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Fiscal Regimes for Extractive Industries—Design and Implementation

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Fiscal Regimes for Extractive Industries: Design and Implementation

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ACRONYMS AND GLOSSARY

ACE	Allowance for Corporate Equity (for tax purposes)
ACC	Allowance for Corporate Capital (for tax purposes)
Advance Pricing Agreement	Agreement between tax authority and taxpayer as to method by which anticipated transactions will be valued for transfer pricing purposes
AEO	Annual Energy Outlook, US Department of Energy
AETR	Average Effective Tax Rate
bl	barrel
BOE	Barrels of Oil Equivalent (measurement unit for both oil and gas)
Bonus	Lump sum payment made for mineral (oil, gas, or mining) rights, or at contract signature, or at certain production thresholds
Biddable	Item that is open for bidding in auctions
Booking of reserves	Entering reserves in calculating the asset value of a company for stock exchange purposes
Carried interest	A participating interest in a project where the holder does not pay a commercial price for the interest or whose obligations are contributed ("carried") in part by other parties
CIT	Corporate Income Tax
Cost oil	Portion of total production allowed for recovery of costs
DROP	Daily rate of production (a scaling method for sharing profit oil or gas)
Fracking	Hydraulic fracturing (injection of water, sand, and chemicals to fracture shale so that oil or gas can flow)
GAAP	Generally Accepted Accounting Principles
EI	Extractive Industries
EITI	Extractive Industries Transparency Initiative
EMV	Expected Monetary Value
FARI	Fiscal Analysis of Resource Industries (FAD modeling system)
Free equity	Shares in a mining company allocated to a state entity for nil consideration (in practice often accompanied by tax concessions, or contribution of rights or infrastructure, and hence not strictly "free")
Gold plating	Incurring costs beyond the minimum needed
IETR	Incremental Effective Tax Rate (Appendix X)
LNG	Liquefied Natural Gas (methane super-refrigerated to store and transport as liquid)
LTBR	Long-Term Bond Rate
LTO	Large Taxpayers Office
MM	Petroleum industry conventional term for "million"
METR	Marginal Effective Tax Rate
NEIC	National Extractive Industries Company
NOC	National Oil Company
NPV (x)	Net Present Value (at discount rate of x)

Petroleum	Crude oil and natural gas
Production Sharing	Fiscal scheme for petroleum in which production at a surface delivery point is shared between a state entity and a private contractor
PSC (or A)	Production Sharing Contract (or Agreement)
PRRT	Petroleum Resource Rent Tax
Profit oil	Balance of production after subtraction of oil used for cost recovery
Quasi-rents	Rents attributable to past investments, or to factors of production in temporarily fixed supply
Rents	Revenues in excess of all necessary costs of production including the minimum rate of return to capital (sometimes “super-normal profits”)
Ring Fence	Fiscal boundary within which costs and revenues of companies in common ownership may be consolidated for tax purposes
ROR	Rate of Return
Royalty	Charge for the fact of extracting minerals, usually now *ad valorem* (a percentage of gross revenues), but can be a specific charge by volume or weight. May also vary with price. Term also used in “net profits royalty” where some costs are deducted, in which case similar to an income or rent tax.
Henry Proposal	A uniform resource rent tax…[using] an allowance for corporate capital system (Australia, Henry Report, 2010)
Shale	A compacted sedimentary host rock for unconventional oil or gas; its low permeability requires fracking for extraction
SOE	State-Owned Enterprise
TA	Technical Assistance
Thin Capitalization	Extensive use of debt, relative to equity, in financing a project or firm
Treaty shopping	Use of treaty networks to reduce total tax liability
UJV	Unincorporated joint venture (two or more companies acting together with undivided participating interests in a project; not the same legally as a partnership)
Uplift	Addition for tax deduction or cost recovery purposes to the cost of capital assets or of losses carried forward (the former sometimes “investment allowance,” the latter sometimes “accumulation rate”)
VAT	Value Added Tax
VIT	Variable Income Tax
WACC	Weighted Average Cost of Capital
WEO	IMF World Economic Outlook
WHT	Withholding tax
WTI	West Texas Intermediate (US oil price benchmark)

EXECUTIVE SUMMARY

This paper suggests ways better to realize the revenue potential of extractive industries (EI—oil, gas, and mining), particularly in developing countries. This has become an increasingly important topic of IMF policy advice and technical assistance (TA), with recent discoveries in many developing countries lending it a new urgency. The paper sets out the analytical framework underpinning, and key elements of, the country-specific advice given.

Revenues from the EI have major macroeconomic implications. The EIs often account for over half of government revenue in petroleum-rich countries, and for over 20 percent in mining countries. Dependence on EI revenues in resource-rich countries—now about one-third of the Fund's membership—has increased, and this seems set to continue.

Revenue objectives loom large in designing fiscal regimes for the EIs, but involve complex trade-offs. Generating employment in related activities, and addressing environmental impacts, can be significant concerns, but the revenue from the EIs is often the main benefit to the host country. It is the prospect of substantial rents—returns in excess of the minimum required by the investor, arising from relative fixity of supply of the underlying resource—that makes the EIs especially attractive as a potential source of revenue.

Fiscal regimes for the EIs vary greatly, a wide range of instruments being used. The paper attempts to gauge how current regimes share rents between government and investor. Data analyzed here suggest that in mining, governments commonly retain one-third or rather more; simulations suggest higher government shares (40–60 percent), but do not capture all possible sources of revenue erosion. They also suggest that the government share is higher in *petroleum*:[1] around 65–85 percent. Fiscal regimes that raise less than these benchmark averages may be cause for concern, or—where agreements cannot reasonably be changed—regret.

Country circumstances require tailored advice, but a regime combining a *royalty* and a tax targeted explicitly on rents (along with the standard corporate income tax) has appeal for many developing countries. Such a regime ensures that some revenue arises from the start of production, and that the government's revenue rises as rents increase with higher commodity prices or lower costs; in so doing, it can also enhance the stability and credibility of the fiscal regime (though processes to allow renegotiation may also be needed). It can also balance the challenges that each instrument poses for administration. Transparent rules and contracts tend to improve stability and credibility. Poorly designed international tax arrangements, however, can seriously undermine revenue potential.

Effective administration is vital, but complex EI fiscal regimes and fragmented responsibilities are often major impediments. Royalties need not be as easy to administer, nor rent taxes so hard, as is sometimes believed.

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[1] Italics are used on the first occurrence of terms included in the Glossary at the start of the paper.

I. Introduction

1. **This paper[2] considers how best to realize the revenue potential of the extractive industries (EI—oil, gas, and mining), particularly in developing countries**.[3] Designing and implementing upstream fiscal regimes for the EIs—mining and petroleum (oil and gas)—is now a major focus of IMF policy support and technical assistance (TA; Appendix II).[4] The aim here is to set out the conceptual approach and outline the techniques that guide staff advice.[5]

2. **Amplifying the already considerable macroeconomic significance of EI, recent and prospective discoveries make designing and implementing EI fiscal regimes a key challenge—and opportunity—for many developing countries**. These issues are important in G20 countries too, but it is in developing countries that the challenges are least familiar and most important for overall fiscal and wider performance. Appendix II describes the extent and growth of IMF TA on EI tax policy.

3. **Large new developments, notably in oil, gas, and iron ore, are underway in several low-income countries (LICs)** (Table 1). This trend seems likely to continue, as strong commodity prices continue to drive increased exploration and discoveries. New sources, such as *shale* gas (and other unconventional petroleum resources), offer opportunities in a range of countries, and new materials require expanding rare minerals production. Large volumes of resources likely remain to be discovered. Estimates from the Wealth of Nations database (World Bank, 2006 and 2010) indicate that the value of known subsoil assets per square kilometer of sub-Saharan Africa is barely one-quarter that for high-income countries. In recent years, proven reserves worldwide have increased while extraction rates have accelerated. No doubt most of this is due to technological change and high prices. Nevertheless, fiscal regimes seem to play a role: for example, fiscal regime revisions from 1991 onwards seem to have had a major role in expanding exploration and production in Angola's deep water prospects.

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[2] The paper has benefited from consultation meetings with civil society and EI companies, and from an open call for comments: Appendix I summarizes the views expressed; submissions received are at http://www.imf.org/external/np/exr/consult/2012/NR/Comments.pdf),

[3] Non-resource related revenues were discussed in a previous IMF policy paper, *Revenue Mobilization in Developing Countries* (http://www.imf.org/external/np/pp/eng/2011/030811.pdf) and other fiscal aspects of the management of resource wealth are addressed in the companion paper, *Macroeconomic Policy Frameworks for Resource-Rich Developing Countrie*s (http://www.imf.org/external/np/pp/eng/2012/082412.pdf).

[4] There are only four or so instances of Fund conditionality in this area over the last twenty years, the most recent being a structural benchmark for June 2012 on introducing a mineral resource rent tax in Sierra Leone. Conditionality related to EI transparency or auditing EI companies has been more common.

[5] In this, it draws heavily on the recent FAD book, Daniel, Keen, and McPherson (2010).

Table 1. EI Revenue Potential: Selected African Countries

Country/Project	Mineral	Investment US$bn	Average annual revenue potential (US$bn, constant 2011 dollars; percent 2011 GDP)	Lifespan of project(s)
Ghana, Jubilee (Phase 1 only)	Petroleum	$3.15bn	$0.85bn; 2.3	21 years
Guinea, Simandou, and others	Iron ore	$4bn for mining project [with additional $6bn in railway and port infrastructure]	$1.6bn; 30.7	21 years
Liberia	Iron ore, petroleum	$4.5bn	$1.7bn;[1] 147.8	20–30 years iron ore; potential 20+ for petroleum (but no proven project yet)
Mozambique, Rovuma (gas) Tete (coal)	Gas and coal	$20-30bn	$3.5bn;[1] 27.3	30–50 years
Sierra Leone, various	Iron ore, petroleum, diamonds	$4.6bn	$0.4bn; 18.2	15 years
Tanzania	Gas, Gold, Nickel	$20-30bn	$3.5bn;[1] 15.0	10–20 years gold (remaining in existing mines); 20-30 gas and nickel

Source: IMF staff estimates.
Note: Estimates are intended to show order of magnitude. Revenue projections are highly sensitive to assumptions about prices, phasing of production, and underlying production and capital costs.
[1] Data represent annual revenue at peak production.

4. **Revenue potential from oil is especially substantial**. For East Africa, Gelb, Kaiser, and Viñuela (2012) estimate exploration and development costs at $6–14 per barrel; applying these costs across sub-Saharan Africa as a whole with oil at $80 per barrel, and assuming that governments secure 50 percent of the excess of price over cost (and many regimes in the region seem likely to capture more), increasing production by 1 million barrels per day would increase government revenue in the region annually by about $12 billion, or 1 percent of the 2011 GDP of sub-Saharan Africa.[6] Angola alone increased production by 1 million

[6] Includes Sudan, now both Sudan and South Sudan.

barrels per day over 2001–11, while more than doubling its proven reserves. Sub-Saharan Africa as a whole increased proven reserves by 50 percent over this period (to 68 billion barrels), so the increase in daily production over 10 years could well exceed 1 million barrels. In iron ore, sub-Saharan Africa has reserves that can provide an estimated 120 years of total world supply (out of about 500 available globally).[7] If all these reserves could be developed, and the government revenue resulting were to be apportioned (improbably) over 500 years, the annual revenue addition would be about 0.7 percent of the region's 2011 GDP.[8]

5. **Country-level simulations confirm this potential**. The interaction of geology, prices, fiscal regimes, and technology changes makes accurate forecasting of likely revenue additions impossible. Nevertheless, using (admittedly crude) assumptions for sub-Saharan Africa, discovery and development of a single additional oil field in each of at least 18 countries with petroleum potential would add in a year nearly 2 percent of collective GDP to the revenue of these countries in the peak production years of these fields. The country by country impact differs widely. Natural gas may have similar potential.

6. **The central fiscal issue is ensuring a 'reasonable' government share in the rents often arising in the EIs**. 'Rents'—the excess of revenues over all costs of production, including those of discovery and development, as well as the normal return to capital—are an especially attractive tax base as they can, in principle, be taxed at up to 100 percent without making the activity privately unprofitable. There are, however, substantial obstacles making this effectively impossible—which will be a central concern below. By 'reasonable' is meant a sharing that at least provides private investors with an adequate incentive to explore, develop, and produce; beyond that, views on reasonableness may well differ.

7. **The paper is structured as follows**. Section II explores the key features of EI sectors that bear on fiscal regime design and then considers the design and assessment of EI fiscal regimes; Section III examines revenue administration and transparency; Section IV examines what is known (which is too little) about government revenues from EIs; and Section V considers some of the most pressing current and emerging issues. Appendices elaborate on key technical issues.

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[7] Estimate by BHP Billiton, Presentation at the Geological Society of London by Andrew Mackenzie, "Mineral Deposits and their Global Strategic Supply," December 14, 2011.

[8] Staff calculations assuming CIF iron ore price of $107 per ton (current WEO), overall costs of $70 per ton, and government share of surplus over costs at 40 percent.

II. Designing and Assessing EI Fiscal Regimes

This section outlines the tax-relevant distinctive features of EIs and then the main issues in designing and assessing fiscal instruments, both individually and in combination.[9]

A. Key Tax-Relevant Characteristics of the EIs

8. Prominent among these are

- ***Potentially sizable rents arise***. These are an especially attractive tax base on efficiency grounds—and on equity grounds too if, as is often the case, they would otherwise accrue to foreigners.

- ***Pervasive uncertainty***, most obviously but not only on commodity prices, the most fundamental difficulty being less their wide variability (Figure 1) than the difficulty of predicting them (Figure 2).[10] Substantial uncertainty also arises in relation to geology, input costs, and political risk (ranging from expropriation to changes in future fiscal regimes, including those potentially arising from climate and environmental policies).

- ***Asymmetric information***. Private investors undertaking exploration and development, for instance, are likely to be better informed than host governments on technical and commercial aspects of a project; the host government will be better informed on its own future fiscal intentions.

- ***High sunk costs, creating time consistency problems***. EI projects commonly involve very substantial upfront outlays by investors that cannot be cashed in if the project is terminated. The balance of negotiating power thus shifts dramatically from investor to host government once these costs are sunk. Even the best-intentioned government has an incentive to offer attractive fiscal terms before a project is begun, but afterwards—as the tax base becomes much less elastic—reset the regime in its own favor; and investors' awareness of this can discourage investment (the "hold-up" problem), to the detriment of both sides.

- ***Extensive involvement of multinational enterprises in many countries***…raises complex tax issues (with multinationals likely more expert than most developing country administrations) and sensitivities on sharing the benefits from national resources.

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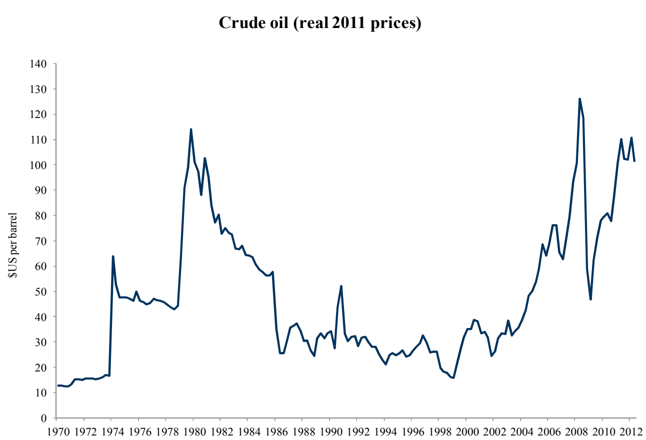
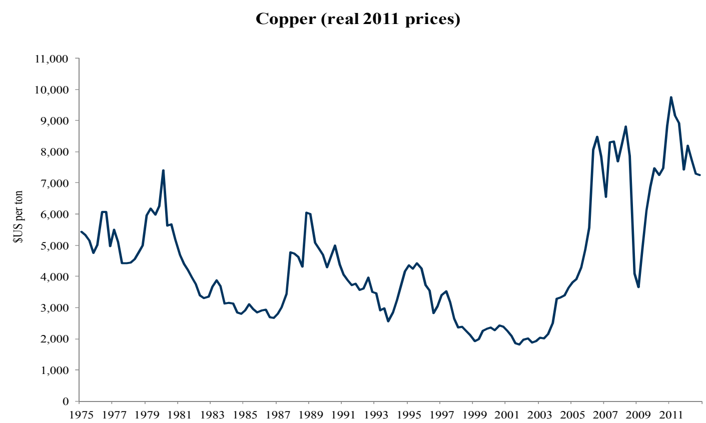
[9] These issues are discussed, and valuable materials provided, by the Natural Resource Charter (www.naturalresourcecharter.org) and the World Bank-supported Extractive Industries Sourcebook (www.eisourcebook.org).

[10] The IMF Research Department has produced numerous studies on the topic in recent years, for example Bowman and Husain (2004) and Reichsfeld and Roache (2011).

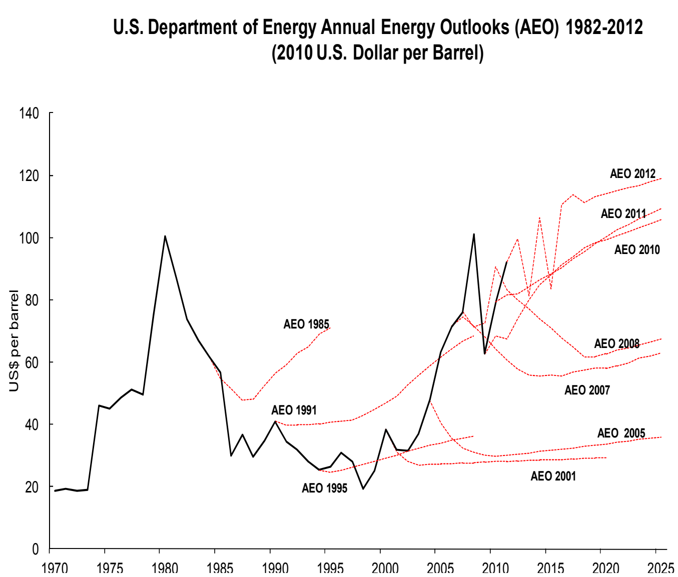
Figure 1. Developments in Oil and Copper Prices

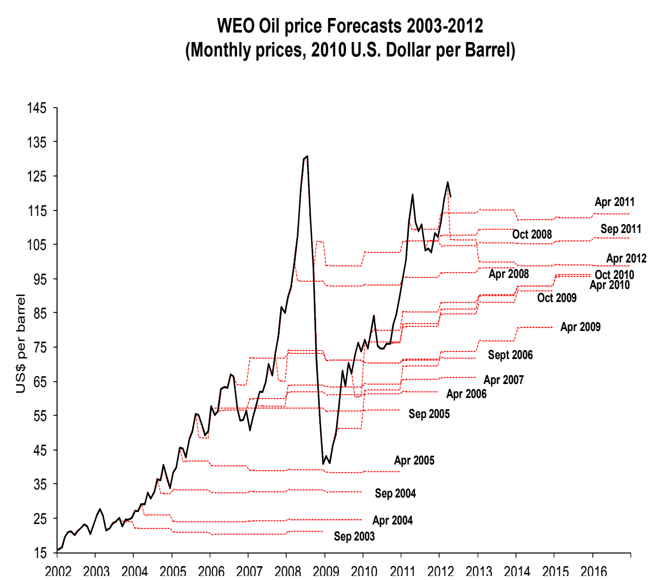




Source: IMF WEO database.

Figure 2. Oil Price Forecasts and Outturns





Sources: U.S. Department of Energy Outlook (1982, 1985, 1991, 1995, 2000, 2004–08, and 2009–12); and IMF World Economic Outlook (2003–12). After Ossowski et al. (2008).

Note: Solid lines on the left chart are spot West Texas Intermediate (WTI) oil prices; on the right chart are WEO average of WTI and Fateh. The dashed lines are price projections.

- ***…and of state-owned enterprises (SOEs) in others***, potentially easing asymmetric information issues but also raising concerns on the efficiency of operations and allocation of taxing responsibilities.

- ***Producers may have substantial market power*** *w*here they control a significant part of global deposits. In mining, for example, most internationally traded supplies of iron ore are shipped by just three companies; Saudi Arabia is widely viewed as able to influence oil prices.

- ***Exhaustibility***. The importance of the finiteness of petroleum and mineral deposits to long-term economic performance and commodity price developments is questionable.[11] At project level, however, exhaustibility can be a major concern; a key opportunity cost of extracting today is the future extraction foregone.

9. **It is the scale and combination of these characteristics that distinguishes EIs**. Exhaustibility aside, the other features are found elsewhere: pharmaceutical companies, for instance, face considerable uncertainty in their research activities, and natural monopoly features can create substantial rents in telecoms. But in other sectors, these rarely rise to the same level of macroeconomic significance (though it may be that some of the lessons learned in taxing EIs will come to be applied to other sectors).

10. **There are important differences between the oil, gas, and mining sectors**. Exploration is often costly and riskier for petroleum (a deep water well, for instance, can cost over US$100 million, and the chance of success in a new basin may be 1 in 20 or less). But the risks in the 'development' phase (bringing a discovery to extraction), and of failure during the extraction phase, may be greater for mining. Mining may also involve greater political and environmental risks, being typically based on land rather than offshore,[12] and so more disruptive of communities.

11. **Commercial structures tend to differ between petroleum and mining**. For tax, financing, or sometimes technological reasons, unincorporated joint ventures (UJV) have been common in petroleum projects, with capital separately provided by the partners and production shared. This sets up conflicting interests from which tax authorities can benefit in controlling costs. UJVs have been much less common in mining, with major companies owning majority stakes in locally-incorporated vehicles.

12. **The EI sectors, especially oil and gas, are entering a period of change**. '*Fracking'*, (hydraulic fracturing), becoming viable at current prices, enables fuller exploitation of onshore unconventional oil and gas, making their extraction more similar to conventional

[11] Proven oil reserves, for instance, have continued to rise despite increasing consumption levels.

