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Evaluation of the Oil Fiscal Regime in Russia and Proposals for Reform

Brenton Goldsworthy and Daria Zakharova

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Evaluation of the Oil Fiscal Regime in Russia and Proposals for Reform

Prepared by Brenton Goldsworthy and Daria Zakharova[1]

Authorized for distribution by Poul M. Thomsen and Mark Horton

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Abstract

Oil revenue plays a central role in Russia's economic development. Thus, the recent decline in oil production and investment, and the possible contribution of the current fiscal regime to these developments, have prompted a reassessment of the oil tax system in Russia. Some important changes have already been made, while others are underway. This paper uses a simulation model to evaluate Russia's current oil fiscal regime. Based on these simulations, the paper proposes ways to make the fiscal regime more supportive of investment, while ensuring an appropriate share of oil sector profits for the government.

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Author's E-Mail Address: BGoldsworthy@imf.org, DZakharova@imf.org

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I. Introduction

Oil and gas receipts are an important source of export earnings and government revenue in Russia. In 2008, oil and gas exports accounted for two-thirds of all Russian exports by value, while oil and gas revenue amounted to a third of general government revenue. In addition to being a significant source of foreign exchange, oil and gas earnings play an important role in macroeconomic management in Russia.

In 2004, Russia set up an oil stabilization fund (OSF) with the objective of reducing the impact of oil price volatility on the budget and the non-oil economy. In 2008, the OSF was split into two oil funds—the Reserve Fund and the National Wealth Fund. The main purpose of the Reserve Fund was to save federal government oil and gas revenue and to use it to finance the non-oil budget deficit set in an annual budget law.[2] The National Wealth Fund was established to fund pension obligations. By the end of 2008, the two oil funds combined stood at some US$225 billion (16 percent of GDP).

The oil wealth accumulated in the oil funds was central to the authorities' response to the 2008–09 global financial crisis. Russia's relatively prudent policy of taxing and saving much of its oil wealth left it in a strong position at the onset of the crisis. Despite some weakening of fiscal policy discipline in recent years, the budget was still balanced at an oil price of just half the world market price when the crisis hit. Russia's sizable reserves, fortified by the savings in the oil funds, initially allowed the central bank to cushion the impact of the crisis by easing monetary policy. The resources from the oil funds were also used to recapitalize banks, to shore up the domestic equity market, and to jump-start credit to small- and medium-sized enterprises. The more significant use of the oil funds themselves was to finance the large fiscal stimulus in 2009 to support domestic demand. In sum, Russia would not have been able to mount a swift and substantial crisis response in the absence of oil savings.

Going forward, oil wealth is going to continue playing a vital role in ensuring economic stability and sustainability of public finances. Russia faces a number of important medium- and long-term challenges, including reducing its dependence on primary commodities to mitigate Dutch disease, while financing critical public sector reforms. Significant revenue outlays would be required to pay for a much-needed reform of pensions, as well as to finance rising healthcare costs and investment in infrastructure. Properly managed, oil wealth would be key to financing these reforms, while ensuring consistent provision of high-quality public services to generations to come.

These considerations underscore the importance of having in place a petroleum taxation regime that maximizes to the fullest extent the revenue-raising potential of Russia's oil and gas sector, while encouraging productive investment and efficient development of resources.

[2] All federal government oil revenue is saved in the oil funds. Annual budget law specifies the size of the transfer from the oil fund to finance the non-oil deficit. Until 2013, the non-oil deficit is determined annually in the budget law. From 2013, Russia's Budget Code imposes a limit on the non-oil deficit of the federal government equivalent to 4.7 percent of GDP.

And while Russia has come a long way in designing an effective framework for managing its oil wealth, it can arguably still improve on the design and implementation of its petroleum taxation regime. In particular, while a number of factors, including uncertain property rights and increasing extraction costs in maturing fields, could have contributed to low investment in the oil and gas sector and a recent decline in oil production[3], questions have been raised about the role of the current petroleum fiscal regime in these developments.

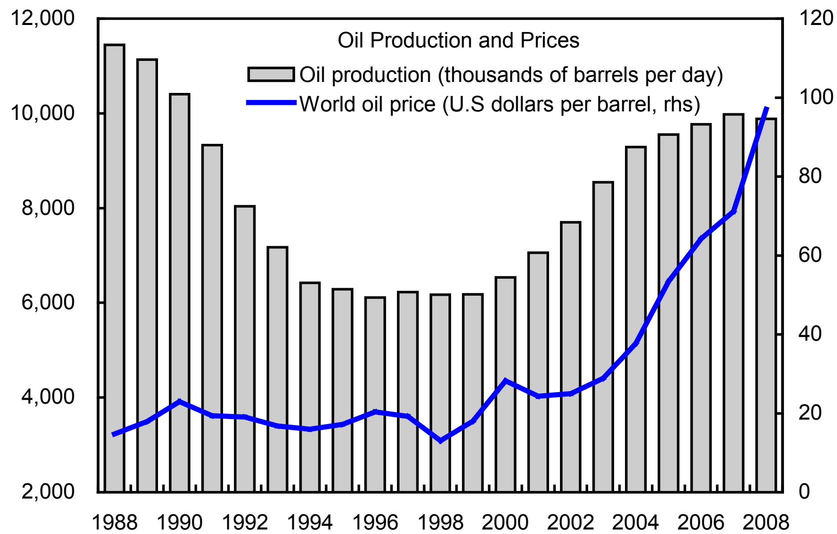
This paper uses a simulation model to evaluate Russia's fiscal regime and to suggest ways to make it more supportive of investment while still providing the government with an appropriate share of oil sector profits. Section II provides a brief overview of Russia' oil and gas sector. Section III outlines the main principles in designing oil taxation regimes and describes the current regime in Russia. It goes on to evaluate Russia's oil fiscal regime by using three oil project examples and international comparisons. Section IV reflects on other important considerations in designing and implementing an effective petroleum taxation regime, including transfer pricing and transition arrangements. Finally, Section V concludes with reform recommendations.

II. Russia's Oil Sector[4]

Russia's modern oil industry developed rapidly following the discovery of major oil reserves in West Siberia in the 1960s. Oil production peaked in 1987 at just under 12 million barrels per day (see figure). During the post-Soviet transition, oil production collapsed to about one-half of this level, as a result of under investment owing to uncertain ownership rights, domestic price controls, and soft world oil prices. Privatization and the application of modern production technology to existing fields led to a sharp reversal of this trend, with oil production climbing to almost 10 million barrels per day by 2007. The increase during 2000–07 provided over one-half of global oil production growth. Russia still has proven oil reserves of 79 billion barrels representing 6 percent of the world total and 45 percent of non-OPEC reserves.

[3] Production has increased in 2009, reflecting a one-off impact of new Eastern Siberian fields coming on stream.

[4] The source for most of the information in this section comes from the *2008 Oil & Gas Yearbook* by Renaissance Capital, the Energy Information Administration in the US, and *TNK-BP Today*.



Sources: British Petrolium, *Statistical Review of World Energy, 2009;* and IMF, *World Economic Outlook.*

However, there are concerns that oil production may have reached another peak. By 2005, oil production growth had begun to slow, and in 2008 fell for the first in many years. There are two factors at play, both of which involve an increase in production costs. First, the brownfields in West Siberia and the Volga-Urals are maturing, and while they still have many years of productive life, the process of extracting further oil is becoming more difficult and, as a result, more expensive. Second, greenfields in frontier regions, such as East Siberia and the Continental Shelf in the Arctic Sea, remain relatively underdeveloped. This is in part due to their higher cost of production since the oil fields tend to be smaller in size and technologically challenging, and the supporting infrastructure less well developed.

About one-half of Russia's crude oil production is exported. The majority of exports are transported by Transneft-controlled[5] pipelines with the remainder exported by sea, rail or road. The crude oil transported by Transneft is Urals blend—a mix of crude oils of various qualities—disadvantaging those fields producing crude oil of higher-than-average quality. The Urals blend price is closely correlated with world oil prices. Crude oil sold domestically for refining obtains a lower price, reflecting lower transportation costs and the export duty. Transfer pricing and differential taxation of upstream and downstream activities may further depress domestic upstream prices since the majority of domestic sales are between related parties: the process of privatization created several large vertically integrated companies involved in exploration, production, refining, and distribution.

[5] Transneft is a state-owned company in charge of operating Russia's national oil pipelines.

III. Fiscal Regimes

A. Principles and Design of Fiscal Regimes

A key benefit for an oil-producing country is the government revenue that is generated. It is therefore critical that the fiscal regime be designed to secure the government maximum revenue, while still providing investors with sufficient incentive to undertake exploration and development. In seeking to achieve this objective, fiscal regimes for oil tend to differ from those for non-resource sectors due to the presence of resource rents: surplus revenues from an oil field after the payment of all costs, including an investor's risk-adjusted required return on investment. Since rent is pure surplus, it can be taxed without creating distortions. Furthermore, since oil, the source of the rent, is an exhaustible natural resource that belongs to all citizens of a country, there is added pressure on the government to secure the rent for the benefit of the country as a whole.

