

Exploring the elements of an optimal hydrocarbon fiscal regime

Sheldon McLean



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Exploring the elements of an optimal hydrocarbon fiscal regime

Sheldon McLean



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Abstract

Many small, open hydrocarbon-rich developing economies commonly possess insufficient technical and financial capacity to fully extract their hydrocarbon resources. Hence, these governments commonly encounter the policy dilemma of designing a competitive hydrocarbon fiscal regime, which delicately balances the policy objective of earning a fair share of their natural resource wealth with the profit-maximizing interest of the multinational hydrocarbon companies. The hydrocarbon-rich Western Hemispheric region, including the Caribbean, face similar challenges. All oil- and gas-rich Latin American and Caribbean countries rely heavily on foreign direct investment (FDI) to extract their hydrocarbon resources and develop their downstream sector. This FDI can shift between countries and jurisdictions that offer attractive fiscal terms to explore, extract, and process the host country's hydrocarbon resources.

The study analyzes the process for the awarding of blocks among select countries within the western hemisphere, namely Brazil, Guyana, Mexico, Suriname and Trinidad and Tobago. The findings allow for the determination of key elements of what can be considered an optimal hydrocarbon fiscal regime for Caribbean economies that would allow governments to get their fair share of hydrocarbon rents, while ensuring sufficient exploration and production activity. The study therefore suggests that for the Caribbean, the optimal fiscal regime should include a reservation price, royalties, and a windfall tax. Mindful of the sunk costs which may be incurred by the multinationals in exploration and production activities, invariably, fiscal incentives would be necessary. The study, however, argues in favor of collusion among oil and gas endowed regional countries in pursuit of hydrocarbon sector FDI. This would simultaneously avoid the proverbial race-to-the-bottom and go a long way in optimizing each country's hydrocarbon rents.

Introduction

Guyana, Suriname and Trinidad and Tobago are the member states of the Caribbean Community (CARICOM) that possess commercial reserves of hydrocarbons and are currently extracting crude oil for commercial use. Trinidad and Tobago's oil sector dates back to 1859 with the first successful onshore well drilled in 1866, and the first export of oil occurred in 1910. Later in 1968, commercial quantities of oil were found off the east coast. Later in 1971, natural gas was also discovered in the offshore blocks (Rajnauth and Boodoo, 2004). The country incurred its first oil boom in 1973. The majority of the hydrocarbon reserves offshore have been found in Trinidad and Tobago's shallow-water shelf area (Rajnauth and Boodoo, 2013). Interest in the deep-water blocks emerged from as early as the 1990s (Rajnauth, 2012).

Oil was first discovered in Suriname in 1928 and coordinated oil exploration commenced in the 1960's. Commercial discoveries of crude oil were made in Guyana by ExxonMobil affiliate, Esso Exploration and Production Guyana Ltd., in 2015. Since the first discovery at the Lisa-1 well, several discoveries were made in the Stabroek block, some 190 kilometers (km) offshore Guyana (Exxon Mobil, 2015). Presently, ExxonMobil estimates that there are at least 10 billion barrels (bbls.) of proved reserves of crude oil offshore Guyana.

Following this discovery, the Government of the Cooperative Republic of Guyana (GoG) entered into negotiations with the multinational, ExxonMobil, for production sharing contracts (PSCs) to facilitate the continued exploration and production (E&P) offshore Guyana. As this is a new frontier for the Government of Guyana, it is important that they are armed with the tools necessary to receive fair value for their hydrocarbon resources.

Accordingly, the objectives of the study are to:

- review and explore the theoretical framework for the awarding of acreage;
- assess the process for the awarding of blocks in specific countries within Latin America and the Caribbean; and

- provide policy recommendations to allow hydrocarbon-rich Caribbean economies to earn their fair share of hydrocarbon rents, while facilitating exploration and production activity in the offshore blocks.

The rest of the study is structured as follows. Section I explains the concept of acreage and the awarding of blocks in the hydrocarbon industry. Section II reviews the process for the awarding of blocks in Brazil, Guyana, Mexico, Suriname and Trinidad and Tobago. Section III performs scenario analysis, estimates the government take and the effective tax under different fiscal regimes. Section IV posits policy recommendations for the governments to receive their fair share of hydrocarbon rents and section V concludes the study.

I. Modalities for awarding acreage and blocks

In many countries, the ownership of natural resources is vested in the state, and the government acts as the custodian (Sen and Chakravarty 2013). However, the government is unlikely to extract and monetize these resources on its own, particularly in small developing economies. It is more likely to grant the rights to explore, and extract the hydrocarbons to a third party, either a multinational hydrocarbon company or a state-owned hydrocarbon company.

A. Legal systems for exploration and production rights

There are generally two legal systems used by governments to facilitate the exploration and production of hydrocarbon resources, namely, concessions and contracts, both of which will be explored hereunder.

1. Concessions

In the hydrocarbon industry, a concession is a long-term contract, usually over 10 years, that gives an investor the sole right to conduct exploration and production (E&P) activities over a specified area or block. A block is essentially a geographical area of the continental shelf where hydrocarbons are believed to reside. The respective government can decide how its continental shelf will be divided. For example, it can be decided that the maritime areas within the outermost limit of the continental shelf are to be divided into 5 blocks. Historically, hydrocarbon rights are allocated mainly through concessions. Some concession contracts may grant government ownership to the physical capital and equipment and may last over 20 years to allow investors ample time to recoup cost of capital. All the risks and costs involved in the exploration and production activities are borne by the investor and they only pay royalties and taxes to the government on hydrocarbon produced and sold (Tordo et al., 2010; BCG, 2012).

Although investors receive autonomy in the operationalization of E&P, an important characteristic of concession agreements is the grant to the government the right to unilaterally alter the

terms of those terms and conditions that are not negotiated but are set by legislation. While this gives concessions a huge potential for frequent sweeping changes, in practice, there may be little alterations as governments tend to promote stability to maintain investor confidence (Tordo et al., 2010).

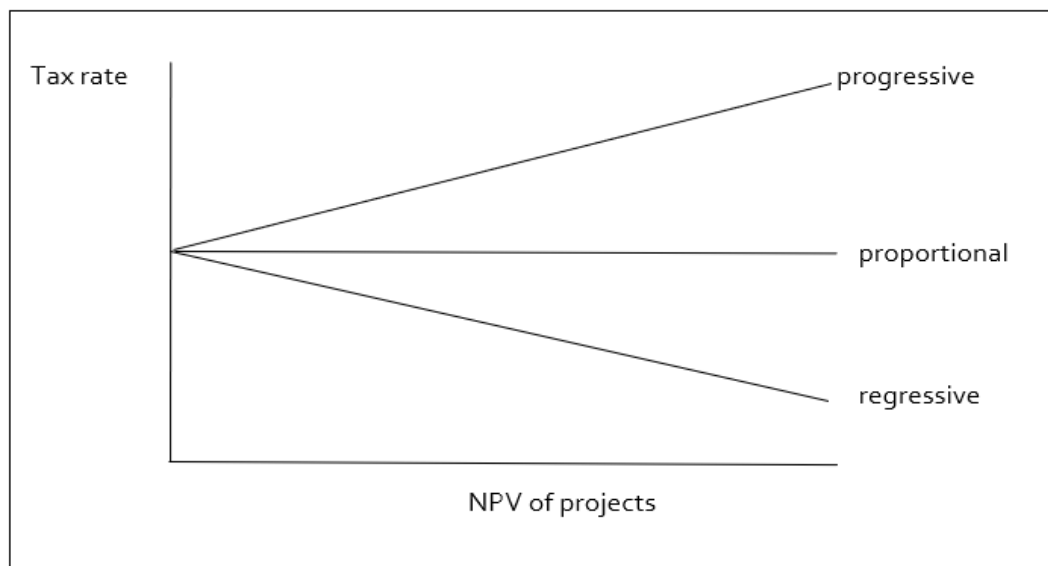
2. Contracts–product sharing contracts (PSC)

Contracts state the terms and conditions to which a government and an investor agree for the development of hydrocarbon resources. There are two types of contracts used, namely, production sharing contracts, and service agreements. Like a concession, under a PSC, an investor is granted the right to engage in exploration and production activities within a specific block or blocks for a specified period.

PSCs differ from concessions to the extent that in a PSC, the investor bears all the risks and costs associated with exploration and production in exchange for a share of the hydrocarbons produced. In contrast, with concession agreements the state has no share of the hydrocarbons but makes its gains through taxes or royalties. Hence, with PSCs, the produced output of hydrocarbons is shared between the investor and the government, the details of which are specified in the product sharing contract (Tordo et al., 2010). In some instances, rather than giving the government its share of physical hydrocarbons, the investor may pay the government for its stipulated share. The government's income comes from the profit oil. Specifically, when the hydrocarbons are produced, the cost of production or "cost oil" is first deducted, then the government receives its share from the remaining oil or "profit oil."

Based on the takes from the government and the PSC holder, PSC can be classified as regressive, proportional, or progressive. Under the regressive PSC structure, the government take or share of the hydrocarbon rents declines as the economic rents or profits derived from extraction and sales from the hydrocarbon projects increase. Under the proportional PSC structure, the government's take remains constant and is independent of increases in the economic rent which accrues to the PSC holder. Under the progressive PSC structure, both the government and the PSC holder's take from the hydrocarbon projects increase as the economic rents increase (see diagram 1).

