taxnotes® international

Volume 100, Number 2 ■ October 12, 2020

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Reprinted from *Tax Notes International*, October 12, 2020, p. 265

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This article is part of the series, "Post-COVID-19: How Governments Should Respond to Fiscal Challenges to Spur Economic Recovery," coordinated by the International Tax and Investment Center (ITIC) to offer tax policy guidance to developing countries during the post-pandemic recovery phase.

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In this installment, the authors analyze whether oil and gas host governments might revisit their upstream fiscal regimes following the coronavirus pandemic and, if they do, what measures they might adopt in the shorter term.

Abstract

The coronavirus (COVID-19) pandemic and subsequent "Great Lockdown" have profoundly disrupted the oil and gas industry, causing a collapse in prices and slashing of investment spending across the sector. Because of the severity of the crisis, some oil companies requested direct government bailout — wrongly in the authors' view — while others hoped for a relaxation of the fiscal terms.

The objective of this paper is to analyze whether host governments might revisit their upstream fiscal regime following the crisis, and if they do, what measures they are likely to adopt in the more immediate term. The list of factors that drive fiscal changes is long; the analysis carried out in this paper focuses on three common and interrelated key drivers — namely oil price, investment trend, and production performance. For illustrative purposes, the paper studies 10 major offshore provinces both in the OECD and emerging markets, which are considered directly competing for international capital. These provinces share similar commercial and technical challenges but government fiscal responses tend to differ, depending on several factors, including the way the fiscal regime is designed, health of the industry before the crisis, and degree of economic dependence on oil revenues.

Key Findings

The analysis confirms the inherent fiscal instability in the oil and gas sector, with the prominent role of oil prices, investment, and production trend as some of the common drivers of fiscal changes. Other factors include the dependence of an economy on oil revenues and the "neighborhood" effect; politics also play a role, albeit more muted. Even in the world's most stable fiscal regime — that is, the Norwegian regime — changes have been implemented to adapt the regime to changes in local and international conditions.[1] The Norwegian experience confirms that no fiscal regime is cast in stone, but changes can be made while maintaining the stability of government take.

Overall, there seems to be consistency in the direction of travel in the more immediate future; the perception is that the industry is going through an unprecedented cycle and an alleviation of the fiscal and regulatory burden may be needed to sustain investment, production, and revenues. However, the reaction of host governments will differ, as are the measures that might be introduced and the speed at which they

[1] Norwegian Government, "Package of Measures to Support the Oil and Gas Industry and the Supply Industry," Press Release No. 76/20 (Apr. 30, 2020).

will be pursued. The longer low oil prices prevail, the higher the pressure to accelerate fiscal reforms is, especially if investment remains subdued.

Host governments, particularly those in developing economies, are usually slow to react to collapse in oil prices (especially as compared to their reaction when prices increase). For those countries that are heavily dependent on oil and gas revenues to meet budgetary needs, this can even take much longer. Furthermore, governments typically attempt to soften the regulatory burden before considering pursuing fiscal changes, since the financial implications on their coffers are lower.

Some governments started to review their fiscal terms before the COVID-19 crisis hit the world economy and subsequently the oil industry. The review was often driven by a decline in activity. Under current circumstances, it might be accelerated to avoid worsening an already challenging pre-crisis situation. However, not all governments will be convinced of the need to relax their fiscal terms, especially those that are more dependent on oil revenues and others where resource nationalistic politics play a central role.

A competitive fiscal regime does not necessarily imply low tax rates. Indeed, evidence shows that such regimes are often unstable. Simple measures such as a focus on swift payback and recovery of capital spending can hold equivalent or even greater appeal to investors, as do low headline tax rates. Similarly, profit-based instruments are much more likely to engender investment than front-loaded, revenue-based instruments, such as royalty and signature bonuses, and are characteristically more stable.

The way the regime is designed will affect the need for, and type of, changes to be made. Profit-based regimes have long proven their superiority to revenue-based regimes: The government share increases or decreases with profitability, thereby automatically adjusting to changes in a wide range of conditions. On the contrary, a regressive regime (the government share varies inversely to profitability) needs continuous tinkering to adapt to changing conditions. Investment typically favors progressive regimes even with higher government share. That said, regressive instruments such as royalty — when properly designed and implemented — are an important source of revenues, especially for poorer nations and regions.

Countries, which are particularly struggling in terms of declining investment and production, can consider measures such as providing fiscal incentives for the development of marginal fields or encouraging exploration and appraisal expenditure within hub catchment areas. Depreciation rules in the tax regulations can also be modified to allow faster front-loading or introducing an uplift on exploration expenditure. This would create a major incentive for operators to reinvest capital to improve project economics.

