Assessing Tunisia's Upstream Petroleum Fiscal Regime

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Natural Resource Governance Institute

Abbreviations

AETR	Average effective tax rate
bcm	Billion cubic meters
BGT	BG Tunisia
bls/d	Barrels per day
bnbls	Billion barrels
boe	Barrels of oil equivalent
capex	Capital expenditures
CIT	Corporate income tax
EIA	U.S. Energy Information Administration
EMV	Expected monetary value
ETAP	Entreprise Tunisienne d'Activités Pétrolières
FARI	Fiscal Analysis of Resource Industries
IMF	International Monetary Fund
IOCs	International oil companies
IRR	Internal rate of return
JV	Joint venture
kbls/d	Thousand barrels per day
MENA	Middle East and North Africa
NOC	National oil company
NPV	Net present value
NRGI	Natural Resource Governance Institute
OECD	Organization for Economic Co-operation and Development
opex	Operating expenditures
/bl	Per barrel
PSC	Production sharing contract
RGI	Resource Governance Index
SG&A	Selling, general and administrative
tcm	Trillion cubic meters
U.K.	United Kingdom
U.S.	United States
USD/bl	U.S. dollar per barrel

Cover image: Mediterranean coast of Tunisia and northwest Libya, NASA

Contents

Key messages

- Tunisia's proven oil and gas reserves are very small, especially by regional standards. With limited geological prospects, the existing context is not conducive to oil and gas investment, especially for exploration.
- The fiscal terms offered by the Tunisian government on the basis of the petroleum law are not sufficiently competitive; comparable terms are more often found in countries with much better geological prospects.
- Tunisia's production sharing contracts (PSCs) contain very different fiscal terms for different projects. As an alternative to PSCs, concession agreements could be more competitive if they did not require a significant equity position for the state-owned company (ETAP).
- If Tunisian government officials want to create a vibrant petroleum industry to support the local economy, reduce the country's increasing dependence on imports, attract investment and boost exploration activity, they might consider the following recommendations:
  - Harmonize fiscal terms across new projects to create equal opportunities for investors and easier monitoring by the state and oversight actors.
  - Review the terms of PSCs to make the fiscal regime more progressive. For instance, officials could increase the cost recovery ceiling and adopt only R-factor based profit-oil splits. Any changes to PSC terms should not apply to existing agreements, unless contracted companies opt in to the new regime.
  - In the longer term, launch additional reforms to stabilize the institutional and regulatory framework, clarify the role of parliament, and improve the competitiveness of license allocations to further enhance Tunisia's international competitiveness in the oil and gas sector.

Executive summary

The overriding objective of this paper is to examine Tunisia's upstream petroleum fiscal regime, in consideration of the government's stated policy priority of reversing a decade-long decline in reserves and production. Although the country's Jasmine Revolution led to improved civic rights and the country is a strong regional performer on the Natural Resource Governance Institute's (NRGI) Resource Governance Index (RGI), foreign investment has dropped since 2011, in part because of regulatory ambiguity and political instability.[1]

Tunisia's proven oil and gas reserves are very small, especially by regional standards. With limited geological prospects, the existing context is not conducive to oil and gas investment, especially for exploration.

Tunisia offers different contractual arrangements and fiscal regimes: a concession-based system, which often involves joint ventures between the state-owned company, ETAP, and international oil companies and production sharing contracts. This paper analyses the various arrangements and fiscal instruments, focusing primarily on production sharing contracts, which have become the dominant contractual forms for foreign investors and do not require any public (ETAP) capital investment. The government of Tunisia publicly discloses all contracts and concessions.

The quantitative analysis carried out in this paper is based on a version of the International Monetary Fund's (IMF) fiscal analysis of resource industries discounted cash flow model, adapted by NRGI to compare Tunisia's fiscal regimes with eight oil and gas producers. The benchmarking exercise reveals that Tunisia offers fiscal terms that are not competitive enough considering that comparable terms are more often found in countries with much better geological prospects. Within the Tunisian context, some of the production sharing contracts have more competitive terms than others, but only under certain economic conditions. The terms of the concession agreements could also be more competitive if they did not require a significant equity position for ETAP.

The fiscal regime is one of the few variables that the Tunisian government can control in the short term. Some adjustments could help attract foreign investments to increase exploration and production. For instance, the government could harmonize fiscal terms across new projects to create equal opportunities and adjust the most competitive version of the production sharing contracts to make the regime more progressive. They could achieve this by using a higher cost oil recovery ceiling, an R-factor based profit oil split with no more than three, but more progressive, thresholds, to improve investors' return on investment, while maintaining a high share of profit oil for ETAP at higher levels of profitability.

In the longer term, additional reforms to stabilize the institutional and regulatory framework, clarify the role of parliament and improve the competitiveness of license allocations could further enhance Tunisia's international competitiveness in the oil and gas sector.

1 NRGI, Resource Governance Index (2017)

1. Introduction

Since the Jasmine Revolution in 2010-11, which ended 23 years of control by former president Zine El Abedine Ben Ali, Tunisia has been working hard to transition to a fully fledged democracy with a healthy, modern economy. In January 2014, the country adopted a new constitution that places a clear focus on transparency. In February 2015, Tunisia formed its first post-transition government, elected through free and fair elections the previous year.

As history has shown in other democracies throughout the world, such transitions take time and can suffer setbacks. Building strong political, economic and social foundations requires commitment to formulating the right policies and consensus on the expected outcomes, while strengthening institutions to support public trust in the government and ensure effective and efficient implementation of policies.

Oil and gas are a symbolic sector for a country that has transitioned from autocracy to democracy. Resources-rich countries often grow more slowly than resources-poor countries and suffer from various socio-political problems.[2] As such, Tunisia needs to avoid the so-called resource curse, which has plagued many neighboring countries endowed with significant oil and gas resources.

Tunisia faces a double challenge: how can it reverse the decline in the oil sector, both in terms of investment and production while restoring public trust in the way it is managed? Since the revolution, various stakeholders have questioned whether oil and gas contracts awarded under the former government of Ben Ali sufficiently protected the public interest and whether the fiscal regime currently in place, either in the traditional joint venture (JV) agreements or the production sharing contracts (PSC), are suitable for future allocations of contracts.

The aim of this report is to analyze Tunisia's upstream petroleum fiscal regime and provide recommendations on how the system can be better suited to the government's stated objective to create a vibrant sector and boost investment, particularly in exploration, while capturing an appropriate share of the value of petroleum production to the nation.[3] The report focuses on the PSC, which is increasingly being used as a contractual vehicle in Tunisia.

The report analyzes the Tunisian fiscal regime using comparative quantitative analysis commonly used by tax policy experts. A stylized oil project is used to model and compare the fiscal regimes that exist in Tunisia and in a selection of other jurisdictions. The fiscal model used is an NRGI adaptation of the IMF's Fiscal Analysis of Resource Industries (FARI) excel-based model.[4]

2 Natural Resource Governance Institute (NRGI), *The Resource Curse: The Political and Economic Challenges of Natural Resource Wealth* (2015), resourcegovernance.org/sites/default/files/nrgi_Resource-Curse.pdf.

3 Amel Bel Hadj Ali, "Tunisie : 26 permis d'exploitation et de prospection des hydrocarbures en 2016", *Webmanagercenter*, 8 March 2017, www.webmanagercenter.com/2017/03/08/404019/tunisie-26-permis-dexploitation-et-de-prospection-des-hydrocarbures-en-2016/

4 NRGI uses this approach in other contexts. For examples, visit resourcegovernance.org/economic-models. Other organizations such as Open Oil also use this approach. Access their modeling here: openoil.net/public-interest-modeling-sprint-2016/.

Although an ideal fiscal regime exists only in theory, the fiscal regime should take into consideration the geology, cost structure, competitive pressures and government priorities, which all vary from one country to another. The report aims to contribute to the existing debate on the hydrocarbons' fiscal regime in Tunisia.

The study proceeds as follows. Section 2 provides an overview of the oil and gas sector in Tunisia. Section 3 covers the main fiscal regimes found in upstream oil and gas, the principles of an ideal regime and the main features of the Tunisian system. Section 4 presents the results of the quantitative analysis, which compares Tunisia's fiscal terms with those found in eight jurisdictions. Section 5 incorporates the concluding remarks and recommendations.

2. Overview of Tunisia's oil and gas sector

The starting point for analyzing the fiscal regime in a country is to acquire a good understanding of the oil and gas sector, including the geology and size of resources, exploration, development and production levels and performance. These elements are the main determinants of investment decisions on a pre-tax basis. The fiscal regime, which is one of the chief policy instruments within government control, can improve or worsen the attractiveness of the investment proposition.

Other policies, such as licensing, play an equally important role. For instance, while the government has limited ways to influence the naturally dictated geology of the country, it can reduce the perception of the geological risk by adopting licensing policies that promote information sharing between government agencies, state-owned companies and private investors. The local business environment, which includes elements such as political stability, government efficiency, regulatory certainty and control of corruption, also have a significant influence in shaping the overall perception of risk in a country. These, however, deserve a separate study on their own and will not be covered at length in this report.

The objective of this section is to provide an overview of Tunisia's oil and gas sector, describing the common understanding of the geological potential known to date, the factors that have shaped production and investment trends in recent years, and the business climate for oil and gas investors.

2.1 GEOLOGICAL POTENTIAL

The common understanding by industry experts is that Tunisia's oil and gas resources are very small by international standards and especially as compared with those of its neighbors. Its proven oil reserves of 0.42 billion barrels (bnbls) and gas reserves of 0.06 trillion cubic meters are equivalent to about 1 percent of those of Libya's and Algeria's, respectively. (See Table 1.)

Country	Proven oil reserves			Proven gas reserves		
	Global rank	Africa rank	Size bnbls	Global rank	Africa rank	Size tcm
Libya	9th	1st	48.36	30th	8th	1.48
Algeria	16th	3rd	12.20	17th	1st	4.45
Tunisia	48th	8th	0.42	56th	12th	0.06

Table 1. Proven oil and gas reserves (2017)[5]

5 "International Energy Statistics," United States Energy Information Administration, accessed 15 April 2019, www.eia.gov/beta/international

By 2016, Tunisia's oil and gas reserves had declined by 81 and 62 percent respectively from their peak in 1980. (See Figure 1.) Tunisia's reserves are therefore depleting faster than they are being discovered, reflecting a decline in fruitful exploration and a reduction in investment. (See Section 2.3.3 below.)

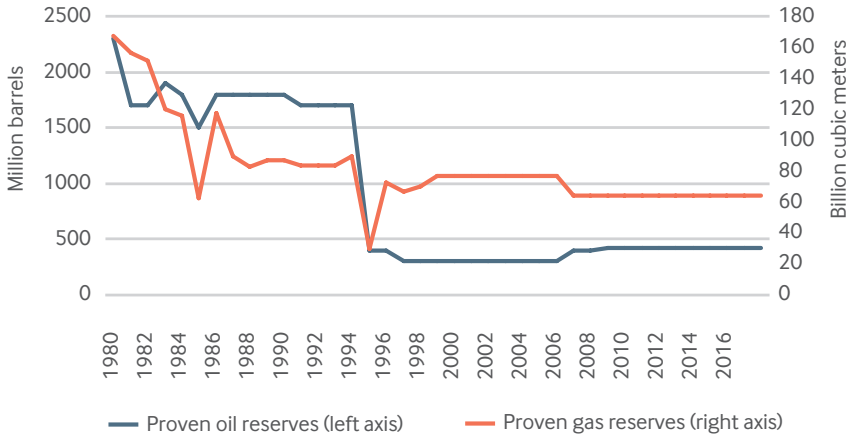


Figure 1. Tunisia's proven oil and gas reserves (1980-2016)[6]

Tunisia's oil and gas potential is not limited to conventional oil and gas. According to the U.S. Energy Information Administration, the country's technically recoverable shale oil and gas resources are 1.5 bnbls and 0.6 tcm respectively, ranking 28th and 33rd in the world, respectively.[7] These shale oil resources are comparable to the UK's, and the shale gas resources are comparable to Poland's. They are, however, yet to be explored and confirmed.

Despite the small resource base, the oil and gas sector plays an important role in the economy. Over the last twenty years, it has represented between 3 percent and 7 percent of GDP, and between 8 percent and 18 percent of exports, as reflected in Figure 2. The sector also contributes significantly to government revenue (see Figure 6) and employs about 3000 people directly and indirectly.

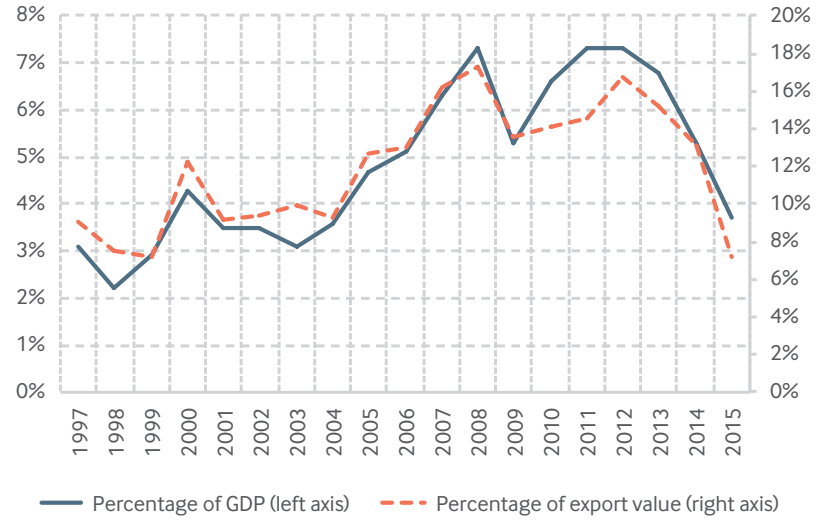


Figure 2. Oil and gas in the Tunisian economy (1997-2015)[8]

6 *Ibid.*
7 United States Energy Information Administration, *World Shale Resource Assessments* (2015), www.eia.gov/analysis/studies/worldshalegas/pdf/Tunisia_2013.pdf
8 "National Statistics", Tunisia's National Institute of statistics, accessed July 30 2018, www.ins.nat.tn

2.2 PRODUCTION PERFORMANCE

Oil production in Tunisia has been steadily declining after reaching a peak of 120,000 barrels per day (bls/d) in the early 1980s. In 2017, it reached 42,000 bls/d, according to the international energy statistics of the U.S. Energy Information Administration (EIA) represented in Figure 3. Natural gas production increased significantly in 1996 when BG Tunisia (BGT), a subsidiary of BG Group, started producing from the onshore Miskar gas field, the largest field discovered to date in the country.[9] In 2017, natural gas production reached 1.3 billion cubic meters (bcm), a decline of 57 percent from the 2008 peak of 3 bcm. (See Figure 3.)[10]

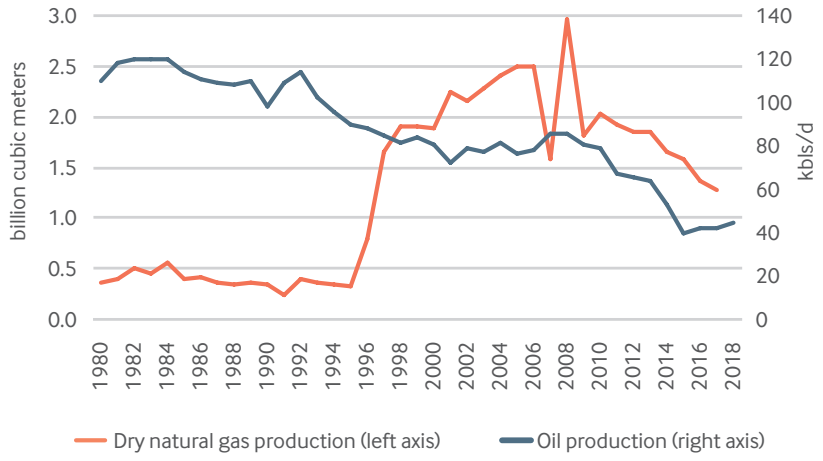


Figure 3. Tunisia's oil and gas production (1980-2017)[10]

As Figure 4 shows, oil and gas dominate Tunisia's primary energy mix, providing 41 and 48 percent, respectively, of its domestic energy needs compared to only 11 percent from renewable energy. [11]

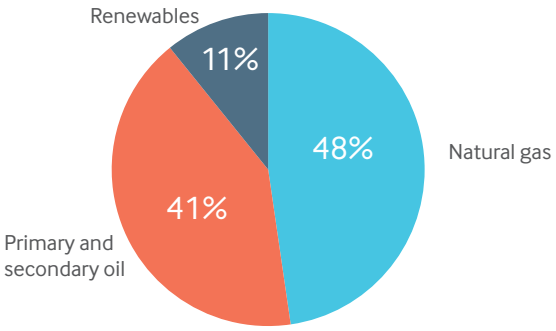


Figure 4. Tunisia's total primary energy supply by source (2016)[11]

9 Prior to Shell's acquisition in 2016.
10 EIA, "International Energy Statistics"
11 "Tunisia Balances for 2016", International Energy Agency, accessed 15 April 2019, www.iea.org/statistics

Given the rapidly rising domestic consumption of both oil and gas (figure 5), the decline in local production has translated into an increasing dependence on imports, aggravating the protracted national energy deficit. According to ETAP, the deficit increased by 67 percent in 2017, year on year.[12]