Diagram 1
Regressive, Proportional, and Progressive PSC



Source: Economic Commission for Latin America and the Caribbean (ECLAC), adapted from Wen (2018).

3. Contracts–service agreements

Under a service agreement, the government hires a company to perform exploration and production activities within a specific block for a specific period. The exploration and production company is paid a fee for its services. The state retains ownership of the hydrocarbons at all times (Tordo et al., 2010).

B. Allocation of rights

Governments generally maintain a policy objective of maximizing the rents derived from their hydrocarbon resources. They often face the conundrum of determining which company or companies should be awarded the rights to explore and extract hydrocarbon resources, and on what conditions such rights should be awarded. Different systems can be used to allocate these rights. These systems may be grouped under two categories: open-door systems, and licensing rounds. The licensing rounds can be further divided into administrative licensing, and auctions.

1. Open-door systems

Under open-door systems, the government may engage in discussions with potential investors concerning the awarding of (E&P) rights for specific blocks. This process may not be transparent, and both parties (the government and the investor) may negotiate the terms and conditions for the rights to the block. If there are multiple stakeholders involved in the hydrocarbon industry, the government may solicit expressions of interest before deciding whom should be awarded the E&P rights to the block.

2. Administrative licensing

With administrative licensing, the government awards licenses based on criteria it has set. This framework is open to subjectivity and can facilitate the awarding of blocks to undeserving investors, especially where the criteria for decision making is not clearly articulated.

3. Auctions

The auction system is one where stakeholders bid for E&P rights in specific blocks, and the government awards the block to the highest bidder. Auction theory defines four auction types, namely, the ascending auction, the descending auction, the first-price sealed bid, and the second-price sealed bid (Sen and Chakravarty, 2013).

- (i) The ascending auction is also known as the English auction. In this auction, the price is successively raised by the auctioneer until only one bidder, the highest bidder, remains.
- (ii) The descending auction is also known as the Dutch auction. In this auction, the auctioneer begins at a very high price, which is then lowered continuously. The first bidder to accept the price wins the auction.
- (iii) In the first-price sealed bid, each bidder submits their own bid, which is independent of the other bidders' bids and the highest bidder wins.
- (iv) In the second-price sealed bid, the highest bidder wins the auction, but pays a price equal to the second-highest bid (Klemperer, 2004).

In practice, the ascending auction and the first-price sealed bid are the most commonly used auctioning mechanism by governments in the hydrocarbon industry (Nordt, 2009).

Under the auction process, the E&P company pays the government a fee to gain rights to perform E&P activities in specific blocks. Alternatively expressed, through an open acreage program¹ the government leases out exploratory blocks to E&P companies. The auction (competitive bidding) process is considered efficient as the price of the winning bid reveals how much value the companies place on specific blocks.² Notably, the bidders do not know how much hydrocarbon they will recover in the exploratory blocks and therefore do not know the actual value of the blocks. The auction process ensures that the blocks are allocated to the companies that value them the most. In contrast, the informal open-door negotiations, and administrative licensing are less efficient as they may be more susceptible to collusion, which in turn reduces both competition among the companies and the revenue the government may earn from the awarding of the lease with the E&P rights to the blocks.

The effectiveness of an auction process depends upon how well it is designed and should consider:³ (i) the uncertainty of the industry; (ii) the characteristics of the blocks; (iii) the potential for collusion; (iv) the reservation price; (v) the work program; (vi) local content; (vii) incentives; and (viii) taxes.

Apart from the aforementioned issues, a well-designed auction program should also include: (ix) an announcement or invitation to bid; (x) a prequalification of potential bidders; (xi) a technical data package; (xii) bidding rules; and (xiii) contractual terms.

Now that the process for the allocation of exploration blocks has been explained, the next section will review how the acreage is allocated in select Western Hemispheric countries.

¹ An open acreage program refers to a program where the government offers exploratory blocks for leasing. The companies that win the lease for the blocks win the rights to perform exploration and production activities in the block. Blocks can be awarded through an auction (competitive bidding process), open-door, or administrative licensing processes.

² Notably, the bidders do not know how much hydrocarbons that they will recover in the exploratory blocks. Therefore, they do not know the actual value of the blocks. This information is considered a competitive advantage (Rodriguez and Suslick, 2009).

³ Explanation of terms found in annex 1.

II. Exploration and production acreage allocations and fiscal regimes in Latin America and the Caribbean

Several countries in the western hemisphere have well defined system for the allocation of E&P rights to acreage (for exploration and production). The acreage refers to the area covered by an exploration and production (E&P) license. This acreage could cover any number of blocks. Once block(s) are awarded to a company for exploration and production (E&P), they have been awarded an acreage Accordingly, this section will explore variances and similarities in the process for awarding acreage in Latin America and the Caribbean, through an examination of the regimes in Brazil, Guyana, Mexico, Suriname and Trinidad and Tobago.

A. Competitive bid rounds in Trinidad and Tobago

Trinidad and Tobago and its surrounding waters are part of the Eastern Venezuelan Hydrocarbon province. Trinidad and Tobago's deep-water area is defined as the area on the east coast of Trinidad that extends from Block 23(a) to the northeast of Tobago to Block 27 in the south. The area includes 6 Blocks and the water depth range from less than 1000m in the southwest to 2000m tending to the northeast of the block (Rajnauth et al., 2004). Trinidad and Tobago has significant upstream activity.

The GORTT historically used PSC in its exploration program. When E&P licenses were awarded, the PSCs (of 1974) made no provision for natural gas. In fact, natural gas found in conjunction with crude oil, also referred to as associated gas, was viewed as a nuisance and was flared off. The PSCs from 1996 contained clauses that specifically address the development of natural gas (Rajnauth and Boodoo, 2004). This change in policy direction was due to the government considering the development of the liquefied natural gas (LNG) export project in the 1990s. In February 1998, Trinidad and Tobago awarded 4 deep-water Blocks to 3 consortiums with operators Shell (Block 25[a]), Exxon (Blocks (25[b] and 26), and Arco (Block 27) (Rajnauth et al., 2004). The PSCs included: (i) a 5-year exploration phase work

program; (ii) exploration wells to minimum commitment depths; (iii) acquisition and processing of seismic data; and (iv) signature bonuses (Rajnauth and Boodoo, 2004).

1. Trinidad and Tobago's competitive bid rounds 1996–2020

Trinidad and Tobago utilizes the auction model to allocate E&P rights. PSCs are used to define the terms under which the winning bidder may produce hydrocarbons (Espinasa and Humpert, 2016). The 1st deep-water auction in Trinidad and Tobago occurred in 1996. This bid round was successful, and 4 blocks were awarded. A total of 3 bid rounds were held between 2001 to 2006 (GORTT MEEI, 2020). Auctions were also held in 2012 and 2013. Collectively, the 2010-2013 through auctions a total of 20 bids were received and a total of 9 blocks were awarded (GORTT MEEI, 2020). The auctions held between 2010 and 2013 facilitated exploration activity in the deep-water blocks. In 2020 a new competitive bid round was launched.

2. Taxes and incentives/concessions

In Trinidad and Tobago, companies operating in the energy sector (crude oil, natural gas, and downstream natural gas) are required to pay a series of taxes. Additionally, several incentives are used to stimulate exploration and production activity. The fiscal regime for the hydrocarbon sector in Trinidad and Tobago is as follows.

(a) Oil sector tax

- A Royalty of 12.5% is charged on the spot price of oil
- A Supplemental Petroleum Tax (SPT)
- $\text{Price} \leq \text{US } \50 —SPT rate = 0%
- $\text{US } \$50 < \text{Price} \leq 90/\text{bbl.}$:
 - Marine 33% {base SPT}
 - Land 18% {base SPT}
- $\text{US } \$90 < \text{Price} \leq \text{US } \200 Formula applicable:
 - $\text{SPT rate} = \text{Base SPT rate} + 0.2\% (\text{P}-90)$
- $\text{Price} > 200$:
 - Marine 55% and land 40% (GORTT MOF 2021a)
- A Petroleum Profits Tax (PPT) and an Unemployment Levy (UL) are charged after SPT. The PPT is 50% on the remaining taxable income, while the Unemployment Levy is 5% on the remaining taxable income.
- Another tax called Green Fund Levy (GFL) is charged at 0.3% of gross revenue.

From January 2023, the tiered system of SPT for new oil wells in shallow water marine areas will be applied as follows:

- \$0 to \$50 oil price—0% SPT
- \$50 to \$70 oil price—15% SPT
- \$70.01 to \$90 oil price—20% SPT
- \$90.01 to \$200 oil price—20% + 0.2%(p-\$90) SPT
- \$200.01 to ∞ oil price—42% SPT

(b) Natural gas and downstream sectors tax

Companies operating in the natural gas sector are subject to a corporation tax.⁴ Notably, for the natural gas and downstream natural gas sectors (ammonia, urea, and methanol) the corporation tax rate is 35%. For the non-energy sector, the corporation tax rate is 30%. The corporation tax is charged on EBIT (EY, 2018; GORTT MEEI, 2021a).