Introduction

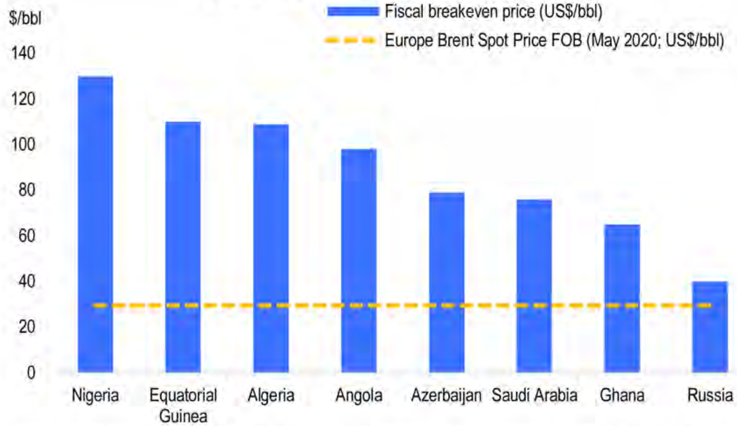
The coronavirus pandemic has caused acute pain the world over. To stop the spread of the virus, countries around the world imposed strict lockdowns, which have hit the global economy and subsequently, oil demand, hard. Nearly all businesses have suffered substantial financial pain and enduring uncertainty, with those in the transportation, hospitality, and energy sector amongst the most severely affected.

The collapse in economic activity brought oil demand down with it; demand destruction exceeded 20 percent virtually overnight. The outcome was an unprecedented decline in oil prices, with West Texas Intermediate prices turning negative in April 2020 for the first time in the industry's history. The severity of the crisis is evident from the actions taken across the industry, from reductions in capital expenditure, operating costs, oil field shut-ins, and in the case of Shell, the first dividend reduction since World War II.

For oil-producing countries, especially those with limited economic diversification, the suffering is particularly severe. The fiscal breakeven oil price, which is needed by oil-producing countries to balance their budgets, is one illustration of the scale of the challenge facing these countries. At current oil prices, for instance, oil producers such as Nigeria, Ghana, and Angola run substantial fiscal deficits (Figure 1). Continued development of oil and gas reserves will be more of a priority for such countries — in particular, to restore public finances and support the local economy.

Some oil companies requested direct government bailouts, wrongly in the authors'

Figure 1. Fiscal Breakeven Oil Prices



Data Source: IMF, "Table 6: Breakeven Oil Prices" (2019); Ministry of Finance (Ghana), "The 2020 Budget Statement and Economic Policy of the Government of Ghana" (2019); and Reuters, "Oil Price Fiscal Breakeven Rates" (2020).

view. Investment can be supported without the need for direct financial aid: The solution lies with the fiscal regime. As the world emerges from the crisis, host governments will be increasingly competing for international capital, which will be much more cautious, selective, and disciplined in today's highly uncertain environment. Investors will therefore have the luxury of more opportunities than can be financed.

The objective of this paper is to analyze whether host governments might revisit their upstream fiscal regime following COVID-19 to safeguard and attract investment, and if they do, what measures they are likely to adopt in the more immediate term. The list of factors that drive fiscal changes is long; the analysis carried out in this paper focuses on three common and interrelated key drivers — namely, oil price, investment trend, and production performance.

For illustrative purposes, the paper studies 10 major offshore provinces both from OECD and emerging markets, which are considered as directly competing for international capital. These provinces share similar commercial and technical challenges, and most have significant potential deepwater resources that they are keen to unlock. Nigeria and Brazil, for instance, hold the largest remaining crude oil deepwater and ultra-deepwater reserves, respectively.[2]