In 2017, Tunisia exported 87 percent of its crude oil and imported 85 percent of its refined fuels, compared to 65 percent in 2000.[13] Domestically produced natural gas was sold entirely in the local market but covered only 38 percent of the national demand (compared to 61 percent in 2000). The remainder came from Algeria (49 percent), and the royalty levy (13 percent) on the transit of gas from the Enrico Mattei gas pipeline that is received in kind.[14] [15]

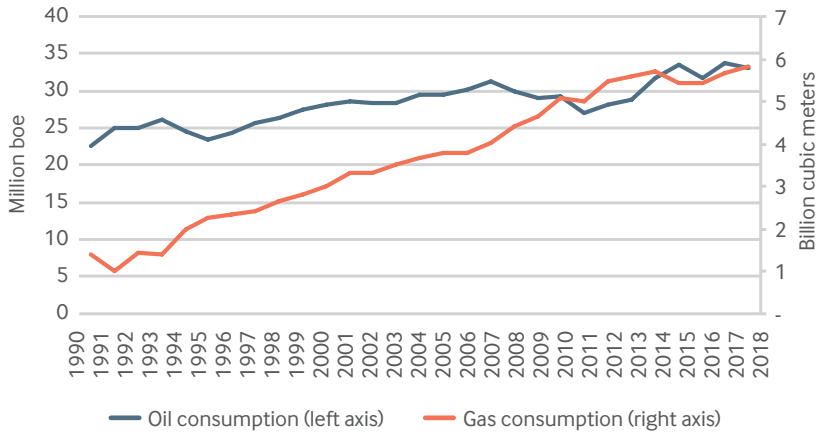


Figure 5. Tunisia's oil and gas consumption (1990-2017)[15]

The decline in production, compounded by falling prices, has dramatically reduced revenues to the state, as Figure 6 shows, with negative consequences on the economy.[16]

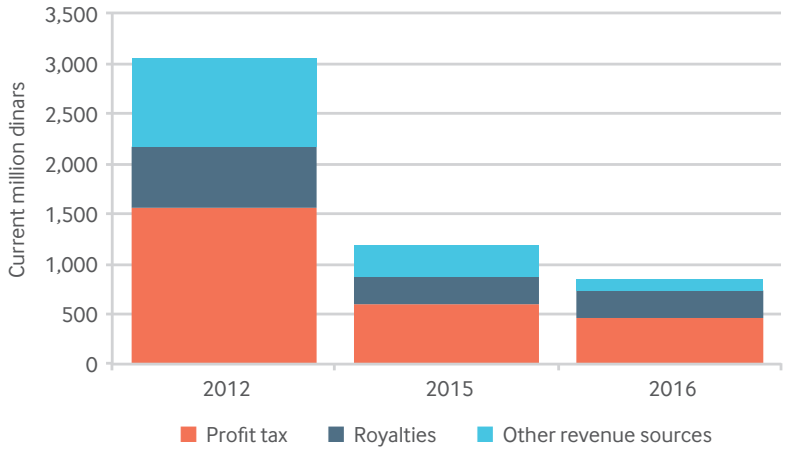


Figure 6. Tunisia's oil and gas revenues[16]

12 Entreprise Tunisienne d'Activités Pétrolières, *Conjoncture Énergétique décembre 2017 Rapport mensuel* (2018), data.industrie.gov.tn/conjoncture-energetique-decembre-2017
13 "Open Data: Plateforme des données ouvertes du Ministère de l'Industrie, de l'Energie et des Mines", Ministry of Energy, Mines and Renewable Energy, Tunisia, Accessed 15 April 2018, data.industrie.gov.tn
14 In 1984, ENI and Sonatrach built the Enrico Mattei gas pipeline, also known as Trans Mediterranean gas pipeline, connecting Algeria to Italia and crossing Tunisia. Tunisia receives royalty gas in kind in lieu of transit fees from Algeria for the gas carried across its territory.
15 Ministry of Energy, Mines and Renewable Energy, "Open Data." Oil consumption includes refined fuels.
16 Ministry of Energy, Mines and Renewable Energies, Tunisia, official presentation (2017). In nominal terms, includes ETAP's share of physical oil and oil revenues.

2.3 OIL AND GAS INVESTMENTS

Small and large companies alike have been operating in Tunisia, although smaller players dominate the sector, reflecting the modest expectations of discovery sizes.[17] (See Figure 7.) In recent years, however, some companies divested their assets in Tunisia and others significantly reduced their investment.

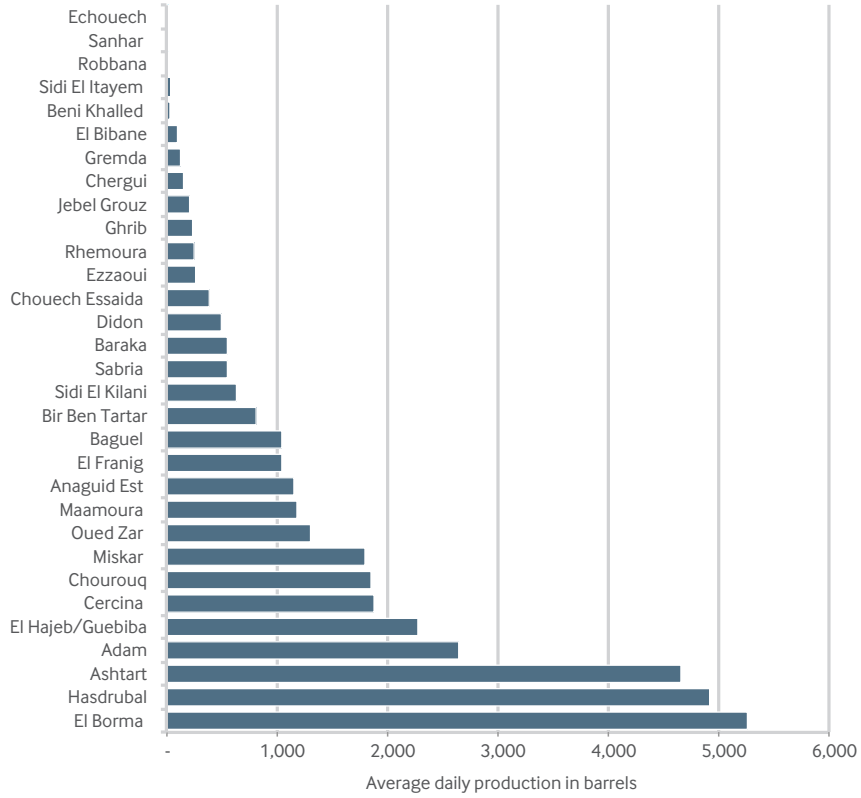


Figure 7. Average daily production of Tunisian fields by concession, in barrels (2017)[18]

2.3.1 Corporate landscape

Prior to its takeover in April 2016 by Shell, BG was the largest foreign investor and gas producer in Tunisia.[19] The company was responsible for supplying over 60 percent of domestic gas production through the offshore Miskar gas field (BG is the operator and sole owner of the project), and offshore Hasdrubal oil and gas field (BG shares a 50 percent interest with ETAP). However, Shell has been reportedly planning to divest its Tunisian assets.[20]

The second major company is Italy's Eni, one of the oldest international oil companies (IOCs) in Tunisia, present since 1961. Its operations are concentrated offshore in the Mediterranean and onshore in the desert area in the south of the country. In 2016, Eni produced approximately 25 percent of total oil production in Tunisia. Eni has a 50 percent interest in El Borma field, the largest onshore

17 For a full list of companies operating in Tunisia, see Ministry of Energy, Mines and Renewable Energy, "Open Data"
18 Ministry of Energy, Mines and Renewable Energy, "Open Data"
19 The investments of BGT amounted to $3.5 billion in 2015. Invest in Tunisia, Foreign Investment Promotion Agency, "Success Stories: BG Tunisia", accessed 15 April 2019, www.investintunisia.tn/En/success-stories_113_114_D112#.XOgSElhKiUk
20 Ron Bousso, "Shell is seeking to sell its gas fields in Tunisia for some $500 million," Reuters, 18 May 2017,www.reuters.com/article/us-shell-tunisia/shell-seeking-500-million-in-sale-of-tunisian-gas-assets-sources-idUSKCN18E1V5

oil-producing field in the country. Eni also jointly built with Sonatrach, Algeria's national oil company (NOC), the Trans-Mediterranean gas pipeline.[21]

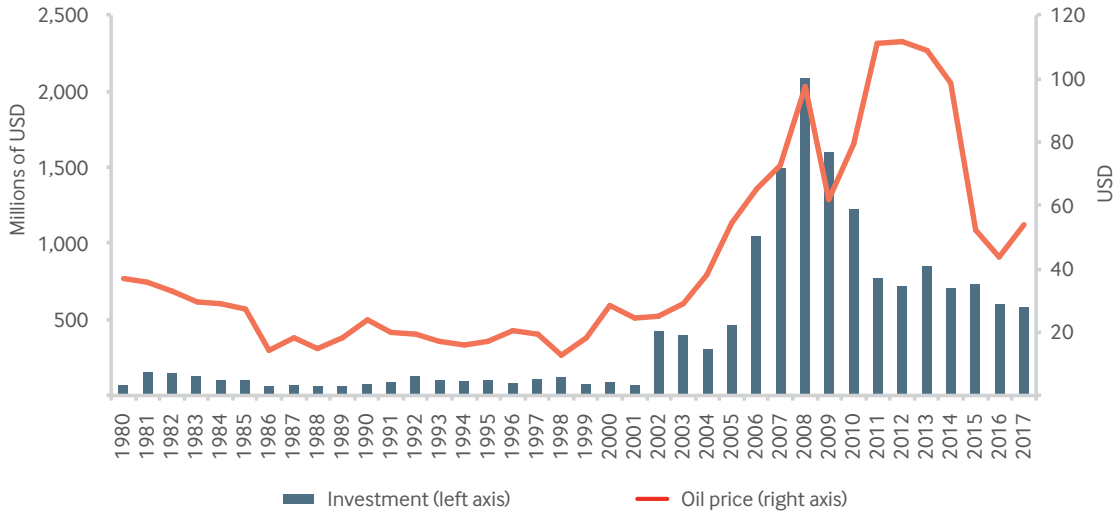
Austria's OMV is another prominent company, operating and holding a 50 percent stake with ETAP in the onshore Nawara gas development project, which they project will deliver gas and by-products to the Tunisian market, replacing a significant volume of gas imported from Algeria.[22]

Smaller players are also present and have shown enthusiasm to invest in exploration and development.[23] In 2013, John Nelson, the CEO of Canadian Africa Hydrocarbons Inc., said during an interview that "[j]unior companies can be very successful on projects that may not meet the economic threshold of the majors, but can propel juniors quickly to mid-tier producers. This makes Tunisia a good place for smaller companies to explore."[24]

2.3.2 Declining investment

This varied corporate landscape has not sustained investment in recent years. In one decade, investment in oil and gas exploration more than halved in Tunisia, both in terms of total spending (e.g., $583 million in 2017 compared to $1,498 million in 2007, nominal) and number of wells drilled, as Figures 8 and 9 show, respectively.

Figure 8. Oil and gas exploration investments in Tunisia and oil prices (nominal terms, 1980-2016)[25]



21 Eni, "Eni's activities in Tunisia", Accessed 15 April 2019.www.eni.com/enipedia/en_IT/international-presence/africa/enis-activities-in-tunisia.page

22 OMV, "Factsheet OMV Tunisia," last modified January 2019, www.omv.com/services/downloads/00/intranetomv/1522152769560/factsheet-tunisia-upstream

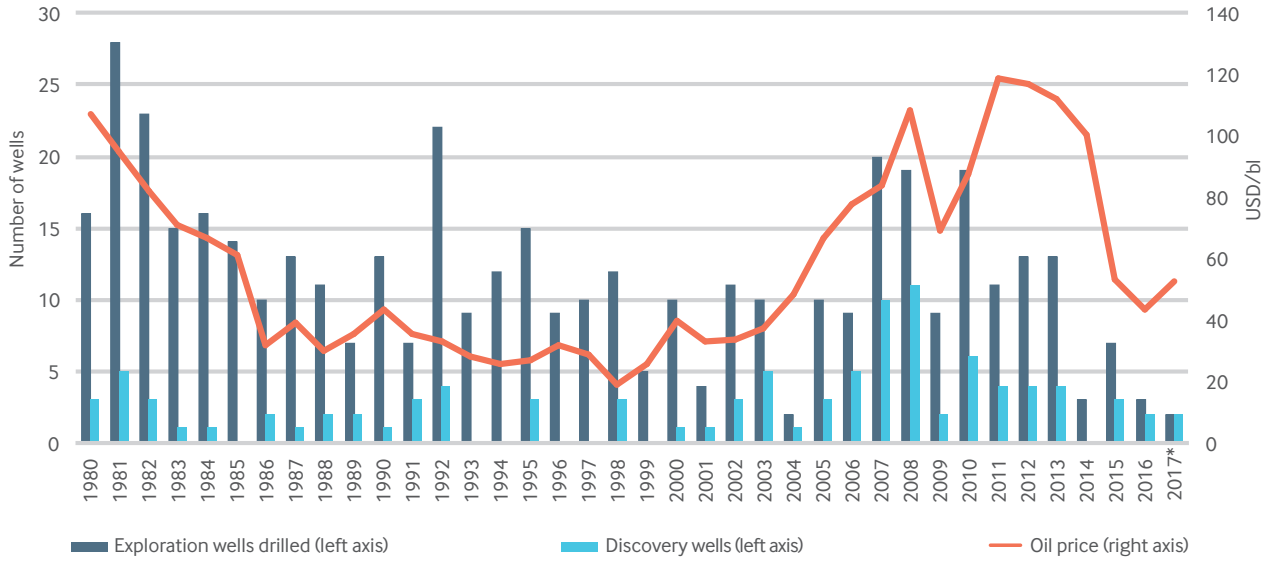
23 Small companies include Sweden's Lundin Petroleum, Atlantis Holding Norway, Storm Ventures International a subsidiary of Canada's Chinook Energy Inc., Texas's Pioneer Natural Resources, Canada's Candax Energy, France's Perenco, Netherland's Mazarine Energy and others.

24 James Stafford, "Is Tunisia the New Hot Spot for Energy Investors?" Interview with John Nelson, *Oil Price*. 4 April 2013, oilprice.com/Interviews/Is-Tunisia-the-New-Hot-Spot-for-Energy-Investors-Interview-with-John-Nelson.html.

25 Ministry of Energy, Mines and Renewable Energy, "Open Data" and "International Energy Statistics", and EIA, "International Energy Statistics". Exploration Investments and oil price are in nominal terms. Oil price is Dated Brent.

Between 2011 and 2017, the number of new discoveries and exploratory wells have significantly decreased. In 2017, companies drilled only two exploration wells and made two discoveries, compared to 20 wells and 10 discoveries in 2007. (See Figure 9.) By 2017, there were 39 oil and gas companies operational in Tunisia compared to 73 in 2010.[26]

Figure 9. Exploration and discovery wells drilled in Tunisia and oil prices (1980-2017)[27]



The global decrease in oil prices since 2014 may have partially caused the decline in investments in Tunisia. Typically, a positive correlation exists between the price of oil and investment spending. High oil prices encourage investment in new production capacity. When prices decline, investment tends to follow, particularly in the upstream part of the oil and gas industry. The trends in Tunisia confirm this relationship, as Figures 8 and 9 above show. However, investment in Tunisia's upstream oil and gas sector started to decline in the period between 2011 and 2014, when oil prices still hovered around $110 per barrel (/bl). Furthermore, the overall investment trend in the country followed a similar pattern, dropping in 2011.[28] This indicates that other factors linked to the country's political transition likely played a significant role in deterring investment.

26 Ministry of Energy, Mines and Renewable Energy, "Open Data"
27 Ministry of Energy, Mines and Renewable Energy, "Open Data" and EIA, "International Energy Statistics". The number of exploration and discovery wells data is for the end of October 2017. Oil price is Dated Brent, in real terms.
28 OECD, *Études économiques de l'OCDE: Tunisie (synthèse)*, March 2018, www.oecd.org/fr/eco/etudes/Tunisia-2018-OCDE-etudes-economiques-synthese.pdf

2.4 BUSINESS ENVIRONMENT

Geologic potential and oil prices are some of the key factors shaping investment decisions, but they are not the only ones. Government policies that are unattractive to investors can drive investment away even with proven geological potential and high oil prices. Venezuela, which sits on the largest proven oil reserves in the world, has seen its production declining at record levels, as investors have shied away from the country because of unappealing policies and political instability. In contrast, to halt a decline in oil and gas reserves, the Omani government enacted in 2006 several investment-friendly policies which encouraged the application of the latest technologies to squeeze more oil out of existing fields. Oman's oil and gas production subsequently recovered; oil production increased by 42 percent from 2007 to 2016 and gas production increased by 91 percent between 2004 and 2016.[29]

Tunisia is at a crossroad in terms of its investment environment. On the one hand, its recent democratization offers better prospects for long-term growth and prosperity.[30] Two-thousand and ten marked the beginning of the Jasmine Revolution, which gave Tunisia a special place in the Arab world's history as the country that started the so-called Arab Spring.[31] A wave of protests then toppled several dictators, from its own President Zine El Abidine Ben Ali, to Egyptian President Hosni Mubarak and Libyan strongman Muammar Qaddafi. In most of the countries that saw similar uprisings, the struggle for democracy has suffered serious setbacks. In contrast, the transition in Tunisia from 23 years of dictatorship to a working secular democracy seems to be heading in the right direction, including in the governance of its non-renewable resources. Tunisia scores higher than other countries in the region in the sector specific RGI, as shown in Figure 10.[32]

29 Carole Nakhle. *The technological revolution in Oman's oil and gas industry* (Geopolitical Intelligence Services, 2017),www.crystolenergy.com/technological-revolution-omans-oil-gas-industry/.
30 Daron Acemoglu, Suresh Naidu, Pascual Restrepo and James A. Robinson, "Democracy Does Cause Growth," Journal of Political Economy, vol 127(1), pages 47-100, 2019, doi.org/10.1086/700936 .
31 The Tunisian Revolution, known as the Jasmine Revolution, started in December 2010, and led to the ousting of long-time president Ben Ali in January 2011.
32 NRGI, "Resource Governance Index", June 2017, resourcegovernanceindex.org.