(c) Hydrocarbon sector incentives in Trinidad and Tobago

The PSCs of 1996 were structured as a favorable incentive for E&P companies. First, in exchange for conducting E&P activities in the deep-water blocks, 50% of the recovered hydrocarbons were assigned as cost oil, and the other 50% as profit oil. Therefore, taxes could only be charged on the 50% of the production that was profit oil, and the other 50% that was cost oil was analogous to an allowance.

Second, the government paid all the petroleum taxes (Royalties, PPT, SPT) on the behalf of the deep-water PSC holder. This effectively waived the taxes from the PSC holder on the deep-water production. Therefore, the only economic rents that Trinidad and Tobago acquired came from its net earnings of profit petroleum after paying the contractor's taxes.

The same structure of PSC was used for the 1999 bid rounds. However, a revised structure of PSC was proposed for the 2006 auction.⁵ The proposed PSC structure was a taxable PSC, and it required the contractor to pay all their taxes from its share of the profit oil.

For the 2010 auction, the government increased the cost recovery limit (cost oil) from 50% to 60% and reduced the PPT from 50% to 35% for the taxable deep-water PSCs. In the 2012 auction, the cost recovery was increased to 80% for the deep-water PSCs. The Government of Trinidad and Tobago (GORTT) also offered to pay all the PSC holder's taxes from the state's (the government) share of profit oil (Harewood, 2020).

Over the 2010 to 2020 period, the government also offered capital allowances on E&P activities on tangible costs and intangible drilling and development costs as follows:

- Tangible and intangible capital exploration expenditure may be deducted in full (100%) in the year incurred. This was applied over the January 2014 to December 2017 period (PWC, 2021).
- Tangible and intangible exploration and production expenditure was granted an initial allowance at 50%, a year-two allowance at 30%, and a year-three allowance at 20%. The allowances were based on the expenditure incurred. This allowance expired on December 31, 2019 (PWC, 2021).
- Tangible and intangible exploration and development expenditure is granted an allowance at 20% per annum. The allowance is computed on a straight-line basis over 5 years. This allowance took effect from January 1, 2020 (PWC, 2021).
- A dry-hole allowance which allows for the deduction of 100% of the costs incurred drilling a dry-hole (GORTT MOF, 2021a). This allowance can only be claimed in the year that the dry hole was drilled, and it must be verified by the Ministry of Energy.

⁴ Upstream companies such as BPTT and Shell that engage in E&P activities are supposed to pay royalties, PPT, UL, GFL. However, under the PSCs issued in 2012, the government agreed to pay the taxes for the companies engaging in exploration in the deep-water blocks (Harewood, 2020). This was an incentive granted to the E&P companies. Atlantic LNG, the downstream operator is liable to pay corporation tax.

⁵ No blocks were awarded from the 2006 auction, so the proposed PSC was not used.

- Any company undertaking exploration activities in a deep-water block is eligible for an uplift allowance of 140% of capital expenditure incurred on the drilling of exploration wells. Additionally, the PPT rate is reduced to 35% (PWC, 2021).

In fiscal year 2021/2022 an incentive to encourage enhanced oil recovery was introduced—allowing the investor to recover and write off up to 30% of the project costs up to TT\$500,000 against their tax liability (GORTT MOF, 2021b).

B. Awarding of acreage and fiscal regimes in Brazil

Until 1997, exploration and production activities in Brazil were conducted exclusively by the state-owned petroleum company, PETROBRAS (Rodriguez and Suslick, 2009). In August 1997, the Government of Brazil passed the Petroleum Law to govern the country's hydrocarbon sector. This law made the Government of Brazil the owner of the hydrocarbon resources in reservoirs on land or in marine locations. However, the state-owned agency – Agencia Nacional do Petróleo (ANP), has the authority to grant E&P rights to companies (Tordo et al., 2010).⁶ The ANP falls under the jurisdiction of the Mining and Energy Ministry (Rodriguez and Suslick, 2009).

Since 1998, the ANP has been hosting licensing rounds for leasing acreage for petroleum exploration rights under a concession regime.⁷ Foreign E&P companies were allowed to participate in the auction process. The adopted model is competitive sealed bid auctions, that evaluate bids on a weighted average of the cash bonus, the exploration program, and the percentage of local content in E&P projects (Rodriguez and Suslick, 2009).

In 1998, ANP signed 397 concession contracts, with 115 exploration areas, 51 development areas, and 231 production fields (Rodriguez and Suslick, 2009). This licensing event is known by the Brazilian community as “Licensing Round Zero” (Furtado, 2004; Rodriguez and Suslick, 2009). The success of the auction was influenced by the commercial find of 9 billion bbls of original oil discovered at the Roncador oilfield in 1996 (Rodriguez and Suslick, 2009).

ANP adopted the practice of soliciting E&P companies' feedback through public stakeholder consultations, to ensure that the terms and conditions of the concession contracts matched the foreign companies' experience and expectations in Brazil's petroleum exploration. Additionally, interest is retained by the government's assurance that the companies would be allowed to export the petroleum. This is an important issue since the Petroleum Law stipulated that under a force majeure scenario where there are strong petroleum shortages, the companies would be mandated to sell the petroleum on the domestic market.

Although the Brazil E&P industry is now liberalized, PETROBRAS enjoys a high participation in the auction process. Following the discovery of pre-salt reserves⁸ (Antolín and Cendrero, 2013), in 2010 the government started to use PSCs to increase its take from the hydrocarbon industry (EY, 2019). Notably, the success in the deep waters in Brazil motivated international oil companies to explore the deep waters of Guyana (Krauss, 2021).

⁶ Prior to the ANP, the Conselho Nacional do Petróleo (CNP) played the role of an embryonic regulatory agency. auditing and giving permits for petroleum exploration activities up to 1990 (Rodriguez and Suslick, 2009).

⁷ Concessions were the only instrument used in Brazil for the contracts over the 1998 to 2010 period (Antolín and Cendrero, 2013). PSCs were used in Brazil from 2010.

⁸ Brazil's pre-salt reserves are very large deposits of hydrocarbons trapped below 2km of salt under the seabed (Pickard and Makhijani, 2014).

The Brazilian fiscal regime that applies to the hydrocarbon industry is comprised of corporate income tax, and government and third-party takes. The income tax system is structured as follows:

- An income tax of 15%.
- A surplus tax of 10% for yearly annual income over (US \$60,835).
- A 9% on income for the Social Contribution Tax on Profits (CSLL) (Pedra, 2020).

The aforementioned 3 taxes constitute 34% of taxable income. The taxable income is derived from the revenues minus allowed deductions. Part of the taxable income deductions is the depreciation (Pedra, 2020).

Apart from the income tax, E&P companies are required to pay a royalty. For concessions, the royalty varies between 5% and 10% of the hydrocarbons produced. For PSCs, the royalty is 15% of the volume of the hydrocarbons produced. Notably, the royalties can account for as much 90% of the government's petroleum revenues (Antolín and Cendrero, 2013).

The government and third-party takes include the signature or the cash bonus that is paid on the awarding of E&P rights to blocks, and the take based on the type of contract. The two (2) kinds of contracts that are utilized are concessions, and PSCs. With concessions, bids are evaluated based on the cash bonus, the exploration work program, and the local content (EY, 2019). In contrast, PSCs apply to the pre-salt and other strategic areas. Under PSCs, the bid that offers the greatest volume of oil to the government becomes the winning bid (EY, 2019). This system allows the government to get a larger take from the awarding of acreages.

Brazil has a policy framework called Repetro, which is an incentive regime for E&P activities. Repetro is a special customs regime for export and import of equipment used in the E&P activities (Pedra, 2020). It was created in 1999 with a 20-year initial application period. However, in 2017, the government issued Decree 9.128/17 which extended the program from 2020 to 2040 (Patria Amada Brazil, 2017).

C. Awarding of acreage and fiscal regimes in Guyana

Commercial deposits of crude oil were discovered in the Staebroek block offshore Guyana by Exxon Mobil's subsidiary Esso Exploration and Production Guyana Limited (EEPGL) in 2015. Since the discovery of hydrocarbons in the Liza I field, several additional discoveries were made, pushing Guyana's proved reserves to 10 billion barrels (Oil Now, 2021). In 2020, Exxon Mobil exported its first barrel of oil from Guyana.

Guyana has two main petroleum provinces: (i) the Guyana-Suriname Basin (Guyana Basin) is approximately 120,000 sq. km and is located in the country's Maritime Area, and (ii) the Takutu Basin, which measures 980 sq. km and is situated in south-central Guyana. The Guyana-Suriname Basin is bounded to the south by the Demerara Plateau and to the north by the Pomeroon Arch. It is considered a frontier basin in South America (Balza et al., 2020).

Guyana's hydrocarbon fiscal regime is governed by the Petroleum (Exploration and Production) Act of 1986, which grants the Government of the Cooperative Republic of Guyana (GoG) the authority to grant E&P licenses, and to negotiate PSAs (World Bank 2019). All the E&P licenses in Guyana were awarded through bilateral negotiations. By 2020, 9 offshore blocks were leased, with E&P activity already conducted in 6. E&P activity occurs mainly in the offshore blocks, while the onshore blocks are under-explored.

