OIL CONTRACTS AND GOVERNMENT TAKE: ISSUES FOR SENEGAL AND DEVELOPING COUNTRIES

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Introduction

The oil sector is a major source of income for most countries that develop their hydrocarbon resources. The challenge in the case of developing nations that are endowed with these natural resources is how to attract international investors that will bring these projects into fruition while ensuring that the state receives a sufficient share of the oil revenue. Thus, from a policy perspective, a nation is faced with the difficult trade-off of how best to "design" an oil tax system, which determines the level of resource exploitation and the oil rent-sharing.

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Senegal, which is located in western African, is among the continent's most stable countries. Its robust economic growth of greater than 6 percent in 2015 and 2016 makes Senegal one of the most dynamic economies in sub-Saharan Africa.[1] However, despite a fast-growing economy, Senegal falls into the category of least-developed countries (LDCs).

Although the nation is not listed among the richest countries in terms of natural resources, it does possess several mineral resources of significance. Most notably, Senegal has major mining projects involved in the extraction of phosphate, industrial limestones, gold, and zircon. Since 1985, approximately 40 mining concessions have been granted. So prominent is the role of natural resources that gold is the top export product of Senegal, accounting for close to 14 percent of total exports.[2] Even though Senegal is less dependent on the extractive industries sector when compared to some highly resource-endowed African states, extractive industries provide the country with more than 20 percent of its exports. In 2014, the total amount paid by mining companies to the Senegalese government was double that in 2013, reaching West African CFA Francs (CFAF) 104 billion. In the same year, the extractive industries sector (mines and hydrocarbons) contributed CFAF 109 billion to the government budget, a contribution of more than 5 percent.[3]

The hydrocarbon sector in Senegal is less developed than the mining sector. Indeed, only two blocks situated in Diender, as of now, have production rights. The Gadiaga block is currently producing natural gas for local consumption with the Senegal national electricity company (SENELEC) as the main client. Additionally, by decree n°2008-287, the Senegalese government has allowed for the upstream development of the Sandiaratou well by Foresta International and the Senegal oil company PETROSEN. Exploration licenses were delivered in several other blocks. In addition, Kosmos Energy discovered a gas field on the Senegalese-Mauritanian border with reserves estimated at 12 billion cubic feet (bcf) of gas.[4] Finally, in 2014 Cairn Energy and its partners discovered two major offshore oil fields: FAN and SNE. The SNE was the world's largest oil field discovered in 2014, according to the operating companies.

Given the size of these discoveries, the stake for Senegal in these last two oil deposits is crucial. The development of these reserves could prove to the proverbial game changer and allow Senegal to increase its income substantially and thus leaving the LDC category. Therefore, the choice of what oil tax system to select is a key issue for this country, as it is for any developing country wishing to monetize its hydrocarbon resources. It must allow a "fair" share of government take to mobilize the resources required to raise the population's standard of living.

This article aims to estimate both the oil rent-sharing between the state and the operating companies and, more generally, the tax system, according to several criteria based on the economic data of the SNE field. The following section presents the Senegalese oil tax system followed by our calculations on the oil rent-sharing between the state and operating companies. The subsequent section assesses, according to various criteria, the Senegalese tax system. Finally, the last section provides our conclusions and draws lessons for developing countries that plan to either define or review their oil codes.

Tax Design for Oil Exploitation in Senegal

The Senegalese first oil code (OC) dates back to 1986. The OC now in force was enacted on January 8, 1998 with the aim of attracting investments from foreign oil companies. Early on, the country recognized the importance of harnessing external capital to develop its oil resources as articulated in the OC: "To be competitive, Senegal must not only take into account the evolution of global energy data but also offer potential players in the oil industry attractive conditions…."[5]

Any petroleum extraction activity requires a mining right. Hydrocarbon extraction can be conducted with either a temporary exploitation license or an exploitation concession. A temporary exploitation license is granted for a maximum period of two years and allows its holder "to exploit the productive wells temporarily."[6] Granted by decree, the exploitation concession has a maximum initial duration of 25 years, which can be extended for a 10-year period, renewable once.

A hydrocarbon operating company can be linked to the Senegalese government via a service contract that lays out the rights and obligations for each party throughout the duration of operations as described in the OC, "According to the provisions of article 6, the state or a state company can conclude risky service contracts for hydrocarbon exploration and exploitation."[7] Under a service contract, the state grants a qualified company the right to carry out exploration for and subsequent exploitation of hydrocarbons. During the exploration period, that company has the same rights and obligations as has an exploration license holder. Similarly, the holder of a service contract is considered as holding an exploitation concession during the extraction period. However, the OC specifies in article 35 that, unlike exploitation concession holders, service contract holders do not own the quantities of hydrocarbons produced. The service contract provides for operator compensation arrangements that can take the form of a production sharing agreement.

The OC outlines that "The production sharing contract is a risky service contract under which the state or a state company entrusts to one or several individuals or legal entities the exclusive rights of hydrocarbon exploration and exploitation within a defined perimeter." Under a production sharing contract (PSC), the produced quantities are shared between the state and the operating companies after deduction of oil costs, that is, the expenses incurred by the companies in the producing process.

Taxation applied to the oil sector results from the oil code, which refers to several taxes and fees, to the general tax code (GTC), and the agreement between the state and the operating company. An exploration and production sharing contract (SNE contract) was concluded on November 23, 2004 (decree n°2004-1491) between the Senegalese government, the Senegal oil company (PETROSEN), and Senegal HuntOil company for three blocks: Rufisque offshore, Sangomar offshore, and Sangomar deep offshore. A decade later, this last zone was where both the FAN and SNE hydrocarbon discoveries were made. Since being signed, the contract has been the subject of numerous amendments (table 1),