In order to attract capital to convert the oil into financial assets, the government must ensure that the investor receives an adequate return commensurate with its risk. The production of oil is inherently risky on account of the long payback period to recover the large initial "sunk" investment and volatile prices. However, the fiscal regime can influence the sharing of risk, in addition to the sharing of rewards. For example, as discussed below, tax regimes that rely on oil revenue (rather than profit) as a tax base provide for a stable low-risk revenue stream for the government, since tax revenue accrues regardless of whether the investor makes profit. However, as this shifts more of the risk onto companies, government will most likely need to accept a lower overall expected level of taxation.[6] Some governments might therefore prefer a more progressive regime that would allow government take to vary with the project's profitability. A more progressive regime would thus involve the government assuming more risk but receiving a higher take on average. Importantly, a progressive regime will also ensure the government automatically benefits from an increase in oil prices. Depending on its risk preference, the government would face a trade off between assuming lower risk and accepting lower, but stable revenue or assuming higher risk and more revenue volatility, but receiving a higher take on average.

The risk preferences of government will vary with its fiscal health, access to capital markets, and the breadth of its portfolio of oil fields (Daniel, et al). Based on these criteria, Russia is relatively well equipped to manage risk. To the extent that Russia does take on greater risk, the investor's risk-adjusted required rate of return will be reduced, enabling the government to secure a higher government take.

A summary of the key fiscal objectives of a desirable oil taxation regime is provided in the table below.

[6] When the government and investor have different time preferences and risk attitudes, there may be some scope for mutual benefit from changing the time and risk allocation between them.

Fiscal Objectives

Objective	Description
Neutrality	Avoids investment and production distortions. The fiscal regime should not alter the order in which projects are undertaken; nor should it change the speed of extraction, decisions about reinvestment, etc.
Capture of rents	Satisfies the neutrality criterion, enables the government to share in the upside of projects, and supports the government's role as owner of the oil.
Stability and timing of revenue	Provides a stable revenue stream to government. Governments favor stable and early revenue. However, the counterpart to this goal is a transfer of risk to the investor and delayed payback. This objective should be less of a concern when there are multiple oil fields at different stages of development.
Progressivity and adaptability	Ensures progressivity. A progressive regime yields a rising government take as the project's profitability increases. A system that responds flexibly to changes in prices and costs might be perceived as more stable, lowering the investor's perceived risk of regime stability and avoiding the rent-seeking behavior associated with discretionary changes. It also ensures a low tax burden on marginal projects.
Administrative simplicity and enforceability	Supports ease of administration. To the maximum extent possible, given other objectives, the regime should be transparent and simple to administer. It should also be designed to avoid leakages through abusive transfer pricing and other tax avoidance practices.
International competitiveness	Supports competitiveness. Adjusting for investor's perceptions of country risk, the regime should be competitive with those of other countries in order to attract investment.

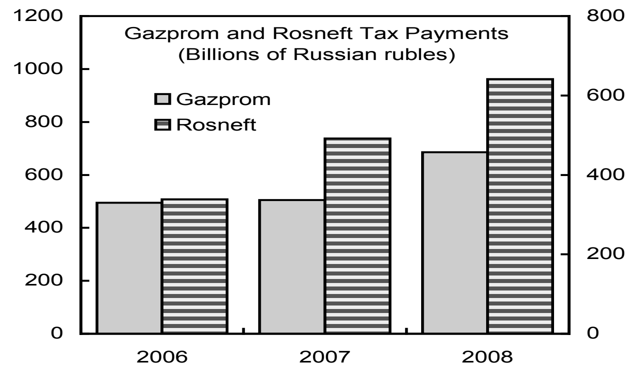
The desire to satisfy these multiple objectives has led to the use of a wide variety of fiscal instruments. As is summarized in the table below, each has its advantages and disadvantages with respect to the objectives (see Garnaut and Clunies Ross (1975) and Baunsgaard (2001) for further details). Some of these instruments use revenue or production as a base to determine tax liability (e.g., royalty, trade duties), while others rely on profit or income as a base (income and rent-based taxes).

Key Fiscal Instruments

Instrument	Advantages and Disadvantages
Royalty	A fixed fee per unit produced or a percentage of production or gross revenue. Royalties provide a minimum payment for resources used, produce stable and early revenue, and are relatively easy to administer. However, beyond modest levels they can distort investment and production decisions because they are insensitive to costs. They are regressive.
Income based taxes	Corporate income taxes are less distortionary since they are based on revenue less cost. Foreign investors appreciate the fact that they give rise to foreign tax credits. However, they are relatively more complex to administer. Revenue is also delayed: by how much depends on capital depreciation allowances, which are often made generous to attract investment (i.e., provide faster payback).
Rent based taxes	Pure rent-based taxes are neutral since payment is only required after the investor has earned its required rate of return. However, in practice rent is approximated (Appendix II). Those based on a measure of achieved return are most effective but are also the most difficult to administer. The balance of risks is skewed towards the government.
State equity	Enables the government to share in the upside and is often viewed to increase the sense of national involvement. However, "paid" equity requires the government to contribute to initial capital outlays, and often gives rise to conflicts of interest arising from the government's role as regulator.
Export duties	Not very common. Export duties are relatively easy to administer but they distort the decision of whether to sell crude oil domestically or abroad and are insensitive to costs.
Import duties	Provides revenue even before royalties due to the import needs during project development. To mitigate the negative impact on investors, full or partial exemptions are often provided.
Other	Other instruments include: signature and production bonuses; land rental payments; withholding taxes on interest, dividends, and services; and value added tax, if applicable.

Production sharing arrangements (PSAs) offer an alternative structure altogether. In the traditional tax & royalty regime, the government grants the investor a license to operate a concession for a specified period. The investor takes title to the oil and in return pays taxes and royalties set by law. In contrast, under a PSA, the company agrees to produce oil for the government in exchange for some portion of the production. There is no intrinsic reason to prefer one over the other since the two can be designed to be fiscally equivalent.[7]

Finally, state participation in oil companies is another way in which government can benefit from the oil industry. Large state-owned oil and gas companies in Russia, including Gazprom and Rosneft, are subject to the same tax regime as private-sector companies and remit dividends to the state. In 2008, the two companies accounted for almost a third of general government oil and gas tax revenue.



Sources: Gazprom; and Rosneft.

The level of taxation and its nature varies widely across countries. The level is likely to vary with country risk from the investor's perspective, since the lower the country risk the higher the level of taxation consistent with a given project exceeding the minimum required return.[8] The level of taxation might also vary with perceptions of exploration risk and the size of rent available in the event of successful exploration. This explains why a country with a proven history of commercial discoveries can command a higher level of taxation, and why taxation terms tend to be more onerous for low-cost onshore fields than higher-cost offshore fields.

Some governments may prefer production-based instruments (such as royalties) as they appear to be easier to administer since there is no need for tax administrators to audit costs and transfer pricing concerns are circumvented (see below). As discussed earlier, production-based instruments also provide earlier and more stable revenue. On the other hand, more progressive regimes could deliver a higher, if more volatile revenue stream. Moreover, the seeming simplicity of administering production-based taxes may be misleading, as companies or governments attempt to re-negotiate them over time to reflect changing production costs and oil prices, thus complicating tax administration down the road. A summary of current arrangements for selected countries is provided in Appendix 1.

[7] PSAs were first adopted by Indonesia in the 1960s as a means to maintain government ownership of resources while bringing in foreign expertise to extract the oil. Tax & royalty systems remain predominant in OECD countries. See Sunley, Baunsgaard, and Simard (2003) for a detailed discussion.

[8] Country risk is sometimes referred to as political risk, but may also encompass broader factors relating to the risk of operating in a specific country including, for example, political and legal stability.

B. Russia's Current Regime

Russia's petroleum sector is governed primarily by a tax & royalty system that relies on petroleum revenue as a tax base. Total revenue from upstream oil activity, involving exploration, recovery, and production of crude oil was 9.5 percent of GDP in 2008, over 80 percent of which came from the mineral extraction tax and export duty, with the remainder coming from the corporate income tax. There are currently only three PSAs in Russia (Sakhalin 1, Sakhalin 2, and Kharyaga) and no further agreements will be entered into under current policy. Our focus is therefore on the tax & royalty system.