[12] There are exceptions, such as offshore diamond dredging in Namibia.

mining. In copper mining, production has continued to accelerate despite declining grades of ore mined, as development of new techniques has markedly increased processing efficiency. And the transparency agenda is transforming both the openness of many private EI companies and what is expected of host governments.

13. **Resource-rich countries differ widely in ways that matter for tax design**. Beyond the large differences in their reliance (potential and actual) on EI revenues are structural differences germane to the choice of fiscal regime. There are differences too in standard (and likely appropriate) tax practice between oil, gas, and mining. In some countries, there are likely to be only one or a few major projects (such as uranium or niobium in Malawi), whereas in others there are many, and the expectation of more to come (as in Iraq). In some countries (Guinea, Lao PDR, Sierra Leone, Tanzania), constraints set by past agreements are tight for existing projects and change is possible only slowly by mutual agreement; most have greater scope in designing regimes for future projects. In some, known deposits will soon be fully exploited (oil in Yemen, Bahrain, and Indonesia). Some have strong traditions and national sentiments favoring state participation (in Mexico, for instance, this is a constitutional constraint, while it is standard in many middle-eastern countries, notably Iraq, Kuwait, and Saudi Arabia); others do not. Countries exploiting oil fields spanning borders (especially where disputed) face distinct tax issues. Far from least, administrative capacity and governance standards differ massively.

14. **Many developing countries have large numbers of artisanal miners—notably for gold and precious stones**. Historically this was a large sector in Brazil; it is now substantial in, for example, Sierra Leone, Suriname, Tanzania, Thailand, and Zambia. Operations have often been illegal but encouraged by exchange controls or restrictions on channels of sale for minerals. These operations are not considered at length in this paper: the fiscal issues (though not environmental, or law and order issues) have more in common with small scale agriculture than with large scale mining. Nevertheless, good practice appears to lie in attempting to levy royalties by requiring traders to withhold and pay (rather than attempting to tax miners directly, except perhaps for a small license fee) and otherwise ensuring that consumption taxes are levied and collected in mining areas.

B. Objectives for Fiscal Regimes for EIs

15. **Though not their only concern, revenue is generally a primary source of potential benefit to host countries**. Employment creation, directly and in related activities, minimizing community disruption, and addressing environmental consequences are also common priorities—especially though not only for onshore activities. Many such objectives can have implications for fiscal regime design, but the focus here is on core issues of revenue-raising. A key objective is thus to maximize the present value of net government revenues from EI, an objective best served by taxes explicitly targeted on rents: by definition,

any other tax leads to distortion that reduce those rents, and hence the amount of revenue that can be raised.

16. **There are limits to the rate at which rents can be taxed—but little guidance as to precisely what a 'fair' or 'reasonable' sharing might be**. Several obstacles to full taxation of rents arise. Asymmetric information means that host governments (as principal) generally need to forego some rents in order to provide appropriate incentives for better-informed producers (their agent).[13] Practical difficulties arise in accurately observing revenues and costs, and from tax avoidance devices.

17. **Designing a tax on rents also requires careful attention to costs at all stages of production, beginning with exploration (including unsuccessful)**: returns in excess of the minimum required after costs have been sunk in exploration and development—sometimes called '*quasi-rents*'—cannot be taxed at 100 percent without making the overall venture ex ante unprofitable. Tax competition may also play a role: even though the resources themselves are immobile, limited availability of technical expertise and specialist equipment may limit the number of areas in which exploration and production can take place, so that those offering more favorable tax treatment will be favored. Fairness considerations in themselves say little about how rents should be shared, though some see an intrinsic right for the host government to extract the maximum return from its ownership of natural resources.

18. **The timing of receipts, not just the level, may be important**. Where access to credit markets is limited—or simply as a result of political myopia—governments may prefer revenue to accrue early in the life of a project. On the other hand, willingness to defer revenue (through lower royalties, or accelerated depreciation, or greater reliance on rent taxes) may reduce perceived risk to investors and thus the expected return they require before deciding to explore or develop.

19. **Efficient risk-sharing between government and investor may limit the value of 'progressivity' in EI fiscal regimes for some developing countries…** The 'progressivity' of a fiscal regime—meaning, roughly speaking,[14] the extent to which revenue increases as the price of the commodity rises or production costs fall—shapes the sharing of risk between the two sides. Efficiency requires that more risk be borne by the party better able to bear it. In developing country contexts, this may often be private investors, given their ability to diversify across deposits (though the exposure of even large multinationals to single large projects should not be underestimated). This calls for fiscal regimes that are not especially

[13] Suppose, for instance, that only producers know whether extraction costs will be high or low. Then a fiscal regime which left no rents when these costs are low would mean that no producer could make a profit when they are high—even though such a project might yield large pre-tax rents and so be socially desirable.

[14] The term is used very imprecisely in discussions of resource taxation. One might also define it, for instance, in terms of how the present value (PV) of taxes varies with the lifetime PV of a project.

responsive to commodity prices, so that the investor gains most of the upside while the government is protected on the downside.[15]

20. **…but this may conflict with a desire for revenues to increase with current prices**. Limited progressivity also means that revenues increase less when commodity prices (or project returns) are high, which can cause incumbents political difficulty. By the same token, progressive regimes, being more politically robust, may be more credible.[16] The more diverse a country's portfolio of projects, moreover, the less strong is the risk-sharing argument against progressivity.

21. **Ease of administration (for the authorities) and compliance (for taxpayers) are ubiquitous concerns**—just as in all areas of taxation.

22. **Governments differ in the relative importance attached to these objectives**. Those hosting many projects, for instance, or with strong credit market access, may care less about ensuring early payment by each in isolation. Those with ready access to alternative sources of revenue may be less concerned by risk-sharing. Political pressures to show acceptable revenue from national assets, acceptably responsive to current prices, can be powerful. Table 2 summarizes these potential government objectives as criteria against which to evaluate the individual fiscal devices set out in Section II.D.

C. Overall Fiscal Schemes for EI

23. **There are two main approaches to fiscal regime design for EI: contractual schemes (including *production sharing* or service contracts), and tax/royalty systems with licensing of areas**. The latter dominates in mining; for oil and gas, both are common; and some countries use a hybrid. A third possibility is for payment largely as the construction of physical infrastructure; such packages are now mainly associated with investment from China, but were also a feature of investment from Europe in the 1970s. In all cases, the overall framework can be combined with state participation. It is possible to design economic terms that are equivalent under alternative approaches (Daniel, 1995), but these likely imply different structures of operational control.

24. **The apparent contrast between the two broad schemes is deceptive**. Case-by-case negotiation is possible under either and not just under contractual systems. Tax and royalty schemes prevailed historically since resource owners (private or public, and if public sometimes sub-national) charged specific or ad valorem royalties, with the remaining

[15] Such an arrangement also limits the macroeconomic challenges of managing volatile revenue flows.

[16] Boadway and Keen (2010) set out a simple model of political economy in which this is the case; Nellor and Robinson (1984) provide an early argument to the same effect. Stroebel and van Benthem (2010) explore, theoretically and empirically, the link between contract structure and expropriation risk, finding, for instance, that (in the present terminology, and consistent with the thrust of the argument here) regimes are more progressive in price the lower are the costs incurred by an expropriating government.

Table 2. Fiscal Mechanisms in the EI: Evaluation against Key Objectives

	Bonus	Royalty	Sliding-scale Royalty	Resource Rent Tax	CIT and VIT	State Participation
Maximize government NPV:	All risk onto investor, hence lowest expected government revenue. But, early revenue. Useful bidding mechanism to mop up expected rent.	Deters some projects and fails to capture upside from projects that go ahead.	Different effect on different projects; likely deterrent to low grade/high cost projects.	Captures higher expected NPV for the government in return for government taking on more risk.	Relatively neutral and progressive. Vulnerability to *thin capitalization*.	If fully non-concessional (Brown Tax) would maximize government expected revenue in return for taking on equal share of risk. However, usually some concessional element, hence distortions.
Progressivity when higher returns result from price.	No response: regressive (bonus reflects expected, not actual prices).	Regressive: government share of profit falls as commodity prices rise.	Different effect (share of profit) on different projects.	Effectively captures upside; but higher share maybe deferred. Reduces burden for low prices.	Instant VIT response to profitability changes.	*Free equity* is regressive (as is dividend withholding tax (DWT)); carried equity progressive.
Progressivity when higher returns result from lower costs.	No response: regressive.	Does not respond: regressive.	Does not respond: regressive.	Captures upside however caused. Automatically lowers burden on high cost projects.	Instant VIT response to cost changes.	Free equity is regressive; carried equity progressive.
Neutrality—avoid distorting investment and operating decisions (and thereby dissipate revenue potential).	Impact on exploration decisions; no impact on development or operating decisions.	Risks deterring marginal projects and shortening life/ reducing production of viable projects.	Different effect on different projects, hence distortions. High risk that parameters mis -specified.	Neutral: share is only paid by projects that actually exceed minimum return.	Depends on parameter design. Potential distortion in VIT from depreciation (step-change in rate).	Free/carried equity has negative impact on exploration decisions.
Ensure adequate incentives for investment.	Increases exploration risk, but relatively neutral if part of competitive bid.	Deterrent if too high; increased risk of unviable projects.	Depends on parameters. Reduces investor upside: likely deterrent.	Modest deterrent as long as sufficient upside left with investor.	Effective as long as maximum rate is not set too high.	Perceived negatively by investors unless fully non-concessional; but some risk mitigation benefits.
Risk to government.	Minimizes government risk,	Risk onto investor.	Risk onto investor.	Risk (of no revenue, or only late in life) onto government.	Government taking on risk if minimum VIT rate is below CIT rate.	Depends on terms: free equity acts like a DWT—low risk; carried equity like a RRT—higher risk.
Minimize administrative burden and risks.	Simple to administer;	Relatively simple calculations, but measurement, and valuation risks.	Complex: requires multiple parameters for each mineral. Net margin royalty requires definition of margin.	Relatively simple. Same data as required for income tax. Simple additional calculation (for cash flow RRT).	Same data for VIT as required for CIT. Simple additional calculation of rate.	Complex. Leads to pressure for negotiation at expense of other fiscal elements.

business income from EI subject otherwise to normal business taxation. Most European and North American jurisdictions continued this pattern while introducing more targeted taxation of resource rents. In the developing world, however, the desire for public expression of full sovereignty over resources led to development of contractual schemes: fee-for-service contracts where existing industries were fully nationalized, and production-sharing where governments desired still to attract private investment (Indonesia was the pioneer of this scheme in the mid-1960s). Contractual schemes commonly developed where national oil companies (NOCs) were granted an effective monopoly of rights to resources in the ground, with the right to make contracts with foreign providers of investment and services.

25. **Under *production sharing contracts (PSC),* common in petroleum, a contractor recovers costs by retaining some of the physical product as '*cost oil*/gas' and the remaining '*profit oil*/gas' is shared with the government**. Box 1 describes the leading variants that are sometimes made with the aim of increasing the government's profit share on more profitable projects.

Box 1. Forms of Production Sharing

Daily Rate of Production (DROP)	Government share of profit petroleum increases with the daily rate of production from the field or license, often with several tiers. Weaknesses are that field size is often a poor proxy for profitability and the mechanism is not progressive with respect to oil prices or costs. Attempts have been made to blend this with a scale of prices.
Cumulative production from project	Government share of profit petroleum as total cumulative production increases—again an inaccurate proxy for the contractor's rate of return. Such schemes are becoming rarer.
'R-Factor'	Government's profit share increases with the ratio of contractor's cumulative revenues to contractor's cumulative costs (the 'R factor'). This improves on DROP in being a more direct measure of profitability, but does not recognize the time value of money (Box 2).
Rate of Return (ROR)	This is a form of rent tax (provided that exploration is part of costs) under which the government's share is set by reference to the cumulative contractor rate of return, no tax being levied if that falls short of some benchmark rate. Single or multiple tiers are used, though staff analysis suggests a single tier is effective.

26. **Staff advice works within both systems, emphasizing design to achieve fiscal efficiency and regime transparency in either case**. The choice of overall framework will be determined, at least in part, by institutions and tradition, and by non-financial objectives. Companies also work within both schemes, though major oil companies tend not to favor contractual forms unless these permit *"booking" of reserves* under stock exchange rules. Some companies have preferred the PSC because it fills legal gaps and provides one comprehensive document covering operations; that though is equally achievable with a petroleum agreement under a tax and royalty system.

27. **The renewed popularity in developing countries of resource investments coupled with infrastructure contributions presents different challenges**. In principle, these are not complex: they require a cost-benefit analysis of whether the infrastructure contributions, when valued with risk apportioned, offer a payment for resources that is equivalent to the likely take from any foregone royalty or tax, and if not whether the mode of infrastructure delivery provides offsetting benefits. Arriving at such an assurance, however, is in practice difficult.

D. Fiscal Instruments for EI

28. **Within these broad approaches, a wide range of instruments is used**. This subsection considers each from a design perspective; implications for administration and compliance are addressed in Section III.

29. ***Bonus payments* (signature, discovery, and production bonuses)—can be part of any fiscal scheme**. Bonuses are single (or sometimes staged) lump sum payments triggered by events; they can be set in legislation or negotiated, and could be *biddable*. Bonuses in some petroleum exploration rights auctions have been very large (over $1 billion as a top bid in Angola’s 2006 round) but are much more modest, for example, in the USA’s offshore auctions. Signature bonuses become a sunk cost for companies that they may recover only in the event of successful development, and even then the fact that they are sunk may pose new political risk if a project is especially profitable.

30. ***Royalties on gross revenues*[17] have the attraction of providing government revenue from the start of production**. But, since they are a simple addition to cost, they can make the extraction of some resource deposits unviable. They are an implicit depletion policy (since the range of feasible projects is narrowed) and an invitation to negotiate. Where royalties form a major part of the overall fiscal regime, they tend to become more complex because refinements are needed to make them responsive to profitability (using proxy measures like price, location, or production level). Royalty rates that vary with price have easy appeal but, by definition, do not vary with costs and so will not be appropriate across the marginal cost curve of possible mines; moreover, any rate scale geared to prices requires frequent adjustment when forecasts are wrong.[18]

31. **Royalties can be rationalized as correcting for possible overexploitation, but the practical importance of this is unclear**. For instance, the interest of a firm will be misaligned with the social interest if it receives no payment for resources left in the ground at

[17] Otto et al. (2006) provide a detailed account of issues and experiences with royalties. Royalties as a specific charge on a unit of production are now little used for major EI.

[18] Both Mongolia (2007) and Zambia (2008) attempted introduction of windfall taxes that were effectively price-related additional royalties; both quickly withdrew them.

the end of the contract period. The government can correct this by charging a royalty that reflects the diminution in the terminal value of the resource (Conrad, Hool, and Nekipelov, 2009). In practice, however, extraction rights are usually granted for long periods, and renewable if further extraction seems warranted, so that contractors will internalize impacts on terminal values unless a significant charge is levied for renewal.

32. **The use of gross royalties protects revenue against overstatement of cost, but too little knowledge of costs can weaken the government's position**. Companies can reduce profit-related taxes by increasing deductible costs, and gross royalties can be used to guard against this.[19] But if royalties yield significant revenue and prices fall, companies will argue for reduced rates and governments will have no sound basis to challenge their case if they have not been closely monitoring costs. "Net profits" royalties and related schemes (popular in both North and South America) have the character of income taxes more than royalty; the name usually persists because of attribution to a sub-national tier of government.

33. ***The corporate income tax (CIT)* is a core component of most EI fiscal regimes**. Application of the CIT to the EIs is needed to ensure that the normal return to equity is taxed at corporate level just as in other sectors. Some countries apply a higher than standard rate on the usual CIT base (as in Indonesia in mining, and Nigeria and Trinidad and Tobago in petroleum); others have separate income tax regimes addressing sector-specific issues (the most important of which are addressed in Appendix III). A variable income tax (VIT***)*** uses the CIT base, but varies the rate of tax according to the ratio of profits to gross revenues. This is relatively simple but may introduce distortions, particularly if a high rate of tax applies when a period of high accounting profit occurs early in the life of a project, before the required return has been earned. The VIT may also increase debt-bias unless deduction of interest is limited to the standard rate of CIT.

34. **A variety of taxes explicitly target EI rents** (Box 2). Since it taxes the full return to investors, including the required return to equity holders, the CIT is a blunt instrument for reaching rents. A high CIT rate, for instance, can discourage investment by increasing the required pre-tax return; a tax on rents does not. The CIT is also biased toward debt-financing, since (with rare exceptions) interest is deductible whereas the cost of equity capital is not. Other tax instruments, such as royalties, also cause distortions whose effect is to erode the total of pre-tax rents to be shared between government and operator. Rent taxes aim to preserve that surplus, and to transfer a substantial part of it to government. Though equivalent, in principle in being non-distorting, alternative forms of rent tax differ importantly, not least in the timing of the government's receipts.

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[19] Box 7 of Boadway and Keen (2010) spells out how.

Box 2. Two Leading Forms of Rent Tax[1]

1. The **'Brown Tax,' or 'R-based cash flow tax,'** has as its base all current receipts less all current expenses (both non-financial), with immediate refund (or carry forward at interest) when this is negative. Accounting and tax depreciation do not feature—all capital is immediately expensed—and there are no deductions for interest or other financial costs. There are two main variants:

- ***Resource rent tax***. This replicates many features of the Brown Tax, with the investor receiving an annual *uplift* on accumulated losses until these are recovered. (As originally designed by Garnaut and Clunies Ross (1975) the uplift rate is set at the minimum required rate of return for the investor; this choice is now widely questioned, as discussed in Appendix IV). Australia uses this scheme for both mining and petroleum, while Angola's production-sharing scheme uses the mechanism. It is usually applied with *ring-fencing* by license.

- ***Tax surcharge on cash flow***. Adjusting accounting profit by adding back depreciation and interest, and deducting any capital expenditure in full, yields a base of net cash flow. This, too, could form the base for a surcharge. Instead of permitting an annual uplift for losses carried forward, a simple uplift (investment allowance) could be added to capital costs at the start—this is done in the United Kingdom by a time-limited uplift on losses. In the UK, this surcharge is combined with conventional CIT, within the same sector-wide ring fence. The "R-factor" or payback ratio scale used in some PSCs is a further variant, as is the "investment credit" of Indonesian PSCs.

2. **Allowance for Corporate Equity (ACE) or Capital (ACC) schemes**. The former amends the standard CIT by providing a deduction for an imputed return on book equity; tax depreciation remains, but becomes irrelevant in that faster depreciation reduces equity and hence future deductions by an offsetting amount. The latter also gives the interest deduction at a notional rate, so eliminating any distinction between debt and equity finance. Norway's special petroleum tax approximates the ACC, though its combination of uplift on total investment and limitation on interest deduction differs from a "pure" ACC. It also offers refund of the tax value of exploration losses and of ultimate losses on licenses. In 2010, the Henry Report proposed for Australia "a uniform resource rent tax…[using] an allowance for corporate capital system" (*Henry Proposal*). Several countries (Belgium, Brazil, Italy, and others) apply ACE-type schemes as their main corporate tax.[2]

A central difference between these two types of rent tax is the timing of tax payments—which is generally earlier under the ACE/ACC. Under the Brown Tax, tax is payable only at the perhaps distant date in which costs have been fully recovered; under the ACE/ACC by contrast, it is payable as soon, roughly speaking, as annual income covers the annual cost of financial capital.

A key and contentious issue for both types is the choice of imputed rate of return (for carry forward under the Brown Tax and for capital costs under the ACE/ACC; Appendix IV).

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[1] Boadway and Keen (2010), Land (2010) and Lund (2009) provide detailed discussions of rent taxation in the EI. The first shows that there is, in principle, an infinite number of non-distorting tax schemes; the focus here is on the most common in practical discussions.

[2] Klemm (2007).

35. **Use of *resource rent taxation* is increasing, notably in petroleum but also in mining**. Staff advice in developing countries has usually been to combine one of the devices shown in Box 2 with a royalty to make up the combined 'resource charge': the balance between the two is determined in specific cases by the relative ability to bear risk and the government's tolerance for potential delay in revenue. The trade-off can be finessed by using a device such as the ACC, where depreciation allowances (instead of cash flow deductions) advance tax payments, or the cash flow surcharge with limited-time uplift. Any measure that brings forward revenue in this way causes a counterpart increase in investor risk and thus may ultimately diminish rent available for taxation.

36. ***State equity* is used by many countries to secure additional government take (beyond tax revenue) from profitable projects**. This is sometimes motivated by non-fiscal concerns: a desire for direct government ownership, a "seat at the table," or to facilitate the transfer of knowledge. But these benefits could also be achieved by regulation (Sims, 1985). State equity can take different forms. *Fully paid-up equity* on commercial terms puts the government on the same footing as a private investor—akin to a Brown Tax (Box 2). Under a *carried interest* arrangement, the private company finances the government participation with the cost, including interest charges, offset against the future state share of production, proceeds, or profits—again equivalent to a Brown Tax. Or the government may negotiate free equity—equivalent to a dividend withholding tax (DWT) as a charge on profits, though this usually leads to some offset against other tax payments.

Instrument choice in practice

37. **A wide range of mechanisms is used, though there is little evidence on their relative yields**.[20] The final columns of Table 3 show the frequency with which instruments are used in a sample of 25 mining regimes and 67 petroleum regimes analyzed by staff. There is considerable variation both within and across mining and petroleum. In the mining cases, royalties are ubiquitous while production sharing and bonuses are absent; in petroleum, one-sixth of cases have no royalties, nearly one-half have production sharing, and just under 20 percent have bonuses. And even with the mining royalty regimes, there is considerable variation in the precise form. Information on the relative revenue importance of these instruments is hard to find (even from the survey of IMF desks). Figure 3 reports the breakdown in two cases.

[20] There are many variations on each theme and the distinction between different mechanisms is often blurred —elements from different mechanisms may be combined, or multiple mechanisms applied in a single regime. Classification in this analysis is for convenience only, but reflects reasonably common usage.