Table 1
SNE CONTRACT EVOLUTION

Date	**Object**
July 15, 2004	Signature of the exploration and production sharing contract between the Senegalese state, PETROSEN, and Senegal HuntOil Company.
Nov. 23, 2004	Approval of the exploration and production sharing contract by decree n°2004-1491.
Dec. 13, 2005	Approval of the first renewal of the exploration period by decree n°2005-1201.
March 9, 2006	30% transfer of the rights, obligations, and interests, resulting from the exploration and production sharing contract, to the First Australian Resources Limited company by Senegal HuntOil company. Transfer approved by decision n°1706.
Nov. 23, 2008	Extension of the first renewal of the exploration period.
Jan. 26, 2009	Approval of the extension of the first renewal of the exploration period by decree n°2009-35.
Feb. 25, 2009	Transfer of the rights, obligations, and interests, resulting from the exploration and production sharing contract to the First Australian Resources Limited company by Senegal HuntOil company. Transfer approved by the decision n°2021.
Feb. 6, 2012	Approval of the second renewal of the exploration period by decree n°2012-243.
July 1, 2013	65% transfer of the rights, obligations, and interests, resulting from the exploration and production sharing contract to the Capricorn Senegal company by First Australian Resources Limited. Transfer approved by decision n°10049/MEM/DHCD.
Presently (as of 2018)	The contract's rights and obligations are shared as follows: Capricorn Senegal: 40%; ConocoPhillips Senegal: 35%; First Australian Resources Limited: 15%; PETROSEN: 10%.

Source: Published decrees in the Republic of Senegal, "Official Journal," available at http://www.jo.gouv.sn.

and it specifies, via its article 33, a stability agreement that freezes the taxation regime to the level of the 2004 tax provisions, contained in various codes, for the entire duration of operations.

Chapter 7 of the OC presents tax provisions applicable to the Senegalese oil sector. To aid in our analysis, we shall distinguish between the concession contract and the production sharing contract according to the 1998 oil code.

The Concession Contract (CC): This contract is based on three taxation instruments specific to the oil sector: royalty, additional tax, and surface rent. The royalty is addressed by article 41 of the OC:

> The holder(s) of a hydrocarbon exploitation concession are subject to a royalty on the value of the hydrocarbons produced, to be paid in cash to the State. The royalty is calculated from the total quantities of hydrocarbons produced in the concession and not used in oil operations (...).[8]

Based on the turnover of the operating company, the royalty rate can reach 10 percent for onshore exploitations and 8 percent for offshore exploitations, with a minimum of 2 percent. Regarding gaseous hydrocarbons, that rate can reach 6 percent regardless of the extraction conditions. The additional tax is provided by article 46 of the OC:

> Holders of agreements or service contracts are subject to an additional petroleum levy calculated on the basis of a profitability criterion for petroleum operations, the rate of which, the methods of assessment, declaration, liquidation and recovery are specified in the agreement or the service contract(...).[9]

The aforementioned article refers to the agreement entered into between the state and the operating company concerning the rate, the base, and the methods of calculating the tax. The surface rent applicable to the oil sector is governed by article 45 of the OC, which states:

> Annual superficial rent is payable from the signing of the agreement or service contract. The amount and terms of recovery are determined in the agreement or service agreement with the owner.[10]

The SNE contract regulates this tax amount, only for the exploration license, between U.S. \$5 and \$15 per square kilometer (km^2), according to the contract period (attribution or renewals).

Furthermore, the OC provides for a minimum state ownership interest in the capital of the operating company (state participation). The level of the state participation is specified by the contract. The SNE contract states: “from the effective date of this contract, PETROSEN has an undivided interest share of ten percent (10 percent) in the Contract Area (...).” The state free interest can be increased up to 18 percent for deep-water operations.

More "traditional" taxes are also applied to the oil sector. Oil contract holders are subject to income tax (IT). The effective general tax code in 2004 was at a rate of 33 percent as well as for the SNE contract. The income tax rate is applied to the accounting profit after reinstatement of non-deductible expenses. The minimum tax (MT) is the minimum amount payable under the IT, even in the case of either a loss or a nil result. In 2004 the MT rate in force varied between CFAF 500,000 and CFAF 1,000,000, depending on the turnover of the operating companies (turnover less than CFAF 250,000,000 is CFAF 500,000; turnover between CFAF 250,000,000 and CFAF 500,000,000 is CFAF 750,000; turnover greater than CFAF 500,000,000 is CFAF 1,000,000). The GTC provides for a withholding tax on securities, set at 10 percent for dividends and 16 percent for interests.

Finally, in addition to production-based taxes and those depending on either the profitability or the exploitation surface, the operating company is subject to other payments such as training costs and social funds. According to the SNE contract, the training costs vary between $200,000 and $400,000 depending on the permit type (exploration or exploitation).

The Production Sharing Contract (PSC): The PSC supersedes the production royalty and the additional tax during the exploitation period. Other taxation instruments of the concession contract (CC) are also applied to the PSC.

Thus, the state share is a key point in PSC negotiations. Incurred costs in the production process must be deducted from the oil production before the sharing, but all charges are not deductible. The contract also sets a ceiling of recoverable costs (cost-stop). It is set at 75 percent by the SNE contract. According to that contract, the production sharing between the state and the operating company depends on the daily production and the water depth. Since the SNE deposit is situated at a water depth greater than 500 meters, the state sharing varies according to the daily hydrocarbon production (table 2). The various taxation instruments specified by the Senegalese oil tax system are summarized in table 3.

Table 2
PRODUCTION SHARING AS PLANNED BY THE SNE CONTRACT

Daily Production (in barrels)	State Share	Company Share
0 – 50,000	15%	85%
50,000 – 100,000	20%	80%
100,000 – 150,000	25%	75%
150,000 – 200,000	30%	70%
200,000 and more	40%	60%

Source: SNE contract.

Table 3
THE SENEGAL OIL TAX SYSTEM[a]

Taxes	Oil Code	SNE Contract	General Tax Code (GTC)
Signature bonus	NS	NS	NE
Training and promotion costs ($)	NS	200,000 – 400,000	NE
Social funds ($)	NS	NS	NE
Surface renderings	NS	20% – 30%	NE
Surface rent ($/km^2)	NS	5 – 15	NE
Production royalty	2% – 8%	NE	NE
Additional tax	NS	NE	NE
Tax on dividends and interests	NS	NS	10% and 16%
Income tax	Refers to the GTC	33%	33%
Minimum tax (CFAF)	NS	NS	500,000 – 1,000,000
Loss carry-forward (years)	3	NE	3
Amortization carry-forward	NS	NS	Unlimited
Amortization for equipment	NS	5 years	According to the practices
Amortization for exploration costs	NS	100%	NE
Deductible head office costs	NS	NS	20%
Production sharing (state share)	NE	30%	NE
Costs recovery (cost-stop)	NE	75%	NE
State participation	NS	10% – 18%	NE

[a] NS = not specified; NE = not existing; \$/km^2 = in U.S. dollars per square kilometer; and CFAF = West African CFA Franc.

