure have yet to be issued.

East Timor has also created a "shadow" petroleum fund by accumulating its share of "first tranche petroleum" (royalty) from small oil development in the are a of the Timor Sea jointly administered with Australia. The motive of this accumulation is also precautionary. The government budget is small and currently dependent on donor support. While major petroleum developments may occur there is too much uncertainty about them to rely on projected revenue flows from them for the time being.

Figure 2: Experience of Nonrenewable Resource Funds

	Successful?	**Funding Source**	**Date**
Stabilization Funds			
Chile	Yes	Revenues above copper reference price	1987
Kuwait	Yes	Residual budget surplus	1960
Oman	No	Residual oil revenue surplus	1990, abolished 1993
Papua New Guinea	Yes, in early years, not after 1990	All mining and petroleum revenues	1974, abolished 2000
Venezuela	Too early to say	50% of oil revenues above reference prices	1998
Savings Funds			
Alberta (Canada)	Yes (accumulation now discontinued)	Fixed percentage of resource revenues	1976
Alaska (USA)	Yes	Fixed percentage of certain resource revenues	1976
Kuwait	Yes	10 percent of all government revenue	1976
Norway	Yes	Net government oil revenues (budget surplus)	1995
Oman	Yes, but framework not stable	Oil revenue in excess of budgeted amount	1980
Precautionary Funds			
Azerbaijan	Precautionary balances established	Designated oil revenues (mainly bonuses and state profit shares)	2000 (virtual fund since 1995)
East Timor	No major revenues as yet	First Tranche Petroleum (equivalent to royalty under PSCs)	2000

99. Clearly, the integration of any fund with the overall stance of fiscal management is vital. Without this any potential benefit from creation of a fund could be eliminated by poor general fiscal policy[8]. Three features are particularly important.

- ***A consolidated budget framework***. Domestic government expenditure decisions should be taken within one consolidated budget envelope, avoiding one expenditure programme financed by the fund and another by the general budget. Setting of expenditure priorities occurs best under a single constraint. Moreover, the macroeconomic impact of the budget comes from the overall budget deficit or surplus, if the fund is separate from the budget the consolidated deficit or surplus must still be the focus of policy.

- ***Liquidity constraint on the general budget***. Saving in a NRF will be of little benefit if there are no counterpart restrictions on the domestic or external borrowing capacity of the non-petroleum budget. Establishment of a large NRF savings balance will, of course, make a country an attractive target for foreign lending; there is little point is offsetting assets by counterpart liabilities under any of the possible objectives for a fund. Similarly, excessive domestic borrowing by a government would defeat the counter-inflationary benefit of offshore saving through a fund.

- ***Limits on domestic investment by the fund***. Investment activities by the fund in the domestic economy will reduce the level of apparent financial saving. Domestic investment will also equate to similar activities by the general government budget, whether capital expenditure or net lending.

100. Integration of a NRF within the consolidated budget using these three features makes the NRF a "financing fund". Surpluses accumulated in the fund represent a true consolidated budget surplus while at the same time the fund finances the true non-petroleum deficit of the general government – either by transfers out of the fund or by leaving deficit-financing petroleum revenues outside the fund. The Norwegian State Petroleum Fund most clearly exhibits this mode of operation

[8] A case strongly argued in Jeffrey Davis, Rolando Ossowski, James Daniel and Steven Barnett, *Stabilization and savings Funds for Nonrenewable Resources: Experience and Fiscal Policy Implications*, Occasional Paper 205, International Monetary Fund, Washington DC, 2001.

Box 7: The Norwegian State Petroleum Fund

Norway established its petroleum fund by legislation in 1990, though accumulation in the fund began only in 1996. By the end of 2001 savings in the fund stood at about US$80 billion or 45 percent of GDP. The fund has two purposes:

- Smoothing of spending out of volatile oil revenues;
- Long-term savings from oil revenues to cope with expenditures on an ageing population.

