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Transitioning the Tax System to Take Advantage of the Natural Gas-Rich Economy in Trinidad and Tobago

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Abstract[1]

In this paper, the author examines the current structure of the tax system for hydrocarbon production in Trinidad and Tobago in light of global trends in hydrocarbon taxation. Some of the main features of the tax regime are compared and benchmarked against what the literature has defined as best practices. The author calculates marginal effective tax rates, given assumptions of oil and gas prices and changes in tax incentives, and finds that tax levels are relatively adequate from an international perspective. Some of the more recent tax incentives, although helpful in terms of cash flow relief for companies, do not make as big of a difference to tax revenues and investment plans as do, for example, changes in international conditions when considered over the long run. Moreover, given the preeminence of natural gas in the economy, the tax system could be better modified to consider the special structural features of the gas market, while still encouraging investment in other energy sectors.

JEL codes: H2, Q3, O3, Q4

Keywords: energy, natural gas, hydrocarbon taxes, production-sharing contracts, marginal effective tax rate, enhanced oil recovery, Trinidad and Tobago

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Contents

Acronyms and Abbreviations

bbl	oil barrel
CARICOM	Regular Meeting of the Conference of Heads of Government of the Caribbean Community
LAC	Latin America and the Caribbean
LNG	Liquid natural gas
METRs	Marginal effective tax rates
NGC	National Gas Company
PSC	Production-sharing contract
SPT	Supplemental Petroleum Tax

I. Introduction

Trinidad and Tobago is gradually becoming a natural gas–dependent economy, given that production changes in the past decade have transformed the output mix. Less than 15 percent of hydrocarbon production is petroleum, yet the tax system is still designed as if the country were an oil-rich economy, so oil companies pay taxes that are redistributed as compensation to the population. The discovery of shale gas in the United States and other large countries has also affected Trinidad and Tobago's global competitive edge. This shift has occurred alongside Trinidad and Tobago's longer-term economic diversification policy, whereby attempts are being made to retool the economy toward industries and activities that will enable the country to wean itself off the resource curse, which means that the global market determines the price of domestic resources.

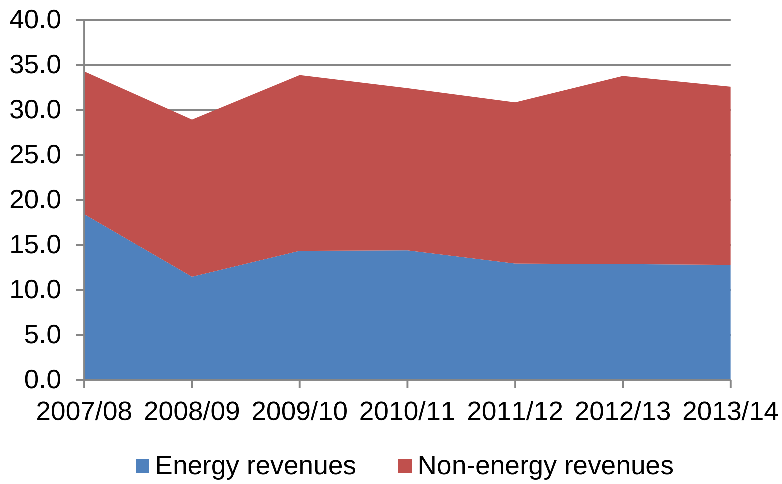
This paper examines Trinidad and Tobago's current hydrocarbon production tax structure in light of global trends in hydrocarbon taxation and considers whether the tax system's design is well suited to the country's current production structure and future development path. It compares some of the main features of the tax regime to those of other countries and benchmarks the tax regime against what the literature defines as best practices. In addition, marginal effective tax rates (METRs) are estimated for the oil and gas sector under different price assumptions.

The author finds that tax levels are not unreasonably high in Trinidad and Tobago, but could become problematic under certain price scenarios. Also, some of the more recent tax incentives, although helpful in terms of cash flow relief for companies, do not make as big a difference to tax revenues and investment plans, as do, for example, changes in international conditions. Moreover, given the preeminence of natural gas in the economy, the tax system could be better modified to consider the special structural features of the gas market while still following the government's strategy of encouraging investment in the energy sectors and other promising sectors. The currently used production-sharing contract (PSC) system, however, seems to have many beneficial features consistent with creating investment incentives.

This paper is divided into five sections. The first discusses overall tax revenues and the fiscal regime, trends in the production structure, and how the tax regime compares to those of other hydrocarbon economies. The second section discusses the features of a good hydrocarbon taxing regime, taking account of the production structure. The third describes the hydrocarbon fiscal regime in Trinidad and Tobago as of 2012 and analyzes it in light of the features discussed in the second section. The fourth section uses the METRs to evaluate the effect of some of the recent tax incentives for investment, and the fifth concludes with some recommendations.

II. Hydrocarbon Fiscal Regimes in the Context of Natural Gas Production and Diversification for Development

Figure 1. Trinidad and Tobago: Central Government Revenues (percent of GDP, fiscal years)



Source: Ministry of Finance Trinidad and Tobago.

This section discusses some of the main structural issues of the economy's production that need to be taken into account when designing a tax regime.

Trinidad and Tobago is facing short- and long-term transition challenges. In the short term, the country is recovering not only from the global recession but also from the many outages that have affected oil and gas output. Over the long term, the country faces an apparent dichotomy between diversifying the economy and encouraging investment in the oil and gas sector—the latter will eventually lead to extended benefits as greater possible or probable reserves can be classified as proven reserves, therein providing a source of income for the population. The government continues to strive to design a revenue system that will allow Trinidad and Tobago to transition to an economy that is less dependent on hydrocarbons, while also encouraging investment in this very important sector.

Government revenues still largely depend on energy. Figure 1 shows that about half of the fiscal revenues in Trinidad and Tobago come from energy sector taxes. However, this source of revenue is also the most volatile (it was only 12.9 percent of GDP in fiscal year 2013/14, but almost 18.4 percent of GDP in fiscal year 2007/08). Nonetheless, the Heritage Stabilization Fund, an intergenerational savings fund, is a well designed, very important instrument for saving the country's excess revenues. Every year, the government designs a budget that assumes a deliberately conservative price for oil and gas as well as a rule stipulating that any surplus tax revenue will be saved in the Heritage Stabilization Fund.[2] This conservative price assumption is a mechanism used by many commodity producers because prices are more likely to deviate above than below the budgeted price. Moreover, the rule to save all unplanned revenue is strictly adhered to and has led to a substantial growth of the fund. Furthermore, the government has made a deliberate decision to save more than the minimum required by the rule, despite some mild fiscal deficits. Consequently, total assets were valued at almost 20 percent of GDP at the end of 2013, almost double its value at its inception in 2007.

Small economies that are dependent on nonrenewable natural resources find it difficult to diversify. Therefore, rather than working against global market forces, Trinidad and Tobago is preparing for when it will no longer depend on oil and gas revenues. Preparing for this economic shift is a challenge, and there is a lively debate as to whether diversification is necessary and, if so, to what extent. While the pros and cons of change are beyond the scope of this paper, Box 1 discusses some key points.

One criticism of saving too much from hydrocarbon revenue in developing countries is that each country needs to set the stage for growth by investing in its infrastructure rather than saving for future generations. In Trinidad and Tobago, public investment typically does not meet budget projections because the rate of public investment execution is low as a result of weak implementation capacity. Even if public investment does not substantially increase as a percentage of GDP in the near future, if there are efforts to strengthen capacity, the conditions for greater infrastructure spending will come when the time merits it (that is, when the contribution of oil and gas to GDP begins to fall dramatically). After all, the pace of investment needs to be set by the capacity to absorb it efficiently. On the expenditure side, fuel and electricity subsidies are still generous (about four percent of GDP), and they discourage investment in energy-saving transport infrastructure. Moreover, the expenditures on subsidies could be better spent on public investment.

[2] The savings (withdrawal) rule is triggered when actual energy revenue exceeds (falls below) budgeted energy revenue by at least 10 percent. For a detailed discussion of the structure and performance of the structure and performance of the Fund see International Monetary Fund (2012).

Box 1. Does Trinidad and Tobago Need to Diversify?

Trinidad and Tobago's high dependence on hydrocarbons has sometimes sparked debate on whether the country should diversify its economy by developing other sectors. The dependence means the economy is susceptible to the resource curse, in which national (and international) booms and busts are determined by global market prices for oil and commodities. This limits policy options for smoothing fluctuations, particularly for very small, open economies, and leads to macroeconomic volatility that negatively affects investment. Moreover, one theory holds that productive resources naturally gravitate to the 'tradable' (oil and gas) sector, which further impedes diversification. And with limited proven oil and gas reserves, encouraging resource allocation into new sectors is a way to mitigate the risk of dwindling public sector resources for development.

