Cash Flow Analysis of Fiscal Regimes for Extractive Industries

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ABSTRACT: Mining and petroleum projects share characteristics distinguishing them from other sectors of the economy, which has led to the use of dedicated fiscal regimes for these projects. The IMF's Fiscal Affairs Department uses fiscal modeling to evaluate extractive industry fiscal regimes for its member countries, and trains country officials on key modeling concepts. This paper outlines important preconditions needed for effective fiscal modeling, key evaluation metrics, and emphasizes the importance of transparent modeling practices. It then examines the modeling of commonly-used fiscal instruments and highligts where their economic impact differs, and how fiscal models can inform fiscal regime design.

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ANNEX

Glossary

AETR	Average Effective Tax Rate
CD	Capacity Development
CIT	Corporate Income Tax
CO2	Carbon dioxide
DCF	Discounted Cash Flow
EBITDA	Earnings before interest, depreciation, and amortization
EI	Extractive Industry
EMV	Expected Monetary Value
FAD	Fiscal Affairs Department
FARI	Fiscal Analysis of Resource Industries
FAST	Flexible, Appropriate, Structured, Transparent
FE	Free Equity
GHG	Greenhouse Gas
IMF	International Monetary Fund
IOC	International Oil Company
IRR	Internal Rate of Return
JV	Joint Venture
METR	Marginal Effective Tax Rate
MOF	Ministry of Finance
NOC	National Oil Companies
NPV	Net Present Value
PCT	Platform for Collaboration on Tax
POB	Pay-on-Behalf
PSC	Production Sharing Contracts
ROR	Rate of Return
RRT	Resource Rent Tax
STB	Share of Total Benefits
VAT	Value Added Tax

I.   Introduction

Mining and petroleum projects share several characteristics that distinguish them from other sectors of the economy, due either to their sheer scale, location-specific and immobile nature, or to the special features associated with extracting non-renewable resources. These characteristics create the potential to generate economic rents varying by deposit and over time.[1] Extractive industry (EI) fiscal regimes commonly diverge from the tax system applicable to the rest of the economy and vary in structure, choice of fiscal instruments and rates, as well as in the way fiscal instruments interact with each other.

Fiscal Analysis of Resource Industries (FARI) is a methodology and a project-level cash-flow based modeling tool developed by the Fiscal Affairs Department (FAD) of the International Monetary Fund (IMF) for quantitatively evaluating the impact of fiscal regimes in the EI. The FARI methodology maps project cashflows over time, calculates and applies fiscal regime instruments, and then allocates those cashflows between the project stakeholders: typically, investors and government (although third parties such as financiers may also be included). Interaction between fiscal instruments can result in effects that may not be easily inferred from headline tax parameters and analyzing fiscal instruments individually can distract decision makers from the impact of the fiscal regime as a whole.

FARI is relatively simple to work with once the core concepts are understood and sufficient data is available. An Excel-based framework, FARI allows users to quickly assess the combined impact of multiple fiscal instruments, to inform policy decisions. The approach used mirrors the analysis investors routinely use to assess new investments. FARI and its analytical outputs can create a platform for a dialogue between governments and companies that can lead to a common fact-based understanding of the workings and impact of a fiscal regime. The methodology was initially developed to support tax policy analysis, but with some modifications, it can also be used to forecast EI fiscal revenues and assess risks to revenue collection.

The IMF uses the FARI framework in its capacity development (CD) and training activities to support its members.[2] The IMF published updated mining and petroleum models in 2021. [3] Whilst the FARI models used internally for CD are somewhat more comprehensive in the range and specification of fiscal mechanisms, the core cashflow modeling concepts and evaluation metrics used are largely the same as those in the published FARI models.

This working paper describes how to harness FARI to analyze fiscal regimes, complementing a 2016 Technical Note (IMF 2016). Section 2 discusses key preconditions for effective fiscal regime analysis, and Section 3 discusses features of key EI fiscal mechanisms. Section 4 concludes by comparing comprehensive fiscal regimes and demonstrating how fiscal regime analysis using FARI can inform policy evaluation and design.

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[1] These include the presence of high sunk costs, long production periods, pervasive uncertainty, and resource exhaustibility (see discussion in IMF (2010).

[2] The FARI model used by IMF staff differs from the published models in its level of complexity and its ability to support a comparison across countries.

[3] Models and the supporting technical note are available at https://www.imf.org/en/Topics/fiscal-policies/fiscal-analysis-of-resource-industries

II.   The Groundwork for Fiscal Regime Analysis

A. Ensuring a Conducive Institutional Environment

The responsibility for designing the fiscal regime and collection of tax and non-tax revenue for the extractive sector is often shared across several governmental institutions. A commonly observed institutional framework includes a ministry of finance (MOF) responsible for the design of the general tax regime, a revenue authority which administers and collects taxes, a sectoral mining/petroleum ministry (or regulator) responsible for granting and supervising license and production sharing agreements and sometimes overseeing sector-specific fiscal instruments such as royalties, other fees, and state participation, if applicable.[4] National oil companies (NOCs) remain relatively common in the petroleum sector as the holder of state participation interests, in some instances also with a role in administering production sharing. Such entities are less common in mining.

Without strong cooperation between agencies, fragmentation of roles and responsibilities can undermine holistic fiscal regime analysis, administrative oversight, macro-fiscal management, and data collection and sharing. Fragmentation increases the risk of losing sight of the "big picture" impact of the fiscal regime as a whole and the interactions between fiscal instruments. Misalignment can also occur, when sectoral agencies or NOCs advocate for incentives to attract investment or argue for higher state participation which they manage (at the expense of other fiscal instruments).

A well-functioning inter-agency working group or committee can address these concerns, helping to break down silos, making the best use of scarce expertise, and sharing information. For fiscal regime analysis, an inter-agency group can also ensure consistency of methodology and assumptions, for instance where models are built and used for different purposes. Experience shows that well-functioning groups typically comprise two levels: a senior policy group (to set fiscal regime strategy, design policies, interrogate model assumptions and inputs, and feed results into government-wide decision-making processes) and a technical modeling group (to collect data, construct, quality assure and maintain models, and present findings to senior officials).

B. Configuring Fiscal Models

The core functionality of the FARI models[5] focuses on the comparison of outcomes under alternative fiscal regimes applied to individual EI projects. However, FARI-based models can also be used for other purposes including revenue forecasting and budget outlook analysis, contract negotiations, revenue administration risk assessment and compliance activities.[6] Fiscal models are an important input for decision makers, but they are not the only one: for example, in setting fiscal regime parameters decision makers will also need to consider the economic outlook for the resource and how resource production will affect the macroeconomy.

Depending on the objective, FARI models may need to be tailored to focus on the set of analytical routines and parameters relevant to that objective. For example, in a revenue forecasting model, the main output is usually a short- to medium-term revenue forecast from the set of existing projects in or near production that could inform budget estimates or revenue administration targets, and consequently the main analytical routines would focus

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[4] For further information on fiscal regime administration, see IMF (2014).

[5] This paper refers to the 2021 versions of the models published on the IMF's website (https://www.imf.org/en/Topics/fiscal-policies/fiscal-analysis-of-resource-industries) unless stated.

[6] Other analysis, such as technical analysis related to the optimal development and configuration of a natural resource endowment may require other modeling frameworks to be employed.

on scenarios with alternative prices, production and cost profiles under the settled fiscal regime applying to each project.

For each modeling tool, tradeoffs will exist such as between accuracy of the model and simplicity. To convey key concepts, a "pedagogical" version can be used, whilst in contrast a model built to inform compliance activities will require more detail (e.g., cost categories which have separate depreciation rules). For revenue forecasting models, it is important to keep the structure of the extractive sector in mind: if the sector consists of many projects, larger and more revenue-critical projects could be modeled individually, and a simplified approach taken for smaller projects with only modest revenue flows. Decisions about model design should be informed by the objectives that the model is intended to serve, materiality for instance by looking at impact on investor and overall government revenue, and capacity to manage complexity. Transparency is also important, so that model users – particularly those who review the model at a later point – can easily follow the calculations made, identify errors and update the model as needed. The FARI models have been developed with transparency as a key priority (see Annex III for discussion of modelling transparency principles).[7]

Understanding differences between mining and petroleum FARI models is also necessary to ensure they are tailored to industry characteristics. While the two model versions have a similar look and feel, there are some key differences:

- **Commercial structures:** The petroleum model assumes the project will be set up as an unincorporated joint venture whereas the mining model assumes the operation will be managed by an incorporated (resident) company which is a subsidiary of an (offshore) international mining company. This has an impact on fiscal calculations, especially in regimes where the government has direct state participation in the project (discussed in Section 3).

- **Production sharing mechanisms and production-based bonuses:** these are common in upstream petroleum, and the petroleum model therefore includes several different types of production sharing mechanisms and production-based bonuses (the mining model does not). The petroleum model also includes "expected monetary value" - a key metric used to inform exploration decisions.[8]

C. Data Requirements

With the modeling objective established, this will inform the level of detail and coverage of data required.

- **Fiscal regime analysis** can be done with stylized project data representative of the size and cost structure of actual or potential projects in a country. Data sources include recently approved projects from within the country, or from another country with a similar geology and/or cost structure. This data can be sourced from feasibility studies or technical reports provided to the host country regulator or, in the case of publicly traded companies, disclosed in compliance with exchange disclosure requirements. For-profit data providers also maintain project-level information.

- For **revenue forecasting**, detailed historical information and medium-term projections are required. For projects already in production this includes; (1) historical cost, production and sales data, as well as

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[7] The FARI models have been developed to align closely to international transparency principles such as the "FAST" modeling standard (see FAST Organization website: https://www.fast-standard.org/).

[8] Expected monetary value is an indicator to support exploration decisions by weighing the probability and cost of unsuccessful exploration against the probability and net present value of a successful exploration. Whilst also a relevant concept for mining, the scale and relative riskiness of petroleum exploration (particularly offshore) mean EMV is more commonly used in petroleum.

information on taxes paid, to enable reconciliation of the model with actual tax outcomes (and, if applicable, work plans and cost recovery statements); (2) projections of costs and production for the forecast period or for the remaining life of the project (usually provided routinely by operating companies, e.g., through updated life of mine plans), and (3) the detailed fiscal terms applicable to each project. For prospective projects, the information needed also includes forecasts of expected production and costs. While revenue forecasts for government budgeting may focus on the short to medium-term (3-5 years), ideally these are prepared in the context of a longer-term outlook for the sector. Revenue forecasts must also focus on what taxpayers are expected to *actually* pay over the forecast period, factoring in tax planning and the timing of receipts to government, which require judgements to be made from model users.

- For **compliance risk assessment**, the focus is primarily backward-looking with more detailed data required regarding the history of the project. This includes the history of the projects (cost recovery statements, asset registers for depreciation, production volumes, realized prices, etc.) and tax data to reconcile model outputs to actual outcomes. Compared to revenue forecasting, even more granular information is needed to identify and quantify fiscal risks. This analysis can also inform whether policy changes are needed to protect future revenue.

- For **contract negotiations**, data needs are similar to fiscal regime analysis. Investors often share their own project model as part of license or contract negotiations that require interrogation to identify key inputs and assumptions. These models are usually presented assuming full equity financing, so that the tax benefit of debt does not influence the results. Whilst this may be appropriate for the investor in assessing the viability of the project, it is important that government can evaluate the impact of debt financing on government revenues – a key feature of FARI – and detailed financing information is needed. Investment incentives may be sought, requiring an assessment of their impact on project economics and likely revenue cost. Detailed analysis can provide the evidence needed to enable government negotiators to resist concessions.

Once the data has been obtained, the model can then be used to consider the economic and fiscal impact of each fiscal instrument. In setting up the model, a key parameter is the discount rate. There is still debate as to how to set the appropriate rate, and it is likely to be the case that governments tend towards a lower discount rate. This is because governments are more likely to incorporate intergenerational considerations into their decision making (i.e., not discounting the future too heavily). One of the simplifying compromises of the FARI approach is the assumption that investors and government have the same discount rate. This assumption is made primarily so that project costs and benefits from a resource project have the same discounted basis and can therefore be allocated to different parties, thereby enabling judgements on the distribution of those costs and benefits.[9]

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[9] This discount rate is also set consistently across countries to enable cross-country comparisons of key metrics for fiscal regime evaluation (outlined in the next section).

III. Fiscal Regime Analysis for Policy Evaluation and Design

A. Tax Policy Objectives

The fiscal regime is the main policy tool for sharing risk and reward from natural resource extraction between the investor and government. In considering the overall impact of the fiscal regime, results can be assessed against common tax policy objectives (see also Box 1).

1) **Capacity to generate revenues**: A well-functioning fiscal regime should generate a "fair" share of revenues for the government over the life of the project, however defined. Some governments attach a higher value to receiving early and stable revenues from the start of production while other governments want to maximize revenues over the life of a project (even if that entails taking on more risk). The capacity to generate revenue can be measured by the Average Effective Tax Rate (AETR), which is the share of a project's net present value (NPV) captured by the fiscal regime. The capacity to generate early revenues can be analyzed by measuring AETR at a higher discount rate – thereby attaching a higher NPV weighting to early revenue - or by calculating the minimum share of project earnings that flow to government from the start of production (e.g., as measured by the effective royalty rate).[10] Setting aside the realities of administration, a fiscal regime that includes progressive elements and minimizes regressive ones will maximize revenue collections.

2) **Neutrality**: A fiscal regime should be designed to minimize economic distortions. Distortions caused by the fiscal regime can result in marginal projects becoming unviable or in changing the investor's ranking of potential projects. The distortive effect can be analyzed by comparing the post-tax breakeven price to the project's breakeven price before the fiscal regime or by calculating the Marginal Effective Tax Rate (METR).

3) **Adaptability and progressivity**: Volatile commodity prices and costs are an intrinsic feature of EIs, and so adaptable and progressive regimes can reduce the likelihood that projects will be shut down prematurely or that fiscal terms will need to be renegotiated. A progressive regime is one that provides a stable or increasing share of project benefits to government (as measured by the AETR on a discounted basis) when the project generates returns above the investors' hurdle rate, whilst reducing the fiscal burden on investors if the project is not profitable. In doing so, a progressive regime has a better prospect of being perceived as fair by the citizens of the host country. The first-best option would be a constant marginal tax rate above a minimum return generated for the investor (IMF 2018). However, since governments often prefer revenues from the start of production, they may choose a second-best option of mineral royalties (which are regressive) combined with a progressive instrument such as a resource rent tax.

4) **Attractiveness to investors**: The fiscal regime should be sufficiently attractive to encourage investors to carry out exploration activities and develop profitable projects. While neutrality and adaptability play an important role for investors, there are additional elements that investors care about. The most important is

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[10] The minimum effective royalty from start of production is often simply the royalty rate divided by gross revenues. However, in case of production sharing the interaction between the cost recovery limit and the profit oil sharing creates an additional revenue stream from start of production usually calculated as: royalty rate + (1 – royalty rate) * (1 – cost recovery limit) * lowest share of government profit oil.

the discounted after-tax value of the investment, the payback period, and the breakeven price.[11] Considering the long time-horizon of projects and large upfront investments, stability is also a key concern for investors: constantly changing fiscal regimes are likely to attract a higher risk premium that add to the cost of financing when investors consider new projects. To protect themselves, investor often seek fiscal stability assurances in sectoral legislation or in contracts (IMF (2008) and Mansour and Nakhle (2016)).

Fiscal regimes need to be administered within existing capacity constraints. Before new fiscal instruments are introduced, sufficient capacity needs to be developed to administer those instruments. FARI does not have specific indicators to measure the ease of administration, however.

Governments differ in the relative importance attached to these objectives. Countries hosting many projects, or with strong credit market access, may be less concerned about ensuring early payment by each project in isolation. Those with ready access to alternative sources of revenue may be less concerned by taking on more risk. Political pressures to show acceptable revenue from national assets, acceptably responsive to current prices, can be powerful.

