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Royalties in Mature Upstream Oil and Gas Developments: Progression, Reduction or Abolition?

Eduardo G Pereira

Professor, School of Business Management, Siberian Federal University–Russia; Research Fellow, Institute of Energy and Environment, University of São Paulo–Brazil

egp.portugal@gmail.com

Leanna Ramkhalawan[1], Juliana Carvalho Travassos da Costa[2], Lucca Galatro[3], Hirdan Katarina de Medeiros Costa[4], Theophilus Acheampong[5] , Aaron Koenck[6]

Abstract

Since 2000, over one hundred (100) countries either replaced their existing oil and gas royalty regime or made major amendments to it. However, there is still a continuing debate on whether royalties should be reduced or eliminated, especially in mature oil provinces where fields are declining in production from their plateau rate. Using integrative legal analysis and economic reviews, this work examines the impact of the royalty regime on oil and gas fields with higher emphasis on mature fields and provide recommendations through case studies of countries across multiple continents that depict a progressive fiscal system through royalty implementation, countries that have reduced royalty rates to date, and received favourable fiscal outcomes, and countries that wholly abolished royalty rates altogether. We find that royalty structures in general have advanced from regressive to more progressive rates considering production volumes (daily/cumulative), location (whether onshore, nearshore, shallow-water or deep-water), price, time or category of product (whether crude oil or natural gas). While sliding scale royalties are useful, they nonetheless complicate regimes while failing to address the fundamental drawback of not being linked to costs or underlying project profitability. This makes some marginal projects uneconomic, affecting efforts to maximise economic recovery. It is neither adequate nor economically attractive to fix a royalty amount for fields with production declines in the same manner as those producing at optimal levels. Decreases in royalties for mature fields would incentivize the continuity of their production and, consequently, delay premature field decommissioning, thereby sustaining jobs and domestic energy security.

Keywords: Royalties; Oil and Gas; Energy transition; Decommissioning; Mature provinces; Energy security

1 Legal Advisor, Perenco T&T Limited, Trinidad and Tobago

2 Associate, Veirano e Advogados Associados, Rio de Janeiro–Brazil

3 Associate, Energy and Natural Resources Practice, Campos Mello Advogados in cooperation with DLA Piper–Brazil

4 Deputy Director of the Energy Policy & Economics Programme, São Paulo–Brazil

5 Department of Economics & Aberdeen Centre for Research in Energy Economics and Finance, University of Aberdeen Business School, Aberdeen–UK; Centre for Energy, Petroleum and Mineral Law and Policy (CEPMLP), University of Dundee–UK

6 Attorney, Marine & Energy Disputes Practice, Hall Maines Lugrin, Houston, Texas–USA

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التطورات بشأن العوائد في مشاريع التنقيب عن النفط والغاز في الحقول التي هي على وشك النضوب: نحو التقدم أو التخفيض أو الإلغاء؟

إدواردو بيريرا
أستاذ بكلية إدارة الأعمال، الجامعة الفيدرالية السيبيرية–روسيا؛ زميل باحث، معهد الطاقة والبيئة، جامعة ساو باولو–البرازيل
egp.portugal@gmail.com

ليانا رانخلاوان[1]، جوليانا كارفالو ترافاسوس دا كوستا[2]، لوكا جالاترو[3]، هيردان كاتارينا دي ميديروس كوستا[4]، ثيوفيلوس أتشيمبونج[5] ، آرون كوينك[6]

ملخص

منذ عام 2000، قامت أكثر من مائة دولة إما باستبدال نظامها الخاص بشأن عوائد النفط والغاز وإما إدخال تعديلات رئيسية عليه. ومع ذلك، لا يزال النقاش دائرًا حول ما إذا كان ينبغي تخفيض تلك العوائد أو إلغاؤها، خاصة فيما يخص حقول النفط التي هي على وشك النضوب، والتي يتراجع فيها الإنتاج عن معدله الاحتياطي. باستخدام التحليل القانوني المتكامل ومراجعة السياقات الاقتصادية. يدرس هذا البحث تأثير نظام العوائد على حقول النفط والغاز، لا سيما تلك الحقول التي توشك على النضوب. ويقدم البحث أيضا التوصيات الملائمة من خلال دراسات الحالة لعدة دول من قارات مختلفة، بعضها تبنى نظامًا ماليًا تصاعديًا من خلال استخدام نظام العوائد، وبعضها خفض – ولا يزال يخفض – معدلات – العوائد ما أسهم في الحصول على نتائج مالية جيدة، وبعضها الآخر ألغى معدلات العوائد تمامًا. وبوجه عام، نجد أن هياكل العوائد قد تطورت من معدلات تنازلية إلى معدلات أكثر تصاعدية مع مراعاة حجم الإنتاج (يوميًا/ تراكميًا)، والموقع (سواء كان على اليابسة أو بالقرب من الشاطئ أو في المياه الضحلة أو العميقة)، والسعر، وكذلك الوقت أو فئة المنتَج (سواء كان نفطًا خامًا أو غازًا طبيعيًا). ومع أن نظام العوائد المتدرجة مفيد، إلا إنه يتصف بالتعقيد ويخفق في مواجهة العيب الأساسي المتمثل في عدم ارتباطه بالتكلفة أو ربحية المشروع الأساسية. وهذا، بدوره، يجعل بعض المشاريع الهامشية غير اقتصادية، مما يؤثر في الجهود الرامية التوصل إلى التعافي الاقتصادي. وليس مجديًا، أو مفيدًا اقتصاديًا تحديد مبلغ العوائد للحقول التي تشهد انخفاضًا في الإنتاج بنفس الطريقة التي تُحدّد بها عوائد الحقول التي يصل فيها الإنتاج إلى مستويات مثالية. يؤدي تخفيض العوائد في الحقول التي على وشك النضوب إلى تحفيز استمرارية إنتاجها، وبالتالي تأخير إيقاف تشغيلها قبل الأوان، ما يعني بالنتيجة الحفاظ على الوظائف وأمن الطاقة المحلي.

الكلمات المفتاحية: العوائد، النفط والغاز، تحول الطاقة، إيقاف التشغيل، حقول النفط على وشك النضوب، أمن الطاقة

1 مستشارة قانونية شركة بيرينكو تي آند تي المحدودة، ترينيداد وتوباغو.
2 محام مشارك، فيرانو إي أدفوجادوس أسوشيادوس، ريو دي جانيرو–البرازيل.
3 محام مشارك، ممارسة الطاقة والموارد الطبيعية، كامبوس ميلو أدفوجادوس بالتعاون مع دي إل إيه بايبر–البرازيل.
4 نائب مدير برنامج سياسات واقتصاديات الطاقة، ساو باولو–البرازيل.
5 قسم الاقتصاد والطاقة مركز أبردين للأبحاث في اقتصاديات الطاقة والتمويل، كلية إدارة الأعمال بجامعة أبردين، أبردين–المملكة المتحدة؛ مركز قانون وسياسة الطاقة والبترول والمعادن (CEPMLP)، جامعة دندي–المملكة المتحدة.
6 محامٍ، ممارسة المنازعات البحرية والطاقة، هول ماينز لوجرين، هيوستن، تكساس–الولايات المتحدة الأمريكية.

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Introduction

The fiscal system is an essential part of the oil and gas industry as it governs the manner in which revenue is earned or expended on the part of either Host HGs or IOCs and in some cases even HG national oil companies (NOCs) (i.e., state-owned oil companies). The central objective in designing a petroleum fiscal regime is *to acquire for the state in whose legal territory the resources in question lie, a fair share of the wealth accruing from the extraction of that resource, whilst encouraging investors to ensure optimal economic recovery of the hydrocarbon resources*.'[1] Despite these noble intents, what is "fair" can often be the subject of controversy, and in some instances, legal dispute between investors and HGs.[2] Regardless of the fiscal regime type—contractual or concessionary—, the key components of any fiscal system tend to involve fiscal instruments such as royalties, bonuses, profit oil, and taxes, among others. Royalties are preferred by HGs as they are often the first line and most assured revenue stream for many HGs without the complexities of tax calculations or cost deductions.

The term royalty traces its antecedents to the English language from the word "royal" meaning "belonging to royalty" or "related to the King", under the applicable rules of British royalty.[3] Thus, originally, royalty referred to the King's right to receive an amount from his subjects, in the form of taxes, for the use of resources available in the kingdoms or for the exploitation of the natural resources available in its lands. General definitions of royalties include: (i) payment for the financial compensation of extracting a scarce resource, such as oil and gas. It guarantees that the government gets a share of gross revenues regardless of the profitability of a venture;[4] (ii) rights to a portion of the production (or value of production) of one or more wells without the normal costs of drilling and producing;[5] or (iii) fundamental element in the international petroleum fiscal system through either concessionary or contractual fiscal systems.[6]

In current practice, royalties are simply payment of a fee due to a third party for obtaining the right to use, explore and commercialize a specific asset. Examples of these assets include intellectual property, brand identity and, of course, natural resources. Royalties can either be paid to the HG or to the private sector, based on which entity holds the title to the asset. In the case of payment of royalties to governments, the fee is usually due for the production of natural resources that are owned by the government—such as minerals, coal, oil and gas—according to the specific legislation applicable in a given country.

1 International Monetary Fund, The Taxation of Petroleum and Minerals: Principles, Problems and Practice, Routledge (2010).

2 Barry Land, 'Capturing a Fair Share of Fiscal Benefits in the Extractive Industry' (2009) 18(1) Transnational Corporations 157; R Weijermars, 'Natural Resource Wealth Optimization: A Review of Fiscal Regimes and Equitable Agreements for Petroleum and Mineral Extraction Projects' (2015) 24(4) Natural Resources Research 385

3 'Royalty' (*Britannica Money*) https://www.britannica.com/money/royalty-law accessed 8 September 2024.

4 ATFS Gaspar Ravagnani, GA Costa Lima, CEAG Barreto, FP Munerato and DJ Schiozer, 'Royalty and Tax versus Production Sharing Petroleum Fiscal Models: An Analysis of Risk and Return of the Optimal Production Strategy Applied in Brazil' SPE 153487 (2012) 1, 3.

5 WH Ellis, 'Property Status of Royalties in Canadian Oil and Gas Law' (1984) 22(11) *Canadian Oil and Gas Law*.

6 JC Echenduand and O O Lledare, 'Progressive Royalty Framework for Oil and Gas Development Strategy: Lessons from Nigeria' SPE 174846 (July 2016).