The fiscal terms for the PSC in Guyana are specified in Article 15 as follows:

- A cost recovery limit of 75% of the value of the hydrocarbons produced from the contract area.
- A minimum government share of oil profit of 50% on a per field basis.⁹
- The GoG is liable to pay the PSCs tax obligations¹⁰ from its share of the profit oil.
- The contractors and subcontractors are allowed to import capital goods, materials and supplies that are used solely for the hydrocarbon operations duty-free.
- An excise tax of 10% (Balza et al., 2020; GoG, 2013).
- Pay an annual license rental fee of US \$100,000 (GoG, 2013).

This notwithstanding, Guyana's Petroleum (Exploration and Production) Act lacks provisions for activities other than exploration and production. Therefore, the fiscal terms are specified primarily through the PSCs. The large cost recovery, and the wavering of taxes could be interpreted as a tilting of the incentives offered by the Government of Guyana slightly in favour of multinational E&P companies. Guyana's Petroleum (Exploration and Production) Act may require updating to support the enhancement of the transparency, governance, legal, regulatory and institutional frameworks for the domestic oil and gas sector. Furthermore, there may also be a need for the modernization of Guyana's hydrocarbon regulatory frameworks in support of the development of the sector, focusing on critical issues such as oil revenue management, licensing, contract models (PSA), local content, and Health, Safety, Environmental and Social (HSES) management (World Bank, 2019).

D. Awarding of acreage and fiscal regimes in Mexico

Mexico has several decades of experience in the hydrocarbon industry. In 1938, the state-owned oil company - Petróleos Mexicanos (Pemex) was formed, and the country's oil industry was nationalized. Pemex was granted exclusive rights over exploration, extraction, refining, and commercialization of oil in Mexico (IMF, 2019).

Mexico's crude oil production peaked at 3.4 million bpd in the year 2004. Since then, the country has experienced falling hydrocarbon production. The decline in production was a consequence of the depletion of the Cantarell oil field, Pemex's lack of financing and technical capacity to explore the offshore Gulf of Mexico, and the restrictions on participation by foreign E&P companies. Subsequently, in the year 2014, the Government of Mexico reformed and liberated its hydrocarbon industry (IMF, 2019).

Under its liberalized framework for the hydrocarbon industry, Mexico uses two systems to allocate E&P rights. First, entitlements contracts, where the National Hydrocarbons Commission (CNH) allocates E&P rights to blocks exclusively to Pemex.¹¹ Secondly, CNH auctions E&P rights to specific blocks (Velarde, 2021).

The auction process is generally structured into four main stages:

- (i) Questions and answers: At this stage of the process companies may request information in respect of the block available, and a draft of the model contract. Companies may also

⁹ The cost oil is 75% of production. Therefore, profit oil is 25% of product. The government receives its 50% share from the profit oil, resulting in an effective share of 12.5%.

¹⁰ The tax obligations are the royalty, the corporation tax, and the property tax. In the PSC with Repsol, the royalty was 1% (GoG, 2013). Guyana's corporation tax rate for commercial companies is 45%.

¹¹ After the 2014 reform, Pemex was granted E&P rights over 83% of the proven and probable reserves and 21% of Mexico's prospective reserves. Therefore, multinationals are essentially used for to conduct E&P for prospective reserves.

indicate a certain acreage that they are interested in bidding on. Companies are required to pay a non-refundable fee to participate in the auction. In the 2018 auction, this fee was US \$46,000.

- (ii) Pre-qualification: During this stage the CNH may submit an expression of interest, and allow companies to submit information on their credentials and capacity.
- (iii) Bid submission: Where the interested companies submit proposals and bids to undertake a work program of E&P activities in specific blocks. The companies are usually given between 10 to 12 months to submit bids.
- (iv) Bid evaluation and award: Here the proposals are reviewed and evaluated by the CNH. The CNH then awards companies E&P rights to specific blocks based on the work program, the local content, and the profit oil for the state.¹² Notably, the terms and conditions of E&P contracts are non-negotiable. Any company that has been awarded the E&P rights to a block is expected to implement the final version of the model contract without changes (Velarde, 2021).

Pemex is allowed to take an existing entitlement and farm-out a block through an auction. Pemex can also use CNH to facilitate the auctioning of its acreage.

The fiscal regime for the hydrocarbon industry in Mexico is stipulated by the Law on Hydrocarbons Revenue of 2014 (Talamantes, 2014; EY, 2019). The companies are required to pay the state as follows:

- An upfront reservation price. Companies that have been awarded E&P rights to blocks are required to make an upfront lump sum payment to the state. This is determined by the Ministry of Finance for each contract, and it is revealed during the bidding process.¹³
- A contractual quota for exploration period (CQEP). The CQEP is a periodic fee that must be made before extraction activities begin. For the 2019 fiscal year, the CQEP was US \$70 per square kilometer (km²), and it was scheduled to increase to US \$168/ km² for each period thereafter.
- A revenue-based royalty: For a spot oil price under US \$49.36/ bbl., the royalty is 7.5% of the price of oil. For a price of oil greater than US \$49.36/ bbl., the royalty is computed via a formula.¹⁴
- Over-royalties: Payments in addition to the royalties are made to the Mexican government. An adjustment mechanism is added to effectively capture extraordinary profits.

¹² The reservation price is not necessarily a deciding factor in the award of the acreage since the CNH states what reservation price it wants.

¹³ For example, one time the Ministry of Finance decided that the reservation price should be \$1,150 pesos per km² and from month 61 and thereafter in the amount of \$2,750 pesos per km² (Deloitte, 2015).

¹⁴ $Royalty = ([0.122 \times \text{oil price}] + 1.5) \%$.

For associated natural gas,¹⁴ the spot price is divided by 102.85.

For non-associated natural gas, if the spot price is less than US \$5.15 per million British thermal units (mmbtu), the royalty is 0%.

For non-associated natural gas, if the spot price is between US \$5.15/ mmbtu, and US\$5.65/ mmbtu the following formula is used.

$Royalty = ([\text{natural gas price} - 5.15] \times 60.5) / \text{natural gas price}$.

For non-associated natural gas, if the spot price is more than US \$5.65/ mmbtu, the royalty is equal to the spot price divided by 102.85.

Condensates royalty. For condensates, if the spot price is less than US \$61.71 the royalty is 5%.

For condensates, if the spot price is greater than US \$61.71/ mmbtu, the following formula is used.

$Royalty = ([0.122 \times \text{contractual condensate price}] - 2.5) \%$.

If the daily production reaches a determined cap, an over-royalty is paid to the Mexican government based on a formula that is contained in the contract. This applies to both PSCs and concessions.

- Government's percentage of operating profit: For PSCs, the cost recovery limit (cost oil) and the profit oil are stated in the contract. During the auction process, the company proposes in its bid what share of the profit oil would be allocated to the government. Notably, this is one of the factors that the CNH considers in the awarding of blocks. Additionally, this provision also makes the tax progressive.

Under the PSCs, the operating profit (profit oil) is determined by subtracting from the value of the hydrocarbons, the royalties, and the cost recovery limit (cost oil). The following costs are considered non-recoverable: (i) financing costs; (ii) costs incurred from negligence or fraud; (iii) donations; (iv) expenses derived from the acquisition of land; (v) non-approved advisory services; (vi) cost from non-compliance of the relevant provisions; (vii) unqualified training expenses; (viii) cost from non-compliance of warranties; (ix) expenses for the use of owned technology; (x) legal fees; (xi) broker fees; (xii) royalties; (xiii) expenses and investments related to other contracts; and (xiv) costs that are not necessary for the implementation of the contract. There is also a cap on the cost recovery for up to 60% of the value of production in any month. Unrecovered costs can be carried forward until fully recovered (EY, 2019).

Capital costs for exploration, secondary and enhanced oil recovery, and non-capitalized maintenance are allowed to depreciate up to 100% of its total costs. Up to 25% of the original investment costs in the development of oil and natural gas deposits can be written off as depreciation. Depreciation can be included as part of the costs in the cost recovery. Other elements of the hydrocarbon fiscal regime, include:

- Income tax rate. Companies registered in Mexico are required to pay an income tax of 30% on the chargeable income. An incentive for businesses operating in the northern border zone of Mexico was introduced in 2019, which reduced the income tax rate from 30% to 20% for the beneficiary companies.
- Dividend payments income tax withholding. From 2014, the Mexican government charged a 10% withholding tax on dividends paid to Mexican individuals and foreign residents.
- VAT — 0% (i.e., E&P activities).

E. Awarding of acreage and fiscal regime in Suriname

Oil was first discovered in Suriname in 1928 (Biharisingh-Raghoenath and Griffith, 2013) at a 160 m depth while drilling for water in a schoolyard in Calcutta Village, in the coastal District of Saramacca (Cool and Vioria, 2021). Systematic exploration only started in the 1960s when international oil companies (IOCs) became interested (Biharisingh-Raghoenath and Griffith, 2013). The onshore Tambaredjo oil field was discovered in 1968, and the first oil was produced in 1982.¹⁵ The original oil in place (OOIP)¹⁶ was 1 billion bbl. (Cool and Vioria, 2021).