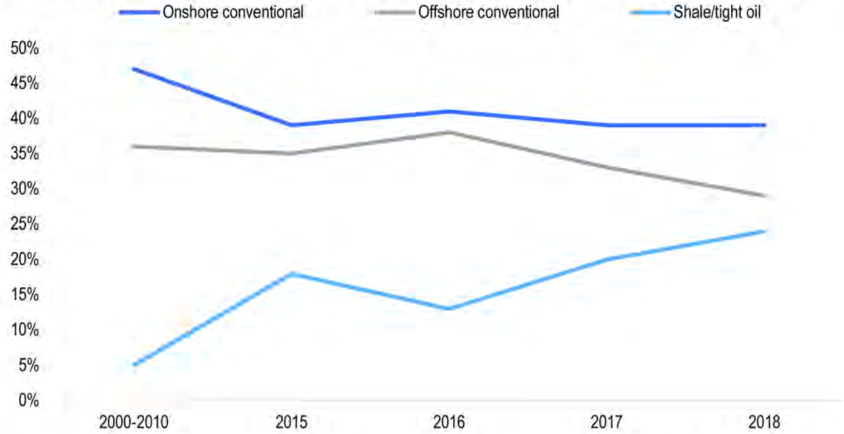
Furthermore, the impact of a downturn cycle in the industry tends to be more notable on offshore investment, given the higher cost and longer payback period of such projects, which usually worsen with rising water depth. Following the collapse in prices in 2014, companies increasingly diverted their capital to projects with shorter payback periods, such as onshore and especially shale, at the expense of offshore projects (Figure 2). As put by the International Energy Agency (IEA), the rapid growth of shale's weight in the global upstream investment in recent years implies that the industry is shifting toward shorter cycle projects able to generate cash flow faster.[3] In this respect, the COVID-19 crisis is likely to have a bigger and more enduring impact on the offshore industry.

The remainder of this paper proceeds as follows: The next section analyzes the drivers of

[2] According to GlobalData Upstream Analytics, as quoted in *Offshore Technology*. *See* "Nigeria Tops Countries With Largest Remaining Deepwater Oil Reserves" (Feb. 2, 2018); and "Brazil Tops Countries With Largest Remaining Ultra-Deepwater Oil Reserves" (Feb. 8, 2018).

[3] IEA, "Share of Upstream Oil and Gas Investment By Asset Type, 2000-2018" (last updated Dec. 9, 2019).

Figure 2. Share of Upstream Oil and Gas Investment by Asset Type, 2000-2018



Data Source: IEA, "Share of Upstream Oil and Gas Investment by Asset Type, 2000-2018" (last updated Dec. 9, 2019).

fiscal changes; the third section studies the measures taken by the selected provinces, focusing on the main fiscal modifications implemented, if any, following the fall in prices in 2014, then those announced or likely to be implemented after the oil price collapse in 2020; and the final section provides the recommendations and concluding remarks.

Drivers of Fiscal Change

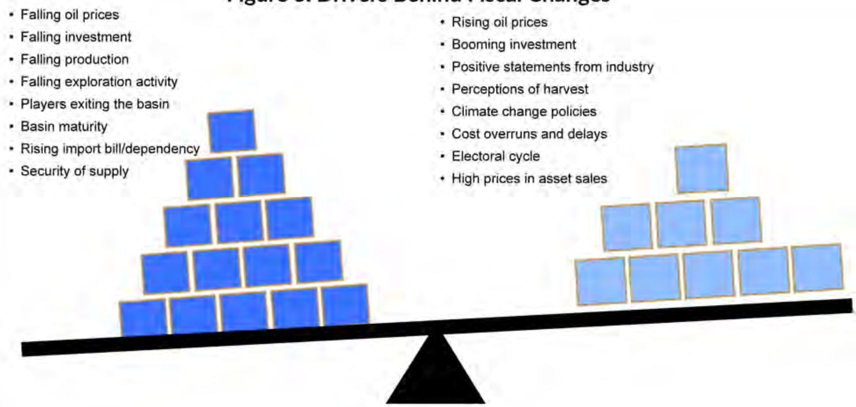
Although the importance of fiscal stability is a popular mantra for the oil and gas industry, it is rarely delivered, particularly in extractives-based developing economies, as circumstances are constantly changing. Several factors can drive governments to revisit their fiscal terms and for companies to lobby for fiscal changes. The list of such factors is long.[4] (See Figure 3.)

The oil price is the most obvious driver, as it has an immediate palpable impact on government revenues, as well as its impact on the perception of fairness with respect to the sharing of the proceeds. Other factors include investment trend, which is a function of both market dynamics and domestic policies, and production life cycle. Factors such as climate change policies will play an increasingly important role in the longer term and deserve a separate detailed analysis in their own right. Of course, it is difficult to attribute fiscal changes to only one factor; a combination of factors, some mutually reinforcing and others exogenous to the oil industry, leads to fiscal changes.

A certain degree of flexibility is to be allowed in any tax system if it is to adapt to significant changes in domestic and market conditions. The government response, however, largely depends on the design of the fiscal regime and its ability to adjust automatically to such changes. For instance, a regime in which the fiscal take is heavily front-loaded and revenue-based typically requires more tinkering than a profit-based system. In Nigeria, where the system's reliance on royalty — a regressive instrument — is notable, the revision to fiscal terms is legislated, and seems to be getting more frequent under newer legislation. For instance, the 2019 amendment of the Deep Offshore and Inland Basin Production

[4]For a detailed analysis, see Mario Mansour and Carole Nakhle, "Fiscal Stabilization in Oil and Gas Contracts: Evidence and Implications," Oxford Institute for Energy Studies Paper: SP 37 (Jan. 2016); and Nakhle and Raymond Hall, "The Taxation of Upstream Oil — Principles, Practice and Prospects," Centre for Global Energy Studies (2012).