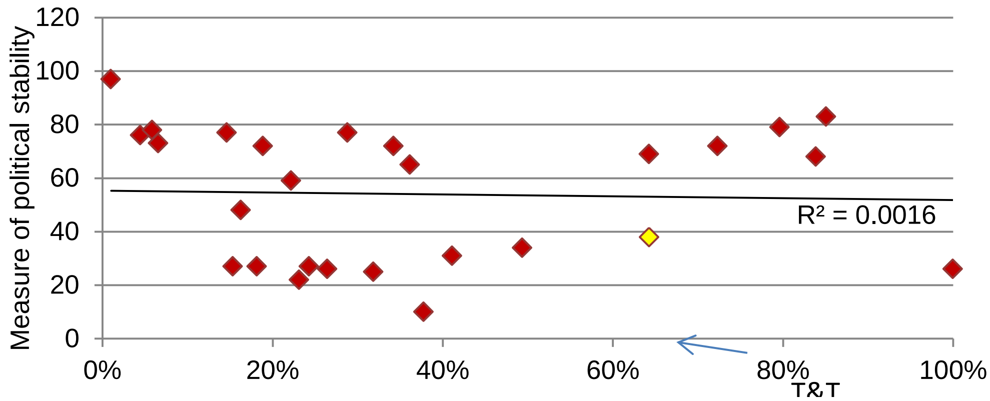
The current government's tax policies presume that the country's best strategy for long-term growth is to continue investing in the oil and gas sector. There are two reasons for this stance. First, as a small country, Trinidad and Tobago cannot immediately diversify; it takes time to specialize and become good at new and diverse activities in sectors given the economy's limited resources—the country would have to spread itself too thin at the outset. Second, many of the policy efforts help to substantially mitigate potentially destabilizing effects of the resource curse. For example, the Heritage Stabilization Fund, equivalent to more than 20 percent of GDP, was designed in part to help stabilize temporary government revenue shortfalls from lower oil and gas prices. The fund uses deliberately conservative oil and gas price assumptions when projecting budget revenues, so as revenue exceeds estimates, the resulting savings cushion is used to offset spikes in fiscal expenditures. With this practice and the very low external debt (which is smaller than the size of the Heritage Stabilization Fund), the country has considerable mechanisms to defend against external fluctuations. To protect against longer-term effects, the budget is used to redistribute oil and gas tax revenues to the population in the form of free education and a variety of generous health and social services, as well as employment programs and production-incubator services. If designed well, these programs can spur the development of innovative sectors to compete in the export market.

Moreover, the country's near-universal tertiary education opportunities strive to ensure that productive and skilled labor is available for the oil and gas sector. Within oil and natural gas areas, the workforce is particularly diverse. Firms are managed and operated by highly skilled and trained nationals who frequently export their services. The high average education levels permit nationals to thrive in other services such as welding, food processing, the arts, etc. Therefore, the economy does not have the enclave feature of other small hydrocarbon producing countries, in which foreign skilled workers are the main decision-makers, and technology and know-how does not permeate further into the local economy.

Furthermore, as argued in this paper, natural gas markets are very different from other commodity markets. The resource curse phenomenon is not the result of having a natural gas market: liquid petroleum is easier to trade and transport, so natural gas prices are set according to long-term contracts based on the necessary gas infrastructure. Trinidad and Tobago's production structure is substantially diversified within the sector, which, combined with the country's preeminence as an oil-services exporter, helps the economy diversify as much as possible. As such, calls for more investment in the sector do not necessarily contradict diversifying the skill set of workers.

Even so, it is necessary to create the right incentives for investment in hydrocarbons because investments are likely to increase the proven reserves.[3] The key questions, then, are how to maximize revenues while attracting investments and how to use those additional revenues to enhance long-term growth through the development of other sectors outside of traditional oil and gas production. Two important aspects should be considered: the general macroeconomic and political stability of the country, in particular as it manifested in the fiscal regime, and the need to take into account the growing importance of gas production—which creates different challenges than oil production.

Figure 2. Relationship Between Governance Indicators and Share of Oil and Gas Revenues on Total Government Revenues (various countries)



Source: Boadway and Keen; WBI Governance Indicators; author's calculations.

The first of these factors, macroeconomic and political stability, seems to be an important incentive for oil and gas investors. Related research (see Hvodzyk and Mercer-Blackman, 2010) shows that investors are more concerned with the whether the tax regime provides certainty and stability, in addition to the level of political stability, than with the tax take or average tax rate. Moreover, there seems to be little relation between the share of oil and gas revenue in total government revenue and political stability (see Figure 2). Therefore, the fact that Trinidad and Tobago's tax take is somewhat above average may be counteracted by the country's relatively high rank on political stability and governance. This is related to a more general global trend of preference for high cost and risky technology in an environment of political and fiscal stability. Moreover, the above research did not find that fiscal variables in the host country were statistically significant in explaining investment across companies. Political

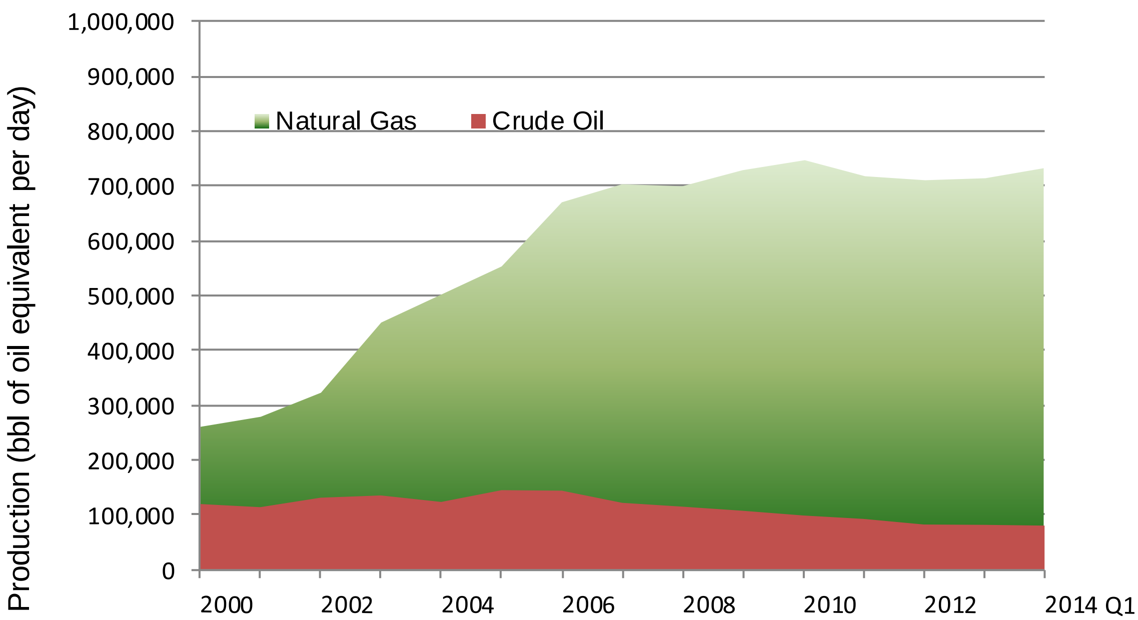
[3] Proven reserves are defined as an estimated quantity of crude oil or natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Therefore, the reserves can increase with more exploration.

stability had an indirect but negative impact on investment; fears of resource nationalism increased uncertainty about investment in a less tangible way—by diverting resources elsewhere. Results suggest that oil companies would prefer to gamble on high-cost technically risky methods (such as fracking shale gas) in a stable environment, rather than take on the necessary steps to hedge against political uncertainties.

The research also suggests that companies do not necessarily invest less in countries in which the share of government revenues from oil and gas as a share of total revenues (a proxy for the tax take) is high. Trinidad and Tobago in general has an average to above-average tax take when compared with other oil and gas producers. Taking into account the relative stability of the political regime and the low probability of expropriation likely makes it a more attractive place to invest relative to other countries.

Many countries offer investors tax stability clauses, but in light of the many renegotiations needed over the past decade, as oil prices reached unexpectedly high levels, the process in which these contracts were negotiated turned out to be important. There are risks to the investor and the government (in terms of stability and timing of government revenue, for example). It is important to not design these clauses too rigidly but rather to include contingent

Figure 3. Trinidad and Tobago Oil and Natural Gas Production, 2000–2014



Source: Ministry of Energy and Energy Affairs.

clauses that allow some form of renegotiation in the event of an abrupt or very large change in resource prices. The contract should specify how the taxes would be renegotiated under such circumstances.

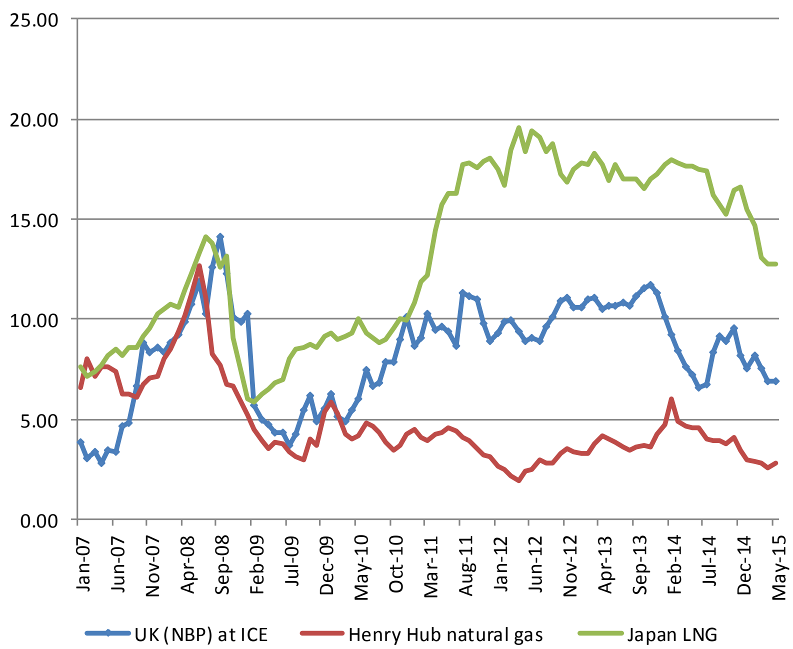
Another important aspect related to designing a tax regime is the increased share of gas production in hydrocarbons over the past decade (see Figure 3). This trend has complicated the choice of an appropriate tax regime, given the peculiarities of the gas market. About 40 percent of the natural gas produced in Trinidad and Tobago is used as an input in the petrochemical sector.[4] Although the exploration and production aspects resemble oil (given that deposits are generally found in the same places, and many skills required for extraction are similar), the distribution and demand markets are very different. Moreover, many of the exploration companies use both oil and gas and are global companies. Most gas export sales are based on long-term (20–30-year) contracts, and the terms-of-sale agreements reflect numerous factors (for example, tariff levels charged by the bearers of the shipping, regasification, and pipeline costs in addition to those set by jurisdiction rules). In contrast, oil is sold in well-developed spot markets where prices are global and can change almost instantly. Most importantly, because gas cannot be readily transported internationally, it is a segmented market, with prices dependent on the specifics of the relevant local market. Figure 4 shows that the range of gas prices across the world seem to have no relation whatsoever. The markets are completely segmented.