Within oil and gas fiscal systems, royalties have undergone major changes as competition to attract oil and gas activities has intensified. Since 2000, over one hundred (100) countries including mature provinces with declining oil and gas production either replaced their existing oil and gas royalty regime or made major amendments to it.[7] Pertinently, royalty structures have advanced from "regressive rates" to more "progressive type rates" considering the cost of production (daily/cumulative), location (whether onshore, nearshore, shallow-water or deep-water), price, time or category of product (whether crude oil or natural gas). These changes were undertaken through either the laws applicable to the country or via concession agreements or production sharing agreements or related HGI. In some cases, an amendment to the law resulted in an adjustment to such HGI with a resultant impact on the decisions of various IOC's to invest in the exploration and production.

Nevertheless, the role of royalties and the current trends regarding such practices in mature provinces has not been extensively studied in the literature, and this is the primary motive behind writing the current paper.[8] A mature province does not have a specific single definition. According to PetroWiki, a research page created by the Petroleum Engineering Handbook published by the Society of Petroleum Engineers (SPE), mature provinces could be defined as follows: "Often, engineers consider fields mature when they have declined in production by more than 50% of their plateau rate." Different companies might apply their own specific definitions though. For example, Total considers the surface and the subsurface. For the subsurface, they consider a field mature when the cumulative production has reached 50% of the initial 2P (proved plus probable) reserves, and for the surface, they consider a field mature after 10 years of production. They use other criteria, but these are the main ones. Halliburton defines a mature field as "one where production has reached its peak and has started to decline." The criteria for basin maturity significantly comes down to fields declining in production from their plateau rate.[9] There is also a time element where mature oil provinces, according other definitions, are those established onshore or offshore provinces where such oil fields are twenty-five (25) years or older from the date of first commercial production.[10] Examples include the United Kingdom Continental Shelf (UKCS) and Norwegian Continental Shelf (NCS).[11]

There is a continuing debate on whether royalties should be reduced or eliminated. For the purposes of this paper, we seek to address the impact of the royalty regime on mature fields and provide recommendations through case studies of countries that depict a progressive fiscal system through

7 EY, *Global Oil and Gas Tax Guide 2019*. https://www.ey.com/en_gl/tax-guides/global-oil-and-gas-tax-guide-2019 accessed 8 September 2024.

8 'Mature Fields' (*PetroWiki*) https://petrowiki.spe.org/PetroWiki accessed 8 September 2024.

9 G Gordon and J Paterson, 'Mature Province Initiatives' (2010) https://doi.org/10.3366/edinburgh/9781845861018.003.0005; C Nakhle, 'Do High Oil Prices Justify an Increase in Taxation in a Mature Oil Province? The Case of the UK Continental Shelf' (2007) 35(8) Energy Policy 4305.

10 EY Global, Oil and Gas Tax Guide (n 7) 178.

11 T Acheampong and AG Kemp, 'Health, Safety and Environmental (HSE) Regulation and Outcomes in the Offshore Oil and Gas Industry: Performance Review of Trends in the United Kingdom Continental Shelf' (2022) 148 Safety Science 105634; T Acheampong, E Phimister and A Kemp, 'An Optimisation Model for Incentivising the Development of Marginal Oil and Gas Fields Amidst Increasingly Complex Ownership Patterns: UKCS Case Study' (2021) 207 Journal of Petroleum Science and Engineering 109109.

royalty implementation, countries that have reduced royalty rates to date, and received favourable fiscal outcomes and countries that wholly abolished royalty rates altogether. The rest of this paper is structured as follows: firstly, we delve into the origin and context of royalties, the main challenges faced by mature provinces through the implementation of royalties, followed by a comprehensive snapshot into alternatives to adjust the royalty system. This snapshot would provide succinct evidence of royalty regimes in mature provinces such as Nigeria, Mexico, Colombia and Brazil, as well as the lack of royalty regimes in mature provinces such as Norway and the United Kingdom. Recommendations to address challenges faced in mature provinces through its implementation of royalties are provided to identify potential contributions to economic growth and development in the oil and gas sector, especially given energy transition imperatives.

1. Oil and Gas Royalties

1.1 Origin and Context

Royalty is a duty imposed on the amount (a quantum royalty) or value (an ad valorem royalty) of production.[12] In the oil and gas industry, usually royalties are defined as a compensation to the State/HG or fiscal authority so that it receives a financial return for the transfer of hydrocarbons' exploration and production rights to the investor, as well as to take part in the earnings related thereof. It should be noted that this consideration is given by entities with the intent of obtaining profit from the commercialization of resources that belong to the sovereign country and its people, as compensation for the exploration of these assets (i.e., oil, gas, coal, iron, among others). From the perspective of investors (including IOCs), royalties represent a fixed cost as the amount of royalty payment is independent of profitability. From government perspective, royalties are relatively 'simple' to administer, difficult to avoid, predictable and provide revenue as soon as production starts; that is, they are front-loaded.

Even though each country also has its own rules as to how royalties are calculated, the royalties' amount is generally defined, charged, and paid according to the revenue generated by those who are using, exploring, or commercializing such asset.[13] In Brazil for example, royalties are calculated considering the profitable characteristic of each field and the rate varies from 5% to 15% of the field production amount per month.[14] The value of oil production is ascertained by the reference (norm)

12 EG Pereira, *Encyclopaedia of Upstream Oil and Gas* (Globe Law and Business Limited 2020).

13 The exploration and ownership regime of natural resources in the United States differs from other regimes. In the U.S. model, the soil and the subsoil are considered an indivisible whole, in such a way that the rights to the subsoil mineral resources are the property of the owner of the surface, independently if it belongs to local, state, federal governments or private owners. Thus, royalty payments in the United States can be made to both private and public entities, depending on whom detains the title to the soil above the reserves.

14 As provided for Article 12, §1st of Decree No. 2.105/1998 "12. The amount of royalties due each month for each field will be determined by multiplying the equivalent of ten percent of the total volume of oil and natural gas production from the field during that month by their respective reference prices, defined in the form of Chapter IV of this Decree. §1st. The ANP may, in the bidding notice for a given block, provide for a reduction in the percentage of ten percent defined in this article up to a minimum of five percent of the total volume of production, considering geological risks, production expectations and other factors pertinent to that block."

price established by the applicable regulation.[15] Several factors may influence the calculation of royalties, such as geological risks, field production values or estimated reserves, and the international value of the petroleum product for the reference time in question.

1.2 General challenges of royalties, and in mature provinces

1.2.1. General challenges of royalties

Before delving into challenges in mature provinces, we highlight some general challenges with royalties presently:

i. **Blind to costs and profit level** – Fixed royalty rates are payable whether the oil price is high or low. While this stability appears attractive for the State with less fluctuation towards the country's economy, it is potentially detrimental to investment. Lower oil prices reduce the State's take from royalties and a decline in government revenue can deter investment by financiers seeking to understand how IOC would be able to pay off its debt in a low oil price scenario. An example of a fixed royalty rate can be seen in the Republic of Croatia. Here, a fixed 10% royalty rate[16] was seen as too high of a royalty rate for future projects as a result of an environment of unstable crude oil and natural gas prices over the past few years.[17] However, studies showed that Croatia would be able to benefit from applying foreign solutions in its own legislative and fiscal framework including using a sliding scale for royalty calculation.[18] Additionally, due to Croatia's use of Production Sharing Agreements (PSA) for all new concessions, it was recommended that the royalty be rescinded altogether as it was a remnant of previous fiscal regimes that introduced royalty in the first place.

ii. **Capable of deterring production and encourages premature abandonment of fields** – Royalties can deter production at the end of the field life by accelerating the point at which the field is no longer economic to operate. Where there is a rise in production cost and decrease in the internal rate of return or other project profitability metrics, it eventually leads to premature field abandonment. This can be especially hard for smaller or marginal projects needed to keep production platforms in clusters or hubs from shutting down all together because there is not enough throughput.[19]

iii. **Disincentivises exploration activities** – Increased difficulty for investors to produce from small,

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15 ANP Resolution No. 874/2022 provides for the calculation methodology to establish the oil reference price.

16 EY Global. Oil and Gas Tax Guide (n. 7) 178.

17 M Kolovrat, L Jukić and DK Sedlar, 'Comparison of Hydrocarbon Fiscal Regimes of Some European Oil and Gas Producers and Perspectives for Improvement in the Republic of Croatia' (2021) 14(16) *Energies* 5056 https://doi.org/10.3390/en14165056 accessed 12 August 2024.

18 Ibid.

19 T Acheampong, E Phimister and A Kemp, 'An Optimisation Model for Incentivising the Development of Marginal Oil and Gas Fields Amidst Increasingly Complex Ownership Patterns: UKCS Case Study' (2021) 207 Journal of Petroleum Science and Engineering 109109 https://doi.org/10.1016/j.petrol.2021.109109; T Acheampong, AG Kemp, E Phimister and L Stephen, 'The Economic Dependencies of Infrastructure Assets in the UK Continental Shelf (UKCS)' (2015) SPE Offshore Europe Conference and Exhibition, SPE-175445 https://doi.org/10.2118/175445-MS; Y Abdul Salam, A Kemp and E Phimister, 'Unlocking the Economic Viability of Marginal UKCS Discoveries: Optimising Cluster Developments' (2021) 97 Energy Economics 105233 https://doi.org/10.1016/j.eneco.2021.105233

marginal or technically challenging fields or develop new fields as it does not account for levels or cost of production.