Table 3. Fiscal Mechanisms in the EIs: Nature and Prevalence

Mechanism	Description	Prevalence Number of countries Mining	Prevalence Number of countries Petroleum
Signature bonus	Up-front payment for acquiring exploration rights. Commonly used as a bid parameter (Notably for petroleum in the US offshore continental shelf)	1	16
Production Bonus	Fixed payment on achieving certain cumulative production or production rate	None	10
Royalties	Specific (amount per unit of volume produced)	2	1
	Ad-valorem (percentage of product value)	17	31
	Ad-valorem progressive with price	1	9
	Ad-valorem progressive with production		8
	Ad-valorem progressive with operating ratio/profit	3	1
	Royalty applied to operating margin (net profits royalty)	2	0
State, provincial, and/or local CIT[1]	Rate of corporate income tax at the state, provincial, or local level in addition to federal level. Common in Canada and the U.S. as a province/state resource charge in addition to federally imposed CIT.	2	5
Variable income tax	CIT where the tax rates increase with the ratio of taxable income to revenue, between an upper and lower bound	3[2]	None
Resource rent taxes	Cash flow with accumulation rate/uplift. Can be assessed before or after CIT.	5	5
	Cash flow with limited uplift on losses (UK). (surcharge tax on cash flow)	None	2
	Allowance for Corporate Capital	None	1[3]
	Allowance for Corporate Equity	None	1[4]
Other additional income taxes	Other profit taxation mechanisms that do not fall under any of the categories above	1	3
Production sharing	Fixed production share	None	5
	Cumulative production	None	None
	R-Factor: ratio of cumulative revenues to cumulative costs	None	13
	Rate of return, pre- or post-tax	None	3
	Production Level	None	13
State participation	Free equity: government receives percentage of dividends without payment of any costs	2	None
	Carried equity: government contributions met by investor and recovered from dividends with interest	3	8
	Paid equity: government pays its share of costs	None	19
Social investments/infrastructure	Resource companies build infrastructure or make other social investments (hospitals, schools, etc).	1	6
Number of countries		25	67

Source: IMF FARI Database.

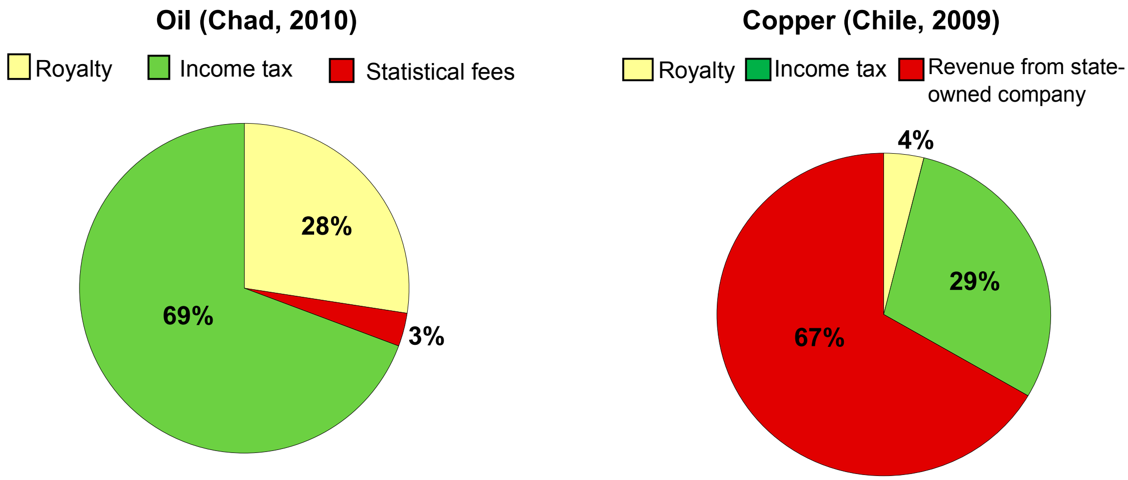
[1] In addition to Canada and the United States, Argentina, Italy, and the Russian Federation impose provincial, local, and state CIT, respectively. All countries in the sample impose corporate income tax (CIT) with the exception of the cases where VIT is used.

[2] VIT is used in Botswana, South Africa (in gold mining), and Zambia.

[3] Norway.

[4] Italy.

Figure 3. Composition of Revenue



Source: Data compiled for this paper.

Source: Data compiled for this paper.

38. **Some 80 percent of world petroleum reserves are controlled by state companies and 15 of the 20 largest oil companies are state-owned**. In all of these, the government (or NOC) pays for the private services it contracts and sometimes uses ingenious types of service contracts to approximate the risk-reward arrangements of PSCs. Except for Iraq's contracts, these systems do not allow private firms to "book" reserves under SEC rules—for which they will seek compensation.

39. **Several G20 and high-income countries have scope to tax EI rents more effectively**. Although not the principal focus of this paper, Box 3 provides a summary of some key issues and experiences.

E. Understanding Tax Effects on Exploration, Development, and Extraction

40. **Taxation potentially affects decisions at all stages—exploration, development, and production—and in potentially complex ways**. Key margins of choice include the intensity of exploration, the timing and intensity of initial development, the timing and intensity of extraction and enhanced (or secondary) recovery, and the eventual abandonment of the mine or oil field. No single model has satisfactorily encompassed all these dimensions. For this paper, Smith (2012) develops a manageable framework (Appendix V) for analyzing the behavioral impact of tax design in a coherent framework capturing the full lifecycle of EI activities.[21] Simulations described in Smith (2012) highlight a range of considerations.

[21] Though designed and calibrated for oil and gas projects, the model could easily be adapted for mining.

Box 3. EI Fiscal Regimes in Higher-Income Countries

Recent debates in, for example, Australia and Brazil, and reviews of mineral royalties in the United States and the Russian Federation, make clear that weaknesses in the design of fiscal regime are not limited to developing countries or new producers. In many of these countries too, more effective fiscal regimes could make a significant contribution to meeting intensified revenue needs. As stressed in IMF (2010): "Most [G20 countries] are sufficiently able to diversify the risks of natural resource exploitation to make profit/cash flow based instruments more efficient than fixed fees and royalties, yet some—including the U.S and Russia—still place heavy reliance on the latter. Movement toward explicit rent taxation, and use of auctions, could produce a marked revenue enhancement. This is not to argue that average effective tax rates are necessarily low…but that tax structures could be modified both to promote investment and to secure for governments higher shares of resource rent in profitable projects."

Among major producers:

- The U.S. uses auctions with bonus bidding for the Outer Continental Shelf, coupled with corporate income tax (CIT) and royalties; onshore, and for mining, both public and private resource owners mainly impose gross revenue royalties although net profit royalties are also common in some states.
- Russia operates a complex and distorting system combining a royalty, export taxes, and different prices for domestic sales and exports. In both Russia and the U.S., alternatives have been much debated but not adopted.
- Canadian provinces have moved rapidly toward profit or cash flow related taxes on oil and gas (including unconventional shale-sourced petroleum), though these are still (confusingly) called "royalties."
- Norway has perhaps the closest to a pure rent tax (in ACC form), coupled with CIT, for its North Sea oil and gas under a system also noted for its stability.
- The United Kingdom began oil and gas production with a more complex (and frequently changed) system, but in recent years has used a cash flow tax as a surcharge to the CIT. Both the U.K. and Norway effectively refund the tax value of losses.
- Australia has explored differing approaches to petroleum and mining. From 1987, offshore petroleum was subject to a petroleum resource rent tax (PRRT) imposed as deductible for CIT, but onshore petroleum and all mining remained subject to state royalties and CIT. In 2010, the government proposed for all EI a version of the allowance for corporate capital scheme (the Henry Proposal)—conventional tax depreciation was used, with uplift of losses and undepreciated balances carried forward at the government's Long-Term Bond Rate (LTBR); government guaranteed ultimate refund of the tax value of losses. The rate was to be 40 percent, deductible for CIT; and the CIT rate was to be reduced over time to 25 percent. After an outcry from mining companies (and a change in the composition of the government) the proposal was replaced with a Minerals Resource Rent Tax (MRRT) which now applies to iron ore and coal only. The MRRT applies at an effective 22.5 percent rate, after uplift on cash outflows of LTBR, plus 7 percentage points, and allows for crediting of state royalties. At the same time, the PRRT was extended to apply to onshore activities.

41. **The impact on exploration depends on the total government take in the event of success, interacting with tax offsets and the probability of success**. The decision to explore rests on comparing the fixed cost of drilling with the probability of success (updated as exploration progresses) and the return conditional on successful discovery. Simulations in Smith (2012) suggest that a tax regime with government take of approximately 50 percent of quasi-rents in the event of success (ring-fenced, so that exploration costs do not attract immediate tax reduction) reduces the acceptable number of exploratory failures appreciably, by 15–25 percent.

42. **Royalties, and production sharing agreements (PSAs) that create effective royalties, can plausibly cause significant distortion**. For instance, a 20 percent royalty or a 40 percent minimum profit oil share to the state (allowing only 50 percent of available oil for production costs) reduce initial investment by some 20 percent and the extraction rate by approximately 1 percentage point per year. The same terms delay investment in enhanced recovery by 1 or 2 years, with a further overall investment reduction of 20 percent.

43. **A resource rent tax may increase investment if the uplift rate on capital expenditure exceeds the company's cost of capital**. This circumstance leads to a negative marginal effective tax rate, and thus an implicit subsidy to resource extraction (Mintz and Chen, 2012). This incentive to *"gold plating"* (inflating costs), or suboptimal timing of investment (sooner rather than later) depends on both the excess of the uplift rate over the cost of capital and the resource rent tax rate; where both are low, the incentive is small (Appendix IV).

44. **It is important to consider tax effects over the full project cycle**. The sequential nature of the process means that distortions at one stage likely impose distortions at others, too. Effects emerge more subtle than the impact of taxation of quasi-rents on exploration decisions. High royalty rates, for instance, are associated with longer production lifetimes—somewhat counter-intuitive, this is because the expectation of high royalty rates leads to lower development investments, which imply higher marginal extraction costs. Total extraction over this expanded lifetime remains smaller than without the tax.

F. Scenario Analysis of Resource Tax Regimes: The FARI Model

45. **FAD's model for the Fiscal Analysis of Resource Industries (FARI)—presented in some detail in Appendix VI—is now widely employed by staff in country and TA work**. Excel-based, it enables detailed design, modeling, and comparison of fiscal regimes across the entire lifecycle of petroleum or mining projects. It is also increasingly used as a forecasting tool linked to the macro-economic framework for resource-rich countries. It does not incorporate behavioral responses of the kind just discussed, though extensions of the

model can simulate tax effects on investors' perceived risk.[22]

46. **One key output of FARI is project-specific estimation of the government tax take under alternative fiscal regimes, alternative prices, and other outcomes**. This is captured by the "Average Effective Tax Rate" (AETR): the government's share of pre-tax net present value (NPV), usually measured at the government's assumed discount rate. By way of illustration, Figure 4 reports estimated AETRs for a range of actual fiscal regimes in both mining and petroleum. These show that most petroleum fiscal regimes have a higher AETR and include more progressive elements than do mining regimes.

G. Evaluation of Alternative Fiscal Regimes

47. **Table 4 evaluates several families of mechanism against a range of criteria capturing the objectives set out above**.[23] The judgments there reflect both general principles and quantitative analysis, using the FARI Model, sketched in Appendix VI. Table 4 uses those results to match instruments to government objectives.[24]

48. **No regime is ideal for all, but for LICs combining a modest ad valorem royalty, CIT, and resource rent tax has considerable appeal**. The first ensures some revenue whenever production is positive. The second ensures that the normal return to equity is taxed at corporate level in EI as in other sectors and, moreover, that foreign tax credits will be available where investing companies' home countries (notably the US) tax them on worldwide income. And the third exploits the distinct revenue potential of the EIs. Such a framework can be applied across a wide range of circumstances and work for oil, gas, and mining projects, though the balance between mechanisms and parameters may differ.[25] There may be scope for other instruments, too: if there is competitive allocation of licenses or contracts, for example, then either a bonus or some parameter of the fiscal regime could be a bid variable (though of course use of a bidding system will affect the design of the fixed tax elements in the system).

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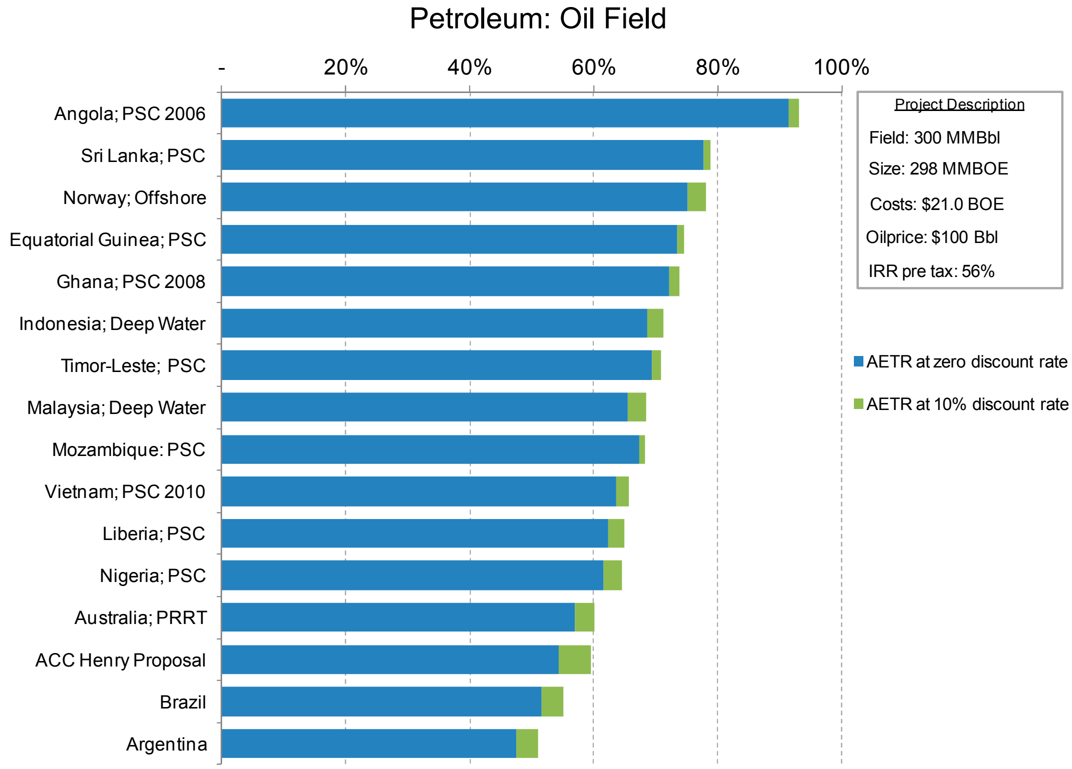
[22] FARI is similar to other simulation frameworks used for scenario analysis within the petroleum industry (Tordo, 2007) but specifically adapted for staff tax policy advice and for linkage to the macro-framework.

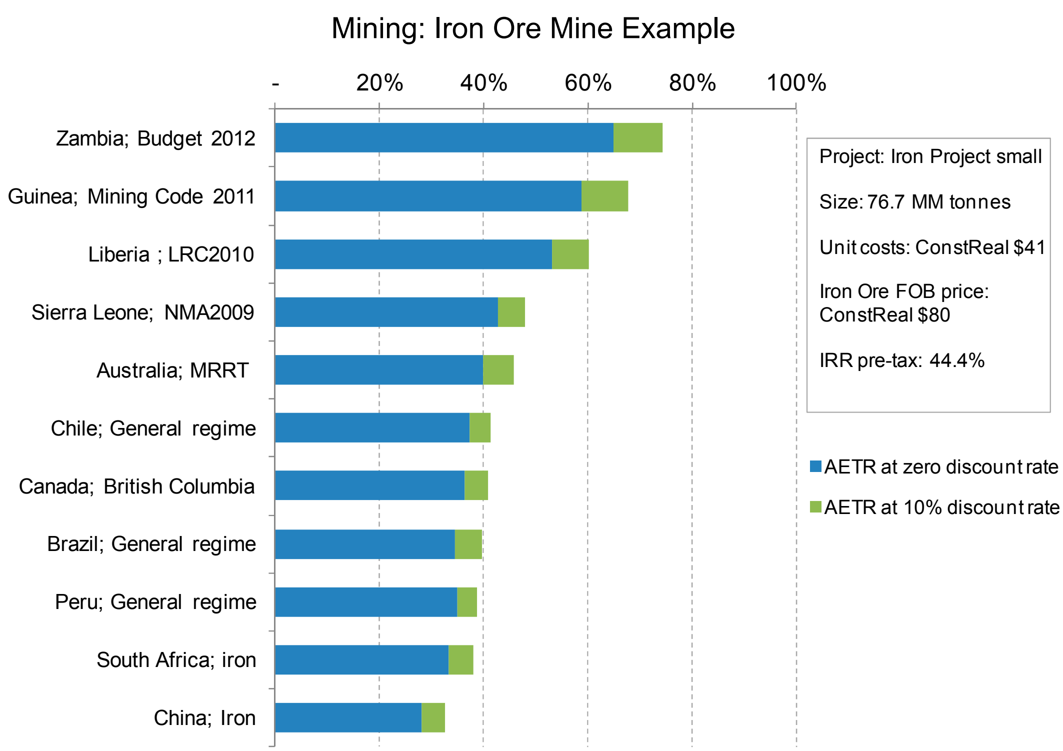
[23] These criteria are adapted from Daniel et al. (2010).

[24] Such simulations likely overestimate government take, as they take no account of the use of international tax and financing structures to reduce tax payments or the opportunity to deduct costs from one project against revenues from another if there is no ring-fencing, and do not allow for imperfections of implementation.

[25] There are interactions between the CIT and rent tax which means that the latter, even if deductible from the former, in general ceases to be neutral.

Figure 4. Average Effective Tax Rates (AETR) for Petroleum and Mining





Source: IMF staff calculations using FARI model and database.

Table 4. Primary Government Objective and Relevant Mechanism[1]

	Signature Bonus	Flat Royalty	Sliding-scale Royalty	Resource Rent Tax (and ACE)	CIT/VIT	State Participation
Maximizing government share over project life				X	X	
Securing early revenue	X	X				
Ensuring adequate incentives for exploration				X	X	
Visible share of commodity price increases			X			
Strategic ownership interest						X
Maximize resource utilization				X	X	
Minimize administrative burden and risks	X	X				

[1]Includes production-sharing equivalents of tax and royalty devices.

49. **A suitable tax structure and a target range of AETRs result from this analysis**. These simulations, and those of other sources, suggest reasonably achievable ranges of discounted AETRs will be 40–60 percent for mining[26] and 65–85 percent for petroleum.

50. **In some LICs, a focus on immediate revenue gains from EI projects is perhaps inevitable**. Most of these will come from improved tax administration. Retrospective changes of terms will usually damage the prospects for future investment. That said, there is room in a properly designed system for bonuses, for royalties, and for shifting revenue forward by taxing gains on transfers of interest (Appendix III).

III. Administration and Transparency

Administration[27]

51. **There is no intrinsic reason for effective and transparent administration of EI fiscal regimes—critical for both revenue and investor confidence—to be harder for EI than other industries**. They are simpler than other industries (such as finance and telecoms) in that they involve physical operations with outputs that can be analyzed, weighed, and measured, with prices in most cases quoted on international exchanges. And the vast bulk of revenues is often paid by a few large taxpayers, with a high stake in maintaining government goodwill.

52. **Administration is nonetheless often difficult and badly performed**. The (often excessive) variety and complexity of EI fiscal regimes often pose serious challenges; important tax rules are often complex, unclear, or open to abuse. Even with just a few EI companies, countries often struggle to cope with routine processing and reporting, hampering effective filing and payment enforcement. Royalty administration is often particularly inefficient, with frequent assessments, no annual return, and no reconciliation to commercial accounts and CIT returns. Fragmented administration prevents development of coherent risk-based audit and taxpayer service functions. Pay, status, and authority for operational staff are often inadequate to recruit staff of the quality required.

53. **An efficient structure for administration of the fiscal regime may require changing the responsibilities of EI ministries and any national EI companies (NEICs)**.

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[26] Aside from the special case of large-scale diamond mining where government shares have often been higher.

[27] Guidelines for effective EI tax administration are reviewed briefly here and set out in more detail in Appendix VII. Staff of the IMF and World Bank are working together on detailed guidelines for administering EI fiscal regimes.

Fragmented tax-type-based administration of the kind still common for EI revenues has many well-known disadvantages. The allocation of fiscal responsibilities to EI regulators and NEICs furthermore weakens their focus on their main roles. Self-assessment, a basic principle for effective tax administration that tax authorities in LICs often fail to apply, fits even less well into the culture and practices of NEICs and EI regulators, whose normal regulatory and commercial roles require real-time intervention. They often lack tax audit capacity, and outsource their audit function, a decision that should not rest merely on the fact that this function has been allocated to non-tax agencies. There is a fundamental conflict of interest when the NEIC combines fiscal and commercial responsibilities. To preserve integrity, fiscal roles within the EI ministry/NEIC should be clearly separated from regulatory and commercial roles. Putting the former in the tax department is the most obvious and effective way to do that.[28]

54. **Claims that administration of profit/rent-based EI taxes is so hard for LICs that they should rely on royalties instead are often misplaced**:

- ***Royalties are not always as easy to administer as is sometimes claimed…*** The ease of valuing sales should not be overstated. Although pricing from benchmarks may reduce transfer pricing risks, it is technically demanding, particularly for mining; and "netback" of processing, transportation, and other costs from benchmark refined mineral prices to establish market value at mine gate or export point can be challenging, posing similar difficulties to income-based taxes. In some cases, there are no international benchmark prices on which to base valuation. Regulations or *advance pricing agreements* to establish monitorable, transparent valuation formulae may be possible, but require considerable administrative sophistication.