In 1980 Staatsolie Maatschappij Suriname NV (Staatsolie) was established (Tjon-Akon and Hausil, 2020). Staatsolie is involved in the full value chain of the oil industry, including E&P upstream, transportation and refining at the midstream, and marketing and distribution at the downstream (Biharisingh-Raghoenath and Griffith, 2013). The company is the sole holder of mining rights to

¹⁵ First oil was produced by Staatsolie.

¹⁶ The OOIP refers to the total volume of oil in a reservoir.

hydrocarbons in Suriname, both onshore and offshore. Additionally, the company acts as the petroleum regulator, it is responsible for promoting open offshore acreage, delegating E&P rights to blocks, and negotiating PSCs with IOCs (Tjon-Akon and Hausil, 2020).

Staatsolie produces and refines oil from its onshore operation in the Tambaredjo oil field, but it licenses out the other acreage (Nat Law, 2002). Between 1982 to 2013, 100 million bbl. of Saramacca Crude, a heavy sweet oil, were produced. The Calcutta and the Tambaredjo Northwest Fields have been in operation since 2003 and 2009 respectively (Biharisingh-Raghoenath and Griffith, 2013).

Exploration activities offshore were less successful. Between 1957 and 1980, 4 exploration wells were drilled offshore, but they were dry holes. In 2000, a study conducted by the United States Geological Survey (USGS) revealed that the Suriname-Guyana Basin is an under-explored basin with a resource potential of 15 billion bbl. Staatsolie used this information and started to offer acreage through auctions. An auction was held in 2004, and Repsol and Murphy each drilled 2 wildcat wells over the 2007 to 2011 period. These wells were also dryholes. Subsequently, in 2013 a 2D and a 3D survey were conducted over the Suriname-Guyana Basin by RWE Dea¹⁷ (Biharisingh-Raghoenath and Griffith, 2013).

In 2017, Tullow announced a discovery of natural gas at the Araku-1 well offshore Suriname (Cool and Viloría, 2021). The first commercial oil discovery offshore Suriname was made on January 7, 2020, by Apache Corporation and Total in the Maka-1 exploration well in Block 58. Additional commercial discoveries (of oil and gas) were made by the consortium on April 2, and July 29, 2020 (Tjon-Akon and Hausil, 2020). Petronas Suriname announced an oil discovery at the Sloanea-1 well in December 2020 (Cool and Viloría, 2021).

The fiscal regime for the hydrocarbon industry in Suriname can be summarized as follows:

- Auctions are not mandatory. Staatsolie can choose to hold an auction or engage in open-door negotiation to award blocks to E&P companies (Nat Law, 2002).
- 30-year PSCs to govern E&P activity (Krauss, 2021).
- A royalty equal to 6.25% of oil companies' revenue (Krauss, 2021).¹⁸
- Companies (including E&P companies) are liable to pay an income tax of 38% (Nat Law, 2002). Companies with PSCs are required to pay their taxes from their share of the profit oil.
- Cost oil, profit oil, and the reservation price are negotiated by parties in the PSCs.

¹⁷ RWE Dea is a private sector hydrocarbon company. It acquired a 40% equity stake in Block 52 when it was farmed-out by Petronas Suriname.

¹⁸ In the United States, companies typically pay a royalty of 12% for oil found on public land. In developing countries, the average rate for a royalty on oil is 16% (Krauss, 2021).

III. Comparison of fiscal regimes

The hydrocarbon fiscal regimes are computed for each country. Note the calculations do not reflect the actual revenues earned by each country. Rather, assumptions are made from each country's fiscal regime, and are used to show how the government's take and effective tax would differ based on a given set of production data as well as oil prices. The fiscal regime of Trinidad and Tobago is the first one considered.

A. Trinidad and Tobago

Although the average price of oil in 2020 was \$39.16, this value was not used to compute the tax. This is due to the tax in Trinidad and Tobago being paid quarterly, in March, June, September, and December. The oil prices for the aforementioned months were \$29.21, \$38.31, \$39.63, and \$47.02 respectively. This produced an average price of oil of \$38.54. Subsequently, this 4-month average price was used to compute the taxes in the year 2020.

The same principle was applied for 2021. The oil prices for March, June, September, and December 2021 were \$62.33, \$71.38, \$71.65, and \$71.71 respectively. The 4-month average price was \$69.27. For the year 2022, September price of \$84.26 was used.

The total marine production for Trinidad and Tobago in 2020 was 461,616 barrels (GORTT MEEI, 2021b). Although the oil production for Guyana differs from Trinidad and Tobago, for cross-comparison, this 461,616 barrels in production is used for all the countries. The reservation price is not incorporated for any of the countries as this information is not publicly available. Furthermore, as reservation price is often negotiated, it will vary on a contract basis.

The fiscal regime for Trinidad and Tobago is computed and presented in table 1. Multiple scenarios of the different oil prices are displayed to show how the government take would change as the revenue changes.

Table 1
Fiscal regime for Trinidad and Tobago using a hypothetical production level

Fiscal regime	2020	2021	Sep-22	New fiscal regime ^a based on Sept 2022 prices
Values in percentages ^b				
Royalty	12.5	12.5	12.5	12.5
Effective tax	31	48	53	50
Total marine production in 2020 (barrels)	461 616	461 616	461 616	461 616
Values in US dollars				
Average oil price	38.54	69.27	84.26	84.26
Total revenue	17 790 681	31 976 140	38 895 764	38 895 764
Average total cost per barrel	20	20	20	20
Cost oil	9 232 320	9 232 320	9 232 320	9 232 320
Royalty revenue	2 223 835	3 997 018	4 861 971	4 861 971
Supplemental petroleum tax	0	2 935 462	5 218 938	3 162 993
Taxable income for petroleum profit tax	6 334 526	15 811 340	19 582 535	21 638 481
Petroleum profit tax	3 167 263	7 905 670	9 791 268	10 819 240
Unemployment levy	158 363	395 284	489 563	540 962
Green fund levy	53 372	95 928	116 687	116 687
Total tax paid	5 602 833	15 329 362	20 478 427	19 501 853

Source: Economic Commission for Latin America and the Caribbean based on official figures.

^a The estimations for the new fiscal regime only apply to new oil wells in shallow water marine areas. Furthermore, it is scheduled to take effect from January 2023 not September 2022. Therefore, the calculations are only a scenario based on assumptions.

^b Values in percentages unless otherwise specified.

As can be seen in table 2, when 2020 oil prices of US\$38.54/bbl. is used, the effective tax paid to the GORTT is 31%. However, when the price of oil is increased to US\$69.27/bbl., the effective tax paid to the government is 48%. Likewise, when oil prices increased to US\$84.26, the effective tax to the government increased to 53%. Therefore, the SPT included in Trinidad and Tobago's fiscal regime ensures that the tax structure is progressive.

Note, that even under high oil prices of US\$84.26/bbl., the tax that would accrue to the government would only be approximately US\$20.4 million. The total cost of an offshore drilling campaign can be as high as over US \$200 million. Therefore, if Trinidad and Tobago uses a fiscal incentive that allows 100% of the cost of exploration activity to be written off its tax liability, it can result in the multinational hydrocarbon corporation paying no tax.

B. Guyana

The fiscal regime based on the assumptions for Guyana is displayed in table 2. Note, the assumption of oil production of 461,616 barrels (*the total marine production for Trinidad and Tobago in 2020*) is made merely to allow for cross-country-comparison.

Table 2
Fiscal regime for Guyana using a hypothetical production level

Fiscal regime	2020	2021	Sep-22
Values in percentages ^a			
Royalty	2	2	2
Effective tax	14.5	14.5	14.5
Corporation tax	45	45	45
Assumed cost oil (share of total revenue)	75	75	75
Government share of profit oil	50	50	50
Guyana's assumed marine production in 2020 (barrels)	461 616	461 616	461 616
Values in US dollars			
Average oil price	38.54	69.27	84.26
Cost oil	10 674 408	19 185 684	23 337 458
Total revenue	17 790 681	31 976 140	38 895 764
Royalty revenue	355 814	639 523	777 915
Production sharing contract government take	2 223 835	3 997 018	4 861 971
Total Government take	2 579 649	4 636 540	5 639 886
Corporation tax revenue	1 000 726	1 798 658	2 187 887

Source: Economic Commission for Latin America and the Caribbean based on official figures.

Note: Total government take comprises of royalty and production sharing contract government take. Guyana's assumed marine production in 2020 is derived from Trinidad and Tobago's marine production in 2020.

^a Values in percentages unless otherwise specified.

As can be seen in table 3, under the scenario of 2020 oil prices of US\$38.54/bbl, the effective tax for Guyana was 14.5%. Under the scenario where oil prices rose in 2021 and 2022 to US\$69.27/bbl. and US\$84.26/bbl the effective tax for Guyana remained at 14.5%.

Assuming an oil production of 461,616 bbls., and an oil price of US\$38.51/bbl., if the government paid the royalty and the corporation tax on the behalf of the multinational hydrocarbon company out of its share of the profit oil, it would forego approximately US\$1 million in revenue. Since the government owns the Guyana Revenue Authority, the government's payment of the aforementioned taxes (royalty and corporation tax) is essentially a payment to itself. This effectively waives the multinational from paying the royalty and the corporation tax.