2017 RESOURCE GOVERNANCE INDEX				
Performance (score band)	**Regional ranking**	**Global ranking**	**Country**	**Score/100**
Weak (45-59)	1	26	Tunisia (oil and gas)	56
	2	33	Kuwait	54
	3	37	Morocco	52
	4	39	Oman	50
	5	48	Tunisia (mining)	46
Poor (30-44)	6	53	Qatar	43
	7	54	United Arab Emirates	42
	8	59	Bahrain	39
	9	60	Egypt	39
	10	61	Iraq	38
	11	62	Iran	38
	12	69	Saudi Arabia	36
	13	73	Algeria	33
	14	78	Yemen	30
Failing (<30)	15	82	Mauritania	29
	16	87	Libya	18

Figure 10. Resource Governance Index 2017, Middle East and North Africa[33]

Conversely, Tunisia's democratic transition has seen disruptions and delays in the legal and institutional restructuring of various sectors in the economy, including oil and gas. Such a situation can be a source of anxiety for investors, especially when the relatively newly established political institutions decide to reform the institutional and contractual framework and the fiscal regime of the hydrocarbon sector. According to the Fraser Institute Global Petroleum Survey conducted in 2017, around 63 percent of respondents found that the lack of political stability and security in Tunisia is a deterrent to investment, while the same survey carried out in 2009 found that only 35 percent of respondents did.[34]

In Figure 11, the Worldwide Governance Indicators show the complexity of Tunisia's situation.[35] There has been a dramatic increase in the country's ranking on the "voice and accountability" indicator, however, Tunisia's place in all other indicators have either stagnated ("rule of law" and "control of corruption") or decreased ("government effectiveness," "regulatory quality"), with a dramatic decline on the indicator "political stability and absence of violence."

33 *Ibid.*
34 Fraser Institute, *Global Petroleum Survey 2017*, 2017, www.fraserinstitute.org/studies/global-petroleum-survey-2017 and Fraser Institute. Global Petroleum Survey 2009. 2009, www.fraserinstitute.org/sites/default/files/GlobalPetroleumSurvey2009.pdf
35 World Bank, *World Governance Indicators* (2019), info.worldbank.org/governance/wgi/ - home.

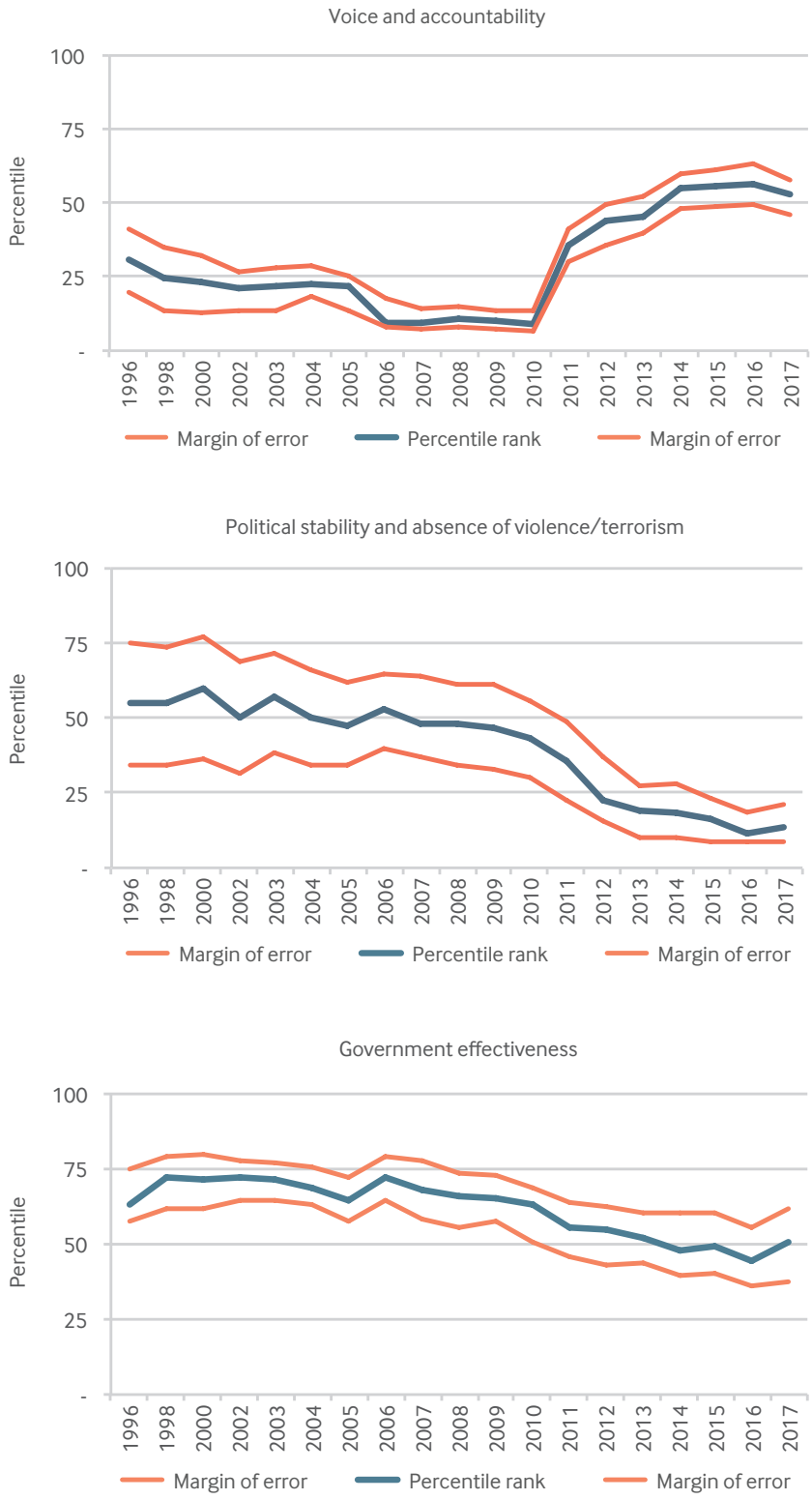
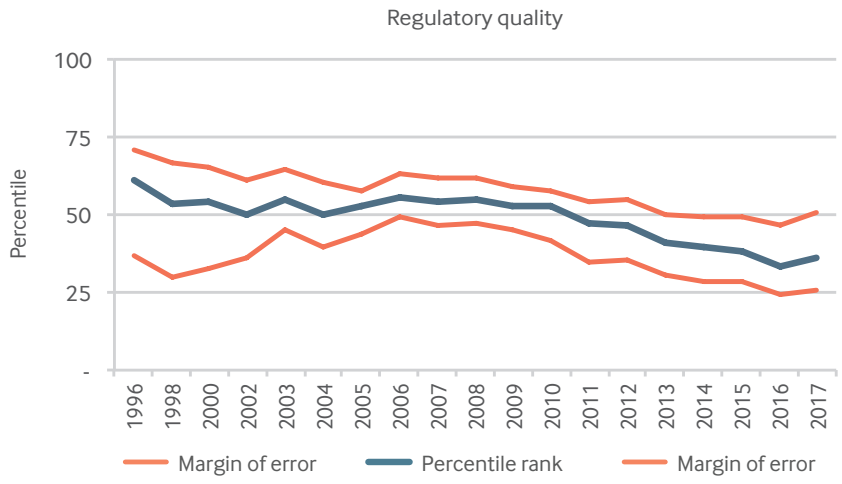


Figure 11. Worldwide Governance Indicators, time-series, 1996-2018, Tunisia[36]

36 Daniel Kaufmann, Aart Kraay and Massimo Mastruzzi, "The Worldwide Governance Indicators: Methodology and Analytical Issues", *World Bank Policy Research Working Paper No. 5430.* (2010), ssrn.com/abstract=1682130


Regulatory quality
Percentile
100
75
50
25
-
1996
1998
2000
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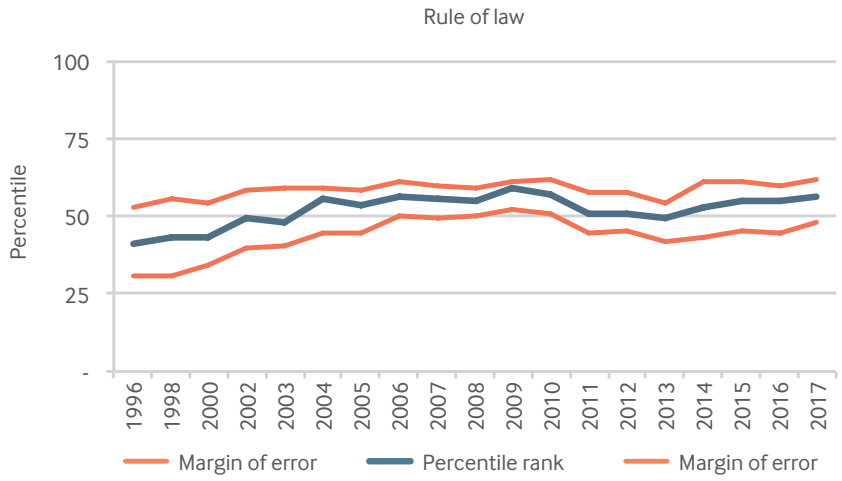
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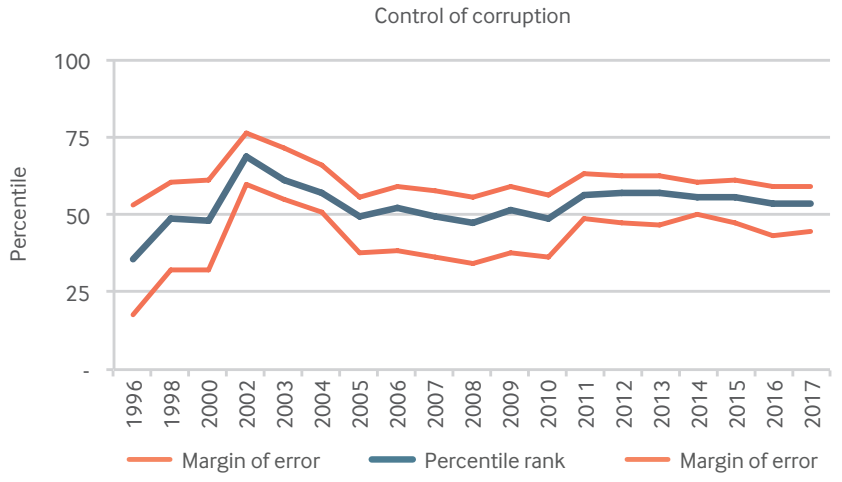
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Tunisia has yet to fully restructure the institutions carried over from the Ben Ali regime. Successive governments' attempts to try different options have created an impression of fragility. For instance, the government has revised the structure of the designated ministry in charge of hydrocarbons repeatedly since the revolution. Until 2011, it was known as the Ministry of Industry and Technology. In 2012, it first became the Ministry of Industry and then the Ministry of Industry and Commerce. In 2013, the government separated the portfolios of Ministry of Industry and Commerce again. In 2016, the government split into the Ministry of Industry into the Ministry of Energy, Mines and Renewable Energies and the Industry and Commerce. In September 2018, Tunisia once again placed the Ministry of Energy under the Ministry of Industry and Small and Medium-Sized Enterprises. Such organizational changes have brought reform programs to a halt, because commitments and trajectories agreed by former ministers and other stakeholders in the extractives process have been repeatedly abandoned.[37] The ministry in charge of energy has been led by 10 ministers since 2010 and the repeated reshuffling and relocation of key staff have negatively impacted the sustainability of reform programs.

Post-revolution Tunisia has also required important legal revisions, with implications on the energy sector. It adopted a new constitution on 26 January 2014, with the objective to establish rules for the new democracy. In the resource sector, this took the form of an increased role for the legislature. Article 13 of the new constitution requires that elected representatives of the parliament approve extractive contracts and agreements: "[. . .] Investment contracts related to these resources shall be submitted to the competent committee of the Assembly of the People's Representatives. Agreements related to these resources shall be submitted to the Assembly for approval."[38] Prior to the Constitution, oil and gas permits were granted under the Hydrocarbons Code promulgated by law n° 99-93 of 17 August 1999. Conventions ("Convention Particulière") approved by decree by the head of the executive (Article 19.5. of the hydrocarbons law) governed the permits and were therefore not subject to legislative approval.

The Assembly therefore had to amend the Hydrocarbons Code to align with the new constitution. It took two years for the parliament to agree on the amendments and enact the revised code into Law 2017-41 in April 2017.[39] During this time, Tunisia did not grant new exploration permits. For businesses, such delays in permit approval resulted in higher costs, especially when the potential returns on investment were limited.

37 Wissem Heni. "Five Ways Tunisia's New Mining, Energy and Renewables Minister Can Maintain Positive Momentum" (Natural Resource Governance Institute, 2016), resourcegovernance.org/blog/five-ways-tunisia's-new-mining-and-energy-minister-can-maintain-positive-momentum.

38 Government of Tunisia, *Constitution of the Tunisian Republic* [unofficial translation], 2014, www.jasmine-foundation.org/doc/unofficial_english_translation_of_tunisian_constitution_final_ed.pdf

39 Government of Tunisia, *Law nº 2017-41* (2017). This law, which amended certain dispositions of the Hydrocarbons Code, was published in the Journal Officiel de la République Tunisienne (Official Gazette of the Republic of Tunisia) on 2 June 2017.

The parliament has been testing its new-found authority. Without a history of parliamentary oversight, it is still defining the exact contours of its role. In the oil and gas sector, the situation has created some disruptions. Legislative assembly approval of resource contracts is a practice in many countries, which has both pros and cons.[40] But approval of micro sector-level decisions is much less common. By nature, a parliament is better suited to make broad, long-term policy and legal decisions than to manage every aspect of oil and gas licensing. Parliamentary oversight can strengthen the management of the hydrocarbon sector if it is adapted to the role and capacity of its members. Norway's experience can provide good insights. The Storting (Norwegian Parliament) plays a vital role in the oil and gas sector, but only at a high level of decision-making. Its main responsibilities are to provide the guiding principles for petroleum activities and major developments in the country, and to supervise the executive actions of the government. All technical matters are left to the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate. The former Norwegian Minister of Energy and former member of parliament, the Honorable Einar Steensnæs, warned in 2016, "Please do not convert parliamentarians into technocrats."[41]

In the Tunisian context, the ambiguity about the extent to which companies require the parliament—the Assembly of the People's Representatives'—approval has been disruptive. British company Enquest, for example, announced in 2013 that it would acquire a 70 percent stake from Sweden's PA Resources in the onshore Didon oil field. However, in 2015, the parliament failed to approve the deal, and Enquest simply left the country.[42] As noted in a separate NRGI report on Article 13, the transparency and accountability goals need to be implemented in a way that decreases the likelihood of parliamentary approval becoming an impediment to investment.[43] This requires clarity on the roles and responsibilities of various government bodies and functional partnerships between those bodies to restore relative efficiency to the licensing process.