- ***…and profit/rent-based taxes are not necessarily as hard***. Most LICs apply CIT to complex activities, such as banking and telecoms, even if sometimes accompanied by turnover taxes; and there is no special reason it should not apply to the EIs. Rent taxes can then be designed to require the same data, with a <u>less</u> complex calculation: the R-based cash flow tax, for instance, avoids any need to calculate depreciation, financial costs, or gains on license transfers. Angola, despite exceptional capacity constraints successfully applies production-sharing scaled to internal rates of return.

55. **The principles of effective modern tax administration are equally relevant to the EIs but too often are not applied in practice**. They include simple, well-designed

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[28] There is a case for the EI ministry retaining responsibility for physical audit. This is consistent with its regulatory role, requires real-time intervention and specialist mineralogical skills, and is distinct from normal tax administration functions (where natural resources are exported, this function is sometimes allocated to Customs, whose responsibilities likewise require real-time physical intervention). Sharing information from physical audit with the tax administration is vital, and often needs improvement, and it would still be the tax department's function to reconcile reported volumes with taxpayers' returns and financial records.

legislation with a minimum number of taxes; an integrated, function-based organizational structure; coherent, self-assessment-based procedures; and taxpayer-focused compliance risk management. But fragmentation of fiscal policy and administration often makes them difficult to implement (and also weakens the focus of EI ministries and NEICs on their own responsibilities, creating conflict and confusion of roles). Reforming this flawed approach can, however, be extremely disruptive, and also face major political obstacles.

56. **Strengthening EI revenue administration is an increasing focus of FAD TA**. But since this paper does not aim to discuss general principles of tax administration reform, its importance, and the weight given to it in FAD TA, are not fully reflected in this brief discussion. Nevertheless, there are immediate gains available from simple steps to improve audit (Appendix VII).

Transparency

57. **The risk that resource wealth will undermine governance is well documented**.[29] Tax policy design and administration may not be the greatest areas of concern, but here too transparency is vital, and often lacking. One-off confidential agreements make the law opaque, and the negotiation process is open to abuse. Government accounting for resource revenues is often poor and unreliable.

58. **Governments often make achieving transparency difficult**. Multiple taxes; contract confidentiality; complicated, inefficient, and incoherent filing and payment procedures; responsibilities for returns and payments fragmented across different agencies, with different banking arrangements and separate accounting and IT systems; revenues paid in kind; and no single department responsible for accounting for assessment and collection: all create non-transparency for no good reason.

59. **The *Extractive Industry Transparency Initiative* (EITI), to which many resource-rich countries subscribe, has had some success, but many countries still do not tackle the underlying issues**. EITI requires EI companies to publish what they pay, and governments what they receive, and that these amounts be audited and reconciled. (Confidentiality barriers must be removed.) Initiatives extending this approach now include Section 1504 of the US Dodd-Frank Act, requiring SEC-listed EI companies to report payments to governments; similar disclosure is required by a proposed modification of the EU Transparency Directive. While EITI has led to important progress, more needs to be done. For example, some countries now publish one-off tax agreements, but have not moved to taxing companies on the basis of published legislation. And government accounting remains poor.

[29] The IMF's *Guide on Resource Revenue Transparency* (2007) considers the issues comprehensively.

IV. Revenues from EIs

This section reviews revenue raised from the EIs.

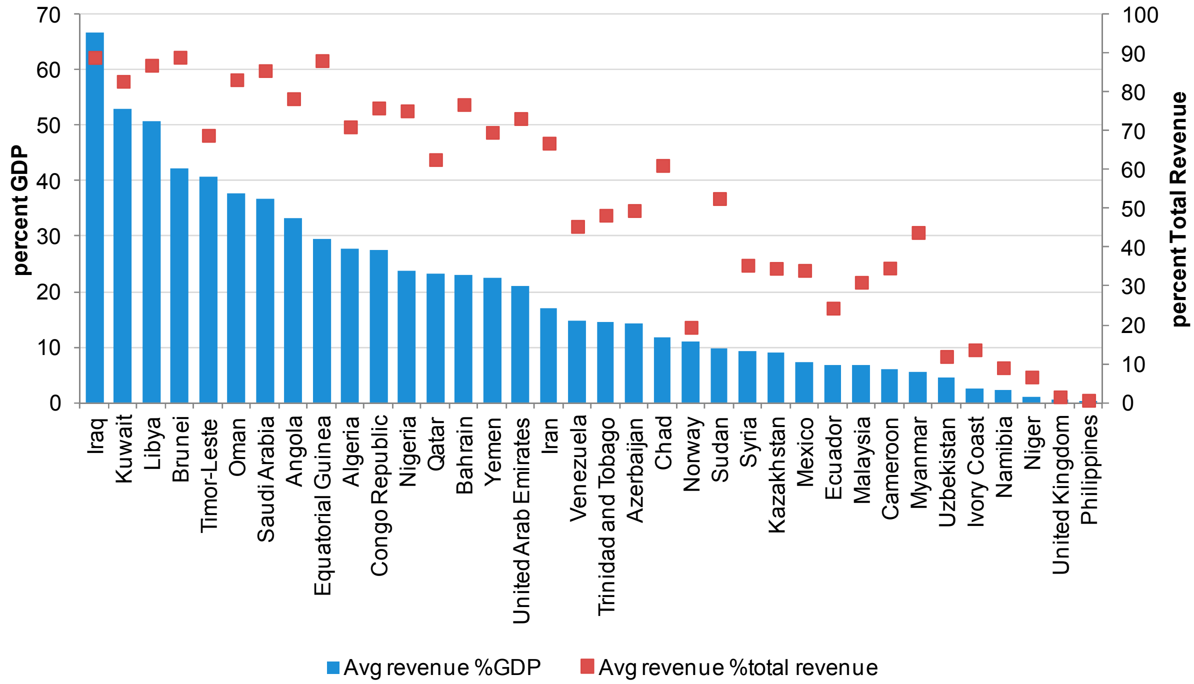
A. Government Revenues from the EIs

60. **Data on government revenues from the EIs are poor—a current IMF initiative aims to improve them**. Difficulties include the sector-specific and conventionally "non-tax" nature of many of the instruments used (bonuses, royalties and production sharing, or concessional state participation, for instance), the need to identify resource-related components of the CIT and other standard instruments, and fragmented and inefficient data collection across ministries and agencies. The Statistics Department plans pilot work toward routine collection of such data (Appendix VIII). The discussion that follows uses data provided by country desks on 57 resource-rich countries for 2001–10 (Appendix IX).

61. **Government revenue from EIs is substantial in many countries, with reliance especially high in some developing countries** (Figures 5–7, the last covering countries for which revenue cannot be distinguished by sector.) Petroleum revenue can be especially large: over 10 percent of GDP in 22 countries. These revenues are also substantial in many advanced and emerging economies, but dependence upon them is especially marked in some developing economies: revenues from petroleum accounted for about 93 percent of all government revenue in Timor-Leste (2008), for instance, and around 82 percent in Angola (2007).[30]

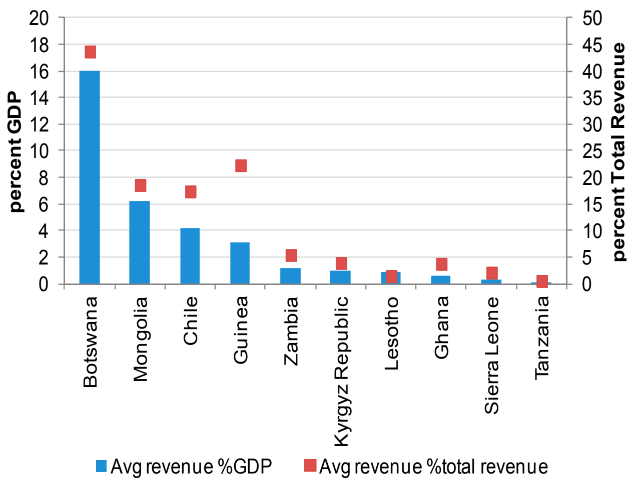
[30] Not discussed here are the implications of resource revenues for non-resource tax policies. The data assembled for this paper suggest that a one percentage point increase in EI-related revenue (in percent of GDP) is associated with a reduction in other revenues of around 0.2 points—broadly consistent with estimates for oil in Bornhorst, Gupta, and Thornton (2009) and reported for resources in sub-Saharan Africa in IMF (2011).

Figure 5. Petroleum: Government Revenue by Country 2001–10



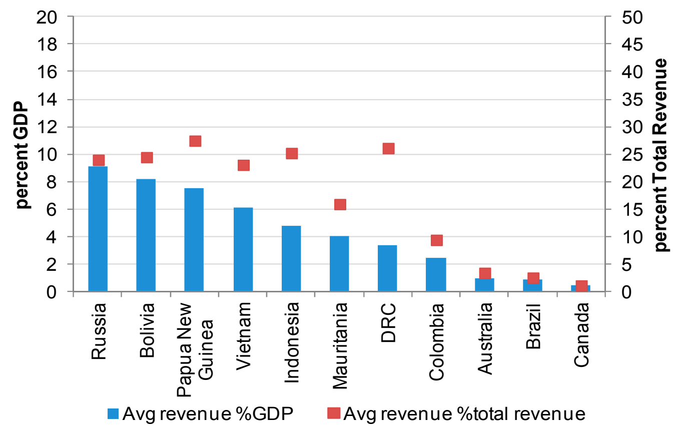
Source: IMF staff estimates.

Figure 6. Mining: Government Revenue by Country, 2001–10



Source: IMF staff estimates.

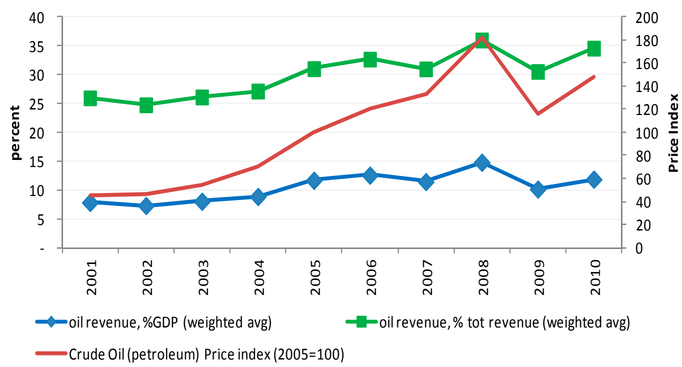
Figure 7. Mining and Petroleum: Government Revenue by Country, 2001–10



Source: IMF staff estimates.

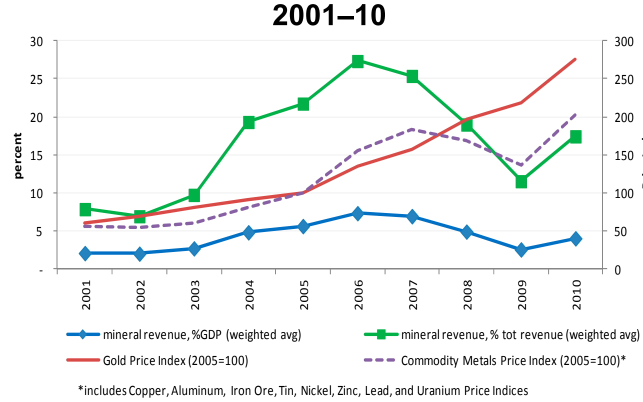
62. **Revenues from the EIs increased over the past decade, most consistently in petroleum producing countries** (Figures 8 and 9).[31] Revenues from petroleum rose in the countries shown from an average (GDP-weighted) of 8 percent of GDP to 12 percent, and from 26 percent of government revenue to 35 percent. For mining countries, the increase in revenue has been somewhat less marked relative to GDP, but much greater (and very volatile) relative to all government revenue—reflecting that mining-intensive countries are relatively low income, so tend to have fewer alternative revenue sources. In both sectors, revenues appear to have moved more or less in line with commodity prices (movement in mining tracking less the strong rise in gold prices than the evolution in the prices of the other main metals—copper, aluminum, iron ore, tin, nickel, zinc, lead, and uranium). In neither case (and this emerges too from simple regressions) is there sign that revenues are strongly progressive in current prices, though this would be hard to detect from these data for oils given that price movements may also powerfully affect the denominator of the revenue/GDP ratio.

Figure 8. Petroleum: Government Revenue, 2001–10



Source: IMF staff calculation using data described in Appendix VIII.

Figure 9. Mining: Government Revenue, 2001–10



Source: IMF staff estimates.

B. Effective Tax Rates in Practice

63. **Appendix IX elaborates on two complementary (but crude) methods to evaluate (somewhat different concepts of) effective tax rates on EI activities**: simulation methods (using the FARI model described below), and analysis of accounting data. Each method has its strengths and weaknesses: simulation exercises, for instance, can take full account of all taxes over the lifetime of a project, but require the analyst to project future prices and costs and may overstate effective tax rates as they do not capture all possible sources of revenue

[31] Similarly, EI exports rose from a weighted average of 7.7 percent of GDP in 2001 to 12.3 percent in 2010. Petroleum dominates these exports, though its share decreased over this period from 93 percent to 87 percent.

erosion (through imperfect administration, for instance); accounting data reflect actual outcomes, but provide only a snapshot across a miscellany of activities.[32] The results are thus no more than suggestive—and the methods capable of further refinement.

64. **These exercises suggest that effective tax rates are commonly higher in petroleum (around 65–85 percent) than in mining (45–65 percent), and increase with earnings, most markedly for petroleum**. These conclusions broadly match general perceptions on these issues.

65. **The reasons for these differences between petroleum and mining are not fully understood**. Possible explanations include that the expectation of rents, and the shaping of fiscal regimes to capture them, may simply be longer established for petroleum (mineral commodity prices having until fairly recently been in a slow decline that most thought would continue); the perception of greater non-fiscal benefits from mining (especially relative to offshore oil) may have led to more intense tax competition; and/or asymmetric information (on exploration and development risk), with related administrative challenges (from the absence of spot prices for some commodities, for instance) may have been a greater constraint in mining. While in some respects currently narrowing (rent capture having emerged as a greater a focus in mining), it may be that these differences will reassert themselves: some see substantial potential supply that will dilute rents in minerals, whereas in petroleum, restricted access to reserves and increasing costs of marginal production (Canadian oil sands or ultra-deep water) mean that significant rents for lower cost producers will remain.

V. Selected Current Issues

A. Stability and Credibility

66. **Stability and credibility of the fiscal regime for the EIs—critical to overcoming the hold-up problem—do not necessarily require a contractual assurance of fiscal stability**. Such an assurance is unlikely to substitute for a credible commitment by government to maintain predictability in its fiscal regime. Predictability is needed not only for the fiscal regime itself but, not least, for a process and/or criteria by which a regime may be modified (Daniel and Sunley, 2010; Osmundsen, 2010).[33]

67. **A stability assurance can have the strengths and weaknesses of fiscal rules more generally** (Debrun and Kumar, 2008). For the government, it may be a commitment

[32] Staff experimented with a third method, comparing companies' actual market values with estimates of what, given reserves and current costs and prices, it would be expected to be in the absence of taxes. Further work is needed, however, to have reasonable confidence in the results.

[33] Investment agreements may also have an important role in relation to expropriation risk.

technology aimed at binding all parts of government and future governments. Or it could be a signaling device aimed principally at encouraging other investors to enter. In some cases, it could function as a 'smokescreen,' with the government intending to make less visible changes to other aspects of the legal arrangements over time. The value to investors is not always clear—and if the assurance has to be invoked, relations with government have already broken down to a point where continued operation will be hard.

General legislation versus imposition by contract

68. **Administrative costs, political difficulties, and, probably, investors' perceived risk can be reduced by legislating terms applicable to all EI projects**. The alternative of setting them out in a model agreement can make them little more than a basis for negotiation.

69. **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 deposit, about which investors are likely to be better informed.[34] They also require concentration of administrative effort, negotiating skills, and detailed assessment of each investor's requirements which, in many circumstances, may be difficult to achieve.

70. **Countries that have attracted substantial mining investments in recent decades have used general fiscal terms rather than case-by-case negotiation**. These include not only advanced countries such as Australia, Canada, or Norway, but also Bolivia, Brazil, Chile, Indonesia, Namibia, Peru, and South Africa. Use of general rather than negotiated terms seems much more prevalent in South America than it remains in sub-Saharan Africa.

71. **Sometimes negotiation is inevitable**.[35] The key for governments is then access to project-specific information (for example, known deposits), to information on fiscal regimes available elsewhere, and to expert advice. A general rule favoring publication of negotiated outcomes deters corruption, and is more likely to produce an outcome that is sustainable and in the mutual interests of host country and companies.

72. **While the obligation to respect contracts is vital, renegotiations do and sometimes should occur**. Renegotiation can be warranted when terms have become egregiously out of line with international practice, or with terms in comparable

[34] Optimal tax design in the presence of asymmetric information in principle requires offering a menu of fiscal regimes: for instance, one involving a royalty and high rate rent tax, another no royalty and a lower rate of rent taxation (the former appealing where the investor knows the project to be high cost)—as in Box 6 of Boadway and Keen (2010), for instance. Negotiation might be seen as a way of presenting such a menu of options, too complex to set out in legislation. The theory remains far from practical implementation, however, and a willingness to negotiate carries implications for relative bargaining strengths.

[35] The Fund's policy has been not to advise on specifics of (re)negotiations, while recognizing that it is when these are taking place—indeed, especially then—that advice on general EI fiscal regimes is most valuable.

circumstances: no contract can anticipate all conceivable outcomes. When this happens through consultation, or by mutual agreement, the investment climate may be strengthened rather than weakened. In contract schemes, provisions for periodic reviews are increasingly common.

B. International Issues

73. **International tax issues for the EIs merit more attention than they have often received**.[36] Most of these issues are not specific to the EIs, and are of increasing importance to developing countries more generally—but they arise with special force in the EIs.

74. **The tax treatment of gains on the transfer of an interest in mining or petroleum rights has become a pressing and controversial issue**. This has become a major concern as large gains were achieved by sellers in transactions in exploration projects, for example, in Ghana and Uganda; the tax amount at issue in one case in the latter, for instance, was around $400 million.[37] Appendix III reviews the highly complex and very material tax issues that arise.

75. **Tax treaties sometimes erode the tax base of EI projects**. They frequently reduce permitted levels of border WHTs or even eliminate them altogether. *"Treaty shopping"*—routing and characterizing remittances so as to exploit advantageous treaty provisions—can substantially reduce withholding tax (WHT) obligations on dividends, interest, and management or technical service fees. Developing countries with substantial investment inflows to EI sectors, and negligible outward investments of their own, need to design treaty strategies that minimize base erosion and consider adopting rules against treaty shopping.

76. **Vulnerability to abusive transfer pricing exists for EI as for other sectors**. Higher taxes on upstream activities increase this risk, the companies involved are often integrated multinationals, and the use of tax havens is common. On the other hand, features of EI mitigate these risks: there are observable physical operations and outputs, there are standard measurements and benchmark international prices, and (in petroleum) the joint venture structure creates conflicting interests that work in the government's favor in controlling costs. Good practice requires clear and transparent transfer pricing rules producing a reasonable approximation of arm's length prices, using industry-specific practices where possible, and reflecting upstream input and output values. EI sectors have useful pricing benchmarks for outputs and transparent practices, such as transfer at cost, for some inputs; these benchmarks provide a comparable uncontrolled price with which to value transactions. The onus should be on the taxpayer to use the rules and show they have done so. Published

[36] Mullins (2010) provides an overview of international tax issues for the EIs; FAD held a workshop exploring these topics in more detail in May 2012 and plans a book on the topic.

[37] Myers (2010).

benchmark prices should be used where available, and tax authorities need a vigorous data collection program to support a coherent risk-based audit strategy.

77. **Regional coordination, while potentially worthwhile, is likely less urgent for EI fiscal regimes than for other aspects of business taxation**. Downward pressure on tax rates to attract scarce exploration and development capacity is a genuine concern. This creates a case for such agreements provided that countries can levy royalties and rent taxes appropriate to their own EI prospectivity and cost structure. Moreover, committing to maximum tax rates—not just minimum, as is usually thought of for regional agreements—could help overcome the time consistency problems. Nonetheless, the coordination issues are less pressing than, for instance, those in relation to tax incentives for more mobile activities.

C. Taxation and the Granting of Rights

78. **Taxation of EI is linked to the manner in which mineral rights are granted**. In some cases, governments may benefit from separating exploration from extraction—for example, by auctioning known deposits to the highest bidder—provided that prior rights for the investor have not been created during the exploration period. Most companies will not invest in exploration without assurance of extraction rights in the event of success, but deposits are sometimes relinquished and government may be able to increase the feasibility of competitive licensing rounds (including auctions) by acquiring exploration data itself (Tordo, Johnston, and Johnston, 2010).

79. **The design of any auction is critical**. There has been more success in auctioning petroleum exploration awards than in other EI activities, perhaps because more data are available from adjacent finds that encourages competition. The bid variable may be a bonus payment and/or some other item: the key is not to impose too many variables or criteria. The auction procedure best-suited may vary according to circumstances (Cramton, 2010). Auctions are unlikely to succeed unless participation by a significant number of qualified bidders is encouraged, and collusion among them averted.

80. **The first step is defining the product under auction: the term of the license, the lot size, royalties, and tax obligations**—and deciding which terms are biddable and which are fixed. Next, a number of basic design issues must be resolved: sequential versus simultaneous sale (with lots sold either one after another or all at once); dynamic or static auction (using either an ascending auction process or a single sealed bid); the information policy (what bidders know when they place their bids); and reserve prices (the minimum selling prices).

81. **Bidding can be combined with taxation (which is a future contingent payment liability)**. Indeed, this combination is usual and means that the structure of the fiscal regime (other than any biddable item) is integral to the design and revenue potential of the auction, and vice versa.

Appendix I. Key Points from Consultations with Civil Society Organizations (CSOs) and EI Companies

Civil Society Organizations (CSOs)

There is need for strong tripartite partnership between CSOs, the government, and the private sector. CSOs usually have limited knowledge of the sector, and donors and the IMF should work with and increase the CSOs' capacity in this area.