Mineral Extraction Tax (MET)

The MET was introduced in 2002 to replace a number of other taxes. It is a volume-based royalty with a current base rate of 419 rubles per metric ton that is adjusted depending on the c.i.f.[9] price of Urals blend on the world markets (Mediterranean and Amsterdam) and the exchange rate:

419 rubles per metric ton * (Urals $/bbl - $15) * rubles/$ exchange rate / 261

The base rate and oil price threshold have been adjusted periodically (Appendix III).[10] As this formulation specifies production in tons and price in barrels the implicit tax rate and base are not clear. However, if it is assumed that there are 7.31 barrels per ton of production[11], the MET can alternatively be expressed in dollars as:

0.22 * barrels of production * (Urals $/bbl - $15)

Thus, the implicit tax rate is 22 percent and the tax base is the value of production in excess of $15 per barrel. Transportation costs can be deducted in calculating the base. MET payable is the same regardless of whether the investor exports the crude or sells it domestically at the lower price.

On January 1, 2007 the MET was amended to encourage investment in high cost fields in several fundamental ways. First, the rate was set to zero for new oil field developments in East Siberia for the first 10 years or the first 25 million tons of production, whichever comes soonest. Further MET holidays were subsequently introduced in three other geographic

[9] C.i.f. means cost, insurance and freight; i.e., it is priced at a specific ultimate delivery point.

[10] The need to adjust the tax system often arises when the government take is based on anticipated relationships between project profitability and proxies, such as the volume of production, rather than on actual profitability. See McPherson and Palmer (1984) for an extended discussion of this issue.

[11] The conversion factor for tons to barrels varies depending on the type of crude oil. For example, "heavy" crude oil has fewer barrels per ton. The tax is specified in tons and not barrels because this is the most common measure of oil production in Russia.

regions.[12] Second, an oil field depletion coefficient was introduced, in order to reduce the tax burden from the MET on heavily depleted fields. The base coefficient of 1 decreases by 0.035 for each one percentage point increase of depletion above 80 percent of total estimated recoverable reserves, down to a minimum level of 0.3. For example, if an oil field is depleted by 95 percent, a coefficient of 0.48 would apply (1 - 0.035 * 15).

Export Duty (ED)

The ED rate on crude oil is calculated on a sliding scale based on the c.i.f. Urals price. The marginal rates are: 35 percent for the Urals price in excess of $15 per barrel up to $20 per barrel; 45 percent for the excess over $20 per barrel to $25 per barrel; and 65 percent over $25 per barrel. The average duty rate is revised monthly based on the preceding one-month period average Urals price. Until recently the rate was revised every two months but the consequent lag between export duty rate changes and oil price created an effective duty rate in excess of 100 percent when oil prices fell sharply in late 2008. Crude oil exported to CIS countries, other than Belarus (which receives a discounted duty rate) and Ukraine, are not subject to export duties.

Separate export duty rates apply to refined products. The rate is set using discretion by the Minister of Finance but is understood to broadly follow a formula equal to the Urals price less $15 per barrel multiplied by a coefficient of 0.224 for dark oils (e.g., fuel oil) and 0.416 for light oils (e.g., petrol, diesel). The discount for refined products relative to crude reflects the higher transportation costs associated with products as well as a desire to encourage the refining industry. Since the discount is greatest for dark oils, producers tend to focus on quantity rather than upgrading refineries to produce higher quality products. Furthermore, since the discount and thus the incentive to refine domestically varies in line with the oil price, the allocation of crude between export and domestic refineries changes over time.

Corporate Income Tax (CIT)

Petroleum operations are subject to the standard CIT rate of 20 percent.[13] Both the MET and ED are deductible expenses in calculating the CIT. For purposes of depreciation, assets are allotted into 10 groups according to their assumed life: from group one (short life assets with a life of one to two years) to group 10 (life of over 30 years). Oil assets mostly fall between groups three and seven (three to 20 years). In 2009, the immediate capital investment allowance for assets in these groups was increased from 10 percent to 30 percent. Taxpayers have a choice between straight-line and declining balance methods of depreciation for most groups of assets. The loss carry-forward period is 10 years provided that the amount does not exceed 30 percent of the tax base in any tax period.

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[12] Arctic continental shelf (10 years or 35 million tons); Azov and Caspian Seas (seven years or 10 mt); and Nenets autonomous region, Yamal-Nenets autonomous region, and the Yamal peninsula (seven years or 15 mt).

[13] This is comprised of a federal rate of 2.5 percent and a regional rate of 17.5 percent. Regions have the option of reducing their rate to 13.5 percent. The CIT rate was 24 percent prior to January 1, 2009.

Other taxes

A VAT rate of 18 percent is payable on crude oil sold on the domestic market (exported goods are zero rated). VAT paid on inputs can be offset by the taxpayer against VAT received although administrative delays in processing refunds can present cash flow difficulties. Other taxes include a dividend withholding tax (9 percent for residents, 15 percent for non-residents), interest withholding tax (20 percent), unified social tax[14] (ranging from 2 percent to 26 percent of gross payroll), a property tax (up to 2.5 percent of assets), and import customs duties (ranging from 5 percent to 30 percent, although capital goods imported by Russian companies are exempt).

Summary and analysis of tax system

From the MET, ED, and CIT combined, the government receives 90 cents from each additional dollar of export earnings when the Urals oil price exceeds $25 per barrel for a field with oil depletion below 80 percent (see table). This top marginal rate of the overall oil taxation system in Russia is high by international standards and is triggered by what is now considered a low oil price.

The reliance on revenue-based instruments, and in particular the ED, is unusual by international standards (Appendix I).[15] As discussed earlier, this offers some advantages in terms of ease of administration, an early stream of revenue, and the assurance of a minimum payment for the use of resources. However, revenue-based regimes also have a number of important shortcomings. Specifically, by raising the marginal cost of extracting oil, they may deter investments in higher-cost fields, and lead to the early abandonment of productive wells. Furthermore, from the investor's perspective, such regimes postpone and increase uncertainty over when payback will be reached, leading to an increase in the perceived risk of investment. Also, multinational companies, particularly those based in the U.S. or the U.K., cannot claim tax credits in their home countries for revenue-based taxes, further raising the effective tax burden. Finally, export duties distort the choice between exporting crude or selling it to domestic refineries. These and other issues are discussed in detail in the next section.

[14] From January 1, 2010 the UST will be replaced by insurance contributions paid directly to pension, medical, and social insurance funds. The insurance contributions will be applied with a two-rate scale: 34 percent of gross payroll for yearly wages less than Rub 415,000 (about US$13,366) and nil for higher wages.

[15] It is also in contrast with the rate-of-return based approach to determining the sharing of profit oil in Russia's PSAs. See Johnston (2008) for a discussion of why the PSAs were unpopular.

Marginal Rate of Tax on Petroleum

	Oil field depletion below 80 percent				Oil field depletion of 95 percent			
	Below $15/bbl	Between $15-$20/bbl	Between $20-$25/bbl	Above $25/bbl	Below $15/bbl	Between $15-$20/bbl	Between $20-$25/bbl	Above $25/bbl
Exports								
Total	0.20	0.66	0.74	0.90	0.20	0.56	0.64	0.80
MET	-	0.22	0.22	0.22	-	0.10	0.10	0.10
ED	-	0.35	0.45	0.65	-	0.35	0.45	0.65
CIT	0.20	0.09	0.07	0.03	0.20	0.11	0.09	0.05
Domestic sale								
Total	0.20	0.38	0.38	0.38	0.20	0.28	0.28	0.28
MET	-	0.22	0.22	0.22	-	0.10	0.10	0.10
ED	-	-	-	-	-	-	-	-
CIT	0.20	0.16	0.16	0.16	0.20	0.18	0.18	0.18

Source: IMF staff estimates.

IV. Evaluation of the Fiscal Regime[16]

A. Oil Field Examples

Oil fields vary widely in terms of size, quality of oil deposits, and the cost of oil extraction. We use three oil field examples intended to represent a low cost structure for a traditional field in West Siberia, a new high cost development in East Siberia, and a very high cost development on the continental shelf (see table). The field examples are illustrative only. For the Urals oil price, we base the projections on the IMF World Economic Outlook (WTI, Brent, Dubai), which predict a steady increase in prices up to $82 per barrel by 2014.[17] Prices are assumed to remain constant in real terms thereafter. In line with recent data, one-half of oil produced is assumed to be exported.

Oil Field Examples

		Low cost	High cost	Very high cost
Oil production	Millions of barrels	742	742	742
Oil production	Years	23	23	23
Exploration costs	Millions of U.S dollars	96	153	229
Development costs	Millions of U.S dollars	4,081	6,307	11,802
Operating costs	U.S. dollars per barrel	3.5	5.9	7.2

Source: IMF staff estimates.

[16] The model used to evaluate the Russia's oil fiscal regime was developed in the Fiscal Affairs Department of the IMF.