In addition to parliamentary issues, Tunisians' exercise of their post-revolution freedom to protest has impacted the sector. In these early days of democracy, there may be a higher concentration of such actions, which have caused significant challenges for oil and gas operators. In 2016, for instance, UK's Petrofac suspended its activities because of social unrest linked to the local economic situation. The company's operational expenditures in Tunisia subsequently dropped from $334,000 in 2015 to $80,000 (in nominal terms) in 2016, a decrease of 76 percent.[44] Similarly, protests in Southern Tunisia in 2017 forced two energy companies to halt production or remove staff as a precaution. Consequently, oil and gas production in onshore oil and gas fields stopped for more than two months in the southern governorates of Tataouine and Kebili. Oil and gas production in Tatouine decreased by 18 and 17 percent respectively in 2017, while in Kebili they decreased by 41 and 38 percent respectively, negatively impacting total production in the country.[45]

40 NRGI, *Parliamentary Guide for Approval of Natural Resource Contracts in Tunisia*, 2016, resourcegovernance.org/sites/default/files/documents/tunisia-parlguidecontract.pdf
41 *Ibid.*
42 Enquest, Enquest exits Tunisia, 2015, www.enquest.com/media/press-releases/article/enquest-exits-tunisia
43 NRGI, *Parliamentary Guide for Tunisia.*
44 In 2018, Petrofac announced the sale of its entire 45 percent interest in the Chergui asset in Tunisia to Perenco. Petrofac, *Annual Reports and Accounts*, 2016, www.petrofac.com/media/3186/annual-report-and-accounts-2016.pdf
45 In 2016, cumulative oil production from the Tataouine and Kebili regions accounted for 48 percent of total oil production and 25 percent of total gas production in Tunisia. Ministry of Energy, Mines and Renewable Energy, "Open Data"

Finally, because investors initiated most oil and gas operations before the revolution, these investments fall under popular suspicion that encourage unrealistic claims against the industry. Some people have called for existing oil and gas contracts to be renegotiated, under the perception that foreign businesses are exploiting local resources to their own benefit.[46] Parliamentarians blocked many permits on the perception that they were either too favorable to foreign companies or that the foreign firms violated the permits to their own financial gain. The Miskar and Hasdrubal offshore gas fields that fall within the Amilcar permit, which BGT and ETAP hold jointly, are a good illustration. The operational license for Amilcar ran until 2018, but the exploration license expired in December 2014. An extension of the exploration permit was approved by the then Ministry of Industry, but later rejected by the parliament on the ground of several alleged infringements, all of which BGT denies. The former interim Prime Minister, Mehdi Jomaa summarized the impact of such measures on investment, saying in 2015 that the blocking of permits "sends negative signals to foreign investors [...] especially if they are accused of corruption."[47]

2.5 RESTORING INVESTMENT

The government has repeatedly expressed its concerns with the decline in investment in the oil and gas sector and its desire to reverse the trend, which is clear in its Energy 2030 strategy. It is important to distinguish the main factors that have contributed to the existing situation. Some of these factors are outside of the government's control, such as global oil prices and geology. Other factors, particularly elements of the legal and fiscal framework, directly depend on government policies, which is why the rest of this paper focuses on the evaluation of the fiscal regime and potential changes that the government could make to improve the system. However, there are limitations on the impact of changes to the fiscal regime on investor attractiveness, and other policy measures may be necessary to promote investment in the sector effectively, in tandem.

Even in areas that are nominally outside of the government's control, such as limited geological prospects, the right policies can ameliorate risk perception. For instance, investing in geological exploration and information, attracting smaller players, reforming the allocation approach and offering competitive acreage to increase likelihood of investor participation can all contribute to promoting exploration activities in the sector, which may lead to reducing the geological risk.

46 Sarah Yerkes and Marwan Muasher. *Tunisia's Corruption Contagion: A Transition at Risk* (Carnegie Middle East Center, 2017).

47 The Economist Intelligence Unit, "Government unblocks oil and gas permits", 2014, country.eiu.com/article.aspx?articleid=962374080&Country=Tunisia&topic=Economy&subtopic=Forecast&subsubtopic=Economic+growth&u=1&pid=1472678731&oid=1472678731&uid=1. Mehdi Jomaa acted as the interim prime minster from 2013 to 2015.

Other areas that are within the control of the government and can have an impact on investment include the political and institutional stability of the country. As shown previously, some key elements of the investment environment have proven disruptive to foreign investors, particularly the uncertainty created in the lack of clarity about the role of key institutions, delays in decision making, protests and lack of trust among various stakeholders. Investors perceive these elements as risk factors, but the government could work to improve them over time with a popular mandate, clear policies and political will. The government could try to restore stability by addressing some of the issues identified above such as the role of parliament, the efficiency of the licensing and permit approval process, the institutional stability and recurrent social unrest. To do so, the government could build a strong national plan, explain its objectives and its limitations to the population and engage with parliament on a constructive relationship.

In the short term, the government could work on factors more directly under its control by assessing whether the fiscal terms applicable to oil and gas companies are adapted to its current geological and political context, and changing them if necessary. This will be the focus of the remaining sections of the report.

3. Upstream petroleum fiscal regime

The objective of this section is first, to provide a brief description of upstream petroleum fiscal regimes and the main fiscal instruments typically imposed; and second, to highlight the key features of the fiscal regime in Tunisia, whether the legal arrangement is a PSC or a JV agreement, but with a focus on the former.

Tunisia first introduced PSCs by decree-law in 1985.[48] They have been an option for investors in Tunisia since, and confirmed in the hydrocarbon code in 1999. The other contractual option is the allocation of a petroleum permit to a JV between a private contractor and ETAP. Investors select either the PSC or the JV option and offer specific terms in their submission to access an open acreage. Tunisia has used the JV type of arrangement for longer and therefore governs a larger part of current Tunisian production. Only two out of 52 concessions are under PSCs, but 11 out of 20 research permits are, which indicates that investors may be increasingly favoring PSCs over JVs.[49] As JVs require ETAP to finance the development and operating costs of any new projects in proportion to its equity, the PSCs may be more adapted to maximizing private investment in the sector and limiting ETAP's financial exposure. The analysis that follows therefore focuses on describing and analyzing the PSC, using the JV system as a benchmark where relevant.

3.1 GENERAL OVERVIEW

A fiscal regime is the set of instruments or tools (such as taxes, royalties and state equity) that determines how the host government and investors share the rents from hydrocarbon projects. In most jurisdictions, including under Tunisia's 2014 constitution, the state owns oil and gas resources on behalf of the population and has a duty to manage it in the interest of its citizens. Taxation is a key element of the good management of extractive industries and one of the twelve precepts of NRGI's Natural Resource Charter, which is a set of principles for governments and societies on how to best harness the opportunities created by extractive resources for development.[50] According to the Charter, tax regimes and contractual terms should enable the government to realize the full value of its resources consistent with attracting necessary investment, and should be robust to changing circumstances. The government's central objective in designing petroleum fiscal regimes should therefore be to acquire a fair share of the rents accruing from the extraction of that resource, whilst encouraging investors to ensure optimal economic recovery of the hydrocarbon resources.[51]

The details of what fiscal tools are used and how they are applied to a petroleum project is part of a country's legal framework, which includes laws, regulations and contracts.[52] Two types of fiscal regimes prevail in oil and gas exploration and

48 Government of Tunisia, *Décret-loi n° 85-9* (1985), www.legislation.tn/sites/default/files/journal-officiel/1985/1985F/Jo06585.pdf.
49 Ministry of Energy, Mines and Renewable Energy, "Open Data"
50 NRGI, Precept 4: *Taxation*, resourcegovernance.org/approach/natural-resource-charter/precept-4-taxation.
51 For a succinct presentation of fiscal regime design, see NRGI, *Primer: Fiscal Regime Design* (2015), resourcegovernance.org/analysis-tools/publications/primer-fiscal-regime-design.
52 On the legal framework of extractive industries, see NRGI, Primer: Legal Framework (2015), resourcegovernance.org/analysis-tools/publications/primer-legal-framework.

production activities– concessionary systems and contractual systems.[53] The concessionary system originated at the very beginning of the petroleum industry (mid-1800s) and is still predominant in OECD countries such as the UK, Australia, Canada, the US and Norway. The contractual system emerged a century later (mid-1950s) and developing countries like Indonesia, Azerbaijan, Angola, and Iraq have been typically favored this system. The two systems are described briefly in Figure 12 and in more detail in the sections below.

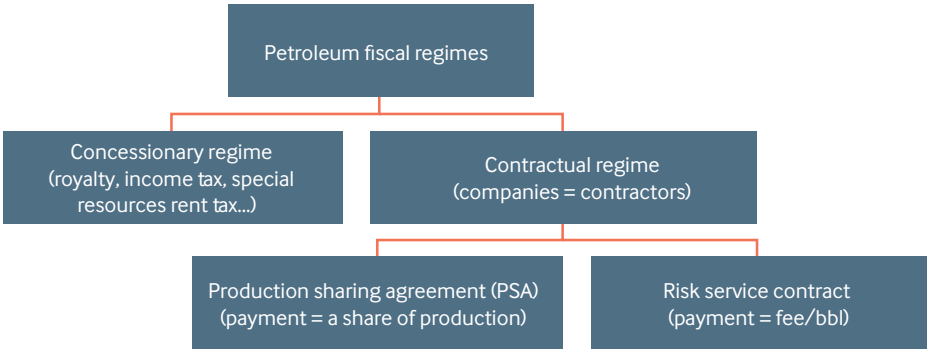


Figure 12. Petroleum fiscal arrangements

It is tempting to pass judgement on a fiscal regime based solely on its type– concessionary or contractual. However, both fiscal regimes can be made equivalent in terms of overall economic impact and government take—the share of government revenues from a project's net cash flows. Today there are more fiscal regimes than there are countries and many countries use more than one fiscal structure and regime. Petroleum fiscal regimes have become very elaborate and continue to evolve.

In addition to the different fiscal tools described below, governments can participate in the ownership of oil and gas projects directly or indirectly under any type of fiscal regime. The state can take an equity or participating interest in the oil venture (minority or majority interest of 51 percent or more), directly or through its NOC. In this case, the state becomes a partner alongside other companies, and receives a proportionate share of production and profits, in addition to royalties and taxes. State participation increases the overall government take in the venture and can also allow greater government control and supervision over the operational management of the project. Where it exists, it is mandatory or at the option of the state. The participating interest can be fixed or biddable, effective from the signing of the contract, upon the declaration of commerciality of an oilfield or at another date. In many cases, the IOCs will carry all the costs of the NOC until production starts. This approach is common in developing countries, particularly if the government is short of cash and wishes to see its NOC grow in scale and expertise. The IOC may then recover the carried costs from the NOC's equity share of production until the carry is repaid. Dedicated rules may allow interest on the carried costs. If the carry is not refundable and the project makes no commercial discoveries, the IOC may never recover the carried costs. Generally, the IOCs do not favor such arrangements since they materially increase the exploration risk (cost of failure) and reduce the project's economics especially when combined with tough fiscal terms. In other cases, the state pays its way, which is more suited for governments that are not short of cash and are willing to take on the risk exposure.

53 Carole Nakhle. *Petroleum Taxation - Sharing the oil wealth: a study of petroleum taxation yesterday, today and tomorrow* (Routledge, 2008).

3.1.1 Concessionary regimes

A concession provides an oil company with the exclusive right to explore, develop and export oil in a given territory. It also gives the company a title to the oil produced, along with the requirement to pay the appropriate royalties and taxes. Because modern concessionary regimes include various combinations of a royalty, an income tax and a resource rent tax, they are also known as "Royalty and Tax Systems." The basic features of different oil and gas concessions are similar, but the fiscal terms vary considerably and are likely to evolve over time as the fields and basins mature. The main elements are described below and Figure 13 illustrates how the different fiscal terms interact.

Royalty

A government typically imposes a royalty on a specified level of production (unit or specific royalty) or on the value of the output or gross revenues (ad valorem royalty). From a government's perspective, a royalty is relatively simple to administer, difficult to avoid, predictable (for it varies with production) and provides an early revenue stream (as soon as production starts). From a company's perspective, royalties may deter marginal projects, since they are not profit related (i.e., investors pay royalties whether a project is profitable or not). The regressive nature of royalties– the lower a project's profitability, the higher royalty payments are relative to profits– can cause operating income to become negative even when gross revenues exceed extraction costs, and consequently can lead to premature abandonment of a field. Some governments apply a sliding scale to make their royalties more progressive.

Corporate income tax (CIT)

This usually consists of a basic, single-rate structure, levied at a corporate or legal entity basis rather than at the oil field level. Some countries include the oil industry within the standard CIT regime for all industries, although they may use a higher rate to capture more rent or incorporate additional tax incentives to accommodate and attract oil operations. In the computation of the tax base, governments typically allow taxpayers to deduct all operating costs, depreciation of assets and, with some restrictions, interest expenses and losses carried forward and/or back. Most countries provide an incentive for exploration and development by allowing investors to recover exploration costs immediately and allowing accelerated depreciation of development costs.

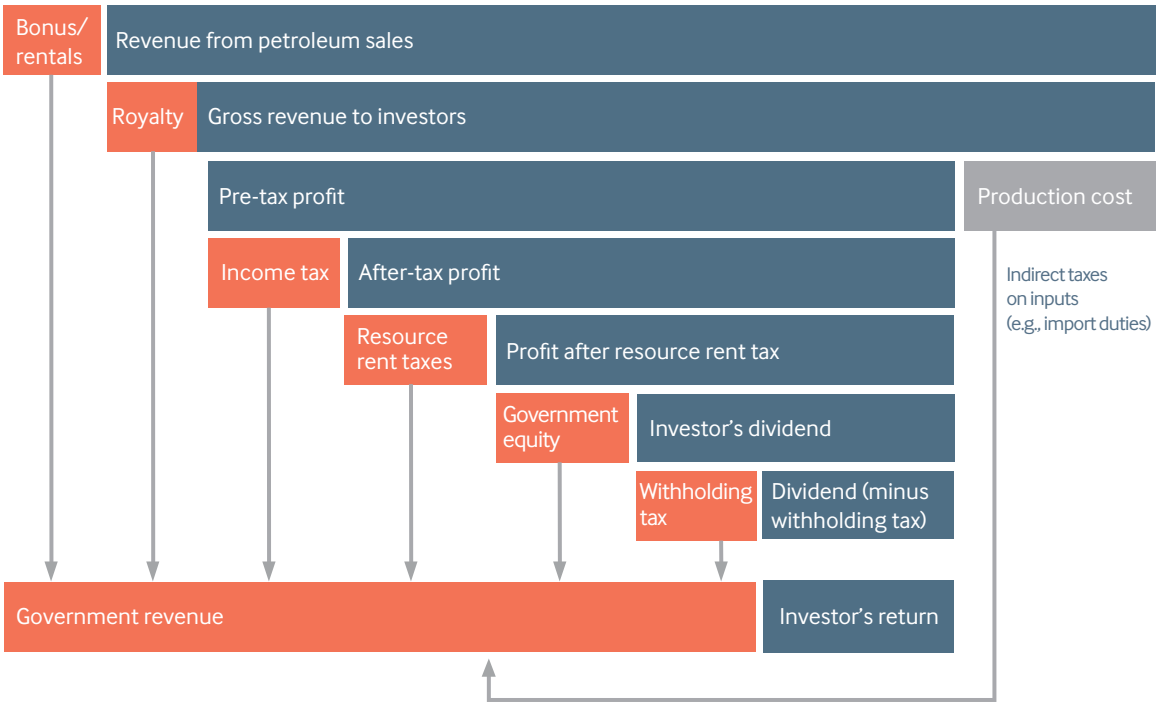
Resource rent tax

The aim of this special petroleum tax is to capture a larger share of economic rent from oil production, when oil projects reach certain thresholds of profitability. The tax is levied on a project or a field's cash flows rather than accounting profits, a key difference between the taxable base for resource rent tax and CIT. A resource rent tax is described as a neutral tax, for it is not paid before a project reaches payback and achieves a certain rate of return.

Other fiscal tools

Other significant payments from petroleum companies can include bonus payments when specific events occur (e.g., signature or first production), indirect taxes on inputs such as duties on imported goods or withholding taxes on overseas payments of interests and dividends. When investors are foreigners, the withholding tax on dividends remitted abroad can be an important component of the fiscal regime, unless reduced through preferential terms in bilateral tax treaties. These instruments can exist under the contractual regime as well.

Figure 13. Revenue flows from a typical tax and royalty system[54]



3.1.2 Contractual arrangements

According to typical contractual systems, the title to hydrocarbons remains with the state and all production belongs to the government unless it is explicitly shared. The IOC carries out petroleum operations in accordance with the terms of the contract and operates at its own risk and expense, providing all the financing and technology required for the operation.

The parties agree that the contractor will meet the exploration and development costs in return for a share of production, or a cash fee for this service, if production is successful. If the company receives a share of production (after deduction of the government's share), the system is known as a PSC– also called a production sharing agreement (PSA)– which is a binding commercial contract between an investor– the IOC– and a state (or NOC).[55] A PSC defines the conditions for the exploration and development of hydrocarbons in a specific area over a determined period of time. Under a PSC, the company takes title to its share of petroleum attributed in physical barrels at the delivery point.

54 Figure 13 is for illustrative purposes only. It does not reflect the exact order in which various instruments are paid, which varies by country.

55 On state owned companies, see NRGI, *Primer: State Participation and State-Owned Enterprises* (2015), resourcegovernance.org/analysis-tools/publications/primer-state-participation-and-state-owned-enterprises.

Under service contracts, the host government hires the services of an IOC and, in case of commercial production, pays the company a fee (often subject to taxes) for its services without taking title to any petroleum extracted.

Governments can design their contractual regimes in different ways, but they tend to have the following elements:

Cost recovery

The IOC bears all the costs and risks of exploration and development. If a commercial discovery moves forward to development, the company can recover the costs it has incurred. This is known as "cost recovery" or "cost oil" (or cost gas or petroleum, accordingly). Cost recovery is similar in concept to deductible expenses for tax purposes (including depreciation of capital assets) under the concessionary system. It mainly includes unrecovered costs carried over from previous years, operating expenditures, capital expenditures, abandonment costs and some investment incentives. Financing costs or interest expenses are generally not recoverable costs. Typically, in any one year, there is a fixed proportion of total production that investors can use to recover their costs– called a "cost recovery ceiling." If costs exceed the cost recovery limit, the difference is carried forward for recovery in subsequent periods. A fixed ceiling on cost oil secures up-front revenues to the government as soon as production commences, similar to a royalty.