The fiscal regime in Trinidad and Tobago updates some tax rates but may soon need to be modified to reflect the importance of natural gas globally for three reasons. First, shale gas extraction and new fracking technologies will reduce demand for liquid natural gas (LNG) from major markets (including the United States and China).[5] Second, the demand from Latin America and Caribbean countries could potentially expand, not only for natural gas but also for products such as cheap electricity and fertilizers that use natural gas as feedstock. Last, there is global pressure for more transparency, which may allow governments to obtain better estimates of the resource rents different companies receive for the extraction of natural gas. At the

[4] Unlike oil, the natural gas sector is dominated by a powerful and profitable state company, NGC. As a monopsony with an increasingly large influence on all aspects of the gas economy, the NGC provides the entire feedstock used by Trinidad and Tobago's downstream petrochemical sector, which is one of the largest world exporters of urea and methane. The company partly owns Atlantic LNG, the LNG-exporting terminal that has some of the lowest operating costs in the world. Moreover, NGC has equity investments in some of the most important new projects: (i) it now owns 100 percent of Phoenix Park Gas Processing Limited, one of the largest gas-to-liquid processing plants in the western hemisphere; (ii) it has an equity stake in the Eastern Caribbean Pipeline project and the Gasfin project to set in motion medium-scale natural gas regasification floating barges for exporting gas to other Caribbean islands; (iii) it is the sole source of fuel for the country's electricity sector; and (iv) it fully funds the country's compressed natural gas projects.

[5] Demand for Trinidad and Tobago LNG from the United States has already declined. Trinidad and Tobago has diverted US shipments to higher priced markets, but low prices and high uncertainty will affect investment. Fracking and increased tradability of natural gas may also affect determination of prices, which were originally linked to Henry Hub prices, so relatively correlated to oil prices.

Figure 4. Trends in Natural Gas Spot Prices at Major Global Markets (in dollars per million BTUs)



Source: US Energy Information Agency; ICE; Quandl.

moment, very few countries disclose the terms of their production-sharing agreements with oil and gas companies.

However, over the medium term, gas may allow Trinidad and Tobago to become less vulnerable to fluctuating commodity prices, a feature that is typical of solely oil-dependent economies. Gas prices tend to be more stable than oil prices given that the demand for oil is mostly for transportation use. Although oil demand fell drastically in the last year, it is likely to bounce back barring an unforeseen large technology change in transport fuel. China alone produced almost 20 million cars in 2014, mostly for domestic consumption, and although demand may have cooled at the start of 2015, forecasters still expect China's automobile market to reach an annual production rate of 30 million cars by end-2020. In contrast, although demand for natural gas (buoyed by power generation) is also expected to increase strongly, according to the International Energy Agency, natural gas supply will increase its share of the global energy mix, growing at 2 percent per year until 2020.

The low prices of natural gas in the United States could also affect the petrochemical sector indirectly because the Untied States may reduce its demand for imported methane and urea from Trinidad and Tobago and produce its own. Therefore, natural gas prices in Trinidad and Tobago have to be offered to the petrochemical sector at competitive prices so that the methane and urea industry can stay internationally competitive.

Given the tax structure of oil and gas production in Trinidad and Tobago, the next section looks at the suitability of the current tax regime design to the new structure of the oil and gas sector in Trinidad and Tobago.

III. The Tax System in Trinidad and Tobago

III.i What to Look for in a Good Hydrocarbon Tax System

Taxing nonrenewable resources is different than taxing the production of goods, because resource extraction essentially means the country is depleting a national asset (given the exhaustibility of the natural resource). Therefore, a greater proportion of the revenues from hydrocarbon taxes should be put into national savings compared to tax revenue from consumer goods. In this regard, the Heritage Stabilization Fund and the decision about the optimal rate of extraction given the country's circumstances are an integral part of the overall policies of intergenerational savings and the role of hydrocarbon resources (as discussed earlier). In addition to this principle, five main aspects need to be taken into account when taxing hydrocarbon resources:

1. *High sunk costs and long production periods*. Each of these makes it very difficult to calculate, ex ante, the appropriate non-distortionary tax. The problem does not arise from duplicity or ill will on the part of government or investors; it simply reflects the general principle of efficient tax design that tax rates be set in inverse relation to the elasticity of the underlying tax base. The fundamental difficulty is simply the inability of the government to commit in advance to apply the optimal scheme at the outset, given that once the hydrocarbon is discovered, the optimal practice is to set very high taxes.

2. *The prospect of substantial rents*. This issue emerges when a government is trying to decide on the royalty tax rate. According to good tax principles, an efficient tax regime should tax resource rents, not quasi-rents. The full cost of resource exploitation also includes the cost of unsuccessful exploration. Therefore, if the full rent was applied for unsuccessful exploration as well, exploration would be inefficiently low. Consequently, royalties can be discounted as a cost for the purpose of charging other taxes.

3. *Uncertainty over a very long horizon, which makes planning difficult for investors and governments*. There is uncertainty about the geology of the home country and uncertainty over external conditions, as reflected in volatile prices (which, in part, may reflect the geology of other countries). The discovery of shale gas is an example of a change in world gas markets that was completely unanticipated only three to four years ago and that changed the perception of investors in Trinidad and Tobago.

4. *International considerations.* The effective rate of taxation on any project depends not only on the tax system in the host country, but also on tax rules in the home country of the

investing firm, the home countries in which owners of the investing firm reside, and so forth. This has to be considered when setting the profits tax rate, in particular. This is complicated by extensive transfer pricing practices done by international oil companies (although transfer pricing is less of a problem for oil because many prices of the commodity and the oil services are set using international benchmarks).

5. *Asymmetric information*. The government is likely to be at a severe informational disadvantage in relation to the resource extraction companies. Some of this imbalance can be mitigated by hiring experts internationally to conduct surveys, but the host country will only partially understand the incentives, benefits, and constraints of international hydrocarbon investors.

In addition to the specifics of oil and gas exploration in terms of designing a good tax system, the literature has defined other factors as important (for example, see Boadway and Keen, 2010). Designing tax regimes for extractive industries is difficult because governments know these rents are not permanent. One has to consider the following:

- The relaxation of source tax attracts investments but results in loss of revenues.
- A well-designed tax system should also enhance transparency.
- Rent taxes should be kept simple (and rent should be charged on anything with a fixed supply).
- Governments should strive to make the system neutral (that is, taxes should not affect decisions of exploration, abandonment, and timing).
- In theory, the system should tax oil as a resource rent.
- The global downward trend of corporate income taxes resulting from capital mobility has also been evident in recent years for natural resources. Even though the resource is immobile, income received from the resource is mobile, which makes it more price elastic. If a jurisdiction has a relatively high corporate tax, companies may settle in jurisdictions with lower corporate tax rates. Given the global nature of oil companies, tax rates in Trinidad and Tobago also have to adjust to global factors.

III.ii Considerations Specific to Natural Gas

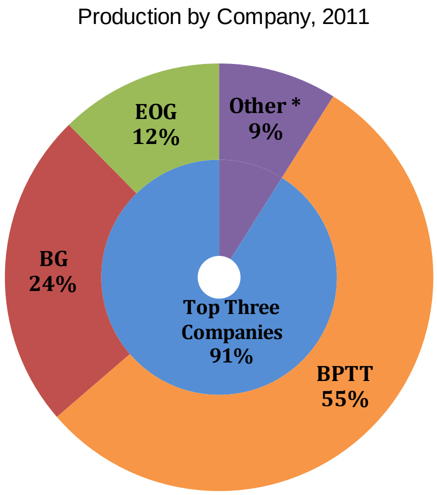
Even more complicated tax considerations pertain to natural gas. The premise behind this complication relates to the difficulty of attributing production costs in the financial accounts to oil and gas (such as maintenance costs). Moreover, not having specific price terms in spot markets makes the government's job difficult. Also, supplemental gas is sometimes less profitable, so it is unusual for natural gas sale contracts to offer parity with oil; sometimes there is a 28 percent discount. Trinidad and Tobago, similar to a few other countries (such as Egypt, Indonesia, Malaysia, and Nigeria), tries to take this into account by exempting gas from certain taxes.

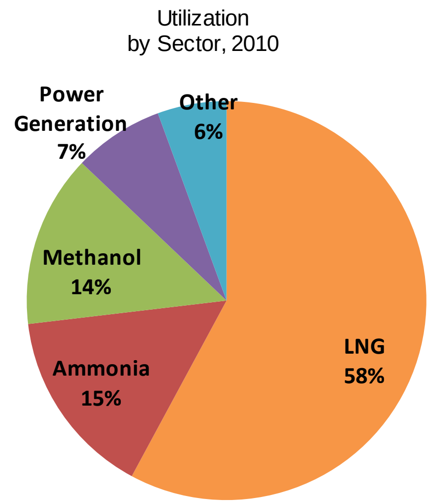
There is another complication for tax designers, which relates to the structure of the natural gas market. Natural gas by definition is a very uncompetitive industry in the domestic market of Trinidad and Tobago. Figure 5 shows the natural gas production and utilization profile. Other than natural gas exported as LNG—which, to some extent, can compete in international markets—natural gas for local domestic consumption is difficult to price. There is a monopsony in purchasing by the publicly owned gas distributor, National Gas Company (NGC), which purchases the gas from oil producers at a price likely equivalent to what the Atlantic LNG terminal receives. Then, NGC distributes to buyers, the majority of which are petrochemical companies. At what price should NGC buy from gas-producing companies, and at what price should it sell to exporters and downstream? NGC sells at a premium that sometimes could be twice the original price. When this is the case, the tax could be considered as a hidden tax on natural gas.

