FERDI

FONDATION POUR LES ÉTUDES ET RECHERCHES SUR LE DÉVELOPPEMENT INTERNATIONAL

Working Paper 209 December 2017 Development Policies

Oil contracts and government take : Issues for Senegal and developing countries

Awa Diouf, Bertrand Laporte

Awa Diouf, PhD student, Université Clermont Auvergne, CNRS, Cerdi
E-mail: awa.diouf@etu.uca.fr

Bertrand Laporte, Corresponding author, Université Clermont Auvergne, CNRS, Cerdi | **E-mail: bertrand.laporte@uca.fr**

Abstract

The challenge of developing countries that have natural resources is to attract international investors for the valuation of that wealth and to get a « fair » share of oil revenue. So, the « design » of the oil tax system determines the level of resource exploitation and the oil rent-sharing. The analysis of the Senegal oil tax regime is based on the assessment of oil revenue sharing between the government and the operating companies for a 2014 oil discovery, according to two types of contract: a concession contract and a production sharing contract. Regardless of the contract, average effective tax rates in Senegal are low, compared to other African producer countries, and the taxation regime is regressive. Developing countries must, therefore, 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 the tax system progressivity or a sufficient government take. The taxation rules that specify the production sharing contract must, therefore, be established by skilfully 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 balance between these two types of taxation should be systematically calibrated using a rent-sharing model. For Senegal, in particular, it involves a revision of the oil code in force.

Keywords: Extractive industries, oil contract, government take, Senegal, developing countries

LA FERDI EST UNE FONDATION RECONNUE D'UTILITÉ PUBLIQUE.
ELLE MET EN ŒUVRE AVEC L'IDDRI L'INITIATIVE POUR LE DÉVELOPPEMENT ET LA GOUVERNANCE MONDIALE (IDGM).
ELLE COORDONNE LE LABEX IDGM+ QUI L'ASSOCIE AU CERDI ET À L'IDDRI.
CETTE PUBLICATION A BÉNÉFICIÉ D'UNE AIDE DE L'ÉTAT FRANCAIS GÉRÉE PAR L'ANR AU TITRE DU PROGRAMME «INVESTISSEMENTS D'AVENIR»
PORTANT LA RÉFÉRENCE «ANR-10-LABX-14-01».

1. Introduction

The oil sector is a major source of income for most countries that exploit hydrocarbon deposits. The challenge of developing countries that have natural resources is to attract international investors for the valuation of that wealth and to get a sufficient share of oil revenue. So, of this difficult trade off results the « design » of the oil tax system, which determines the level of resource exploitation and the oil rent-sharing.

Senegal, which is located on the extreme West of the African continent, is among the continent's most stable countries. The growth of more than 6% registered in 2015 and 2016 makes Senegal one of the most dynamic countries in sub-Saharan Africa (World Bank, 2017). Despite a fast-growing economy, Senegal falls into the category of least-developed countries (LDCs).

Although the country is not listed among the richest countries in terms of natural resources, several mineral resources are presents. Big mining projects are involved in extracting phosphate, industrial limestones, gold, and zircon. Since 1985, approximately forty mining concessions have been granted. With a part close to 10%, gold is the first export product of Senegal. Even though Senegal is less dependent on the extractive industries sector when compared to some African countries rich in natural resources, extractive industries provide the country with more than 20% of its exports. In 2014, the total amount paid by mining companies to the Senegalese government was double that in 2013, reaching 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% (EITI Senegal, 2014).

The hydrocarbon sector in Senegal is less developed than is the mining sector. Indeed, only two blocks situated in Diender have a production right. The Gadiaga block is currently producing gas for local consumption, with the Senegal national electricity company (SENELEC) as the main client. Also, by the decree n°2008-287 the Senegalese government allows the exploitation of Sandiaratou well by Foresta International and the Senegal oil company (PETROSEN). Exploration licences were delivered in several other blocks. In addition, Kosmos Energy discovered a gas field on the Senegalese–Mauritanian border of a capacity estimated at 12 billion cubic feet of gas (EITI Senegal). Finally, in 2014, Cairn Energy and its partners discovered two offshore oil fields: FAN and SNE. The latter is the biggest oil field discovered in 2014, according to the operating companies.

The stake for Senegal of these two last oil deposits is crucial. It could allow the country to increase its income substantially and thus leave the LDC category. The oil tax system choice is, therefore, a key issue for this country, as it is for any developing country wishing to exploit its hydrocarbon resources. It must allow a "fair" share of government take to mobilise the resources required to raise the populations' 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. The third section calculates the oil rent-sharing between the state and operating companies. The fourth section assesses, according to various criteria, the Senegalese tax system. Finally, the last section concludes and draws lessons for developing countries that plan to either define or review their oil code.