No regime is ideal for all, but for many countries an ad valorem royalty, CIT, and RRT in combination have considerable appeal. The royalty ensures some revenue for government whenever production is positive, while the CIT ensures that the normal return to equity is taxed at corporate level in EI, as it is in other sectors. And the RRT specifically targets potential economic rent. 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. Moreover, any fiscal outcome of a tax/royalty regime can be achieved by a production sharing arrangement or a hybrid of the two.

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[11] The position of a particular project on the global breakeven cost-curve is also important when considering attractiveness to investors: e.g., if high on the cost-curve there is a greater risk that commodity prices may fall and make a project unviable. A government need to understand a project's position on these global cost-curves to inform fiscal regime decisions.

Box 1: Key Indicators Used in FARI Analysis – Investors

Post-tax NPV

The post-tax NPV is the discounted present value of the total stream of net cash flows received by the investor over the life of the project. In this case, the investor's net cash flows are derived from gross revenues after deducting all project costs and all tax payments to the government:

$$NCF_t^{Post-TaxInvestor} = Pre\text{-}taxNCF_t \ - \ Royalty_t - Taxes_t$$

As in standard discounted cash flow (DCF) analysis, the post-tax investor NPV is then calculated as:

$$Post\text{-}tax\ InvestorNPV = \sum_{t=0}^{n} \frac{NCF_t^{Post-tax\ Investor}}{(1+r)^t}$$

where $NCF_t^{Post-tax\ Investor}$ is the investor net cash flows in year t, r is the discount rate, and n is the last year of the project. Other things equal, an investor prefers projects with higher positive NPVs.

Post-tax IRR

A complementary measure to the NPV is the IRR, or the discount rate at which the NPV of the stream of cash flows is zero. The IRR in this case is the return on total funds (whatever the proportions of equity and debt), but the model also calculates the return to equity by netting out the lender cash flow from the two equations above.

Payback Period

In EI projects, the payback period occurs when the cumulative cash inflows from production are sufficient to recover the cumulative cash outflows incurred with exploration, development, operating costs and taxes. The payback period can be calculated on undiscounted or discounted cash flows, and on leveraged and unleveraged funds. Other things equal, an investor prefers a short payback period.

Box 1 Continued: Key Indicators Used in FARI Analysis - Government

Average Effective Tax Rate (AETR)

The AETR is the ratio of the NPV of government revenue (including royalty, income tax, resource rent tax, withholding taxes and so on, but excluding for instance taxes on the salaries of employees) to the NPV of the pre-tax net cash flows of a successful project, both calculated in discounted value. The AETR thus indicates how much revenue a fiscal regime raises and is one of the definitions of "government take".

$$AETR = \frac{NPV(Gov\ Revenue)}{NPV(Revenue - Exploration - Dev\&ReplacementCapex - Opex - Decomm)}$$

The level of the AETR curve, not just its slope, is also important to consider: if the government's share is so high that investors cannot recover their capital and a normal rate of return, investments will not take place.

Marginal Effective Tax Rate (METR)

The METR is the wedge that the tax system drives between the minimum after-tax return that the investor requires, and the pre-tax project return needed to realize it. The METR reflects the burden placed by the fiscal regime on a project at the margin of viability (i.e., projects that lie at the far end of a sector's cost curve), thus indicating the extent to which the regime affects business investment decisions.

$$METR = \frac{Pre\text{-}Tax\ IRR - Post\text{-}Tax\ IRR}{Pre\text{-}Tax\ IRR}$$

In the model, an important first step in the calculation of the METR is to determine the price at which the post-tax investor return equals the hurdle rate, or the breakeven price. The pre-tax return is then calculated assuming the project is executed with this price.

Breakeven Price

An indicator of the fiscal burden on a marginal project and complementary to the METR, the breakeven price is the minimum price required to yield a specified post-tax return to capital over the full life of the project. The breakeven price is determined by the model through iterations and then compared with the initial user price assumption. A breakeven price above the user price implies that the project is economically unviable post-tax.

Progressivity

Progressivity is broadly defined as the ability of the fiscal regime to capture a larger share of profits in highly profitable projects, while reducing the tax burden in low profitability ones. The degree of progressivity in a fiscal regime can be analyzed by plotting the AETR over a range of pre-tax rates of return. The range of project pre-tax rates of return is obtained by varying the assumed prices or unit costs in the model.

Share of Total Benefits

An alternative to the AETR is the government's Share of Total Benefits (STB). "Total benefits" measures operating profits, without deducting the cost of capital investments, over the life of the project. It represents the amount of a project's net revenues available to be shared between the government and investors, from which investors expect to recover their investment and earn a profit. As with AETR, STB can be plotted at different levels of profitability to make visual comparisons of progressivity across fiscal regimes.

With the foundations established, FARI can be harnessed to model and analyze fiscal instruments individually, and then in aggregate. The next section introduces the common features of a tax/royalty concessionary regime, then discusses production sharing arrangements for petroleum. Other fiscal instruments are then considered (state participation, carbon tax, and value added tax, VAT).[12]

B. Royalties

A royalty is essentially a fiscal charge levied directly on the extraction or production of the resource.[13] Royalties are justified as a payment to the resource owner in exchange for accessing the owner's property and mineral wealth. In some jurisdiction royalties may also be paid to private landowners. They can also be understood as a reservation price for the extraction of a finite resource.

Royalties are usually defined as a payment either on an *ad valorem* basis – as a percentage of the value of the resource extracted – or on a specific basis where payment is per unit of the resource extracted. Ad valorem royalties are much more common, but specific rates are still used in some countries for industrial materials such as sand.

Royalties are attractive to government as they provide early revenues from the start of production, are relatively easy to administer and have less avenues for avoidance than profit-based instruments. The downside is that they do not consider extraction costs and, thus, increase the marginal costs of production. This can in turn distort investment and production decisions.

The Point of Imposition and the Royalty Base

For most countries, ad valorem royalties are applied based on the seemingly straightforward concept of the value of what is produced and sold from the mine or well, as reflected by a market price. When assessing ad valorem royalties, it is important to use a price that reflects what independent buyers and sellers would agree, based on the characteristics of the product, as well as the supply and demand conditions for that mineral/metal and its substitutes. For some commodities (e.g., oil, gold, and copper), international reference prices are readily available to guide price discovery (though adjustments may be necessary), but for others where products are more complex (e.g., mineral sands) and/or markets are more opaque, there may be a need to access specialist publications or industry expertise (PCT, 2017).

Establishing the assessable value for royalty purposes requires clarity on two interrelated elements: i) the point in the production process at which the royalty will apply (i.e., the valuation point), and ii) the adjustments or deductions that are permitted in establishing the royalty value (i.e., the royalty base).

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[12] For the following sections, we use the pre-loaded projects in the published 2021 FARI models. General assumptions can be found in Annex 2.

[13] Some countries, for example Chile and Peru for mining, use the term royalty less conventionally to refer to a fiscal payment that is based on a measure of mining profits.

The Valuation Point

Royalties can be imposed at different stages in the production process (see Box 2 and Figure 1). These different points are relevant because the price of the commodity will change (increase) as the valuation point moves further from the well head or mine gate to the final customer, and because additional costs are incurred.

Commonly used valuation points are where the resource leaves the license area (i.e., at the well head or mine gate), or where the first transfer of title to the resource takes place, which could be, for example, at the border, or at the port of export.[14]

- For petroleum, it is common to set the valuation point at the earliest point where production can be measured, or where the contractor takes ownership of the production.

- For mines, the port of export is often used for bulk commodities or ores with little processing, but for others such as precious metals, countries may impose the royalty on the value of the precious metals at the point they leave the mine site.[15]

The Royalty Base

The simplest way to assess the royalty is on the gross value of what is produced at the chosen valuation point, with no consideration of project costs, deductions, or allowances, and this is the approach applied in some jurisdictions. However, many countries do permit adjustments when applying royalties, such as for transport costs or downstream processing, and these need to be factored into the modeling.

FARI applies a "gross/net" concept to determine the royalty base. The gross base is calculated as the assumed price times the volume of production without any deductions. Using the net base, specified costs may be deducted. For petroleum projects, usually only transport costs (e.g., pipeline costs) are included, while for mining projects, downstream transport, smelting and refining costs can be allowed.[16]

Where transport and processing costs are a relatively small proportion of finished product value (more common in precious metal projects), the difference between the gross/net basis for the royalty may be modest; but for other minerals the difference can be significant, and a more detailed modelling of upstream costs may be warranted.

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[14] With the commonly used incoterm Free on Board (FOB).

[15] Countries sometimes modify royalty rates to incentivize domestic processing and value addition (i.e., a lower royalty, applied at a later valuation point).

[16] Some countries also allow for metals that may be lost during downstream processing (e.g., a smelter that does not recover all metal content during the process), and it may be necessary to incorporate this into the analysis (e.g., as an assumed reduction in the production quantity).

Box 2: Royalty Valuation Points

Figure 1 illustrates a stylized value chain for a mineral product, from extraction to a sale to final customers. Points A to F on the value chain indicate potential valuation points for the calculation of royalties. As the valuation point gets closer to the final customer (further away from the point of initial extraction), the value of the product increases as it is beneficiated and transformed into a more homogeneous product that is in line with market requirements.

Figure 1: Royalty Valuation Points
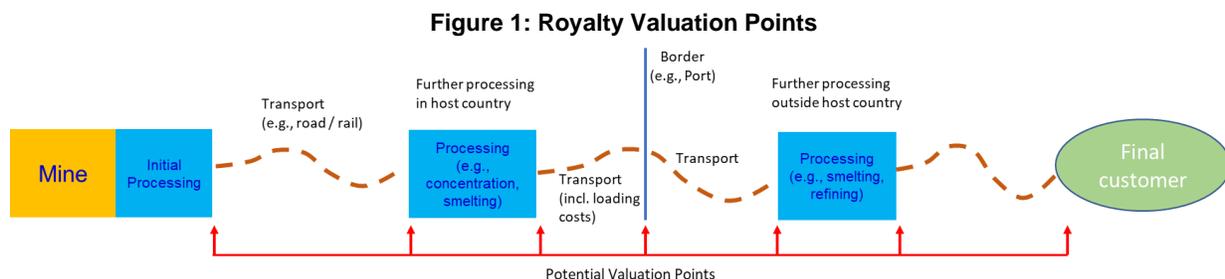
Source: IMF staff

It may be possible to reconcile the price applied at each valuation point to other valuation points via the addition/subtraction of relevant costs (for example, the mine gate price of a bulk commodity such as coal could be reconciled to the FOB export price by deducting local transport costs to the port). However, for some minerals this may not be a 'perfect' reconciliation: as minerals are processed (e.g., from bauxite to alumina), the reference price for its sale might change and each product may be influenced by its own market dynamics such as available inventories, capacity constraints, and market demand.

The relative costs and value addition between mine, processing, transportation, and final market price varies significantly between different minerals, and also between oil and gas.

Structure of Royalty Rates and Interaction with other Fiscal Instruments

Ad valorem royalty rates can be set at a flat percentage, or vary according to price, production levels (common for petroleum), and between product type (e.g., a lower rate is commonly applied to natural gas). A flat rate simplifies collection and administration of the royalty, while variable rates can make a royalty more progressive while maintaining some of the simplicity advantages.

However, commodity price or production levels are only imperfect measures of profitability, meaning progressive royalties are still likely to be distortionary, since they can only approximate targeting economic rents.[17] Setting price thresholds to capture economic rents is challenging, and requires monitoring and potentially, adjustment over time - for example, to account for inflation.

Royalties are an expense for the resource company (paid for the right to exploit a deposit), and it is therefore appropriate to allow a deduction for the cost of the royalty when determining the tax base for CIT and other taxes. Where this CIT deductibility is not provided, this will directly increase CIT liabilities, raising the overall

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[17] Other (imperfect) measures of profitability include, for petroleum projects, the type of terrain (with royalty rates on offshore projects commonly being lower than on onshore projects), and the maturity of fields (with lower rates for more mature fields or those requiring secondary recovery methods).

project AETR (see Figure 2). Since royalties will normally be payable from the start of production when there are no taxable profits, tax rules should allow any resulting tax losses to be carried forward.

Under a production sharing regime, revenues shared are usually net of royalties. Where a production sharing contract has a cost-recovery limit, it is important to determine whether the cost oil limit is calculated before or – as is more common – after royalties.

Figure 2: Government Revenues Under Alternative Royalty Arrangements

The effect of the deductibility of the royalty is illustrated below. Using the gold project, making a 5 percent royalty non-deductible results in higher CIT revenues and (assuming a 30 percent CIT rate), increases the discounted AETR by 3 percentage points (notice that royalty revenues remain unchanged).

For an equivalent result in terms of revenues from a deductible royalty, the royalty rate would need to be increased to 7 percent. Although there is a numerical equivalency between the royalty rate and its deductibility from CIT, the composition between the two instruments will also have consequences for the progressivity of the overall regime – again highlighting the importance of evaluating a fiscal regime using different metrics.

Government revenues under alternative regimes

Project: Gold(2MMoz)
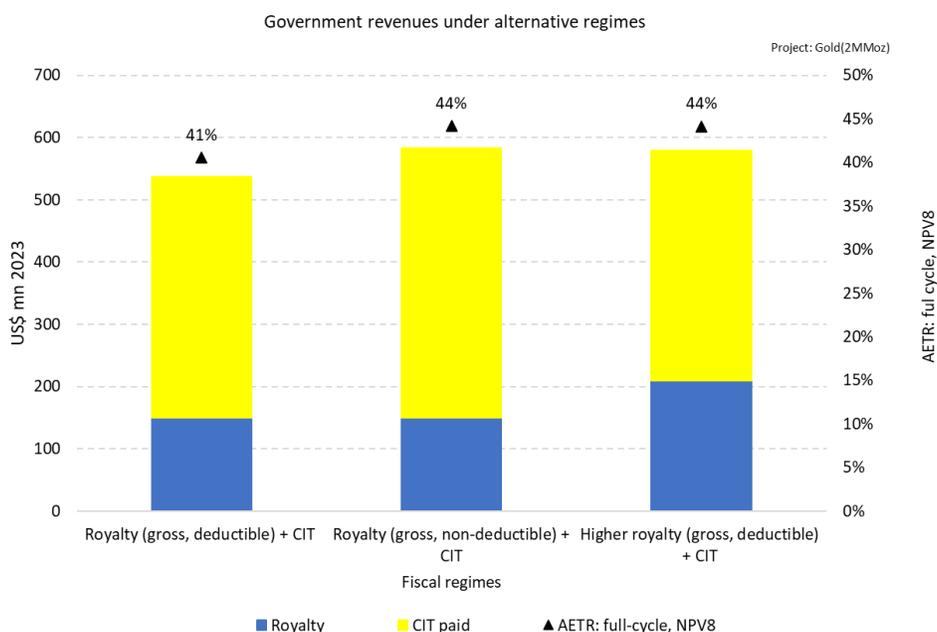
Source: IMF Staff

The FARI model includes commonly observed options for the specification of the royalty (the published version, however, only recognizes one mineral product per project as a simplification). A flat royalty applies the same royalty rate regardless of other variables, while for price-based royalties, the model allows two different rates that apply above and below a price threshold. Price thresholds can be defined depending on whether the price threshold is adjusted for inflation.

Economic Analysis

The government's share of revenue from a flat royalty does not vary with changes in prices, production, or costs. This makes royalties regressive in isolation: as project profitability rises, the AETR falls (see Figure 3a where the profitability of an iron ore project varies by changing the iron ore price). By allowing the deduction of transport costs from the royalty base, the royalty becomes slightly less regressive.

Another option is to have the royalty rate vary with a proxy measure of the project's profitability – prices and production volumes are the most widely used since they can be relatively easily assessed. This can introduce progressivity into the royalty (represented in Figure 3.a by the AETR curve for the indexed price-based royalty that begins to curve upwards once iron ore prices exceed the threshold for a higher royalty rate).

Royalties that vary with price can lessen their regressive nature but are based on an imperfect measure of profitability that make them second-best progressive fiscal mechanisms. Price thresholds are inevitably set arbitrarily, can be overtaken by market events, and ignore cost structure difference between projects. Further, they may increase the "cut-off" grade and therefore reduce the mineable resources for a given project.