1.2.2. Mature fields

Among the challenges faced today by producers from mature fields, is the legal burden of paying royalties in the same percentages and systematics as those provided to fields in their production commencement and peak stages. This structuring of royalties can have a deleterious effect on mature fields due to its characteristic of being levied on gross revenue, generating taxes even before the project makes a profit.[20] The point is that if the value of the financial return to the investor differs—higher value to fields with great production and lower value to fields with lower production—so should the regulatory and/or tax treatment. A disproportionate tax treatment leads the applicable tax being considered too high and burdensome, which, consequently, makes the investment expensive in the eyes of the developers.[21]

IOCs often at later field life need to make additional investment in projects including procuring new machinery, technical and engineering professionals to sustain continuing production. In this scenario, companies generally need to prioritize investments in the face of several options and scarce resources. Thus, there may be a need to incentivize these firms to make their investments viable, contributing to job creation, energy security, maximizing the recovery, and extending the useful life of the field.[22]

Understanding that a field with high production must have a tax regime different from the one applied to a field with lower production and in decline is the first step to creating regulatory rules aiming at increasing the competitiveness of the investments in mature provinces. The granting of fiscal incentives is one of the proven mechanisms to reduce the risks of oil and gas recovery investment, as a flexible regulatory framework can boost the oil and gas recovery projects by decreasing the financial burden of investors, thereby generating a win-win scenario, under the premise that for a State to win, companies must win as well.[23]

The geological reality of a field at the end of their useful life may require a regulatory treatment that would incentivize IOCs to prioritize the investments in mature provinces, since while the investments on enhancing production of the field are heavier, the government takes may be lower but is compensated for by jobs created and sustaining domestic energy security. In addition to the merits of the discussion

20 F Delgado, M Chabriard, P Gonçalves and T B, 'Royalties e EOR em Campos Maduros no Brasil: Discussões sobre Alíquotas e Arrecadações' (2018) FGV Energia https://fgvenergia.fgv.br/sites/fgvenergia.fgv.br/files/site_coluna_opiniao_93_-_royalties_rev1.pdf

21 According to The Word Bank in submission "Paying Taxes," higher taxes are associated with fewer formal business and lower private investments, and keeping tax rates at a reasonable level can encourage the development of the private sector and formalization of the business. The World Bank submission "*Paying Taxes*' is available at: https://subnational.doingbusiness.org/en/data/exploretopics/paying-taxes/why-matters.

22 National Petroleum, Natural Gas and Biofuel Agency, *Technical Note No. 01/2018/SPG: Reduction of the Royalty Rate on Incremental Oil and Natural Gas Production in Mature Fields. Impacts on Government and Third-Party Participations* (para 28).

23 G Franco, 'Enhanced Oil Recovery: Incentives to Promote' https://mexicobusiness.news/oilandgas/news/enhanced-oil-recovery-incentives-promote

on the differentiation of royalties for fields with higher and lower production, it is important to deepen the discussion on the criteria that the regulator should use to define a field as a mature field other than the age or production of the field.[24] Therefore, the premise for this analysis remains the same, which is that the greater the investment needed to continue production, the more flexible regulatory regime should be.

The analysis of the profiling of a mature field for the purpose of receiving a tax incentive of royalties' reduction should include an analysis on a case-by-case basis, considering different, individual and specific factors of the reality of each field. The parameters to understand a mature field as susceptible to receiving the tax benefit should consider its location (onshore or offshore), proven reserves, rate projections, current reserves, reduced production, declining production, production time, use of secondary or tertiary recovery, economy, peak production, well-defined field, high water and sediment production, among others.[25]

Establishing a field's production volume as the only parameter for granting a benefit that could impact several projects with different economic and technical difficulties may lead to the inefficacy of the implemented policy. Thus, the characteristics to be considered in the granting of incentives for mature fields must be thoroughly analysed in order to attest the effective impact of envisioned regulatory incentives in the oil and gas industry.

The rationale behind charging a tax or government participation is to assign its value correspondingly to the economic value in place and to the financial return of an investor against its commercial balance of cost vs. profit. It is neither adequate nor economically attractive to fix a royalty amount for a field with a production deterioration in the same manner as to a field that does not require huge investments such as high-level technology on extraction of oil. In the case of a field in declining production, with a greater need for investment to continue production, the royalties should apply proportionally to the profitability of such field in the face of the challenges to surpass the difficulty to keep the asset producing, preserving the economic return in detriment of the costs. The granting of regulatory incentives to keep mature fields economically attractive should be a factor that, alone, could prolong the continuity of production through the conservation of the financial viability of the field.

Any decrease in royalties for mature fields would incentivize the continuity of their production and, consequently, cause the delay of the abandonment of the wells. This could help the government to allay its concern regarding the management of fields surrendered to the government at the end of a concession, an issue for government agencies responsible for dealing with such abandoned fields. In addition, a tax

24 In Brazil for example, the National Petroleum, Natural Gas and Biofuels Agency Resolution No. 749/2018 defines "Mature Field" as an oil or natural gas field with a history of effective production, carried out from definitive production facilities, greater than or equal to twenty-five years, or whose accumulated production corresponds to at least 70% (seventy per cent) of the volume to be produced, considering the proven reserves (1P).

25 RJBC Câmara, *Mature Fields and Marginal Fields – Definitions to Regulatory Effects* (Dissertation, Master's Programme in Regulation of the Energy Industry, University Salvador 2004). https://tede.unifacs.br/tede/bitstream/tede/317/1/Dissertacao%20Roberto%20Camara%202004%20texto%20completo.pdf

incentive that helps maintaining an investment with a positive commercial balance also leverages the continuity of the exploration, and, consequently, keeps the IOCs' liable before the government for royalty payments, even if decreased percentagewise. As such, it is important to review the applicable royalties to the productivity reality in each field, which would be harmonious with the foundation for the existence of a fiscal regime, that should be equivalent to the profit of the product to which it refers.

2. Options for Adjusting the Royalty System

In this section, we address the impact of the royalty regime on mature fields and provide recommendations through case studies of countries that depict a progressive fiscal system through royalty implementation, countries that have reduced royalty rates to date and received favourable fiscal outcomes and countries that wholly abolished royalty rates altogether.

2.1 Progression

i. Equity – State benefiting where investor also benefits; and

ii. Flexibility and Stability – An adjustable rate depending on changes in circumstances, e.g. price.

In terms of a 'progressive' royalty rate, such rate can be enhanced without completely changing it for example, deferring royalty until payback, the point at which the investor's costs had been paid off from production revenue. In addition to this there is an option for companies to stop making royalty payments at the point when the IOC starts making payments into an abandonment fund. Royalty payments can also be paused whilst the company invests in enhanced oil recovery infrastructure as an incentive to maintain production. Such progressive methods prove to be less complicated as other tax mechanisms such as corporation tax or profit tax. Countries that demonstrate progressive royalty rates include for example, Nigeria and Mexico.

2.1.1 *Nigeria Case Study*

In Nigeria, oil was reportedly first discovered in commercial quantity at Oloibiri, Bayelsa State, in the Niger Delta, in 1956. Nigeria currently has the world's tenth largest crude oil reserves and is the world's thirteenth-largest crude oil producer.[26] In 2020, its total proved oil reserves were 36.9 billion barrels.[27] In 2020, oil production was at a rate of one 1.8 million barrels per day whereas in 2021, oil production decreased to 1.6 million barrels per day.

A. Snapshot summary of laws governing oil and gas royalties payable in Nigeria

Oil and Gas companies in Nigeria operate under concessions or Production Sharing Contracts ("PSCs") with the umbrella guidance of legislation. Snapshots of legislative provisions to guide the royalty rate in Nigeria can be seen below:

26 'Ogoniland's Oil History' (*UNEP*) https://www.unep.org/explore-topics/disasters-conflicts/where-we-work/nigeria/ogonilands-oil-history accessed 8 September 2024.

27 BP, Statistical Review of World Energy (70th edn., 2021) 16.

Table 1: Snapshot summary of Oil and Gas Royalties payable in Nigeria

Legislative Framework	Royalty Rate
Regulations 13 and 15 of the Petroleum Royalty Regulations 2022 made under section 304(2) of the Petroleum Industry Act 2021 ("PIA") [The Petroleum Royalty Regulations].	**Daily Production & Location:** Sliding Scale for deep offshore production: ● Regulation 13(1)(a) states that for production less than or equal to 50,000bopd the rate shall be 5%. ● Regulation 13(1)(b) stipulates that for production greater than 50,000bopd the rate shall be a weighted average rate of 5% of 5000bopd plus 7.5% of incremental daily production above 50,000bopd divided by total production per day. ● Regulation 13(2) (c) states that for onshore areas where production is greater than 10,000bopd, the rate shall be the weighted average rate of 5% of 5,000bopd plus 7.5% of 5,000bopd plus 15% of incremental daily production above 10,000bopd divided by total production per day. **Price:** ● Pursuant to the Schedule to the Petroleum Royalties Regulations, the benchmark price should be adjusted by applying 2% annually and the results rounded to entire US$ cents. ● Regulation 15(3)(a) states that for fiscal oil price less than or equal to the benchmark price pursuant to paragraph 11(1)(a) of the Seventh Schedule to the Act, the royalty price shall be 0%. ● Regulation 15(3)(b) adds that for fiscal oil price between the benchmark prices pursuant to paragraph 11(1)(a) and (c) of the Seventh Schedule to the Act shall be based on linear interpolation, ● Regulation 15(3)(c) states that for fiscal oil price greater than or equal to the benchmark price pursuant to paragraph 11(c) of the Seventh Schedule to the Act, the royalty by price rate shall be 10%.
Section 94 of the PIA.	**Marginal field operations** ● There are Producing Marginal Fields and Non-Producing Marginal Fields catered for. The PIA allows Operators under the former field to continue operating under the original royalty rates and farm out agreements. ● For Onshore fields and shallow waters with production less than or equal to 10,000bopd in a month – 5% royalty for the first 5,000bopd and 7.5% for the next 5,000bopd. Above 10,000bopd is charged as follows: (a) Onshore areas – 15% (b) Shallow Water (up to 200m water depth) – 12.5% (c) Deep Offshore (greater than 200m water depth) – 7.5% (d) Frontier basins – 7.5%