2. Tax design for oil exploitation in Senegal

The Senegalese first oil code (OC) dates from 1986. The OC in force was enacted on January 8th, 1998, and it aimed to attract investment from foreign oil companies. *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 (…)* (oil code, 1998).

Any petroleum extraction activity requires a mining right. Hydrocarbon extraction can be conducted with either a temporary exploitation licence or an exploitation concession. A temporary exploitation licence is granted for a maximum period of 2 years and allows its holder *to exploit the productive wells temporarily* (oil code, 1998). Granted by decree, the exploitation concession has a maximal 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 plans the rights and obligations for each party throughout the duration of operations; *According to the provisions of article 6, the state or a state company can conclude risky service contracts for hydrocarbon exploration and exploitation* (oil code, 1998). 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 licence holder. In the same logic, the holder of a service contract is considered as holding an exploitation concession during the extraction period. However, the OC specifies in its 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 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 (oil code, 1998). 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, for 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 23rd, 2004 (decree n°2004-1491) between the Senegalese government, Senegal oil company

(PETROSEN), and Senegal HuntOil company for three blocks: Rufisque offshore, Sangomar offshore, and Sangomar deep offshore. This last zone was the object, 10 years later, of the discovery of both the FAN and SNE deposits of hydrocarbons. Since being signed, the contract has been the subject of numerous amendments (Table 1), 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 simplify the understanding, we shall distinguish the concession contract from the production sharing contract (risky service contract according to the 1998 oil code).

Table 1. SNE contract evolution

Date	Object
July-15-04	Signature of the exploration and production sharing contract between the Senegalese state, PETROSEN, and Senegal HuntOil Company.
Nov-23-04	Approval of the exploration and production sharing contract by the decree n°2004-1491.
Dec-13-05	Approval of the first renewal of the exploration period by the decree n°2005-1201.
March-09-06	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 the decision n°1706.
Nov-23-08	Extension of the first renewal of the exploration period.
Jan-26-09	Approval of the extension of the first renewal of the exploration period by the decree n°2009-35.
Feb-25-09	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-06-12	Approval of the second renewal of the exploration period by the decree n°2012-243.
July-01-13	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 the decision n°10049/MEM/DHCD.
Presently	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 Senegalese official journal.

2.1. 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 planned 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 (...)*'. Based on the turnover of the operating company, the royalty rate can reach 10% for onshore exploitations and 8% for offshore exploitations, with a minimum of 2%. Regarding gaseous hydrocarbon, that rate can reach 6% 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*'. *[...]*. 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*'. The SNE contract regulates this tax amount, only for the exploration licence, between 5 and 15 dollars per 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%) in the Contract Area (...)*. The state free interest can be increased up to 18% 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 GTC in 2004 provided a rate of 33%, as well as 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 < CFAF 250,000,000 : CFAF 500,000; turnover between CFAF 250,000,000 and CFAF 500,000,000: CFAF 750,000; turnover > CFAF 500,000,000: CFAF 1,000,000). The GTC provides for a withholding tax on securities, set at 10% for dividends and 16% 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 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).

2.2. The production sharing contract (PSC)

The production sharing supersedes the production royalty and the additional tax during the exploitation period. Other taxation instruments provided for the CC are also applied to the PSC.
The state share is, thus, 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% by the SNE contract. According to the SNE 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 metres, the state sharing varies according to the daily hydrocarbon production (Table 2).

Table 2. Production sharing as planned by the SNE contract

Daily production (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.

The various taxation instruments specified by the Senegalese oil tax system are summarised in Table 3.

Table 3. The Senegal oil tax system

Taxes	Oil code	SNE contract	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
Signature bonus	NS	NS	NE
Surface rent ($/km^2)	NS	5 - 15	NE
Production royalty	2% - 8%	NE	NE
Additional tax	NS	NE	NE
Tax on dividends and interests	NS	NS	10% et 16%
Income tax	Refers to the GTC	33%	33%
Minimum tax (CFAF)	NS	NS	500,000 – 1,000,000
Loss carry-forward (years)	3	NE	3
Amortisation carry-forward	NS	NS	Unlimited
Surface rent ($/km^2)	NS	5 - 15	NE
Amortisation for equipment	NS	5 years	According to the practices
Amortisation 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

Note: NS: Not specified – NE: Not existing.

3. The sharing of oil rent in Senegal

3.1. Methodology

Among empirical studies that attempt to quantify natural resources' rent-sharing between state and investors (Laporte and de Quatrebarbes, 2015), the oil sector is the most studied (notably: Lund 1992; Black and Roberts, 2006; Daniel et al, 2008; Tordo, 2007; Smith, 2013; Gab-Leyba and Laporte, 2016; and others…). For the investor, the economical rent represents the income perceived beyond the minimum required by the production process. More specifically, it is '*Revenues in excess of all necessary costs of production including the minimum rate of return to capital*' (IMF, 2012).