The economics literature offers very little guidance on recommending the appropriate price for natural gas in Trinidad and Tobago. The domestic market is too small, too heavily subsidized, and too diversified to allow willingness-to-pay calculations. The lack of transparency or uniformity in contracts makes this challenge worse. The Ministry of Energy commissioned a Natural Gas Master Plan in 2014 to review and, if necessary, reconsider the structure of the country’s natural gas market and pricing in the medium term.

Even assuming an adequate price for natural gas can be set, the government of Trinidad and Tobago should consider their taxes against international comparator benchmarks, and then add a premium to the sale price that includes the distribution costs, a fair rate of return, and a posted tax. This is particularly important given the country’s desire to develop a thriving downstream sector. It is important to give as much certainty as possible to domestic end-users. One possibility is to follow the guidelines set by the United States Federal Energy Regulatory Commission, which offers ways for utility regulators and states to calculate pricing at different planning stages and at a fair rate of return. Trinidad and Tobago should establish taxation on the basis of reasonable gas prices. After all, the petrochemical sector (which buys most of the country’s natural gas) competes with other exporting countries, including the United States.

Figure 5: Trinidad and Tobago Production and Distribution of Natural Gas





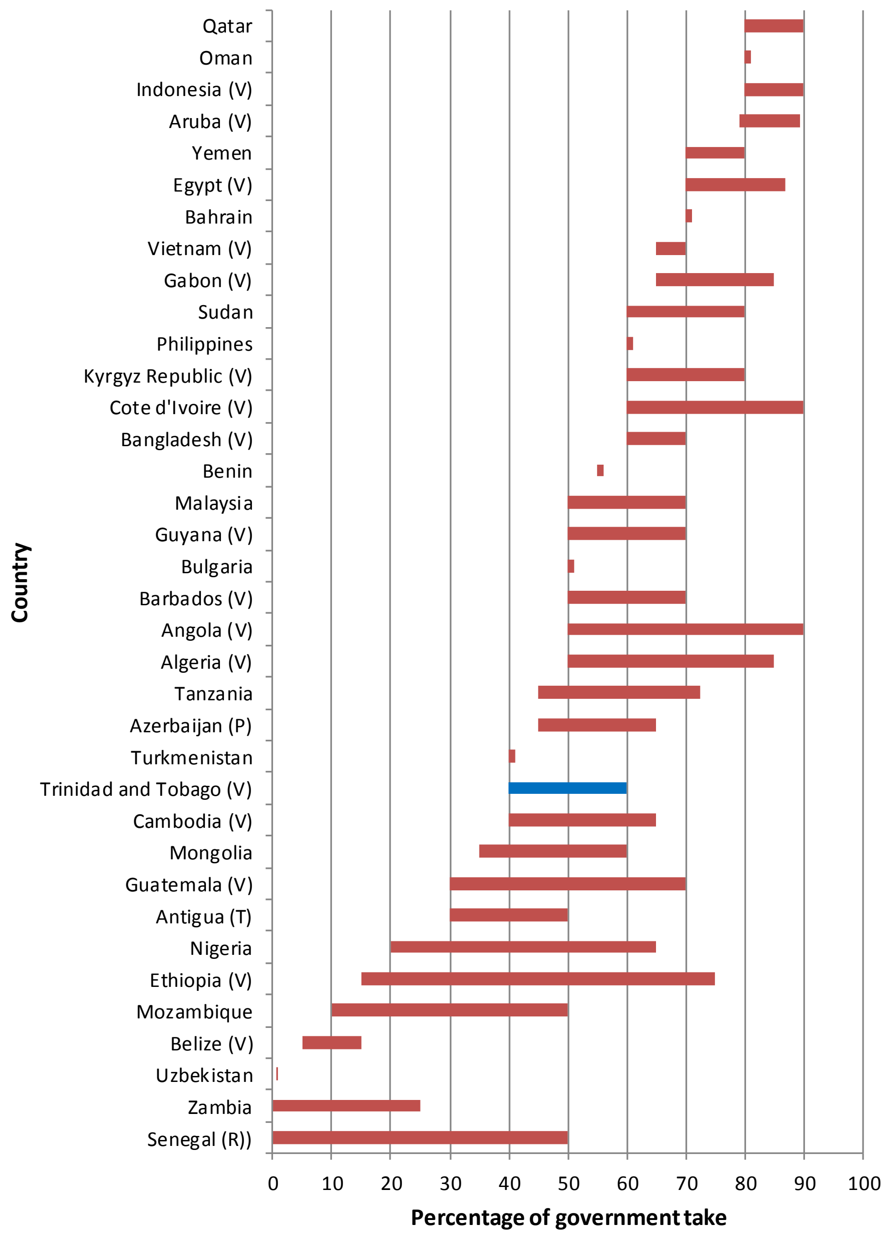
Source: Ministry of Energy and Energy Affairs.

** BHP Billiton, Repsol, and Petrotrin including its Trinmar operations.*

In terms of LNG taxation, most gas export sales are regulated in long-term (20–30-year) contracts, and the terms-of-sale agreements reflect numerous factors. The most typical factors are the level of tariffs charged by the shippers; and regasification and pipeline costs (which may depend on the alternative supply link), distances; and operating costs, among others. However, the construction of more LNG terminals, particularly in Asia, will continue to help integrate the global market for LNG. Because Trinidad and Tobago is still a small player with low capital and operating costs among international LNG terminals, the country should be able to continue exporting its supply to Asian countries while renewing markets as well. With regard to potential regional purchasers in CARICOM (Regular Meeting of the Conference of Heads of Government of the Caribbean Community), such as Barbados and St. Vincent and the Grenadines, because they constitute a small share of oil and gas exports, the effect of taxation changes on these exports is minimal.

III.iii PSCs

Figure 6. Production-Sharing Agreements of Oil and Gas Projects Around the World (approximate range of government take by country*)



Source: Sunley et.al. (2002).

** Production sharing linked to physical volume of production (V), years of production (T), realized profitability (P) or rate of return*

In addition to offering a standard tax regime for oil and gas, considerations about PSC bidding processes are very important, in particular as a first step to attracting new investors. Most of Trinidad and Tobago's blocks are contracted as PSCs, though older blocks function under concessionary contracts, or tax and royalty regimes. The advantage of PSCs is that the oil company bears the mineral and financial risk of the initiative and explores, develops, and ultimately produces the field as required. When successful, the company is permitted to use the money from oil produced to recover capital and operational expenditures (including royalty taxes), known as cost oil. The remaining money is known as profit oil and is split between the government and the company. PSCs can be beneficial to governments of countries that lack the expertise and capital to develop their resources and wish to attract foreign companies to do so. These agreements can be very profitable for the oil companies involved; however, they often involve considerable risk. Table 1 describes the key differences between a concessionary system (which is the system used for many of the contracts with British Petroleum of Trinidad and Tobago[6]) and a contractual system such as a PSC.

PSCs are widespread: about two-thirds of the main hydrocarbon-producing countries use a PSC as the main core of their fiscal regime. The most common form is to have the share of profit oil linked to production, with at least 50–60 percent of profit oil going to the state. In many countries (as in Trinidad and Tobago), even if income taxes are nominally due, they are paid out of the state's share of production. In most cases, the wide difference within countries of the share of profit oil that goes to the country reflects differences in bargaining power, which could depend on particular circumstances. A country with attractive geological prospects combined with macroeconomic and political stability can generally command a stricter fiscal regime.

Table 1. Main Differences Between Concessionary Systems and PSCs

Characteristic	Concessionary systems	PSCs
Ownership of nation's mineral resources	Held by sovereign state	Held by sovereign state
Title transfer point	At the wellhead	At the expor point
Company entitlement	Gros production less royalty	Cost oil/gas + profit oil/gas
Entitlement percentage	Typically 90%	Typically 50%–60%
Ownership of facilities	Held by company	Held by the state
Management control	Typically less government control	More direct government control and participation
Government participation	Less likely	More likely
Ring fencing	Less likely	More likely

Source: Johnston (1994b).

In terms of the differences across regions, about half of Africa's oil producers and the majority of Middle Eastern countries rely on PSCs, whereas they are widespread in Asia (see Figure 6). In contrast, production sharing is rare in Latin American countries. Colombia has enacted a few reforms that Trinidad and Tobago has considered using as a model.

[6] British Petroleum of Trinidad and Tobago is an established company that has had little incentive to increase production in the latter part of the past decade—despite the global oil boom—for various reasons related to local and international environments. The government of Trinidad and Tobago recently looked at the company's tax and royalty structure with a view to increasing incentives for investment in deepwater fields.

Other differences across countries related to the PSCs are the possible limits of what a company can take at any one time on deductions from costs (the cost recovery limit); this is done mostly to ensure the government receives some income. Moreover, there is a stipulation on ring-fencing (enforced in Trinidad and Tobago), which means that a contract is self-contained and the company that operates the project or the PSC is not allowed to consolidate accounts for the purposes of abiding by the fiscal regime.

Most of the final and detailed terms of PSCs between a company and a government are confidential, so access to data on the final terms of PSCs are typically not publicly available. However, the public can see the terms and conditions offered by the government when bids are tendered. According to the Ministry of Energy, more than about half of the country's production is from projects with PSCs.

III.iv How Does Trinidad and Tobago's Tax System Measure Up?