Legislative Framework	Royalty Rate
Paragraphs 6 to 11 of the Seventh Schedule to the PIA.	**Production** ● Paragraph 10 (2) of the Seventh Schedule states that royalty shall be at a rate per centum of the chargeable volume of the crude oil and condensates produced from the field area in the relevant month on terrain basins as follows: (a) Onshore areas – 15%; (b) Shallow waters – 12.5%; (c) Deep Offshore (greater than 200m water depth) – 7.5%; (d) Frontier basins – 7.5%. ● Paragraph 10(6) states that royalty based on production for natural gas and natural gas liquids shall be at a rate of 5% of the chargeable volume and royalty rate for natural gas produced and utilised in-country shall be 2.5% of the chargeable volume.[28] **Price** Pursuant to Paragraph 11(1) of the Seventh Schedule, there shall be payable, in addition to the royalty set out in paragraph 10 for onshore, shallow water and deep offshore a royalty by price with respect to crude oil and condensates at the rates set out below: (a) Below USD 50 per barrel, 0% (b) At USD 100 per barrel, 5% (c) Above USD 150 per barrel = 10% (d) Between USD50 and USD100 per barrel or USD100 and USD150 per barrel, the royalty by price shall be determined based on linear interpretation.
Section 5(1) & (4) of the Deep Offshore and Inland Basin PSC (Amendment) Act, 2019. The key objective of this Amendment Act was to maximise government take from PSCs in the face of changed prices of oil and gas.[29] It introduced a revision to the royalty rates straying from royalties calculated based on water depth of the field ranging from 0-12% to eliminating the 0% rate and calculating royalties on a field basis, dependent on the chargeable volume of the crude and condensates produced per field.[30]	**Production & Location:** Baseline Royalty of 10% for crude oil and condensates produced in the deep offshore i.e.,> 200-meter water depth[31] for the Frontier and Inland Basin. **Price:** Royalty based on the applicable price of crude oil, condensate and natural gas applies as follows: (a) From $0 up to $20 per barrel – 0% (b) Above $20 and up to US $60 – 2.5% (c) Above $60 and up to US $100 – 4.0% (d) Above $100 and up to US $150 – 8.0% (e) Above $150 – 10.0%[32]

28 PWC, Tax Data Card Nigeria – 2023, September 2023, 16.
29 KPMG in Nigeria. 'Deep Offshore and Inland Basin PSC (Amendment) Act, 2019 Issue 12.3.
30 PWC 'Nigeria introduces amendments to increase royalties on Deep Offshore and Inland Basin operations,' (2019).
31 EY Global. Oil and Gas Tax Guide (n7) 479.
32 KPMG in Nigeria. 'Deep Offshore and Inland Basin PSC (Amendment) Act, 2019 Issue 12.3.

Legislative Framework	Royalty Rate
Paragraph 2 (1) of the Marginal Field Operations (Fiscal Regime) Regulations S.I. No. 8, 2006.	**The Marginal field operations' royalty rates are:** (a) For production below 5,000bpd – 2.5%. (b) For production between 5,000 and 10,000bpd – 7.5%. (c) For production between 10,000 and 15,000bpd – 12.5%. (d) For production between 15,000 and 25,000bpd – 18.5%.[33]
Petroleum Act Chapter P10 (Chapter 350 LFN 1990) Part VI sections 61(a) and (b).	**Royalty at a rate per centum of the chargeable value of the crude oil inter alia:** (a) In onshore areas – 20%. (b) In areas up to 100 metres water depth – 18.5%. (c) In areas up to 200 metres water depth – 16.5%. (d) In areas from 201 to 500 metres water depth – 12.5%. (e) In areas from 501 to 800 metres water depth – 8%. (f) In areas from 802 to 1000 metres water depth – 4%. (g) In areas beyond 1000 metres water depth – 0%. **Royalty at a rate per centum of the price received by a licensee/ lessee in the relevant area and sold (without waste gas):** (a) Onshore areas – 7%. (b) Offshore areas – 5%.

Prior to enactment of the PIA, Nigeria was regulated by several statutes and subsidiary legislation e.g., the Petroleum Act and the Deep Offshore and Inland Basin PSC Act. Most of the laws and regulations were deemed outdated and inconsistent with present economic and industry realities. The PIA serves to provide a more robust framework to drive growth within the sector.[34] It also provides a new fiscal regime for all marginal field operators in Nigeria.[35]

Through such legislative provisions, considerations for equity, flexibility and stability were implemented to encourage a balance for both the government and the investor. Royalty rates based on a sliding scale of production demonstrated that Nigeria accounted for the State to maximize where the investor also maximizes. Additionally, in terms of royalty based on price, the royalty rate was adjusted to account for circumstances such as increases or decreases in the price of crude oil in this way, it showed a flexible regime with a form of stability for both the State and the investor. In other words, due to the regulated royalty provisions regarding price tiers, the higher oil prices accounted for the higher royalty payments to the government. Notably based on Nigeria's statistics, royalties paid by one of Nigeria's oil and gas companies Seplat Energy, as at September 2022 was $132.2million whereas in 2021 it was $92.1million.[36] This was as a result of higher realised oil prices.

33 PWC, Tax Data Card Nigeria – 2023 (n30) 19.

34 PWC, 'The Petroleum Industry Act – Redefining the Nigerian oil and gas landscape,' (2021).

35 Ibid.

36 Seplat Energy, Unaudited results for the nine months ended 30 September, 2022 (2022) 9.

B. Interaction between royalties in Nigeria and other tax mechanisms

Pursuant to the Petroleum Profits Tax Act Cap 354 LFN 1990 and the Deep Offshore and Inland Basin Production Sharing Contract (Amendment) Act, 2019, upstream companies receive graduated royalty rates and lower PSC tax rates to encourage offshore production.

Under the PIA alongside the royalty rates include Hydrocarbon Tax (HT) which is a tax on the profits of IOCs and Company Income Tax which is applicable on profits of upstream petroleum companies for example, 15% for Petroleum Prospecting Licensees operating in onshore and shallow waters.[37]

C. Deductions

The only deduction allowable against royalties which simply ensures that royalties are paid on actual produced and saleable volumes is contained in paragraph 11(3) of the Petroleum Royalty Regulations made under section 304(2) of the Petroleum Industry Act 2021 (the "PIA"). It specifies that:

> *"any gas measured at the gas delivery meter and re-injected in reservoirs of the Petroleum Mining Lease shall result in a royalty credit amount based on the applicable royalty rates for domestic gas… This royalty credit amount shall be deducted from the royalty applicable to crude oil or condensates or both. Where the royalty is paid in cash the deduction shall be in cash and where the royalty is paid in kind, it shall be a reduction of the royalty volume of a value equal to the royalty credit."*[38]

2.1.2 Mexico Case Study

Mexico is the world's 10th largest oil producer.[39] At the end of 2020, its total proved oil reserves were 7.9 billion barrels.[40] In 2020, oil production was 1.9 million bbls/d and about the same in 2021.[41]

A. Snapshot of laws governing oil and gas royalties payable in Mexico

Oil and gas companies in Mexico function utilizing License Contracts/PSCs but are also guided under legislative provisions. The model contract for exploration and extraction of hydrocarbons under production sharing modality (the Model Contract) was a milestone in the implementation of the energy reform. The royalty therein was established as a payment based on gross income and highlighted as an increasing rate based on the price of hydrocarbons. Table 2 below provides a snapshot into the regulated royalty rates on oil and gas in Mexico:

37 KPMG, Nigeria Fiscal Guide 2023, June 2023, 7-8.

38 Paragraph 11(3) of the Petroleum Royalty Regulations made under section 304(2) of the Petroleum Industry Act 2021.

39 CR Seelke, M Ratner, MA Villarreal and P Brow, *Mexico's Oil and Gas Sector: Background, Reform Efforts, and Implications for the United States* [2015] Congressional Research Service 7-5700, R 43313

40 BP, Statistical Review of World Energy 2021 (n28).

41 BP, Statistical Review of World Energy 2022 (n29).

Table 2: Snapshot of Oil and Gas Royalties payable in Mexico

Legislative Framework	Royalty Rate
Hydrocarbons Revenue Law (HRL).	**Revenue based Royalty Rates on the Category of Product**
	Oil Royalty ● The royalty rate is based on the value of the barrel of oil. If the price is under US$ 49.36 per barrel, the rate is fixed at 7.5%. If the price per barrel is above US$49.46, the rate will be increased according to the following formula: [0.122 x contractual oil price) + 1.5] %[42] **Gas Royalty** The royalty rate for: ● Associated Natural Gas Royalty is the Contractual price divided by 102.85. ● Non-associated Natural Gas utilizes the following formulae: i. If the price is less than or equal to US$5.15 per million British Thermal Units (BTUs) the royalty is 0%. ii. If the price is between US$5.15 and US$5.65 per million BTUs the following formula should be used: Rate= ([contractual natural gas price- 5.15] x 60.5)/contractual natural gas price. iii. If the price is more than US$5.65 per million BTUs, the formula for determining the royalty is the same as associated gas.[43] ● Condensates Royalty: With respect to condensates (i.e., natural gas liquids formed primarily by pentanes and heavier components of hydrocarbons), a progressive rate is established based on the price of the condensates. Under US $61.71, the royalty rate will be fixed at 5%. Over US$61.71 the following formula applies for determining the royalty rate: [0.122 x contractual condensate price) - 2.5] %.[44]

The HRL was amended in 2019 based on the premise that upstream petroleum activities were taxed too heavily and therefore constrained their ability to invest in exploration and production. Increasing private investment and rising condensate production helped reverse a downward trend in Mexico's oil production that began in 2004. In 2022, private investment growth was seen through private companies who funded five percent (5%) of total production from almost none in 2017 and there was also five percent (5%) of total natural gas production from private companies that showed an increase from one percent (1%) in 2017.[45]

B. Interaction between royalties in Mexico and other tax mechanisms

For License Contracts, there is an adjustment mechanism available to capture extraordinary profits

42 EY Global, Oil and Gas Tax Guide (n7) 412.

43 Ibid.

44 Ibid.

45 U.S. Energy Information Administration (EIA), *Country Analysis Brief, Mexico* (2020).

for the State. In such a case, where daily production reaches a determined cap, the over-royalty (payments made to the State based on a percentage rate of the value of hydrocarbons) that is paid to the Mexican State is increased by a formula contained in the License Contract.

For PSCs, there is also an adjustment mechanism for the same reason as License Contracts. Apart from royalties, a Corporate Income Tax (CIT) rate is payable at 30% as Mexican resident companies are taxed on their worldwide earnings pursuant to the Mexican Income Tax Law.[46]

C. Deductions

In Mexico, there is no specific concept of deductions in the context of royalties. There is however a cap on cost deductions which are associated with profit-sharing in an effort to try and contain costs. The HRL introduced caps expressed as a percentage of revenue which range from twelve-point five percent (12.5%) to eighty percent depending on the location of the activity and the type of hydrocarbon being extracted.[47] This cap on cost deductions, just like a royalty, secures up-front revenues to the government as soon as production starts by ensuring a minimum quantity of production revenue subject to the profit sharing fee.