The Sharing of Oil Rent in Senegal

Methodology: Among empirical studies that attempt to quantify natural resource rent-sharing between state and investors, the oil sector is the most studied (notable among these are the works of D. Lund, A. Black and M. Roberts, P. Daniel et al., S. Tordo, J. Smith, B. Laporte and de C. Quatrebarbes, and G. Gab-Leyba and B. Laporte).[11] For the investor, the economic rent represents the income beyond the minimum required to cover the production process. More specifically, it is the "Revenues in excess of all necessary costs of production including the minimum rate of return to capital."[12]

In most articles, the oil rent-sharing model is based on a theoretical project. Authors can either apply several tax systems to that project or amend one tax base to determine its impact on either investment indicators or the government take (as in the works of D. Lund, A. Black and M. Roberts, and P. Daniel et al.).[13] The discounted cash-flow model associated with ad hoc sensitivity analysis is the most common methodology employed, although some authors have used the financial asset valuation model; among these researchers are M. Brennan and E. Schwartz, D. Laughton, and M. Grinblatt and S. Titman.[14]

To assess the Senegalese oil tax regime, a discounted cash-flow model, applied to the "real" economic data of the SNE deposit, has been used. Indeed, operating companies have published economic data about the SNE deposit, covering its technical characteristics and cost structure (table 4). The analysis focuses on oil rent-sharing, progressivity of the tax system, and the internal rate of return, although other indicators are discussed.

The pre-tax net present value (NPV) is a good proxy of the rent generated by the exploitation, provided that the chosen discounted rate is sufficiently high to take the opportunity cost of capital into account. The project NPV is calculated as follows:

$$\mathrm{NPV} = \sum_{t=0}^{T} \frac{Z_t - C_t - K_t}{(1+i^*)^n} \tag{1}$$

Table 4
ECONOMIC DATA OF THE SNE DEPOSIT ACCORDING TO THREE SCENARIOS

Data	**Pessimistic**	**Reference**	**Optimistic**
Exploitation duration (years)	12	12	12
Water depth (meters)	1,100	1,100	1,100
Estimated reserves (barrels)	150,000,000	330,000 000	670,000,000
Daily production (barrels)	37,000	100,000	170,000
Exploration costs in 2016 ($)	150,000,000	150,000,000	150,000,000
Exploration costs in 2017 ($)	125,000,000	125,000,000	125,000,000
Exploration costs in 2018 ($)	75,000,000	75,000,000	75,000,000
Investment costs in 2019 ($)	200,000,000	200,000,000	200,000,000
Investment costs in 2020 ($)	125,000,000	125,000,000	125,000,000
Investment costs in 2021 ($)	900,000,000	900,000,000	900,000,000
Investment costs in 2022 ($)	1,750,000,000	1,750,000,000	1,750,000,000
Investment costs in 2023 ($)	1,025,000,000	1,025,000,000	1,025,000,000
Investment costs in 2024 ($)	975,000,000	975,000,000	975,000,000
Investment costs in 2025 ($)	650,000,000	650,000,000	650,000,000
Investment costs in 2026 ($)	175,000,000	175,000,000	175,000,000
Operating costs ($/barrel)	5	10	15

Source: Cairn Energy and the Senegalese Ministry of Energy.

where Z_t is the expected turnover from the selling of the crude oil, C_t is the unit cost of exploitation (operating cost, expressed in $ per barrel), and K_t is the capital cost (initial investment and renewal investment).

The internal rate of return (IRR) is used to assess the project profitability. The exploitation is feasible only if the IRR is either greater than or equal to the minimum expected by operating companies. The pre-tax IRR is obtained from the following equation:

$$\mathrm{NPV} = 0 = \sum_{t=0}^{T} \frac{Z_t - C_t - K_t}{(1+i)^{\mathrm{n}}} \tag{2}$$

The IRR is represented by i^* in equation (2) and is matched with the discount rate that cancels the NPV.

To estimate the rent generated by the project, the average effective tax rate (AETR) is calculated as the sum of all levies collected by the state on the pre-tax NPV, namely:

$$AETR = \frac{\sum_{t=0}^{T} R_t}{\sum_{t=0}^{T} Z_t - C_t - K_t} \tag{3}$$

where R_t represents state levies.

Data for Modeling the Rent-Sharing—Economic Data of the SNE Deposit: Discovered in November 2004, the SNE deposit is offshore and at 1,100 meters depth. Its reserves are assessed at 330,000,000 barrels of oil. By 2024, the daily production could be approximately 100,000 barrels. Three production scenarios have been considered by the operating companies:

Pessimistic scenario: According to Cairn Energy estimates, this scenario is the least advantageous for stakeholders, including the state. Indeed, reserves are assessed at 150,000,000 barrels, which is half of the expected production.

Reference scenario: Cairn Energy estimates oil reserves at 330,000,000 barrels. This scenario is the most foreseeable and is the closest to the forecast of the Senegalese Ministry of Energy (475,000,000 barrels).

Optimistic scenario: The estimated reserves of this scenario are 670,000,000 barrels of oil.

Table 4 shows the economic data of the SNE deposit according to these three scenarios. The price per barrel utilized in the following analysis is $50.

Data for Modeling the Rent-Sharing—Selected Fiscal Data for the Oil Rent-Sharing Model: Table 5 represents the oil tax regimes selected for the rent-sharing assessment. The production sharing and the production royalty mainly distinguish the two contracts.