Moreover, if a variable rate is applied to the full mineral value, this will create a "cliff" effect, where small variations in price lead to abrupt changes in the rate of the royalty (see Figure 3b). This can be ameliorated by applying the variable rates to the incremental value above a price threshold, resulting in a gradually upward sloping effective royalty rate (the smooth line in Figure 3b).

Figure 3a: Progressivity Analysis Under Different Royalty Structures

Progressivity analysis across a range of mineral prices

Project: IronOre(250MMt)

12%	13%	15%	16%	18%	19%	21%	22%	23%	24%	26%	27%	28%	29%
73.2	77.1	80.9	84.8	88.6	92.5	96.3	100.2	104.0	107.9	111.7	115.6	119.4	123.3

IRR: Project % real / Iron Ore price: US$ / DMT const

—— Flat Royalty (gross)   —— Price-Based Royalty (gross)   —— Price-Based Royalty (gross, indexed)

AETR: full-cycle, NPV8
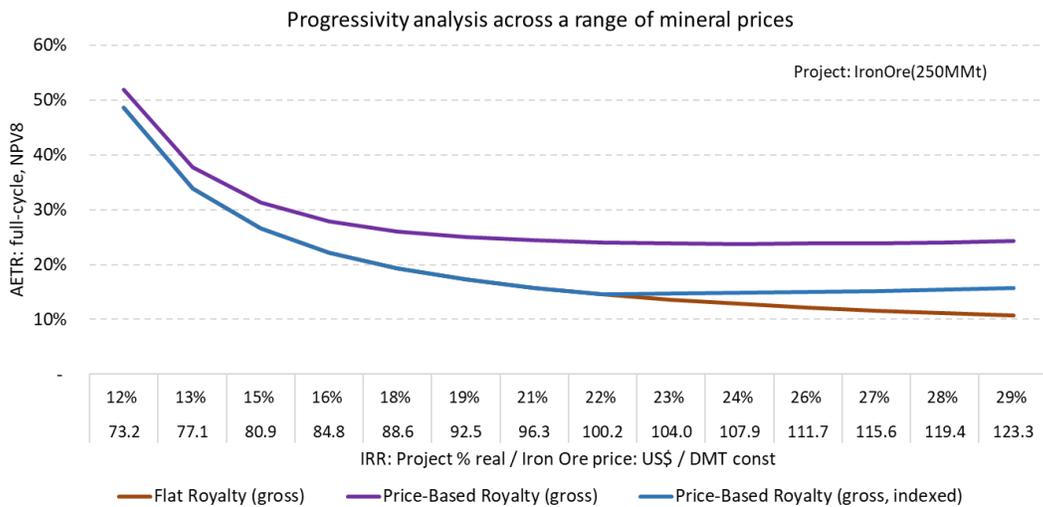
Source: IMF Staff. Note: a price-based royalty step increase occurs at USD 100 / dmt.

Figure 3b: Price-based Royalty Rates Under Different Royalty Structures

Price-based Royalty Rates Under Different Royalty Structures

Royalty rate

Price of mineral (gold, USD/Ounce)

—— Royalty rate (variable rate applied to the full mineral value)

—— Royalty rate (applying the variable rates to the marginal value above a price threshold)
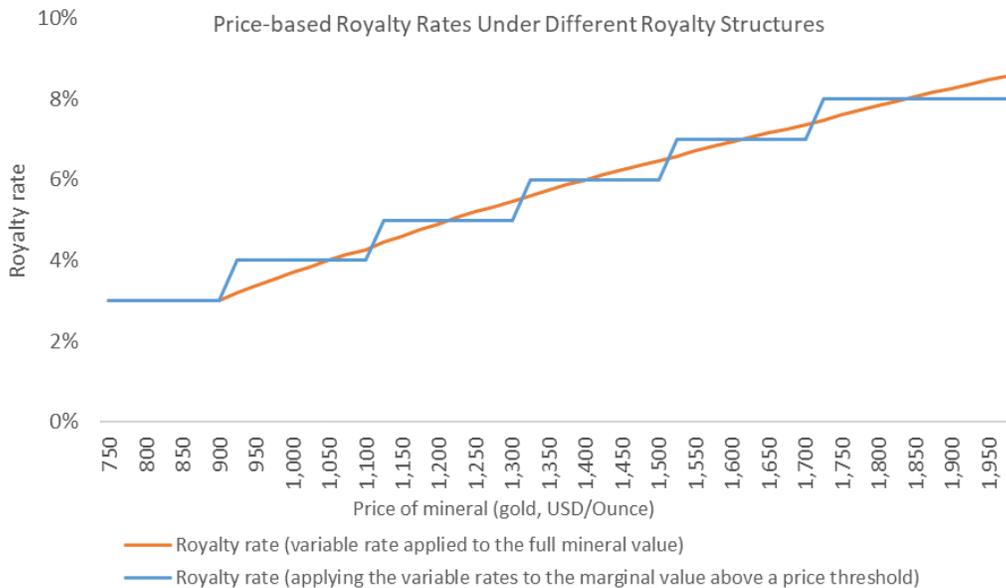
C. Corporate Income Tax

The CIT is commonly applied to mining and petroleum operations, albeit with varying degrees of country satisfaction with its performance.[18] Whilst in some areas special CIT treatment may be granted to EI projects (e.g., a modified rate, accelerated depreciation, rehabilitation provisions, longer loss-carry forward), other general provisions would still be expected to apply (e.g., transfer pricing regulations).

CIT is a notable area where notional calculations are required that differ from pure cash flows. Depreciation calculations, for example, create a wedge between when a cash event occurs (e.g., the purchase of an asset) and the deduction claimed under the CIT (spread over several years). With cash flow discounting, the size of the wedge can materially affect the overall analysis (discussed further below). Moreover, this divergence requires careful presentation in the model, to distinguish how each calculation is used.

Determination of the Tax Base

Taxable profits are determined by subtracting allowable costs (deductions) from gross taxable income. Cost deductions are exploration costs, royalties, operating costs, interest payments (subject to certain limitations), and depreciation allowances for capital costs. Some countries provide incentives for exploration and development, such as by allowing accelerated depreciation of these types of costs or direct expensing (common for exploration expenses).

Ring-fencing limits the scope for a mining or petroleum company to consolidate income and expenses across projects, but also across corporate activities. The ring-fence can be introduced in legislation to apply at several levels, including the sector level (so a taxpayer cannot consolidate mining or petroleum activities with other economic activities) at the level of the license or contract area, or at the project level. With FARI's project-based modeling approach, the ring-fence is assumed to apply at the license or contract area.[19]

Depreciation allowances for capital costs

The FARI models include five cost categories, with three categories of capitalized costs that may be subject to depreciation: exploration costs, development costs and replacement capital costs. A single straight-line depreciation calculation is included in the model and a simplifying assumption is made by choosing the straight-line depreciation rate that most closely matches the type of development assets for each country, including, when applicable, accelerated allowances.

The tax rules for expenses on tangible and increasingly intangible capital assets are particularly important for EI. In principle, the rate of depreciation should reflect each asset's economic life. For practical reasons, tax systems apply rules that approximate the economic life of capital assets by constructing a schedule of depreciation allowances for different classes of assets. Exploration costs are often treated separately, as not all costs are of a capital nature. The model provides options to capitalize and subsequently depreciate these costs (and to choose when), or to expense them.

Figure 4 illustrates how a shorter depreciation period allows for earlier recovery of investment, but lower initial payments of CIT. It is, however, important to stress that the effect is only one of timing: in undiscounted terms, the sum of CIT collections over time and the AETR over the life of the project remains unchanged. But with the

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[18] An alternative approach is discussed in IMF (2021a) with a cash-flow-based fiscal mechanism replacing the CIT to address profit shifting challenges, particularly in low-capacity countries.

[19] With some modifications, it is possible to model multiple development phases, aggregate multiple mines or to incorporate mid- and downstream activities subject to a different fiscal regime from the upstream activity.

discounting of future cashflows, faster capital expensing can make the overall fiscal regime more attractive to investors.

Figure 4: Timing Effects of Different Straight-Line Depreciation Periods on Capital Allowances and CIT

4a: Capital allowances

Capital allowances

Project: Gold(2MMoz)

Legend: Immediate expensing — Depreciation (3 years) — Depreciation (7 years)

4b: CIT paid

CIT paid

Project: Gold(2MMoz)

Legend: CIT only (Immediate) — CIT only (3 year depreciation) — CIT only (7 year depreciation)
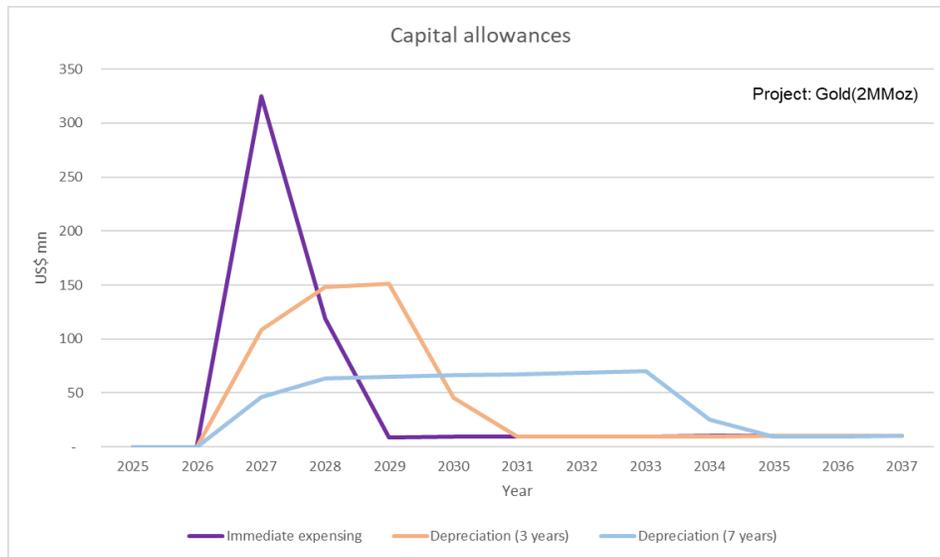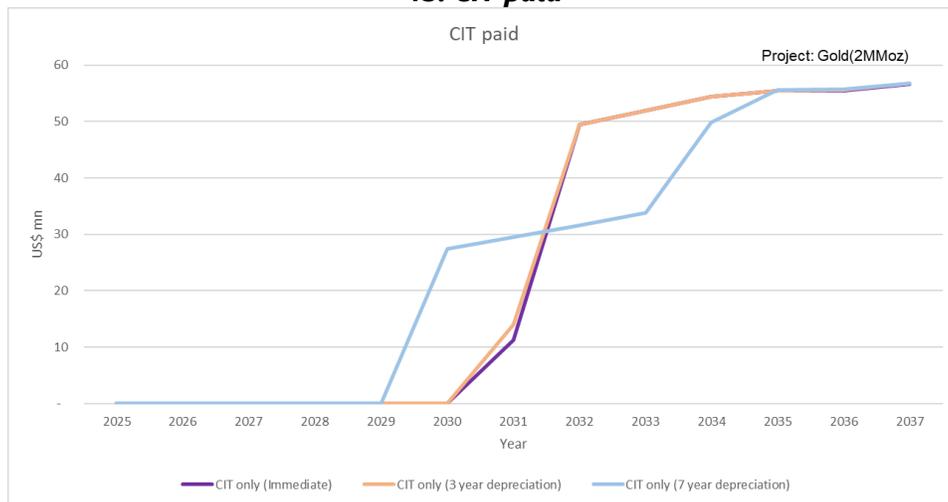
Source: IMF Staff estimates. Modeling CIT only (no other fiscal instruments).

Treatment of CIT losses

Allowing a longer loss carry-forward may be appropriate given the long investment recovery period that is typical in the EI sector and especially during any pre-production period. In some cases, countries go as far as providing for indefinite loss carryforward periods. As a compromise, some countries allow a longer loss carryforward period for EI than for other activities.

However, some countries limit the amount of losses that can be deducted from CIT for a given period (for instance, specifying that losses can only reduce CIT liability by a specified percentage each year). In setting these policies, it is important to note how loss carryforward interacts with the method for capital depreciation allowances to avoid unintended negative consequences for investors. As an example, faster upfront depreciation without a longer carry forward of losses is more likely to result in an expiry of some tax losses (and thus higher CIT payments). For simplicity the published FARI model does not model loss limitation rules, in effect assuming indefinite loss carryforward.

Treatment of decommissioning and abandonment expenses

Toward the end of production in a mine or petroleum field, there are usually material costs associated with rehabilitation and closure, usually under a plan mandated and approved by the regulator at the beginning of development and periodically updated.

Since there will be relatively little income generated at the time these expenses are incurred, governments commonly require investors to set aside funds in advance to cover the expected decommissioning and abandonment costs. Usually, the tax legislation will allow companies to claim tax deductions for decommissioning expenses or contributions to decommissioning funds while the project still generates income. A final reconciliation between provisioned funds and actual outlays will also be carried out (and rules on the treatment of any surplus or deficit in the fund are usually required).

Debt financing and deductibility of interest costs

Many countries limit the deductibility of financing or leasing charges, to address the risk that either the amount of borrowing, or the cost of borrowing (or both) is inflated through related party transactions, reducing income taxes.[20] The most common safeguards are to set a limit on the interest payments that can be deducted from CIT, by either limiting the debt-equity ratio (with interest payments above that limit potentially treated as dividends) or by including an earnings-stripping rule capping interest payment at a certain ratio of income (e.g., earnings before interest, tax, depreciation, and amortization, EBITDA).

The FARI model includes debt financing calculations, based on a general assumption that debt is provided by the parent company. This reflects relatively common international practice (particularly for medium and larger firms) whereby parent companies raise funds at the corporate level through debt and equity and advance funds to their subsidiaries, often as debt. The inclusion of debt enables the evaluation of outcomes for the parent company reflecting the potential benefit of interest deductions in reducing tax payments in the host country.

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[20] See IMF (2022) for case study examples from Sub-Saharan Africa.

Withholding taxes

Withholding taxes allow the EI host country to collect taxes from payments made by local taxpayers to non-residents who are otherwise not taxpayers in the host country. This is particularly relevant given the dominant role of MNEs and the use of international subcontractors for specialized services that may not be delivered physically in the host country. Withholding taxes can provide a safeguard against excessive profit shifting by strengthening source country taxation, but risks remain as multinational investors may arrange for payments through third-party countries where withholding tax rates may be reduced or removed in double taxation treaties.[21]

A withholding tax on dividends will be economically equivalent to a free government participation in a project structured as an incorporated joint venture (see discussion below under state participation). It is also worth noting the tradeoff that these taxes protect revenue, but negatively affect project economics.

For FARI analysis, withholding tax assumptions will depend on the nature of the modelling task. For prospective projects, the lowest rate available for a treaty country might normally be used (which implies an assumption that the investor might seek to route its inbound investment via that country), but for existing projects with established cross-border corporate structures, the actual rates of the relevant countries can be used if that information is available.

CIT rates for petroleum and mining companies

Generally, statutory CIT rates are applied to mining and petroleum activities, but some countries apply a higher or variable rate to the EI sector, while others might offer lower CIT rates or a tax holiday for an initial period to attract investors.

The justification for reduced rates is suspect, due to the potential for location-specific economic rents associated with the natural resource (IMF 2015) and because a CIT holiday will not make an unviable project suddenly viable.[22] However, the reasoning for a CIT rate above that applying to other sectors is less clear: it may be appropriate as a second-best option when there is no resource-rent tax in place, but with the acknowledgement that the higher rate might invite greater tax planning efforts from investors to move income outside the EI project's ring fence.