2.2 Reduction

"Reduced" Royalty Rates refer to countries that either lowered their initial royalty rates or regulated royalty discounts.

Countries that implement reduced royalty rates include for example, Colombia, Brazil, and the United States.

2.2.1 Colombia Case Study

Colombia is among the top twenty (20) producers globally. Its geology is very similar to Venezuelan fields since it is located in the Orinoco Belt Basin, which is the biggest petroleum basin in the world in terms of reserves. Its total proved reserves amount to 2 billion barrels.[48] In 2020, its total production was 781 million bbls/d.[49]

A. Snapshot of laws governing oil and gas royalties payable in Colombia

In Colombia, oil and gas companies operate under concession agreements with the umbrella guidance of legislative provisions. Colombia has a progressive and flexible fiscal system including income tax and royalties. In July 2004, the first model contract was released, i.e., the modern concession agreement/ exploration and production contract. This modern concession agreement was essentially a royalty/tax agreement loaded with progressive fiscal mechanisms that respond to different oil price conditions and quality of oil produced in a relevant area. This contract was further amended, and its

46 EY Global, Oil and Gas Tax Guide (n7) 416.

47 Shah, A. International Monetary Fund Working Paper: Natural Resource Taxation in Mexico: Some considerations, WP/21/245 (2021) 20.

48 BP, Statistical Review of World Energy 2021 (n28).

49 BP, Statistical Review of World Energy 2022 (n29).

latest model contract issued in May 2012 as used at the Colombia round 2012.

Table 3: Snapshot into Oil and Gas Royalties payable in Colombia

Legislative Framework	Royalty Rate
	Production and Location
Hydrocarbon royalties were established in Law 141 of 1994 (as amended by Law 756 of 2002). Law 1530 of 2012 highlights the organization and functioning of the General Royalty System.	Monthly average in barrels of crude oil per day: ● Up to 5,000 = 8%. ● 5,001 to 125,000 = 8%+ ([production- 5,000] x 0.10). ● 125,001 to 400,000 = 20%. ● 400,001 to 600,000 = 20%+ ([production-400,000] x 0.025). ● More than 600,000 = 25%.[50] Royalties for natural gas: ● Onshore and offshore below 1,000 ft. depth = 80%. ● Offshore more than 1,000 ft. depth = 60%.[51] Royalties for natural gas and heavy oil: ● Onshore and offshore up to a water depth of 1000 ft. = Discount of 20% and 25%, respectively. Royalties for natural gas: ● Offshore water depths greater than 1000 ft.= Discount of 40%.

Colombia's oil and gas royalties were $6.4 trillion dollars[52] as of December 31, 2021. Notwithstanding this, in July 2022, Colombia's government agreed to continue royalty deductions in exchange for an increase in income and export taxes by 5% and 20% respectively for oil and coal sold above certain threshold prices.[53]

B. Interaction between royalties in Colombia and other tax mechanisms

In addition to royalties, natural gas and heavy crude have general tax considerations and special incentives which include but are not limited to a CIT Rate from financial year 2022 at 30%, equity tax (in specific cases), capital allowances and investment incentives for example, donations and investments in research.[54]

C. Deductions

It is pertinent to pinpoint that in 2022, the Colombian Tax Reform was approved by the Colombian Congress i.e., *Law 2277-2023*. It marked for the oil and gas industry, the suppression of deductibility of royalties for income tax purposes. Particularly, *Paragraph 1 of Article 19 of Tax Reform Act 2277-*

50 EY Global, Oil and Gas Tax Guide (n7) 148.

51 Nunez, C. B., *Colombia's regulatory and fiscal hydrocarbons regime*, (2012) JWELB Vol. 5, No. 3

52 Bnamericas, 'Ministério de Minas y Energía de la República de Colombia (Minenergía)' <https://www.bnamericas.com/en/company-profile/ministerio-de-minas-y-energia-de-la-republica-de-colombia-minminas> accessed 30th August 2024.

53 Reuters, *Colombia agrees to ease tax changes to oil, mining* (2022) <Colombia agrees to ease tax changes to oil, mining | Reuters> accessed 30th August 2024.

54 EY Global, Oil and Gas Tax Guide (n7) 142.

2023, which prohibited the deduction of non-renewable natural resources royalty payments by oil and gas companies to the Colombian Government. It specifically stated:

> *"The economic consideration as a royalty referred to in Articles 360 and 361 of the Political Constitution shall not be deductible from income tax nor may it be treated as a cost or expense of the respective company, regardless of the denomination of the payment and the accounting or financial treatment that the taxpayer performs, and regardless of the form of payment thereof, either in cash or in kind. For income tax purposes, the non-deductible amount corresponding to royalties paid in kind will be the total cost of production of the non-renewable natural resources."*[55]

The Constitutional Court pursuant to Judgment C-480 of 2023[56] declared that it would be unconstitutional to prohibit such deduction for income tax purposes, meaning, the deductibility of royalties from income tax for the tax year in 2023 for example was not permitted to be challenged by the Colombian Tax and Customs Directorate (DIAN). This ruling provided a step towards long-term investment.

2.2.2 Brazil Case Study

The average yearly production of oil and gas in Brazil in 2024 was 4.322 million barrels of oil equivalent per day (boe/d), which was nearly unchanged from 2023.[57] Compared to the previous year›s total, which hit a record of 4.344 million boe/d, there was a 0.5% decrease in 2024.[58] The production of oil in 2024 was 3.358 million barrels per day (bbl/d), which was 1.29% less than the record set in 2023 (3.402 million bbl/d).[59] The average annual production of natural gas in 2024 was 153 million cubic meters per day (m^3/d), which was 2% more than the previous year›s production of 150 million m^3/d.[60] Pre-salt reservoirs accounted for the majority of output in 2024, accounting for an average of 78.29% of the country›s total oil and natural gas production in barrels of oil equivalent.[61] Onshore and post-salt production made up, on average, 5.38% and 16.33% of the nation›s total production, respectively.[62]

A. Snapshot into laws governing oil and gas royalties payable in Brazil

In Brazil, oil and gas companies operate under concession contracts, transfer of rights surplus, and

55 Artículo 19° Parágrafo 1 de la Ley 2277 de 2022.

56 Sentencia C-489 de 2023, Demanda de Inconstitucionalidad contra el artículo 19 (parcial) de la Ley 2277 de 2022, 'Por medio de la cual se adopta una reforma tributaria para la igualdad y la justicia social y se dictan otras disposiciones' (Bogotá, D.C., 16 November 2023).

57 Brazil Energy Insight, 'ANP – Brazil 2024 Annual Oil & Gas Production' (2025) https://brazilenergyinsight.com/2025/02/03/anp-brazil-2024-annual-oil-gas-production/amp//>, accessed 28 April 2025

58 Ibid.

59 Ibid.

60 Ibid.

61 Ibid.

62 Ibid.

PSCs with the umbrella guidance of legislation.[63] In terms of royalties, such amendments/implementations were undertaken via Resolutions. Table 4 provides a snapshot into the regulated royalty rates on oil and gas in Brazil:

Table 4: Snapshot into Oil and Gas Royalties payable in Brazil

Legislative Framework	Royalty Rate
	Production
Law No. 9,478 of August 6, 1997.	● Royalties paid monthly from commencement of commercial production of each field, in an amount corresponding to 10% of production of petroleum or natural gas.[64]
Law No. 12,351.	● 15% royalty rate of production value, from date of start-up of the commercial production of each field.
Resolution 749/2018 of the National Agency for Petroleum, Natural Gas and biofuels ("ANP").	● Royalty reduction on incremental production for mature fields (25 years or more of production or that accumulated production ≥70% of the expected production volume).
ANP Resolution No. 853/2021 [Article 9].	● Royalty reduction for small and medium-sized companies for the production of the month following the date of signature of the amendment to the concession agreement: - Fields operated by small-sized companies (average annual production <1000 boe/d in Brazil and abroad) permitted a reduced royalty rate to 5%. - Fields operated by medium-sized companies (average annual production <10,000 boe/d in Brazil and abroad) permitted a reduced royalty rate to 7.5%. - Under the PSC, royalties are levied at a rate of 15%.
CNPE Resolution No. 05/2022.	● Authorizes ANP to grant, based on pre-established criteria, a reduction in royalties to the legal minimum (5%) for fields and accumulations with marginal economic viability (i.e, marginal fields and accumulations), and implement strategies to reduce the regulatory burden with a view to modernizing, reducing bureaucracy, simplifying and speeding up regulation. Although the parameters for qualifying marginal fields are provided under ANP Resolution No. 877/2022, as of the date hereof, ANP has not implemented the royalty reduction for marginal fields.

63 IM Machado E Silva and HK de Medeiros Costa, 'Brazilian Social Funds: The Lessons Learned from the Norway Fund Experience' (2019) 129 *Energy Policy* 161 https://doi.org/10.1016/j.enpol.2019.01.062

64 More details: HK de Medeiros Costa and E Moutinho dos Santos, 'Institutional Analysis and the "Resource Curse" in Developing Countries' (2013) 63 *Energy Policy* 788 https://doi.org/10.1016/j.enpol.2013.08.060

Between 2010 to 2016 royalty collection totalled US$17.99 billion and such expansion of the sector was stimulated by the rise in international commodity prices and increased collection of oil and natural gas royalties.[65]

B. Interaction between royalties in Brazil and other tax mechanisms

CIT is applicable on Brazilian resident legal residents' entities' worldwide income at a rate of fifteen percent (15%) with a surtax of ten percent (10%) for profits exceeding US$46,789.10 a year. A social contribution tax is also imposed on corporate net profits at a rate of 9%. The combined CIT rate being thirty-four percent (34%).[66]

C. Deductions

It is pertinent to highlight that, as of October 2024, royalties on oil and gas production are fully tax-deductible. Expenditures incurred in the exploration and production activities are immediately deductible for purposes of calculating the taxes to be levied by the Brazilian government against exploration and production companies. For the development phase, specific rules on accelerated exhaustion apply.[67]

D. Royalty Reductions

Reductions were implemented on royalty rates in Brazil to encourage investment, especially for small and medium sized operators, incremental production in mature fields and for marginal fields.