The IMF should support CSOs in their efforts to bring transparency through the disclosure of contracts with the companies and tax collection from EI projects.

The IMF should play a decisive role supporting governments in their effort to implement effective tax collection policy and auditing.

Natural resources represent an injection of funds in the economy but not necessarily growth for its resource-rich communities.

Key principles guiding public policy in EI industries should address the issue of natural resources' limitedness and the consequent need to use them in a way that properly serves the interests of future generations.

Royalties have many disadvantageous features for the host government. Income taxes offer much more positive benefits to host authorities, but require capacity building to monitor abusive transfer pricing.

In its advice, the IMF should propose that a percentage of taxes collected from extractive activities be allocated directly to the involved local communities (but see next two points).

Empirical evidence suggests that earmarking resource revenues for the provinces where the mines or wells are located can in some cases be beneficial, but it is often not.

Rents from EI industries need to be shared in a fair manner among the different stakeholders—companies, national governments, and regional governments. Transparent, balanced, progressive, and environment-friendly tax regimes should be promoted—this is the best way to avoid corruption and erosion of tax revenue, and assure citizens and investors that the rents from EI are shared fairly.

EI companies

Mining

It is important to focus not only on the division of rents and revenue-sharing, but also on broader measures of the economic and social impact of mining.

Resource revenues should also be used to support improvements in institutions and administrative capacity.

Because companies compete, there can be over-investment and enhanced price volatility over time.

The risk profile of projects is just as important as the straight measurement of expected NPV.

Among the stakeholders, governments have seen the largest increases in their returns since 2005; mining companies use their own higher profits to fund future investments. Substantial cash on the balance sheet does not mean a company is under-taxed.

Auctions only maximize value when there is sufficient knowledge about the resource base (emphasizing that this is less common in mining than in petroleum).

The tax system should be predictable and substantially profit-related, with no retrospective imposition of taxes. There is no ideal division of rents between companies and states—it varies with circumstances.

Petroleum

Exploration risk is large and many discoveries remain uneconomic.

The commercial success rate is influenced by fiscal terms, though not by those alone.

The sector is changing as exploration moves to deeper water and unconventional sources of gas and oil; these efforts have longer timelines and sometimes higher risks.

The average government take worldwide for oil and gas projects is around two-thirds, and the sector is not under-taxed.

Oil companies need clear, stable, and simple fiscal regimes.

Gas and oil prices have increasingly diverged and fiscal regimes have not taken this into account.

Oil companies' analysis is not all about tax rates; they consider: balancing risk with governments, avoidance of double taxation, and the ability to tax-deduct expenses.

Auctions have had mixed success: some secured bids that were unsustainable. Bonuses are problematic in that they often cannot be claimed as a tax deduction; auctions on production targets or contingent payments might be preferable.

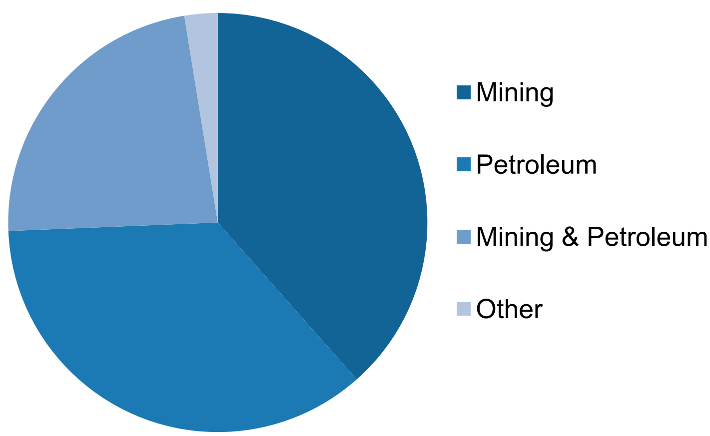
Royalties or levies on gross production do distort investment and production decisions.

Appendix II. Technical Assistance on Extractive Industry Fiscal Regimes Since 2006

TA on taxation of natural resources, provided by Fund staff and experts to member countries, is significant and gradually growing. Over the last seven fiscal years (2006–12), staff delivered around 85 TA missions, in 37 countries,[38] that involved taxation of natural resources—approximately half of these in 2011 and 2012 alone (Appendix Figures 1 and 2). In 2006 there were just 6 such missions, while by 2012 there were 31. The increase in 2012 is substantially the result of the start of the Topical Trust Fund on Managing Natural Resource Wealth (MNRW TTF), but 2011 already saw a steep rise (to 15) in missions funded internally or from elsewhere. There are already 33 HQ-led missions on taxation of natural resources planned for FY13, not including workshops or short-term expert visits that FAD will organize. The IMF Legal Department (LEG) joins in much of this work.

HQ-led TA missions are the foundation of staff work on EI fiscal regimes, but not the only component. Staff assist countries through country visits, often with external experts, addressing specific issues during area department missions, and offering occasional workshops and conferences (the latest being a workshop on *Resources without Borders*, held in Washington, DC in May 2012, addressing international issues in fiscal regimes for extractive industries). The IMF published a major book on the topic in 2010 (Daniel, Keen, and McPherson). The relative stability in numbers of missions 2008–10 is partly explained by concentration on that book, the conference from which it emerged, and associated outreach activities.

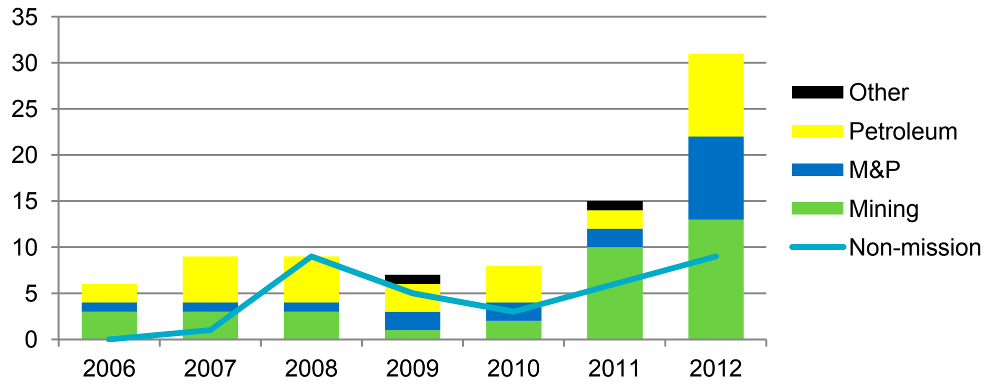
Appendix Figure 1. TA on Natural Resources Taxation by Sector, FY06–12



Source: IMF staff estimates.

[38] Including a small number of Article IV consultations for which Selected Issues Papers on EI fiscal regimes were prepared.

Appendix Figure 2. Numbers of Missions and Other Activities by Year, FY06–12



Source: IMF staff estimates.

The Fund's tax policy advice focuses mainly on taxation of petroleum (oil and gas) and mining (most commonly gold, copper, iron ore, and coal, but also uranium and diamonds), though other natural resources are occasionally also addressed: hydropower and geothermal energy (Iceland 2011) or forestry and commercial agriculture (Liberia 2009). Recently staff pioneered advice on designing a fiscal regime for shale gas development (Poland 2012). Most of these TA activities were devoted solely to taxation of natural resources. In other cases, these issues were addressed as part of a broader tax policy review (such as Malawi 2011 or Tanzania 2012) or spread more widely into issues such as fiscal decentralization (Peru 2006, Liberia 2009, or Bolivia 2010).

The FARI modeling framework is used to advise on macro-fiscal issues and resource revenue management. Statistics on these activities are not separately compiled, but examples range from Uganda 2008, Ghana and Nigeria 2010, Timor-Leste 2011, to Sierra Leone 2012. FARI itself has also been embedded with four country teams in AFR and, with FAD support, AFR is building its own staff capacity in this area.

The IMF has also expanded its work on revenue administration for resource-rich countries—which has been a relatively neglected topic. Although growth has not been as fast as for policy aspects, the MNRW TTF also covers revenue administration: projects are launched in the Democratic Republic of Congo, Sierra Leone, Lao PDR, and Mongolia. Uganda and Zambia have also received advice.

Appendix III. Corporate Income Tax Issues of Special Importance for Extractive Industries

Valuation of production for income

Valuation principles for income tax may not always conform to those for royalties. While consistency makes administration simpler, it may not be possible to make either the valuation point or pricing basis consistent. This is because valuation for income tax must usually reach "net gain" and permit all necessary deductions back to the same point as permitted for costs—at least if the tax is to qualify for foreign tax credit. With royalty, there is greater flexibility to choose a valuation point and to use a reference price.

For bulk minerals such as bauxite, rutile, and iron ore, valuation is complex. The same is often true for natural gas. Reference prices are not as transparent and readily available as for, say, oil, gold, and copper. Reliance on realized prices exposes government to considerable risk. Reference prices are sometimes available from proprietary sources (such as Platts for iron ore), but require adaptation for quality and transport cost differentials. Where minerals are sold on contract and arm's length pricing does not hold, government should have a right of contract approval. The revenue authority should be able to offer advance pricing agreements.

Interaction of CIT and production sharing

Production sharing potentially creates a complex relationship with CIT in that a two-stage calculation is needed, often under different rules. The contractor's receipts in both cost oil and profit oil are aggregated, treated as gross income for CIT, and the regular CIT deductions applied. This system frequently leads to separate administration of production sharing and tax (see below). Some systems use "pay-on-behalf" in which the contractor's CIT liability is settled from the state share of profit oil, automatically stabilizing any tax faced.

Allowable deductions

Deductible costs should usually give rise to taxable income for the person paid.[39] This important principle requires, for example, that WHTs can be levied on interest or technical service payments made to nonresidents.

[39] Though not for royalties paid to government, and some payments may be capitalized even where giving rise to current income for the recipient.

Rate of CIT and link to additional rent taxation

The appropriate CIT rate for EI is linked to wider goals. It depends upon (1) whether government intends to reduce the general rate over time; (2) whether government wishes to maintain a higher CIT rate for EI; and (3) the overall balance with other taxes—in particular, dividend WHT on distributions, and any possible additional rent taxation.

A common rate of CIT across all sectors is usually preferable. CIT is regarded as a tax attributable not specifically to resource extraction, but to doing business in the country; by contrast, royalty and any additional rent taxation are specific to resource extraction, representing a levy for the right to extract. Companies, however, will look at the aggregate tax impact, first in terms of the intrinsic economics of the project and then in terms of tax-efficient financing and organizational structures, ability to take advantage of tax credits at home, and use of other tax planning opportunities. Thus, the CIT will enter into companies' appraisal of the effect of tax on their internal rate of return, or NPV at a threshold discount rate.

Additional rent taxation makes the rate of CIT less important. This would be especially so if the rent tax rate were to adjust (in either direction) to changes in the rate of CIT.

Capital allowances and definitions of capital expenditure

Tax depreciation (capital) allowances for EI are often generous relative to book depreciation or likely economic depreciation. These can be justified on grounds of risk reduction but delay government revenue.

Capital allowances counted from the year of expenditure permit unintended accumulation of losses in large EI projects. A more common practice is to start initial capital allowances in the year of commencement of commercial production, and even then to employ a partial year rule (if production starts after six months, provide half a year's capital allowance). In this way, all assets are treated identically relative to income produced, irrespective of when they are purchased or constructed.

Mining and petroleum capital expenditure requires definition. Development capital expenditure on drilling, waste removal, overburden stripping, shaft sinking, and like activities is often immediately expensed. *International Financial Reporting Standards* (IFRS) now provide a basis for determining what should be expensed and what should be amortized.

Losses carried forward by EI companies, and ring fencing

EI sectors often have an extended or unlimited loss carry forward period. This creates no special problem, except for keeping track of the losses. There is, in any event, no case for denying deduction of losses properly incurred (in practice through application of capital allowances).

The license-by-license ring fence requires criteria for implementation. Countries such as Norway and the UK permit consolidation within a sector-wide ring fence for offshore petroleum. For developing countries concerned about deferral of revenue, ring-fencing by license may be appropriate.

Deductibility of interest

The general rules regarding thin capitalization should usually apply, but if these are weak, special provisions may be needed. The approach of denying immediate deduction for interest payments that exceed some proportion of income (for instance, 50 percent plus interest earned) is a useful anchor for permitting interest deduction—possibly with addition of a "safe harbor" at a debt equity ratio of, say, 1.5:1.

The deductible rate of interest needs limitation. An arm's length equivalent criterion, at least, should be included in tax legislation, normally as part of a general transfer pricing rule. An alternative is to specify a margin over a benchmark international US$ interest rate.

Environmental reclamation and rehabilitation—fiscal treatment

Special rules should provide for eventual abandonment and reclamation expenses. A provision against a future expense is not usually tax deductible, but in this case all parties have an interest in this provision. Detailed rules are needed for the specification of plans and budgets, and for cost deduction against them. For example, is the calculation to include projected inflation or not? Should the future budgeted cost be discounted to the present at an appropriate interest rate? Many countries now have schemes for tax-deductible contributions to an abandonment or reclamation fund.

Treatment of hedging

Gains and losses on hedging can work both ways. Government may lose or gain from the closing out of hedging positions, relative to regular spot or contract transactions. The government has no control over commercial decisions about hedging, and may not wish to be exposed to the results. One option is to disregard hedging transactions completely, requiring reference prices to be used instead. Hedging transactions would not fall under the mining tax regime, but under general CIT provisions for such transactions. Another and more difficult route is practiced in Australia: separate hedging transactions into those that are "commercial" and those that are "financial" in character. The exclusion of hedging is probably simpler.

Staff tend to advise that governments should not be exposed to companies' hedging operations except by positive choice (hedging of gold prior to the price rise, for example, gave rise to realized revenue losses) and should tax on fair market value—usually meaning the benchmark price for spot market transactions. There may be exceptions, however, noting that long-term gas prices, for example, frequently have a built-in hedging mechanism.

Gains on transfers of interest

Two related sets of issues arise:

- ***Should these gains be taxed?*** Since the gains presumably reflect an increase in expected future rents, it may not be necessary to tax them if those rents will be adequately taxed: in Norway, where an efficient rent tax has been in place for a long time, gains and premiums paid in such transactions are disregarded for tax purposes. Other countries tax them, often under highly complex rules (as in the UK). The question then is whether the gain should be deductible (or step up the tax value for the asset) against potential future income or gains? If not, there will likely be double taxation of the purchase—but this would then be reflected in the purchase price paid and so reduce tax on the initial transaction. If some future tax reduction is allowed, should this be only against gains on similar transactions in future, or treated as an acquisition cost of the EI right and amortized against future income? Under any of these offset options, the probable outcome of taxing the gain is to change the timing of government revenues rather than their absolute amount. Such taxation may, however, be politically necessary, and will also increase the PV of government revenue.

- ***Who should/can tax the gain****?* Transactions frequently involve not the direct transfer of mineral rights but sales of shares in companies that hold mineral rights, or in companies that hold shares in such companies, and so on along an often complex and border-crossing chain of ownership. A locally incorporated company holding mineral rights will often be beneficially owned by companies resident abroad, and beyond the taxing jurisdiction of the host country. South Africa offers an example of a "look through" provision that tries to deal with this: where more than 80 percent of a company's assets consist of mineral rights (treated as immovable property), transactions in its shares are treated as transactions in the mineral right itself. If the gain is made by a non-resident, it is still taxable as South Africa-sourced gain. Problems can arise with such provisions if taxing such gains to a non-resident is prohibited by a tax treaty. Practical difficulties also arise in identifying and successfully taxing transactions involving non-resident companies. Various schemes have been put forward to deal with that: one route is to impose heavy penalties for evasion (for example, forfeiture of the mineral right if a change of control is not reported), another is to tax a "deemed gain" in the local company on a simultaneous sale and repurchase of the mineral right.

Care is needed that the taxation of gains does not stifle exploration. In new areas, this tends to be undertaken by junior companies, for which the possibility of gain on farm-in or takeover by a major company is a primary motive.

Fiscal terms for downstream processing

The fiscal treatment of downstream processing needs to be addressed. In mining, companies may take mineral processing to a further stage, beyond the first saleable product. For example, in processing bauxite to alumina, an alumina refinery would probably be treated as a manufacturing or processing operation, and not part of mining; thus, normal CIT rules would apply, not royalty or mining tax rules. In this case, rules on the transfer price of alumina to the refinery would be needed. In petroleum, the parallel is processing and transportation of remote gas, where rules for the transfer pricing of upstream production will be needed, in order to ensure that resource taxation applies to the upstream only and that rent accrues at that stage.

Taxation of income by withholding

Withholding taxes (WHTs) can be important both as a direct source of revenue and in combating avoidance, but need careful crafting. Those on payments to subcontractors (in lieu of income taxes) may be a significant source of early revenue, but can also increase the cost of exploration and development since these payments are commonly grossed up to cover WHT. This also increases deductions against the CIT, which dilutes any revenue gain. Host governments seek to impose tax obligations on providers of services (such as drilling), including non-resident, to ensure tax compliance. Lack of clarity on WHTs can be a major source of friction between governments and taxpayers, particularly in exploration and development phases. Care is also needed on dividend and interest WHTs, which are often reduced or eliminated in tax treaties.

Appendix IV. What "Uplift" Rate should be used in Rent Taxes?

The benchmark result on this issue is that if deferred tax benefits are certain to be ultimately received by the taxpayer (including, if necessary, as payments from the government), then carry forward of unrealized benefits at a risk-free rate is in principle appropriate (Fane, 1987; Bond and Devereux, 1995 and 2003). Where there is doubt as to the government's commitment to provide these benefits, risk-adjustment for that possibility—which, importantly, does not mean adjusting for the riskiness of companies' own cash flows—is appropriate. Theory is as yet silent on the appropriate rate to use when there is no risk-free rate; in many developing countries, there is not even a reliable long-term bond rate in local currency or in US$. If rates adjusted for the riskiness of activities are to be used, it can be argued that these should decline over time as project uncertainties diminish.[40]

In practice:

- Norway and the U.K. provide uplift broadly related to the costs of capital, but are time-limited (4 and 5 years respectively) and so mimic a decrease over time.

- In the Australian debates of 2010, the initial proposal was an ACC scheme with losses carried forward at the government bond rate. Under industry pressure, however—in part on the argument that the tax value of losses was by no means certain—the government reverted to risk-adjusted uplift. Australia also provides higher PRRT uplift for exploration expenditures than for development costs, which means that the uplift rate in effect falls over time.

- Importantly, risk-adjusted uplifts have sometimes been pushed to such high levels (in Ghana and Papua New Guinea) as to undermine credibility of the fiscal regime (since nothing was paid). But systems with risk-adjusted uplift have collected significant revenue in at least Angola, Australia, Timor-Leste, and Zimbabwe.

Using these considerations and experiences, staff generally advise developing countries to use low rates of uplift and to consider time-limiting them.

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[40] It might also be argued that the rate should fall over time as the government's commitment to provide the promised tax benefits becomes more credible.

Appendix V. Modeling the Impact of Fiscal Regimes on Resource Exploration and Exploitation

The central model developed in Smith (2012) characterizes the company's optimal investment choice in two stages.

First, it chooses its investment in exploration, modeled as a decision on the maximum number of failures it will accept before abandoning a prospect. It takes as a given the geological and technical probabilities of discovery and the fiscal regime that a country will apply if drilling is successful. The optimal exploration decision maximizes the expected NPV of the project, after all taxes are taken into account.

Second, once a field has been discovered, the company chooses primary and secondary recovery from the field well, again given the fiscal regime, as well as the time at which to abandon the field. The primary investment to install productive capacity is a continuous choice variable that fixes the initial extraction rate; the secondary investment is a discrete timing decision, which determines by how much a remaining field reserve can be enhanced. The optimal investment choices of the company are obtained jointly by maximizing the NPV after all taxes. The firm chooses to abandon the field once the marginal net revenue from continued extraction becomes negative.

The model is calibrated for a typical oil field, using parameters based on actual investments. It is then used to analyze the impact on investment of three stylized fiscal regimes: (1) a royalty-only regime; (2) a production sharing contract, either fixed or progressive; and (3) a resource rent tax, either fixed or progressive.

Investment decisions by oil and gas companies are more complex than the basic model captures. Several extensions are therefore explored, for example, by looking at the impact of price uncertainty on the decision to delay investment or the effect of ring-fencing on exploration decisions. The basic framework, however, gives both a qualitative characterization and a quantitative indication of the size of distortions induced by various tax regimes.

Appendix VI. FARI Appraisal of Different Rent Tax Mechanisms[41]

This appendix uses staff's FARI model to analyze alternative fiscal regimes against various criteria, and in so doing illustrates its capabilities. Appendix Table 1 below sets out the evaluation criteria, which elaborate those in Table 1 of the main text and lists comparative measures staff commonly uses.[42]

Appendix Table 1. Objectives and Measurable Indicators

Government objective	Indicators
Maximize government revenue: maximum share from broadest base	**Average Effective Tax Rate** (share of pre tax NPV) **Expected government revenue** under price uncertainty
Progressivity with price	**Share of total benefits** (= government NPV as a proportion of NPV of project positive cash flows, excluding initial investment): price sensitivity[43]
Progressivity with costs	**Share of total benefits**: cost sensitivity
Avoid distortion of investment and operating decisions (neutrality)	**Marginal Effective Tax Rate** (METR) (government proportion of pre-tax return for a project which is just viable for the investor post-tax) **Breakeven commodity price** (required to reach hurdle return) **Probability of negative NPV** under price uncertainty **Gold plating analysis** (see below)
Adequate incentive to invest	**Post-tax internal rate of return** to investor (IRR) **Years until discounted payback** achieved **Coefficient of variation** of investor IRR and NPV **Probability of negative NPV** with price uncertainty **Expected Monetary Value (EMV)** (NPV weighted by exploration risk)
Manage government risk	**Time profile of revenues** **Proportion of total revenue received in first 5 years of production** **Coefficient of variation** of NPV of government revenues
Minimize administrative burden and risks	**Complexity**; vulnerability to manipulation.