Economic Analysis

As CIT rates are usually fixed, the government take tends to remain stable across a broad range of outcomes and trends towards the CIT rate. At very low profitability, the CIT becomes regressive as costs cannot be fully deducted from income and become expired tax losses – however, the CIT will normally be less regressive than

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[21] For the parent company of the local investor, withholding tax relief may be possible via a tax credit or a deduction against that country's CIT. Under PSCs, the payments may be considered a recoverable cost - the treatment will depend on their consideration as a necessary cost of production according to domestic legislation or the stipulations in a PSC. Unless more detailed modeling is added, FARI adopts a simplified approach of assuming a deduction for withholding taxes, with no further consideration of the tax affairs of the parent company abroad.

[22] Widespread implementation of the Global Anti-Base Erosion Model Rules (Pillar Two - effectively a global minimum tax on corporate profits) will also weaken the case for reduced CIT rates to attract investment. See discussion in IMF (2023a).

the royalty. Combined, the two instruments ensure a minimum take at low profitability and from the start of production while at high profitability the government take is more stable than with a fixed rate royalty alone.

D. Resource Rent Taxes

A pure rent tax (often called a Brown tax) applies to positive cash flows in a tax year, but in contrast to most CIT systems, where a project has *negative* cash flows, a proportion of those negative cashflows (equal to the tax rate) is refunded to the investor. This is not common in practice, except for a variant in Norway in which unsuccessful petroleum exploration is refunded. A pure rent tax is economically equivalent to government participation in a project through fully paid equity.

A more common formulation is the cashflow resource rent tax (RRT), where rather than government immediately meeting its share of negative cashflows, these are carried forward with an "uplift". The rate of uplift is often set at a rate equivalent to the investor's minimum required return to invest, to compensate for lack of immediate refunds of negative cashflows.[23] There is no deduction for financing costs, as the return on capital costs are incorporated through the uplift (but even without the uplift, the immediate expensing of capital costs provides a substantial time value benefit). Moreover, there are further simplification benefits as the RRT does not require tax depreciation calculations or deductions for interest payments – the latter is a key benefit of such taxes since it limits profit shifting opportunities.

In a fiscal regime with both a CIT and RRT, the interaction between these two taxes becomes important in fiscal regime evaluation. Policymakers will have to choose whether to apply the resource rent tax before or after the calculation of CIT: if the RRT is applied on a post-CIT basis, the threshold hurdle rate should be lower than it would be if applied pre-CIT. There is also a tradeoff to consider between the safeguards of having the RRT as a post-tax backstop against CIT leakage, against the administrative complexities this can introduce, especially in an unincorporated joint venture structure where CIT calculations could be different for each of the joint venture partners.

One of the biggest challenges when designing a RRT is to ensure a correct choice of the imputed rate of return or hurdle rate, which determines when the tax is applied. If the permitted investor rate of return is set too high, the tax will never apply (see IMF, 2010); if set too low, it may distort investment decisions as it will tax part of the investor's normal return to capital. Therefore, when the cumulative cash flow turns positive, the specified minimum required rate of return will have been reached, and the tax applies to cashflows that exceed the minimum return.

In practice RRT rates are significantly below a rate that would capture all economic rents, as there may be costs that are not observable to government (and hence actual economic rents might be lower than observed rents (IMF, 2018). If the marginal tax rate is set too high, it reduces incentives to invest and may create incentives for tax avoidance. A single rate would result in a simpler administration of the tax, while a multi-tier rate would allow a more progressive taxation.

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[23] It is worth noting an alternative view is that the rate should be set at a long-term government borrowing rate to maintain the value of the unrefunded cashflows, plus some allowance accounting for the risk that some projects may not be able to recoup all carried forward losses. See, for example, discussion in Australian Government (2016).

E. Production Sharing Regimes

In production sharing regimes, investors incur all project costs and investors and government share between them a cashflow-based measure of profits (which can be before or after payment of royalties, depending on the arrangement), with the investors receiving an additional share of revenues to cover their costs. Production sharing has significant similarities with both RRTs and CITs, but also some differences in the determination of the base and the structure of the sharing rates. Production sharing fiscal regimes are usually agreed in Production Sharing Contracts (PSC).

Determination of the Production Sharing Base (Profit Petroleum)

The portion of production, either in monetary value or in-kind, that is allocated to the investors to recover costs incurred with respect to petroleum operations is commonly referred to as "cost petroleum" (or, in some cases it is calculated separately as "cost oil" and "cost gas"). The base for production sharing – the profit petroleum - is calculated by subtracting cost petroleum from net revenue after royalties.

The concept of cost recovery is analogous to the deductions allowed in the calculation of taxable income for CIT. However, in production sharing there is often immediate expensing for capital expenditures, and deductions are capped by an aggregate cost recovery limit (specified as a percentage of the value of production after royalties). The latter ensures that the government receives a share of production from the start of production, even when from an economic point of view the project is not yet profitable. In this sense, the combination of the cost recovery limit (when it is binding) and the government share of profit petroleum operates like a minimum effective royalty on production until the recoverable costs are lower than the cost recovery ceiling.[24] PSCs typically do not allow interest deductions.

Structure of Profit Petroleum Sharing Rates

Although there are examples of fixed-rate of production sharing, most countries use a variable rate that provides for an increasing sharing rate for more profitable projects (i.e., most systems aim to be progressive). Countries use a variety of different mechanisms to determine the rate for sharing the profit petroleum, among them some of the more commonly used are the daily rate of production (DROP), the R-factor (defined later in this section), and the rate of return (ROR) methods.

Daily Rate of Production

Under this mechanism, the government's share of profit petroleum increases with the average DROP from a field or contract area. Given a typical production profile for a conventional oil field, the government share under the DROP method would increase gradually with production, reaching the highest level when production is at its peak, and then decrease again gradually as production tails off.

Production sharing under DROP usually operates on an incremental basis, meaning that the effective government share is a weighted average of the different tiers of government shares corresponding to each DROP for a given production rate.

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[24] The minimum effective royalty is calculated as: royalty rate + ((1 – royalty rate) * (1 - cost recovery limit) * lowest tier of government profit oil share.

The main advantage of a DROP system is the simplicity of calculation, which also translates into more readily verifiable payments, but this approach has the drawback that the level of production is an incomplete measure of profitability, since it does not consider changes to profitability from changes in petroleum prices or costs. Some countries have attempted to blend DROP systems with scales of prices to make it more progressive, but this significantly increases complexity.

R-Factor

Under the R-factor mechanism, the government's profit petroleum share is based on the ratio of a measure of the contractor's cumulative revenues to cumulative costs. The actual formula used varies across countries, but there are two main models: (1) revenues divided by costs or (2) operating profits divided by initial investment costs. An attractive feature of the latter approach is that the ratio (R) equals one is when the investment cost has been recovered in nominal terms (see Figure 5).

Figure 5: Cumulative Revenues/Costs and Determination of the R-Factor
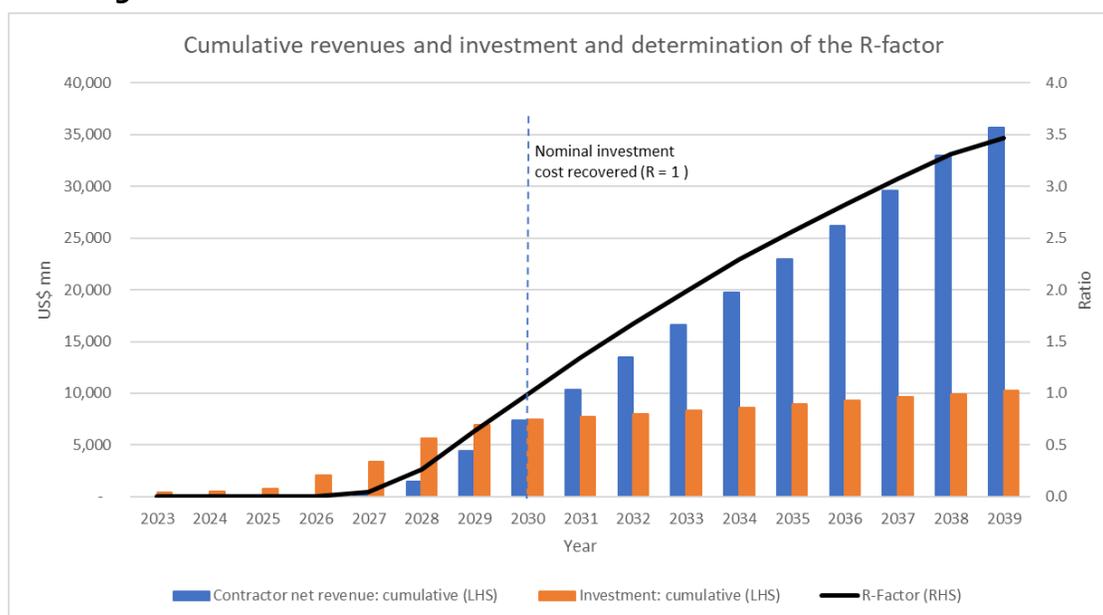
Source: IMF staff

When the R-factor is less than one, the minimum share of government profit oil applies. Thereafter, there are two options: (i) a scale of tiers in which each is a discrete step to a new rate of sharing, or (ii) a band in which progressive increasing rates of sharing to government are interpolated between the government's minimum and maximum shares. Since the first option requires making somewhat arbitrary decisions about the jumps in the marginal tax rate as steps are met, distortions may occur when crossing from one tier to another. In this case, a sliding scale with interpolation may be favored. Note that the maximum R-factor and corresponding share is usually reached at the end of project life, meaning the government share exhibits a ratcheting effect where it only ever increases.[25]

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[25] It is conceptually possible for the ROR to fall, associated with additional investment late in a project's life that generated negative cashflows for a sustained period (IMF, 2010).

Rate of return

A similar mechanism to the R-factor is the ROR, which tends to be more closely aligned with profitability indicators also used by investors for decision making. The ROR sets the government profit petroleum share relative to the cumulative internal rate of return (IRR) earned by the project from the start of exploration to the date of sharing.

The main difference between the ROR and the R-factor is that the former takes into account the time value of money by providing an uplift to negative cashflows that are carried forward in time. Production sharing based on the project's ROR can be thought of as a form of rent tax, provided that exploration is part of the cost in the ROR calculation, under which the government's share is set by reference to the cumulative contractor ROR, and no tax is levied if the project return falls short of some benchmark rate. However, in practice usually a minimum share of profit petroleum applies even below the first IRR threshold – it is essentially equivalent to a RRT + royalty fiscal regime.

Pay-on-behalf systems

In many PSC arrangements, the contractor is subject to CIT on their share of profit oil (IMF, 2010). In theory, governments can be made indifferent between production sharing that is "pre-tax" (i.e., a share of profit oil before CIT is paid) or "post-tax" (also referred to as a pay-on-behalf, POB, arrangement).[26] This indifference is predicated on the government's share of profit oil in the POB case being higher (to compensate for the absence of separate CIT payments by the contractor); there being no CIT leakages; and that full PSC revenues flow quickly to the budget.

POB systems have three main advantages: 1) revenue and costs only need to be verified and audited once instead of separate compliance activities under different rules for production sharing and CIT;[27] 2) fiscal terms are stable irrespective of changes to the CIT rate; and 3) automatic ring fencing by contract area applies to the determination of taxable income (i.e., no deduction of costs from operations on other contract areas). Historically, POB systems evolved to create a creditable tax payment in the home country of the investor, but with the trend towards territorial tax systems, this may be less relevant (IMF, 2021a).

Economic Analysis

Production sharing rates often vary with a proxy indicator for profitability. Hence, production sharing can be a progressive fiscal instrument. However, the degree of progressivity will depend on the nature of the sharing mechanism and decisions on key parameters. For example, the presence of a cost limit will add a regressive element similar to a royalty. In principle a multiple, rather than single, tier RRT regime could be made to closely emulate the R-factor progressivity profile. In other words, the difference in result is principally choice of parameters rather than an inherent difference between R-factor and RRT, a conclusion readily drawn out by fiscal modeling.

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[26] Although it is possible to have post-tax sharing without POB. For instance, Nigeria (pre-2019) is an example where the PSC was implemented on a post-tax basis but without POB, by including a Tax Oil calculation in the PSC mechanism.

[27] This however, reinforces the importance of clear agency roles in revenue collection and enforcement, and of tax authorities participating in profit oil audits. Moreover, the recipient of the CIT payments – e.g., between the tax authority versus a NOC – can affect the budget implications of POB systems.

F. State participation

In most countries, the State holds the custodial ownership of sub-soil assets for current and future citizens, and this often translates into the State wishing to participate in some way in mining and petroleum activities. At one end of the spectrum is full government ownership, where national oil companies hold licenses and directly undertake exploration, development, and production activities. Alternatively, the state can take a shareholding in the project entity as an active or passive partner. Some countries take larger participation in projects considered strategically important or otherwise significant.

For fiscal regime analysis, state participation is treated as another fiscal instrument and hence analyses the direct monetary costs and benefits to the state and the investor.[28] To analyze the impact of state participation, the first step is to delineate the state's involvement. This initial consideration focuses on the legal structure to be used, if and how the state's share of project costs will be paid for, and the timing of those payments. The legal arrangement between the joint venture (JV) partners informs whether the project is taxed as a separate stand-alone entity with after-tax profits then distributed to owners (an incorporated JV), or whether each partner will be taxed separately on their share of project cashflows (an unincorporated JV).

The FARI mining and petroleum models are configured differently reflecting common international practice: the mining model assumes a corporation holding the mining license is established in the producing country subject to all fiscal mechanisms (royalty, corporate income tax, etc.) with shareholders receiving dividends from after-tax profits, while the petroleum model has JV partners taxed separately (treating all private investors as a single shareholder and the NOC as another). The private investors are subject to all fiscal mechanisms on its share of the unincorporated joint venture (share of project cashflows before income and rent-targeting taxes, but after bonus, royalties, production sharing, and carbon tax. With government participation the NOC is allocated its respective share of project net cash flows (often along with a carry arrangement discussed further below), but no further taxes on the NOC are modelled unless required in a particular country context.

The next step is to consider which project costs are part of the arrangement and how the State will pay its share. Countries often have a legal or contractual right to participate in a project after feasibility studies demonstrate its viability, meaning they would only finance their share of development and operating costs. This means private investors bear full exploration costs and risks, which impacts EMV decisions.

The most common state participation arrangements are:

- Working interest: The State contributes its share of all project costs as they fall due. For projects that have passed final investment decision, this aligns the risks and rewards for the participants since the state shares in all project cash flows in real time. In this way, the working interest is conceptually akin to a pure rent tax (Brown tax).
- Carried interest: The parties may establish a financing arrangement to cover ("carry") the state's proportional share of development spending. Repayments – usually with interest – are then made after production starts, using some (or all) of the cash flows from the state's share of production. Carried

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[28] This analysis could also include valuing the equity stake as a government asset. In addition, FARI can present revenue associated with state participation separately from the rest of the fiscal regime, to consider any delays in government's budget inflows (e.g., SOEs holding equity stakes may have dividend payment policies to the central government that delay or limit such payments).

interests are favored in some countries since they avoid placing a lumpy financing burden on the budget, even with the cost associated with interest repayments. They are also favored by some investors since they remove the risk of project delays if the state fails to pay its way in a timely fashion. Carried interests can be conceptually equivalent to a RRT where the RRT rate equals the equity share and the RRT uplift rate equals the interest rate on the carried interest.[29]

- Free equity: The state is afforded an equity stake in the project without making contributions to projects costs or paying interest or fees. Free equity works much like a dividend withholding tax for an incorporated JV, with government revenue only commencing once profits are made and in accordance with dividend payment decisions.

For carried interests, there are three main dimensions of the financing arrangement to consider: (i) the quantum that needs to be carried, (ii) the "price" of the loan (i.e., the interest rate), and (iii) the pattern of repayments. Under an incorporated JV, the majority investor will usually determine its mix of debt and equity to pay for its share of the project, factoring in any interest limitations in tax law. The level of debt financing for the project taken on by the investor is critical to the overall impact on government revenues from its participation, as the more debt that is used, the lower the after-tax cashflows available for distribution out of the JV entity.[30] In contrast, for an unincorporated JV, each private investor will finance its portion of the development and operating costs only (for which it may use debt, often sourced from its parent company).