The objectives formed part of the political process for establishing support for saving rather than higher immediate spending. The key features of the fiscal rules governing the Norwegian fund are:

- The fund is integrated with the budgetary process; net accumulations in the fund are realised budget surpluses;
- The fund is not earmarked for any specific purpose (despite the political aim of pension provision);
- The fund is invested abroad; domestic spending from the fund is restricted to that needed to fund the non-oil budget deficit and is therefore spent through the budget process;
- The fund is established under law, managed by the Ministry of Finance and accountable to the legislature;
- The fund is technically a Norwegian kroner deposit of the government at the central bank; the bank acquires counterpart foreign assets. The Ministry of Finance delegates day-to-day management to the bank which, in turn, appoints fund managers within each investment sector for specific periods by competitive tender;
- The managers work under guidelines specifying the permitted ranges of bond and equity holdings, rules for the regional distribution of investments and upper limits on holdings in individual companies;
- Investment success is measured against a "virtual" portfolio establishing a benchmark in each sector; deviation from the benchmark must currently be no more than 1.5 percent.

The Norwegian fund remains relatively new and its structure means that legislators could, in principle, alter its rules at short notice. It is best viewed as a fiscal framework for long-term saving rather than a "fund". It meets the criteria for potential success set out in this paper.

101. The three broad motives for establishing a fund conceal a range of fiscal issues facing petroleum-producing countries that may differ according to the stage or circumstances of petroleum development.

B. Revenue Timing Problems

102. The nub of the fiscal problem is that the timing of petroleum revenues does not follow a desired or known path. Fiscal management, perhaps supported by a fund, tries to shift the path of absorption and reduce the impact of uncertainty. The degree of uncertainty and the problem of the revenue path may change

103. At the commencement of petroleum development, and perhaps at other points, uncertainties are caused by exploration, development and commercial risks. Here the precautionary motive for saving revenues is important. Revenues of certain kinds may experience temporary increases during construction booms – especially true where major offshore construction facilities are developed onshore or where significant gas processing activities are involved. Once production has started there is typically a period of cost recovery (or use of depreciation allowances under an income tax system), the government will experience stepwise increases in revenue when major revenue shares start to accrue to the State. These two circumstances invite not only a precautionary stance but also an effort to smooth the economic impact of revenue increases that may be temporary.

104. Larger producers in mature petroleum provinces are more likely to be affected by cyclical fluctuations in revenue caused by price variations. Here the stabilization motive predominates.

105. Concerns about the intergenerational distribution of oil revenues may call for a "permanent income" approach (see previous section) in which the sustainable current spending out of petroleum wealth is regularly re-estimated as prices change and there is better knowledge about the extent of reserves. By contrast, the government (as in Norway) may have a specific intergenerational problem it wishes to address – such as the effect of an ageing population on pension and social security provision.

106. A NRF will not resolve any of these issues on its own but, adjusted to the particular circumstances, a NRF integrated with sound overall fiscal strategy may help.

C. Allocation Problems

107. In addition to the timing issue there is the allocation or deployment of petroleum revenues. As petroleum is extracted, should other assets be created using the revenues? Or should the revenue simply be treated as a normal part of state income (as it was in economies as diverse as the United Kingdom and Papua New Guinea). Will the separation of petroleum revenues in a NRF better promote capital spending or economic diversification? Will a NRF make it easier to avoid wasteful spending above absorptive capacity through the budget? Finally, does a separate NRF help or hinder transparency of use? These questions have no universal answer. The context is vital.

7. MARKET-BASED ALTERNATIVES: IS HEDGING AN OPTION?

A. Introduction

108. Recent research has thrown doubt upon the efficacy of NRFs and proposed instead the use of hedging strategies by small or medium petroleum exporters – the examples of Mexico and Venezuela were cited[9]. Since IPCs and traders use hedging strategies to reduce risks from price volatility, it is argued, why should governments not do the same?

109. The active futures market for light sweet crude oil[10] on NYMEX extends out for about six years, although the market for futures extending beyond one year is thinner than for shorter term hedging. The market for futures and options contracts up to one year is liquid and accessible. There are three possible approaches, or a mix of them.