Profit oil (/gas/petroleum)

Under a PSC, the oil that remains after the oil company has taken its cost oil is usually termed "profit oil." The cost oil ceiling ensures there is always a minimum quantity of profit oil. The host government and the company divide profit oil according to a pre-determined percentage negotiated in the contract. The split can be constant, or on a scale linked to cumulative or daily production rates, or to achieved levels of project profitability (e.g., rate of return).

Service fee

Under a service contract, following cost recovery, the government pays the contractor a remuneration fee, which they agreed on up-front in the contract. The remuneration is usually determined using project performance indicators linked to actual production rates and based on pre-agreed capital budgets. In practice, service contracts often carve out a share of revenue in the same fashion that a PSC shares production.

CIT

Both profit oil and the service fee can be subject to CIT. In many PSCs the government pays the contracting company's income tax from its share of profit oil; these are called "pay-on-behalf" PSCs. In these jurisdictions, the contract includes a requirement for the NOC to pay various taxes, usually the income tax, and where relevant the royalty, on behalf of the PSC contractor, in some cases retaining an additional share of the production from a field. The precise legal provisions that give effect to these pay-on-behalf regimes are important to IOCs in the context of assessing their foreign tax credit position, as they may face additional tax liability in their home country if poorly constructed.

Figure 14 illustrates the basic mechanism of a PSC with a royalty, which is paid out of total production.

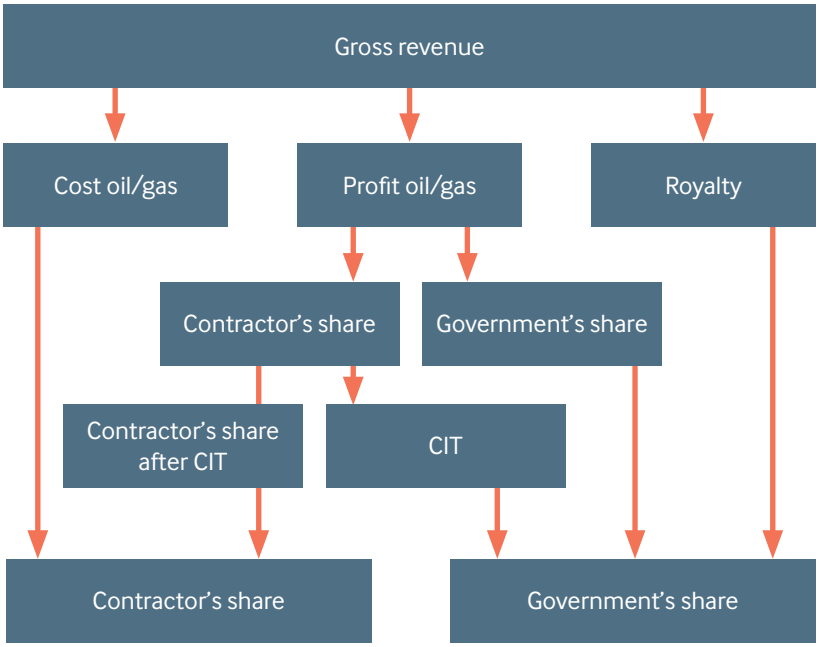


Figure 14. Simple mechanism of a PSC with a royalty

Table 2 below summarizes the key differences between concessionary and contractual regimes.

Concessionary (without state equity)	Contractual PSC	Contractual service contracts
State owns resource; IOC owns production	State owns both resource and production; contractor's remuneration is a share of production, hence acquires ownership of that share of oil	State owns both resource and production; contractor's remuneration is a fixed fee
IOC bears most risk and gets all dividends and pays taxes accordingly. Government only exposed to oil price risk through taxes.	Contractor bears all exploration and development risks and shares commercial (oil price) risks.	Contractor bears all exploration and development risks; government takes commercial (oil price) risk
IOC entitlement: gross production less royalty, taxes and bonus	Contractor's entitlement: cost oil plus profit oil, less income tax	Contractor's entitlement: cost oil plus remuneration fee, less income tax

Table 2. Key features of concessionary and contractual arrangements

3.2 DESIRABLE CHARACTERISTICS

While there is no one ideal fiscal regime, there are several fundamental principles that governments should take into consideration when designing a fiscal regime. These include simplicity, neutrality, progressivity, risk-sharing and stability. Because no single fiscal instrument can satisfy all these criteria, countries use a combination of different measures to design fiscal regimes for oil and gas upstream activities adapted to their own context and goals.

Simplicity

A government levies a fiscal regime that is simple to understand, implement and oversee on a well-defined tax base. It increases transparency and reduces the administrative burden for both administrations and taxpaying businesses. The more transparent the means by which the government obtains revenues, the better informed the investors are and the less the scope for errors or administrative discretion there is.

Neutrality

A neutral fiscal regime is an economic ideal that would not distort investment decisions: it would neither deter exploitation of a full range of field sizes nor alter project rankings, nor interfere with production decisions. In practice, few governments have found neutral regimes practical. To be completely neutral, a regime should provide relief for exploration costs and compensation for failed projects, which would be very attractive to investors, but would impose significant risk exposure as well as some financial obligations to the state.

Progressivity

Progressive fiscal instruments like profit-based taxes increase the proportionate tax burden on companies as their profitability increases and similarly decreases it as their profitability decreases. Regressive fiscal instruments like signature bonuses do the opposite, as illustrated in Figure 15. Constructing a fiscal regime in which the government take rises automatically or formulaically with rising profitability gives the host government the predictability of receiving a rising share of any price windfall or cost cut, while avoiding the need for intervention to change the fiscal regime. It also provides the investor with a predictable and stable fiscal framework. However, a regime that is based on progressive instruments can delay revenue generation to the government. That is why instruments like royalties, although regressive, often exist in various fiscal arrangements, since they are paid as soon as production starts, regardless of the project's profitability.

Stability

Host governments can minimize one important risk related to oil and gas investment– that is the fiscal risk. A tax system subject to continuous tinkering tends to undermine investors' confidence and raise investment hurdles to compensate for increased risk, thereby reducing the value investors place on future income streams. In contrast, fiscal stability boosts investors' confidence in government policy, enhances the regime's appeal for new investment and secures the basis on which investors made prior decisions. While stability of the fiscal

regime is desirable, circumstances are constantly changing. Governments and contractors therefore may need a certain degree of flexibility to adapt the fiscal regime to differing conditions and to evolving factors such as geology.

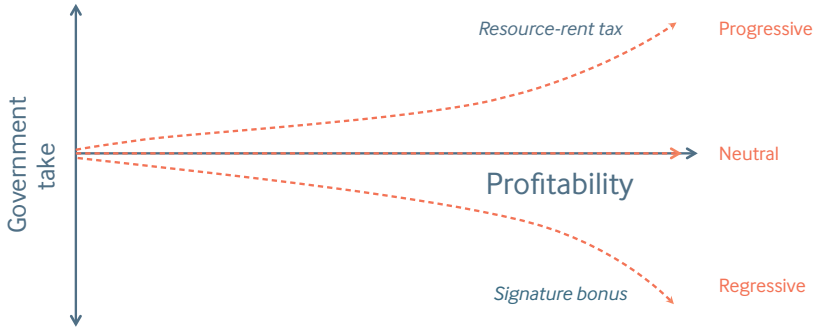


Figure 15. Progressive and regressive systems

3.3 OVERVIEW OF THE TUNISIAN PETROLEUM FISCAL REGIME

The Hydrocarbons Code is the main legal framework that covers oil and gas prospecting, exploration and exploitation in Tunisia and broadly defines the applicable fiscal regime, though some terms are set in individual contracts.[56]

As per the Hydrocarbons Code Articles 91 to 99, Tunisia can apply either the joint venture regime (*contrat d'association*) or the PSC to a given project. In the first case, a joint venture between private companies and ETAP own the license (concession). In the second case, ETAP owns the license and contracts a private company to explore, develop and operate the field. The Hydrocarbons Code provides ETAP with a strong position. Under the open door policy used by the government, private companies applying for permits have typically indicated their preference for one type of contractual arrangement or the other, and made specific offers regarding the percentage of ETAP participation in a JV or the cost recovery/profit oil split in a PSC.

Under the JV regime, ETAP has the option to acquire a participation share in any exploitation concession granted because of a commercial discovery under an exploration permit. Under the PSC, ETAP has an entitlement to a share of hydrocarbons production, with the share determined in the respective PSC.[57]

By September 2018, Tunisia had revised its Hydrocarbons Code four times: 1) Law 2002-23, dated 14 February 2002; 2) Law 2004-61, dated 27 July 2004; 3) Law 2008-15, dated 18 February 2008, and 3) Law 2017-41, dated 30 May 2017. (See Figure 16.)

56 Government of Tunisia, *Hydrocarbons Code under Law No. 99-93, 17 August 1999 And Amendments* [unofficial Translation], 2017. www.droit-afrique.com/uploads/Tunisie-Code-2017-hydrocarbures.pdf This law was amended and completed by law 2002-23, Law 2004-61, Law 2006-80, Law 2008-15 and Law 2017-41.

57 Government of Tunisia, *Hydrocarbons Code Article 98.*

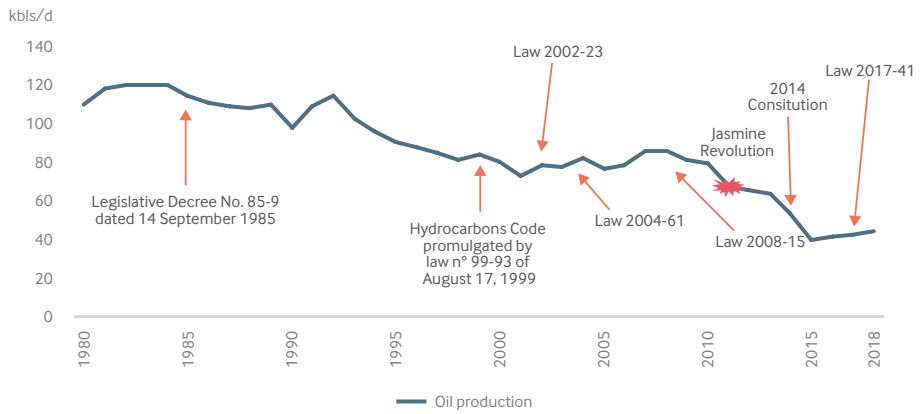


Figure 16. Evolution of Tunisia's hydrocarbon laws and key events[58]

Fifty out of 52 oil and gas concessions in Tunisia are operated under JV agreements. Fourteen of these 50 concessions are operated by companies without any participation of ETAP, though some have direct state participation.[59] The others are under JVs in which ETAP owns from 20 percent to 100 percent equity, and at least 50 percent in most projects, as illustrated in Figure 17. The notion of PSC appeared for the first time in 1985 under the decree law n°85-9 of 14 9 1985. In 1994, the Tunisian government approved an agreement for "Nord Medenine," which was the first PSC under the decree law of 1985. The hydrocarbons law in 1999 confirmed the option to develop oil and gas projects under PSCs. Since then, the government has signed ten more PSCs, but only two have been granted concessions: Sfax Offshore and Sud Remada.

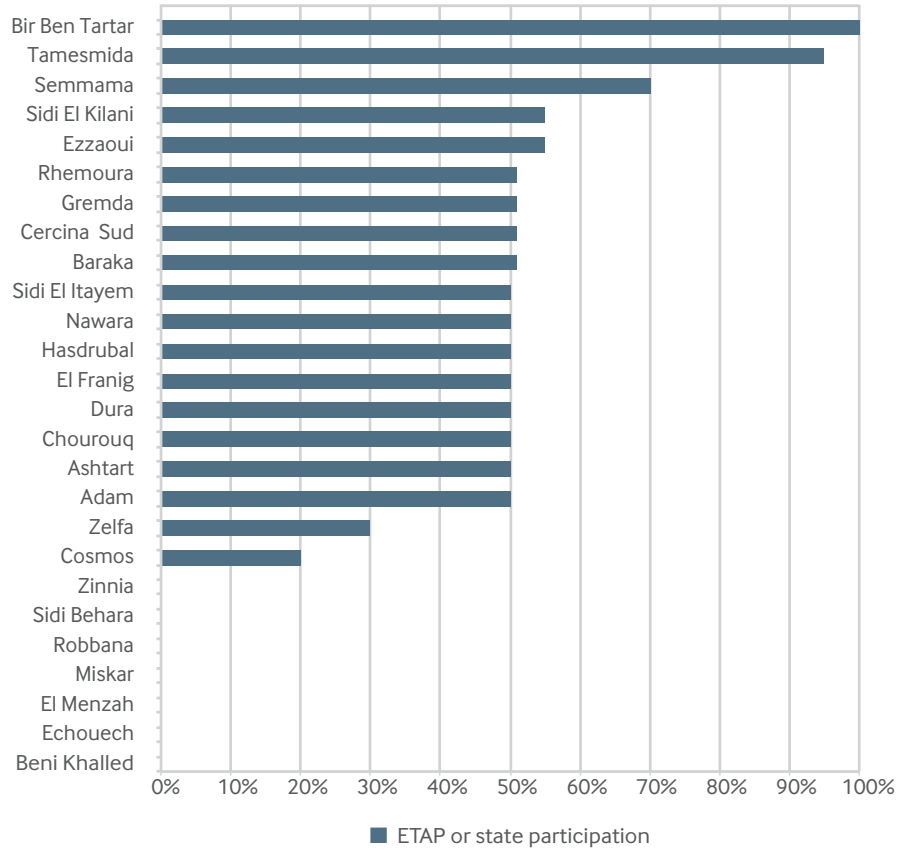


Figure 17. State/ ETAP participation in concessions

58 EIA, "International Energy Statistics" and ETAP, "Conjoncture Énergétique décembre 2017"
59 E.g., El borma or Sidi el Itayem.

In recent years, PSCs have become a more frequent choice for new investments. From 23 active exploration permits, 11 are PSCs and 12 are JVs.[60] As new investments require funding that ETAP may not be able to provide through JV agreements, PSCs provide an attractive option, as private contracts cover all investment costs. The question is whether the current terms represent the right level of taxation when considering the government's objective. The analysis in this section therefore focuses on the PSC terms, as applicable in Chapter II of the Hydrocarbons Law, and particularly as found in two PSCs both signed in 2005 and available on the official Tunisian resource contract repository as well as on ResourceContracts.org.[61,62] These are the only contracts the Tunisian government has entered into since 1999 that have moved to the exploitation phase:

- The Sud Remada permit, which covers the Bir Ben Tartar onshore project, and originally included Storm Venture and ETAP. In 2014, Medco Energi acquired Storm Ventures' assets in Tunisia.[63]
- The SFAX Offshore permit, which covers the Ras el Besh project, and is in the prolific Gulf of Gabes. Apex, Eurogas and ETAP are the signatories to this contract.[64]

The main fiscal terms found under the PSC regime are summarized below and in Appendix I (found online as part of the model accompanying this report).

3.3.1 Royalty

According to the hydrocarbons law, different royalty rates apply for oil and gas. In both cases, the government imposes a royalty on a sliding scale depending on an R-Factor – ratio R – where:

R-factor = Accumulated Net Earnings/Total Accumulated Expenditures

- Accumulated net earnings are equal to the total turnover for all fiscal years less the sum of tax charges due or paid for all fiscal years prior to the present fiscal year and relative to the considered concession.[65]
- Total accumulated expenditures are equal to the total sum of exploration, development and production expenses incurred, and administrative cost, except for taxes and levies due or paid by the holder for the exploitation thereof.

60 Ministry of Energy, Mines and Renewable Energy, "Open Data"
61 *Ibid.*
62 ResourceContracts.org, *A directory of Petroleum & Mineral Contracts*, NRGI and others, accessed 15 April 2019, resourcecontracts.org
63 "Contrat de partage de production Sud Remada", tunisia.resourcecontracts.org/contract/ocds-591adf-4478492664/view - /pdf
64 ETAP, " Contrat de Partage de Production Sfax Offshore", tunisia.resourcecontracts.org/contract/ocds-591adf-2556454498/view - /pdf
65 In the case of PSCs, these are the taxes paid by ETAP, excluding taxes on profits paid on behalf of contractor.

The rates, as stipulated in the Hydrocarbons Code (Article 101.2.4), apply as shown in Tables 3 and 4.

Table 3

Rate	R-factor
2%	R ≤ 0.5
5%	0.5 < R ≤ 0.8
7%	0.8 < R ≤ 1.1
10%	1.1 < R ≤ 1.5
12%	1.5 < R ≤ 2.0
14%	2.0 < R ≤ 2.5
15%	R > 2.5

Table 4

Rate	R-factor
2%	R ≤ 0.5
4%	0.5 < R ≤ 0.8
6%	0.8 < R ≤ 1.1
8%	1.1 < R ≤ 1.5
9%	1.5 < R ≤ 2.0
10%	2.0 < R ≤ 2.5
11%	2.5 < R ≤ 3.0
13%	3.0 < R ≤ 3.5
15%	R > 3.5

Table 3. Royalty rate for oil

Table 4. Royalty rate for gas

According to the Hydrocarbons Code (Article 114), under a PSC, ETAP pays the royalty on behalf of the contractor, in line with the pay-on-behalf approach described above. Under the JV regime, the contractor pays the royalty according to Tables 3 and 4, except in cases where ETAP does not hold any equity, in which case the minimum royalty rate is set at 10 percent.