The carried interest loan will typically incur an interest rate above the investor's cost of provision, generating net interest income[31] and the higher the rate, the longer it will take to repay.[32] To repay the carried interest, countries usually use their share of positive project cash flows generated when production starts. Payments may be structured to prioritize quick repayment or alternatively to generate some revenue to government at an earlier stage (i.e., a longer repayment period).

Economic Analysis

State participation terms affect not only the timing and profile of revenue to government (see Figure 6), but also affect the progressivity of the fiscal regime (Figure 7) and incentives to undertake marginal projects. Free equity looks initially attractive since the state doesn't have to contribute upfront capital and doesn't share the investor's risk, but it is the most regressive and is rarely "free" - the state must often reduce other fiscal instruments as compensation. A working interest requires upfront capital and the government to meet its share of the project risk but in return, the reward is the highest with the government receiving its share of free cashflows without any financing costs and with no distortions on marginal projects.[33] The working interest is therefore the most progressive form of participation. Carried interests do not require initial capital by the government, but rewards are reduced by financing costs. The government only shares the project's risk if the carry loan is a loan with recourse on the project's assets or if the carry loan is guaranteed by the state.

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[29] The timing and size of carried interest repayments would also influence whether the equivalence holds.

[30] Much like CIT, state participation dividends can be susceptible to international profit shifting by the main JV partner.

[31] If the interest rate charged is less than the rate of return to the state from the equity participation, this financing arrangement can positively impact the NPV of benefits to the state (IMF, 2010).

[32] Financing with no interest is sometimes (somewhat confusingly) referred to as a "free carry".

[33] Note however that the FARI modeling assumes the state contributes its working interest share from its existing cash assets, rather than by borrowing. If the state must borrow to finance a working interest, the conclusion on relative returns must factor in the financing terms.

Figure 6: State Participation - Revenue Profile of Alternative Forms

Government Revenues / Outlays

Project: Gold(2MMoz)

Free Equity (10 percent)   Carried Interest (10 percent)   Working Interest (10 percent)
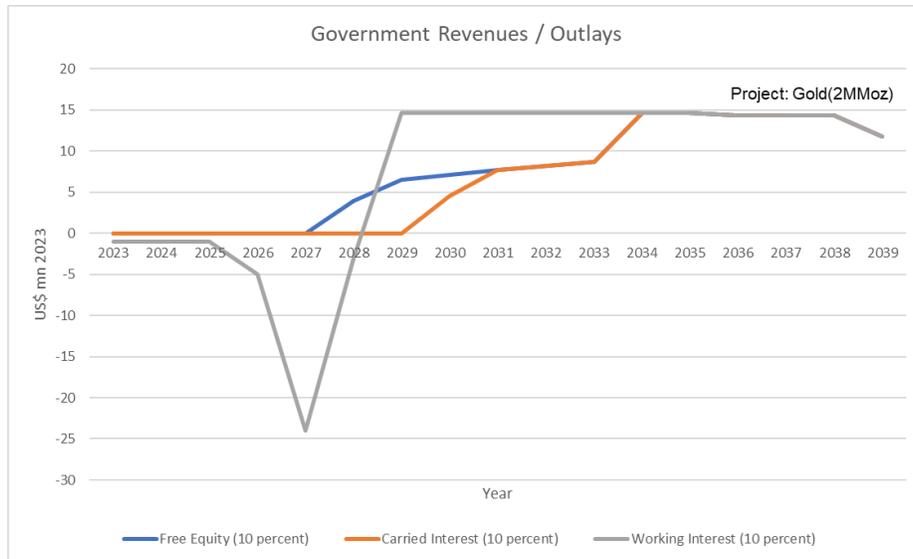
Figure 7: State Participation - Government Share at Different Project Profitability Levels

Government Share at Different Mine Profitability

Project: Gold(2MMoz)

IRR (%) real, Gold price (USD/oz)										
975	1050	1125	1200	1275	1350	1425	1500	1575	1650	1725
13%	16%	19%	22%	25%	27%	30%	32%	35%	37%	40%

Free Equity (10 percent)   Carried Interest (10 percent)   Working Interest (10 percent)
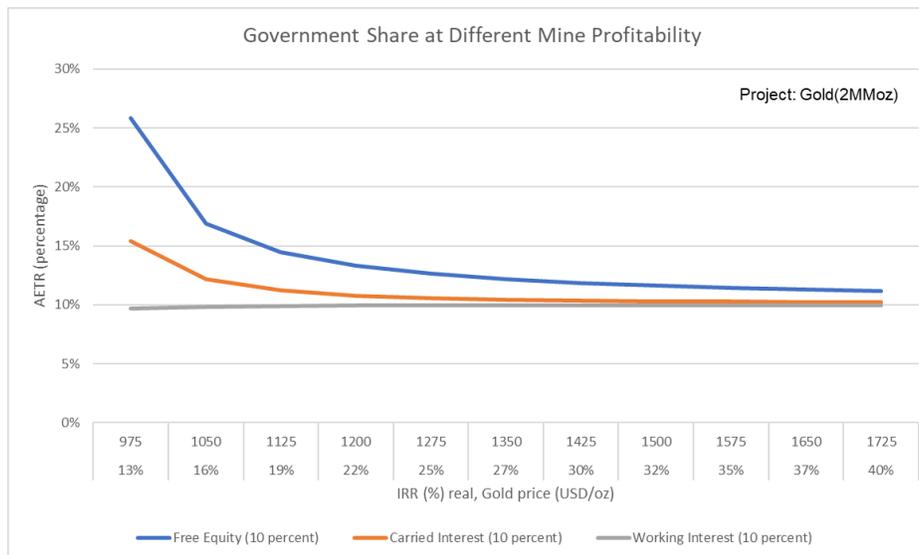
Source: IMF staff. No other fiscal instruments modeled.

G. Carbon Tax

Producing and burning fossil fuels imposes costs on society through greenhouse gas (GHG) emissions contributing to global warming, local air pollution, and other impacts. Without government intervention, individuals and firms that emit GHGs do not pay for the associated societal costs, resulting in excessive pollution and the potential for catastrophic climate change.

Carbon pricing provides a solution by internalizing the cost of emitting activities so that energy consumers consider the societal cost of emissions when making consumption and investment decisions. While mitigation policy has traditionally focused on the end use of fossil fuels, there are growing efforts to reduce emissions from fossil fuel extraction, transportation, and processing.[34]

Carbon pricing creates a financial incentive to reduce the emissions-intensity of production by causing the producer to pay for the cost of its pollution. This is intentionally distortive and discourages investment in relatively high emitting fields, and production from projects that are late in life (when operating margins are smaller) since the tax base does not consider the project's underlying profitability. To avoid impacting overall investment and production in the sector, the introduction of a carbon price could be made revenue-neutral by reducing another distortive tax, such as a royalty, or using a feebate type approach (Parry et al 2022).

The carbon tax is also relevant for modelling a shadow carbon price that factors in the full cost of pollution, which energy companies are increasingly using to inform their investments (McKinsey, 2021b; and CDP, 2017). A shadow carbon price can be used to assess whether a project remains viable if the host country introduces a carbon price in the future (i.e., an evaluation of policy risk) and to promote company-level portfolio allocation decisions that efficiently reduce emissions-intensity and achieve emissions reduction objectives. Whether the shadow carbon price is tax deductible and cost recoverable would depend on the purpose of the shadow carbon price and company-specific methodology.

There are three primary parameters when designing a carbon tax applied to fossil fuel extraction: the base, the rate, and the interaction of the carbon tax with other fiscal instruments.

Determination of the Tax Base

GHG emissions for a given activity are generally allocated to Scope 1, 2, or 3.
- Scope 1 emissions are those directly caused by extraction and on-site transportation, power generation, and processing of fossil fuels,
- Scope 2 emissions come from the generation of any purchased electricity (and should be taxed at the point of electricity generation and therefore built into the electricity price),
- Scope 3 emissions are all emissions occurring after the fossil fuel leaves the taxation ring-fence, including the combustion of fossil fuels.

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[34] These increased efforts are partly due to two facts. First, novel research has shown much higher than expected methane emissions by fossil fuel producers (EDF, 2018; and Nature, 2021), with the sector emitting 33 percent of all human-caused methane emissions (IEA, 2021a). And second, there are relatively low costs to abate emissions in the sector, with 50 to 75+ percent of fossil fuel production-based emissions avoided at a carbon price of USD 50 per tonne of CO_2 equivalent (IEA, 2021a; and McKinsey, 2019).

The unit for emissions-intensity as applied in FARI is grams of carbon dioxide equivalent (CO2 eq) per megajoule (MJ).[35] Scope 1 and 2 emissions-intensities vary significantly across projects and are a function of technology and drilling techniques used, as well as geology (McKinsey, 2019). There are some published estimates of petroleum project emissions-intensity—for instance, average Scope 1 and 2 carbon-intensities by country range from 3 to 30 g CO2 eq/MJ (Masnadi and others, 2018).[36] Since there is little comparable data for mineral production (and the Scope 1 and 2 emissions-intensity of mineral production is thought to be lower, except in the case of coal), FARI only includes a carbon tax on Scope 1 emissions in the petroleum model.

A carbon tax on Scope 1 emissions would induce reductions in the emissions-intensity of production, which can be achieved through flaring or reinjecting - rather than venting - unmarketable methane, eliminating routine venting through leak detection and repair, technology to detect leaks, electrifying operations, and choosing reservoirs that require less energy intensive drilling techniques (McKinsey, 2019). It should be noted that a switch from venting to flaring reduces total GHG emissions (and, thus, results in a lower tax liability and less global warming) since methane has a higher warming potential than CO_2 but flaring is still problematic, and efforts should be made to safely eliminate routine flaring in tandem with those for methane.[37]

The IMF generally advises to remove fossil fuel subsidies if they are in place and impose a carbon tax on Scope 1 emissions as this ensures that the producer internalizes all societal costs stemming from its extraction activities (see IMF 2023b). A tax on Scope 2 emissions should be applied at the point of power generation (or upstream from that point), while a Scope 3 emissions tax would generally apply in the consuming country and the cost may be passed on to consumers (outside of the scope of the published FARI model).[38]

Tax Rate

The optimal carbon tax level is highly debated, but the IMF highlights three generally applicable approaches for determining the tax rate.

- First, phase in the tax with progressive increases over time. This provides time for emitters to adjust input choices and accounts for increasing damages from marginal increases in global warming.
- Second, consider a target level that is roughly consistent with that needed to achieve global temperature objectives, e.g., warming "well below" 2-degrees Celsius, (UNFCCC, 2015) as this is assumed to be roughly optimal from a societal perspective—a widely cited study puts this level at USD 40 to 80 in 2020 and USD 50-100 by 2030 (Stern and Stiglitz, 2017).
- And third, if production occurs close to populated areas, increase the tax level to include local health costs of methane emissions and particulates (see IMF (2021c) for country-specific optimal tax levels).

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[35] E.g., a 16 g CO2 eq/MJ equates to 0.1 tonne per barrel of oil equivalent, so a USD 50 per tonne carbon tax on a project Scope 1 emissions-intensity of 16 g CO2 eq/MJ results in a tax of USD 5 per barrel of oil.

[36] IEA (2021a) provides estimates on methane-intensity. Estimates should be interpreted and compared with caution as the methodologies may not be consistent across sources and some emissions measurement technology is still improving.

[37] Venting releases methane directly into the atmosphere while flaring combusts the methane and converts it to CO_2. A tonne of flared methane releases about three tonnes of CO_2, resulting in a 90 percent reduction in global warming relative to a tonne of methane, as methane generates 30 times more warming than CO_2 over a 100-year time scale.

[38] There are some cases where a Scope 3 tax could impact producer prices, such as a coal producer that competes with cleaner fuels domestically and has restricted access to international markets due to, for example, high transportation costs.

The carbon tax is usually set as a specific charge per tonne of CO_2 equivalent[39] emitted. In FARI the tax can be fixed in nominal or real terms or variable with either a linear increase to a target level in a specified year or increased at a fixed percentage per year.

Since marginal tax rates on profit can be exceedingly high once capital costs are recovered, the decision on deductibility and cost recovery of any carbon tax has a significant impact on whether the tax distorts investment and production decisions. In general, taxes on negative externalities should be treated just like labor and capital costs and, therefore, be deductible and recoverable since a negative externality is as much a cost as labor and capital from an economic perspective. As with royalties, a lower non-deductible carbon tax could be calibrated to have similar effects to a higher deductible carbon tax.

Economic Analysis

The impact of the Scope 1 carbon tax on project economics and government revenue largely depends on the emissions-intensity of production and whether the carbon tax is deductible against taxes such as CIT. In the stylized oil project example (Figure 8), imposing a US$ 75 per tonne carbon tax has little impact on project viability when the emissions-intensity is low. The investor IRR falls by 1 to 2 percentage points relative to no carbon tax (left panel). However, the same carbon tax makes the high emissions-intensity project marginal or unviable, with the investor IRR falling to 7 percent - 19 percentage points lower - when the carbon tax is not deductible or cost-recoverable (Figure 8, right panel). This illustrates how the carbon tax provides a significant incentive to reduce emissions-intensity.[40]

Figure 8: Carbon Tax Impact for Low and High Emissions Oil Projects
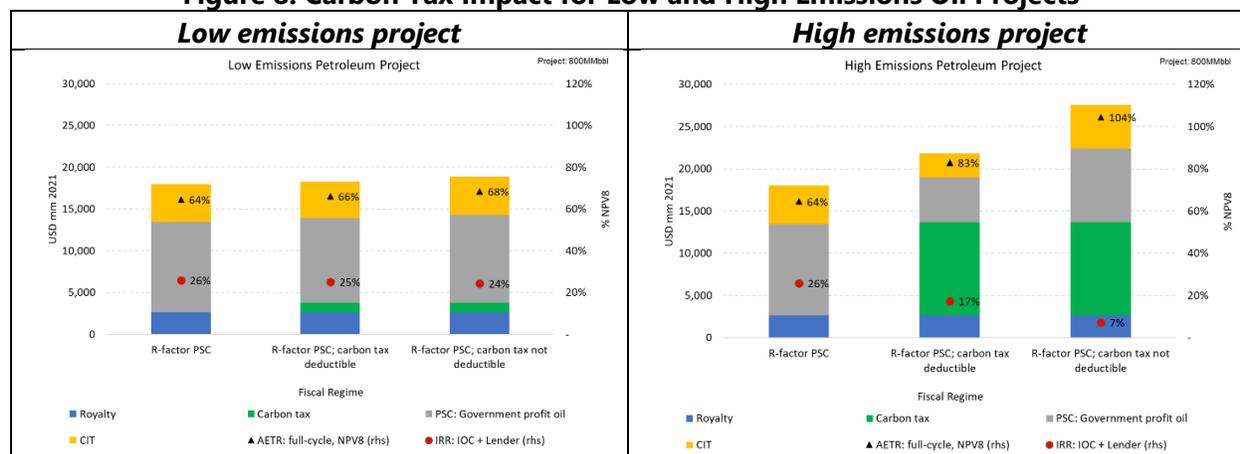
Source: IMF Staff estimates. Assumes emissions-intensities of 3 and 30 g CO_2 eq/MJ for the low and high emissions project, respectively.

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[39] The CO_2 equivalent (or CO_2 eq) is a metric used to compare the global warming impact or potential (GWP) of different GHGs. Methane has a GWP of 72 over a 20-year time horizon (i.e., one tonne of methane causes 72 times as much warming as one tonne of CO_2) (IPCC, 2007).

[40] The FARI model does not automatically include any behavioral response to the carbon price.

A Scope 1 carbon tax may also cause a project to stop production earlier (reach its "economic limit") than it otherwise would by increasing the marginal costs of production. As with a royalty, the carbon tax increases the variable cost of production (under the assumption that emissions are correlated with production), potentially causing the tax-inclusive costs to exceed revenue and, thus, making it uneconomic to continue production. In the above example, production stops five years earlier for the high-emissions intensity project when the carbon tax is not deductible and recoverable and one year earlier for the same project when the tax is recoverable and deductible. The economic limit is not impacted by the carbon tax for the low emissions intensity project.[41]

Overall, the carbon tax is a way to make companies consider the cost of pollution and climate change when making investment and production decisions. It induces investment in low-emitting projects and abatement technologies, while decreasing production from marginal and higher-emitting projects. Norway is a prime example of a producing country that has successfully imposed carbon (and methane) taxes on fossil fuel projects and significantly reduced the emissions-intensity of production.