[17] Projections as of October, 2009.

B. Application of Russia's Fiscal Regime to the Oil Field Examples

The overall tax burden can be estimated by the Average Effective Tax Rate (AETR), which is calculated as the ratio of government revenues to the before-tax net cash flow from the project, both expressed in real net present value terms (see table). The AETR is higher for the higher cost projects—the before-tax net cash flow is lower due to the higher costs, but tax payable is relatively unchanged because the ED and MET are not responsive to costs. The AETR is also higher when calculated using a 12 percent real discount rate due to the timing of cash flows: the government receives ED and MET as soon as production commences, which is prior to the project generating positive net cash flows for the investor. An AETR in excess of 100 percent at a 12 percent discount rate indicates that the project is not economical for an investor requiring a rate of return of 12 percent or higher.[18]

Summary Results

	WEO Oil Prices		
	Low cost	High cost	Very high cost
Project:			
Real before-tax net cash flow (undiscounted)	39,828	35,821	29,364
Investor:			
Before-tax real internal rate of return (IRR)	38%	27%	15%
After-tax real IRR	19%	11%	4%
Government:			
Revenue (millions of U.S. dollars)	26,617	25,481	23,868
MET	7,919	7,919	7,919
Export duty	12,138	12,138	12,138
Income tax	3,889	2,957	1,630
Dividend and interest withholding tax	2,671	2,467	2,180
AETR (NPV, 0 percent discount rate)	67%	71%	81%
AETR (NPV, 12 percent discount rate)	80%	102%	310%

Source: IMF staff estimates.

C. International Comparisons

In order to benchmark Russia's fiscal regime against international comparators, we evaluated the effect of imposing other countries' tax systems on the three oil development project examples.[19] In evaluating a project, investors will take into account the AETR, as well as the perceived risk or uncertainty surrounding the after-tax expected rate of return. The impact of

[18] A required rate of return of between 10 and 15 percent is understood to be typical in the Russia oil sector. The analysis focuses mainly on investors making a decision about developing existing fields, rather than exploring new ones.

[19] Such comparisons must be treated with care. There is always a risk that comparative terms are not correctly interpreted and modeled. More importantly, these comparisons do not take into account differences in geological risks, costs and operating conditions that may prevail in other places. This analysis merely isolates the effect of the fiscal regime, treating all other factors as equal.

the fiscal regime is therefore analyzed from a number of perspectives: (i) overall tax burden; (ii) progressivity of the system; (iii) sensitivity of the regime to the cost of extraction; and (iv) perceptions of risk stemming from price uncertainty. The analysis takes place from the perspective of an investor without operations in the country (i.e., tax consolidation benefits, if any, are not modeled).

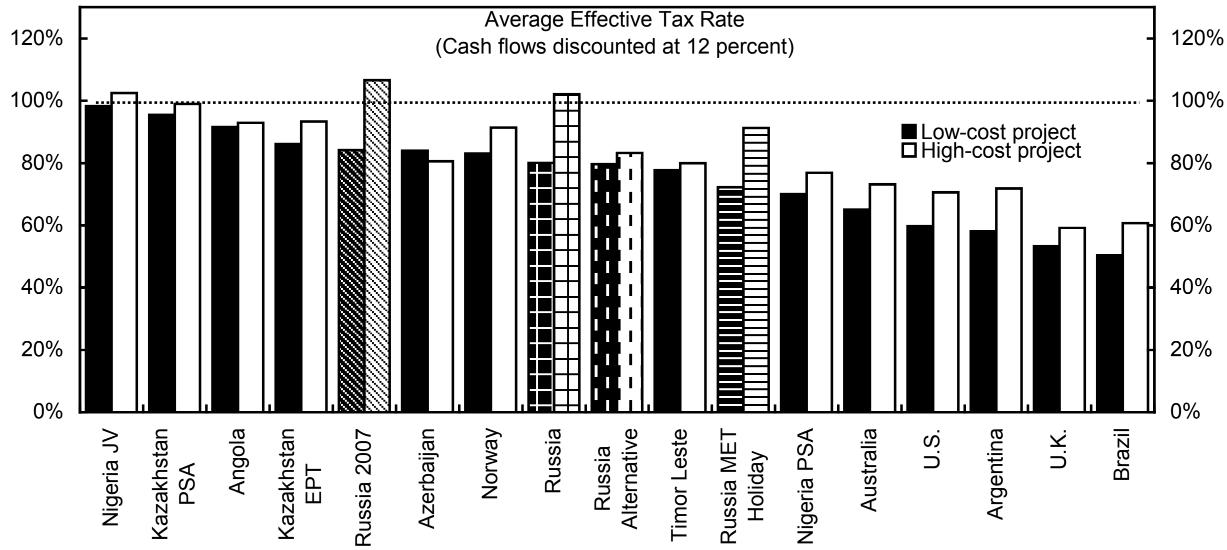
We also model the current regime for an oil field eligible for an MET holiday, the regime Russia had in place prior to 2007, and an alternative profit-based regime. The alternative regime has a similar top marginal rate and is comprised of three main elements: ad-valorem royalty, corporate income tax, and a supplementary income tax based on the R-factor.[20] The R-factor method is used for illustrative purposes. Many other suitable alternatives are available, such as those described in Appendix II. The proportion of profit-based revenue rises to almost 80 percent from 15 percent currently, but is still below some other countries, including Australia, Norway, and the UK whose regime's are fully dependent on profits. Details of the regimes in Russia and elsewhere are provided in Appendix I.

Overall tax burden

As described above, the overall tax burden can be estimated by the AETR: the "government take" from pre-tax net cash flows. For the low-cost project, the current regime gives rise to a high AETR but one that is below some other countries (see figure). The alternative Russia regime has a very similar AETR. However, the rankings are quite different for the high-cost project. In particular, the AETR is substantially higher for the current regime—reflecting very little change in government revenue (since output remains unchanged) despite lower pre-tax net cash flows—and is now above all other countries in the sample. The AETR for the alternative regime is relatively unchanged due its reliance on profit-based instruments. The very high-cost project is not economical under WEO oil prices[21] for any of the regimes; that is, if included in the figure, the AETR for all countries would lie above the horizontal line. This might change for those regimes that provide significant tax consolidation benefits, such as Norway (see below).

[20] The rate at which the supplementary income tax is applied is based on the R-factor, defined as the ratio of the project's cumulative gross receipts to the project's cumulative gross outlays. When the ratio is less than one, payback has not been reached and the rate is zero; as it exceeds one the rate becomes positive (see Appendix II for further detail).

[21] Oil price assumptions are drawn from the IMF's October 2009 *World Economic Outlook.*



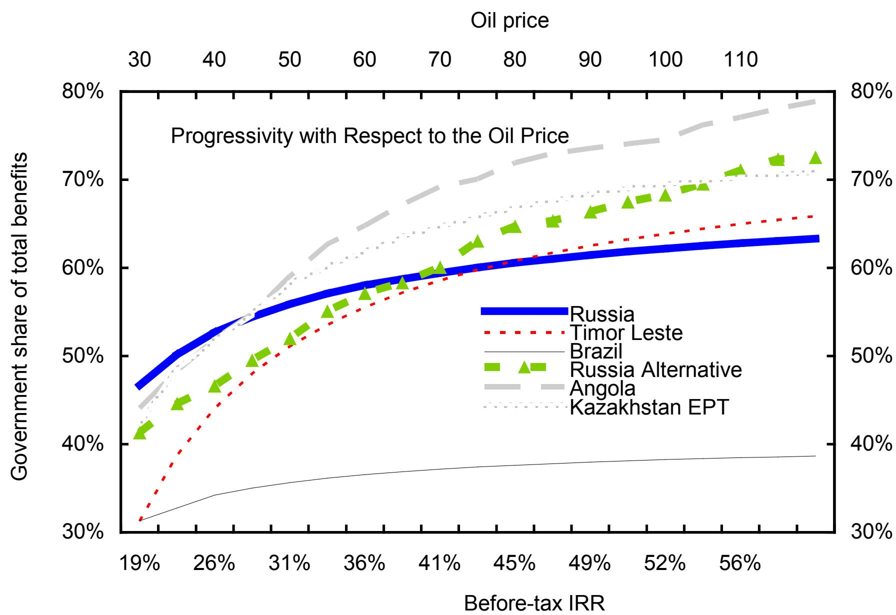
Source: IMF staff estimates.