For instance, 15 of 113 fields belonging to small and medium-sized companies did not produce oil in 2021 due to the uneconomic feasibility of their activities, greatly impacted by the applicable royalty rates.[68] Therefore, Resolution 853/2021 came into play and allowed small or medium-sized operators to request reduced royalty rates for their concession contracts, such request to be analysed by the ANP and, if approved, formalized by means of an amendment to the applicable concession contract.

With respect to marginal fields, the National Council for Energy Policy (CNPE) published its Resolution No. 05/2022, which provides for measures to stimulate the development and production of hydrocarbon fields or accumulations of marginal profitability, specifically dealing with the reduction of royalties for such fields. Through Resolution No. 05/2022, CNPE authorized ANP to grant, based on pre-established criteria, a reduction in royalties to the legal minimum (5%) and implement strategies to

65 RN Santos, LC de Santana Ribeiro and JR de Santana, *The Effects of Oil Royalties on Regional Inequality in Brazil* [2022] CEPAL Review No 136.

66 EY Global, Oil and Gas Tax Guide (n7) 67.

67 EY Global, Oil and Gas Tax Guide (n7), p. 68.

68 Ministério de Minas y Energía (Agência Nacional do Petróleo, Gás Natural e Biocombustíveis), 'ANP's 17th Bidding Round Will Generate Investments of R$136 Million' (2021) https://www.gov.br/anp/pt-br/canais_atendimento/imprensa/noticias-comunicados/anp2019s-17th-bidding-round-will-generate-investments-of-r-136-million accessed 4 August 2024.

reduce the regulatory burden with a view to modernizing, reducing bureaucracy, simplifying and speeding up regulation.

Royalty reductions for incremental production in mature fields was provided for under ANP Resolution No. 749/2018, which provided for reduction of rates up to the legal minimum (5%). Such royalty reductions may be granted for fields with at least twenty-five years of production, or whose accumulated production corresponds to at least 70% of their proven reserves. The royalty reduction benefit shall be requested by the mature field operators and must be accompanied by the submission of a revised field development plan, which shall provide for additional investments in infrastructure to maximize the field's production. If approved, the ANP and the concessionaires shall formalize the reduced royalty rate by means of an amendment to the concession contract.

Taking into consideration the benefits provided under the Brazilian regulation for challenging production assets, Brazil is one of the royalty regimes that wholeheartedly encourages investment and reinvestment in oil and gas no matter how small a company is classified or how defying the producing conditions of a field are considered.

E. Other relevant payments

It is worthy to note that other relevant payments are owed by exploration and production companies in Brazil in connection with their activities.

For instance, Law No. 9,478/1997 provides for special participation payments in specific situations, characterized as an extraordinary financial compensation owed by concessionaires for the exploration and production of oil or natural gas for large production volume fields. Special participation is due when, in a given trimester, a field's production surpasses a certain threshold, which varies in accordance with the type of field (onshore, shallow water or deep water). The special participation may amount to 10% of the production in excess of such threshold.

As an incidental payment arising from the special participation payments, the ANP includes an item known as the "1% clause" in concession contracts for the exploration and production of oil and natural gas. The clause requires concessionaires to invest in research, development and innovation (RD&I) at an amount equivalent to 1% of the gross revenue generated by highly profitable fields or fields with a large volume of production (those that pay the special participation).

Another relevant payment is applicable to onshore fields and constitutes a landlord cost percentage due to the owner of the land in which the concession area is located. This percentage usually varies between 0.5% to 1% of the oil and gas production considering the reference price.[69]

2.2.3 *United States of America Case Study*

The United States has significant onshore and offshore oil and gas assets. As for offshore assets, the

69 EY Global, Oil and Gas Tax Guide (n7), p. 67.

Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement, have jurisdiction over 1.76 billion acres on the Outer Continental Shelf, where they manage 8,300 active oil and gas leases.[70] As for onshore, the Bureau of Land Management governs approximately 700 million acres of onshore subsurface mineral rights.[71] Many of the leases have been produced for over 50 years and are by all accounts mature. Notably, for the first time in 100 years, the onshore minimum royalty was increased.[72] The rate was previously 12.5% and will increase to 16.67% over the next decade.[73] In the coming decades the royalty relief discussed below may ultimately be implemented as these fields mature.

- **Legislative System**

Recipients of oil and gas royalties can vary between governmental and private entities depending on where they are found. This includes sovereigns such as the federal, indigenous, and state governments which may own onshore or offshore minerals. However, private entities generally only own onshore minerals. Accordingly, there can and will be various legal regimes potentially applicable to royalties owed. For the purposes of this paper we examine federal onshore and offshore as it is the most comparable to other government's systems.

Federal offshore royalty relief is increasingly important considering that shallow water fields have been produced for over 75 years.[74] With significant reserves already from many of the fields owned by the government onshore and offshore, the economic potential of these fields is not enough to keep major oil and gas companies interested in the leases. Nonetheless the many of the leases remain economically valuable to the United States government who seeks to ensure the remaining oil and gas is produced from a revenue and energy security perspective. As such the Bureau of Land Management and the Bureau of Safety and Environmental Enforcement, pursuant to Federal law, have enacted royalty reduction programs to help ensure maximum value is extracted from federal lands. The below table provides a summary of the legislations and regulations that allow royalty reduction.

70 D Sigler, LF Gomar, A Ketner and S Shelton, 'Responding to the Oil Price Crisis: An Overview of Onshore and Offshore Federal Royalty Relief' (24 November 2020) *Lexology* https://www.lexology.com/library/detail.aspx?g=63687b9d-0ca7-40f2-b9f6-74624bcac984

71 Ibid.

72 AA Helm, 'Royalty Wars: The Dark Side to Raising the Minimum Royalty Rate for Oil and Gas Leasing on Federal Land' (2024) 10 *Tex. A&M J. Prop. L.* 473 https://doi.org/10.37419/JPL.V10.I4.2

73 Ibid.

74 Bureau of Safety and Environmental Enforcement, 'Shallow Water Gulf of Mexico Decline' (19 November 2019) https://www.bsee.gov/sites/bsee.gov/files/reports/shallow-water-report-01.pdf accessed 8 September 2024.

Table 5: Snapshot into Oil and Gas Royalties Reductions in United States

Legislative Framework	Royalty Rate
Federal Offshore	**Outer Continental Shelf Lands Act (OCSLA)**
43 U.S.C. § 1331-1356.	● Governs Federal offshore leasing.
43 U.S.C. 1337(a)(3)(A).	● BOEM may reduce or eliminate any royalty or a net profit share specified for an OCS lease to promote increased production.[75]
43 U.S.C. 1337(a)(3)(B).	● BSEE may reduce, modify, or eliminate any royalty to promote development, increase production, or encourage production of marginal resources on certain leases or categories of leases.[76]
43 U.S.C. 1337(a)(3)(C).	● BSEE may suspend royalties for designated volumes of new production from any lease if: (1) The lease is in deep water (water at least 200 meters deep); (2) The lease is in designated areas of the GOM (west of 87 degrees, 30 minutes West longitude); (3) The lease was acquired in a lease sale held before the DWRRA (before November 28, 1995); (4) BSEE finds that new production would not be economic without royalty relief; and (5) The lease is on a field that did not produce before enactment of the DWRRA, or if a proposed project to significantly expand production under a Development Operations Coordination Document or a supplementary, that the Bureau of Ocean Energy Management (BOEM) approved after November 28, 1995.
42 U.S.C. 15904-15905.	● BSEE may suspend royalties for designated volumes of gas production from deep and ultra-deep wells on a lease if: (1) The lease is in shallow water (water less than 400 meters deep) and produce from an ultra-deep well (top of the perforated interval is at least 20,000 feet TVD SS) or the lease is for waters entirely more than 200 meters and entirely less than 400 meters deep and you produce from a deep well (top of the perforated interval is at least 15,000 feet TVD SS); (2) The lease is in the designated area of the GOM (wholly west of 87 degrees, 30 minutes west longitude); and (3) The lease is not eligible for deep water royalty relief.
30 C.F.R. §203.50-56 (End-of-life lease).	● To qualify for relief, lessee must demonstrate that the sum of royalty payments over the 12 qualifying months exceeds 75 percent of the sum of net revenues (before-royalty revenues minus allowable costs).
30 CFR § 203.80 (Special Case).	● Generally, the lease or project must not qualify for formal programs and satisfy two or more criteria stated in the rule.
Federal Onshore	**Mineral Leasing Act of 1920 (MLA)**
30 U.S.C. § 209.	● The Secretary of the Interior, [through the Bureau of Land Management] for the purpose of encouraging the greatest ultimate recovery of coal, oil, gas, oil shale … and in the interest of conservation of natural resources, is authorized to waive, suspend, or reduce the rental, or minimum royalty, or reduce the royalty on an entire leasehold, or on any tract or portion thereof segregated for royalty purposes, whenever in his judgment it is necessary to do so in order to promote development, or whenever in his judgment the leases cannot be successfully operated under the terms provided therein.

75 BOEM Royalty Relief Programs Page: https://www.boem.gov/oil-gas-energy/energy-economics/royalty-relief

76 This authority is restricted to leases in the GOM that are west of 87 degrees, 30 minutes West longitude, and in the planning areas offshore Alaska.

Like the United Kingdom, United States policy, as it relates to mature fields focuses on the efficient use of existing infrastructure (especially offshore) and avoiding cost wastage of the final barrels of oil where existing infrastructure is available and adequate to produce them. However, as evident above, the questions of whether there will be a reduction in royalties is a case-by-case question for the lease or project. However, there are critics of the royalty reduction programs, who argue the royalty reduction programs are overused and subsidize the production of oil at the cost of United States taxpayers.[77]

2.3 Abolition

Royalties were essentially seen as a regressive tax as it applied to gross revenue and acted as a disincentive to exploration and production.[78] It should be understood that the United Kingdom (UK) and Norway abolished royalty as part of their fiscal systems as their focus shifted from maximizing fiscal revenues from highly profitable fields towards more emphasis on optimal development of less profitable resources. These countries are close to each other in the North Sea and also shared ownership of some cross-border fields.[79]

2.3.1 The United Kingdom (UK) Case Study

UK's oil and gas sector is dominated by production from offshore areas. Production of natural gas began in 1967 with the West Sole field in the Southern North Sea. Offshore oil production began with the Argyll field in the Central North Sea (CNS) in 1975. At the end of 2020, its total proved oil reserves were 2.5 billion barrels.[80] In 2020, oil production was at a rate of 1.1 million bbls/d and 874,000 bbls/d in 2021.[81] The past royalty rate in the UK was twelve-point five percent (12.5%) of the value of petroleum which was generally measured as "wellhead value." The UK utilized royalties when production was just starting, returns were high, fields were large, and costs were relatively low. It was usually charged on the licence rather than a field basis.