Box 3: The Impact of the Energy Transition on Fiscal Regime Design

The energy transition has broader implications for fiscal regime design. Hydrocarbon and coal demand, investment, and prices are expected to fall (IEA, 2021b) as the energy transition progresses. This will invariably lead to more competition for upstream investment and lower economic rents.

Policymakers face a choice: do they try to attract new investment or maximize benefits from existing projects? Rebalancing the fiscal regime from distortive to progressive fiscal mechanisms (e.g., reducing royalties and increasing profit-based taxes) may incentivize investment but at the cost of government revenue as economic rents are less likely to materialize and profit-based taxes are more difficult to administer. Maintaining (or introducing) production-based taxes could increase revenue from existing projects at the risk of triggering earlier decommissioning and reducing the attractiveness of new investment.

There are several non-fiscal considerations as well, and where a country's projects sit on the cost curve will matter: low-cost producers are more likely to be able to attract continued investment, regardless of fiscal regime design, while the presence of state-owned companies may introduce additional considerations.

Another element to this energy transition is the demand effect on the minerals needed to manufacture transition components such as electric vehicle (EV) batteries and the magnets needed for wind turbines and EV motors (IEA, 2021c). A significant expansion in the mining of key minerals such as rare earth elements, copper, nickel, lithium, cobalt, and manganese are expected, which in turn highlights the importance of fiscal settings (and geological data) that encourage exploration and the development of economically viable resources in a timely way. Those countries endowed with the minerals required could experience windfall gains but at the same time, the pressure to bring production online quickly risks rushing fiscal negotiations.

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[41] For simplicity, the FARI petroleum model is configured assuming a constant emissions intensity per unit of production. In practice emissions intensity may increase over time as reservoir pressure drops and artificial lift, and more energy intensive water handling, are required. The model could be readily modified to establish an emissions intensity time-series.

H. Value Added Tax

While fiscal regime analysis primarily focuses on taxing production and economic rents, investor and government outcomes may also be impacted by the VAT. As a tax largely borne by domestic consumers, a properly designed and implemented VAT should not affect investment decisions. This is not the case when the VAT does not function as intended.

As a domestic consumption tax collected at each stage of the supply chain, businesses generally pay VAT on inputs, charge VAT on their outputs, and remit any excess output VAT to the government. To avoid taxing investors and exporters, no VAT is charged on exports and the government refunds businesses that have input VAT credits that exceed output VAT.[42]

The often-long EI development phases require a properly functioning refund mechanism to avoid unintended costs. During the development phase, extractive companies accumulate refund credits – if they are allowed to register - because they pay VAT on inputs without generating any outputs. Extractive projects where a large share of products can be exported, are faced with a similar situation because VAT is not charged on exports. This leaves the extractive company permanently in a net credit position if the input VAT is not refunded in a timely fashion.

Delayed refunds increase project costs and can potentially distort investment decisions. During the development phase, the unrefunded or delayed refunds of the input VAT generate additional costs that need to be financed for the investor. During the development and the production phases, delayed refunds generate a present value cost due to the time value of money.

When governments struggle to pay timely refunds due to constrained administrative and cash management practices (IMF 2021d), there is pressure to reduce input VAT paid by EI companies through providing special VAT schemes, such as zero-rating or exempting company inputs. Many of these measures can cause problems elsewhere in the VAT system and among suppliers to the EI project.

The configuration of the VAT in FARI has been kept simple, with the focus on quantification of the impact of delayed VAT refunds. There are four important assumptions for modelling the VAT in FARI: (1) all production is assumed to be exported, meaning that the investor does not charge any output VAT and requires refunds on all input VAT; (2) the cost of VAT exemptions is fully borne by suppliers, unless project costs are inflated to reflect a passthrough to the investor;[43] (3) input VAT paid before the investor is registered for VAT is not captured, while, in reality, it may stick to input costs (meaning that it becomes cost recoverable and tax deductible), be eligible for a refund upon registration, or borne by the supplier; and, (4) some VAT schemes are not included in the model, such as offsets against other tax liabilities.[44]

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[42] In some countries, businesses with input VAT exceeding output VAT are not owed refunds but, rather, the business carries forward excess input VAT to credit against output VAT in future periods. This is rare in the EI, however.

[43] If a transaction is exempt from VAT, the seller/supplier does not receive a credit on the input VAT that is associated with the transaction. This increases costs for the supplier, with the burden of the cost increase borne by the supplier or/and purchaser (if the supplier can charge a higher price to reflect the cost of irrecoverable input VAT).

[44] Additional features in the FARI model used internally by FAD include scope for less than 100 percent input VAT credit; roll-up of non-credited VAT into project costs; and including VAT on the domestic proportion of sales.

Economic Analysis

The VAT does not impact the government take or investor profitability when refunds are paid immediately but can affect investor profitability and government revenue as the refund delay lengthens.[45]

Under the case of immediate refunds, the investor pays input VAT but receives an offsetting refund from the government in the same period, resulting in no net VAT paid and outcomes identical to the case of no VAT. The investor IRR declines as the refund delay lengthens, with the impact being larger for more capital-intensive projects. The reductions in investor profitability illustrate that VAT refund delays can deter investment – put another way, governments can improve the fiscal regime's competitiveness through ensuring prompt refunds (see Figure 9).

Figure 9: AETR and Investor IRR with VAT Refund Delays

Source: IMF staff. Note: 80 percent of capital costs and 50 percent of operating costs are assumed subject to VAT.

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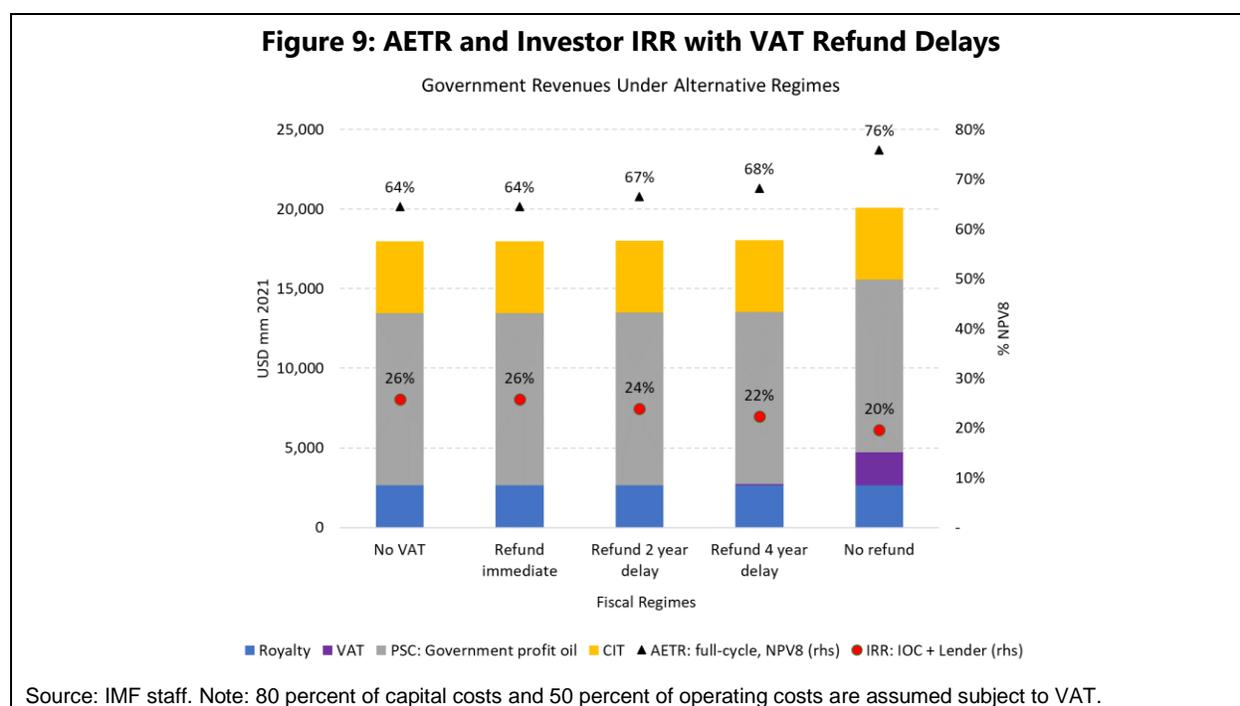
[45] Where the country policy is to refund VAT to taxpayers, VAT revenue received may be better excluded from estimates of total revenue from the fiscal regime, since it generates a corresponding refund liability.

IV.   Bringing the Pieces Together to Analyze the Overall Fiscal Regime

A. Comparing Overall Fiscal Regimes

Having discussed policy design issues for individual fiscal instruments in the subsections above, this chapter describes how multiple regimes can be compared at an aggregate level using a project example with four fiscal regimes. For the illustration in this section the gold project in the mining model is used. The project is profitable with a pre-tax IRR of 28 percent and a project NPV of nearly US$ 600 million.

Table 1 sets out the main parameters of the four illustrative fiscal regimes. The illustrative regimes and tax rates used should not, however, be inferred as reflective of current IMF policy advice to member countries (for example, the RRT uplift on negative cashflows used in Table 1 is likely to be higher than would be appropriate in many countries).
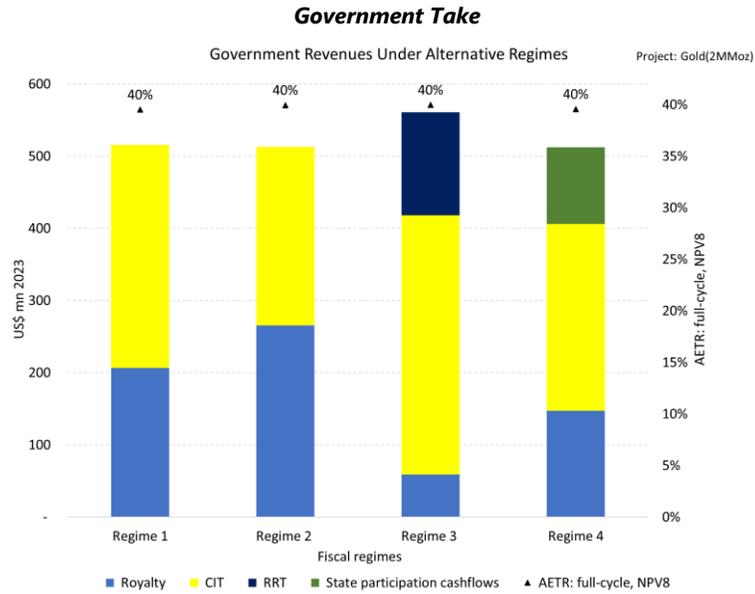
Table 1: Summary of Stylized Fiscal Regimes With Equal AETRs

Illustrative fiscal regime	Regime 1: Royalty + CIT	Regime 2: High royalty / low CIT	Regime 3: Low royalty + high CIT /+ RRT	Regime 4: Royalty + CIT + SP
Royalty rate (net, deductible)	7 percent	9 percent	2 percent	5 percent
CIT rate (straight-line depreciation over 5 years)	25 percent	21 percent	26 percent	20 percent
RRT rate (20 percent uplift on negative cashflows)	-	-	20 percent	-
State participation percentage (free equity)	-	-	-	10 percent

At a first glance, the four regimes (intentionally) provide similar results at a gold price of US$ 1500 per ounce. The AETR NPV is 40 percent for all four regimes (see Figure 10). However, using the analytical routines provided in FARI, it quickly becomes clear that the regimes result in a different sharing of risks and rewards between the investor and the government and varied impact on marginal projects and investment decisions.

For regimes 1 and 2 the only revenue streams are from royalty and CIT while fiscal regimes 3 and 4 have an additional revenue stream – the resource rent tax and the state participation, respectively. Moreover, the relative importance of each fiscal instrument varies across the fiscal regimes with, for instance, regime 2 relying heavily on the production-based royalty while other regimes have a greater proportion of take from profit-based mechanisms (government take chart). While AETR NPV is around 40 percent for all four regimes at the base case US$ 1500 / ounce gold price, undiscounted government revenues over the life of the project differ which hints at differences in the time profile of the revenue. Regime 3 has the higher undiscounted revenue, but these are relatively backloaded versus the other regimes, which can be a feature of RRT mechanisms, depending on their detailed design (see Figure 10 revenue profile chart).

Figure 10: Comparison of Illustrative Fiscal Regimes: Government Take and Revenue Profiles Over Time

Government Take

Government Revenues Under Alternative Regimes   Project: Gold(2MMoz)

Revenue Profiles

Government Revenues Including Participation   Project: Gold(2MMoz)
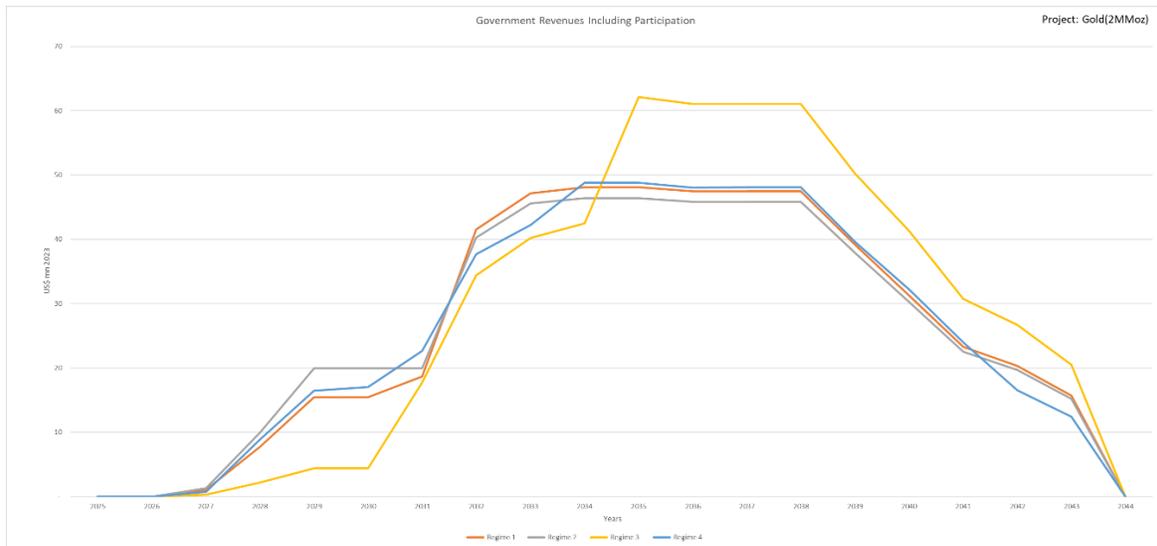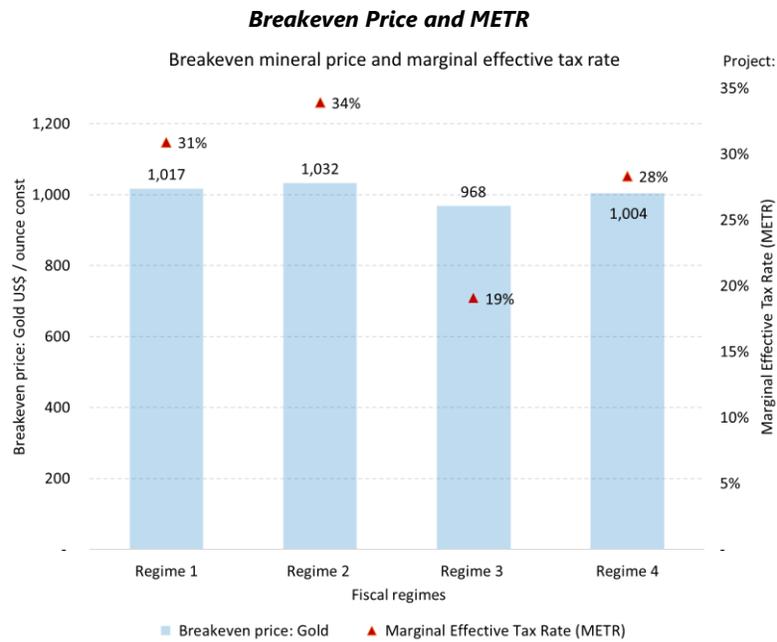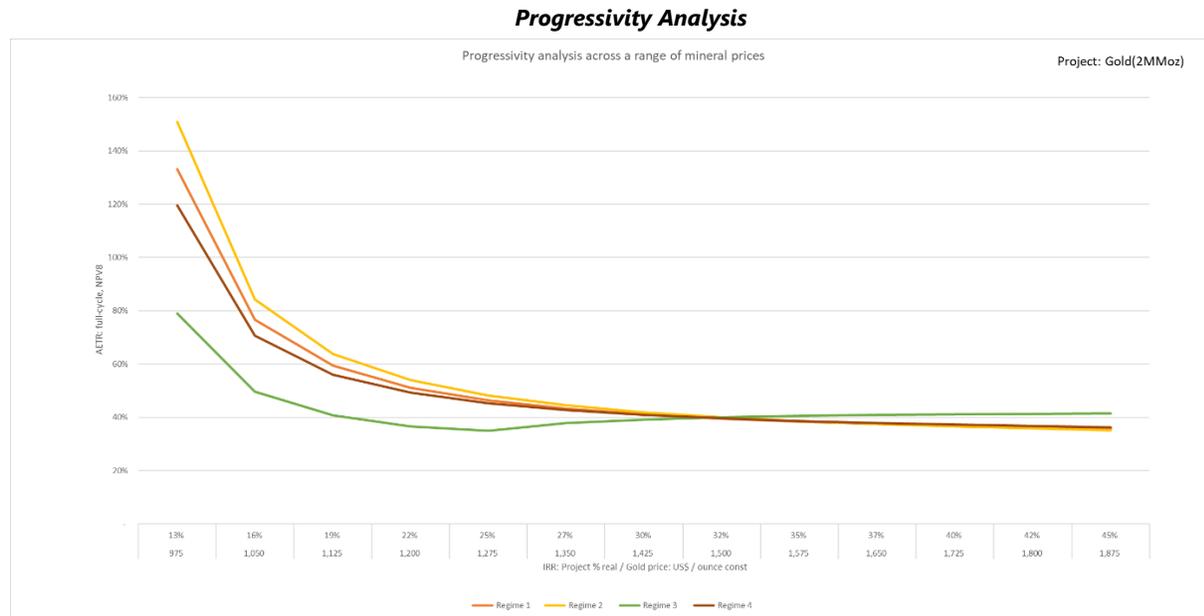