Progressivity

Progressivity with respect to the oil price

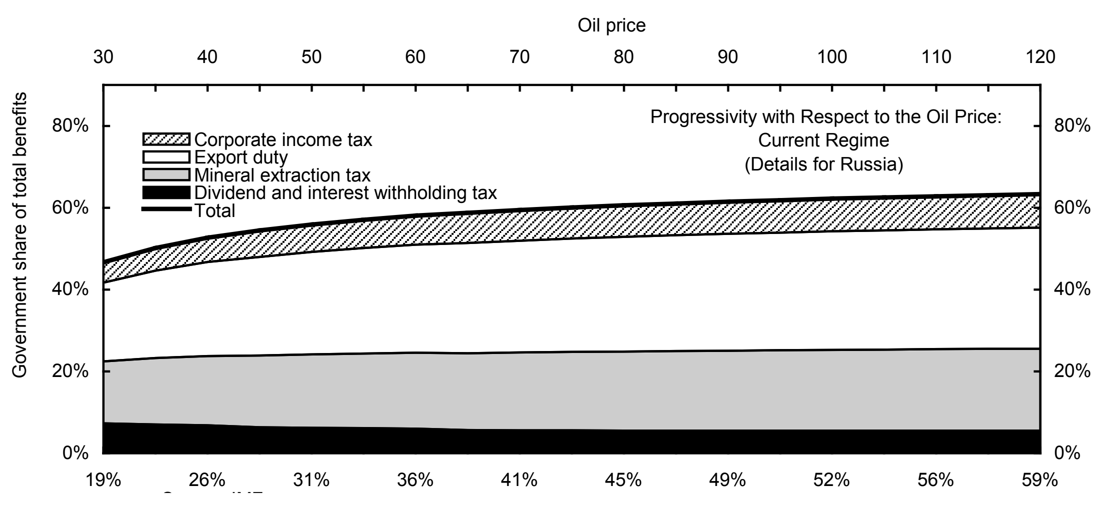
Progressivity can be analyzed using the government share of project net benefits calculated over a range of before-tax rates of return.[22] Net benefits are equal to revenues less operating costs and replacement capital—it is the "cake" from which taxes are paid, debt is serviced, and equity providers are rewarded on their initial capital investment. The variation in before-tax rates of return is first generated solely by adjusting the oil price for 2009 and keeping it constant in real terms thereafter (see figure). In a progressive regime, the government share of total net benefits rises in line with the before-tax rate of return.

[22] Progressivity can also be analyzed using the AETR. However, graphically the net benefits measure produces a clearer result.

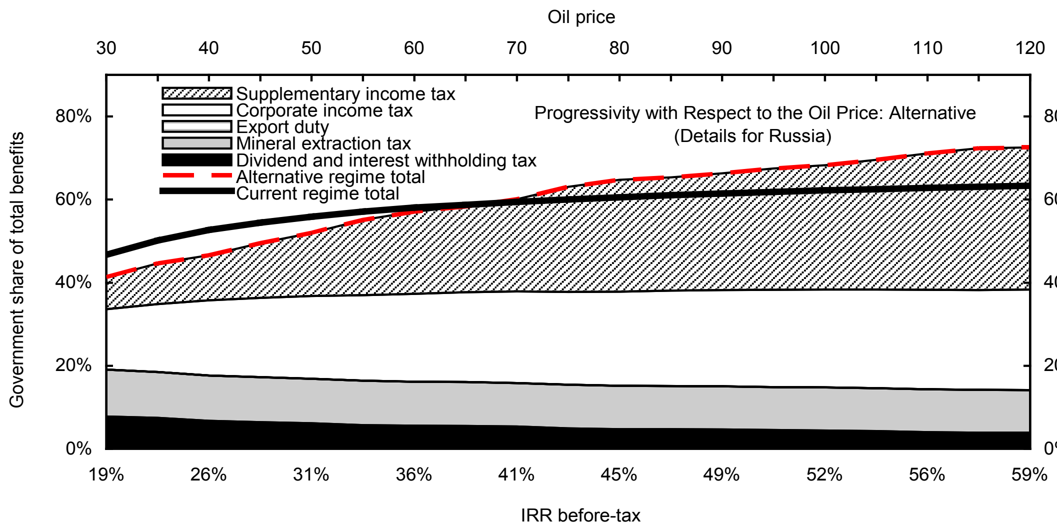


Source: IMF staff estimates.

Fiscal regimes with the highest ad-valorem royalties and traditional corporate income tax systems tend be the least progressive (e.g., Brazil). On the other hand, countries with an excess profits tax related to cash flow (e.g., Kazakhstan), a rate-of-return based approach to sharing oil under PSAs (e.g., Angola), or a supplementary profits tax (e.g., Timor-Leste) display a high degree of progressivity. Russia's current regime is also relatively progressive with respect to the oil price on account of the export duty (see figures). In the alternative regime, the supplementary income tax drives an even higher degree of progressivity.



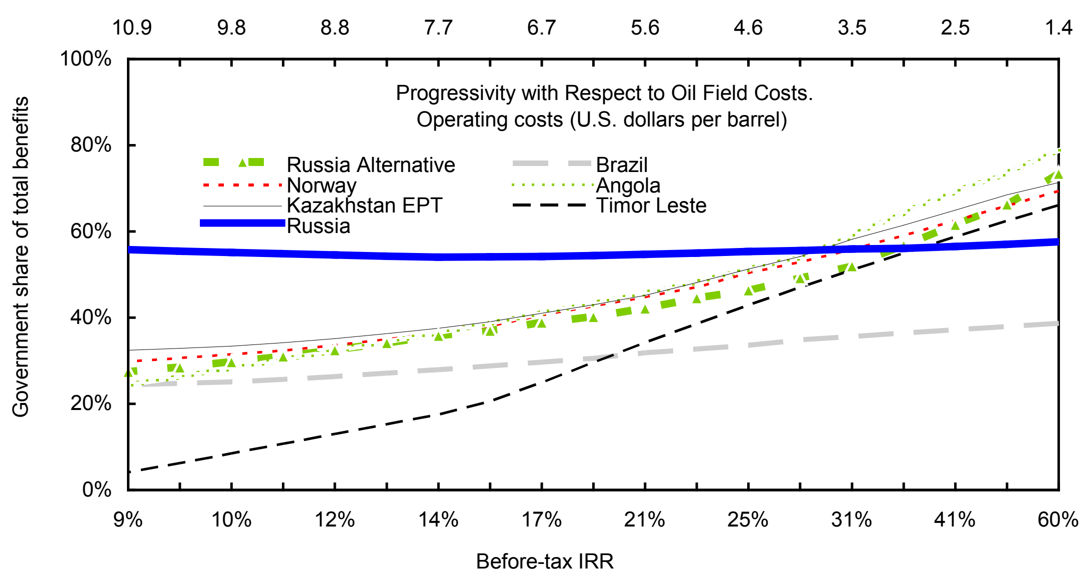
Source: IMF staff estimates.



Source: IMF staff estimates.

Progressivity with respect to oil field costs

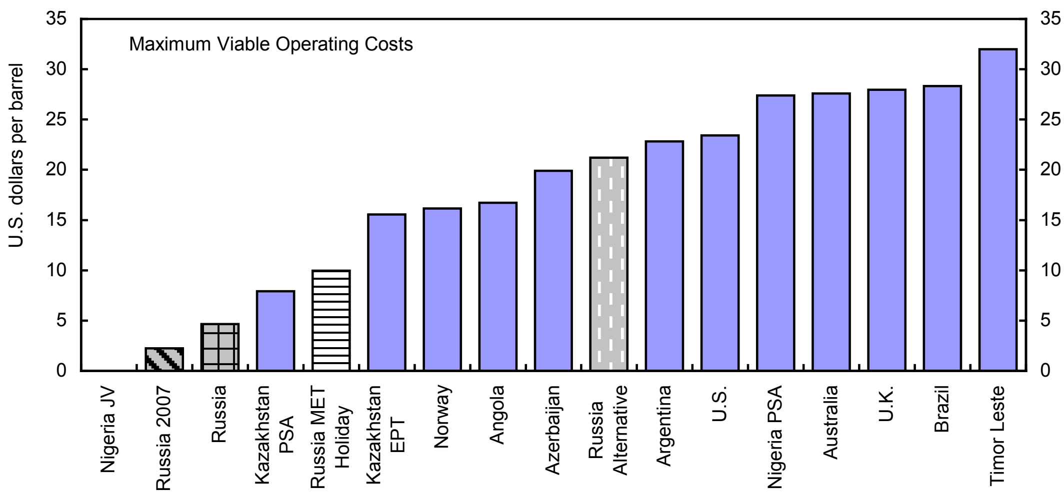
The variation in before-tax rates of return can also be generated by adjusting capital and operating costs (see figure). If the fiscal regime is largely based on profits, the results should be similar to those presented earlier, as the regime is indifferent to an increase in profit generated by higher prices or lower costs. This is broadly the case for most of the countries in the sample. However, in Russia the results are in stark contrast with the earlier results: as profits rise on account of a fall in costs the government share declines (rather than increases) owing to the dominance of revenue-based instruments as a source of revenue. The alternative regime displays the desired responsiveness to costs.