Table 5
FISCAL DATA FOR THE MODEL[a]

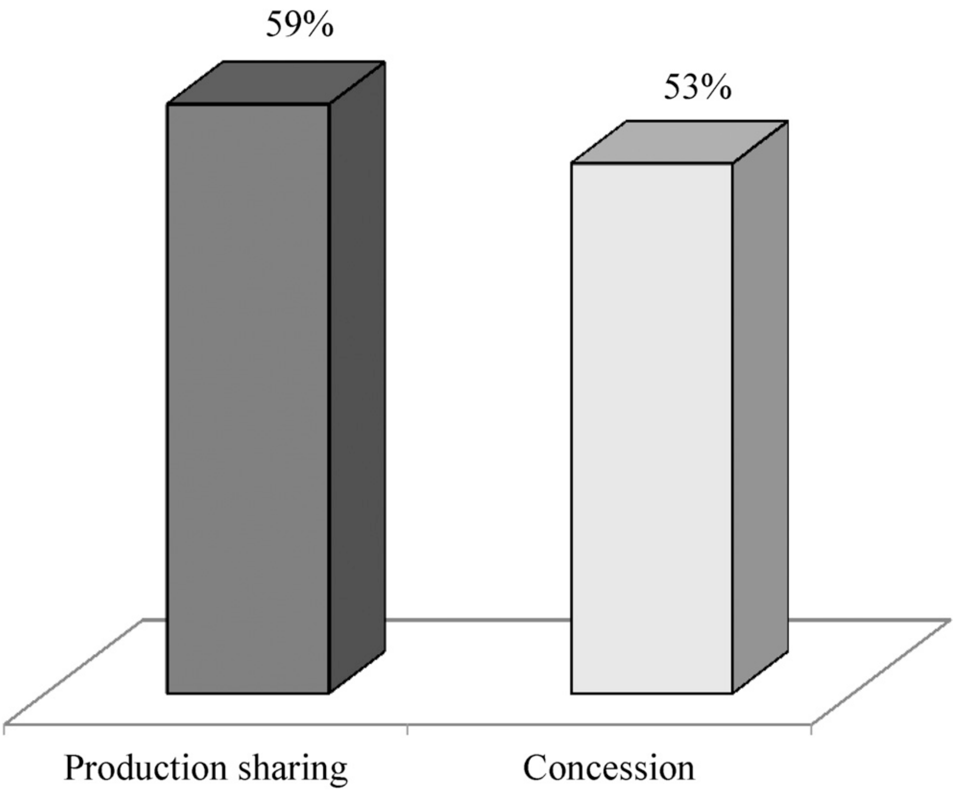
	Oil Rent-Sharing Model	
Taxes	**Concession**	**Production Sharing**
Signature bonus	500,000	500,000
Training and promotion costs ($)	200,000 – 400,000	200,000 – 400,000
Social funds ($)	150,000	150,000
Surface renderings		20% - 30%
Surface rent ($/km^2)	5 - 15	5 - 15
Production royalty	5%	
Additional taxes		
Tax on dividends and interests	10% and 16%	10% and 16%
Income tax	33%	33%
Minimum tax (CFAF)	500,000 – 1,000,000	500,000 – 1,000,000
Loss carry-forward (years)	3	3
Amortization carry-forward	Unlimited	Unlimited
Amortization of equipment (years)	5	5
Amortization of exploration costs	100%	100%
Deductible head office costs	20%	20%
Production sharing (state share)		30%
Costs recovery (cost-stop)		75%
State participation	10% – 18%	10% – 18%

[a] $/km^2 = in U.S. dollars per square kilometer and CFAF = West African CFA Franc.
Source: Authors' compilation of several legal texts.

Government Take in the Senegalese Oil Sector: The SNE project rent can be divided into three parts: the government take, the company share, and an "other" share. Some levies can be for social expenses, administration training, or environmental protection; this is the case for social funds and training costs in the Senegal OC. In the same way, the operator can either construct roads, hospitals, and schools or even make donations. These expenses incurred by the company in its social policy can also be considered as a part of the "other" share. Regardless of the contracts under consideration—concession or production sharing—this category is estimated at less than 1 percent of the rent. The government take, represented by the AETR, is 59 percent under the PSC and 53 percent for the CC (figure 1, with a 5 percent rate of production royalty).[15]

Therefore, a greater part of the oil rent is obtained with the PSC. Nevertheless, the AETR for the CC is very sensitive to the rate of the production royalty (figure 2). With a rate of 7 percent, these two contracts have equivalent AETRs. With a rate higher than 7 percent, the CC allows for a greater government take than does the PSC.

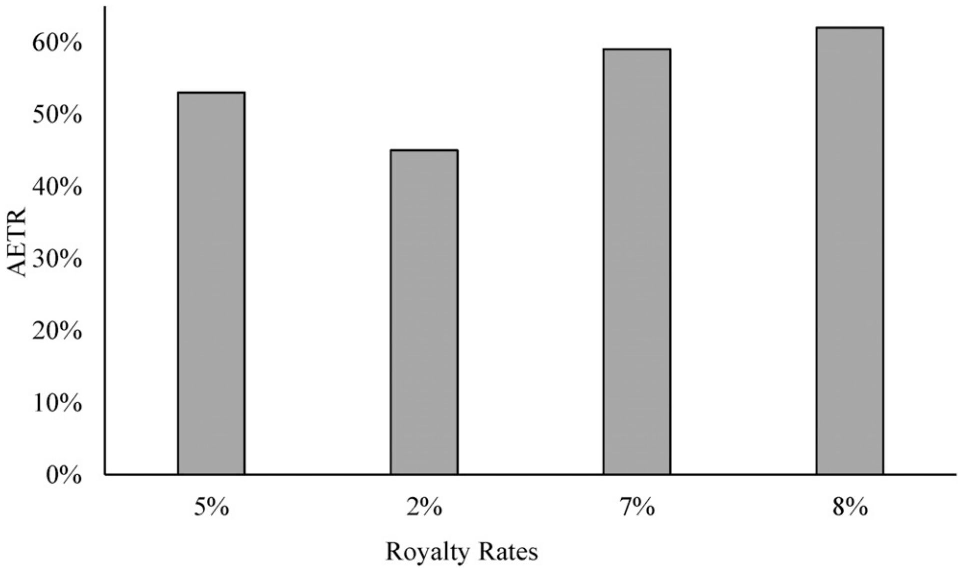
Figure 1
AVERAGE EFFECTIVE TAX RATE (AETR) FOR THE PRODUCTION SHARING CONTRACT (PSC) AND THE CONCESSION CONTRACT (CC)[a]



[a] Oil price = U.S. $50 per barrel and discount rate = 10 percent in the reference scenario. Source: Authors' calculations.