Source: Staff estimates

While all four regimes start generating revenues from the first year of production (2025), the high royalty regime (Regime 2) generates 5 times higher revenue in year four of production than the regime with a low royalty and a resource rent tax (Regime 3). In return, after the initial investment has been recovered and profits go up, the opposite is observed. From the seventh year of production onwards, Regime 3 generates the highest revenue until production ends.

The chart also shows that Regime 1 with a higher CIT rate and Regime 4 with a lower CIT combined with free equity have a nearly identical revenue profile. This, however, needs careful interpretation as the income from state participation assumes full dividend distribution by the government entity holding the equity stake - in reality, this may not occur, and the dividend policy would be an important area to clarify.

The progressivity chart (Figure 11, first panel) shows the government take over life of the project at different commodity price levels. As discussed above, a downward sloping curve is interpreted as regressive while a flat or upward sloping curve is progressive. Not surprisingly, Regime 2 with the heaviest reliance on the royalty is the most regressive. This is explained by the definition of the tax base – the value of minerals sold – which does not consider if the underlying operations are profitable. At lower commodity price levels, the royalty takes an ever-increasing share of the cash flows of the project. By contrast, Regime 3 with a modest royalty and RRT produces a relatively flat progressivity curve across a wide range of outcomes including a pre-tax IRR of only 15 percent. IMF (2018) suggests that this may be a desirable outcome, as the progressive RRT is counter-balancing the regressive effect of the royalty, resulting in a relatively consistent profile of sharing across a wide range of outcomes.

Lastly, the breakeven analysis chart in Figure 11 (second panel) shows the gold price necessary to achieve a 10 percent after tax IRR in real terms under each regime and the accompanying METR (the proportion of pre-tax return taken by the regime at the breakeven point). Regime 2 with high royalty impacts marginal projects most negatively of all four regimes with a breakeven price of US$ 1032 per ounce. Regimes 1 and 4 have a similar breakeven price at US$ 1,004 and US$ 1,017 per ounce respectively, while regime 3 has the lowest breakeven price at US$ 968 per ounce.

Figure 11: Comparison of Illustrative Fiscal Regimes: Progressivity, Breakeven Prices and METRs

Progressivity Analysis

Progressivity analysis across a range of mineral prices

Project: Gold(2MMoz)

Breakeven Price and METR

Breakeven mineral price and marginal effective tax rate

Project:

Source: Staff estimates

B. Final Comments

When comparing AETRs, progressivity curves and breakeven prices for regime across different countries, it is important to focus more on relative rankings and how regimes deal with volatility and uncertainty rather than absolute levels. Differences in level (overall AETR) need to be considered in the country context, including the maturity of the basin (in the case of petroleum), the quality of infrastructure to support operations, certainty of license tenure, fiscal stability mechanisms, and the impact these factors may have on the risk premium attributed by investors. In the end, such qualitative considerations may be more influential on investors than fine details of the fiscal regime itself.

The quality of overall fiscal regime analysis depends on both the tool used (such as FARI), and the assumptions and data available. But there are also judgements made by model users that must be transparently accounted for so that decision makers understand where there are modeling uncertainties, and that actual project outcomes will likely over- or under-perform what the model might predict. For capacity constrained governments in developing countries, in the short term it may be better to prioritize skills that enable decision makers to interrogate models built by others (e.g., models built as part of a contract negotiation), so that misleading results, errors, and overly-optimistic assumptions can be identified quickly.

The IMF continues to invest resources in further improving the FARI model and accompanying training of country officials on its use. These investments will continue as international economic and market conditions evolve (e.g., to incorporate GHG considerations). The goal for fiscal modelers remains to ensure models are as accurate and realistic as possible, without drowning users in complexity.

Looking ahead, new technologies such as generative artificial intelligence (AI) may emerge to reshape the fiscal modeling of resource projects. This may include speeding up the mechanical creation of fiscal models or extending further to providing AI-generated evaluations of resource projects and fiscal regime options. Whichever way the technology develops, some tried and trusted rules will still hold: decision makers should remain skeptical of the results or advice derived from a black box that cannot be investigated. Underlying this kind of analysis remain user preferences, fine judgements, and biases that need to be examined - and addressed - so that sound policy decisions are made on EI projects.

Annex I. Practical Guidance

This annex provides practical guidance so that a FARI model user can commence working with the model, adjust it to a specific context, and understand the underlying assumptions. To do so, the annex covers the following topics: (i) adding a new fiscal regime, (ii) adding a new project and project data assumptions, (iii) key FARI assumptions, (iv) differences between the published FARI model and the model used in IMF capacity development work, and (v) adding fiscal instruments to the model inputs and calculations.

A. Adding a New Fiscal Regime

A fiscal regime is a set of tax and non-tax mechanisms that a host country uses to raise government revenue from a natural resource project. Fiscal regime user inputs are in yellow-colored cells, located towards the top of "FiscalModel" sheet (see Annex Figure A1.1 below to the right of column J, black outline). In this section of the model, each column contains a single fiscal regime, with the regime name in row 11 and fiscal terms below. The model is pre-loaded with several fiscal regimes to illustrate different structures and inputs.

FARI can store inputs for up to 40 regimes at once but only performs calculations for the fiscal regime selected in cell C6 of "Dashboard". Using an index-match formula, the terms of the selected fiscal regime are reflected in column F (Annex Figure A1.1, red outline) of "FiscalModel" and this set of cells in column F are referenced in the fiscal calculations below. It is important that the user enters fiscal regime inputs in the yellow cells and maintains the formulas in column F, as entering inputs in column F will cause model errors.

Figure AI.1. Fiscal Regime Inputs

	E	F	G	I	J	K	L	M	N	O	P
8											
9	**Fiscal regime selection**					alternative sets of fiscal parameters					
10	Regime number		number			1	2	3	4	5	6
11	Regime name		Regime name			Royalty + CIT	RRT	DROP PSC	R-factor PSC		
12	Fiscal regime selected	Royalty + CIT	Option								
13	Selected regime number	1	Regime number								
14	TOP OF FISCAL REGIME PARAMETERS										
15	**Bonus**										
16	Signature bonus (first period of activity)	10	US$ mn			10	10	10	10		
17	Production bonus (start of production)	50	US$ mn			50	50	50	50		
18	Bonuses cost recoverable and CIT and RRT deductible	no	Option			no	no	no	no		
19	**Royalty**										
20	Royalty rate	20.00%	%			20.00%	5.00%	8.00%	8.00%		
21	Additional royalty rate above price threshold	-	%								
22	Threshold for price royalty (0 = no price royalty)	-	US$ / bbl								
23	Price threshold inflation indexed	-	Option								
24	Royalty base (net/gross)	net	Switch			net	net	net	net		
25	Royalty, CIT and RRT deductible	yes	Option			yes	yes	yes	yes		
26	**Carbon tax**										
27	Tax per ton of CO2 eq emitted in start year	-	US$ / t CO2 eq								
28	Start year of carbon tax (0=from beginning)	-	Calendar year								
29	Carbon tax in real or nominal terms	-	Option								
30	Method to change carbon tax over time	-	Option								
31	Percentage - Annual increase above inflation	-	%								
32	TargetYear - Tax per CO2 eq emitted in future year	-	US$ / t CO2 eq								
33	TargetYear - Year in which Tax reaches target level	-	Calendar year								

Source: FARI petroleum model. FiscalModel sheet.

To add a new fiscal regime, the user can simply enter the desired values into an empty fiscal regime input column (e.g., column O in Annex Figure A1.1), using a descriptive regime name as it will be displayed in the analytical routines and charts.

The next step is to ensure that the "Dashboard" sheet displays the new fiscal regime. First, enter the new fiscal regime name in cell C6 of "Dashboard" (or use the drop-down list in that cell), which causes the charts and indicators at the top to "Dashboard" to reflect the new fiscal regime. Second, add the new fiscal regime to the analytical routines by entering the name of the new fiscal regime in one of the yellow-colored cells of the top data table (Annex Figure A1.2, red outline). The data tables[46] can be updated to reflect the current selection of fiscal regimes by pressing the key "F9", while the breakeven price analysis is updated by pressing the button titled "Breakeven" in the relevant section of the "Dashboard".

Figure AI.2: Adding a Fiscal Regime to the Dashboard
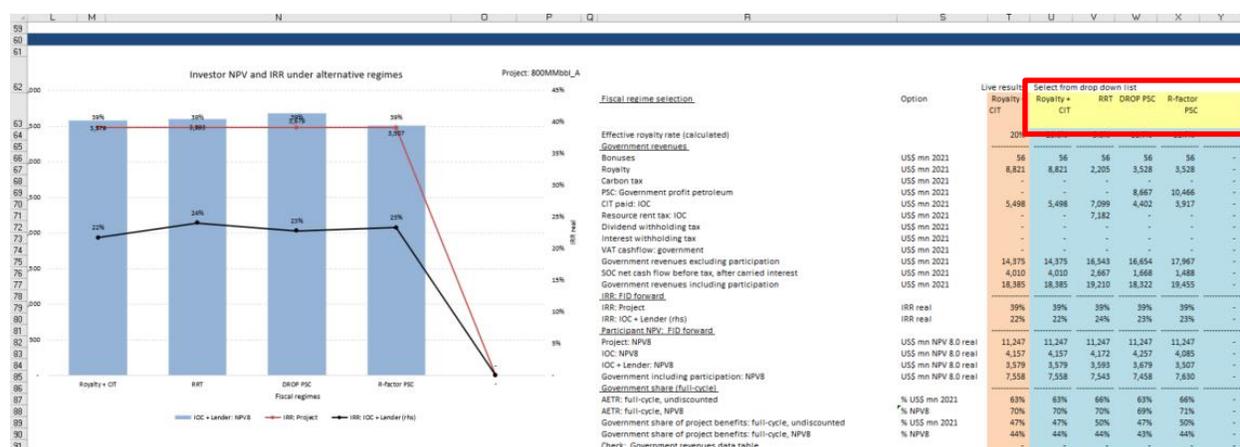
Source: FARI petroleum model. Dashboard sheet.

Fiscal regime information can be found in domestic legislation, contractual agreements, and publicly available summaries. While some contractual agreements are confidential, there is a trend to disclose more information on fiscal terms. Annex Table A1.1 lists several potential data sources, most of which can be accessed using a descriptive search on an internet search engine.

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[46] See the Microsoft support page on data tables or search for explanatory videos and description to better understand data tables.

Table AI.1: Data Sources for Fiscal Regime Information

Source	Descriptions
Resource contracts	Mining and petroleum contracts for 90+ countries.
Government websites	The host government's websites for the Ministry of Finance and natural resource regulatory agencies often have information on the fiscal regime and may include contracts.
IMF publications	IMF publications, particularly from the Fiscal Affairs Department, may periodically summarize the key features of fiscal regimes across countries. For example, IMF (2021b) summarizes fiscal regime details for mining in resource-intensive Sub-Saharan African economies.
Regulatory filings	Filings with the London Stock Exchange, US Securities and Exchange Commission, Canada Stock Exchange (under NI 43-101), Australian Stock Exchange (JORC Code) and other stock market regulators may include feasibility studies including fiscal terms.[47]
Ernst and Young Global Oil and Gas Tax Guide	Summaries of oil and gas fiscal regimes for 100+ countries. Note however it has not been updated since 2019.
Consultancy summaries	Accounting consultancy firms, such as E&Y, PWC, Deloitte, and KPMG, and others, such as Lexology often provide summaries of domestic legislation, especially when changes are made.
Company websites	Companies are increasingly publishing contractual agreements and disclosing more fiscal information in public investor presentations.

B. Adding a New Project

Project data required includes information on annual production and costs. Production is entered as a daily rate in the petroleum model (thousands of barrels of oil per day) and annual volumes in the mining model (thousands of a mineral's relevant unit). Costs are entered in millions of US dollars in real terms (i.e., constant prices) of the first model year, meaning that costs should not include the impact of inflation.

Costs are disaggregated into six categories, as different types of costs often receive different fiscal treatment (e.g., income tax depreciation) and relate to specific stages of a resource project (e.g., exploration, development, production, decommissioning). Transport (and refining) costs post-fiscal point correspond with costs incurred outside of the fiscal ring-fence (such as maritime shipping), while the other costs are those incurred within the fiscal ring-fence. See IMF 2016 for details on cost categories.[48]

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[47] The Canadian form is called National Instrument 43-101 (website), while the US and Australia feasibility studies may be located in various forms and can be found through searching the websites (US SEC, AU ASIC) or by a general internet search.

[48] The cost categories are slightly simplified as compared to IMF 2016, as the current model does not disaggregate mining operating costs or petroleum development costs.

To add a new project, copy the worksheet of an existing project (e.g., "800MMbbl_A" or "Gold(2MMoz)") by right-clicking on the sheet name, choosing "Move or Copy…" and selecting "Create a copy". Name the new project using a descriptive title for the sheet name and update the project data assumptions as necessary.

The user specifies the mineral produced in the mining model by linking the relevant cell in the project data sheet to the desired variable in "Translate" (Annex Figure A1.3, red outlines). Next, the sheet name needs to be added to project section of "Inputs", and then the user can select the project in cell C7 of "Dashboard".[49] The model assumes that user does not add any rows above the decommissioning costs row in the project data sheets and doing so will cause the model to malfunction. Lastly, the modeler will need to update the price in the "Dashboard" if the mineral was not previously included in the model.