[41] The full analysis from which this is drawn is presented in a forthcoming working paper.

[42] Not all indicators are used in this appendix.

[43] The concept is approximately the same as that of quasi-rent on sunk investments.

A. Approach

In order to isolate the effect of each rent tax mechanism, the approach is to

Define a set of petroleum and gold mining project examples which have stylized production and cost profiles consistent with actual projects encountered;

Define a set of fiscal regimes, each of which comprises: (1) an identical CIT with commonly encountered parameters; (2) a single additional rent tax mechanism (in some cases, different in petroleum than in mining);

Calibrate each additional rent tax mechanism such that the AETR (NPV(10))[44] for all regimes is identical at around 70 percent for the petroleum regimes and 60 percent for the mining regimes, for project pre-tax rates of return of around 40 percent for oil and 30 percent for mining. These pre-tax returns represent relatively profitable projects, and the calibrated AETRs are within the range observed in actual petroleum and mining regimes.

Evaluate the application of each rent tax mechanism to different projects, including responsiveness to changes in project profitability by varying commodity prices and costs.

B. Petroleum

The petroleum analysis examines a "success" case, then includes exploration risk, and finally the risk of "gold plating."[45] Appendix Table 2 sets out the mechanisms selected for analysis and Appendix Table 3 the project examples drawn from deep water offshore West African developments. Appendix Figure 3 shows initial analysis evaluating "success case" economics—where exploration risk is not directly taken into account. The effect of taking oil price risk into account is then discussed and presented in Appendix Figure 4, and exploration risk in Appendix Figure 5. A range of design considerations for fiscal mechanisms including as parameter some rate of return is then elaborated, including how to minimize "gold plating" risk.

[44] Meaning the AETR measured with both numerator (government revenues) and denominator (pre-tax project cash flows) discounted at 10 percent.

[45] 'Gold plating' is a situation in which the fiscal regime creates an incentive to spend more than is necessary, or bring forward investment. This is described more fully later in this appendix.

Appendix Table 2. Petroleum Fiscal Regimes

Parameter	Regime description	Minimum marginal share 1/	Maximum marginal share	Note
30%	Corporate Income tax only	0%	30%	2/
$1.925 Bn	Signature bonus	n/a	30%	
	State participation			
70%	Full government participation (Brown Tax)	70%	70%	3/
50%	Carried participation	0%	50%	4/
	Royalties			
35%	Flat royalty	35%	58%	5/
Flat 20% Prog 25%	Flat + price progressive royalty	20%	62%	6/
	Resource Rent Taxes			
39%	Norway-style Special Petroleum Tax	0%	69%	7/
55%	Australia-style Petroleum Resource Rent Tax	0%	69%	8/
35%	Cashflow surcharge without uplift	0%	70%	9/
	Production sharing			
	PSC: DROP sharing	13%	87%	
	PSC: ROR 5-tier	7%	74%	
	PSC: R-Factor	11%	69%	
	PSC: ROR Single tier (Pre-tax)	0%	69%	

Parameters for PSC regimes

PSC: DROP sharing			PSC: ROR 5Tier			PSC: R-Factor			PSC: ROR Single tier (PreTax)		
Royalty		0%	Royalty		0%	Royalty		0%	Royalty		0%
CR		70%	Cost Recovery limit (CR)		70%	CR limit		70%	CR limit		100%
MBpd		Share	ROR		Share	R-Factor		Share	ROR		Share
<	25	42%	<	15.0%	23%	<	1.20	35%	<	15.0%	0%
<	50	52%	<	20.0%	33%	<	1.70	40%	>	15.0%	55%
<	75	62%	<	25.0%	43%	<	2.20	50%			
<	100	72%	<	30.0%	53%	<	2.70	55%			
>	100	82%	>	30.0%	63%	>	2.70	55%			

1/ Marginal share in revenue assuming full use of available cost recovery limit/tax deductions.

2/ Standardized income tax assumed for all regimes (except Brown Tax)—30 percent tax rate; 5-year straight-line depreciation; unlimited loss carry forward; zero dividend WHT assumed.

3/ Government participates in all negative and positive cash flows alongside private investor from signing of the license.

4/ Government share of cash contributions carried at 15 percent interest.

5/ Royalty deductible for CIT.

6/ Price royalty triggered for oil price above $60; reaches maximum rate at $160.

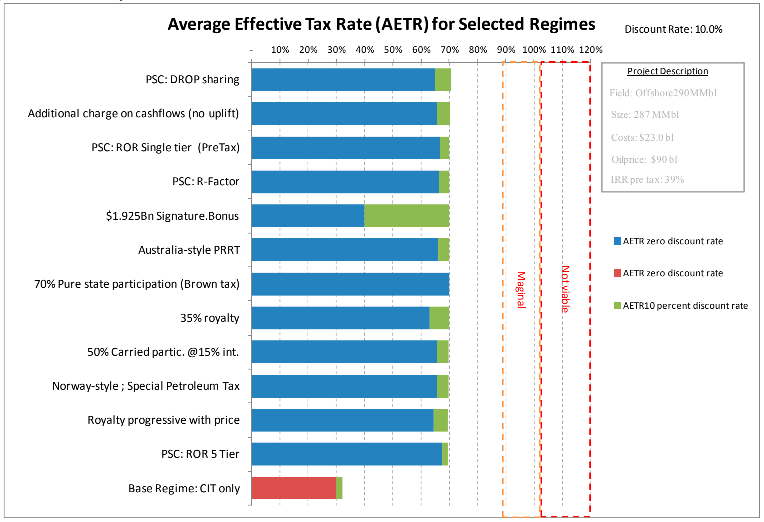
7/ On same base as income tax with deduction for 30 percent uplift on capital expenditure over 4 years; immediate payout of tax-value of exploration costs and payout of unrecouped losses plus accumulated interest at end of project.

8/ PRRT tax on net cash flows after deduction of uplift on exploration (bond rate + 15 percent) and other expenditure (bond rate + 5 percent). PRRT deductible for CIT.

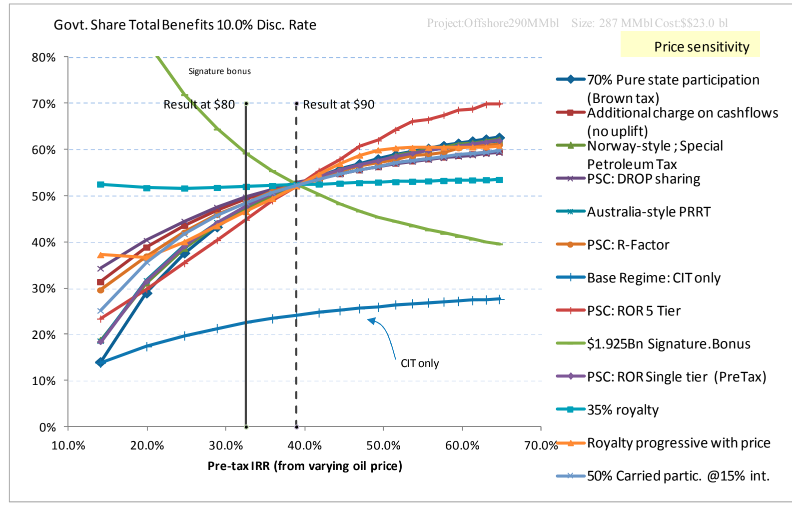
9/ Additional tax on same base as income tax, with interest charges added back. Immediate write off of capital expenditure. No uplift added to carried forward balance.

Appendix Figure 3. Evaluation of Petroleum Fiscal Mechanisms: Deterministic/Success Case Economics

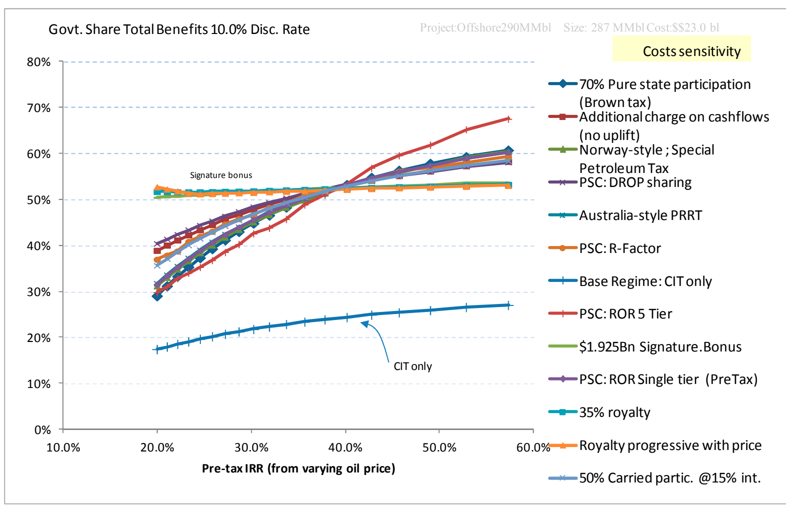
All regimes have the same AETR for the base project, at the base case oil price of $90 per barrel



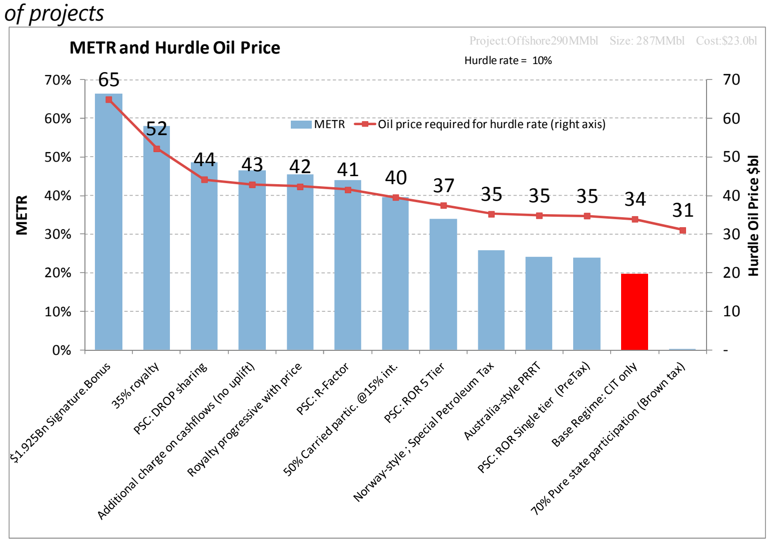
But they respond very differently to changes in prices ...



And costs—with royalty regimes hardly responding at all



And royalty regimes do more to distort decisions and limit the feasible range of projects



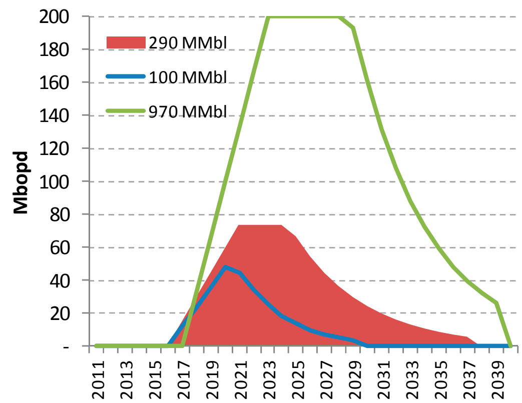
Appendix Table 3. Project Examples

Project Details

Project name		100 MMbl	290 MMbl	880 MMbl
Production	MMBl	104	287	883
Production life	years	13	21	22
Costs over project life	$mm			
Exploration		295	330	295
Development costs		1,992	2,500	3,989
Sustaining capital		279	1,125	2,035
Operating costs		884	2,387	5,726
Decommissioning costs		199	250	399
Total		3,649	6,592	12,444
Per barrel	$Bl			
Exploration		2.8	1.1	0.3
Development costs		19.2	8.7	4.5
Sustaining capital		2.7	3.9	2.3
Operating costs		8.5	8.3	6.5
Decommissioning costs		1.9	0.9	0.5
Total		35.2	23.0	14.1

Source: IMF staff assumptions.

Production profiles



Taking oil price uncertainty into account: investor perceptions of risk

The results above are for deterministic oil price and project cost forecasts. Appendix Table 4 and Appendix Figure 4 show results when oil price uncertainty is taken into account. The expected pre-tax IRR of the project is now 31 percent—the AR(1) process results in a lower expected oil price than the $90 used to calibrate the different mechanisms.

With lower and volatile oil prices…

Royalty and other principally revenue-based mechanisms result in higher expected AETR and higher risk to the investor. Appendix Table 4 shows lower expected investor IRR and NPV (Columns 1 and 2); higher expected AETR (Column 3); longer payback periods (Column 4); higher variability in returns (Column 5) and higher risk of absolute loss[46] (Column 6). The last measure may be particularly significant for risk-averse investors, and the mean investor NPV most relevant to risk-neutral investors. The expected AETR (Column 3) and probability of absolute loss are also shown in Appendix Figure 4.

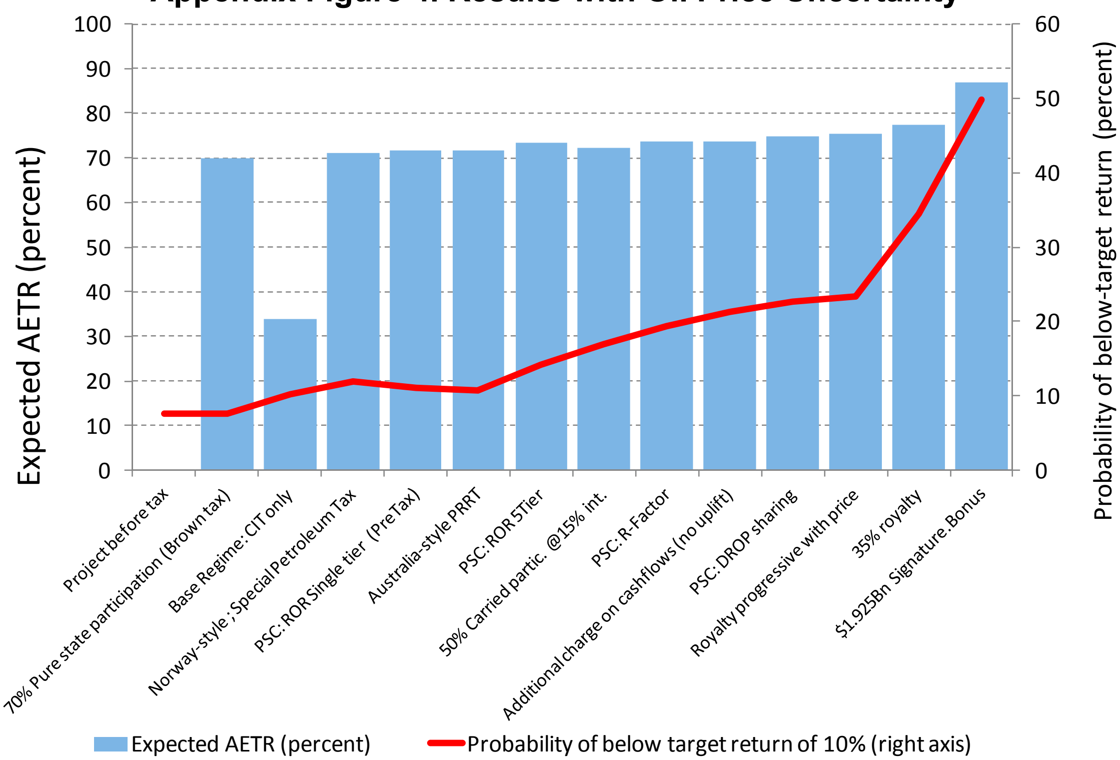
Signature bonus results in the highest AETR and highest risk of loss to the investor—because the bonus is paid irrespective of actual profitability.

[46] This is the proportion of stochastic model runs in which the after-tax investor return is lower than an assumed 10 percent hurdle rate.

Appendix Table 4. Results with Oil Price Uncertainty

Results for Stochastic Oil Price, Ranked by Investor IRR								
Offshore290MMbl	Mean Investor post tax IRR	Mean Investor NPV10	Expected AETR (percent)	Discounted payback (years)	Coefficient of variation of IRR	Tax induced negative NPV10	Probability of below target return of 10%	Government NPV10
	%				%	$mm	%	%
Project before tax	30.7	3,630		11.7	84	n/a	8	n/a
After tax:								
70% Pure state participation (Brown Tax)	30.7	1,089	70	11.7	46	16	8	2,541
Base Regime: CIT only	26.0	2,403	34	12.1	48	-11	10	1,227
Norway-Style Special Petroleum Tax	20.8	1,055	71	12.5	42	0	12	2,575
PSC: ROR Single tier (PreTax)	19.9	1,033	72	12.3	44	-11	11	2,597
Australia-style PRRT	19.8	1,032	72	12.4	44	-11	11	2,598
PSC: ROR 5Tier	19.7	968	73	12.4	44	-29	14	2,662
50% Carried partic. @15% int.	19.1	1,012	72	11.1	48	-21	17	2,618
PSC: R-Factor	18.7	957	74	12.4	51	-47	19	2,673
Additional charge on cashflows (no uplift)	18.4	952	74	12.7	53	-47	21	2,678
PSC: DROP sharing	17.8	918	75	12.9	55	-65	23	2,712
Royalty progressive with price	17.1	890	75	12.9	55	-91	23	2,740
35% royalty	15.7	821	77	13.1	71	-174	34	2,809
$1.925Bn Signature.Bonus	10.1	478	87	14.4	64	-586	50	3,152

Appendix Figure 4. Results with Oil Price Uncertainty[1]



[1]Shows Columns 3 and 7 from Appendix Table 4.

Taking exploration risk into account

The analysis so far has focused on single, project “success-case” economics which ignores exploration risk. This section extends the analysis to assess how the different mechanisms might affect exploration decisions.

The key measure used to evaluate exploration decision is ‘Expected Monetary Value’ (EMV): the expected NPV for the investor taking into account the chance that there will be no commercial discovery (Appendix Box 1).

Appendix Figure 5 sets out an EMV analysis for the 290mm barrel field. This is the same field example using results reflecting oil price uncertainty. This implicitly assumes that the outcomes from this single field example are consistent with the expected outcome from a commercial discovery. In practice, the latter would likely be a risk-weighted NPV from the range of possible outcomes evaluated by geologists, but the analytical approach once this had been established would be similar. Key conclusions are:

All regimes appear viable when evaluated without taking exploration risk into account. The blue (darker) bar in Appendix Figure 5 shows the expected AETR for the success case (Column 3 in Appendix Table 4); before taking into account exploration risk: all regimes appear viable, in that the AETR is less than 100 percent.

Most regimes approach non-viability when exploration risk is considered. The green (lighter) bar shows the government share in the expected NPV if there is a 15 percent chance of success. A government share exceeding 100 percent means a negative EMV for the investor. The fixed royalty and signature bonus regimes are not viable: under the fixed royalty regime, the EMV from investing in exploration is negative and it would therefore not be undertaken. Under the signature bonus regime, no rational investor would pay a $1.925 billion bonus for the exploration rights. Indeed, with a 15 percent chance of success the investor can pay a bonus of no more than $230 million if the EMV is to be positive.

Regimes where the government refunds, or guarantees its share of exploration costs, remain viable. The Norwegian-style regime pays out exploration costs and approaches neutrality.

Appendix Box 1. Expected Monetary Value for Exploration Decisions

EMV is the probability weighted NPV for the decision to explore in a particular jurisdiction, or the decision to drill a specific well:

EMV = p × NPVProject × (1-TaxRate) – (1-p) × NPCExplore × (1-TaxRefund)

where

p ≡ probability of a commercially viable discovery (which averages 10–20 percent worldwide)

NPVProject ≡ expected pre-tax NPV conditional on commercial discovery. This is determined by geology - the distribution of potential projects and specific local cost structure for those projects

Tax Rate ≡ government share of project NPV

NPCExplore ≡ net present cost of exploration activity required before failure is reached. (For example, seismic survey and a single failed exploration well)

TaxRefund ≡ the refund of losses or tax deduction the investor receives in relation to the exploration cost.

A company will seek to invest in exploration in the jurisdiction where EMV is highest, and only where it is positive. The distribution of potential projects varies by jurisdiction—being determined by geology—and therefore so does the expected pre tax NPV. Note that the fiscal regime matters at two points: the government share taken of the successful project and the government refund (if any) of the failed exploration cost. With a low probability of discovery, the latter has a higher weight.