Therefore, the current fiscal regime in Guyana is proportional. Particularly, the potential revenue from corporation tax is significantly larger than the royalty revenue. This represents an opportunity cost to the government since it could have earned this additional revenue from the multinational hydrocarbon company, if the fiscal incentive of paying the company's corporation taxes.

C. Mexico

The fiscal regime based on the assumptions for Mexico is displayed in table 3. Note, the assumption of oil production of 461,616 barrels is made only for cross-country- comparison. The income tax rate of 20% was used to incorporate the effect of the northern border zone incentive. Recall, the over royalty

rate is not set by CNH, but by each bidder as part of its bid for a license. The E&P licenses are given to the bidder that proposes the highest rate. Therefore, in practice, the over royalty rate will vary for each block. For this study, an over royalty rate of 20% is used.

Table 3
Fiscal regime for Mexico using a hypothetical production level

Fiscal regime	2020	2021	Sep-22
Values in percentages ^a			
Royalty	7.5	10.0	11.8
Assumed cost oil (share of total revenue)	60	60	60
Effective tax	34.0	36.0	37.4
Mexico's assumed marine production in 2020 (barrels)	461 616	461 616	461 616
Values in US dollars			
Average oil price	38.54	69.27	84.26
Cost oil	10 674 408	19 185 684	23 337 458
Total revenue	17 790 681	31 976 140	38 895 764
Royalty revenue	1 334 301	3 181 926.54	4 581 812
Income tax	1 156 394	1 921 706	2 195 299
Over royalty revenue	3 558 136.13	6 395 228.06	7 779 152.83
Total government take	6 048 831.42	11 498 860.52	14 556 263.65

Source: Economic Commission for Latin America and the Caribbean based on official figures.

Note: Total government take comprises of royalty and production sharing contract government take. Mexico's assumed marine production in 2020 is derived from Trinidad and Tobago's marine production in 2020.

^a Values in percentages unless otherwise specified.

As can be seen in table 4, when the 2020 oil prices of US\$38.54/bbl. is considered, it yields an effective tax of 34% and a government take of approximately US\$6 million. Under the scenario of US\$69.27/bbl. oil prices, the effective tax was 35.969%, and the government's take was approximately US\$11.5 million and under the scenario of oil prices of US\$84.26/bbl., the effective tax was 37.42%, and approximately \$14.5 million in revenue would accrue to the government. Therefore, Mexico's fiscal regime is progressive. Particularly, the attractive features of this tax regime are:

- setting the cost recovery limit (cost oil) to any month at 60% of the value of the oil;
- including corporate income tax (although it was reduced from 30% to 20% as an incentive);
- setting a higher royalty rate for higher oil prices; and
- including an over royalty tax.

D. Brazil

The fiscal regime based on assumptions for Brazil is shown in table 4. The cost recovery limit is assumed to be 60%. The income tax is set at 34%.

Table 4
Fiscal regime for Brazil using a hypothetical production level

Fiscal regime	2020	2021	Sep-22
Values in percentages ^a			
Assumed cost oil (share of total revenue)	60	60	60
Effective tax	28.6	28.6	28.6
Brazil's assumed marine production in 2020 (barrels)	461 616	461 616	461 616
Values in US dollars			
Average oil price	38.54	69.27	84.26
Cost oil	10 674 408	19 185 684	23 337 458
Royalty	5.78	10.39	12.64
Total revenue	17 790 681	31 976 140	38 895 764
Royalty revenue	2 668 602	4 796 421	5 834 365
Income tax	2 419 533	4 348 755	5 289 824
Total government take	5 088 135	9 145 176	11 124 189

Source: Economic Commission for Latin America and the Caribbean based on official figures.

Note: Total government take comprises of royalty and production sharing contract government take. Brazil's assumed marine production in 2020 is derived from Trinidad and Tobago's marine production in 2020.

^a Values in percentages unless otherwise specified.

As can be seen in table 4, under the 2020 oil prices scenario, the effective tax for the Brazil scenario was 28.6%. The government's take was approximately US\$5 million. For the 2021 oil prices scenario, the effective tax was 28.6% and the government's take was approximately US\$9 million. For the 2022 oil prices scenario, the effective tax was 28.6% and the government's take was approximately US\$11 million. Therefore, the fiscal regime is proportional.

E. Suriname

The fiscal regime based on the assumptions for Suriname is shown in table 5.

Table 5
Fiscal regime for Suriname using a hypothetical production level

Fiscal regime	2020	2021	Sep-22
Values in percentages ^a			
Effective tax	21.5	21.5	21.5
Assumed cost oil	60	60	60
Suriname's assumed marine production in 2020 (barrels)	461 616	461 616	461 616
Values in US dollars			
Average oil price	38.54	69.27	84.26
Royalty	2.41	4.33	5.27
Total revenue	17 790 681	31 976 140	38 895 764.16
Royalty revenue	1 111 917.54	1 998 508.77	2 430 985.26

Fiscal regime	2020	2021	Sep-22
Values in US dollars			
Income tax	2 704 183	4 860 373	5 912 156
Total government take	3 816 101.00	6 858 882.10	8 343 141.41

Source: Economic Commission for Latin America and the Caribbean based on official figures.

Note: Total government take comprises of royalty and production sharing contract government take. Suriname's assumed marine production in 2020 is derived from Trinidad and Tobago's marine production in 2020.

^a Values in percentages unless otherwise specified.

Table 5 shows that under the 2020 oil prices scenario, the effective tax for the Suriname scenario was 21.45% and the government's take was approximately US\$3.8 million. For the 2021 oil prices scenario, the effective tax was 21.45% and the government's take was approximately US\$6.86 million. For the 2022 oil prices scenario, the effective tax was 21.45% and the government's take was approximately US\$8.3 million. Therefore, the fiscal regime was proportional.

The following section will propose the policy recommendations for an appropriate hydrocarbon fiscal regime for Caribbean economies.

IV. Policy recommendations

Generally, country circumstances require customized policy-prescriptions. However, the analysis undertaken in the previous chapter suggests, in a general sense, that a hydrocarbon fiscal regime that combines a royalty, and a tax targeted on windfall rents (along with the standard corporate income tax) tends to be progressive in nature. As such, this paper suggests that an optimal hydrocarbon fiscal regime for oil-and-gas-rich economies in Latin America and the Caribbean could be structured as follows.

A reservation price/ bonus payment

Bonus payments (reservation price, discovery bonuses) can be part of any hydrocarbon fiscal scheme. Bonus payments are usually lump-sum payments triggered by myriad defined events. For example, a bonus payment (reservation price) could be made to the government upon the award of a block to an E&P company. These bonus payments can be set in legislation, negotiated (in concessions), or biddable (in auctions). Biddable bonus payments can generate huge rents for the government for example, in Angola in the 2006 bid round the winning bid for blocks 17 and 18 went to the Chinese oil firm Sinopec that offered over US\$1 billion in the reservation price (Reed, 2009). A reservation price could be proposed by the companies during the auction process.

Royalty

A royalty charged on the gross value on the hydrocarbons should be included in the fiscal regime. In other words, the royalty should be charged directly on the price of oil. Royalties can safeguard potential government revenue from being eroded where a multinational energy company engages in transfer pricing to overstate its costs. Companies can also reduce taxable income by applying a series of deductible costs. This in turn would reduce the tax collected by the government. However, when the government charges royalties based on the spot price of the hydrocarbon these potential sources of loss of income can be obviated.

Windfall tax

In order for the hydrocarbon fiscal regime to be progressive, a windfall tax must be applied. The windfall tax can be charged in 2 ways. In the first option, the windfall tax is applied on the spot price of the hydrocarbon. The framework would allow for the capture of windfall rents in bullish periods. Trinidad and Tobago's SPT provides a good example of a windfall tax based on price. The second type of windfall tax is applied to the production of hydrocarbons. This framework would implement one tax rate for a given scale of the hydrocarbon production, then as the production rate increases to a new scale, and higher tax rate, is applied. For example:

- When the oil production rate is 100,000 bpd, a windfall tax of 5% could be applied.
- When the oil production rate increases to 500,000 bpd, a windfall tax of 10% could be applied.
- When the oil production rate increases to 1 million bpd, a windfall tax of 15% could be applied.

Cost recovery limit

It is common for PSCs to have stipulated cost recovery limits. Even under concession arrangements, income taxes are charged on profit oil rather than gross revenue. Therefore, it is practical for a government to offer a cost recovery limit in its fiscal regime.

As many governments of hydrocarbon-rich developing countries tend to be dependent upon hydrocarbon tax revenue to offset both recurrent and capital expenditures, the timing of the collection of the revenue is also crucial. These governments often cannot await full cost, inclusive of sunk costs, recovery by the multinational hydrocarbon company before it receives any tax revenue. For this reason, governments should consider placing a limit on the cost recovery which can be claimed in any given month. A reasonable cost recovery limit ranges from 60% to 75%. The actual value of the cost recovery limit could be proposed by the bidders in the auction process. Furthermore, cost recovery should be ring-fenced, where the investor would not be able to claim these costs as an allowance after they have been fully recovered. Angola and Australia both have ring-fenced cost recovery limits. The United Kingdom (UK) has a ring-fenced cost recovery limit that is based on time.