Source: IMF staff estimates.

Sensitivity to oil field costs

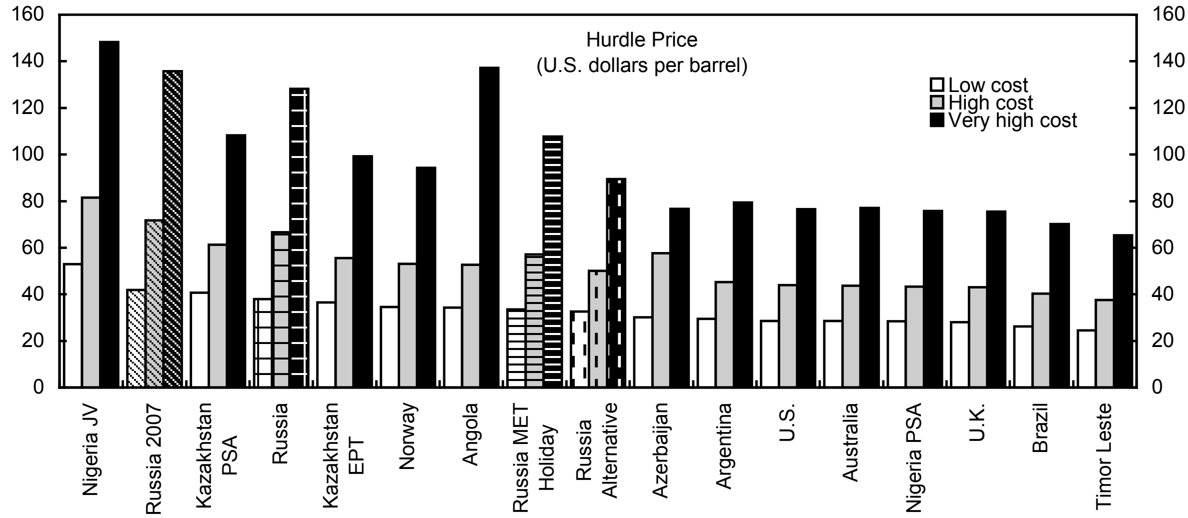
The sensitivity of the fiscal regime to oil field costs can be explored further by calculating the maximum viable operating cost that would still deliver the investor an after-tax rate of return of 12 percent (see figure). Given the exploration and development costs for the high-cost project and WEO oil prices, fields with operating costs above $4.60 per barrel are not viable under the current regime. This rises to $10 per barrel for a field eligible for the MET holiday and $21 per barrel under the alternative regime. More broadly, this analysis indicates that, in addition to the overall tax burden, regimes based more heavily on profits allow higher-cost oil fields still to be viable.



Source: IMF staff estamates.

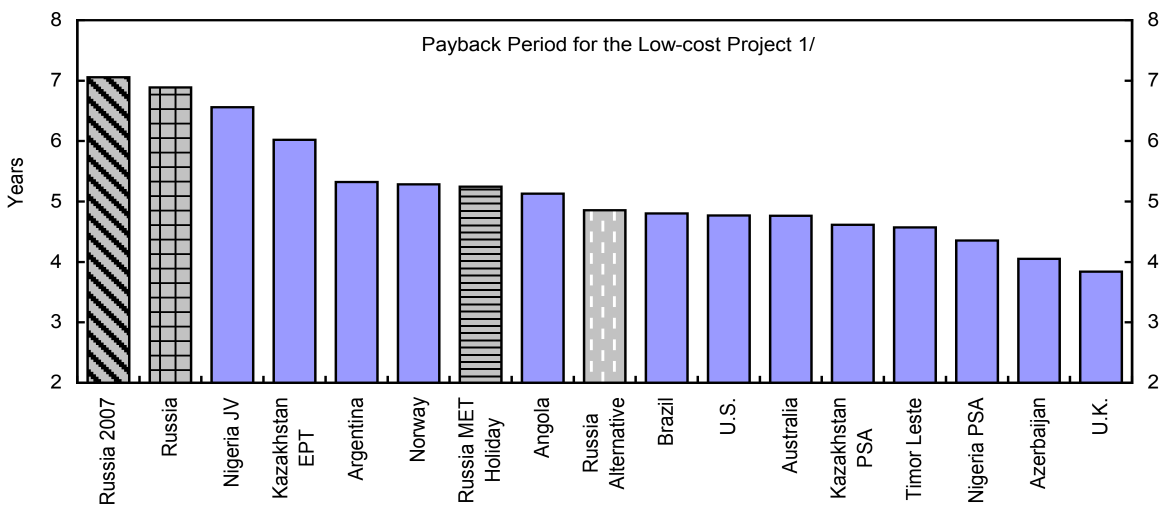
Perceptions of risk

The oil price necessary to deliver an after-tax rate of return of 12 percent—the "hurdle price"—is an indicator of investor risk as it signifies how far the oil price can fall before the investor's after tax rate of return declines to the assumed required rate (see figure). For the low-cost project, the hurdle price for Russia is below that of Nigeria and Kazakhstan. The hurdle price for a field eligible for the MET holiday is almost $10 per barrel below that of the pre-2007 regime. The hurdle price under all regimes increases considerably as project costs increase with the range varying from $148 (Nigeria) to $65 (Timor-Leste) for the very high-cost project. Russia is towards the upper end with a hurdle price of $128 or $108 with the MET holiday. The alternative regime's hurdle price is $89.



Source: IMF staff estimates.

The length of time it takes for an investor to recoup the capital outlay (the payback period) is another measure of risk (see figure). Everything else being equal, the government has a preference for an earlier stream of revenue while the investor has a preference for backloaded government revenue so as to shorten the payback period. To the extent that the government has a lower discount rate (perhaps because it is better able to diversify risks due to alternative sources of revenue), policies that delay tax revenue but produce the same overall revenue over a longer period might deliver a mutually beneficial outcome as more projects become economically viable. Such policies could include a shift from production—to profit-based instruments and the use of accelerated depreciation allowances. The payback period is particularly important in environments where the investor is concerned about fiscal and political instability. Reflecting frontloaded tax payments, the payback period in Russia is longer than elsewhere.



Source: IMF staff estimates.

1/ The high and very high cost projects provide similar rankings.

To further evaluate the effect of the regime on investor risk perception, we used a stochastic price model to simulate 500 possible future oil price scenarios, which enabled us to construct a probability distribution of before- and after-tax rates of return.[23] The table below reports the average after-tax rate of return for the investor, a measure of dispersion around this average rate, and the tax-induced probability of returns below an assumed target rate of 12 percent (regimes are ranked based on the first indicator). For the low-cost project, the three indicators are broadly in line with that elsewhere. The results for the high-cost project (and very high-cost project) support the earlier analysis. Specifically, the project becomes marginal under the current regime with a much higher probability of the return falling below the target rate. In contrast, the alternative provides the investor with better protection from volatile oil prices: it increases the mean expected post-tax IRR by a small amount while significantly reducing the tax-induced risk of negative outcomes.

International Comparison with Price Uncertainty

(Percent)

	Low-cost project			High-cost project		
	Mean Investor post tax IRR	Coefficient of variation of IRR	Tax Induced Probability of below target return of 12%	Mean Investor post tax IRR	Coefficient of variation of IRR	Tax Induced Probability of below target return of 12%
Project before tax	40	28	0	29	34	0
After tax:						
UK	31	29	2	21	38	10
Brazil	30	29	15	21	35	40
US	28	29	3	19	37	12
Argentina	27	31	21	19	37	50
Nigeria PSA	26	26	2	19	34	11
Timor Leste	25	25	1	18	29	6
Russia MET Holiday	24	31	5	15	42	29
Russia Alternative	22	26	4	16	35	21
Azerbaijan	22	23	3	17	31	14
Norway	21	26	7	15	36	25
Russia	20	30	9	13	42	39
Angola	19	23	6	14	31	22
Kazakhstan EPT	19	26	8	14	32	28
Russia 2007	19	31	14	11	45	47
Kazakhstan PSA	19	28	12	14	33	33
Nigeria JV	15	28	27	10	36	58

Source: IMF staff estimates.

[23] Oil prices are modeled as an AR(1) process with a 0.94 autoregression factor and an error term of mean zero and standard deviation equal to that observed since 1960 (see Daniel, et. al).

V. Other Considerations

Transfer pricing

The use of abusive transfer pricing for tax avoidance—payments from one part of an enterprise for goods or services provided by another at non-market prices—has long been a concern in the Russian oil sector. The incentive for this behavior is greatest in situations where the tax burden in one jurisdiction is higher than another. Alternatively, it can occur within a jurisdiction if the tax burden is higher at a particular stage in the production chain, which is typically the case in the oil sector since it is the "upstream" activity of extracting the oil rather than "downstream" activity of refining it that generates the resource rent.