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 (notably: Lund, 1992; Black and Roberts, 2006; Daniel et al., 2008). The discounted cash-flow model associated with ad hoc sensitivity analysis is the most common, although some authors have used the financial asset valuation model (notably: Brennan and Schwartz, 1985; Laughton, 1998; Grinblatt and Titman, 2002).

To assess the Senegalese oil tax regime, a discounted cash-flow model, applied to the "real" economic data of the SNE deposit, has been retained. 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:

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

Z_t the expected turnover of the crude oil selling, C_t the unit cost of exploitation (operating cost, expressed in \$/bbl., and K_t 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:

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

The IRR is represented by i^* in the 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:

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

R_t represents state levies.

3.2. Data for modelling the rent-sharing

3.2.1. Economic data of the SNE deposit

Discovered in November 2004, the SNE deposit is offshore and at 1,100 metres-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 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 barrel price retained in the following analysis is 50 $.

Table 4. Economic data of the SNE deposit, according to 3 scenarios

Data	Pessimistic	Reference	Optimistic
Exploitation duration (years)	12	12	12
Water depth (metres)	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 ($)	175,000,000	175,000,000	175,000,000
Operating costs ($/bbl.)	5	10	15

Source: Cairn Energy and the Senegalese Ministry of Energy

3.2.2. 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

Taxes	Oil rent-sharing model	
	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 renderings
Surface rent ($/km²)	5 - 15	5 - 15
Production royalty	5%	
Additional tax		
Tax on dividends and interests	10% et 16%	10% et 16%
Income tax	33%	33%
Minimum tax (CFAF)	500,000 – 1,000,000	500,000 – 1,000,000
Loss carry-forward (years)	3	3
Amortisation carry-forward	Unlimited	Unlimited
Amortisation of equipment (years)	5	5
Amortisation 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%

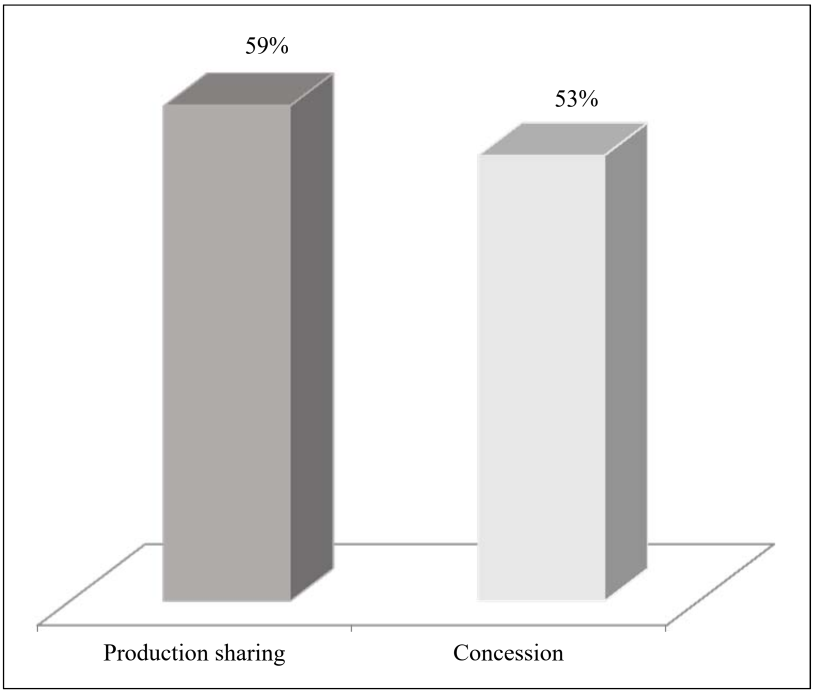
Source: authors' compilation of several legal texts.

3.3. Government take in 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 considered contract (concession or production sharing), this category is estimated at less than 1% of the rent. The government take, represented by the AETR, is 59% under the PSC and 53% for the CC (Figure 1, with a 5% rate of production royalty)[2].