3.3.2 Cost oil/gas

As per the Hydrocarbons Code (Article 98.d. as modified by law 2002-23 of 14 February 2002), the respective contracts specify the cost recovery ceiling.

- For the Sud Remada permit, the cost recovery ceiling is 42.5 percent of annual oil production and 45 percent of annual gas production .[66]
- For the Sfax Offshore permit, the cost recovery ceiling for gas is up to 60 percent and for oil, it applies on a sliding scale varying with monthly oil production. (See Table 5.)

Average monthly oil production in bls/d	Contractor's share
0-5,000	55%
5,001-10,000	50%
> 10,000	40%

Table 5. Sfax offshore permit cost recovery ceiling for oil

In both contracts, the cost recovery ceiling is relatively low by international standards, with a higher figure typically found in areas that have less attractive geological potential. In the Tunisian case, a low cost recovery ceiling may have been used to allow ETAP to pay the royalty and income tax that it is required to pay to the treasury on behalf of the contractors, and to supply the domestic market.

66 "Contrat de partage de production Sud Remada", Article 9

3.3.3 Profit oil/gas

According to Hydrocarbons Code, Article 98.e., the respective PSC specifies the profit oil or gas. Investors expect both projects to produce oil rather than gas, so the analysis focuses on the former.

The profit oil/gas split between ETAP and the contractor for the Sud Remada permit apply on a sliding scale varying with the R factor, as shown in Table 6.

Table 6. Sud Remada permit profit sharing

R-Factor	Contractor's percentage share	ETAP's percentage share
R≤1.0	35%	65%
1.0 < R ≤ 1.8	30%	70%
1.8 < R ≤ 2.0	25%	75%
2.0 < R ≤ 2.3	20%	80%
R > 2.3	17.5%	82.5%

The Sfax Offshore permit profit share for gas is fixed at an even split between ETAP and the contractor. For oil, the government imposes it on a sliding scale varying with monthly production, as shown in Table 7.

Table 7. Sfax Offshore permit profit sharing for oil

Average monthly oil production in bls/d	Contractor's percentage share	ETAP's percentage share
0-5,000	42.5%	57.5%
5,001-10,000	32.5%	67.5%
> 10,000	25%	75%

The R-factor or R-ratio used in determining the split of profit oil is slightly different from the R-factor used for the royalty and CIT calculations, as defined in the hydrocarbon code. The PSC R-factor is the ratio of the cumulative value of production, minus the accumulated value of the sharing of oil and/or gas returning to ETAP until the previous year to the total cumulative expenditure. Such a difference may have been an unnecessary complication that leads ETAP to spend time on detailed procedures for the R-ratio determining profit oil splits with each PSC contractor.

3.3.4 Corporate income tax

In the case of a PSC, ETAP pays the CIT and royalties on the contractor's behalf, as set out in the Hydrocarbons Law, Article 114, a common feature of a PSC. (See Section 3.1. above.) ETAP's revenue, essentially its share of profit oil, should therefore be sized to cover payment of the IOC's CIT and royalties. This approach is in the IOC's interest: while the IOC's tax liability is nominally determined according to current policy, regulations, and administrative norms, the NOC manages all payments and the IOC only needs to conform to the cost recovery and profit oil provisions agreed to in the contract.[67] Contracts with these provisions are considered to be some of the most stable arrangements in the world, since they significantly limit fiscal maneuvering by governments or companies and protect IOCs against increasing tax rates.[68,69]

Tunisia's PSCs under the hydrocarbons law reference the main fiscal instruments described above, namely royalty, CIT and profit oil. However, since the law requires ETAP to pay the royalty and CIT on behalf of the investor, profit oil is the only significant direct payment from the investor to the state.

Under the JV regime, the contractor pays CIT according to a progressive scale based on the R-factor thresholds and percentage described in Tables 8 and 9. However, for JVs in which ETAP's participation is 40 percent or higher, the income tax rate applicable to the considered concession is set at 50 percent. The R-factor is defined similarly for both the royalty and the CIT calculations. Importantly, the CIT is calculated separately for each permit.

Table 8

Rate	R-factor
50%	$R \leq 1.5$
55%	$1.5 < R \leq 2$
60%	$2 < R \leq 2.5$
65%	$2.5 < R \leq 3$
70%	$3 < R \leq 3.5$
75%	$R > 3.5$

Table 9

Rate	R-factor
50%	$R \leq 2.5$
55%	$2.5 < R \leq 3$
60%	$3 < R \leq 3.5$
65%	$R > 3.5$

Table 8. CIT rate for oil

Table 9. CIT rate for gas

To analyze whether the fiscal regime is adapted to Tunisia's geology and investment environment, the following section relies on a quantitative assessment and takes international benchmarks into consideration.

67 For a more complete discussion of this feature, see Mario Mansour and Carole Nakhle, "Fiscal Stabilization in Oil and Gas Contracts: Evidence and Implications." *The Oxford Institute for Energy Studies OIES PAPER: SP 37*, 2016. www.oxfordenergy.org/wpcms/wp-content/uploads/2016/02/Fiscal-Stabilization-in-Oil-and-Gas-Contracts-SP-37.pdf.

68 Daniel Johnston. *Stabilization Provisions Economic Logic*. Daniel Johnston & Co., Inc., 2010

69 Though sector experts have criticized the corresponding provisions in the Hydrocarbon Code as too vague and subject to legal interpretations.

4. Quantitative assessment

The objective of this section is to present the modelling work carried out to quantitatively assess Tunisia's upstream fiscal regime, primarily the PSCs as applicable to Sfax Offshore and Sud Remada permits, as well as the JV regime. The analysis extends to comparing Tunisia's fiscal terms with those of other oil and gas producers in the region and beyond. The quantitative assessment is based on the following indicators and metrics:

Average effective tax rate (AETR)

The government's share of the total pre-tax net cash flows of a project. It is calculated over the entire life cycle of a project, typically using the net present value (NPV) of future estimated cash flows. It represents how much of the revenue of a project, net of all costs, the host country can capture through the fiscal regime. It represents a good basis to benchmark fiscal regimes with very different features.

Post-tax internal rates of return (IRR)

Comparing the pre-tax and post-tax IRR allows analysts to assess the impact of a fiscal regime on investors' financial incentives.

Composition of government revenue

How much revenue the government collects through different fiscal instruments, thereby highlighting the relative importance of individual taxes and quasi-taxes.

Progressivity

To assess the progressivity of the selected benchmarked fiscal regimes, the government share of total benefits is measured first at different levels of oil prices, then at different operating expenditures (opex) levels—in both cases all other assumptions are kept the same.[70] By fixing the other variables, the changes in oil prices or operational costs can reflect changes in profitability.[71] A fiscal regime will be more progressive if the government share of total benefits changes as much with respect to prices as it does with respect to costs.

70 It is standard practice to show this measure, rather than the AETR, purely for graphical reasons: charting the AETR does not clearly illustrate the differences in tax regimes and is highly dependent on the range of price and cost choices. See Philip Daniel, Michael Keen and Charles McPherson. *The Taxation of Petroleum and Minerals: Principles, Problems and Practice* (Routledge, 2010), 202.

71 In practice, the oil price is a poor proxy for profitability as costs follow prices with a typical time lag of six to nine months—higher oil prices are usually accompanied by a cost inflation in the industry.

4.1 MODEL DESCRIPTION AND ASSUMPTIONS

The fiscal model used to provide the quantitative analysis in this report is an adapted version of the IMF's FARI model.[72] The model provides estimates of the respective net impact of different fiscal terms and of the fiscal regime in aggregate over the entire life of a project. Such a project-level modeling produces results that are approximations of effective amounts of payments to government agencies and are not intended to be perfect forecasts. However, the exercise is valuable when comparing the impact of different fiscal regimes on government revenue and projects' economic returns.

For the simulation, five project profiles were originally selected (Figure 18.)

- Four real projects, which are under development or in early production in Tunisia: Ras el Besh (covered by the Sfax Offshore permit), Bir Ben Tartar (covered by the Sud Remada permit), Nour (in the Adam concession, covered by the Borj El Khadra permit) and Maamoura (covered by the Enfidha permit), two comparable oil projects in terms of size and characteristics; and
- A model project, using stylized data that represents a larger and more profitable field than the other four selected projects in order to test the fiscal regime on different project economics.

The project data was sourced from the Ucube database of Rystad.[73] The original data from the four Tunisian projects was difficult to compare, given varying exploration and development periods, as well as different proportions of historic data and forecasts. As such, several adaptations were made, as follows:

- opex, capital expenditure (capex) and abandonment costs were aggregated for each project from actual or expected annual amounts to an average figure per barrel of oil equivalent (boe), dividing each category of costs by total expected production.
- actual or estimated exploration periods were removed to analyze the projects on a "sanction forward" basis, which is the point of view of an investor before committing any capital to exploration activities.
- the development period of all projects was reduced to two years.
- all capital expenditure was assumed as being spent prior to the start of production.

Such adaptations lead to project cash flows that are slightly different from the original data, but do not alter the fundamental project economics. They also better reflect how investors look at a hydrocarbon project prior to investment, which is in line with the main purpose of the aim of this study, which is to evaluate potential changes to the fiscal regime that could impact future investment decisions. Table 10 below summarizes the adapted data and production profiles.

72 A publicly available template of the FARI manual and a user guide that explains all the concepts and workings of the model are available here: www.imf.org/external/np/fad/fari/. For the analysis carried out in this study, NRGI is fully responsible for the adaptation of the original model, the numbers and assumptions used, and the results of the adapted model. The model is available for anyone to download, modify and use under the Creative Commons Attribution 4.0 International License. Any such use is at the user's responsibility. Questions and comments on NRGI's adapted version of the FARI model can be sent to tlassourd@resourcegovernance.org.

73 Rystad, *Ucube proprietary database*, last accessed October 2017, www.rystadenergy.com/products/EnP-Solutions/ucube/

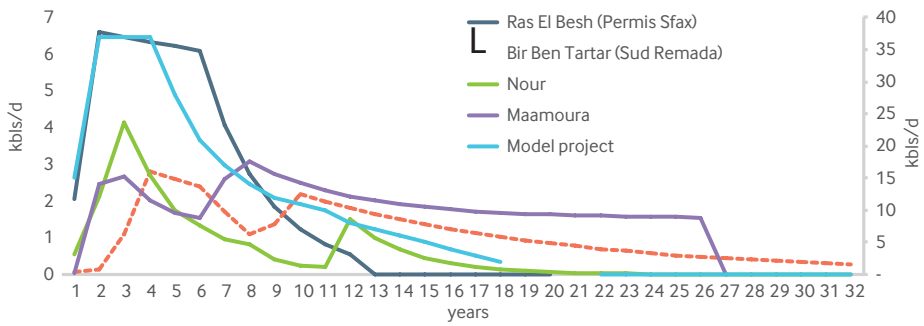


Figure 18. Average annual level of daily production (thousand barrels per day)

Model project on right axis, all others on left axis

Table 10. Project profiles

	Ras El Besh (Sfax permit)	Bir Ben Tartar (Sud Remada)	Nour (Adam)	Maamounra	Model project	Units
Total recoverable resources[74]	16.44	12.67	7.21	18.05	100.00	Million barrels
Well capex	0.33	17.62	6.73	6.78	3.00	USD/boe
Facility capex	5.77	22.35	15.69	6.24	5.00	USD/boe
SG&A opex	2.06	1.72	1.42	0.74	1.00	USD/boe
Transportation opex	1.81	1.35	0.95	0.84	1.00	USD/boe
Production opex	12.93	26.34	1.40	9.38	5.00	USD/boe
Abandonment cost	0.05	0.5	2.00	2.33	0.50	USD/boe
Total cost/boe	22.95	69.37	28.20	26.32	15.50	USD/boe

The main economic assumptions used in the model, for all the fiscal regimes analyzed, are as follows:

- The model follows the original data and assumes all resources are recovered and produced. This could overestimate the yield of the projects, as in practice commercially recoverable reserves, i.e., proven reserves, are smaller than total resources. This assumption strengthens the choice to limit the analysis to the most profitable project profiles.
- A central scenario of a base constant oil price of $60/bl. The price sensitivity analysis is carried out for a range of prices from $40 to $80/bl to test the performance of the fiscal regime under different oil price scenarios.
- The inflation rate is assumed to run at a constant 2.1 percent per annum, from the first year onwards.[75] Price and costs are inflated at this rate. All figures reported are in real US dollar terms (inflation adjusted).
- The discount rate used in the calculations of the NPV is 10 percent in real terms—which is in line with the practice of international organizations such as the IMF—unless noted as 0 percent (undiscounted), 12.5 or 15 percent (for

74 Economically recoverable resources as defined by Rystad Energy: www.rystadenergy.com/clients/help-center/products/documentation-methodology/upstream-solutions/ucube-upstream-database/ucube-methodology/hydrocarbon-production-and-resources/resources/.

75 PricewaterhouseCoopers. *Economic projections* (2018), www.pwc.com/gx/en/issues/economy/global-economy-watch/projections.html.

the sensitivity analysis). Investors and governments may use different discount rates, based on their relative time preferences and opportunity costs. Results are reported in both undiscounted and discounted terms. The present values are all discounted to Period/Year 1.

- The project is fully equity funded, i.e., no debt financing, as is typically assumed in fiscal regime benchmarking. The simplifies the analysis when comparing different levels of ownership by the state; adding debt financing would require too many assumptions on data that is not available.
- For the sake of simplicity, the analysis is based on a single project and does not consider possible consolidation of a project accounting of different projects by the same investor.

Table 11 illustrates the NPV of the selected projects, before tax and on a sanction forward basis, under different oil price assumptions. Of the four Tunisian projects, three have a positive pre-tax NPV. Bir Ben Tartar has an all-in cost of almost $70/boe, and is therefore uneconomic under various oil price scenarios, not even at $80/bl.

Oil price (USD/bl)	40	50	60	70	80
Ras El Besh (Sfax)	106.4	193.6	280.9	368.1	455.3
Bir Ben Tartar (Sud Remada)	-443.3	-405.1	-367.0	-328.8	-290.6
Nour (Adam, Borj El Khadra)	-29.6	5.0	39.7	74.3	109.0
Maamoura	-70.9	-17.0	36.9	90.7	144.6
Model project	860.6	1,355.0	1,849.4	2,343.9	2,838.3

Table 11. Pre-tax NPV10 on a sanction forward basis (USD million)

In looking at the full cycle economics to include the exploration risk, the expected monetary value (EMV) is calculated, assuming an average exploration cost equivalent to $2/bl. [76,77] Results are shown in Table 12 below, first for a success rate of 20 percent then for a more ambitious 50 percent. According to data from 40 companies by Richmond Energy Partners, between 2010-15, commercial success rates for drilling in mature areas, which is the situation of most of Tunisia's known oil and gas deposits, is 36 percent and for frontier areas in hydrocarbon exploration, it is 8 percent.[78]

76 Under the "success case," i.e., a commercial discovery, the NPV is calculated. To take into account the exploration risk, several scenarios are then set, each with different probabilities of occurrence (e.g., chance of geological success, production costs and price variation). For each scenario, the NPV is calculated. By multiplying each NPV by its associated probability and then summing for all scenarios, one can determine the EMV of a given event. For this analysis, only the exploration risk is considered. In this case, $EMV = p_s NPV - (1 - p_s)EC$, where ps is the probability of success and EC is the exploration cost.
77 The aggregate exploration costs from the four Tunisian projects range from $1.35 to $2.68/bl.
78 As quoted by Myers (2016)

Oil price (USD/bl)	40	50	60	70	80
Success rate	20%	20%	20%	20%	20%
Ras El Besh (Sfax)	-11.6	5.9	23.3	40.7	58.2
Bir Ben Tartar (Sud Remada)	-114.0	-106.4	-98.7	-91.1	-83.5
Nour	-20.3	-13.4	-6.5	0.4	7.4
Maamoura	-50.3	-39.5	-28.7	-18.0	-7.2
Model project	-27.9	71.0	169.9	268.8	367.7
Success rate	50%	50%	50%	50%	50%
Ras El Besh (Sfax)	20.3	63.9	107.6	151.2	194.8
Bir Ben Tartar (Sud Remada)	-247.0	-227.9	-208.8	-189.7	-170.7
Nour	-29.2	-11.9	5.4	22.8	40.1
Maamoura	-71.5	-44.6	-17.7	9.3	36.2
Model project	230.3	477.5	724.7	971.9	1,219.1

Table 12. Pre-tax EMV (USD million)

When the exploration risk is taken into consideration, even in a very optimistic scenario, Bir Ben Tartar, Nour and Maamoura would not be viable under oil prices between $40 and $60/bl. (Only Nour has a positive, yet very low EMV under a 50 percent success rate and an oil price of $60/bl.) That three relatively new representative fields have very low economic returns helps to illustrate why investors have shown limited interest in Tunisia's hydrocarbon sector in recent years.

The above analysis determined which two projects are economically viable on a pre-tax basis at a wide range of oil prices. These two projects—Ras El Besh and the model project—were therefore selected as the bases on which to apply the various fiscal regimes from the international benchmark to see how the Tunisian fiscal regimes compare.

Table 13 presents additional economic characteristics of these two projects. Ras El Besh is slightly more profitable using the IRR metric, with its lower capital costs and shorter duration. However, the model project, because of its size, generates more than six times as much cash flow in NPV terms. The Rash El Besh profile is the most referenced in the following analysis because it is more representative of Tunisia's hydrocarbon assets. However, the model project profile, with its larger production potential, is used for complementary analyses on progressivity of fiscal terms.