Evaluation of the Oil Tax System—Beyond the Government Take: According to the optimal taxation theory, 100-percent oil rent taxation should not affect the investment decision. However, uncertainty over the operational conditions and generated profits does not allow the states to accurately assess *ex ante* the oil rent, for geological, economic, or political reasons. Therefore, from the beginning of the project, it is impossible to define an economically "neutral" tax system for the investor. From that perspective, the retained fiscal regime determines the level of taxation borne by the investor and its economic repercussions. Each state attempts to define the most appropriate tax system to capture a "fair" oil rent share according to its own objectives: whether to secure

Figure 2
AVERAGE EFFECTIVE TAX RATE (AETR) SENSITIVITY TO PRODUCTION ROYALTY RATE[a]



[a] Oil price = U.S. $50 per barrel and discount rate = 10 percent in the reference scenario. Source: Authors' calculations.

and/or smooth revenues over the project duration, to improve the progressivity of the tax system, to adapt to the capacity of the administration, to reduce information asymmetry with the investors, or to even more widely influence the behavior of operating companies.[16] The choice of fiscal instrument applicable to the oil sector is, therefore, crucial for both state and investor. States must strike a balance between income taxes and production taxes and succeed in building a progressive tax system that is adaptable to costs and world prices to avoid contract renegotiations, which are detrimental in the long term for each party.[17]

Is Oil Rent-Sharing "Fair"?: This is a difficult question to answer because the optimal level of taxation for the exploitation of natural resources is complicated to establish due to several uncertainties that weigh on the activity, as outlined previously. The International Monetary Fund estimates the oil sector average AETR is between 65 percent and 85 percent.[18] Considering the SNE deposit economic data, we see that the Senegalese tax system results in AETR levels that are less than this "norm." A comparison between some African oil producing countries confirms this analysis. Thus, the tax systems of six countries—Chad, Gabon, Congo, Democratic Republic of Congo (DRC), Algeria, and Niger—have been applied to the reference scenario of the SNE field with the results presented in

Table 6
OIL TAX SYSTEM OF SOME AFRICAN OIL PRODUCING COUNTRIES[a]

Taxes	**Chad**	**Gabon**	**Congo**	**Democratic Republic of Congo**	**Algeria**	**Niger**
Year oil code in force	2007	2014	2016	2015	2005	2007
Permit duration						
Prospection	A : 2 y R1 : 2 y	18 m	A: 1 y R1: 1 y	A: 12 m R1: 6 m	2 y	1 y
Exploration	A: 5 y R1: 3 y R2: 2 y	8 y	A: 6 y R1: 3 y R2: 3 y R3: 1 y	A: 4 y R1: 3 y R2: 3 y	A: 3 y R1: 2 y R2: 2 y R3: 6 m	A: 4 y R1: 2 y R2: 2 y
Exploitation	A: 25 y or 30 y R1: 10 y	A: 10 y R1: 5 y R2: 5 y	A: 25 y R1: 5 y	A: 25 y R1: 10 y	25 y	A: 25 y R1: 10 y
Other permits	Yes	Yes	None	None	None	Yes
Contract types						
Production sharing	Yes	Yes	Yes	Yes	None	Yes
Concession	Yes	None	None	None	Yes	Yes
Service	None	Yes	Yes	Yes	None	None
Other contracts	None	Yes	None	None	None	None
Levies						
Bonus	NE	Contract	Contract	Contract	Contract	Contract
Social or environmental funds	NE	Contract	0.05% of the turnover	0.5% of the profit oil	NE	NE
Funds for future generations	NE	NE	NE	Contract	NE	NE
Training costs	NE	Contract	Contract	Contract	NE	SP: $150,000; EP: $200,000

(continued)

Table 6 (continued)
OIL TAX SYSTEM OF SOME AFRICAN OIL PRODUCING COUNTRIES[a]

Taxes	Chad	Gabon	Congo	Democratic Republic of Congo	Algeria	Niger
Fees	SP = \$50,000; EP= \$500,000	Contract	By decree	Contract	NE	FL
Surface rent	Contract	SP: 50; EP: 500 CFAF/ha	By decree	SP: 100; EP: 500 \$/km^2	SP: 4,000; EP: 16,000 \$/km^2	SP: 500 to 2,500; EP: 1.5M to 2M CFAF/km^2
Production royalty	16.5% Min.	9% – 15%	12% Min.	8% – 12.5%	15.5%	12.5% – 15%
Additional tax	NE	NE	NE	Contract	ORT	NE
Income tax	40% - 75%	35%	Exempt	Exempt	26%	45% - 60%
Loss carry-forward	3 y	5 y	3 y	5 y	4 y	3 y
Tax on interests	Exempt	20%	Exempt	Exempt	10%	Exempt
Tax on dividends	Exempt	20%	Exempt	Exempt	Exempt	Exempt
Stability agreement	Possible	Yes	Yes	Contract	Yes	Possible
State participation	25% Max.	20%	15% Min.	20% Min.	20% – 30%	20% Max.
Tax oil	Contract	50% Min.	35% Min.	35% Min.	NE	40% Min.
Cost oil	Contract	75% Max.	70% Max.	50% Max.	NE	70% Max.