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

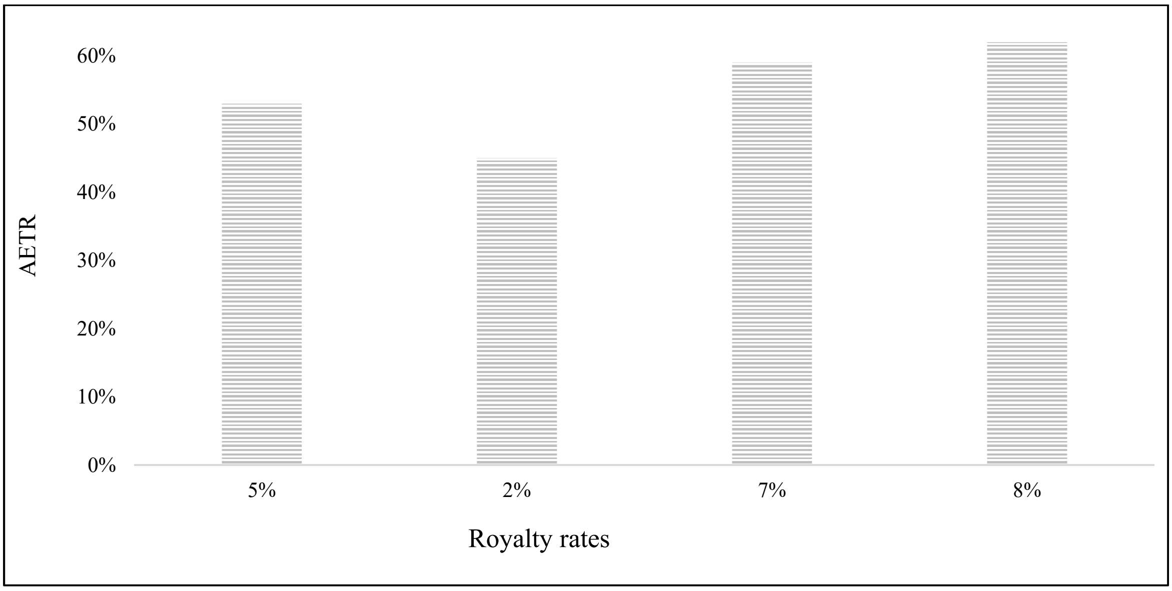
Figure 1. AETR for the PSC and the CC



Notes: oil price: 50$ – discount rate: 10% – reference scenario.
Source: authors' calculations.

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

Figure 2. AETR sensitivity to production royalty rate



Notes: oil price: 50$ – discount rate: 10% – reference scenario.
Source: authors' calculations.

3.4. Evaluation of the oil tax system: beyond the government take

According to the optimal taxation theory, a 100% oil rent taxation should not affect the investment decision. However, uncertainty over the operation conditions and generated profits does not allow the states to accurately assess ex ante the oil rent, for either geological, economic, or political reasons. From the beginning of the project, it is, therefore, 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 and/or smooth revenues over the project duration, improve the progressivity of the tax system, adapt to the capacity of the administration, reduce information asymmetry with the investors, or even more widely influence the behaviour of operating companies (Baunsgaard, 2001). 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 (Boadway and Keen, 2010).

3.5. Is the oil rent-sharing "fair"?

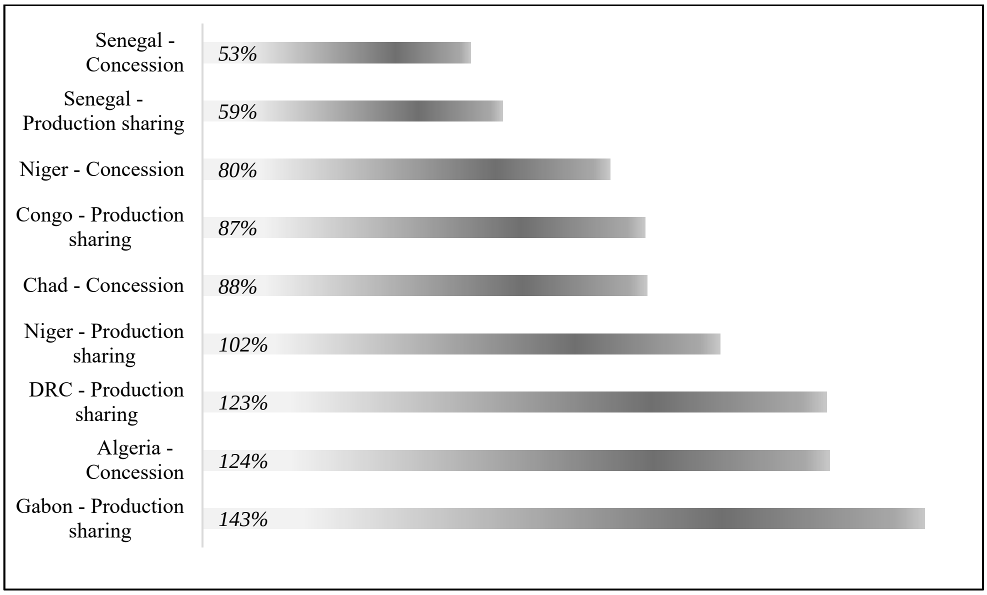
This is a difficult question to answer because the optimal level of taxation for the exploitation of natural resources is complicated to establish, due to several uncertainties that weigh on the activity, as stated above. The International Monetary Fund (2012) estimates the oil sector average AETR between 65% and 85%. Considering the SNE deposit economic data, the Senegalese tax system presents, therefore, 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 (Table 6) have been applied to the reference scenario of the SNE field. Regardless of the considered contract, Senegal has the lowest AETR among the sample of selected countries (Figure 3).