	Ras El Besh (16.4 mbl)	Model project (100 mbl)
Internal rate of return	56.4%	50.7%
Net cash flows (USD million)	609	4,453
NPV10 (USD million)	319	2,111
Payback (years)	3.47	3.6

Table 13. Ras El Besh and model project pre-tax project characteristics

4.2 INTERNATIONAL BENCHMARK

Most governments have a selected list of countries with which they compare themselves, typically those with similar resource potential, geography and cost structure. For this study, eight oil and gas producers were selected to be compared with Tunisia, including:

- Three countries in the region—Libya, Algeria and Egypt—recognizing that, while it is useful for Tunisian policymakers to understand how their fiscal regime compares to those of neighboring countries, these three countries have hydrocarbon reserves and sectors that are much larger than Tunisia's, which gives them a clear competitive advantage and limits their use as benchmarks for Tunisia. Any such comparison should therefore be treated with caution.
- Five international producers with more comparable geological characteristics with Tunisia, namely Ghana, Equatorial Guinea, Cameroon, Papua New Guinea and Romania.

Table 14 summarizes the main characteristics of the petroleum sectors of the selected countries: proven oil reserves, daily oil production, the type of the fiscal regime in place and the average opex per barrel.

Table 14. Benchmark countries' characteristics[79]

	Oil reserves (bn bls)	Daily production (kbls/d)	Fiscal regime	Opex (USD/bl)
Libya	48.4	1,046.00	PSC	6.98
Algeria	12.2	1,378.05	Concessionary	7.28
Egypt	4.4	521.73	Concessionary	7.39
Equatorial Guinea	1.1	128.01	PSC	12.60
Ghana	0.7	217.44	PSC	14.08
Romania	0.6	93.68	Concessionary	9.61
Tunisia	0.4	36.92	Concessionary/PSC	12.38
Cameroon	0.2	64.31	Concessionary/PSC	16.21
Papua New Guinea	0.2	35.79	Concessionary	11.53

The main fiscal terms that apply in the selected countries are summarized in Appendix II (found online as part of the model accompanying this report). Depending on the system in place and the information available, for some countries, the terms selected reflect commonly applicable legislation, for others, a particular contract. For instance, the fiscal terms for Libya, which publishes little information officially, are drawn from the 7 November Block PSC, available on resourcecontracts.org, and may not reflect the level of taxation of the overall sector.[80]

79 EIA, "International Energy Statistics", and Rystad, *Ucube*.
80 Appendix II.

For Tunisia, the fiscal terms used are those that apply under each of the two PSCs and under the JV system described in Section 3.3. For the JV system, the following four scenarios are modeled:

1 Concession without ETAP participation (called "Concession - no ETAP" in the tables and figures below)

2 Concession with three different levels of ETAP equity in the joint venture (JV):

   a 40 percent

   b 50 percent

   c 70 percent

As shown in Figure 17, 40-70 percent is the typical range of ETAP ownership in a JV.

4.3 RESULTS

The following analysis relies on the fiscal model described in the previous section. It is based for the most part on the Ras El Besh project profile, except in Section 4.3.2, for which the model project profile is used to illustrate certain features of the fiscal regimes, as explained previously.

4.3.1 Average effective tax rate

Looking at the AETR while keeping all assumptions constant, the fiscal regime of the Sfax PSC seems to be more favorable to investors than that of the Sud-Remada PSC, or of any other Tunisian regime. The concessionary system without any state participation generates a significantly lower AETR when compared to other Tunisian scenarios with state participation of between 40 and 70 percent.

In terms of international comparisons, the Tunisian JV regime is close to Egypt's, and one of the most onerous to investors after Algeria's. The Sud Remada's PSC is on the high end of the AETR benchmark, while the Sfax PSC and the concessionary regime without state participation are on the lower end, just ahead of Romania and at a similar level to Libya's and Equatorial Guinea's PSC.

Figure 19 shows the results of the benchmarking analysis at a discount rate of 10 percent, while Tables 15 and 16 below illustrates the results under different discount rates.

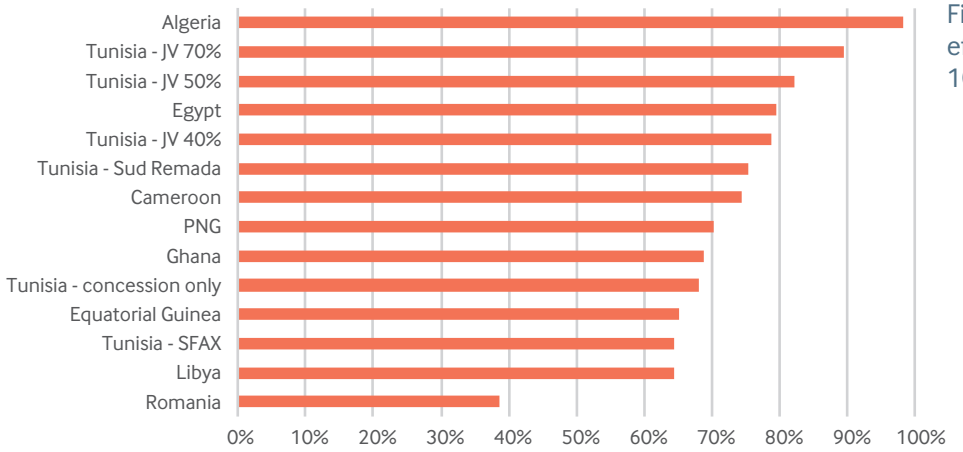


Figure 19. Average effective tax rate (AETR) at 10 percent discount rate

As Table 13 shows, the AETR for the Sud Remada permit is higher than that of Sfax Offshore for all the selected discount rates. This is not surprising, as the Sfax PSC includes a higher cost oil ceiling and a lower share of profit oil to the government. Sfax's share of profit oil is also based on daily production, and Sud-Remada's on profitability, as described in Section 3.3. In this respect, the government share of profit oil in the case of Sfax is less sensitive to profitability than for the Sud Remada. This is probably because Sfax covers an offshore project where more lenient fiscal terms tend to exist than in onshore projects.

In all scenarios, the JV system with government participation generates a higher AETR than either PSC. The AETR of the Sfax Offshore permit is the most generous to investors, second only to the concessionary regime with no state participation.

Ras el Besh profile	Sud Remada	Sfax	Concession – No ETAP	JV – ETAP at 40%	JV – ETAP at 50%	JV – ETAP at 70%
AETR NPV0	69.4%	59.6%	63.6%	76.3%	80.2%	88.1%
AETR NPV10	75.4%	64.4%	67.9%	78.7%	82.2%	89.3%
AETR NPV15	80.3%	68.3%	71.6%	80.7%	83.9%	90.3%

Table 15. AETR of Tunisia's fiscal regimes for the Ras el Besh project profile under different discount rates

Looking at the other selected countries in Table 16, the AETR for the Tunisian fiscal scenarios with government participation and for the Sud Remada PSC are higher than for all the selected countries, except for Egypt and Algeria, under almost all discount rate scenarios. The Sfax Offshore PSC has a very similar profile to Libya's and Equatorial Guinea's PSCs: it generates a higher AETR than does Romania, but lower than all the other countries in the benchmark. The concessionary system without ETAP participation is relatively generous to investors, with an AETR a little lower than Ghana's.

Ras El Besh	Cameroon	Egypt	Equatorial Guinea	Papua New Guinea	Ghana	Romania	Libya	Algeria
AETR NPV0	70.0%	71.7%	60.1%	64.6%	64.6%	33.7%	59.2%	95.1%
AETR NPV10	74.3%	79.5%	65.1%	70.2%	68.7%	38.7%	64.3%	98.2%
AETR NPV15	78.1%	85.5%	69.1%	74.4%	72.4%	42.4%	68.4%	100.9%

Table 16. AETR for selected international benchmark fiscal regimes for the Ras el Besh project profile under different discount rates

The findings indicate that on the one hand, the Tunisian fiscal terms found in the Sud Remada PSC or in the typical concessionary system with a high level of ETAP participation are more aligned with those found in countries, such as Egypt and Algeria, with a much bigger geological potential than Tunisia. From an investor's perspective, these Tunisian fiscal terms are not very competitive with respect to countries with similar oil and gas reserves. Conversely, the terms of the Sfax PSC and the fiscal regime of the concessionary regime with no state participation are more competitive and aligned with smaller oil producers in the benchmark.

4.3.2 Internal rate of return

The post-tax IRR in Figure 20 indicates how fiscal regimes affect investors' returns on a project such as Ras el Besh, with a pre-tax IRR of 59 percent. All IRRs are relatively high in the model as they are calculated based on the certainty of reserves, i.e., without the exploration risk (taken into account in the analysis of Section 4.1).

The results show that the JV regime with government participation in Tunisia generates the second highest post-tax real IRR of all the fiscal scenarios analyzed, after Romania. In fact, the JV scenarios in Tunisia produce almost similar post-tax real IRR, because, although the JV system increases the overall government take, it does not affect profitability and should not in theory distort investment decisions. This is because of the assumption in the analysis that ETAP is paying its full share of the costs; so while the investor receives less revenue when ETAP's share is higher, it also covers a proportionally smaller portion of the project costs. The concessionary system generates a slightly lower post-tax IRR because when ETAP's participation in a project is under 40 percent, the CIT rate is not capped at 50 percent and increases with the R-factor. In line with indications from the AETR, the Sud Remada PSC results in the third lowest post-tax IRR after Algeria and Egypt. At 32.7 percent, the post-tax IRR of the Sfax PSC, is in the range of what investors may find in Ghana, Equatorial Guinea or Libya.

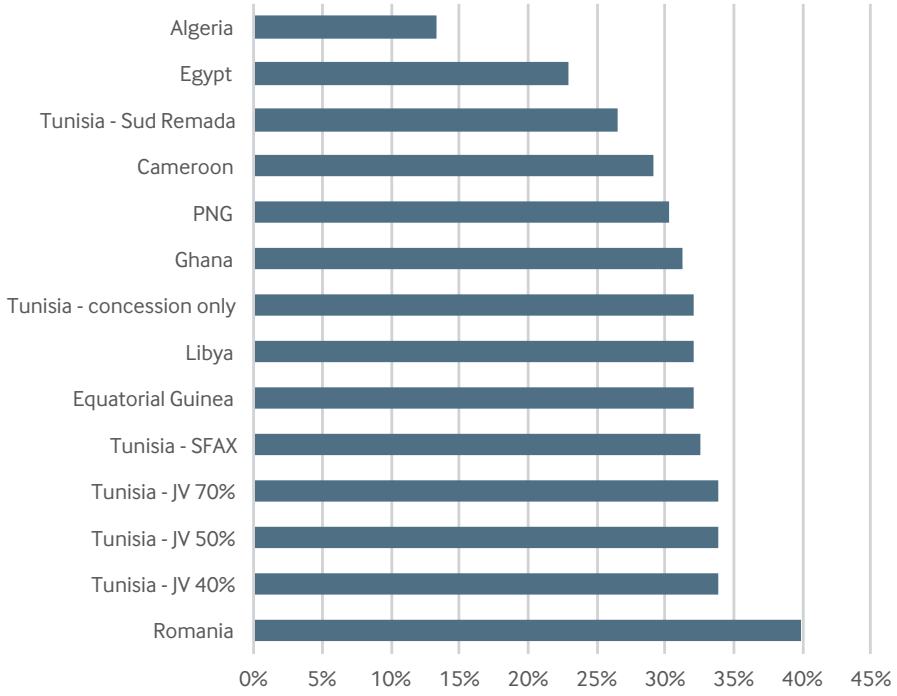


Figure 20. Post-tax internal rate of return under different fiscal regimes

4.3.3 Composition of government revenues

Figure 21 illustrates the composition of total undiscounted project payments estimated from the Ras el Besh project, for the whole duration of the project, for each of the fiscal regimes analyzed.

Project payments under the two Tunisian PSCs would come exclusively from ETAP's share of profit petroleum since all taxes and royalties are paid on behalf, i.e., embedded within the government share of profit oil (as per the Hydrocarbons Code, Article 114). This means CIT and royalties are then collected by the relevant agencies from ETAP and deducted from the profit oil attributed to the state-owned company. The Egyptian and Libyan PSCs use a similar mechanism. Specifically, what is labeled "royalty payable" in Figure 21 for Libya is a 30 percent fixed portion of petroleum production that the NOC collects and from which it pays income tax on behalf of the contractor. Under the PSCs in Cameroon and Equatorial Guinea, without a pay-on-behalf system, contractors pay royalties and income taxes directly to the relevant government agencies.

Tunisia's concessionary regime is comparable to similar arrangements in other countries. In Algeria, Papua New Guinea, and Ghana, the main elements of the fiscal regime include a resource rent tax, though the relative weight of this instrument in terms of revenue generation varies from one country to the other. Only Romania does not apply a resource rent tax. Tunisia seems to have preferred a variable-rate royalty and a variable-rate CIT over a resource rent tax. The composition of revenues under Tunisia's concessionary-JV system is also closer to Algeria's concessionary regime, in terms of the NOC being a major contributor to government revenues.

Figure 21. Composition of project payments under different fiscal regimes

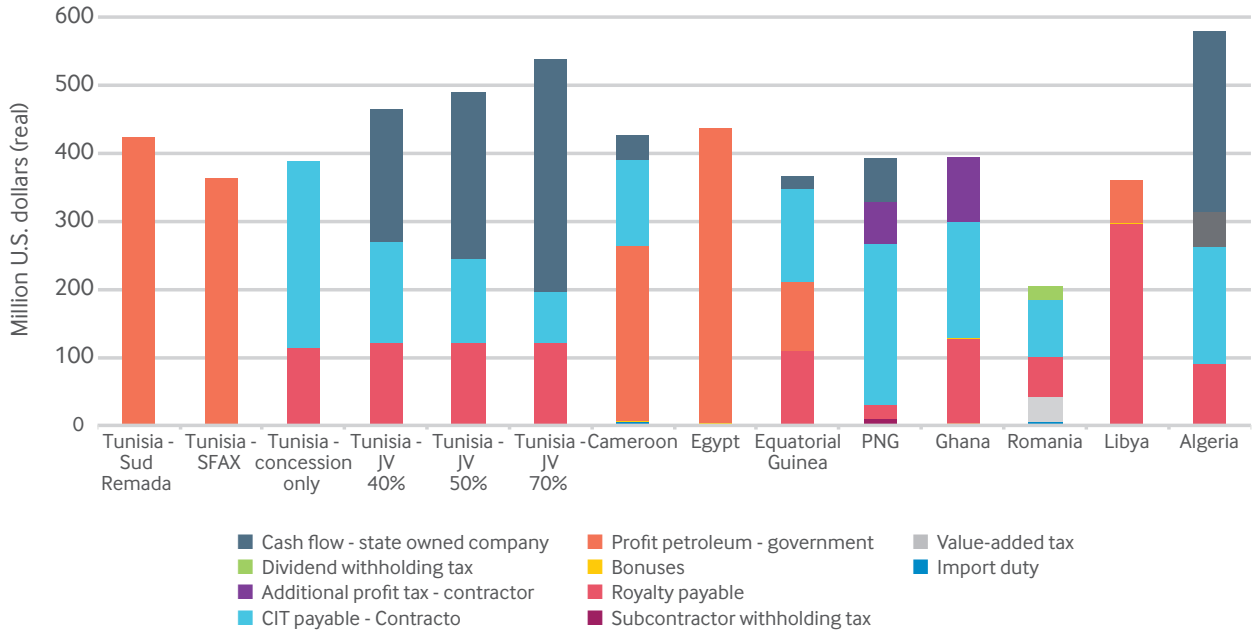


Figure 21 is consistent with the AETR calculation above. In terms of total revenues paid from the model Ras el Besh project, Tunisia's concessionary JVs generate the second highest revenues after Algeria and more than the Sud Remada PSC. The Sud Remada PSC generates slightly less revenue than does Cameroon's and Egypt's PSCs, but more than other countries in the benchmark. The Sfax PSC generates about the same amount of total government revenue as do the fiscal regimes of Equatorial Guinea and Libya.

4.3.4 Progressivity

Progressivity, one of the desirable features of fiscal regimes described in Section 3.2, can be assessed using sensitivity analyses in the model. Figures 22 and 23 illustrate the sensitivity of the selected fiscal regimes to changes in profitability (as expressed in pre-tax IRR) due to changes in oil prices and opex per barrel, respectively. A fiscal regime under which the government share of total benefits increases with the profitability of a project is said to be progressive.[81]

For these figures, the model project is used instead of the Ras el Besh economic profile because the progressivity of fiscal regimes relative to a large range of prices and costs has to be analyzed on a project whose post-tax NPV remains positive under these different assumptions. If it does not, then there would be scenarios under which total government revenues would be higher than the project pre-tax NPV, the contractor's NPV would be negative and the "government share of total benefits" ratio would not be informative. For the same reason, the base case price scenario has been adjusted to $70/bl in Figure 23.

81 In Figure 22, an upward sloping curve indicates a progressive fiscal regime: the tax burden increases as prices rise and therefore profitability rises. A downward sloping curve indicates a regressive regime. In Figure 23, it is the opposite: an upward sloping curve indicates a regressive fiscal regime. The tax burden increases as costs rise and therefore profitability falls. A downward sloping curve indicates a progressive regime. The steeper the curve, the more regressive or progressive the regime is.