To combat transfer pricing the government has relied on fiscal instruments based on volume and the c.i.f. Urals price—both of which are unaffected by transfer pricing. However, as we have seen, this has come at the cost of over-taxing oil fields that are costly to develop. Furthermore, it discriminates against domestic sellers since the MET does not distinguish between oil exported and oil sold domestically at a lower price.

Legislation and effective tax administration are other important protections against transfer pricing. The present rules in place in Russia date back to 1999 and are lax by international standards contained in the OECD's Transfer Pricing Guidelines (Ahrend and Tompson (2006)). In particular, Article 40 of the Tax Code permits transfer prices to deviate from market prices by up to 20 percent (above this amount the tax authorities are entitled to use market prices to calculate the tax base). Furthermore, the authorities are permitted to investigate the validity of prices only in specified circumstances, such as transactions between narrowly defined "related entities", or where the prices fluctuate widely within a short period. Finally, "market price" is not well defined.

Efforts are underway to bring the rules more in line with the OECD's Transfer Pricing Guidelines and to strengthen capacity to enforce the rules. Under the draft amendments the definition of related parties will be broadened significantly and the 20 percent deviation limit will be scrapped. Other key changes include defining arm's length pricing and requiring transfer pricing documentation that describes the nature of the transaction and details of the applied transfer pricing method. Advance pricing agreements, which allow the authorities and taxpayer to agree on the price or pricing method to be used in related party transactions, might also feature under the new rules.

Adjusting tax rates using proxies for costs

The Russian authorities are very much aware of the problems with a revenue-based system. So far the response has been to differentiate the MET rate based on oil field depletion and geographical location, recalling that oil fields in frontier locations tend to be smaller, more challenging, and have higher transportation costs. Consideration has also been given to extending the relief to the ED (although this poses administrative difficulties since it is not in all situations straightforward to trace exports from the pipeline back to individual fields) and taking into account additional proxies for costs, such as the size of recoverable reserves.[24] Elsewhere, Nigeria applies a royalty rate dependent on water depth, and Equatorial Guinea, Madagascar, and others use production as a proxy for profit.

Given the transfer pricing concerns, the approach adopted has been a reasonable interim measure and should help at the margin to prolong oil extraction in a given field and to stimulate new developments in the targeted regions. Nonetheless, once the new transfer pricing legislation has demonstrated its effectiveness, and capacity to audit costs more broadly has been developed, it would be opportune to adopt a profit-based system along the lines of the alternative proposed. This would ensure the tax base reflects actual costs, rather than an imperfect proxy, and in the long-run could be administratively more straightforward than assessing a large number of variables.[25]

Transition arrangements

The nature of transition arrangements to a profit-based system will be important. Given transfer pricing concerns, it is too ambitious to immediately move to such a system. Legislation to strengthen transfer pricing rules needs to be passed and staff need to be recruited and trained to enable the authorities to effectively administer the new rules. To further safeguard revenue, the new regime could be applied to new fields only, maintaining the current system for existing fields. However, this would require the strict enforcement of ring fencing rules to prevent a company from transferring profits between fields operating under the different systems. If this is deemed too difficult, an alternative option would be to make incremental changes to the current system and monitor the impact on revenue and investments. However, this too presents challenges. The road map for reforms would need to be clearly laid out to reduce uncertainty for investors, and to implement the supplementary income tax to existing fields would require assumptions about the starting point for calculations of the R-factor or other indicator (Appendix II).

Fiscal Stability

Russia's petroleum fiscal regime has been amended numerous times (Appendix III). While this reflects an understandable desire to respond to oil price and structural developments (e.g., depleted fields and exploration activities located in remote areas), the legislative approval process takes time and may promote rent-seeking behavior. Furthermore, frequent discretionary changes create uncertainty for investors, making it difficult for them to undertake medium- or long-term planning. Coupled with the lengthy payback period due to

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[24] Other possible indicators include the concentration of recoverable reserves (tonnes/km^2); the depth of the reservoir; the field's proximity to infrastructure; and, for offshore projects, water depth.

[25] As an example, the depletion coefficient is based on initial recoverable reserve estimates. An investor has little incentive to report upward revisions to recoverable reserves as this would lower the coefficient and thus increase MET payable. Furthermore, there are often multiple oil fields within an individual custody transfer point (where reliable measurement of production takes place), only some of which are depleted, which makes it difficult for the tax authority to monitor production from the depleted fields only.

the high tax burden, this will likely increase the investor's assessment of policy risks and as a consequence the project's required rate of return before it will outlay capital. A regime that has built-in flexibility avoids the need for regular amendments since the government take automatically responds to changes in underlying profitability.

Exploration, development, and production decisions

The discussion thus far has focused on whether to develop a proven oil deposit. Estimates of the AETR are an important consideration in this regard. The production decision, which occurs continuously once the investment is sunk and the investor decides if and how much to produce, depends more heavily on the marginal cost and benefit of production. The MET and ED become critical as these, unlike profit-based taxes, directly affect the marginal cost of production. Other things being equal, their imposition will tend to shorten the life of the oil field. The 2007 amendment to reduce the MET for heavily depleted fields was an important step to guard against this, although the marginal cost remains considerable.

The exploration decision places a greater weight on non-fiscal factors such as geological prospects. Nonetheless, the tax system can encourage exploration by providing the right to deduct unsuccessful exploration against income from other oil fields. Like many countries, Russia's current fiscal regime permits such consolidation for the corporate income tax but the dominance of revenue-based instruments limits the significance of this benefit. Norway has gone one step further by providing an equivalent benefit to new investors through a subsidy. Tax consolidation benefits such as these were not analyzed in Section IV.

VI. Reform Options

Russia's oil taxation regime has been successful in providing the government with very large revenue. However, the high tax burden has constrained investment,[26] with oil production declining in 2008 for the first time in many years. With the cost of producing oil in Russia likely to increase going forward—owing to maturing oil fields and the location of additional reserves in smaller, more remote, and more technically challenging fields—production may continue to decline since the current revenue-based system is particularly onerous on high cost fields.

To maintain or expand oil production over the medium term, we suggest adopting a profit-based system that is comprised of:

- A royalty, at an internationally competitive rate, levied on gross petroleum sales calculated using the actual oil sales price.

- A corporate income tax at either the current or a higher rate. Valuation of petroleum sales should be aligned with that used for the royalty.

[26] While beyond the scope of this paper, non-fiscal factors such as the lack of infrastructure in frontier locations, limited pipeline capacity, and perceptions of fiscal regime risk may also have played a role.

- A supplementary income tax calculated by the R-factor method, the resource rent tax method, or another return-based alternative (see Appendix II).

By combining elements of revenue-based tax regime (royalty) with profit-based system (CIT and supplementary income tax), the proposed regime would help the government to balance risks, stemming from inherent volatility of oil prices and profits, by providing some upfront revenue for the government, while preserving desirable features of a more progressive tax system. In particular, the analysis presented above demonstrates that such a regime could: broadly maintain the government take from highly profitable projects; expand the range of oil fields that are viable by reducing the tax burden on marginal projects; and reduce key measures of risk, such as the hurdle price, payback period, and tax-induced probability of the after-tax rate of return falling below the required rate. In addition, the flexibility of the regime to automatically respond to changing price and cost conditions will reduce the number of discretionary changes needed, and thus provide greater certainty for investors.

However, preparations to administer a profit-based regime will take time. Transfer pricing rules need to be tightened and brought in line with OECD guidelines, and the administrative capacity to enforce the rules and assess costs more broadly will need to be strengthened. To further safeguard revenue, the new regime could be applied to new fields only, maintaining the current system for existing fields. This would require the strict enforcement of ring fencing rules to prevent a company from transferring profits between fields operating under the different systems. Given the time it will take to prepare for a profit-based system, an initial set of minimal yet important reforms could be implemented sooner. This could include the following:

- Further lowering tax rates for fields located in frontier regions with higher cost of development and extraction.

- Using other proxies for costs in addition to oil field depletion and location, such as the size of recoverable oil reserves.

- Exploring whether some costs could be made deductible against the ED or MET, as a means of transitioning to a profit-based regime.

- Lowering the ED and commensurately raising the MET to make the distinction between where the crude oil is sold less important.

- Reviewing the ED rates on refined products and adopting a transparent formula to make the tax system more neutral with regard to investor decisions about the products to refine and more predictable in order to encourage investment.