- **Legislative System**

It should be noted that in the UK, the law governing the development of hydrocarbons is the UK Petroleum Act, 1998 which vests rights to oil and gas resources in England and on the UK Continental Shelf in the Crown. Prior to the UK Petroleum Act, in the early 1980's, the government made changes to oil taxation in an attempt to encourage exploration and development activities. This was as a result of a significant decrease in the number of new oil and gas projects generated by the industry. The year, 1983 marked the first of the three (3) tier process towards the complete abolishment of royalties in the UK in an attempt to encourage exploration and development activities.

77 Taxpayers for Common Sense, 'Oil and Gas Royalties: Relief for Oil and Gas Companies, a Fiscal Headache for Taxpayers' (3 November 2009) https://www.taxpayer.net/energy-natural-resources/oil-and-gas-royalties-relief-for-oil-and-gas-companies-a-fiscal-headache-fo/ accessed 8 September 2024.

78 'Petroleum and Mineral Resource Rent Taxes: Could These Taxation Principles Have a Wider Application?' [2012] MqLawJl 4; (2012) 10 *Macquarie Law Journal* 69.

79 ET Jarlsby and EG Pereira, *Petroleum Fiscal Systems* (7th edn, PennWell Books 2019).

80 BP, Statistical Review of World Energy 2021 (n28).

81 BP, Statistical Review of World Energy 2022 (n29).

Tier 1: In 1983, royalties were abolished in the Petroleum Royalties (Relief) Act 1983 for qualifying fields receiving development approval from the Secretary of State on or after 1st April 1982. According to this change, the new fields, which were developed on or after the 1st April 1982, were subject to a tax rate of eighty-nine point five percent (89.5%) (58% for non-Petroleum Revenue Tax (PRT) paying fields) against eighty-eight percent (88%) in old fields.[82] This tax reform was the first stage of abolishing royalties.[83]

Tier 2: The Chancellor of Exchequer announced in the 1988 Budget that all Southern Basin and onshore fields for which a development permit was given after 31st March 1982 would be exempted from royalties with effect from 1st July 1988. In this regard, section 89 of the Petroleum Royalties (Relief) and Continental Shelf Act 1989 stated:

> *"(1) Petroleum won and saved from any relevant Southern Basin or onshore field or relevant onshore area shall be disregarded in determining whether any and, if so, what—*
>
> *(a) payments of royalty; and*
>
> *(b) deliveries of petroleum, are to be made in relation to chargeable periods ending after 30th June 1988 as consideration for the grant of a licence to which this section applies."*

This marked the second stage of abolishing royalties. Also, in June 1988 it was announced that royalties would be taken in cash after 31st December 1988 rather than in kind. In the 1988 Budget, the Chancellor of the Exchequer also reduced the PRT oil allowance.

During the early 1990s the UK petroleum fiscal regime had some problems as fields that were paying PRT faced a high marginal tax rate. This high tax rate led oil and gas companies to attempt to avoid a heavy tax burden. For example, some companies tried to shift income into fields that did not pay PRT and shift expenditure into PRT paying fields, as immediate tax relief was available for PRT paying fields. This practice, plus the low oil prices during that period of time, resulted in a decline in the government tax taking from the oil industry. These factors made the government consider a new relaxation package to reduce taxes in the petroleum fiscal regime.

Tier 3: A major tax change to the North Sea regime came about in 2002 when the Chancellor of the Exchequer announced on 17 April 2002 that companies producing oil and gas in the UK or on the UK Continental Shelf (UKCS) would pay a supplementary charge (SC) of ten percent (10%) on the profits from companies' ring-fenced trades in addition to the thirty percent (30%) corporation tax already payable on these profits. Companies paid the supplementary charge on ring fence profits at the same time as their general corporate tax liability, but special rules for instalment payments covered the transitional period (i.e., the accounting period that includes Budget Day).[84] In the same Budget the Chancellor for the Exchequer announced the intention of abolishing the royalty completely. In November that year the government announced the abolition of North Sea royalty payments from 1

82 The Petroleum Royalties (Relief) Act 1983.

83 HC Deb 04 July 1983 vol 45 cc20-103.

84 Seely, A.'Taxation of North Sea oil and gas' (House of Commons Library) 29 November 2022.

January 2003.[85]

UK's petroleum fiscal regime has always been described as one of the weakest and more complex regimes in the World. Its changes in taxation were due to political priorities altered between budget concerns and concerns for sustaining the business. Changes between Conservative and Labour governments occurred which impacted its fiscal regime. It was evident that the UK exhibited a tendency to sharpen fiscal terms in response to budgetary requirements and at other times relax them to promote more activity/maximise economic recovery.[86] In terms of promotion of the latter, notably, the UK in 2016 published 'the Maximizing Economic Recovery Strategy for the UK" (MER UK). This recognized the government's strategy for intelligent investment in the North Sea as a mature basin. A vital factor for advancing MER UK included the introduction of new entrants as they were deemed crucially important for the basin because they bring new capital, innovative technologies, cost-effective solutions and increased risk appetite. MER UK also focussed on the efficient use of offshore infrastructure and avoiding cost wastage by building new infrastructure where existing infrastructure is available and adequate.

2.3.2 Norway's Case Study

Norway's oil and gas/ petroleum background dates back more than fifty (50) years ago. The first fields developed were in the North Sea and now, it has gradually expanded northwards into the Norwegian Sea and the Barents Sea.[87] At the end of 2020, its total proved oil reserves were 7.9 billion barrels.[88] In 2020, oil production was at a rate of 2.0 million bbls/d per day.

- **Legislative System**

In Norway, its Petroleum Fiscal System was first introduced by the Petroleum Tax Act in 1975 and thereafter supplemented by certain provisions via licences. In this fiscal system, royalty was included to a maximum rate of sixteen percent (16%) depending on field daily rates of production. It is important to understand that its fiscal provisions were based in law and therefore Parliament had the power to change tax rates applicable to existing and new licensees.

The Organization of Petroleum Exporting Countries (OPEC) emerged in or around the period in which royalty provisions were included in Norway. Initially, Norway's fiscal system was structured so as to promote a beneficial gain for its government. This introduction of royalty provisions impacted Norway's global economy and geopolitics. In consideration of its petroleum sector, Norway sought to stimulate exploration and development in fields that were previously unprofitable due to its stringent fiscal terms by abolishing royalties stepwise from 1986. It is pertinent to note that no royalty has been payable since 2005. The increase in the number of producing fields was possible as Norway's economy was capable of taking financial risks. Such capability arose as it's government's share was secured through direct and indirect state participation, corporation tax and petroleum special tax. In addition to this, Norway's stability was due to the broad and enduring consensus between its main political parties

85 HM Treasury, Pre-Budget Report press notice REV/C&E1, 27 November 2002.

86 Jarlsby, E. T., & Pereira, E. G. Petroleum Fiscal Systems' (n79) 46.

87 'Norway's Petroleum History', https://www.norskpetroleum.no/en/framework/norways-petroleum-history

88 BP, Statistical Review of World Energy 2021 (n28).

behind its petroleum policy and taxation.[89]

Norway's tax system is based now on the taxation of the entity as opposed to specific petroleum assets. Notably, the Norwegian Oil and Gas Taxation Code includes direct and indirect taxation. Direct taxation plays the most important role for companies investing in upstream activities on the Norwegian Continental Shelf ("NCS"). Direct taxes consist of ordinary petroleum tax (27%) and special tax at fifty-one percent (51%).[90] The key difference with the aforementioned countries lies in the scope of taxation. Entity-based taxation is more simplified. Taxing an entity's overall profits simplifies tax administration for both the government and the companies and reduces the complexity associated with tracking and valuing specific petroleum assets e.g., production/reserves/individual fields. It is also stable due to its predictability. Entity-based taxation can anticipate tax liabilities based on their overall financial performance rather than fluctuations in individual asset values/production levels.

2.3.3 Deductions in UK and Norway

In the UK, royalties paid in oil and gas extraction were not typically deductible against corporation tax. Royalty was allowable as a deduction against other taxes such as field-based taxes e.g., the petroleum revenue tax (PRT) in the UK. Whereas, in Norway, royalties paid for the extraction of oil and gas were deductible against corporation tax.

3. Lessons Learned & Recommendations

HGs all over the world have indeed benefited over the years through revenue earned as a result of oil and gas exploration. It is evident that in benefitting through such revenue, the fiscal regime applicable to IOCs with respect to their oil and gas production underwent considerable variations throughout the globe. Such variations were implemented as a result of budgetary requirements, an attempt to encourage investment, economic attractiveness, desires for equity, flexibility and stability, and accounting for geological field viability inter alia. The purpose of this analysis is to address the impact of the royalty regime on mature provinces and fields and provide recommendations through case studies as to the options available to promote:

i. Investments that lead to an increase in production;
ii. The extension of the useful life of the fields and postponement of the return of the field;
iii. The maintenance of government take;
iv. Awareness of costs and profit level;
v. Incentives towards exploration and development activities; and
vi. A reduction in the premature abandonment of fields.

The means in which the aforementioned can be promoted as seen earlier includes through:

i. Implementation of proportionate and flexible tax regimes by the State considering the value of financial return for fields with high and low production – a case by case analysis is required considering different, individual and specific factors of the reality of each field. The parameters

89 Jarlsby, E. T., & Pereira, E. G. Petroleum Fiscal Systems' (n79) 46.

90 Deloitte, *Oil and Gas Taxation in Norway* https://www.deloitte.com/gx-er-oil-and-gas-taxguide-norway.pdf accessed 8 September 2024.

to understand a mature field as susceptible to receiving the tax benefit should consider its location (onshore or offshore), proven reserves, rate projections, current reserves, reduced production, declining production, production time, use of secondary or tertiary recovery, economy, peak production, well-defined field, high water and sediment production, among others[91]; and

ii. **Encouraging regulatory incentives,** for example, tax incentives and one-off incentives to make viable investments that can increase oil and natural gas production, maximize the recovery factor and extend the useful life of the field.