In addition to the aspects related to PSCs, the government of Trinidad and Tobago imposes three main taxes for hydrocarbons and a series of small levies or fees. Similar to the taxes assessed in most countries, Trinidad and Tobago imposes a corporate income tax; a petroleum production tax of 50 percent; a royalty tax rate of 12.5 percent; and a somewhat higher supplemental petroleum tax (SPT), which is a windfall tax over the production of only oil, not gas. The SPT takes effect at 33 percent when the benchmark price of oil is US$50 or more, and it is on a rising schedule once the oil price is greater or equal to US$90 per barrel (bbl). In 2011 and 2012, the government of Trinidad and Tobago introduced tax reductions for companies that produce using enhanced oil recovery of mature fields, lowering the SPT progressively depending on the oil price. Table 2 summarizes the tax rates, and Appendix A explains the main taxes in more detail.

All in all, the government seems to rely on a mixture of income taxes and royalties, with an above-average income tax rate for petroleum but an internationally comparable royalty rate (see Table 3). Windfall taxes became more common in oil-producing countries after the oil boom of the past decade, and these taxes are clearly a large deterrent for oil companies considering investment.

The petroleum profits tax, which includes revenue from all sources, is likely the most elastic for companies, given the high international capital mobility. Despite its name, the tax base includes profits from natural gas production because of the difficulty of separating costs attributed to oil and those attributed to gas. Trinidad and Tobago has been able to receive good prices for natural gas given its diversification of export markets to Japan and Asia (where natural gas prices have risen to US$12 per thousand British thermal units [mbtu] compared with US$2.50–$3/mbtu in the United States in 2015). Nonetheless, if such division of costs and profits between oil and gas could be made, clearly oil production has been the more profitable of the two. In this regard, the government could consider applying a simple formula to differentiate them.

Table 2. Hydrocarbon Production Taxes in Trinidad and Tobago

Tax	Rates	Deductions
Royalty	Crude Oil: 10%–12.5% Natural Gas: TT$0.015/mscf – 15%	
SPT	As prescribed in Schedule (Applicable only to Crude Oil Income)	Royalty & overriding royalty
Petroleum Profit Tax	50% of Net taxable income 35% of net taxable income (deepwater)	See Appendix 1
Unemployment Levy	5% of net taxable income	See Appendix 1
Petroleum Production Levy	Up to 4% of gross income from crude	
Petroleum Impost	Rate specified in order provide under the Petroleum Act	
Green Fund Levy	0.1% of gross sales or receipts	
Withholding Tax	Rate as specified in schedule under the Income Tax Act	

Source: Ministry of Energy and Energy Affairs.

In addition, there are the various small fees. The petroleum production levy is used for financing the fuel subsidy because the government does not compensate Petrotrin (the national oil company) immediately for the below-cost sales to fuel distributors. Petrotrin has had some considerable cash flow problems that have negatively affected investment. Regardless of the merits or demerits of the fuel subsidy, earmarking this component makes it more transparent for the population. If seeking to diversify the economy away from dependence on hydrocarbon revenues, eliminating this subsidy is the best policy.

In addition, Trinidad and Tobago imposes an unemployment levy that is similar to a surcharge or fee rather than a tax. This surcharge was created in the 1970s during a very different postcolonial era, when concerns about redistributing oil-sector income to the population and avoiding social dislocation were preeminent. Also, the Green Fund Levy is used to finance environmentally friendly initiatives.

Table 3. Global Taxation of Oil Production

	Royalties (% of production)	Production sharing	Income tax rate
Algeria	10%–20%	60%–88%	Gov. Share
Angola		15%–80%	50%
Australia	40%		30%
Azerbaijan	None	50%–90%	32%
Brazil			15%
Canada	10%–12.5%		31%–39%
Chad	12.50%	None	50%
China	Nat. res. Tax		33%
Ecuador	12.5%–18.5%	None	25%
India			42%
Indonesia		75%–90%	30%
Kazakhstan	Up to 20%	Negotiable	30%
Libya	16.67%	5%–90%	None
Malaysia	10%	50%–70%	38%
Mexico	None	None	35%
Nigeria	0-20%	20%–65%	50%–85%
Norway	50%		28%
Oman	None	77.5%–80%	None
Qatar	None	35%–90%	Gov. Share
Russia	16.50%	Applicable	exp. Tax
Trinidad and Tobago	12.50%	Variable	50%
UK	12.5%	None	40%–70%
United States*	15% average 1/	None	35%
Venezuela	30%	None	50%
Vietnam	6%–25%	65%–80%	Gov. Share
Yemen	3%–9%	50%–86%	None

Source: Sunley (2002); Deloitte and official sdata from national authorities.
* On federal land. May vary by state.

III.v PSCs in Trinidad: Form, Terms, and Conditions

A more conventional-style PSC system was adopted in Trinidad and Tobago in 2010 and reformed in 2012. It was designed to take better account of risks and encourage investment in more difficult-to-explore fields such as deepwater fields (now defined as fields that are greater than 400 meters deep).

The PSC spans a period not exceeding nine years for exploration and 30 years in the event of commercial discovery. The exploration period has three phases: the last two are optional and dependent on the company fulfilling its obligations in the current phase and informing the government of its intention to enter the next phase; otherwise, the contract will be terminated. If the discovery relates to natural gas, then a period for market development is granted, in addition to the 30 years in respect of the production area.

An interesting feature of the PSC law is the provision for sharing information about the project with the government, but part of the effort to offer a business-friendly environment to oil and gas investors in Trinidad and Tobago. For example, a coordination committee is generally established under the PSC, comprising four members—two from the government and two from the company. The committee is tasked with assisting the company to undertake its activities under the contract and provide a forum for continuous dialogue and information sharing between the company and the government. It reviews and periodically evaluates the company's progress in relation to work program, budgets, local content initiatives, and other matters related to petroleum operations under the contract. The contract also comes with strict due-diligence requirements.[7]

Local content is an important feature of the PSC for Trinidad and Tobago. The company is required to maximize its use of local goods and services in its operations and ensure that subcontracts are structured and sized so that local enterprises can manage the risks involved. Moreover, the company is required to engage in developing personnel in analytical and decision-making roles and in energy sector services such as fabrication, information technology support, operations and maintenance, maritime services, business support services, financing, and trading. Expenditure estimates on local content used in petroleum operations are to be submitted along with work programs and budget.

The PSC also allows for cost recovery. Cost recovery oil is allocated to the applicable recoverable crude oil cost account or the recoverable natural gas cost account. Cost recovery relates to exploration operation costs, capital costs related to development and production operations, annual operating costs, and annual administrative overhead costs. Cost recovery limits were fixed at 50 percent, 55 percent, and 60 percent for shallow, average, and deepwater

[7] The company is mandated to prepare and present an annual work program and budget for the contract area, which has to be approved by the Minister of Energy. Status reports on works carried out are also to be provided at the end of each quarter, and an annual summary of the quarterly reports is provided at the end of the calendar year. Under the minimum exploration work program, the company is also required to commence exploration operation within 90 days of the signing date. The minimum work requirements for the company include carrying out work units related to geology, geophysics, and drilling. Failure to comply with these obligations in the minimum work program can result in termination of the contract. The company is also required to prepare financial statements of its operations in accordance with the laws of Trinidad and Tobago and international petroleum industry practices for each calendar year.

acreages, respectively, in the 2010 competitive bid round. However, for the 2012 deepwater competitive bid round, the deepwater cost recovery limit was increased to 80 percent. This is an important item, which used to be biddable, and for some types of project profiles could constitute important relief for cash flow constraints.

The company is obligated to make several annual financial payments to the government at its own expense. It is also mandated to pay an administrative charge of US$300,000 during the first year of the contract term, with an increasing rate at four percent until the unexpired term of the contract. The company is required to facilitate the training of nationals in areas of study associated with the energy sector by making a financial contribution toward the University of the West Indies, University of Trinidad and Tobago, or a similar institution. The amount of the contribution ranges from US$120,000 in the first year of the contract to 0.25 percent of the value of the contractor's share of monthly profit petroleum. In addition, the PSC requires companies to make a contribution to financing petroleum-related research and development; the range of this contribution is similar to the one mentioned earlier.

The remaining available petroleum that is not required to cover costs is referred to as petroleum profit (composed of crude oil profit and natural gas profit), which is then allocated between the government and the company. The company's share of the profit is the remainder after the government collects its share. The government's share is determined separately for crude oil and natural gas monthly by the applicable price classes and production tiers. The relevant price class is determined by the fair market value of profit crude oil and profit natural gas. The relevant production tier is the average daily production of available crude oil and available natural gas produced from the contract area for each month. Under the 2010 PSC model, the government's share of profit petroleum is required to satisfy the contractor's liability for petroleum profits tax, unemployment levy, SPT, royalty, oil impost, petroleum production levy, and the Green Fund Levy. The exceptions are the withholding taxes and stamp duty, which must be paid directly by the contractor. Legislative changes were made to the Petroleum Taxes Act to give effect to this form of PSC.[8]

The matrices for the government's share of profit petroleum are open for bidding by the companies. The price bands and production bands for these matrices in the bidding contract are adjusted by the government to reflect the expected pricing and cost environments. Payment of signature bonuses remains a feature of PSCs. However, for deepwater acreage, signature

[8] This has the perverse effect that any increase in the petroleum profits tax, under certain circumstances, will actually reduce the revenues of the government because the Ministry of Energy is paying the tax from its share of the PSC.

bonuses are required only in the event that two or more companies are evenly ranked at the end of the bid process.

All in all, the recent simplification of the competitive bidding process is a step in the right direction, because it gives companies—which have the best information about the risks, finances, and cash flows—the ability to put forth their best bid. Even though a bonus signing fee seems unnecessary given that it marginally penalizes the potential winner, it has been eliminated for some cases.

Although it is too early to predict the success of this reform, a first useful sign was the positive response to the recent bid tendering for more blocks. In April 2012, the government opened the deepwater exploration bid round for six blocks under the new regime, of which they received 12 bids for five blocks. The bid round was deemed the most successful in 14 years. Moreover, seven deepwater PSCs were signed by the Ministry of Energy and Energy Affairs between 2012 and 2013, with a collective work program valued at US$1.9 billion. A further set of at least five blocks was successfully awarded in 2014.