Table 6. Oil tax system of some African oil producer countries

TAXES	Chad	Gabon	Congo	DRC	Algeria	Niger
Oil code in force	2007	2014	2016	2015	2005	2007
Permit duration						
Prospection	A[1]: 2 y[2] R1[3] : 2 y	18 m[4]	A: 1 y R1: 1 an	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[5]	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$
Fees	SP[6]: 50,000 $ EP[7]: 500,000 $	Contract	By decree	Contract	NE	FL[8]
Surface rent	Contract[9]	SP: 50 EP: 500 CFAF/ha	By decree	SP: 100 EP: 500 $/km^2$	SP: 4000 EP: 16000 $/km^2$	SP: 500 - 2500 EP: 1,5M - 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[10]	NE
Income tax	40% - 75%	35%	Exemption	Exemption	26%	45% - 60%
Loss carry-forward	3 y	5 y	3 y	5 y	4 y	3 y
Tax on interests	Exemption	20%	Exemption	Exemption	10%	Exemption
Tax on dividends	Exemption	20%	Exemption	Exemption	Exemption	Exemption
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

Source: various oil codes.
Notes : (1) Attribution period, (2)Years, (3) Renewal 1, 2, 3, (4) Months, (5) Non-existing, (6) Searching period, (7) Exploitation period, (8) Financial law, (9) Refers to the contract, (10) Oil revenue tax; depends on the project profitability

Figure 3. AETR comparison for African oil producer countries

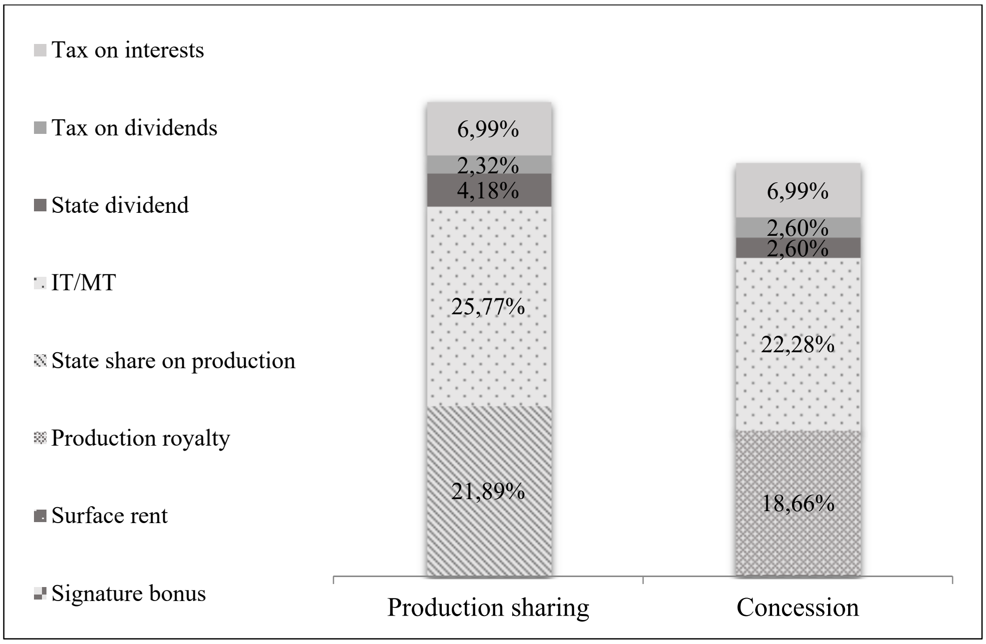


Note: oil price: 50$ – discount rate: 10% – reference scenario.
Source: authors' calculations.

3.6. Is the oil tax system progressive?

Whether for PSC or CC, slightly more than 40% of the AETR results from income tax (42% and 41.8%, respectively). Then for both types of contracts, come "specific" taxation based on the production, namely production sharing for the PSC and a production royalty for the CC, which contribute up to 35% of the AETR (Table 7).

Figure 4. AETR decomposition by tax



Notes: oil price: 50$ – discount rate: 10% – reference scenario.
Source: authors' calculations.

The Baunsgaard (2001) analytical framework allows us to go further in the evaluation of the Senegalese oil tax system (Table 7). The contribution of income-based taxation to AETR is slightly more than 50% for both contracts (52.6 and 51.6% for the PSC and the CC, respectively) (calculation with 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 unfavourable change in costs and/or prices.