In attempting to provide effective recommendations however, countries can consider key methods applied by mature provinces like Nigeria, Mexico, Colombia, United States, and Brazil, as well as the lack of royalty regimes in mature provinces such as Norway and the United Kingdom. We make the following recommendations:

i. **A progressive type rate can ensure that the country has both a balance of equity and flexibility when considering royalties on oil and gas.** It essentially means that where the HG benefits, the Investor/ IOC benefits as well. In terms of progressivity, the royalty rate is adjustable depending on the changes in circumstances. This rate could either be based on production levels, price changes or in reference to a category of product. As an option to push towards investments that lead to a reduction in the decline in production and maintenance in government take, one can consider specifying different thresholds of production for example, tier 1, tier 2 and tier 3. As the tier goes up, production volumes and the royalty rate increases. It represents that where production by an Investor/ IOC in a particular period is less than or equal to a certain amount or more than or equal to a certain amount, royalty rates would also coincide. An example of this is applied in Nigeria with their first tranche being less than or equal to 50,000 and an applicable royalty rate of 5%[92] and it goes up accordingly as described in Table 1.

ii. Rate price considerations could also be implemented to maintain government take; that is, a royalty based on an applicable price on both applies where the price exceeds $20 per barrel. Nigeria's Deep Offshore and Inland Basin PSC (Amendment) Act, 2019 sets out the various price categories with its royalty rate to coincide as seen in Table 1. This provides stability on the part of IOC's and the government, as where the price is extremely low, so too would be the royalty rate. While still earning income for the HG, it does not detract investors' engagement in exploration activities especially where production volumes are low based on the Investor's/ IOC's decision to choose either a small, marginal or technically challenging field. Regarding cost sensitivity, it can reduce the impact of any early abandonment of fields with this approach as the Investor/IOC can save more to contribute to later phases in production. Like Nigeria, other countries with mature fields can benefit from higher oil prices realized.

91 Roberto José Batista Câmara, 'Mature Fields and Marginal Fields – Definitions to Regulatory Effects' (Dissertation, Master's Programme in Regulation of the Energy Industry, University Salvador 2004) https://tede.unifacs.br/tede/bitstream/tede/317/1/Dissertacao%20Roberto%20Camara%202004%20texto%20completo.pdf accessed 8 September 2024.

92 Petroleum Royalty Regulations made under section 304(2) of the Petroleum Industry Act 2021.

iii. **HGs can also consider amending the royalty rate by accounting for revenue-based royalty rates on the category of product produced.** Another approach to correlating price and the royalty rate is Mexico's as seen in Table 2 which looks at the value of the barrel of oil and applies a fixed rate of royalty. For non-associated natural gas, it focuses on the value of the natural gas per million BTUs and applies a royalty rate to coincide. Such a rate application also promotes investment into the sector while attracting income for the HG.

iv. **There is also a reduced rate of royalty that could be considered, should the HG not intend to implement a progressive based type of royalty.** For example, in technically challenging deep water and "end of life" leases or projects, the United States will (and has) allowed operators to apply for and receive royalty reductions so that a project or lease is fully produced. This has taken the form of no royalties for a set number of barrels initially produced (essentially cost recovery) to time-limited royalty reductions due to economic productions. In other words, the royalty reduction schemes are flexible for mature fields. Moreover, the Colombian government in 2022 showed an intention to back royalty deductions in exchange for an increase in income taxes and export tax.[93] This country like Nigeria also has a sliding scale type royalty focussed on production and location meaning where production increases royalty also increases, and in certain cases where the depth increases the discount permitted in terms of royalties increases. This is an example that considers both the interests of the Investor/ IOC and the HG. With respect to mature fields, it seems reasonable that governments encourage investment in those production-declining assets by means of royalty rates, tax burden and special participation reductions. Brazil, for instance, is attempting to implement policies in this regard to promote the continued investment in mature fields.

Another approach for reduced royalty rates to encourage investment and exploration activity is to account for different Investor/ IOC sizes and production levels. With smaller-sized company investment, such endeavours could be encouraged by permitting a reduced rate of royalty for example five percent (5%) where the production is less than 1000boe/d as seen in Brazil. For medium-sized companies, where production is less than 10,000boe/d a reduced rate of royalty can also be applied such as seven point five percent (7.5%). Where there is a viable marginal field development, production of such fields can be encouraged by earning royalty deductions at a particular rate as highlighted in Brazil's legislation.[94] This is one (1) of the royalty regimes that wholeheartedly encourages investment in oil and gas no matter how small a company is. Such an approach maintains government take and attracts further investment into the country leading to a reduction in the decline in production.

3.1 Additional considerations

Apart from the key royalty provisions for progressive and reduced approaches, the State and investors should pay attention to the interaction between royalties and other tax mechanisms as well as any deductions in terms of royalties. Other taxes as combined from Nigeria, Mexico, Colombia and Brazil include the Hydrocarbon tax (applicable on profits of upstream petroleum companies) and/or

93 Reuters, Colombia agrees to ease tax changes to oil, mining' (2022) (n55).

94 ANP Resolution No. 853/2021, Art 9.

Company/ Corporate Income Tax for example, the tax can be applicable on profits of upstream oil and gas companies or it can be a percentage of resident companies' worldwide earnings at a rate of for example, thirty percent (30%) as done in Mexico and Colombia. Corporate Income Taxes are most popular. In Brazil, resident legal entities' worldwide income is taxed at a rate of fifteen percent (15%) with a surtax of 10% for profits exceeding BRL 240,000 a year.

In terms of deductions, royalty deductions can incentivize investments especially from small marginal fields. In Nigeria, alongside its progressive approach, it permits a royalty credit where gas is re-injected in the reservoir and such credit is deducted from the royalty applicable to crude oil or condensates or both. The royalty credit amount is based on the applicable royalty rates for domestic gas.[95] In Mexico, its approach is not like its other fellow progressive country as it considers a cap on cost deductions associated with profit sharing in an attempt to contain costs. Mexico's HRL expressed cost caps which range from twelve point five percent (12.5%) to eighty percent (80%) depending on the location of the activity and the type of hydrocarbon being extracted. Colombia, a country with a reduced royalty rate, is an informative precedent for one to consider. This country provides an example where the State implemented a provision under its Tax Reform Act to prohibit deductions on royalty payments and it was struck down by its Constitutional Court as being unconstitutional.[96] The ruling provided a step towards long-term investment for investors. Royalties on oil and gas production in Brazil are fully deductible. It is noteworthy to commend Brazil again for its deductions as it encouraged investment for small and medium-sized companies and for marginal fields hence resulting in successful bid rounds.

Although there are other taxes apart from royalties within the oil and gas fiscal regime that can generate income for the HG, royalty is still of importance and a major contributor to income in some countries around the world. UK's economy is dominated by the services industries such as retail, hospitality, business administration and finance. UK's recurrent changes in petroleum taxation directly impacts the interest in investing in oil and gas assets in the country, especially considering the country's tendency to sharpen fiscal terms in response to budgetary requirements. From what is perceived from the data analysed, UK understood the royalty's payment obligation as a measure that would discourage the investment in oil and gas projects by private companies. Many petroleum fields contribute to Norway's economy and as such, the exploration leads and prospects to be explored contributed to Norway taking the financial risk. The HG' share in Norway is secured also through corporate tax and petroleum special tax. Norway's stability was due to the broad and enduring governmental consensus regarding its petroleum policy and taxation. HGs should be keen on any decisions with abolishing royalty rates as it can reduce their income where other taxes are not adjusted to account for the loss of income from royalties.

It should be highlighted that reasonable expectation with regards to the tax and royalties impacts on production is considered in IOCs' investment decisions on any given country. The meaning itself of royalties brings the obligation of a financial disbursement of the investor to the competent government,

95 Petroleum Royalty Regulations (n92) Paragraph 11(3).

96 Sentencia C-489 de 2023 (n58).

for the use of the area for extraction of natural resources. A royalty rate must be set according to the value of the asset, argument which reinforces the understanding that the rate of royalties for mature fields must be fixed in a lower percentage when compared to profitable fields or fields with the production curve in its rising phase. As previously said, there are royalty regimes that strongly stimulate investment and reinvestment in oil and gas, regardless of the size of the firm, but only take into account the fields' features, period of production, and proved reserves.

The public policies in place by HGs should inspire other states to stimulate exploration and development in fields that were previously unprofitable due to its stringent fiscal terms. These incentives shall not only warrant the continuance of tax collection but also safeguard energy safety through the offer of oil and gas, especially considering the recent international political issues between Russia and Ukraine that shed light on the world's dependence of Russian reserves.

In summary, in order to achieve the purpose of incentivizing oil and gas production in mature fields, as extensively analysed above, governments may opt to (i) raise government share of net cash flows of a project as the value of the resource increases; (ii) reduce royalty rates by the lowering of initial royalty rates or regulated royalty discounts; or (iii) abolish royalties by emphasizing on optimal development of less profitable resources.

Conclusion

The process for making an investment decision for bidding and/or acquiring the exploration and production rights for any given reservoir takes into consideration many factors, such as the proven reserves, local taxes, applicable governmental takes, term of concession, technical feasibility, projected financial return, among others. The reality for mature fields is that some of the abovementioned factors discourage the investments to maintain production. In this sense, should there not be any governmental incentives for the continuance of operations in this type of asset, some of these reservoirs simply become unfeasible from an economic standpoint. The truth is that there is not a correct answer on how to address the matter of mature fields exploration and governmental incentives.

Each country must analyse the factors that increase or decrease private sector investments in its national energy industry, and regulatorily address solutions that encourage investment, such as the establishment of fair and reasonable government takes. The particularities of each country's economic and social needs must also be taken into consideration, meaning that governments should all learn from other nations' lessons to the extent they are applicable to their economic characteristics. Thus, the tax system must be rigorously examined as to its relevance at each stage of natural resource development, taking into account the financial return of the investment in comparison to the payments required to maintain the asset or the risks involved in deciding to buy the asset.Decisions on the tax policies and governmental takes applicable by any given country should consider the purpose of bringing profitability to the asset in question while reassuring the government's rights over the private exploration and commercialization of the natural resources, whilst simultaneously promoting the competitiveness of investment return in the local industry.

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