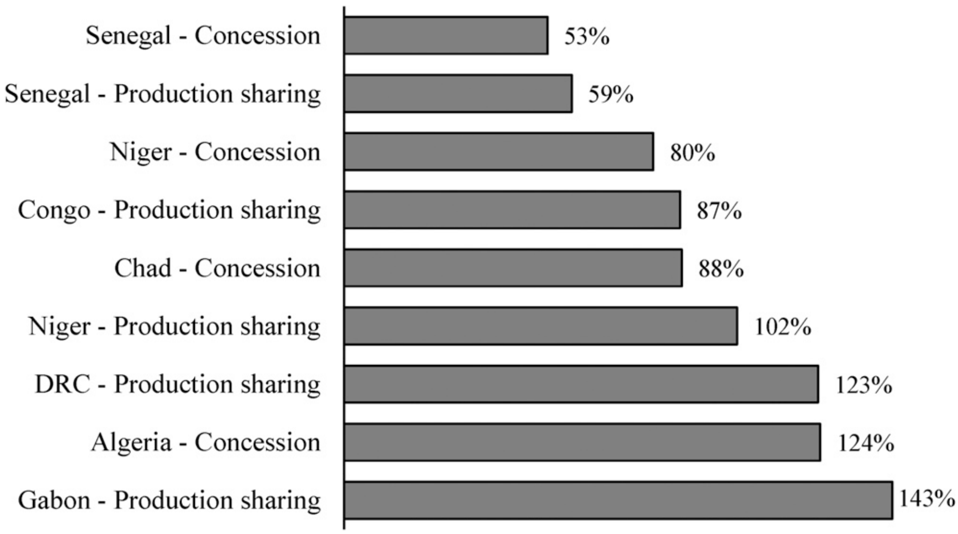
[a] A = attribution period; y = years; R1 = renewal 1; R2 = renewal 2; R3 = renewal 3; m = months; NE = non-existing; SP = searching period; EP = exploration period; FL = financial law; Contract = refers to the contract; Min. = minimum; Max. = maximum; ORT = oil revenue tax, which depends on the project profitability; and Exempt = exemption.

Source: Various oil codes.

table 6. Regardless of whether the contract is production sharing or a concession, Senegal has the lowest AETR among the sample of selected countries (figure 3).

Is the Oil Tax System Progressive?: Whether for a PSC or CC, slightly more than 40 percent of the AETR results from income tax (42 percent and 41.8 percent, respectively). Then, for both types of contracts, come “specific” taxation based on

Figure 3
AVERAGE EFFECTIVE TAX RATE (AETR) COMPARISON FOR AFRICAN OIL PRODUCER COUNTRIES[a]



[a] Oil price = U.S. $50 per barrel; discount rate = 10 percent in the reference scenario; and DRC = Democratic Republic of Congo. Source: Authors' calculations.

the production, namely, production sharing for the PSC and a production royalty for the CC, contribute up to 35 percent of the AETR (table 7).

The Baunsgaard analytical framework allows us to go further in the evaluation of the Senegalese oil tax system (table 7).[19] The contribution of income-based taxation to AETR is slightly more than 50 percent for both contracts—52.6 and 51.6 percent for the PSC and the CC, respectively— (calculation in figure 4). Such a tax design seems attractive to the operating companies, which are subject to a neutral and flexible tax system. The risk is apparently borne more by the state, which, on the one hand, captures a relatively low government take according to international comparisons and, on the other hand, can lose the greater part of its share in the case of an unfavorable change in costs and/or prices.

The equivalence of the two types of contracts (if a 5-percent production royalty rate is applied) for operating companies is confirmed by the IRR analysis. With a $50 per barrel oil price, the project IRR after taxation is 14 percent for the CC and 13 percent for the PSC. The pre-tax IRR is 18 percent (figure 5). For a $70 per barrel oil price, the IRR after taxation increases to 22 percent for the CC and 21 percent for the PSC. The tax system only delays the project profitability by one year, with the IRR after taxation becoming positive in the sixth year before taxation, instead of the fifth year (figure 5).

Table 7
SENEGAL: COSTS/BENEFITS OF THE RENT TAXATION INSTRUMENTS[a]

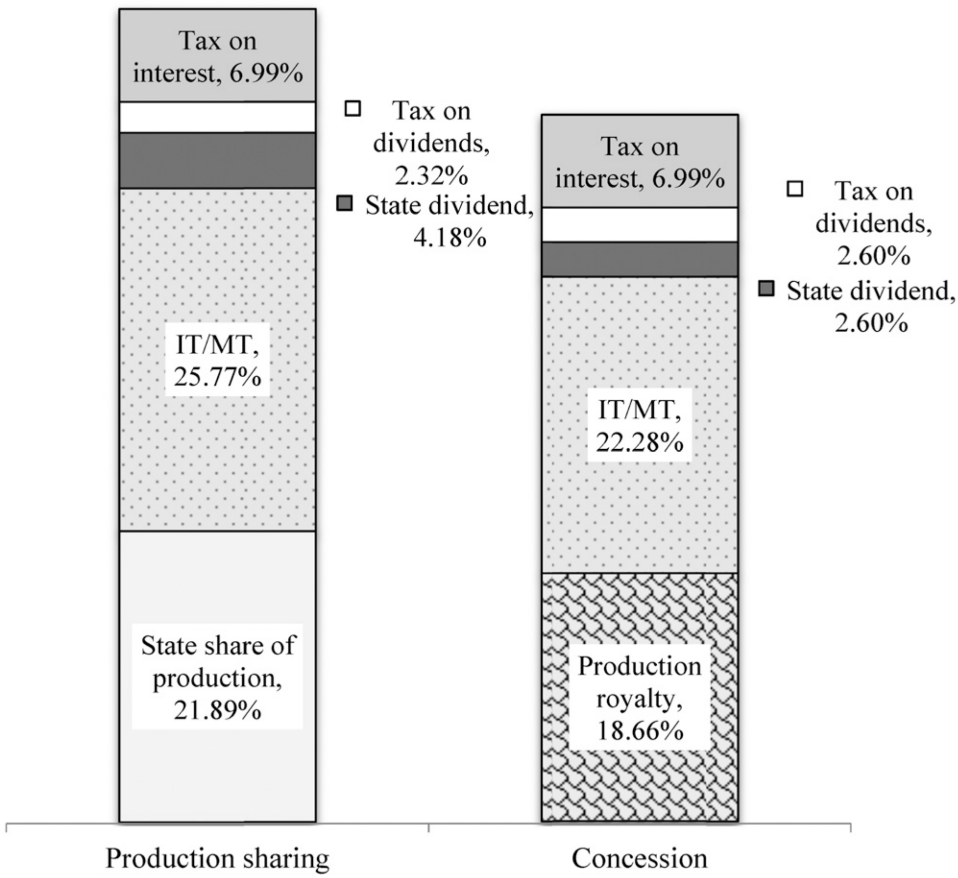
Taxes	Neutrality	Flexibility	Risks of Low Collection	Management Costs	AETR Decomposition	
					PSC	CC
Signature bonus	Weak	Weak	Weak	Weak	0.1%	0.2%
Surface rent	Weak	Weak	Weak	Medium	0.1%	0.2%
Production royalty	Weak	Weak	Medium	Medium	Exemption	35%
Additional tax	ND	ND	ND	ND	None	ND
Production sharing	Weak	Weak	Medium	Medium	35%	None
Income tax	Strong	Strong	Medium	Medium	42%	41.8%
State participation	Strong	Strong	Medium	Weak	6.8%	4.9%
Tax on dividends	Strong	Strong	Medium	Medium	3.8%	4.9%
Tax on interests	Medium	Weak	Medium	Medium	11.40%	13.1%