Table 7 « Costs/Benefits » of the rent taxation instruments

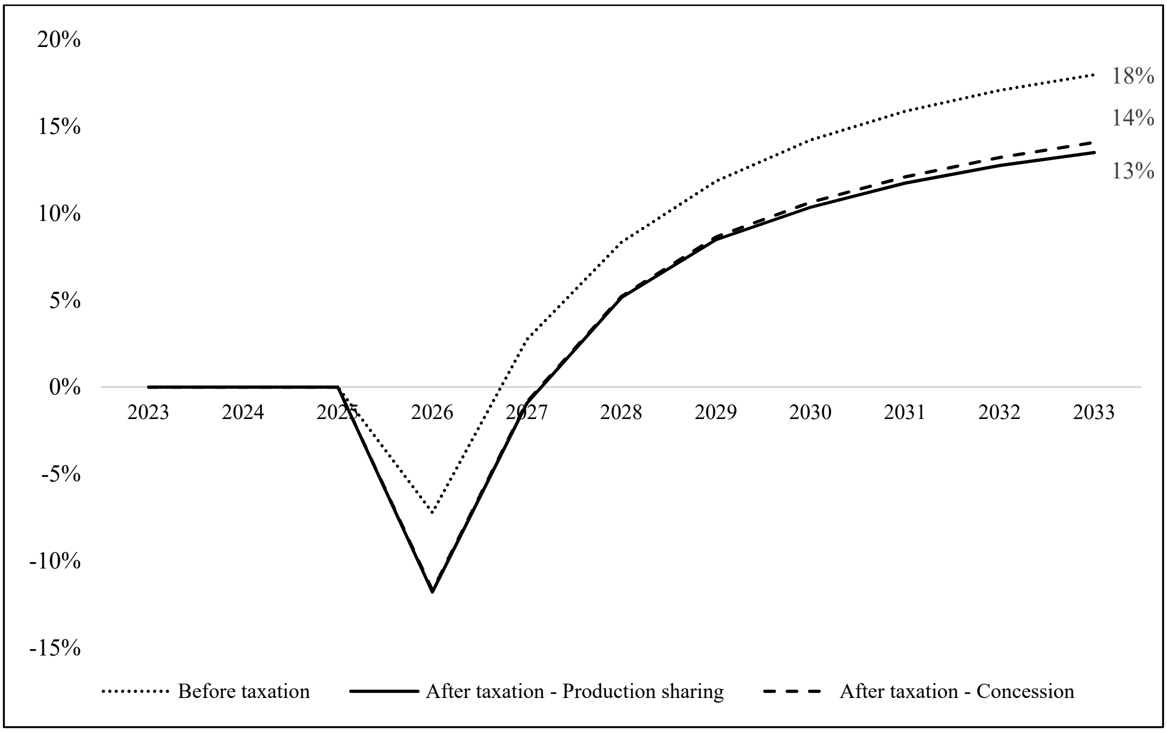
Taxes	Neutrality	Flexibility	Risks of low collection	Management costs	AETR Decomposition	
					PSC	CC
Signature bonus	Weak	Weak	Weak	Weak	0.1%	0.2%
Surface rent	Weak	Weak	Weak	Medium	0.1%	0.2%
Production royalty	Weak	Weak	Medium	Medium	Exemption	35%
Additional tax	ND[3]	ND	ND	ND	None	ND
Production sharing	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%

Source: adapted from Baunsgaard, (2001) by the authors.

The equivalence of the two types of contracts (if a 5% production royalty rate is applied) for operating companies is confirmed by the IRR analysis. With a $ 50 oil price, the project IRR after taxation is 14% for the CC and 13% for the PSC. The pre-tax IRR is 18% (Figure 5). For a $ 70 oil price, the IRR after taxation increases to 22% for the CC and 21% 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).