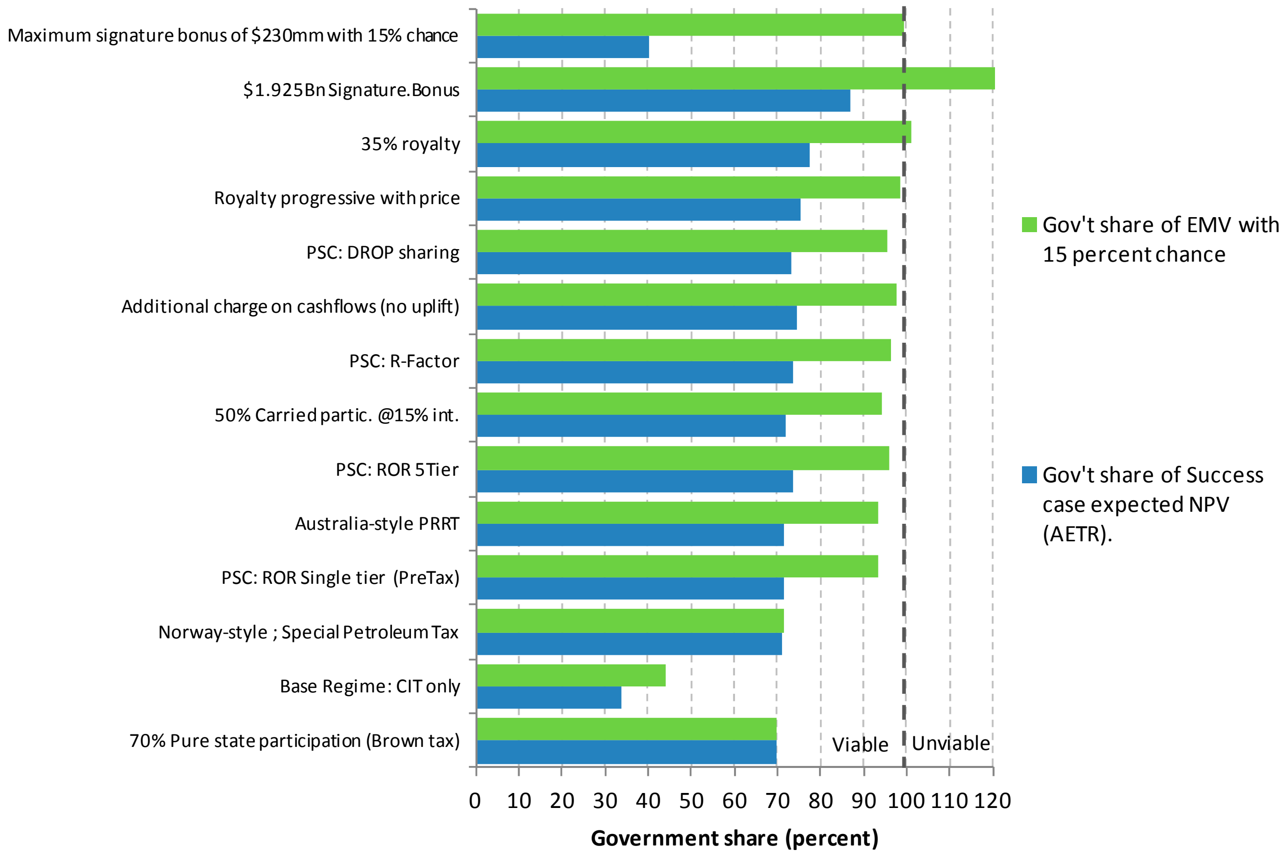
Government can refund failed exploration either directly (as in Norway) or indirectly if the taxpayer is able to deduct the cost against some other tax-paying operations in the same jurisdiction. Staff usually advise developing countries to separately ring-fence each project to insulate the government from exploration risk and deferral of revenues from profitable projects, while recognizing this has some deterrent effect on exploration.

Tax is the only factor that is readily in the control of government (see Example 1 below)—geology determines the rest (Examples 2 and 3): countries with higher prospectivity can set tougher fiscal terms, other things equal.

Probability of success	Exploration cost, failure case	Goverment payout in failure	After tax, failure case NPV10	After tax success case expected NPV10	Gov't share of success case expected NPV	After tax NPV	EMV NPV10
A	B	C	D = B - C	E	F	G = (1 - F)*E	H = A * G - (1 - A) * D
Example 1. Higher *refund of failed exploration* allows higher share of successful project							
20%	50	0	50	1,000	55%	450	50
20%	50	**25**	25	1,000	**65%**	350	50
Example 2. Higher *pre-tax expected NPV* for successful project allows higher share							
20%	50	0	50	1,000	55%	450	50
20%	50	0	50	**1,500**	**70%**	450	50
Example 3. Higher *probability* of success allows higher share							
20%	50	0	50	1,000	55%	450	50
30%	50	0	50	1,000	**70%**	300	55

Source: IMF staff calculations.

Appendix Figure 5. EMV Analysis for 290 Million Barrel Oil Project



This demonstrates that…

Geology is central. By far the most important determinant of relative exploration attractiveness is the type and size of resources in the ground and the likely costs of extracting them (the expected NPV of the success case).

Ultimately, government share has to take exploration risk into account. With modest expected success rates, the government share of a successful project cannot get too high without resulting in negative EMV and deterring exploration.

Government facilitated exploration could have a high return. Reducing exploration risk through providing improved geological information could allow the government to tax more. Government could directly fund basic exploration or facilitate this exploration by others through speculative seismic surveys.[47]

[47] Some companies undertake these surveys at their own cost, in collaboration with the host government, and then sell the data to prospective oil companies. This data can also be used by the government for preliminary prospectivity analysis and reserve estimates—critical input for setting fiscal terms.

Government guaranteed payout of losses also allows a higher share in the event of success. A regime in which the government guarantees it will meet its tax-share of a loss-making project can demand a higher share of a profitable one. Countries that cannot credibly do this need to configure their regimes correspondingly, recognizing that investors are taking on a greater risk of failure and, other things equal, must therefore demand a lower share of success.

'Gold plating' risk

'**Gold plating' is a situation in which fiscal considerations create an incentive to incur real costs that, in the absence of taxation, would be unprofitable**; a related distortion is that in which it creates an incentive to bring forward investment relative to the optimal pre-tax timing.[48] It is equivalent, broadly speaking, to a situation in which the marginal effective tax rate associated with some expenditure is negative.

Gold plating can arise under a standard CIT when the rate of tax is expected to fall… since this means, for instance, that investment-related deductions are taken at a rate of tax higher than that at which the additional profits generated will subsequently be taxed.

…but has attracted particular attention in the context of rent taxes making use of some notional rate or return (ROR), whether as a threshold rate for taxation (and/or carry forward of unused deductions) and/or to provide an allowance for the cost of equity.

A gold plating incentive (GPI) can arise under ROR regimes when the rate of return threshold is materially higher than the investor's discount rate and the tax rate is very high. With a high threshold return, the investor receives a high reward (in the form of reduced future government share) for additional spending. With a high tax rate, there is a higher incentive to defer or reduce government share through spending more.

Multiple-tier ROR schemes are much more likely to create a GPI. This is not because of the progressivity of such schemes in the realized ROR: so long as the tax depends only on the pre-tax ROR, there is no distortion. Rather it is because, in practice, upper tiers often have accumulation rates much higher than investors' discount rates. Staff modeling suggests single tier schemes can provide sufficient flexibility and progressivity.

Whether a GPI exists or not also depends on characteristics of the project in question. Projects with longer, flatter production profiles are more vulnerable to GPI because the project is likely to be earning, and compounding uplift, for longer than a conventional oil

[48] Strictly speaking, such a situation exists where the investor's post-tax NPV is increased by decreasing the pre-tax NPV through intentionally spending more than is necessary or making investment earlier than would be optimal pre-tax.

field which reaches peak production early; hence, increased expenditure in the near term may lead to a higher future reduction in government share after compounded uplift is added.

Even if mathematically possible for a given regime and project, a gold plating incentive is only likely to be taken advantage of for relatively profitable projects. For marginally profitable projects, the investor faces a trade-off between certain higher spending today and an uncertain reduction in future government revenues.

Limiting gold plating risks—and the converse—requires careful attention to the choice of benchmark ROR, as discussed in Appendix IV.

C. Mining Analysis

A similar evaluation was performed of a range of fiscal mechanisms commonly encountered in mining regimes, with broadly similar conclusions. The regimes are set out in Appendix Table 5 and the gold project used as the primary example in Appendix Table 6, central findings being:

Royalty regimes respond weakly to changes in profit resulting from cost differences (Appendix Figure 6, bottom left).

The progressive royalty results in step-changes in share as prices change—suggesting this is a somewhat blunt instrument (Appendix Figure 6, top right). While more refined parameters could be used to smooth out this response (at the cost of added complexity), all parameters chosen would reflect an implicit assumption as to the relative profitability of projects at each price. In practice, all projects are different so any royalty would have a different effect on each project. Royalties that attempt to deal with this by being set by reference to an operating profit ratio become equivalent to a variable income tax.

The mining project generates lower pre-tax rent than the petroleum project. Thus there is less room for the rent tax mechanisms to operate and the range of results is narrower. The regimes have been calibrated with a lower share, consistent with lower observed AETRs in mining (Appendix Figure 6, bottom right).

Appendix Table 5. Mining Fiscal Regimes Evaluated

Full government participation (Brown Tax)/1	
Share of equity, from signature of license	60%
Resource Rent Tax (cashflow basis) /2	
Resource rent tax	16.0%
Return threshold	12.5%
Basis	PreTax
Windfall Profits Tax /3	
Windfall tax rate	16.0%
Gold price trigger	$1,000
Trigger escalated	no
Variable Income Tax /4	
Minimum income tax	25%
Maximum income tax	49%
Corporate Income Tax (assumed for all regimes)	
Corporate Income Tax	30%
Depreciation of development costs (yrs)	5
Depreciation of replacement capital	4
Dividend Withholding tax	10%
Assumed debt/equity	0%

Source: IMF staff assumptions.

Fixed Royalty	
Royalty rate	6%
Progressive Royalty /5	
6 tier Additional royalty min/max	2.0% / 10.0%
Price band lowest / highest royalty	$1050 / $1450
Price bands escalated	yes
Free equity (share of dividends)	9.0%
Resource Rent Tax (ACC) /6	
RRT rate	12%
Add-back interest	no
Uplift on undepreciated capital base	12.5%
Payout of losses at end of life	yes
Additional tax after uplift	
Tax rate	10.0%
One-time uplift on development capital	40.0%
Add-back interest	no
ACC Henry Proposal /7	
RSPT rate	14.0%
Uplift rate	5.6%
Losses paid out at end of life	yes
Australia-style MRRT /8	16.0%
Uplift rate	12.6%
Losses paid out at end of life	no

1/ Working equity—participates in all negative and positive cashflows from commencement of project.

2/ Resource Rent Tax (RRT) triggered with cashflow return reaches threshold. Pre-tax means cashflows exclude CIT, and RRT is deductible for CIT.

3/ Windfall tax: government proportion of gold price above specified trigger. This is similar to the Mongolian and Zambian approach (though both now repealed).

4/ Variable CIT rate determined by ratio of taxable income to revenue. Tax rate % = 60 – 1150/(ratio*100) = max 48.5%.

5/ Gold price determines royalty on total production; non-incremental.

6/ Allowance for Corporate Capital; uplift on undepreciated assets and losses.

7/ Similar structure to Australia's ACC Henry Proposal with modified parameters and zero royalty.

8/ Similar structure to Minerals RRT with modified parameters and zero royalty.

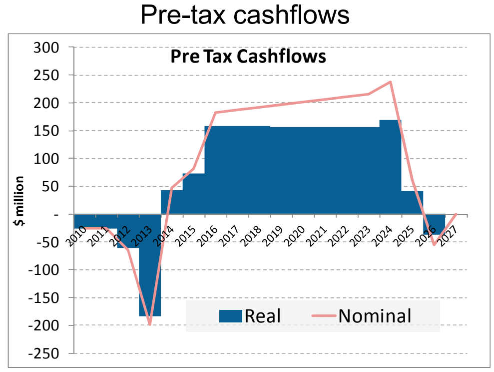
Appendix Table 6. Gold Project Example

Project statistics[1]

Total production	2 MM oz over 12 years	
Project costs	$MM	$Oz
Exploration	50	25
Capex	348	174
Opex	789	395
TC/RC	115	58
Decomm	37	18
	1,339	670
Pre-tax IRR at ConstReal $1300 Oz	30%	

[1] Assumes the project exports a gold concentrate that requires smelting outside the host country.

Pre-tax cashflows



Findings from Appendix Figure 6 include the following:

With deterministic prices, the progressive royalty appears not to add materially to risk (Appendix Figure 6, bottom right). This is further explored in the next section.

Taking into account gold price uncertainty

When using a stochastic gold price forecast,[49] further characteristics emerge. With prices that are volatile and average lower than the $1,300 per ounce assumed for the regime calibration, the pre-tax IRR of the project is reduced to 18 percent, making it relatively marginal.

Appendix Table 7 shows:

The fixed royalty adds materially to investor risk. The expected AETR is now around 94 percent (Column 3), and the royalty regime is 20 percentage points more likely to result in a below hurdle rate return (Column 5).

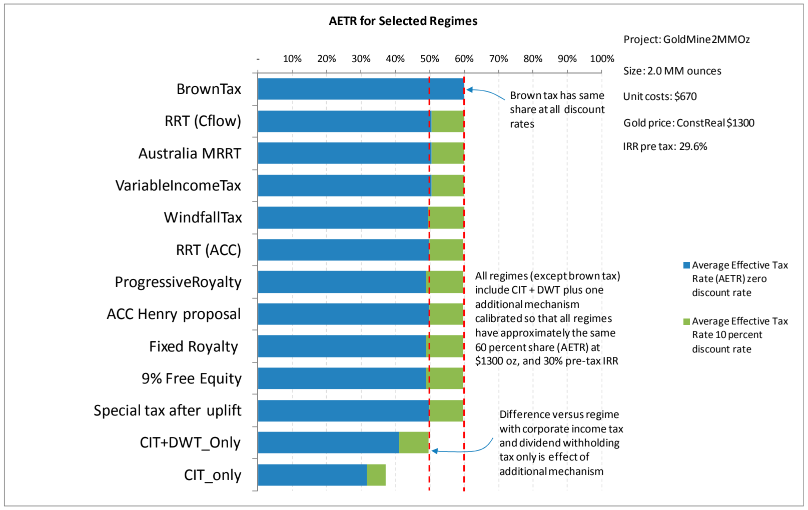
The progressive royalty and 'windfall' (i.e., trigger-price related) regimes also imply higher risk to government. They are asymmetric—capturing only a share of price upside—and more likely to be triggered with stochastic prices, even though the average price is lower.

Rate of return regimes are lower risk, without sacrificing much in terms of AETR and government NPV (Columns 3 and 6).

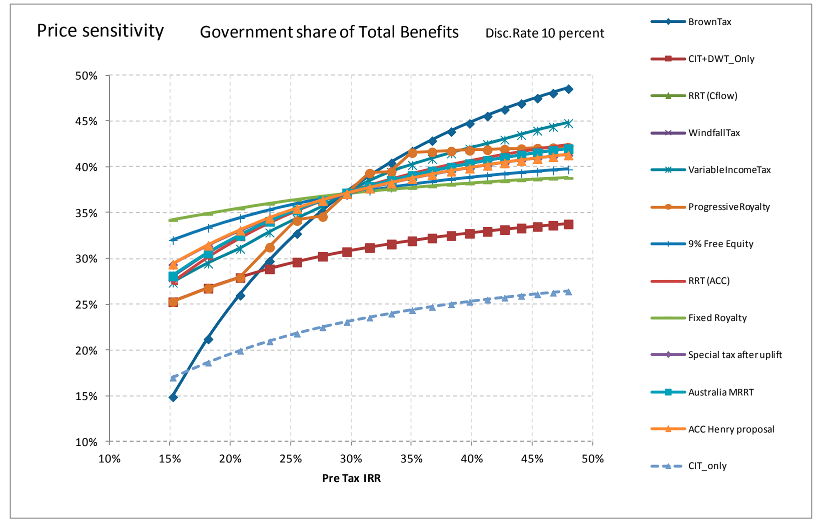
[49] As for petroleum, an AR(1) process was used.

Appendix Figure 6. Evaluation of Mining Mechanisms

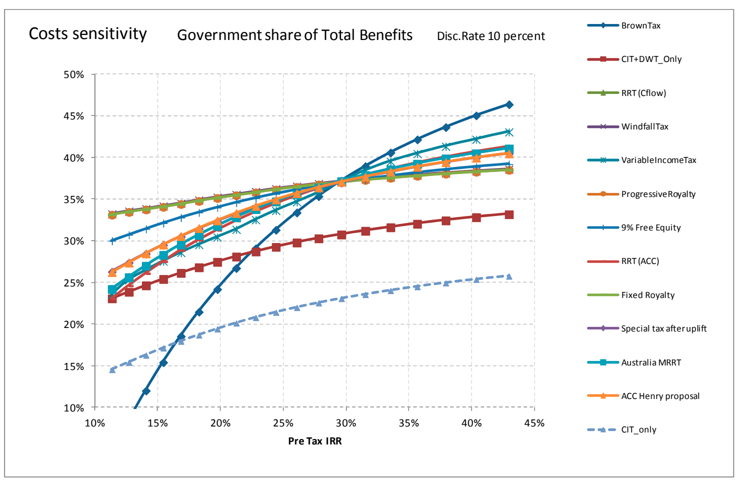
Regimes are calibrated to result in the same AETR at $1,300 per ounce gold price



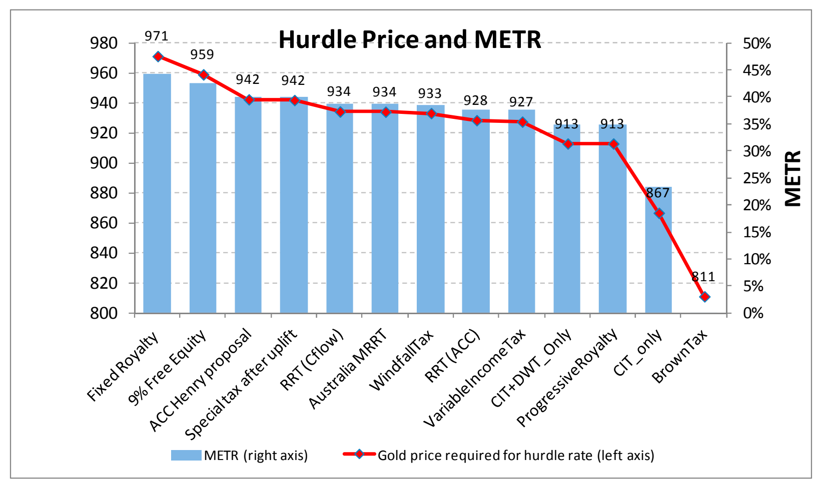
But respond differently to gold price changes....



And cost changes: profit-based regimes respond but royalties do not



And fixed royalty regimes do more to distort decisions and limit the feasible range of projects.



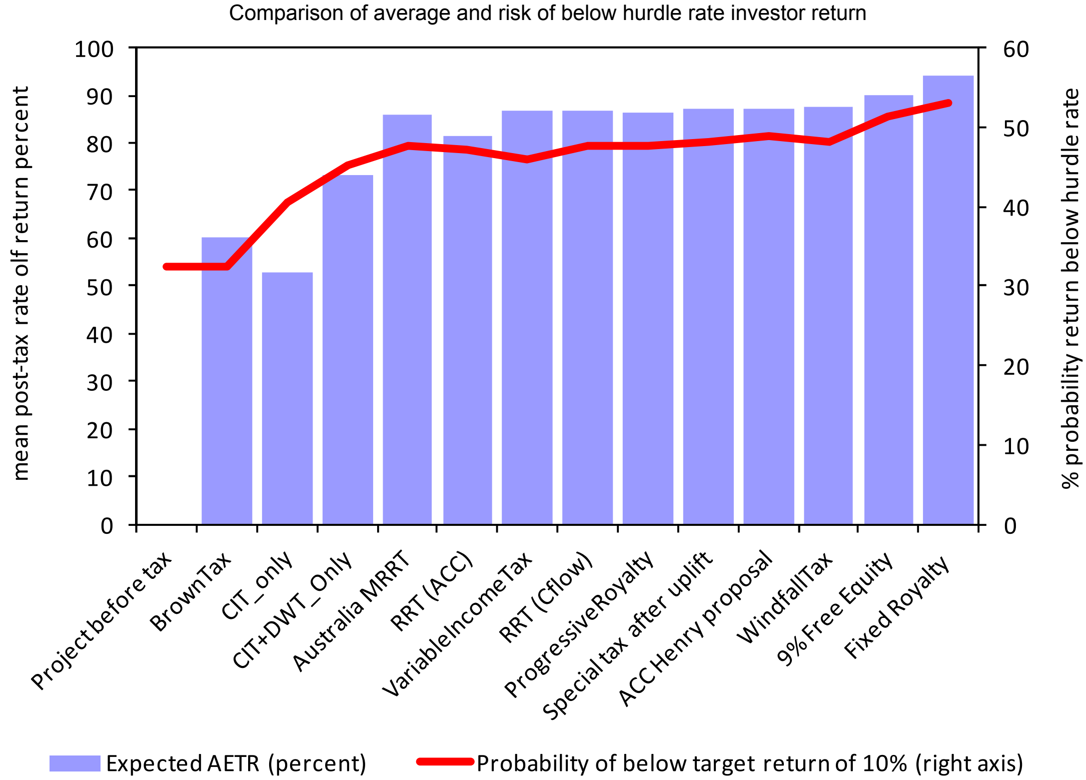
Appendix Table 7. Results with Gold Price Uncertainty

GoldMine2MMOz	Mean Investor post tax IRR	Mean investor NPV10	Expected AETR (percent)	Coefficient of variation of IRR	Probability of below target return of 10%	Government NPV10
	%			%	%	%
Project before tax	17.9			77.0	32	n/a
After tax:						
BrownTax	17.9	64.3	60	77	32	96
CIT_only	14.3	75.8	53	81	41	85
CIT+DWT_Only	12.4	42.9	73	88	45	118
Australia MRRT	11.5	22.9	86	88	48	138
RRT (ACC)	11.5	29.9	81	86	47	131
VariableIncomeTax	11.5	21.0	87	85	46	140
RRT (Cflow)	11.4	21.5	87	88	48	139
ProgressiveRoyalty	11.2	21.7	86	87	48	139
Special tax after uplift	11.2	20.8	87	90	48	140
ACC Henry proposal	11.2	20.5	87	90	49	140
WindfallTax	11.1	20.2	87	89	48	141
9% Free Equity	10.8	16.3	90	93	51	144
Fixed Royalty	10.6	9.4	94	97	53	151

Appendix Figure 7 shows the expected AETR and risk of absolute loss:

Appendix Figure 7. Expected AETR with Gold Price Uncertainty[1]

Comparison of average and risk of below hurdle rate investor return



[1] Shows Columns 3 and 5 from Appendix Table 7.