Figure AI.3. Linking the Project Mineral

Source: FARI petroleum model. Project data sheet (left-hand side) and Translate sheet (right-hand side).

For fiscal regime analysis, it is important that the model uses project data that is representative of a project in the country being analyzed.

The FARI model has pre-loaded resource projects and fiscal regimes, all of which are illustrative and not intended to reflect a specific project or a country fiscal regime. The fiscal regimes reflect common fiscal structures and illustrate key inputs. The pre-loaded projects result in reasonable before tax profitability but, in reality, project costs and production structures vary significantly by project and will need to be adapted to a country context.

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[49] The dashboard contains inputs to vary the cost and production levels in the sensitivity section, which is directly below the commodity price inputs.

C. Key Assumptions

In addition to the fiscal regime and project data, FARI requires several inputs for economic and financing assumptions. The key assumptions, along with potential data sources, are described in Annex Table A1.2.

Table AI.2: Economic and Financing Assumptions

Variable	Sheet	Description	Data sources
Commodity price	Dash board	If available, the commodity price should reflect the long-term expected international benchmark price in real terms of the first modelled year.[50] If there is no international price, then the price can be obtained from publications focused on that specific mineral or relevant feasibility studies. As prices are volatile and difficult to predict, it is often preferable to assume that the long-term price is either equal to the current price, an average of the past several years, or a futures price.	LME, IMF, IEA, Fastmarkets
Inflation	Inputs	Inflation is used to convert project costs and commodity prices to nominal terms for fiscal calculations and then re-convert results back to real terms for key indicators and discounting. In general, the input for inflation should reflect the long-term Consumer Price Index for US dollars, as most costs and commodity prices are quoted in USD or other widely traded currencies.	US Federal Reserve
LIBOR (real terms)	Inputs	The London Interbank Offered Rate (LIBOR) was, until 2023, a benchmark interest rate and it is referred to in the 2021 models. As LIBOR is phased out, another, short-term benchmark interest rate may be used, such as the Secured Overnight Financing Rate (SOFR). A margin above the benchmark rate is assumed for carried state participation financing costs, while the benchmark rate alone is used for decommissioning provisions.	LIBOR (historic) (ICE) and SOFR (US Federal Reserve)
Discount rate	Inputs	Key indicators are calculated as net present values to reflect the time value of money (i.e., the discount rate) for the investor and/or government. This rate is entered in real terms, without any inflation component. A nominal discount rate can be converted to real terms using the formula (1 + nominal discount rate) / (1 + inflation rate) Discount rates vary by country and between the government and investor. However, for simplicity, a single discount rate is assumed for analysis. See IMF 2016 for further discussion on the topic.	NYU dataset for private investors, IMF for government borrowing rates
Hurdle rate	Dash board	The hurdle rate is used to determine the breakeven commodity price. It is the minimum return that a company requires to undertake an investment; this is usually higher than the discount rate to allow for additional risks that may not be reflected in project cashflows, as well as ensure a positive NPV when using the discount rate. As this information is inherently company-specific and often confidential, there are very few good data sources, but company presentations may quote hurdle rates.	OIES 2019 provides a summary
Proportion of devt. costs borrowed	Fiscal Model	The percentage of development costs that are funded using debt, with debt financing available as long as the project cash flows after indirect taxes and royalties remain negative.	None available

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[50] The model calculates the price received by the project by deducting the per-unit transport (and processing) costs post-fiscal point from the international price, which is inputted in the project data.

Variable	Sheet	Description	Data sources
		The public FARI model is configured assuming that any debt is provided by the parent company to its local subsidiary (and the state participant, if relevant), so that the parent is the provider of all of the funding for the project. This enables evaluation of the parent company cashflows including the benefit of debt financing, using a discount rate derived from weighted average cost of capital. The proportion of debt will vary across projects, but is generally assumed to be around 70 percent, reflecting experience from country work; to some extent driven by maximum debt to equity ratios in host countries. In practice debt may be provided by a third-party but this would likely only be possible for a much smaller proportion of the funding requirement, unless guaranteed by the parent company. The dashboard presents results for investor (parent company) and lender combined, as well as the investor alone. Breakeven prices are calculated for the aggregated parent company including the share of debt.	
Repayment period	Fiscal Model	The number of years in which the loan will be repaid, assuming to start the year after debt financing ends. It will vary based on project characteristics and could range from roughly five to fifteen years.	None available
Loan interest rate	Fiscal Model	The interest rate for the loan in nominal terms. This is project specific but should be at least a few percentage points higher than benchmark interest rate in nominal terms reflecting the project and country risk premium.	None available

D. How to Add Fiscal Instruments and Customize the Model

The published model has several simplifications to keep it relatively easy to follow and manage. To accurately capture a given country's fiscal terms, one may need to adjust fiscal calculations, such as adding new fiscal mechanisms and/or adjusting the calculations for existing mechanisms (e.g., adjusting depreciation methods or including new deductions and cost recoverable items). The following section outlines how to add a new fiscal mechanism. It is based on users having relatively advanced Excel knowledge.

First, the inputs for a new fiscal mechanism are added to the inputs section of "FiscalModel". This includes any rates and parameters to determine the tax base (e.g., depreciation rates) by inserting new rows above the lower grey row titled "bottom of fiscal regime parameters". The columns for inputs are color-coded yellow, while column F contains the index-match formula.

Once the inputs are added, fiscal calculations reflecting the specifics of the new mechanisms are added to the relevant section of "FiscalModel".[51] The exact location of the calculation depends on the type of fiscal mechanism—for instance, taxes applying to costs (e.g., import duties) or production (e.g., royalties) occur towards the top of fiscal calculation as they are often deductible for income and rent-targeting taxes as well as cost recoverable under production sharing. It is important that calculations reference the fiscal parameters in column F (not the parameters in the input columns) and include relevant reconciliation checks to protect against errors.

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[51] All fiscal calculations are located between the fiscal regime inputs and government revenue consolidation.

Lastly, the new fiscal mechanism needs to be linked to the rest of model. How it is linked to the rest of the fiscal calculation will depend on the new mechanism—for example, if the new mechanism is tax deductible, then it should be included as a tax deduction in the CIT section of the model. Additionally, the revenue from the new mechanism needs to be added to the list of revenue sources at the start of the results in "FiscalModel", any added reconciliation linked to the full list of reconciliation checks at the bottom of "FiscalModel", and the calculated revenue added to the "Charts" and "Dashboard".

Annex II. Documentation of Modeling Assumptions

A.   Project economics in baseline

Model	Petroleum	Mining	Mining	Mining
Project	800MMbbl_A	Gold (2MMoz)	IronOre (250MMt)	Coal (250MMt)
Production	800 million barrels	2,000, ounces	250,000,000 metric tonnes	250,000,000 metric tonnes
Production years	27 years	17 years	21 years	28 years
Project unit costs	US$ (2021) 38.5/barrel	US$ (2021) 723/ounce	US$ (2021) 43/dry metric tonne	US$ (2021) 39/ metric tonne
Pre-tax IRR (real)	32 percent	28 percent	14 percent	22 percent
Pre-tax NPV	US$ 9,994 million	US$ 505 million	US$ 1,113 million	US$ 1,105 million

B.   General assumptions

Model	Petroleum	Mining
Commodity price in baseline scenario	Oil US$ 55/barrel	Gold US$ 1500/ounce Iron US$ 80/dry metric tonne Coal US$ 90/metric tonne
Discount rate in real terms	8 percent	8 percent
Inflation rate	2 percent	2 percent
Real LIBOR (benchmark interest rate)	0 percent	0 percent
Decommissioning	Fund with provisioning starting at 50 percent of depletion	Fund with provisioning starting at 60 percent of depletion
Debt financing	70 percent of negative cashflows during the development period financed by a loan provided by the parent company. The loan carries an interest rate of 3 percent over the nominal benchmark interest rate and is repaid over 10 years.	70 percent of negative cashflows during the development period financed by a loan provided by the parent company. The loan carries an interest rate of 5 percent over the nominal benchmark interest rate and is repaid over 5 years.

C. Fiscal regime assumptions

Other fiscal instruments available in FARI but not listed in the table below have not been applied in the scenarios used for this paper.

Petroleum

Fiscal regime	Royalty	Carbon Tax	VAT	CIT	RRT	Production Sharing
Royalty + CIT + RRT	8 percent, net base			30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production	40 percent above hurdle rate of 15 percent with CIT deductible	
DROP PSC	8 percent, net base			30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		Cost recovery limit: 80 percent Profit oil sharing following DROP Tier 1: 20 percent DROP <= 20 kbopd Tier 2: 30 percent DROP > 20 and <=70 kbopd Tier 3: 40 percent DROP > 70 and <=120 kbopd Tier 4: 50 percent DROP > 120 and <=170 kbopd Tier 5: 60 percent DROP > 170 kbopd
R-factor PSC	6 percent, net base			30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		Cost recovery limit: 80 percent Profit oil sharing following R-Factor Tier 1: 20 percent R-Factor <= 1 Tier 2: 30 percent R-Factor > 1 and <=2 kbopd Tier 3: 40 percent R-Factor > 2 and <=3 kbopd Tier 4: 50 percent R-Factor > 3 and <=4 kbopd Tier 5: 60 percent R-Factor > 4 kbopd
R-factor PSC; carbon tax deductible	6 percent, net base	US$ (2021) 75/tonne of CO2 eq (real), recoverable for production sharing and deductible for CIT		30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		Cost recovery limit: 80 percent Profit oil sharing following R-Factor Tier 1: 20 percent R-Factor <= 1 Tier 2: 30 percent R-Factor > 1 and <=2 kbopd Tier 3: 40 percent R-Factor > 2 and <=3 kbopd Tier 4: 50 percent R-Factor > 3 and <=4 kbopd Tier 5: 60 percent R-Factor > 4 kbopd
R-factor PSC; carbon tax not deductible	6 percent, net base	US$ (2021) 75/tonne of CO2 eq (real), not recoverable for production sharing and not deductible for CIT		30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		Cost recovery limit: 80 percent Profit oil sharing following R-Factor Tier 1: 20 percent R-Factor <= 1 Tier 2: 30 percent R-Factor > 1 and <=2 kbopd Tier 3: 40 percent R-Factor > 2 and <=3 kbopd Tier 4: 50 percent R-Factor > 3 and <=4 kbopd Tier 5: 60 percent R-Factor > 4 kbopd
R-factor PSC; refund immediate	6 percent, net base		20 percent, 80 percent of CAPEX and 20 percent of OPEX subject to VAT, applicable from	30 percent, exploration costs expensed, development costs		Cost recovery limit: 80 percent Profit oil sharing following R-Factor Tier 1: 20 percent R-Factor <= 1 Tier 2: 30 percent R-Factor > 1 and <=2 kbopd

Fiscal regime	Royalty	Carbon Tax	VAT	CIT	RRT	Production Sharing
			exploration, refund immediate	depreciated over 5 years from start of production		Tier 3: 40 percent R-Factor > 2 and <=3 kbopd Tier 4: 50 percent R-Factor > 3 and <=4 kbopd Tier 5: 60 percent R-Factor > 4 kbopd
R-factor PSC; refund 2 years delay	6 percent, net base		20 percent, 80 percent of CAPEX and 20 percent of OPEX subject to VAT, applicable from exploration, refund 2 years delayed	30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		Cost recovery limit: 80 percent Profit oil sharing following R-Factor Tier 1: 20 percent R-Factor <= 1 Tier 2: 30 percent R-Factor > 1 and <=2 kbopd Tier 3: 40 percent R-Factor > 2 and <=3 kbopd Tier 4: 50 percent R-Factor > 3 and <=4 kbopd Tier 5: 60 percent R-Factor > 4 kbopd
R-factor PSC; refund 4 years delay	6 percent, net base		20 percent, 80 percent of CAPEX and 20 percent of OPEX subject to VAT, applicable from exploration, refund 4 years delayed	30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		Cost recovery limit: 80 percent Profit oil sharing following R-Factor Tier 1: 20 percent R-Factor <= 1 Tier 2: 30 percent R-Factor > 1 and <=2 kbopd Tier 3: 40 percent R-Factor > 2 and <=3 kbopd Tier 4: 50 percent R-Factor > 3 and <=4 kbopd Tier 5: 60 percent R-Factor > 4 kbopd
R-factor PSC; no refund	6 percent, net base		20 percent, 80 percent of CAPEX and 20 percent of OPEX subject to VAT, applicable from exploration, no refund	30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		Cost recovery limit: 80 percent Profit oil sharing following R-Factor Tier 1: 20 percent R-Factor <= 1 Tier 2: 30 percent R-Factor > 1 and <=2 kbopd Tier 3: 40 percent R-Factor > 2 and <=3 kbopd Tier 4: 50 percent R-Factor > 3 and <=4 kbopd Tier 5: 60 percent R-Factor > 4 kbopd

Mining

Fiscal regime	Royalty	CIT	RRT	State participation
Royalty (gross, deductible) + CIT	5 percent, gross base, CIT deductible	30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		
Royalty (gross, non-deductible) + CIT	5 percent, gross base, not CIT deductible	30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		
Higher royalty (gross, deductible) + CIT	7 percent, gross base, CIT deductible	30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		
Royalty (gross)	5 percent, gross base			
Royalty (net)	5 percent, net base			

Fiscal regime	Royalty	CIT	RRT	State participation
Price Royalty (gross)	5 percent below US$ 100/dry metric tonne, 10 percent above US$ 100/dry metric tonne, gross base			
Price Royalty (gross, indexed)	5 percent below US$ (2021) 100/dry metric tonne, 10 percent above US$ (2021) 100/dry metric tonne, gross base			
CIT only (immediate)		30 percent, exploration costs expensed, development costs depreciated over 1 years from start of production		
CIT only (3 years)		30 percent, exploration costs expensed, development costs depreciated over 3 years from start of production		
CIT only (5 years)		30 percent, exploration costs expensed, development costs depreciated over 7 years from start of production		
Royalty (net) + CIT	5 percent, net base	30 percent, exploration costs expensed, development costs depreciated over 5 years from start of production		
Low royalty + low CIT /+ RRT	5 percent, net base, CIT deductible	20 percent, exploration costs expensed, development costs depreciated over 5 years from start of production	20 percent above hurdle rate of 20percent with CIT deductible	
FE-10				10 percent free equity
CI-10				10 percent carried interest, carry repaid out of 100% of state participation cashflows, carry loan available until 10th year of production at % percent over the nominal benchmark interest rate.
WI-10				10 percent working interest

Annex III: Fostering Greater Transparency in Modeling

Adhering to transparent modeling principles is similar to agreeing to grammatical rules for a language. It increases model usability, facilitates communication and review, and simplifies the sharing of models between different owners and users (inside and outside an organization). It also helps in situations of staff turnover as the new staff can learn to "read" the model more quickly if it follows clear rules that are widely adopted by model builders.

The new FARI tools broadly follow the FAST open-source modeling standard.[52] This has helped the IMF to teach financial modeling for fiscal regime analysis and to communicate the results of advisory work to country officials. The key principles implemented in the FARI tools include:

- **Document** models with color coding key, contact details of modeler, model map and description of key functionalities, limitations and data sources.

- Follow a **consistent workbook structure** with a **dedicated input and assumption worksheet** and a **user-friendly dashboard** displaying key results, and consistent worksheet, column structure, color-coding and formatting.

- Mark **inputs** clearly.

- C**alculation blocks** increase the readability of the model. Follow the **"One row, one calculation"** rule, **calculate only once** and refer back to that calculation.

- **Minimize use of macros**, **named ranges and links** to other workbooks to **avoid "black boxes"** (where new users cannot readily see how a calculation has been performed)**.**

- **Write clear, simple formulas** and keep formulas short.

- Avoid **embedded constants** and include spaces between arguments in formulas.

- **Row anchor all links** avoid **daisy chains** (formula links that refer to further links).

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[52] The FAST Standard is outlined at: https://www.fast-standard.org/

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