[3] Not defined

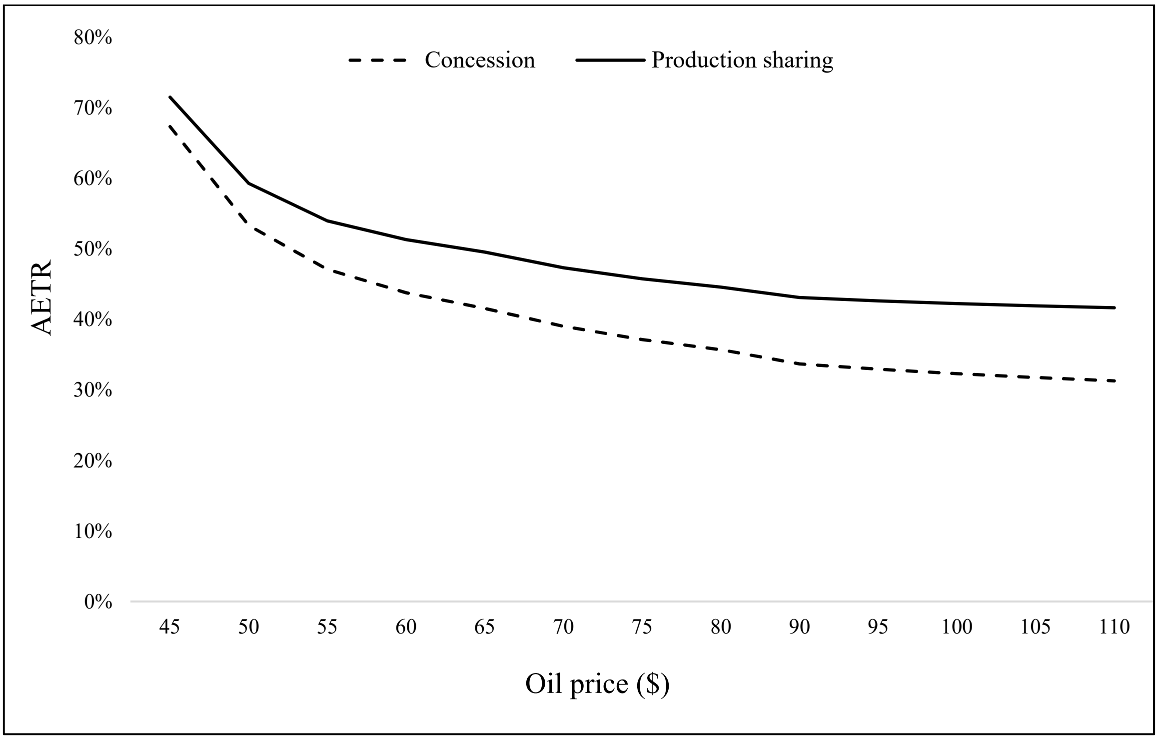
Figure 5. IRR evolution before and after taxation



Note: oil price: 50$ – reference scenario.
Source: authors' calculations.

Several analysing 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% of the state income is perceived at the sixth year, which is half of the expected life of the field, and only 50% at the ninth year, regardless of the contract. For comparing, 50% of the income would be perceived at the sixth year if the oil tax system of either Algeria, Congo, Niger, or the DRC was applied. In addition, the AETR is extremely sensitive to oil price evolution (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). The equivalence of the two contracts for operating companies cannot be transposed to the state. Indeed, Senegal has an interest in favouring 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.

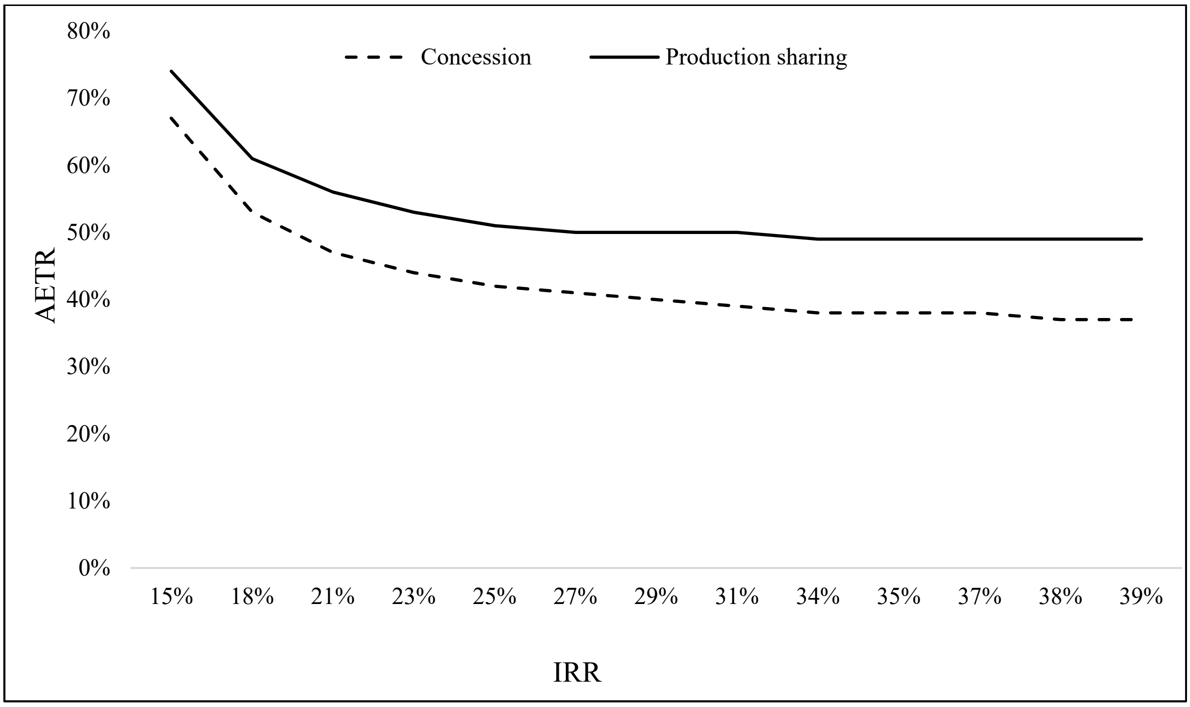
Figure 6. The sensitivity of the AETR to the oil price



Notes: discount rate: 10% – reference scenario.
Source: authors' calculations.