B. Futures Strategy

110. A futures strategy fixes now the oil price the government will receive in future. The government would sell crude oil futures (say 12-month futures) promising delivery one year later at a pre-agreed price. The government would then know with certainty the oil revenue it could expect for budget-making purposes. Under a tax and royalty system the government would undertake the hedging transactions in financial form – not, of course, physically delivering oil. A strategy of partial hedging using futures could also be followed: part of production could be sold at the spot price and part and the forward (futures) price. There is no premium or direct cost incurred in selling forward but the eventual price received is the net result achieved is the product of the sale of oil on the spot market plus or minus the gain or loss on the futures contract. Obviously, the actual outcome could be worse or better for the government than selling all oil on the spot market, the gain is in certainty for fiscal planning.

C. Options Strategy

111. An options strategy is more like purchase of an insurance policy. The government could buy options to sell crude oil (termed "put" options) to sell oil at a specified price 12 months hence – say $25 per barrel; it could then exercise these options if the spot price fell below $25 and decline to exercise them if the spot price rose above. Under this strategy the government can continue to benefit from higher than expected spot prices while maintaining a floor on prices – but at the cost of the premium paid to acquire the option.

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[9] This section draws upon James A Daniel, *Hedging Government Oil Price Risk*, IMF Working Paper, Fiscal Affairs Department, WP/01/185, November 2001.

[10] The marker crude is West Texas Intermediate (WTI).

112. Setting up a "collar" could offset the premium. With a "no-cost collar" the government would acquire put options as just described but would also sell a "call" option for a somewhat higher oil price that would, in effect, limit the government's benefit from sharply higher spot prices. The two premiums offset each other and the range of prices the government would receive in future would be limited to the two strike prices.

C. The Over-the-Counter (OTC) Market

113. Both the futures and options strategies require the government to arrange direct access to the market and to engage in trading. A third alternative is to engage with a financial institution (or more than one) to provide a tailor-made arrangement for hedging the oil price risk according to the government's risk preferences and the cost of the arrangement. In contrast to direct futures and options, which imply trades on single specific dates, OTC instruments (including commodity swaps, bonds or loans, futures contracts or combinations of all the instruments) can cover long periods of time. Thus the government could establish a floor price below which the financial institution would pay price support and a ceiling price above which the intermediary would receive all additional proceeds.

114. In OTC arrangements both parties take greater credit risk (because the transaction is not guaranteed by an exchange) but there may be lower costs. By keeping away from exchanges governments would not need to establish broker accounts, manage or pay margins, monitor the market, comply with regulations or hire and supervise traders.

D. Is hedging feasible for governments?

115. Recent retrospective simulations of hedging strategies suggested that the gain in stability of revenues would have been considerable, while any loss in absolute revenues would have been small. There are, however, substantial political problems. If spot prices fall it is easy for a Finance Minister to blame the markets. If output is hedged and the spot price rises above the hedged price then a government may find it difficult to justify or sustain a hedging strategy. In the case of options or OTC arrangements it may be difficult to justify the expense of the premium payments required.

116. Although market access and liquidity should now be sufficient for the needs of any small or medium producer, the costs of participation could be significant. Certain types of transaction (such as swaps) require adequate credit standing for the government – and the government will have to take credit risk on the other party to the transaction.

117. Development of institutional capacity to operate a hedging strategy may be the biggest obstacle, though this is not to say that the effort could not be worthwhile. It would be important to work out the interaction between the fiscal system governing revenue receipts and any hedging strategy. For example, a fiscal system geared to taking high share of very high rents could be rendered pointless if government's hedging strategy gives up high shares through collar arrangements or OTC agreements with financial institutions.

118. Irrespective of its own hedging strategy (or none) government will need to address the tax and production-sharing implications of hedging by IPCs operating in its jurisdiction. Petroleum tax laws and PSCs tend not, in general, to address the valuation of petroleum where hedging operations take place. The usual presumption is one of spot sales, often adjusted for a reference price, but where realised prices are used these might be current spot prices or the result of past hedging transactions – with significant implications for revenues.