III.vi Additional Fiscal Incentives for Investment in Deepwater Exploration

Notwithstanding the 2012 bid round's success, the government is trying to raise incentives for more production, and it recently reformed the fiscal regime for oil and gas to include more incentives for mature well drilling and enhanced oil recovery.

Given the cost and risks involved in exploring in average-water depths and deepwater environments, additional incentives were provided to increase the attractiveness of these areas. For tax purposes only, first, the definition of deepwater acreages was amended to include areas that are located in depths of more than 400 meters; and second, the petroleum profits tax rate is 35 percent specifically for the deepwater acreage. Moreover, a 40 percent uplift in computing capital allowances was granted for capital expenditures of deepwater exploration.

In 2013, the Petroleum Taxes Act was further amended under the petroleum profits tax and the SPT. Incentives in the form of capital allowances on exploration expenditure calculated by reference to 140 percent of such expenditure were granted to companies drilling exploration wells in deep horizons on land or in shallow marine areas between 2013 and 2017.[9] Costs associated with exploration expenditure exclude the cost of any exploration dry hole, finance, administrative, and other indirect costs.

[9] This allowance is subject to the following: the exploration wells on land are drilled to at least a true vertical depth of 8,000 feet or 12,000 feet in shallow marine areas. Costs associated with exploration expenditure exclude any exploration dry hole, finance, administrative, and other indirect costs.

The incentives geared specifically to encourage investment in crude oil production consisted of lowering the SPT rate to take into account the new reality of higher exploration costs for companies. Under the new SPT regime, the classification of differing rates for the pre- and post-1988 period were removed, and a harmonized SPT rate now applies for all marine areas, with the exception of deepwater and new development fields. For marine areas, in 2013, the SPT rate was set at a base rate of 33 percent for prices ranging from US$50 per bbl to US$90 per bbl, compared with the 2010 base rates of 42 percent and 33 percent for the pre- and post-1988 marine areas, respectively. The SPT rates used for land and deepwater will continue as well as the formula used for SPT rates greater than US$90 per bbl. A special SPT rate of 25 percent was introduced for new development fields, at prices greater than US$50 per bbl and up to US$90 per bbl. For prices greater than US$90 per bbl and up to US$200 per bbl, the SPT formula has not changed. Table 4 summarizes the SPT mechanism.

Table 4. Scale of the SPT

Prices US$/bbl	Marine		Land and deepwater
	Marine	New field development	
P < $50.00	0.00%	0.00%	0.00%
$50.00 < P ≤ $90.00	33%	25%	18%
$90.00	SPT Rate = Base SPT Rate + 0.2% (P – $90.00)		
P > $200.00	55%	47%	40%

Source: Ministry of Energy and Energy Affairs.
Note: Applicable from January 1, 2013.

An investment tax credit equivalent to 20 percent on qualifying capital expenditure was provided in 2010 for mature oil fields and enhanced oil recovery projects in petroleum. This tax credit was to be used only in the year in which the expense incurred has been amended in 2014 to be carried forward for one year, with the objective of ensuring continuity and encouraging new investments.

Further incentives were introduced in 2014 to encourage exploration and development activities in the energy sector. The first is an allowance of 100 percent write-off of exploration costs (applicable from 2014 to 2017) and of workovers and qualifying sidetracks in the year in which they were incurred. The allowance for wear and tear on gas compression facilities used in the midstream energy sector has been increased from 25 percent to 33 percent. For development activities, allowances were also made for expenditures incurred for plant and machinery and the drilling of wells in the first, second, and third years of 50 percent, 30 percent, and 20 percent, respectively.

IV. METRs

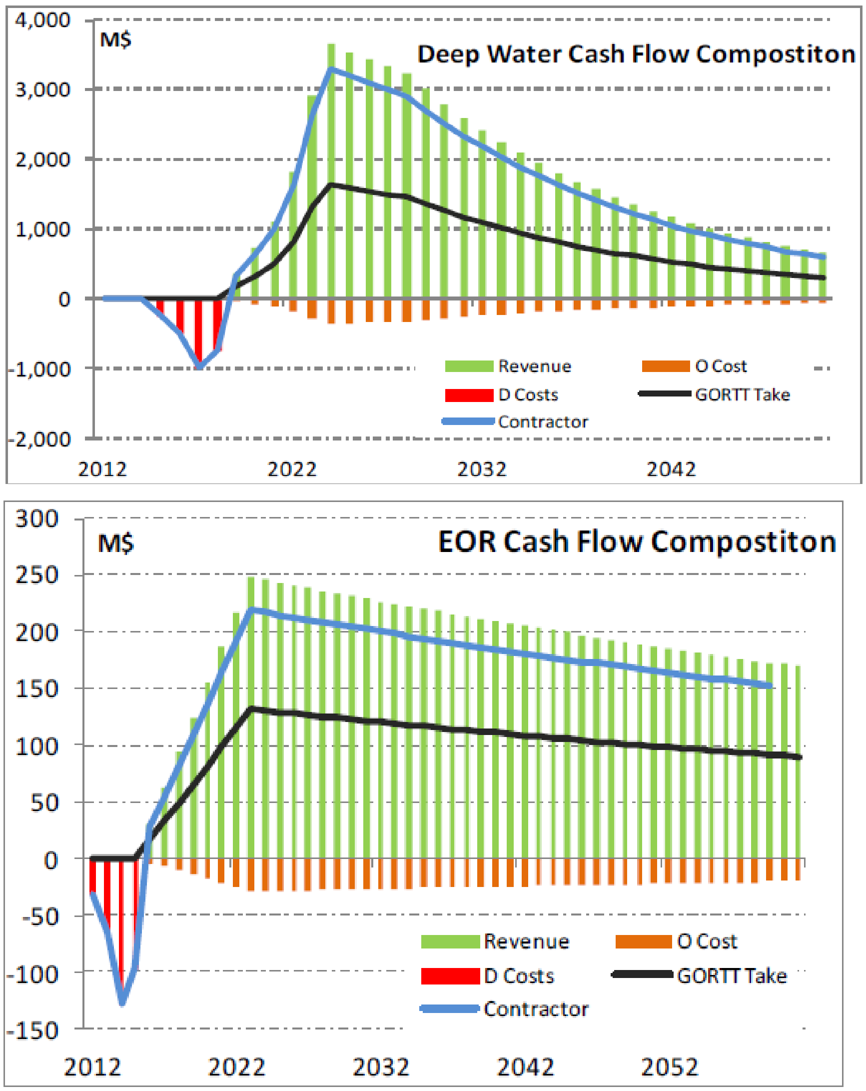
To capture the full effect of the fiscal regime on investment, two aspects need to be considered. The first is the METR, which is an indicator of the deviation between the optimum level of investment to extract available resources and the forthcoming investment in a given fiscal regime. The second is the effect of the full fiscal regime—in addition to changes in conditions—which itself can affect the incentives to invest. Changes in the environment such as a rise in prices will change the tax rates faced, given the SPT sliding scale. How can the authorities respond to this? In general, a delicate balance is needed between a tax regime’s flexibility to keep revenues and incentives stable and its stability, keeping uncertainty for investors minimized.

How do the last tax regime revisions measure up? The answer is found by examining what particular aspects of the new incentives can make a difference on the margin to increase investment. The METR calculation provides this. The METR can also be considered as an indicator of the neutrality of the fiscal regime: Where there is a large tax-induced wedge between the before- and after-tax rates of return, the range of otherwise feasible projects that can be developed will be narrowed. The methods and assumptions are described in detail in Appendix B.

Two important caveats in calculating METRs should be considered. First, the METRs assume the maximization of a smooth production function, and, as Figure 7 shows, the production profiles of different types of oil fields are likely not smooth and can be very different. Therefore, the METRs may be a better explanation of the average effect over a long period of time, as opposed to changes in the investment incentives at a particular time in the exploration-production cycle.

Second, the analysis abstracts from cash flow considerations, but this is appropriate. The METR analysis assumes that there are no cash flow issues for oil and gas projects, although there is an assumption of the division of project financing between debt and equity. As Figure 7 shows, there can be very different cash flow profiles between, for example, an enhanced oil recovery project and a deepwater or even conventional oil field. Moreover, it is not unusual for exploration to last between five and 10 years. Because the government does not have information about the cash flow situation of the company or the exact profile of the cash flow over time, tax incentives geared toward relieving cash flow (such as increases in cash flow recovery limits and the uplift in computing capital allowances) do not necessarily enhance investment. It is also most likely that international oil companies can tap into global financial markets and diversify risk to smooth cash flow geographically, so they are unlikely to have important cash flow issues ex ante. This is important because the government of Trinidad and Tobago has justified many of its tax incentives for

Figure 7: Cash Flow Profile for Simulated Fields in Trinidad and Tobago



Source: Russell and Bududass (2012).

certain types of fields as a way of relieving cash flow situations through lower taxes early on.

Despite its name, the METR should be interpreted not as a fiscal tax but rather as an economic tax or wedge. The important feature is to see the magnitude of the change under different sensitivities of variables (including policy variables).