[a] ND = not defined; AERT = average effective tax rate; PSC = production sharing contract; and CC = concession contract.

Source: Adapted from T. Baunsgaard, "A Primer on Mineral Taxation," International Monetary Fund (IMF) Working Paper WP/01/139, IMF, Washington, D.C., 2001, by the authors.

Several analyzing elements confirm that the arbitrage between attractiveness and oil rent-sharing is more positive for the investors than for the state. The revenue collection profile of the state weakens its rent share. Only 20 percent of the state income is received in the sixth year, which is half of the expected life of the field, and only 50 percent at the ninth year, regardless of the contract. By comparison, 50 percent of the income would be received in the sixth year if the oil tax system of Algeria, Congo, Niger, or the Democratic Republic of Congo (DRC) was applied. In addition, the AETR is extremely sensitive to changes in oil price (figure 6), the quantities of extracted barrels, and the project profitability (figure 7). A crude oil price increase reduces the AETR significantly; this is more pronounced for the CC than for the PSC (figure 6). While the two contracts for operating companies are equivalent, the same cannot be said for the state. Indeed, the government of Senegal has an

Figure 4
SENEGAL: AVERAGE EFFECTIVE TAX RATE (AETR) DECOMPOSITION BY TAX[a]

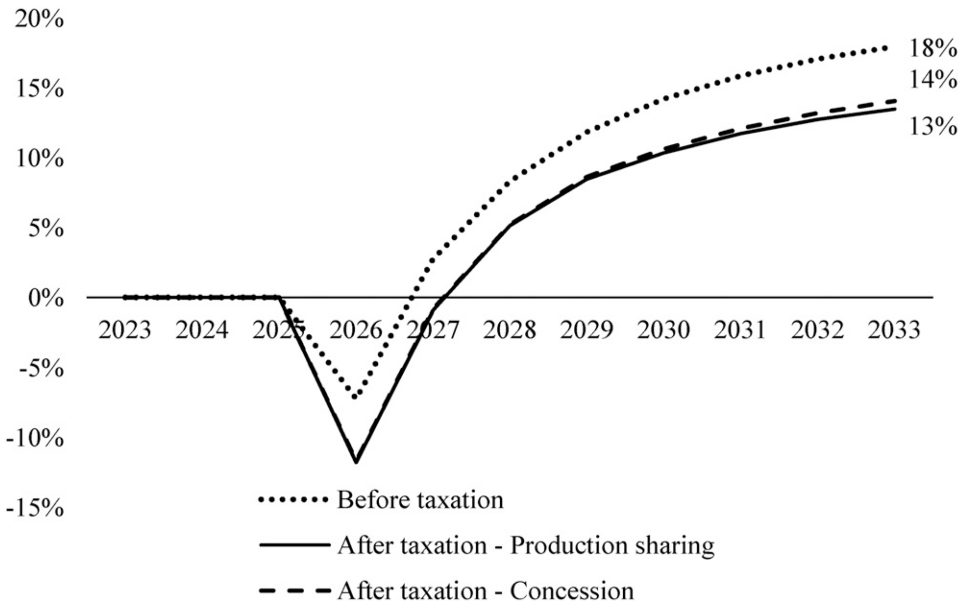


[a] Oil price = U.S. $50 per barrel; discount rate = 10 percent in the reference scenario; IT = income tax; and MT = minimum tax. Source: Authors' calculations.

interest in favoring the PSC. The nature of the chosen taxation instruments and the structure of the resulting levy, namely, the oil tax system has a significant impact on the AETR.

Regardless of the contract, the Senegalese oil tax system is regressive. The optimistic scenario, which increases the daily production from 100,000 to 170,000 barrels, results in an AETR that drops to 35 percent for the CC and 50 percent for the PSC. Likewise, the AETR decreases when the project profitability increases (figure 7). The PSC, as defined by the OC and the SNE contract, is a better option for the Senegalese state than is the CC.

Figure 5
THE INTERNAL RATE OF RETURN (IRR) EVOLUTION BEFORE AND AFTER TAXATION[a]



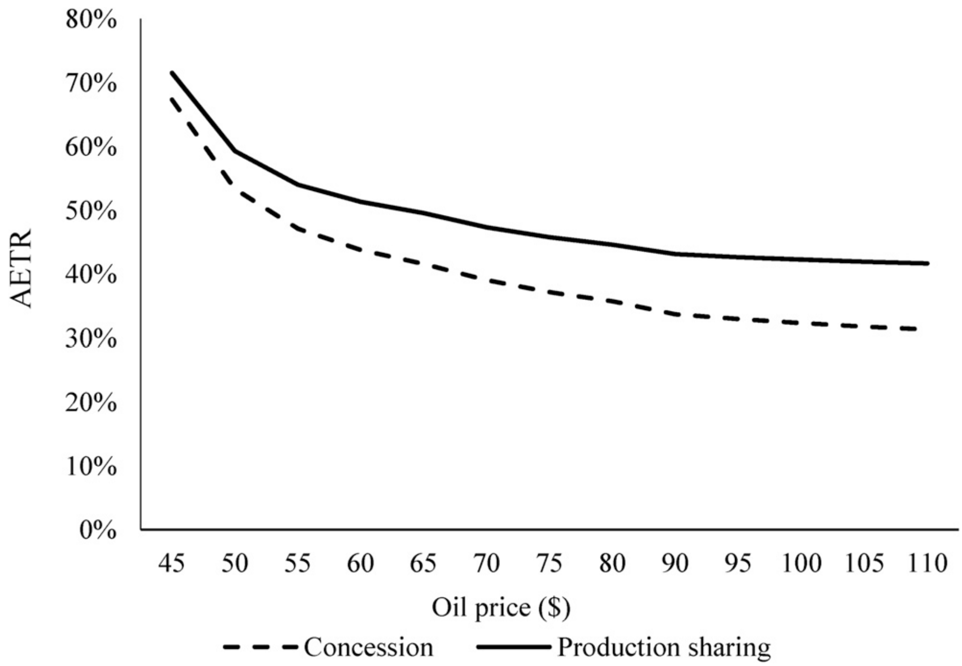
[a] Oil price = U.S. $50 per barrel in the reference scenario. Source: Authors' calculations.