Two clear outliers emerged in the analysis and as such, were taken out of the figures below to better illustrate the behavior of the other regimes at different oil prices and opex: Algeria and Romania. Algeria's fiscal regime is the most progressive but captures a very high share of total benefits at any oil price, while Romania's regime is regressive, and captures a very low share of total benefits. Algeria applies a resource rent tax which kicks in once the oil price exceeds a certain threshold, which explains the progressivity especially at higher oil prices. Romania, however, relies solely on a royalty which it imposes on a sliding scale varying with production and reaching 13.5 percent for large projects, in addition to 16 percent CIT. Such a combination makes the Romanian regime more regressive.

For oil price sensitivity, Figure 22 shows that all the regimes are positively responsive to changes in oil prices, though some more than others. The Tunisian JV regime with state participation ranging from 40 to 70 percent is the most progressive, with a government share of total benefits increasing from 45-52 percent at very low prices to 65-75 percent at very high prices. The progressivity of the JV regime can be attributed to its reliance on state participation, as well as the use of R-factor thresholds for both the royalty and the CIT. Even without government participation in JV, the concessionary regime remains very progressive with respect to prices, though it captures a lower overall government take.

Both Tunisian PSCs are less progressive than the JV regimes, because of the low cost-oil ceiling. But at higher oil prices, the government take increases more rapidly under the Sud Remada PSC. It is not surprising to see the Sud Remada PSC, where the profit-oil is based on an R-factor, more progressive than the Sfax PSC, where the profit-oil is based on the level of production, because the R-factor is a better proxy for profitability than production.

Through the pay-on-behalf system in the Tunisian PSCs, ETAP collects the share of profit oil defined in the PSC, and then pays to the state the royalty and CIT as defined in the Hydrocarbons Code (equivalent under certain assumptions to the "concession only" regime in Figures 22 and 23).[82] Therefore, the stream of revenue that ETAP collects is much less responsive to changes in prices and costs than the payments it has to make to the state on behalf of the contractor. The consequence is that the more profitable a project is, the more ETAP will pay in royalties and income tax to the state on behalf of the contractor relative to its share of profit oil. This means that ETAP may be able to retain a greater share of revenue for itself from less profitable projects. If this was not intended by the lawmakers, it might create the wrong incentives for the state-owned company. Aligning the progressivity of the PSC regime to the hydrocarbons law regime would contribute to better incentives for investors and the NOC.

82 CIT payable under a PSC by ETAP on behalf of a contractor is assumed to be calculated on the taxable profits of the whole field, following the terms of both PSCs (annexe comptable, 7.5), "At the end of each fiscal year, the CONTRACTOR will submit to ETAP an annual statement summarizing the expenditures and costs in order to enable ETAP to calculate the taxes on the profits realized, to be paid by it in accordance with Article 114.1 of the Code." Article 114.1 is however a source of confusion, stating that the income tax "is fixed, for every fiscal year, to the value of the production of crude oil and gas taken out by the contractor as a compensation for the considered fiscal year." The authors welcome feedback and clarifications from practitioners.

Among the other countries in the benchmark, Ghana and Cameroon also have very progressive regimes with respect to prices, though Ghana has a lower government share of benefits than does Cameroon. Papua New Guinea, Egypt and Equatorial Guinea's fiscal regimes are less responsive to price changes. Libya's regime is the least progressive, as the government derives most of its revenue from a flat rate 30 percent share of gross production, equivalent to a royalty but collected by the NOC.

Figure 22. Government share of total benefits, price sensitivity (excluding Algeria and Romania)

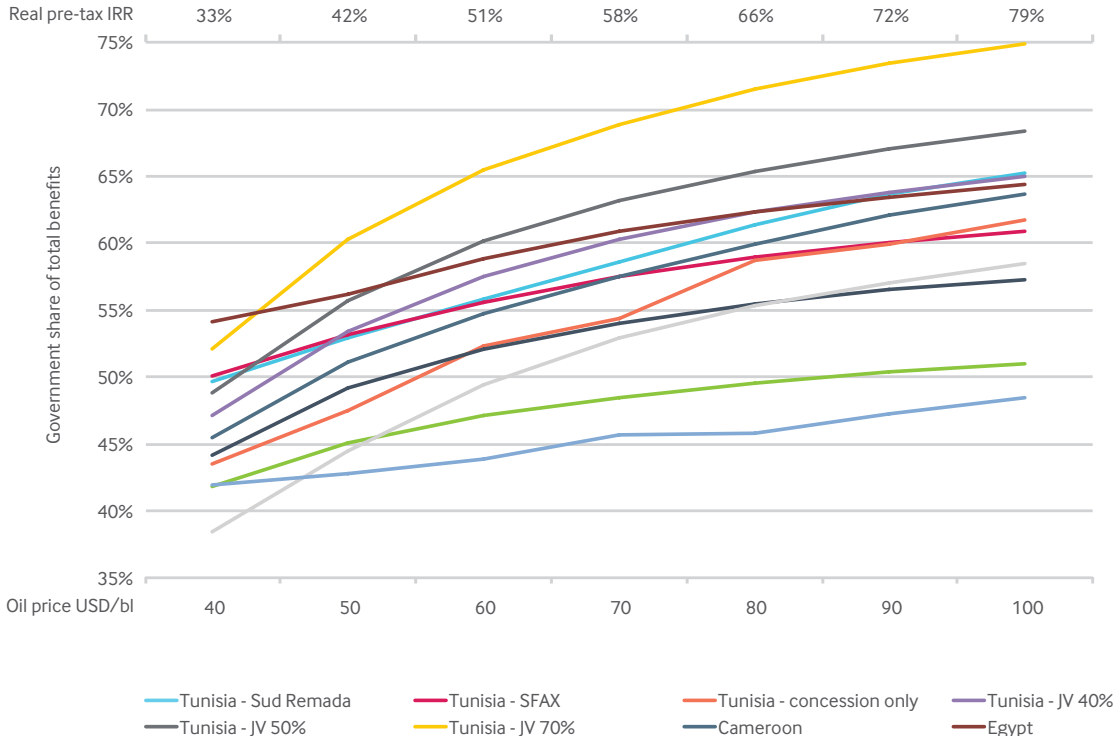


Figure 23 tests the responsiveness of the regimes to changes in opex whereby as costs increase, the pre-tax IRR and the government share of total benefit decline, everything else being equal. The results confirm the earlier findings related to the responsiveness of the fiscal regime to changes in prices, though all fiscal regimes are less responsive to opex than they are to prices.

Figure 23. Government share of total benefits, cost sensitivity (oil price $70/bl) (excluding Algeria and Romania)

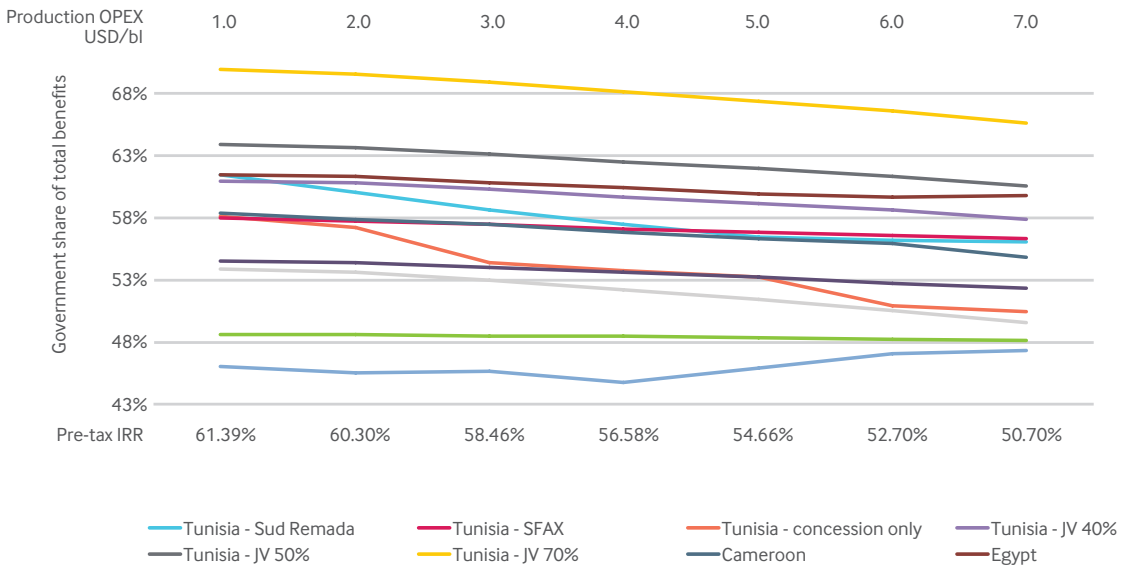


Figure 23 confirms that the Sud Remada is more progressive than the Sfax PSC, being much more responsive to changes in costs. The use of production levels in the Sfax PSC profit oil split again account for this, versus the R-factor threshold in the Sud Remada PSC. Costs are taken into account in the R-factor calculation but not when using the production as the threshold. Both PSC regimes are less progressive than the concessionary regime.

All the concessionary regimes in Tunisia are progressive with respect to costs, at different levels of government share of total benefits. They are followed by the fiscal regimes of Ghana and Cameroon, while Papua New Guinea, Equatorial Guinea and Libya's regimes are not progressive at all with respect to costs.

The impact of changes in capex on the share of total benefits produced similar progressivity outcomes as the opex progressivity analysis in Figure 23, though the results are more pronounced, and can be seen in the fiscal model.

4.3.5 Quantitative analysis summary

The quantitative analysis of Tunisia's fiscal regimes shows the following:

- The design of the two Tunisian fiscal systems, concessionary JV and PSC, means that they have very different economic characteristics: they vary in how responsive the contractor's payments are to different levels of profitability. The PSCs are much less progressive than the JV system, for instance.
- Even within the same fiscal arrangement, the outcomes are different, as the analysis of the Sud Remada and Sfax PSC show, given the differences in the two PSCs designs.

- The most competitive Tunisian fiscal regime is the concessionary system without state participation as it provides a level of government take on the lower range of international benchmarks and is very progressive with respect to prices and costs. This allows the government to capture more revenues if project profitability increases.
- Adding state participation of 40 to 70 percent to the concessionary system does not affect the progressivity of the regime or the post-tax IRR of projects, but it increases the AETR significantly, above the levels seen in most other countries in the benchmark except Algeria, which may be deterring to investors especially given the significant geological disparity between Algeria and Tunisia.
- The PSCs provide overall lower government revenue than the JV system but generate revenues relatively early in the lifecycle of the project, leading to a relatively high AETR (when using a high discount rate), especially the Sud Remada PSC.
- Neither PSC is progressive, because of the low cost oil ceiling provisions.
- The Sfax PSC is more competitive than the Sud Remada PSC, because its profit-oil split is more generous to the investor. However, the Sfax PSC is much less progressive than the Sud Remada PSC, because it uses a production-based scale for profit oil split, while Sud Remada relies on the R-factor. The profit-oil split of the Sfax PSC therefore does not adjust for changes in costs or prices.
- Because ETAP pays royalties and taxes on behalf of PSC contractors, its payments to the treasury are more progressive with respect to prices and costs than the profit oil it collects from the contractor. ETAP could therefore be retaining more revenues from less profitable projects than from more profitable ones.

The overarching conclusion is that none of the existing systems in Tunisia's petroleum fiscal regime are adequate to the country's geology and institutional setting. More precisely:

- The concessionary system without state participation is both competitive and progressive but does not recognize ETAP's legal right to an option to have a participating interest in all projects.
- The JV system with state participation is progressive but would only be competitive for very mature or profitable fields, or if ETAP could take on more of the exploration risks.
- The Sud Remada PSC is relatively progressive, but its cost recovery limit is too low and it is not competitive for Tunisia's existing hydrocarbon assets.
- The Sfax PSC is competitive but is not progressive enough: it might be adequate for a small field with limited potential for additional discoveries, but would not be suited to a range of different fields. When the potential of an upside in reserves or prices is unknown, the government needs a more progressive regime to capture possible windfall profits.
- To ensure a consistent role of ETAP in revenue retention, it would be preferable to adjust the level of progressivity of the PSCs to the fiscal regime of the concessionary (i.e., Hydrocarbons Code) fiscal regime.

5. Conclusion and recommendations

In this report we analyze Tunisia's upstream petroleum fiscal regime with a special focus on the PSC system taking into consideration the existing conditions and trends that have characterized the country's oil and gas sectors, primarily the small geological potential and the decline in investment and production. It is understood that one of the government's priorities for the energy sector is to create a vibrant industry to support the local economy, reduce the country's increasing dependence on imports, attract investment and boost exploration activity.

Given the global nature of the oil and gas industry, investors compare the risk-reward balance that they can achieve in different countries and jurisdictions and allocate their constrained capital, technical and human resources where they can get the best outcome. Investors take into consideration several factors such as the probability of making commercial discoveries, the potential size of such discoveries (which in turn will determine the future production profile), the oil price, cost structure, political risk and the fiscal regime.

In Tunisia, according to the current state of exploration, the potential for substantial new discoveries appears limited, and investors generally do not see the geology as attractive. The ups and downs of a nascent democracy also generate more uncertainty for investors, whether on the institutional and regulatory regime, or on relationships with local communities. Furthermore, the multiple fiscal regimes applicable in the sector are not particularly adapted to the government's objectives. To encourage private investment into exploration and production of oil and gas, the government will need to make policy choices and build a narrative that would put Tunisia on the radar of small and medium size oil and gas companies.

The review of the fiscal regime applicable to the petroleum sector should be the first step of this reform effort to attract investment. Historical changes to the hydrocarbons law and the negotiations of the main fiscal terms in the contracts, particularly for the PSC, have created several fiscal structures, which in turn have increased the administrative burden and complicated the comparative analysis. The two PSCs studied in this paper have completely different fiscal terms – not only in terms of rates but also in terms of mechanism, with no clear rationale behind such divergences. Significant differences exist particularly in profit petroleum sharing scales, resulting in very dissimilar government share across various fiscal structures.

To make the Tunisian fiscal regime more internationally competitive, progressive and transparent, the government could consider the following recommendations:

1 *Increase the cost recovery ceiling of PSCs.* It is currently very low by international standards. Increasing it would allow investors to recoup their costs faster, and therefore increase the progressivity of the PSC fiscal regime. Next, the law should structure the new PSC terms in a way that enables ETAP to pay royalties and income taxes on behalf of the contractor out of its share of profit oil in any given year.

2 *Adopt an R-factor profit-oil split for all PSCs.* For profit sharing, a sliding scale mechanism linked to profitability triggers, such as the R-factor, if effectively monitored by government agencies, is preferable to daily production thresholds, which do not

take into consideration costs and are poor proxy of profitability. To keep the profit sharing simple, Tunisia needs no more than three R-factor triggers.

3 *Simplify the cost recovery ceiling of PSCs.* If Tunisia adopts an effective progressive profit-sharing mechanism, it will not need multi-tiers cost recovery ceilings as in the Sfax PSC. The progressive profit sharing will make the system flexible enough to different levels of profitability and make it self-adjusting to different project types.

4 *Harmonize PSC fiscal terms.* All PSCs should use similar key fiscal terms, especially for cost recovery and profit sharing, to simplify their administration by ETAP and other government agencies and create a more level playing field for contractors. It would also reduce the discretion of government officials in negotiating the terms, while creating a more level field for comparison.

5 *Limit ETAP's equity stakes in new ventures.* The concessionary system as described in the hydrocarbons law has some interesting features, but Tunisia may need to restrict ETAP's participation in JVs to the more mature and profitable fields. The level of ETAP's participation in the JV does not affect the post-tax IRR for investors, but it increases the government take significantly. It also requires significant capital from the state-owned company. Tunisian policy-makers might want to consider limiting ETAP's equity participation in new projects, especially for more frontier or risky investments.

6 *Standardize fiscal terms with the hydrocarbons law.* International best practice recommends the inclusion of fiscal terms in the legislation as this reduces administrative costs, political difficulties, corruption risk and investors' perceived risk while increasing transparency.

7 *Maintain fiscal stability.* While the government reforms the fiscal regime, to avoid discouraging existing and potential investors, it should announce that it will not extend any new terms to existing agreements, unless companies opt to be subject to the new regime.

After a review of fiscal terms, depending on available resources, the government could aim to better showcase the country's geology, for example by funding additional surveys and preliminary exploration, packaging geological information in a way likely to attract companies and then organizing competitive bid rounds for new promising acreage. If the country wishes to engage in non-conventional resources, the government could run some initial surveys in the concerned areas.

Companies need to also be convinced that Tunisia offers long-term stability. There have been many institutional and legal changes in the last few years, and there are no signs that this will end anytime soon. Institutional and legal overhauls after a democratic revolution are legitimate, but they would create less instability if they were conducted in a more orderly fashion. All reforms should follow a rigorous and accountable process, and lead to long-term, nonpartisan solutions that future governments will not continuously question. Tunisia needs to better define the exact role of its parliament, and determine mechanisms to allow it to monitor the government's hydrocarbon policy without becoming an impediment to investment. Finally, the government should reach out more consistently to all Tunisians to explain its policy and the terms under which companies operate, including being transparent about generated revenues to avoid mismanaged expectations, local frustrations and unrest.

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