Table 5. METRs Calculations for Oil and Gas Production in Trinidad and Tobago (various scenarios)

	METRs
1 SPT = 33% and price per bbl of US$60	**82.9%**
2 SPT = 25% and price per bbl of US$60	**80.3%**
3 SPT= 0% and price per bbl of US$89 (hypothetical)	**9.2%**
4 SPT = 25% and price per bbl of US$89 (baseline)	**36.1%**
5 SPT = 27% and price per bbl of US$100	**23.8%**
Mature marine and small marine field incentives	
6 SPT = 20% of 25% and price at US$89/bbl, 20% tax credit on qualifying capital expenditu	**-6.3%**
Deepwater field incentives	
7 SPT= 25%, deepwater fields (PPT is 35%, 40% uplift), price is US$60/bbl	**81.8%**
8 SPT= 25%, deepwater fields (PPT is 35%, 40% uplift), price is US$89/bbl	**43.0%**
Deepwater and enhanced oil recovery incentives	
9 SPT= 25%, PPT is 35%, 40% uplift, 20% tax credit on capital expenditures. US$60/bbl	**69.7%**
10 SPT= 25%, PPT is 35%, 40% uplift, 20% tax credit on capital expenditures. US$89/bbl	**5.2%**
Deepwater field and enhanced oil recovery with 2014 tax incentives (100 percent accelerated depreciation)	
11 SPT= 25%, deepwater fields (PPT is 35%, 40% uplift, 20% tax credit) price is US$60/bb	**69.2%**
12 SPT= 25%, deepwater fields (PPT is 35%, 20% tax credit only for 2014) price is US$60/	**66.4%**
13 SPT= 25%, deepwater fields (PPT is 35%, 20% tax credit only for 2014), price is US$89.	**-4.9%**

Source: Author's calculations (see appendix 2 for derivation and assumptions).

Table 5 shows the results of the METR calculations, and Appendix B shows the derivation and assumptions. The main fiscal regime aspects examined are changes in the external environment, modeled as the impact of price changes, and specific incentives for some types of fields, particularly deepwater. Some incentives for small marine fields are also examined.

The incentive of lowering the SPT rate from 33 percent to 25 percent, from the 2012 fiscal regime, seems to have a relatively small effect: The METR fell less than three percentage points, from 82.9 percent to 80.3 percent. This is assuming that oil prices are at US$60 per bbl and costs worldwide may not meet many oil companies' hurdle rate,[10] particularly international oil companies. Still, under the assumption of oil prices at US$89 per bbl (the average International Monetary Fund benchmark spot price over 2013 and 2014, which leaves an SPT rate of 25 percent), the METR is reduced by more than half (from 80.3 percent to 36.1 percent, lines two and four in Table 5), even though the SPT rate remains 25 percent.[11] A further increase of about US$10 per bbl in the oil price, with the same SPT schedule (which implies a higher SPT rate of 27 percent) still lowers the METR substantially, by almost 13 percentage points, from 36.1 percent to 23.8 percent. It is clear that external forces such as the international oil price can have a much larger effect on the METR and the actual incentive to invest compared to any modification of the tax rate.

Another intention of the 2012 tax regime changes was to give various incentives to deepwater marine fields (as well as older ones) and to enhanced oil recovery. These incentives strive to take into account the higher costs and risks involved in these types of activities relative to conventional oil exploration.

Small and mature fields do receive an important incentive, from an METR of 36.1 percent in the baseline to a negative METR (that is, a subsidy), under the assumption of oil prices at US$89 per bbl. Therefore, lowering the SPT rate does seem to have an important impact, but the largest incentive comes from the tax credit on capital expenditures (which were assumed to be machinery and equipment) as well as price.

If the price per bbl was assumed at US$60, the METR would decrease to 62 percent (compared with 80.3 percent), so the tax credit is an important incentive nonetheless. The assumption in the analysis is that the price increase is a short-term phenomenon, and costs remain the same for companies. Tax credits tend to have a high fiscal cost (not accounted for here) and so should be used only sparingly.

Last, the METRs were explored to compare the incentives to deep-water fields relative to the baseline assumptions. The biggest incentive is the lowering of the income tax from 50 percent to 35 percent, as well as the 40 percent uplift for capital costs, a sort of accelerated depreciation allowance. The METR is lower by about 10 percentage points compared with the benchmark and the lower price baseline (rows four and two in Table 5, respectively). By assuming, in addition, that a project wants to participate in enhanced oil recovery operations in a deepwater field, the incentive package is the largest under the new fiscal regime. Compared

[10] The hurdle rate is the one- to three-year price of a bbl of oil over which a company is willing to invest in any field. Below this threshold, the decision is not to invest. The price is typically a conservative value.

[11] The forecasts at the end of 2015 are for much lower oil prices in the medium term, of $60 per bbl. However, this observation is still valid regardless of the value of oil prices.

with the baseline at US$89 per bbl, the METR is reduced from 36.1 percent to 5.2 percent, an important incentive. Again, in percentage points, the greater the price of oil, the larger the incentive.

Three more illustrative scenarios were added with the assumption of a 100 percent write-off of exploration costs between 2014 and 2017. To partially offset write-offs, the government limited the 20 percent tax credit to 2014 only. The results show that the write-off has a small impact on only the METR, in part because the relief is mostly on cash flow and not the effective tax burden over the life of the project (comparing lines 9 and 11 in Table 5). The government did, however, limit the 20 percent tax credit to 2014 only, so there is an offset (comparing lines 11 and 12). A comparison of lines 12 and 13 show that the assumption of a higher price significantly lowers the METR.

It seems that setting the SPT rate at the right threshold price can be very important for companies. It is a windfall tax and therefore not particularly appealing to suppliers. In particular, if oil prices remain at US$90 per bbl on average, the SPT rate may have lost its justification: It is no longer a windfall tax, but rather a standard tax on production. The government may thus consider raising the threshold at which the 33 percent tax kicks in, particularly considering that it is a considerable burden.

Moreover, oil companies tend to have their own hurdle rates or threshold prices above which they are willing to invest, and these could reflect shareholder preferences, company culture, and so forth. This information is generally not available to the government. To the extent that the prices fall below the threshold, the forthcoming investment—and potential revenue for the government—can change substantially. In sum, the METR analysis has shown that modifying the fiscal system will not necessarily create more investment, because it is difficult to know company price thresholds. The latter is private information.

All in all, Trinidad and Tobago has increased the level of stability for investors through recent reforms of its PSC regime and provided cash flow relief through allowances. However, the SPT is not always as effective a tool as may be needed, especially if the government pays it on the company's behalf under a PSC. It is recommended to expand the PSC regime as envisioned, but to make it transparent and amenable to attracting investment in gas. The economy's infrastructure is well set up to process natural gas if it can be priced correctly and taxed at the different stages of value addition this could improve revenue while preserving incentives for investors.

V. Conclusions

In general, the tax system in Trinidad and Tobago is still designed for an oil-rich economy that requires oil revenue redistribution toward the population. However, the country has become a major gas producer with a need to retool for the high-tech world, toward industries and activities that will enable it to wean itself out of the resource curse. Consequently, although a petroleum profits tax and a royalty tax are in line with good international practices, broader taxation across the value chain may make more sense. The analysis suggests that the SPT needs to be revisited, as it accentuates the variability of oil prices on fiscal revenues and the economy. Given the preeminence of gas, the tax system needs to be modified to consider the special structural features of the gas market and encourage investment in the sector. Second, earmarking fees such as the employment levy and the petroleum production levy should be geared toward opportunities to retool and enhance human capital.

The government should consider reinforcing tax policies that leave the risk management and cash flow management aspects to individual companies rather than trying to influence either through the tax regime. The government does not have enough information to influence these aspects of financing private production, so it should strive for simplicity that rewards transparency. Moreover, as the METR analysis shows, the effect of such small changes is minor in comparison with other factors that investors consider, such as global prices and the stability of a country's fiscal regime. In this regard, the recent reform of the PSCs is very much a move in the right direction. Moreover, the government should consider offering tax stability clauses that allow some flexibility for changes in prices but ensure a certain return to the companies. Such stability is very important for oil and gas projects, which have large horizons and are therefore subject to considerable uncertainty.

The continuation of technological innovations on the distribution aspects of natural gas are a hallmark of the Trinidad and Tobago economy and should be further pursued. The development of natural gas should expand given that natural gas is a relatively clean fuel and can now be more readily used for transportation. Moreover, the government's recent efforts to improve the market structure by commissioning a Natural Gas Master Plan is commendable, as is the management of the Heritage Stabilization Fund.

Overall, Trinidad and Tobago needs to consider a taxation system that will allow it to develop industries related to oil and gas exploration, where the workforce can migrate its skills downstream or into similar industries. The country should therefore increase incentives for investors who can contribute to the infrastructure required for the development of innovative sectors, including oil services and renewable energy.

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Appendix A. Trinidad and Tobago's System of Hydrocarbon Taxation

(Adapted from the website of the Ministry of Energy [2014] and from McGuire, Pantin, James and Seeterram [2009].)[12]

The hydrocarbons fiscal regime in Trinidad and Tobago can best be described as an enhanced two-tier system consisting of the production-based royalty, the production levy, and the SPT, supported by a profits-based corporation tax that includes the petroleum profits tax and an unemployment levy. Incentives and allowances are structured into the system to encourage investment, particularly in exploration projects and enhanced oil recovery schemes. The petroleum taxation system was revised in 1992 to improve its competitiveness by providing additional relief to new investors and an SPT rate structure sensitive to oil price variation. The system includes the following:

- A royalty charged at a rate of 12.5 percent of all petroleum produced and 15 percent for natural gas. The royalty rate is 12.5 percent for land and marine production. The royalty rate is 10 percent for marine production off the West Coast of Trinidad. There are also special sliding-scale royalty rates for some marine production off the East Coast, which extend to as much as 15 percent.
- A production levy of up to three percent of gross income from crude oil. The Petroleum Levy and Subsidy Act determines the petroleum production levy, which is imposed on companies that produce crude oil. The levy provides the subsidy for petroleum products sold on the domestic market.
- An SPT charged on the production of crude oil and based on an oil-price-sensitive rate structure. The schedule is as follows: At crude oil prices at US$50.00 per bbl and below, the SPT rate is zero percent; at crude oil prices greater than US$50 per bbl and up to US$90 per bbl, a fixed rate is charged (either 18 percent for land and deepwater, or 25 percent, or a discount of 20 percent over 25 percent).[13] At crude oil prices greater than US$90 per bbl and up to $200 per bbl, a sliding scale is applied of 0.2 percent for every dollar increment greater than US$90. Thereafter, at prices greater than US$200 per bbl, the rates are capped for marine (pre-1988) operations at 64 percent, marine (post-1988) operations at 55 percent, and for land and deepwater operations at 40 percent.