Payment of taxes

Governments may be tempted to offer to pay the taxes from its share of the profit oil as a fiscal incentive. But this will effectively waive the investor from paying taxes and reduce the government's intake. Therefore, it is recommended that any taxes that the multinationals are liable to pay should be taken from the multinational company's share of the profit oil.

Depreciation allowance

It is common for hydrocarbon fiscal regimes to include incentives to cover the depreciation of capital, therefore in pursuit of the optimal hydrocarbon regime for Caribbean (as well as Latin America) economies, this paper recommends that a depreciation allowance also be included.

A. Incentives and allowances for sunk costs

Designing taxes on hydrocarbon economic rents requires careful attention to costs incurred at all stages of production. At the exploration stage, high sunk costs are incurred, and the risks are high as wildcat wells can be dry holes. Even if hydrocarbon reserves are found in blocks, some of the wildcat wells may not be used as production wells. Therefore, multinational hydrocarbon companies will lobby the

government in the host country for fiscal and other incentives to either cover or offset these risks and costs. If the multinational hydrocarbon companies are unable to recover these costs through incentives, it may make some exploration projects unprofitable.

Therefore, it is only rational for a government to consider granting a multinational hydrocarbon company an incentive to allow it to recover these costs. However, it is imperative that government exercise some measure of caution against granting too many incentives, as this can erode the government's fair share of the economic rent.

Notably, many countries may lack the technical and financial capacity to explore their offshore acreage for hydrocarbons. Therefore, they rely on foreign multinational companies for this expertise. Multinational companies, aware of this fact, are often well equipped and sufficiently nimble to move their capital to jurisdictions with lower effective tax rates. Governments, competing for foreign capital may therefore be tempted to offer excessive incentives. This scenario, which is often referred to as the "*race-to-the-bottom*", may effectively reduce the government's take of the hydrocarbon economic rents (Razin and Sadka, 2012; Readhead, 2018). For this reason, this study argues in favor of collusion between Caribbean (as well as Latin America) governments in efforts to attract foreign investment.

Collusion in searching for foreign capital will go a long way in ensuring that each government captures its fair share of the hydrocarbon rents. Subregional-wide collusive behaviour in this regard would likely strengthen the negotiating position of governments in the consideration of incentives.

Given that Guyana, Suriname and Trinidad and Tobago are CARICOM Member States, it would be rational for the governments of these countries to collectively meet and strategize on how they may attract foreign capital to explore their offshore blocks. This process would involve the sharing of information between countries, and the development of a regional strategy or policy for attracting foreign direct investment in the hydrocarbon sector. The sharing of information with respect to production costs can help reduce asymmetric information and safeguard countries from multinationals that may be inclined to overstate costs.

It should be noted that collusion in the hydrocarbon industry is not uncommon. In fact, multinational hydrocarbon companies often informally collude in the bidding for blocks during auctions to reduce the reservation price. Hydrocarbon companies also formally collude through unitization agreements to jointly explore offshore blocks. Companies also subcontract exploration and production services through lease-out and farm-out arrangements.¹⁹ Moreover, the Organization of Petroleum Exporting Countries (OPEC) colludes by setting production quotas to influence oil prices.

B. Open acreage licensing policy—best practices for E&P

Deposits of hydrocarbons are often trapped in reservoirs offshore. In order to extract and commercially produce these hydrocarbons, the offshore blocks must be awarded to investors, who in turn would implement an appropriate work program of activities. The investor must have both the technical and financial capacity to produce the hydrocarbons. The probability of successful finds can also be increased if the investor utilizes the latest and appropriate technologies to properly image and visualize geological formations. While local hydrocarbon companies may have some technical capacity, foreign multinational hydrocarbon companies are more likely to have a decidedly significant advantage in this area. Therefore, governments can facilitate increased production of hydrocarbons by allowing foreign investor participation. This can be facilitated by the implementation of an open acreage program.

¹⁹ Under the lease-out arrangement only the well is leased out and the operator has limited rights for the development of petroleum resources in the block. Production is generally confined to the formation across which the well was initially perforated. As a result, there is no drilling obligation. With the Farm-out operatorship the operator has unlimited rights to petroleum development in the block at any depth and also is required to drill new wells to develop these resources.

As mentioned before, this can be implemented through either open-door systems or auctions (or a combination of the two). The auction system is advantageous as it encourages competition, and it can be used by the government to gauge the potential value of different blocks.

Many countries such as Australia, Canada, India, Norway, Russia, and the UK use an open acreage licensing policy to grant investors access to their hydrocarbon resources (Pratik, 2020). The attractive features of an open acreage licensing policy are as follows:

Data access

The investor seeking to engage in E&P activity should be given a good data package containing information on geological formations, seismic maps, and drilling success to assess a block's hydrocarbon potential. This practice is implemented in Australia, Canada, India, Norway, Russia, and the UK. In fact, Australia also has a Petroleum Data Repository, which stores the available technical data, and can be accessed by the oil companies to study before bidding for blocks. India also has a National Data Repository, which stores and shares technical data. It is complemented by the country's Petroleum and Natural Gas Rules of 1959 which mandates every exploration and production licensee in India to share all the survey data with the government. This conditionality is useful as it allows the government to accumulate technical data without incurring any additional costs.

Notably, there is a possibility that some blocks may be devoid of data. India has moved to address this issue by classifying its acreages into three types: Zone 1 for which sufficient data is available, Zone 2 for which moderate data is available, and Zone 3 for which no data is available (Pratik, 2020). The Governments of Guyana, Suriname and Trinidad and Tobago (as well as its Latin American partners) may wish to consider adopting a similar approach.

Nomination of blocks

Some countries allow potential investors to nominate the blocks for auctioning. For example, Australia and Trinidad and Tobago allow E&P companies to nominate blocks for competitive bidding. In contrast, some countries only allow potential investors to bid on blocks offered. The first approach is more market friendly as investors may be more likely to submit bids on blocks that they are attractive to them rather than blocks in which they have little or no interest. However, as discussed earlier, Guyana does not utilize the auction process. The country engages in open-door negotiation, and this has been successful thus far in attracting interest in its deep-water blocks. Since this process is presently working, it would be logical for Guyana to continue this practice.²⁰

Formula for awarding blocks

This paper also recommends that subregional hydrocarbon-rich governments should award the E&P rights based on a formula. Notably, a leading policy-objective of these governments may be maximizing their share of hydrocarbon economic rents, as such they may be tempted to place the greatest emphasis on the reservation price/ cash bonus. This approach carries the risk of making the fiscal framework regressive particularly if the winning investor fully implements its work program, and there is little local content. For this reason, consideration should be given to adopting a formula that weights the reservation price, the work program, and the local content participation. An example of formula is given below:

$$\text{Winning bid} = 40\% \text{ reservation price} + 40\% \text{ work program} + 20\% \text{ local content.}$$

²⁰ However, as an industry best practice, the auction model has shown to be a more efficient mechanism for maximizing rents. Accordingly, this study is inclined to recommend that subregional governments that currently don't engage in auctioning of blocks, and which are seeking to attract additional interest in their offshore acreage, could, over time, cautiously integrate an element (marginally at first) of the auction model thereby allowing potential investors to nominate blocks.

PSC and sharing of revenue

Cost recoveries, which are inherent to PSCs, make it necessary for the government to actively monitor the investors' expenditures on a regular basis. However, a government of a country that is new to the hydrocarbon industry, such as Guyana, may find difficulty in effectively monitoring the costs of the foreign investor. Even in experienced jurisdictions, the government may find difficulty in effectively monitoring the foreign investor's costs, as the investor may be a vertically integrated multinational corporation with several subsidiaries. The multinational may conduct several transactions with their subsidiaries, and thus there will be a multitude of opportunities to overstate costs and shift value to the subsidiaries with the lower tax liability. Indeed, if transactions are not conducted on an arm's length basis, there will be huge potential for the loss of value through transfer pricing.

India has addressed this problem (of monitoring costs) by replacing its production sharing contract model with a revenue sharing model, wherein government receives a share of revenues rather than a share of profits.

Notably, this revenue sharing model causes the investor to start sharing revenue with the government from the outset before costs are recovered. While this fiscal regime is designed to ensure that the government maximizes its hydrocarbon economic rents, it is not favored by investors. In fact, India's revenue sharing model has been identified as a limitation to its open acreage licensing policy. Moreover, the revenue sharing model has been flagged as the main reason why India's auctions do not attract many foreign bids (Pratik, 2020).

Therefore, this study argues that the revenue sharing model may be regressive if it causes a loss of investor interest. Subsequently, the production sharing contract model with cost recoveries should be continued in Guyana, Suriname and Trinidad and Tobago. The monitoring of costs should be addressed by hiring sufficient personnel with competence in energy economics.

License for E&P

In Australia and India, the government grants 2 separate licenses for exploration and production, respectively. In Norway and the UK, one license is required to conduct all phases of operations. The same 1 license principle also applies to Guyana and Trinidad and Tobago. For simplicity, hydrocarbon-rich economies in Latin America and the Caribbean should consider utilizing a system that offers one license for both exploration and production.