Appendix VII. Further Aspects of Effective EI Tax Administration

Organizational structures, processes, and capacity for EI tax administration

The same broad principles of organization and procedure apply in relation to EIs as for tax administration generally, and there are the same broad capacity needs. Organizationally, this means integration of administration within a functionally-based structure.[50] Procedurally, it means: clear rules of application,[51] consistent with those of the rest of the tax system, ideally set out in a tax procedure code (TPC); separation of duties to safeguard integrity; efficient, effective routine processing, with filing based on self-assessment; active enforcement of registration and payment; selective, risk-based audit; effective, accessible dispute resolution; and comprehensive taxpayer service programs to foster voluntary compliance. In terms of capacity, good analytical, audit, and legal skills are vital, supplemented by development of specialist EI skills and knowledge. But since most EI tax is usually paid by a few companies, only a small number of professional staff is required.[52] In some countries, however, such as those recovering from conflict, there may be no realistic prospect of developing adequate skills in the short term; outside expertise may need to be bought in, particularly to assist with more difficult functions such as audit and mineral valuation (raising standard issues relating to the development of in-house capacity).

A growing number of governments now accept that NEICs should focus on their commercial role, but some fail to carry this through in practice. Some governments continue to allocate inappropriate fiscal functions to NEICs, such as administration of production sharing: most countries do not require private companies to account to the tax department for government production share. And while budget discipline and avoidance of unfair commercial advantage dictate that NEICs pay profit tax on equity participation just like private companies, in practice their tax compliance is often poor. Nor do they always publish accounts in accordance with international accounting standards, audited by international accountants, with clear and exacting policies for payment of dividends and

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[50] That is, a functionally organized HQ overseeing segmented and functionally organized field operations, with particular emphasis on large taxpayers responsible for the lion's share of revenue; EI companies will normally fall within the LTO. See Kidd (2010) on the organizational structures of administrations.

[51] There may need to be some special provisions reflecting normal practice in the EIs for dollar accounting and payment (the US dollar is standard for most natural resources); payment of tax in kind (where relevant); joint venture returns and audits (JV operating companies keep central accounting records); physical audit and valuation procedures; international arbitration (where agreements provide for this); and confidentiality waivers (where necessary for EITI).

[52] Common capacity problems include salary structures inadequate to retain staff of the quality needed for administration of large sophisticated companies, and inadequate IT support—these are not unique to the EIs, but since a country's economic transformation often depends on revenues from a few large EI companies, addressing those problems is even more vital than usual.

transparent government accounting for them, backed up by close government oversight of NEIC financial management and commercial performance.

Although weak, fragmented administration is the main barrier to transparency and effectiveness of EI administration, there may be major political and practical obstacles to reform. Equity participation, production sharing, and other taxes that complicate administration have strong political appeal. NEICs and EI regulators are often reluctant, with strong political support, to give up their fiscal roles; governments often build up greater expertise and capacity in those agencies than in tax departments (and pay them more), and may object to the disruption and risk of transferring their fiscal responsibilities. Those responsibilities may be built into legislation, contracts, international agreements, even constitutions. Change may be needed to EI legislation and agreements, not just tax legislation. Companies may prefer oversight by a commercial partner that "understands the industry."

These difficulties may make it necessary to settle for second-best options, however inadequate they are likely to be. It may be futile, for instance, to recommend integrated administration as a near-term objective in practice. Second-best options would then include clearer delineation of fiscal roles between the tax authority, EI regulators, and NEIC; improved cooperation and information sharing; and at least centralization of accounting and reporting responsibilities within the finance ministry.

Gaining revenue through audit strategy

Effective revenue administration is focused on risk assessment. Risks of tax loss might arise from non-registration, non-filing, non-payment of taxes due, or under-declarations in returns. For EI, the biggest risks will likely be under-declarations by large companies who pay the bulk of government revenues. Those companies may even be state-owned.

Analysis of risks presented by legislation, compliance history, and standards is the basis for assessing under-declaration risks that large companies present. Tax authorities then have to identify the action best-suited to tackle those risks. This might not be audit or enforcement— it might be clearer legislation and guidance and a self-assessment requirement backed by effective penalties. In the short run, measureable audit results very often come from limited scope audits concentrating on particular technical issues. Common adjustments are on WHTs, capital gains, output pricing, categorization of costs, finance costs, treatment of social expenditure; in all these examples, the scope for error very much depends on the legislation.

Best practice for audit risk assessment by tax authorities is to identify potential errors, estimate their value, probability, and person-hours required for auditing, and allocate auditors to cases with the highest likely return per auditor hour. Authorities then evaluate results after each audit and refine risk profiling over time. Without sound administrative principles in place, these processes will remain difficult to implement.

A short-term strategy to achieve quick returns might be for the different agencies with revenue administration responsibilities to collaborate better. Then, using all their information sources, the agencies identify what they consider the biggest and riskiest companies and the areas the agencies are most concerned about. A unified task force and program to audit those risks could then be established, concentrating on the cases that can be investigated and settled most quickly, perhaps bringing in outside audit expertise to support the exercise.

EI revenues are vulnerable to failure to audit during exploration and development phases. Many developing country revenue authorities face annual revenue targets, and employee remuneration may come from a percentage of revenue collected. These authorities have an incentive to neglect companies that are spending but not generating income. As a result, mining or petroleum projects can commence production with the revenue authority possessing inadequate knowledge of their cost and asset bases in order to perform future assessments or audits. Neglect in auditing exploration and development expenses can cost the tax base dearly as a project starts to generate income.

Appendix VIII. Revenue Data Used in this Paper

Annual data were sought from IMF country teams on both aggregate revenue from the petroleum and mining sectors, and its composition by broad type of tax, for 2001–10. Tax categories include royalty, license fees and bonuses, income tax, additional profits tax or similar, state equity, withholding on interest and dividends, profit oil, and indirect taxes (VAT and import and export duties). The country selection was intended to capture the universe of countries in which the EI sectors rise to any macroeconomic significance. Appendix Table 8 lists the 57 countries for which usable data proved to be available. In many cases, data were not available for all years; complete data on aggregate revenue from the EIs are available on average for only 43 countries out of 67 that responded to the survey and only in a very few cases was a breakdown by type of tax available. For a number of countries, revenue was reported in aggregate for mining and petroleum and such countries were treated as a separate category.

Appendix Table 8. Countries in the Sample

	Mineral Producers		Petroleum Producers				Mineral and Petroleum Producers for which revenue data could not be broken down by sector
1	Australia	1	Algeria	25	Mauritania	1	Australia
2	Bolivia	2	Angola	26	Mexico	2	Bolivia
3	Botswana	3	Australia	27	Myanmar	3	Brazil
4	Brazil	4	Azerbaijan	28	Namibia	4	Canada
5	Canada	5	Bahrain	29	Niger	5	Colombia
6	Chile	6	Bolivia	30	Nigeria	6	Congo DRC
7	Colombia	7	Brazil	31	Norway	7	Indonesia
8	Congo DRC	8	Brunei	32	Oman	8	Mauritania
9	Ghana	9	Cameroon	33	Papua New Guinea	9	Papua New Guinea
10	Guinea	10	Canada	34	Philippines	10	Russian Federation
11	Indonesia	11	Chad	35	Qatar	11	Vietnam
12	Kyrgyz Republic	12	Colombia	36	Russian Federation		
13	Lesotho	13	Congo Republic	37	Saudi Arabia		
14	Mauritania	14	Congo DRC	38	Sudan		
15	Mongolia	15	Ecuador	39	Syria		
16	Papua New Guinea	16	Equatorial Guinea	40	Timor-Leste		
17	Russian Federation	17	Indonesia	41	Trinidad and Tobago		
18	Sierra Leone	18	Iran	42	United Arab Emirates		
19	Tanzania	19	Iraq	43	United Kingdom		
20	Vietnam	20	Ivory Coast	44	Uzbekistan		
21	Zambia	21	Kazakhstan	45	Venezuela, Rep. Bol.		
		22	Kuwait	46	Vietnam		
		23	Libya	47	Yemen		
		24	Malaysia				

Data may lack consistency in the way they are aggregated—for some countries, tax sub-categories were omitted due to poor reporting or level of disaggregation. Revenue in such cases might be slightly underestimated.

Appendix IX. Improving Data on Government Revenues from Natural Resources[53]

The Statistics department at the IMF is in the process of initiating work to ascertain the feasibility of collecting resource revenue data systematically in future. Data would be compatible with *Government Finance Statistics Manual 2001 (GFSM 2001)* format, with comprehensive levels of detail such as level of government, type of revenue (royalty, income tax, additional profit tax or other mechanism to capture rents, withholding on interest and dividends, indirect production taxes, etc.).

The work will begin with pilot studies. Given the limited public availability of data on government revenues from natural resources and the IMF's limited experience in collecting these data, it is recommended that a pilot study be conducted before launching a broader collection effort. A selected group of three to four countries will be visited by Fund missions to investigate the availability of information with a view to producing a template for data collection.

There are a number of methodological and practical difficulties associated with collecting these data:

- ***There is no formal or internationally agreed definition of revenues from natural resources***. Whatever data are available reflect national definitions limiting cross country comparability. A systematic collection of data on revenues from natural resources must start by defining what items are included in these revenues, and identifying the entities that make these payments to government. This definition could be very narrow or very broad depending on why the information is collected. In the absence of such an international definition, initially any available national definitions must be used, while examining the feasibility of additional data. The intention is that countries be requested to provide in the template whatever existing national data are available (regardless of its definition), and to identify the entities it covers. In the course of the pilot study, some definitional issues will need to be investigated, such as the basis of the taxes (for example, resource products or resource industries?) and the coverage of the enterprises making the payments to government.

- ***The quality of the available data on revenues from natural resources is uncertain and needs to be assessed***. The accuracy and reliability of the data to be collected needs to be ascertained. Often these data are subsets of more aggregate data on government operations provided by countries. Therefore, the data on revenues from natural resources must be consistent with the aggregate data on government revenues. In this connection, the framework of the *GFSM 2001* should guide the collection of

[53] Contributed by the Statistics Department.

these data. Any national categories can be easily linked to the corresponding *GFSM 2001* classifications and thereby compared with more aggregate data on government operations for the same country.

- ***The level of government for which the revenue data are collected can make a big difference to the resulting information***. For example, whether the data are collected on revenues for central government or the non-financial public sector can make a significant difference to the resulting figures. Many countries have large national companies involved in the exploitation of its natural resources. The former level of government excludes the operations of nonfinancial corporations, whereas the latter includes them. Again, the intention is for countries to initially provide in the template whatever existing data are available, and the level of government for which they were collected.

- ***Data on revenues from natural resources may be available at entities not usually contacted by the Statistics Department of the IMF***. Data on government revenues from natural resources will possibly have to be collected from entities other than the usual data producing agencies from which the IMF collects macroeconomic statistics. The desired information may possibly be available from other national entities such as a Ministry of Natural Resources (Energy, Mining, etc.) or perhaps a trade organization. This will require developing new contacts and becoming familiar with the formats in which they collect data.

- ***Confidentiality concerns may also hamper data collection***. There could also be legal restrictions preventing collection of data. For example, in some countries disclosure of revenues collected from entities involved in exploiting natural resources may be prohibited by law.

Appendix X. Estimating Effective Tax Rates for EI Companies

This appendix explores the question, central to the assessment of EI fiscal regimes and to public debate more generally, of how the earnings from extractive activities are shared, in practice, between host government and private investor.

It applies two methods capable of shedding light on subtly but significantly different aspects of this general question, corresponding to different notions of the effective tax rates on earnings in the EI sectors: simulation methods to calculate AETRs on particular projects, and the use of accounting data (closer, as will be seen, to incremental effective rates on additional earnings than to AETRs).

All methods, it should be stressed, are highly imperfect. The results should thus be taken as no more than suggestive, including perhaps of the possible benefits of developing these and other methodologies further.

Simulation methods

The FARI model enables the calculation of the pre- and post-tax flows from a specific project under a range of assumptions on the time paths of prices and extraction.[54] The great merit of this approach is that, with proper account taken too of the exploration phase, it enables precise identification of how the rents from a specific project are shared. Its weaknesses are that it inherently departs from reality, including in assuming perfect implementation, abstracting from possible opportunities for international tax planning, and ignoring taxes levied in the investor's home country and at the level of the final shareholder. It also requires an assumption on the distribution of prices and costs that may differ from that perceived by market participants.

As seen in Figure 4 of the text, FARI simulations point to AETRs in the range of 65–85 percent for petroleum and 40–60 percent in mining.

[54] It can be seen as an elaboration for the specific context of the EIs of the methodology for evaluating AETRs in Devereux and Griffith (2003).

Accounting and related data

Annual data

Annual accounts and SEC filings of EI companies provide information on operating income and tax payments by year. Comparing the two does not give an implied tax payment on gross earnings, which would require also taking account of the cost of capital used in the operations. One possibility is to subtract from operating income some estimated cost of capital. An alternative, pursued here, is to take as a benchmark the net return earned in some base year and assume that the operating income required to maintain that net return rises in line with industry costs (as captured by a producer price index). The analysis compares the change in tax payments in subsequent years to the increase in operating income beyond that presumed to be required to maintain the benchmark return. This gives an estimate not of an average effective rate at any date, but of how that rate varies with realized operating income; we refer to this as the "Incremental Effective Tax Rate" (IETR).[55]

Mining

Appendix Table 9 reports illustrative calculations for seven large mining companies. The underlying data on operating income, producer prices (both normalized to 100 in 2004) and total tax payments (including royalties) are in Rows A, B, and D. Comparing actual operating income with operating income adjusted for the increase in producer prices (Row C) gives an estimate of earnings in excess of those required to maintain a net return at the 2004 level (Row D). Expressing the increase in tax payments relative to 2004 (Row F) relative to these incremental earnings gives the implied IETR (Row G).

The implied IETR effective rates are in the order of 35–45 percent, and quite stable—except for a striking peak in 2009, driven largely by a fall in prices and production and a simultaneous surge in taxable non-operating income (foreign exchange and derivative gains) for a subset of companies in the sample. The impression is thus of fiscal regimes for mining that are not very progressive.

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[55] As distinct from the "marginal effective tax rate," which has come to mean the additional tax on an investment that just yields investors their required after-tax return.

Appendix Table 9. Illustrative Calculations of the IETR for Mining

		Source	2004	2005	2006	2007	2008	2009	**2010**
A.	Operating income index	Annual reports	100	175	295.1	381.8	418.6	236.3	515.2
B.	Producer price index		100	116.3	136	145.3	166.3	172.1	187.2
C.	Adjusted operating income	15412×B/100	15412	17924	20960	22394	25630	26524	28851
D.	Actual less adjusted operating income	(A-B)×15412	0	9048	24518	36447	38889	9898	50557
E	Total tax	Annual reports	4481	8280	13904	18114	20179	14969	26900
F.	Additional tax	E-4481	0	4193	9125	13008	14335	8922	20322
G.	Tax on additional earnings	F/D*100		46.3%	37.2%	35.7%	36.9%	90.1%	40.2%

Source: IMF staff calculations using sources cited.

Petroleum

The same methodology cannot be used for petroleum, because petroleum companies' financial statements do not provide information on payments made to government under production sharing agreements (PSAs); this precludes extraction of figures for operating income before tax and government take under PSAs. Progress can be made, however, in assessing tax payments relative to non-shared production by inferring pre-tax earnings on the assumption that costs per barrel rise in line with sector producer prices.

Appendix Table 10 reports results from an exercise of this kind using accounting data for 27 large oil and gas producing companies, together accounting for about 75 percent of the proven reserves of the world's 50 largest oil companies (excluding the national oil companies of OPEC countries). Incremental returns are assessed relative to 2001. Incremental post tax earnings are constructed by comparing actual operating income per barrel to that in 2001; incremental pre-tax earnings are calculated by subtracting from the Brent crude oil price post-tax operating income per barrel in 2001 and production costs per barrel in 2001 indexed by a producer price index for the sector. Comparing the two gives an estimate of the IETR on additional pre-tax earnings. The estimated IETRs, reported in the final row of Appendix Table 10, are in the range 45–65 percent; comparing with Appendix Table 10, the impression is that fiscal regimes for petroleum involve a higher incremental government take than is found in mining. The comparison also tends to confirm that petroleum fiscal regimes are generally more progressive: the IETR varies little with the initial level of earnings in the mining results, but increases sharply in those for petroleum.

Appendix Table 10. Illustrative Calculations of the IETR for Petroleum

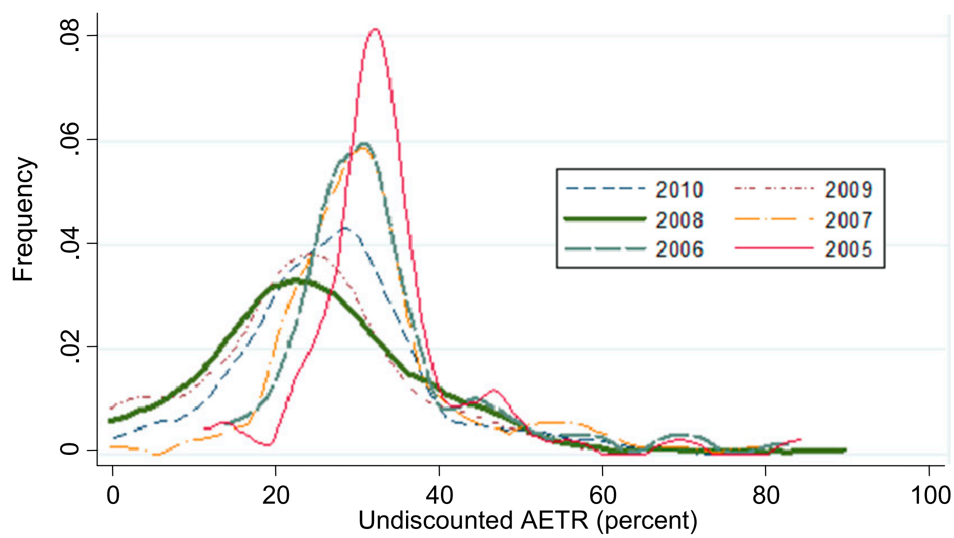
	Data source/Calculation	2004	2005	2006	2007	2008	2009	2010
A. Oil prices (Brent crude, US$ per barrel)	Source: EIA	38.3	54.6	65.2	72.4	96.9	61.7	79.6
B. Post-tax operating income (US$ million)	Source: Evaluate Energy database	186,608	250,690	301,590	319,265	419,229	298,562	361,003
C. Oil & gas production (million boe)	Source: Evaluate Energy database	13,343	13,750	14,306	14,120	13,946	14,050	14,490
D. Post-tax op. income per barrel (US$)	D = B/C	14.0	18.2	21.1	22.6	30.1	21.3	24.9
E. PPI Oil and Gas Extraction (2004=100)	Source: US Bureau of Labor Statistics	100.0	136.0	131.0	138.6	180.3	97.2	124.8
F. Benchmark post-tax operating income per barrel (US$)	= D in 2004	14.0	14.0	14.0	14.0	14.0	14.0	14.0
G. Incremental post-tax operating income(US$)	= D-F	0.0	4.2	7.1	8.6	16.1	7.3	10.9
H. Non-operating costs in 2004, uprated by PPI (US$)	= A-F in 2004; = H(2004)*%ΔE in other years	24.3	33.0	31.8	33.6	43.8	23.6	30.3
I. Incremental pre-tax income, per barrel (US$)	= A-F-H	0.0	7.6	19.4	24.8	39.2	24.2	35.3
J. Implied tax on incremental earnings, per barrel (US$)	= I-G	0	3	12	16	23	17	24
K. Incremental effective tax rate	= J/I	0%	44%	63%	65%	59%	70%	69%

Projections

All companies filing accounts under US GAAP accounting rules engaged in upstream oil and gas production are required to report future cash flows from their proven reserves[56] in their annual financial statements. These use a standardized assumption on future oil and gas prices (broadly speaking, that these will remain at current levels),[57] and separately identify future worldwide income tax expenses, calculated by applying existing tax rules together with future changes already legislated. These cash flow projections are netted against development costs already sunk by companies in order to establish the expected value of proven reserves. Taking the ratio of undiscounted future income tax charges to undiscounted pre-tax net cash flows enables an estimate of the (undiscounted) AETR.

Appendix Figure 8 reports the distribution of such undiscounted AETRs, by year, for a sample of 105 companies in 2005–10 (and a total of 559 company-year observations).[58] These companies account for about 85 percent of the proven reserves of the world's 50 largest oil companies (excluding the national oil companies of OPEC countries).[59]

Appendix Figure 8. Distribution of AETRs for Petroleum Companies



Source: IMF staff calculations using Evaluate Energy data.

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[56] "Statement of Financial Accounting Standards No. 69: Disclosures about Oil and Gas Producing Activities," Financial Accounting Standards Board, 2010. This disclosure is designed to address the concern that the value of a petroleum company's most valuable asset—its reserves—is not included in its historical cost financial statements.

[57] End-of-year, before 2009; an average over the previous years thereafter. Only future price changes specified in contractual agreements may be factored into the calculations.

[58] Data from the Evaluate Energy database, some observations omitted for incomplete information.

[59] Ranked by 2007 worldwide oil equivalent reserves as reported in *Oil & Gas Journal*, September 15, 2008.

Over the full period, mean and median undiscounted AETR are 29 percent. There is though substantial variation over time that reflects differing price assumptions but, somewhat puzzlingly, does not correlate well with changes in the price assumed: the oil price stipulated by the SEC increased by 50 percent between 2006 and 2007, for instance, but the median AETR was essentially unchanged. There is also substantial variation across companies, with highest AETRs commonly 85–90 percent and the lowest close to zero.

These figures must though be interpreted with great caution, and may well underestimate effective tax rates, for three reasons. First, the cash flows reported are after payment of any profit oil under production-sharing agreement, or of royalties and bonus payments, and such payments are omitted from the reported tax obligations. Second, there will also be understatement to the extent that the mandated price expectations are more conservative than investors' and regimes are progressive in prices. Finally, the undiscounted AETR may not accurately capture the AETR with a reasonable discount rate, as tax payments tend to be back-loaded relative to earnings (through the operation of various investment credits and the like). For early-life projects, the AETR will then be lower if calculated in present value terms, but discounting can be expected to have a smaller impact on the AETR of more mature projects that have exhausted investment allowances and credits. On balance, however, it seems prudent to regard the figures reported in Appendix Figure 8 as something of a lower bound on AETRs faced in the petroleum sector.

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