[12] Updates of tax rates and tax regime changes are regularly published in the Ministry of Energy and Energy Affairs website: http://www.energy.gov.tt/for-investors/fiscal-regime/petroleum-fiscal-incentives-2014.

[13] In 2012, the SPT if prices were between US$50 and US$90 was 42 percent for marine fields not in deepwater established before 1988 and 33 percent for marine fields established after 1988.

- The SPT is computed on gross income from crude oil less allowances for royalty payments and various expenditures incurred in exploration and development activity. In addition, companies are eligible for a productivity allowance, equivalent to a 20 percent reduction in the SPT rate, on all production in excess of 90 percent of the preceding year's average. A small field allowance equivalent to a 20 percent reduction in the tax rate is also granted for fields in which the production rate is less than 200 bbls per day per well.
- A petroleum profits tax or corporation tax charged at a rate of 50 percent of gross revenues from all sources less deductible expenses and allowances.
- An unemployment levy of five percent is also charged. Eligible deductions include operating and administrative expenses; royalty, production levy, and SPT payments; capital allowances (depreciation); and a heavy oil allowance on projects designed to recover crude of 18 degrees American Petroleum Institute–specific gravity or lower.

For the computation of SPTs, the following allowances are written off:

- A geological and geophysical allowance up to 50 percent of geological and geophysical costs
- An exploration allowance up to 100 percent of direct costs of drilling exploration wells
- An incremental investment allowance up to 40 percent of direct intangible drilling costs and 40 percent of tangible costs incurred in development activity
- Royalty payments.

In addition, capital allowances, as provided under the Income Tax (in Aid of Industry) Act are also applicable as well as other concessions that may be given under the Customs Act and Value-Added Tax Act.

Appendix B. Construction of the METRs

One of the most common methods in the literature on how the tax system affects the investment decisions of a businessperson in a certain sector is an indicator known as the METR. It measures what the effective tax burden of a dollar invested in a certain industry, taking into account all of the different taxes facing the sector, the structure and composition of assets, the return to the company, and the level of indebtedness of the company. In the simplest case, if there is only an income tax (of 35 percent), and the company has no debt, then the METR is 35 percent. However, with many changes in the tax structure, different levels of the debt-to-equity ratio, different tax bases of the taxes, and different compositions of the assets of the sectors, it is difficult to understand the total effect on the investor's tax burden. The METR captures all of these effects in a single statistic.

The METR calculation is derived from a model in which an entrepreneur chooses the level of capital that maximizes the net present value of profits of the firm. From the problem's solution comes the use of the capital cost and its profitability; hence, the METR is defined as the gap between the return on a dollar investment before and after paying all taxes (see Auerbach 1995; Mintz 2010). For example, in terms of the oil and gas sector, using the same method of calculation from World Bank (2005) with some minor modifications, the investment in an asset whose price is *q* and is considered to have the following:

- ***c*** is the marginal product
- δ is the economic depreciation rate (assuming that the asset has an infinite life and so has an exponential depreciation path)
- ***u*** is the profits tax
- ***t*** is the indirect tax on the purchase of the fixed asset, if there is one
- ***w*** is an asset tax, which is assumed to be zero
- r_f is the discount rate of the project
- ***z*** is the present value of all the depreciation deductions allowed according to the tax legislation, for every dollar invested throughout the useful life of the asset. If the tax code permits an exponentially decreasing balance without inflation adjustments, z is equal to the following:

$$z = \int_0^\infty \alpha e^{-\alpha t} e^{-(r_f+\pi)t} dt = \frac{\alpha}{\alpha + r_f + \pi} ,$$

- ***n*** is the partial expensing tax credit for acquisition of assets for a mature field.

To calculate the discount rate of a project, r_f, it is assumed that part of it refers to the rate received by creditors and part to the shareholders:

$$r_f = \beta(1-u)i + (1-\beta)\rho(1-u)$$

where:

- $\boldsymbol{\beta}$ is the share of debt over assets
- $\boldsymbol{i}$ is the nominal interest rate that an investor receives in the capital market
- **ρ** is the nominal rate of return to shareholders (which reflects earnings and dividends).

The formula reflects the fact that one can deduct interest payments and dividends in Trinidad and Tobago to calculate the taxable income (taxed at rate *u*).

The calculation of the METR assumes that the marginal investment of an asset is such that the net benefits generated by that investment, taking into account all taxes and fees, is equal to the net cost after taxes. Assuming that there is a wealth tax and that this tax is not deductible, the following equality would have to hold:

$$(1-un)(1+t)q = (1-u)\int_0^\infty ce^{-\delta t}e^{\pi t}e^{-(r_f+\pi)t}dt + u(1+t)qz - w\int_0^\infty qe^{-\delta t}e^{\pi t}e^{-(r_f+\pi)t}dt$$

$$(1-un)(1+t) = \frac{(1-u)(c/q)}{\delta + r_f} + u(1+t)z - \frac{w}{\delta + r_f}$$

$$c/q = \frac{(1-un)(1+t)(\delta + r_f)}{(1-u)} - \frac{u(1+t)z(\delta + r_f)}{(1-u)} + \frac{w}{(1-u)}$$

The gross return to investment is thus as follows:

$$r_g = c/q - \delta = \frac{(1+t)(\delta + r_f)}{(1-u)}\left[1-u(n+z)\right] + \frac{w}{(1-u)} - \delta \ .$$

Furthermore, the simplifying assumption is made that the depreciation rate of land and inventory is zero.

Last, $\boldsymbol{r_s}$ is defined as the real return to the investment by the supplier of funds (the saver) net of withholding taxes, personal taxes, and dividend taxes t_d, and net of taxes on interest income (which would likely not be charged in Trinidad and Tobago):

$$r_s = \beta(1-u)i + (1-\beta)\rho(1-u)(1-t_d)$$

If there are taxes on gross income or production, such as the royalty tax, the SPT, the petroleum products levy (only on petroleum), and the Green Fund Levy, the return to the saver is defined as follows:

$$r_n = r_s\ (1 - m)$$

where:

$$m = \textit{royalty tax} + \textit{SPT} + \textit{petroleum products levy} + \textit{Green Fund Levy}$$

This is not completely correct if a particular field in Trinidad and Tobago also produces gas, given that the SPT and the petroleum products levy apply only to oil production. Strictly speaking, they should be multiplied by the share of oil in total production (in bbls equivalent).

The METR is thus the following:

$$METR = \frac{r_g - r_n}{r_g} \ .$$

If the investor is foreign, possible effects of exchange rate changes or tax credits in their country are not included in the analysis.

Data

Because it is required that the structure of assets of the industry be considered, data according to estimates of World Bank (2005) were used. This defines the asset structure for various industries including oil and gas for a developing country. The structure of assets of oil and gas production is quite capital intensive and does not vary much across the globe. It is assumed that production in each sector can be defined as the combination of assets working together in the ratio defined herein (data specific to Trinidad and Tobago were not available).

To obtain indicators of returns on assets, the rate of return to projects was used according to Tordo (2007) and Russell and Bududass (2012). Project estimates from interest rates and the share of debt in assets was assumed to be standard for the oil and gas industry (β = 30 percent). However, the results are relatively less sensitive to this. In most of the analysis, cash flow issues were consulted, as explained in the text. The Appendix Table defines values used for the parameters according to the Trinidad and Tobago oil and gas regime, as well as the assumptions.

Appendix Table: Assumptions for the Construction of METRs

Variable	Notation	Base value	Alternative value
Rate of economic depreciation (assumed accelerated)			
Machinery and equipment	δ_{me}	0,1	
Inventory	δ_{in}	1	
Structures	δ_{es}	0,05	
Office and transport equipment	δ_{oftr}	0,2	
Depreciation rate according to tax legislation			
Machinery and equipment	α_{me}	0,1	0.14
Inventory	α_{in}	1	1
Structures	α_{es}	0,05	0.03
Office and transport equipment	α_{oftr}	0,2	0,3
Partial expensing tax credit for mature fields and EOR projects	*n*	20%	
Petroleum profits tax (income tax)	*u*	50%	35%
Discount rate	r_f	5%	
Gross production taxes	*m*	41%	Depending on values below
SPT	*SPT*	25%	33% (only on oil production)
Petroleum Production Levy	*PPL*	3%	Only on oil production
Green Fund Levy	*GFL*	0.10%	
Royalty tax	*RT*	12.5%	
Internal rate of return	*IRT (Pt)*	4% (US$60)	Value changes according to oil price per bbl assumptions of: US$60, US$89, and US$100

Note: Asset tax (w) inflation (π) and VAT on capital goods (t) are assumed to be zero.

For oil and gas exploration, the division of assets is as follows (see World Bank 2004): machinery and equipment, 54 percent; computers and vehicles, 85 percent; land, 4 percent; structures, 4 percent; and inventories, 9 percent. The assumption is that these are also the shares into which they go into production.

The internal rate of return is calculated from a set of standard projects, and a return (ρ = four percent) corresponds to an oil price of US$60 per bbl. The inflation effect was excluded from the analysis because the relevant inflation rate is not that of Trinidad and Tobago necessarily, which is common. An interest rate of *i* = four percent was assumed, although different values were experimented with.

It was also assumed that the assets depreciate in reality at a rate higher than that provided by the tax system. Further, it was assumed that there is no accelerated depreciation in the baseline case, meaning that the tax depreciation rate is equal to the economic for all depreciable assets (i.e., α = δ).