Technical capacity strengthening

As an additional recommendation, technical capacity strengthening should be seen as a *sine qua non* for hydrocarbon-exporting subregional economies. This will be useful for Guyana which has recently entered into the industry and currently has limited local personnel with technical capabilities in such disciplines as energy economics, geology, petroleum geoscience, and reservoir engineering. As such, the government will need to liaise with the multinationals, seeking to build its domestic capacity to undertake, *inter alia*, contract negotiation, monitoring costs, monitoring spot and futures prices, econometric forecasting of prices, recording declarations of discovery, reviewing annual work programs, reviewing well abandonment plans, ensuring compliance with environmental regulations, ensuring compliance with health and safety regulations, and collecting data from surveys.

V. Conclusion

Oil and gas-rich subregional economies require a fiscal regime that is sufficiently incentivized to attract and retain investors to engage in exploration and production activity, while allowing the government to get its fair share of the hydrocarbon rents.

This study found that an optimal (and fair) fiscal framework should contain the following provisions:

- A reservation price/ cash bonus, for the awarding of blocks.
- A royalty charged on the gross value of the hydrocarbons.
- A windfall tax charged on the profit from the production and export of the hydrocarbons.
- Taxes should be paid from the investor's share of profit oil.
- The fiscal framework should also contain the following incentives.
- A cost recovery limit, to allow the investor to recover their costs. There should be a clearly defined cost recovery limit. There should also be a limit on how much the investor can claim as cost recovery in any taxable month. Additionally, the cost recovery should be ring-fenced, so that sunk costs would no longer be deductible after they have been fully recovered.
- An allowance for depreciation.
- An allowance for tertiary recovery methods, such as enhanced oil recovery.

Governments can concomitantly operate an open acreage licensing program to award the blocks to potential investors. The following features should be included in the program:

- The investor should be given a good data package containing technical information.
- The government should award the blocks based on a formula that weights the reservation price, the work program, and the local content participation.

- If the auction method is used to award acreage, the government should allow the potential investors to nominate blocks of interest.
- The production sharing contract model should be used as the contracting system with the investor.

To safeguard against the proverbial *race-to-the-bottom*, subregional economies such as Guyana, Suriname and Trinidad and Tobago (in collaboration with like-minded Latin American countries) should collaborate in their search for investment. This would involve the sharing of information, which can protect the countries from multinationals that may be inclined to overstate costs. Moreover, a regional strategy and policy for attracting foreign investment in the hydrocarbon sector should be developed and adopted.

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Annex

Annex 1

A well-defined auction process should include:

Uncertainty

Uncertainty is a key aspect of hydrocarbon exploration and production. The government and the E&P company do not know if hydrocarbons will be found, what volumes will be found, what will be the actual cost of production, and at what price it be sold. Hence, each bidder will have a view about the expected risk and the expected return about the acreage, and bids accordingly. If after engaging in exploration activity the winning bidder realizes that they have overestimated the value of the block, they may abandon future exploration activities in the block.

Characteristics of the blocks

When firms engage in exploratory or 'wildcat' drilling, they are attempting to convert a hypothesis that hydrocarbon deposits may reside within a geological formation into a commercial find. To increase the probability of a successful find, firms consider multiple factors including subsurface geology, reservoir characteristics, pore pressure modeling, and the drilling control factors (such as the drilling mud, hydraulics, bits, weight and rotary speed). Despite this, an exploration well can still be a dry hole. Given that the cost of exploratory drilling can go to the millions, drilling dry holes can be an expensive lesson for a firm.

Collusion

Because exploration is a risky and expensive activity, companies frequently attempt to mitigate these risks by collaborating in exploration activities. Companies may undertake joint ventures to engage in exploration activities in certain blocks. Some companies may consider colluding in bidding for blocks. While collaboration in exploration drilling is ethical, collusion in competitive bidding reduces the efficiency of the auction process. Therefore, to be effective, a government should design rules for the auction process that prohibits collusion in bidding.

Reservation price

The reservation price, also referred to as the cash bonus price, is the sum of money companies offer the government for the license with the E&P rights to a block. Governments may specify a minimum value that companies may bid, but there may be no ceiling on the maximum value for bidding. Furtado and Suslick (2003) note that companies may bid from 30% of the expected monetary value for the block or acreage and may extend up to 100%.

Notably, because the rent to the government (the reservation price) can be large, smaller companies may be unable to pay a high reservation price to win a bid. This would eliminate small companies, and some locally owned companies from effectively participating in the auction process. For this reason, many governments do not award bids solely based on reservation prices. Rather, they use a weighted formula the considers multiple factors in addition to the reservation price. For example, the winning formula may be defined as follows:

Winning bid = 40% reservation price + 40% work program + 20% local content.

Work program

In auctions, hydrocarbon companies bid to implement a work program of activities over a period of time defined in the license. The work program may include a minimum exploration area that must be implemented by the E&P company as a condition for the award of the license.

The work program reflects an investor's perception about a block. An aggressive work program with a lot of planned exploration activities highlights that an investor has a positive perception about a block and is eager to recover the hydrocarbons. Such a block may be perceived as more valuable than a block with lower planned exploration projects.

Usually, work program exploration periods operate for 5 or 10 years. Mainly exploration activities are conducted in this period, and projects for tertiary recovery such as enhanced oil recovery may not be included in the work program.

Local content

Local content is defined as the value that extraction of natural resources may bring to a domestic economy beyond the receipt of resource revenues (Tordo et al., 2013). Local content requirements are specific requirements that are set by governments for foreign firms to use local inputs.

Governments can achieve their policy objectives of capturing more value-added locally by including local content requirements in the auction process. For example, a government may mandate that as a requirement to win any acreage, a foreign multinational company must partner with a local company, and there must be training and skills transfer. As an alternate example, a government can mandate that a foreign company must employ at least 10% of its technical staff and 90% of its administrative staff from the local population to qualify for the auction process. These local content requirements help local stakeholders, which would have been eliminated by more efficient foreign competitors, gain income-earning opportunities.

Economic profitability and incentives

Indeed, exploration and production companies must also consider economic factors in their drilling decision including the total cost of drilling, probability of actually finding hydrocarbons, the economic value of the reservoir, the volume and type (oil or gas) of hydrocarbons, the future selling price of the hydrocarbons, the financial incentives offered by the government, the net present value (npv) of the drilling project, the discount rate, and the payback period of the drilling project.

Due to the potential for investors to abandon exploration projects in blocks that are deemed to be too risky given various technical and economic factors, many governments may offer financial incentives to the investors that won the acreage. These incentives may take the form of allowances which can be used to write off tax liabilities.

Governments should be careful in the designing of incentives for the hydrocarbon industry. Moreover, governments should ensure that incentives are ring-fenced to ensure that the incentives do not erode too much of the hydrocarbon tax revenue.

Taxes

Several taxes are charged in the hydrocarbon industry. The main taxes include: (i) royalties; (ii) income tax; and (iii) windfall tax. A royalty is a tax imposed on a hydrocarbon to ensure that the government gets a minimum value. There are 2 variants, a specific levy, which charges a tax based on the volume of hydrocarbons products. The second is an ad valorem tax which is charged based on the value of hydrocarbons produced (Sunley et al., 2002).

Income tax refers to the corporation tax that is imposed on hydrocarbon companies. However, the income tax for the hydrocarbon sector may be higher than the other sectors of the economy (Sunley et al., 2002).

Windfall taxes are ad valorem taxes that are designed to capture additional value from the export of hydrocarbons in favorable market conditions (Sunley et al., 2002).

Sometimes the contract that awards a company a block states how it may pay the government taxes. The contract may state all the allowances the company may receive, how they are charged, and what taxes the company is supposed to pay. For example, in exchange for undertaking exploration activity in a deep-water block that is deemed risky, a company may be exempted from paying windfall tax on hydrocarbons produced in that block.

Apart from the aforementioned issues, a well-designed auction program should also include: (i) an announcement or invitation to bid; (ii) a prequalification of potential bidders; (iii) a technical data package; (iv) bidding rules; and (v) contractual terms.

Announcement

The government ministry or agency that is coordinating the auction should issue a public notice of the auction. The announcement could state the acreage available for bidding, the period of time in which stakeholders are allowed to submit bids.

Prequalification

Depending upon the country, there may be several companies operating in the upstream segment of the hydrocarbon industry. Evaluating all the bids may be too tedious for some ministries. Therefore, to reduce the workload, ministries may create a prequalification process for the bids. During the prequalification process, potential bidders may submit their company's background information such as their registration information, their financial capacity, and the type of activities that they conduct.

Technical data package

The ministry or agency that is administering the auction should provide a technical data package with the available information about potential blocks to the bidders. To prevent spurious offers, some ministries or agencies may require the bidders to pay a small bidding fee to access a package with the technical data and other relevant tender documents.

Bidding rules

To make the process fair and credible, the ministry or agency that is administering the auctions should publicly state what is their evaluation criteria. This public information can help gain investor confidence and retain their interest in submitting bids for blocks.

Contractual terms

The government should decide under what conditions it wants to monetize its hydrocarbon resources. In other words, the government should decide if it wants to monetize the hydrocarbons on concessionary terms, PSCs, or service agreements.



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