Conclusion

Senegal could, with the prudent development of its oil resources, leave the LDC category, provided that the oil tax system allows for a sufficient government take from the oil rent. Despite the fact that the country's oil code dates back to 1998, there are several taxation elements applicable to projects that can be specified by the contracts between the state and the operating companies. Senegal's tax system provides for two main contracts: the service contract, which can take the form of production sharing, and the concession contract, where an exploitation concession is granted by the state.

There is neither a standard production sharing contract nor a concession contract. Each country defines taxation instruments applicable to each contract. The instruments and terms of contracts determine the properties of the tax system. Generally, the taxation instruments of concession contracts introduce more distortions than do those associated with production sharing contracts, in particular because of the effects of royalties as the main taxation instruments. Indeed, royalties tax the production activity regardless of the project's profitability. The result

Figure 6
THE SENSITIVITY OF THE AVERAGE EFFECTIVE TAX RATE (AETR) TO THE OIL PRICE[a]



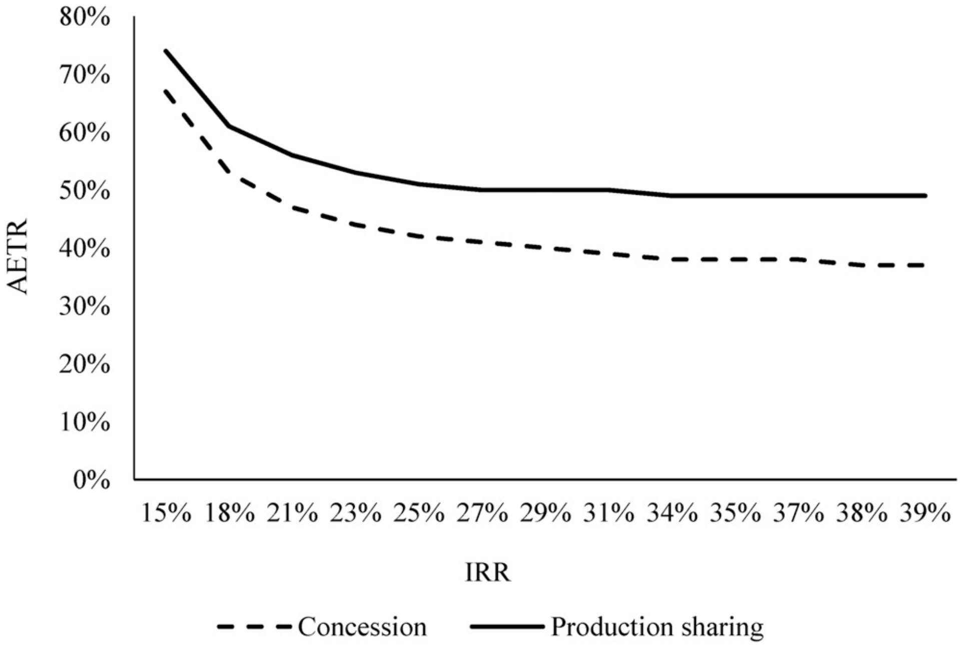
[a] Discount rate = 10% in the reference scenario. Source: Authors' calculations.

is often a regressive tax system. Taxation instruments associated with the production sharing contract result in fewer distortions. Indeed, those taxation methods depend more on the project profitability and result in a more progressive tax system.

A production sharing contract has been signed for the exploitation of one of the discovered oil fields in Senegal: the SNE. Our evaluation of the tax system has been based on the SNE field economic data. The state seems to have made the right choice by favoring the production sharing contract rather than the concession contract. However, this contract is far from being "optimal" for Senegal. The government take is well below "international standards," and the risks of a low taxation over the project life are significant. Arbitrage between investor attractiveness and state revenue is against the latter. The SNE exploration and production sharing contract leads to a regressive tax system, which goes against international best practices.

For the country to fully benefit from oil exploitation—a non-renewable resource—the state must revise its oil code. This revision should allow the country to find a satisfactory balance between income-based taxation and production-

Figure 7
THE SENSITIVITY OF THE AVERAGE EFFECTIVE TAX RATE (AETR) TO THE PROJECT PROFITABILITY (IRR)[a]



[a] Discount rate = 10% in the reference scenario. Source: Authors' calculations.

based taxation, leading to a progressive oil tax system that is flexible to cost fluctuations and world oil prices, allowing for "fair" oil rent-sharing.

Therefore, developing countries must be vigilant in defining the applicable tax regime both for the oil sector and, more generally, for extractive industries. The choice of the production sharing contract is certainly the most widespread, but it does not guarantee either tax system progressivity or a sufficient government take. Hence, the taxation rules that specify the production sharing contract must be established by skillfully combining income-based taxes and production-based taxes to define a progressive and sufficiently remunerative tax system for both parties: the state and the investor. The trade-off between these two types of taxation should be systematically calibrated using a rent-sharing model.

NOTES

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[5]Republic of Senegal, "Petroleum Exploration Code of Senegal 1998," January 1998.

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[8]Ibid.

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[15]In the absence of sufficiently precise information, the CC additional tax has not been included in the analysis.

[16]T. Baunsgaard, "A Primer on Mineral Taxation," International Monetary Fund (IMF) Working Paper WP/01/139, IMF, Washington, D.C., 2001.

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