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, provides an AETR that drops to 35% for the CC and 50% 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 solution for the Senegalese state than is the CC.

Figure 7. The sensitivity of the AETR to the project profitability (IRR)



Note: discount rate: 10% – reference scenario.
Source: authors' calculations.

4. Conclusion

Senegal could, thanks to oil resources' exploitation, leave the LDCs category sustainably, provided that the oil tax system allows for a sufficient government take from the oil rent. The oil code in force dates from 1998, however several taxation elements applicable to projects can be specified by the contracts between the state and 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, when 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 in the activity 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 profitability. The result is an often-regressive tax system. Taxation instruments associated with the production sharing contract introduce less distortions. Indeed, those taxation methods depends more on the project profitability. The result is 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. The evaluation of the tax system has been based on the SNE field economic data. The state seems to have made the right choice by favouring 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 perception over the project life are significant. Arbitrage between 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 good practices.

For the country to fully benefit from the 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-based taxation, leading to a progressive oil tax system that is flexible to cost evolutions and world prices, allowing “fair” oil rent-sharing.

Developing countries must, therefore, 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. The taxation rules that specify the production sharing contract must, therefore, be established by skilfully 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.

Bibliographic references

- World Bank, 2017. http://www.worldbank.org/en/country/senegal/overview.
- Baunsgaard, T., 2001. A Primer on Mineral Taxation. *IMF Working Paper WP/01/139*. International Monetary Fund.
- Blake, A., Roberts, M., 2006. Comparing petroleum fiscal regime under oil price uncertainty. *Resources Policy*. 31: 95-105.
- Boadway, R., Keen, M., 2010. Theoretical perspectives on resource tax design, in Daniel, P., Keen, N., McPherson, C, (eds), 2010. *The Taxation of petroleum and minerals: Principles, problems and practices*. Routledge: London.
- Brennan, M., Schwartz, E., 1985. Evaluating Natural Resource Investments. *The Journal of Business.* 58(2): 145-153.
- Cairn Energy, 2015. Capital markets day Senegal – Building on success. https://www.cairnenergy.com/ (accessed 20 October 2017).
- Daniel, P., et al., 2008. *Evaluating Fiscal Regimes for Resource Projects: An Example from Oil Development*. IMF Conference on Taxing Natural Resources.
- Direction Générale des Impôts du Sénégal: http://www.impotsetdomaines.gouv.sn/ (accessed 20 October 2017).
- Droit-Afrique: www.droit-afrique.com (accessed 20 October 2017).
- International Monetary Fund, 2012. Fiscal Regimes for Extractive Industries: Design and Implementation. Washington DC.
- Gab-Leyba, G.D., Laporte, B., 2016: Oil contracts, progressive taxation and government take in the context of uncertainty in crude oil prices: the case of Chad. *The Journal of Energy and Development*. Vol. 41(1 and 2): 253-278.
- Grinblatt, M., Titman, S., 2002. *Financial Markets and Corporate Strategy*. McGraw-Kill Irwin. Second Edition.
- Extractive industries transparency initiative (EITI) in Senegal: www.itie.sn (accessed 20 October 2017).
- Senegal official journal: http://www.jo.gouv.sn/ (accessed 20 October 2017).
- Laporte, B., Quatrebarbes, C., 2015. What do we know about the mineral resource rent sharing in Africa? *Resources Policy*. 46: 239-49.
- Laughton, D.G., 1998. The Potential for Use of Modern Asset Pricing Methods for Upstream Petroleum Project Evaluation: Introduction. *The Energy journal*. 19(1): 149-153.
- Lund, D., 1992. Petroleum taxation under uncertainty: contingent claims analysis with an application to Norway. *Energy Economics*, 14: 23-31.
- Senegalese Ministry of energy: http://www.energie.gouv.sn/ (accessed 20 October 2017).
- EITI Senegal report, 2014.
- Smith, J., 2013. Issues in extractive resource taxation: A review of research methods and models. *Resources Policy*, 38, 320-331.
- Tordo, S., 2007. Fiscal systems of Hydrocarbons: Design Issues. Working Paper 123/07, World Bank, Washington, D.C.

"Sur quoi la fondera-t-il l'économie du monde qu'il veut gouverner? Sera-ce sur le caprice de chaque particulier? Quelle confusion! Sera-ce sur la justice? Il l'ignore."

Pascal

Created in 2003 , the **Fondation pour les études et recherches sur le développement international** aims to promote a fuller understanding of international economic development and the factors that influence it.

Contact
www.ferdi.fr
contact@ferdi.fr
+33 (0)4 73 17 75 30