119. For gas producers hedging is less of an issue. Many long-term gas contracts are in a sense "internally hedged". They may set fixed prices with an escalator, or be linked to a basket of fuels with a floor and ceiling, or prescribe a portion of annual sales to be made at an initially fixed price. The growth of LNG trade and of related pricing to a US reference price (such as Henry Hub or Southern California) might in due course make hedging more important for gas too.

8. PETROLEUM REVENUE DISTRIBUTION

A. Guidelines for Public Expenditure Management

120. Previous chapters dealt with how to raise petroleum revenues, how to administer the fiscal system and monitor the flow of funds, how to approach the macroeconomic consequences of petroleum revenue inflows and decision-making over the saving and investment of petroleum revenues for future use. This chapter considers mechanisms for distribution of revenues thereafter.

121. If we follow the consensus view that all domestic expenditure out of petroleum revenues should be channelled through the consolidated government budget then general rules of good public expenditure management must be followed and there are no special rules for expenditure from petroleum revenues.[11]

122. The overall guidelines for public expenditure management include:

- Preparation of consistent data on planned and past public expenditures in a consolidated format, compatible with a macroeconomic framework;

- Establishment of adequate budget preparation procedures for determining the level and composition of public expenditure planned for the year before the budget year starts;

- A budget execution system that can deliver planned spending within the approved budget aggregates, using suitable measures of expenditure control; the machinery must include interventions necessary to make in-year adjustments to planned spending;

- Cash planning and management arrangements permitting government to meet its fiscal targets (including borrowing or saving targets) and preventing sudden, unanticipated borrowing (or savings reductions) that could disrupt achievement of monetary policy targets or of longer-term targets for accumulation of petroleum revenues.

B. Earmarking and Extra-Budgetary Funds

123. Should expenditures from petroleum revenues (of from a NRF) be made through an extra-budgetary fund earmarked for specific purposes? It is sometimes argued that public support for saving of petroleum revenues is better mobilized if spending is directed, for example, to specific types of infrastructure provision or to pensions[12]. In the case of Chad, the World Bank-supported Petroleum Revenue Management Program

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[11] Barry H Potter and Jack Diamond, *Guidelines for Public Expenditure Management,* International Monetary Fund, 1999.

[12] Rögnvaldur Hannesson, *Investing for Sustainability: the Management of Mineral Wealth,* Kluwer, Boston, 2001.

seeks to reduce poverty by isolating the petroleum revenues and targeting their use to the priority poverty sectors, but in the context of overall government expenditure patterns.

124. Extra-budgetary funds can increase efficiency by simulating private market conditions where levels and standards of service are linked directly to fees or charges, for example, management of road user charges in a fund dedicated to road maintenance. This benefit, however, hardly applies to management of petroleum revenues. More plausible would be use of petroleum revenues to provide a consistent source of funds for expenditures that yield high benefits but are often unrecognised and subject to cuts.

125. Extra-budgetary funds, however, carry significant disadvantages. They can result in loss of aggregate expenditure control because expenditure from them may lie outside the control of the central budgetary authority. Because they circumvent, by definition, the budget process and normal review of priorities extra-budgetary funds can distort allocation of resources. Earmarked revenues can become entrenched and provide funding for items that may no longer be priority needs. Dedication to infrastructure requirements may lead to rent seeking and misuse of funds. Extra-budgetary funds lead to reduced flexibility at the margin to reallocate when the budget is under stress and they complicate sound cash management practices.

126. It will usually be preferable to put the general budgeting system right rather than to use extra-budgetary funds. There can be exceptions where this is infeasible over a reasonable time horizon: in Chad, for example, certain petroleum revenues are segregated and channelled towards incremental expenditures on high-priority government programmes.

Box 8: The Chad Petroleum Revenue Management Program

The Government of Chad agreed a program with the World Bank in 1999 for management of revenue from three petroleum fields under development in the Doba region of south-western Chad. There are three broad elements:

Petroleum revenues are channelled through audited offshore escrow accounts;

- Royalties and dividends to the state represent about 85 percent of expected revenues in the first ten years of production, these are invested in two ways –
    - 10 percent goes to a "future generations fund" invested externally in long-term instruments;
    - 90 percent goes to "special petroleum revenue accounts" (SPRA) held by the Treasury at private commercial banks in Chad and are used to finance incremental expenditures in five specified priority sectors for poverty alleviation, distributions to the producing region and certain Government recurrent expenditures;
- Income taxes on oil production and the pipeline company will be used for increased general development expenditures (these taxes accrue from about year 7 of production).