Appendix I. Comparative Fiscal Regimes

	Russia	Russia 2007	Russia Alternative	Argentina	Angola	Australia	Azerbaijan	Brazil	Cameroon	Equatorial Guinea
Type	Tax / Royalty	Tax / Royalty	Tax / Royalty	Tax / Royalty	PSC	Tax / Royalty	PSC	Tax / Royalty	PSC	PSC
Signature / Production Bonus	Nil	Nil	Nil	Nil	Nil	Nil	SB & PB	Nil	PB	PB
Royalty	419 R/mt * (Urals/bbl - $15) / 261	419 R/mt * (Urals/bbl - $9) / 261	10%	12% + provincial tax of 3% on gross revenue net royalty	Nil	Nil	Nil	10%	Nil	13-16% based on production
Cost Recovery Limit	N/A	N/A	N/A	N/A	50%	N/A	100% operating and 50% capital	N/A	60%	70%
State Share of Profit Petroleum	N/A	N/A	N/A	N/A	30-90%	N/A	30-80%	N/A	20-60%	10-60%
Basis for Share	N/A	N/A	N/A	N/A	IRR	N/A	IRR	N/A	R-factor	Production
Company Income Tax Rate	20%	24%	30%	35%	50%	30%	25%	24%	40%	35%
Capital Allowance	10%	10%	10%	20%	20%	5%	Declining balance 4 years	10%	20%	20%
Loss Carry Forward	10 years	10 years	10 years	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited	5 years
Supplementary Profit Tax	Nil	Nil	0-85%	Nil	Nil	40%	Nil	10%	Nil	Nil
Base for Supplementary Tax	N/A	N/A	R-factor 1/	N/A	N/A	IRR	N/A	CIT base above a threshold level of profits	N/A	N/A
State Equity Participation	Nil	Nil	Nil	Nil	15%	Nil	10%	Nil	25%	15%
Dividend Withholding Tax	15%	15%	15%	Nil	10%	Nil	Nil	Nil	17%	Nil
Interest Withholding Tax	20%	20%	20%	Nil	10%	Nil	Nil	Nil	17%	Nil
Other	Export duty of 0-65%	Export duty of 0-65%	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil

Source: IMF staff estimates.
1/ The R-factor thresholds and rates are: < 1.5, 0%; < 2, 30%; < 3, 40%; < 4, 55%; < 5, 75%; > 5, 85%.

Appendix I. Comparative Fiscal Regimes (continued)

	Kazakhstan PSC	Madagascar	Mozambique	Namibia	Nigiera Current PSC (deep water assumed for modeling)	Nigeria Current JV (onshore assumed fo rmodeling)	Norway	Timor-Leste	UK	US
Type	PSC	PSC	PSC	Tax / Royalty	PSC	Tax / Royalty	Tax / Royalty	PSC	Tax / Royalty	Tax / Royalty
Signature / Production Bonus	SB	PB	PB	Nil	SB & PB	Nil	Nil	Nil	Nil	SB
Royalty	Nil	8-20% based on production	10%	5%	20% onshore and 0-16.7% offshore based on water depth	20% onshore and 0-18.5% offshore based on water depth	Nil	5%	Nil	17%
Cost Recovery Limit	75%	65%	65%	N/A	100%	N/A	N/A	100%	N/A	N/A
State Share of Profit Petroleum	10-90%	20-70%	10-50%	N/A	20-60%	N/A	N/A	40%	N/A	N/A
Basis for Share	R-factor and IRR	Production	R-factor	N/A	Cumulative production	N/A	N/A	Fixed	N/A	N/A
Company Income Tax Rate	34%	0%	32%	35%	50%	85%	28%	30%	30%	40%
Capital Allowance	17%	25%	25%	33%	20%	20%	17%	10%	100%	20%
Loss Carry Forward	Unlimited	7 years	5 years	Unlimited	Unlimited	Unlimited	Unlimited	Unlimited	3 years	Unlimited
Supplementary Profit Tax	Nil	Nil	Nil	15-50%	Nil	Nil	50%	22.5%	20%	Nil
Base for Supplementary Tax	N/A	N/A	N/A	IRR	N/A	N/A	CIT base less 30% uplift for capital	IRR	Modified CIT base	N/A
State Equity Participation	50%	Nil	10%	Nil	Nil	57%	Nil	20%	Nil	Nil
Dividend Withholding Tax	Nil	15%	20%	10%	10%	10%	Nil	Nil	Nil	Nil
Interest Withholding Tax	Nil	15%	20%	Nil	10%	10%	Nil	Nil	Nil	Nil
Other	Nil	Nil	Nil	Nil	Nil	Nil	No ring fencing	Nil	Nil	Nil

Source: IMF staff estimates.

Appendix II: Supplementary Income Tax

In addition to the general CIT, many tax & royalty regimes also include a supplementary profits tax in an attempt to capture a larger share of the economic rent from oil production. There are three main alternatives.[27] The simplest is a supplementary income tax of the type applied in the United Kingdom, in which a 20 percent supplementary rate is imposed on taxable income less CIT paid. Norway imposes a higher supplementary rate of 50 percent, but investment costs are "uplifted" by 30 percent over 4 years, reducing the base and ensuring that only very profitable projects are subject to this additional tax. A variant would be to use a formula that sets the rate as an increasing function of taxable income. This method is followed by a number of mineral producers in Africa.

Another option is a resource rent tax (RRT) as applied in Australia and Timor-Leste. Under the RRT, all capital and operating expenditure, but not interest, is deducted from revenues as soon as it is made. Negative net cash flows are "uplifted" by a predetermined rate intended to represent the minimum required rate of return on the project. When the accumulated negative cash flows are fully offset by revenues, the positive balance becomes taxable at the rate of RRT (i.e., the RRT is based on the concept of "resource rent" meaning the surplus return above the investor's required rate of return). When the tax is paid in any year, the balance of accumulated cash flows is set at zero for the next year so that the same cash flows are not taxed twice. The RRT can be applied after the CIT (in which case CIT paid is treated as a cash outflow) or before (in which case RRT paid is a deductible in calculating the CIT).

A third alternative is an excess profits tax (EPT) of the type applied in Kazakhstan. The tax base for the EPT is taxable income for the purposes of the CIT less the income tax liability if assessed after the CIT (the EPT can also be applied before the CIT). The EPT rate depends on the R-factor; namely, the ratio of the project's cumulative gross receipts to the project's cumulative gross outlays. When the ratio is less than one, payback has not been reached and the rate is zero; as it exceeds one the rate becomes positive and could increase when higher thresholds are met. This method differs from the RRT in that it does not take explicit account of the time value of money or required return of the investor. In PSAs, the R-factor is often used as a means to allocate profit oil between the government and the contractor.

[27] PSAs can also be designed to provide the government with a larger share of the rent by basing the portion of oil to be shared between the government and contractor on a measure of rent.

Appendix III. History of Changes in Oil Taxation 1/

	Corporate Income Tax
2000	Reduced the rate from 35 to 24 percent.
	Increased the number of expense items that became deductible.
	Increased depreciation rates and introduced a choice between straight-line and declining balance methods.
	Increased loss-carry forward period from 5 to 10 years.
	Eliminated numerous exemptions including the full and immediate deduction of capital investments.
2009	Reduced the rate from 24 to 20 percent.
	Mineral Extraction Tax
2002	Replaced existing regime of mineral resource restoration payments, royalties, and excise taxes, with the MET. The MET formula was RUB340/t * (Urals $/bbl - $8) * rubles/USD exchange rate / 252.
2004	Increased the base rate to RUB347/t.
2005	Increased the base rate to RUB400/t.
	Increased the base rate to RUB419/t to compensate for the abolition of VAT levied on oil exports to non Customs Union CIS countries.
	Increased the threshold oil price to $9/bbl.
	Raised the dollarising denominator from 252 ($8/bbl * RUB31.5/$) to 261 ($9/bbl*RUB29/$).
2007	Introduced MET holidays for new oil field developments in East Siberia.
	Introduced MET holidays for new oil field developments on the continental shelf, northern Timan-Pechora and Yamal peninsula.
	Introduced a depletion coefficient to progressively reduce the MET rate for oil fields more than 80 percent depleted.
	Export Duty
1999	Reintroduced export duties at a rate of 5 euros/t.
2000	Increased the rate to 15 euros/t.
2001	Rates set in dollars using a sliding scale based on the average Urals blend price for the two preceding months. Marginal rates were zero if the Urals price is less than $15/bbl; 35 percent for $15-$25/bbl; 40 percent for above $25/bbl.
2004	Increased the export duty by changing the schedule to its current rates: zero for less than $15/bbl; 25 percent for $15-20/bbl; 45 percent for $20-$25/bbl; 65 percent for above $25/bbl.
2008	Average rate revised monthly based on the preceding one-month period average Urals price (previously it was revised every two months based on the preceding two-month period average).

Source: *Oil & Gas Yearbook, 2008,* by Renaissance Capital.

1/ Year is from when changes took effect.

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