The Government agreed to make disbursements from the SPRA only on the basis of detailed annual expenditure programs designed to reduce poverty, agreed with the World Bank and approved by Parliament as part of the budget. There is an independent oversight committee including NGO and trade union representatives. Ex-post controls include independent audits of the fund and the SPRA.

A revenue management law was passed in 1999 providing for the fund and SPRA. The law also earmarks 5 percent of royalties (after deposits to the future generations fund) to be programmed by local authorities in the producing region.

Although this framework is not an overall long-term fiscal framework (compare Norway) it is explicitly integrated with the budget and sets up simple rules for allocation of revenues received. It has no explicit stabilization goal – that is the task of overall demand management.

C. Local / National Distribution of Revenues

127. For onshore oil and gas projects there is particular difficulty in reconciling local interests with integrity of public expenditure management. Local governments and local communities often seek a direct share of revenues, raising questions about equity among resource-rich and other regions of an individual country. In Nigeria, such tensions have been the cause of major unrest and loss of life in the Niger delta area and led, under the present democratic government, to a decision to assign 13% of revenues directly to the

region of origin. In Chad the petroleum revenue management program calls for assignment of 5% of total revenues directly to the producing regions. In Papua New Guinea royalties (at 2% of output) have long been assigned to the province of production, with part assigned directly to "landowners". The royalty is now treated as a credit against company income tax liability and has been supplemented by a deductible "development levy" (also 2% of production) payable to landowners and provincial governments. In addition, "landowners" now benefit from a vehicle giving equity participation in mining and petroleum ventures and companies can obtain a further tax credit for infrastructure provision in project areas. These measures may have made some contribution to local political acceptability of projects but at considerable cost to the integrity of the national budget.

128. A recent study[13] of this issue arrived at ten principles of local / national relations surrounding natural resource projects, worth quoting in full:

> 1. Government should enter into a national planning program, with inputs from the Local Government Units (LGUs) and NGOs, to define the nature and timing of decentralization and resource rent revenue sharing activities. Alternative models for action should be developed which meet the unique needs of the individual provinces/regions.
>
> 2. National and provincial agencies should assess actual and potential resource development options for individual provinces and establish, to the extent possible, the time frame for such developments and anticipated revenues.
>
> 3. National government, with inputs from LGUs, industry and NGOs should define the economic, social, cultural and environmental impacts of ongoing and planned resource development projects at the local to provincial level.
>
> 4. For those Provinces anticipated to be impacted by resource developments initial planning for the development of necessary infrastructure for the resource development which should be phased with the needs for overall infrastructure development at a national and regional level.
>
> 5. National government should establish Memorandums of Understanding with the LGUs with respect to each group's responsibility and authority with respect to decentralization and activities undertaken under resource rent revenue sharing.
>
> 6. Government social programs should continue at present levels for all provinces, however, impacted/to be impacted provinces should receive supplemental IRA funding to prepare the local communities for participation in the development.
>
> 7. The national government should develop and implement training programs for the LGUs to ensure that they are able to undertake the additional management and

[13] Allen L Clark and Jennifer Cook Clark, "The new reality of mineral development: social and cultural issues in Asia and Pacific nations", *Resources Policy*, 25,3, 1999.

planning activities that will arise as a result of decentralization and revenue sharing

8. The national government should prepare an action program for overall development that reduces, to the extent possible, the inequalities that will arise as a result of resource rent revenue sharing between resource-rich and resource-poor provinces.

9. Intra-provincial working groups should be established in order to share experiences and expertise in implementing decentralization and resource rent revenue sharing programs.

10. Planning at all phases of government should emphasize sustainable and socially responsible resource development that has as a central theme the understanding that virtually no resources are truly renewable and virtually all will be depleted over time