Figure 3. Drivers Behind Fiscal Changes



Note: Adapted from Carole Nakhle and Raymond Hall, "The Taxation of Upstream Oil — Principles, Practice and Prospects," Centre for Global Energy Studies (2012).

Sharing Contract Act (BOIBPSCA) calls for a review of the production-sharing contracts (PSCs) every eight years — that is several times throughout the duration of the contract. If Nigeria's petroleum fiscal regime had more progressive features built in that adjust automatically to changing conditions and projects, it wouldn't need all these regular reviews.

Oil Price Effect

Host governments typically want a "fair share" of the economic rent from the exploitation of the nation's oil and gas resources. The U.K. government's objective with respect to the fiscal regime imposed on the U.K. Continental Shelf is "to obtain a fair share of the net income from those resources for the nation, primarily through taxation."[5] In Liberia, "the fiscal regime shall create incentives for responsible investors while providing a fair and equitable return to" the country.[6]

Achieving this goal is rarely that simple, since there is no objective definition of what represents a "fair share," and it is seldom that both government and the industry agree for long as to whether a fiscal regime is fair or not. The dynamics of oil price volatility ensure that views of what constitutes a "fair share" constantly change. While a government take (total tax paid divided by pretax value, a metric that can be discounted or undiscounted) of 50 percent to 60 percent might be acceptable with oil prices of $60 per barrel (/bbl), it is unlikely to be the view when the oil price shoots up above $100/bbl. In this respect, the issue is always controversial, and governments keep the question of a "fair share" under almost constant review.

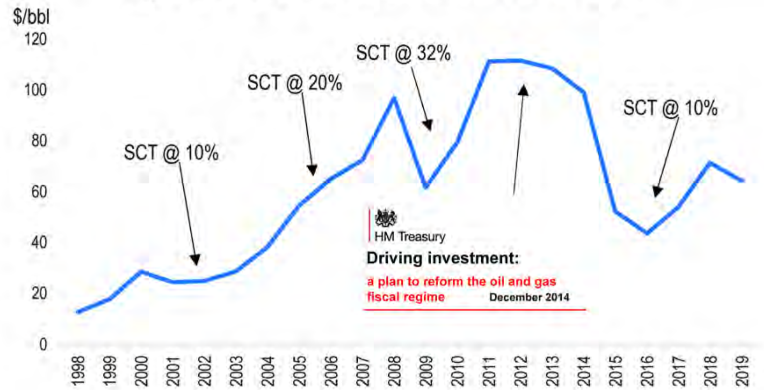
The U.K. experience is a good illustration of how governments closely follow the oil price when it comes to tightening or relaxing their fiscal terms (Figure 4). In Nigeria, the BOIBPSCA of 2004 stipulates that the fiscal regime's reviews are supposed to be triggered when oil prices exceed $20/bbl in real (inflation-adjusted) terms.[7]

[5] HM Treasury, "Driving Investment: A Plan to Reform the Oil and Gas Fiscal Regime" (Dec. 2014).

[6] Liberian Government, "Liberia National Petroleum Policy" (2012).

[7] The provision, however, was never enforced, leading to the 2018 Supreme Court ruling that the oil companies owed the government more than $62 billion. See Dulue Mbachu and Elisha Bala-Gbogbo, "Nigeria Demands $62 Billion From Oil Majors for Past Profits," Bloomberg, Oct. 9, 2019.

Figure 4. Oil Price and UK Government Fiscal Actions



Data Source: EIA, "Europe Brent Spot Price FOB" (2019).

Oil prices play a significant role in determining the degree of bargaining power each party has at the negotiating table. Typically, when the oil price is high, the government has the upper hand; when the price moves in the opposite direction, the pendulum swings in favor of the companies (due to the capital constraints this entails), albeit at a slower pace and asymmetrically.

In the first years of this century, oil prices were on an upward trend, rising from $26/bbl to $100/bbl between 2002 and 2008 (nominal terms), and subsequently triggering a "fiscal storm."[8] From Angola to Argentina, China, Ecuador, India, Kazakhstan, Libya, Nigeria, and the United States (Alaska), governments tightened their upstream fiscal terms on the ground that they were not receiving their fair share of the increasing profitability from the sector. According to *The Economist*, the then-surge in oil prices presented a shift in the global balance of power away from companies to host governments.[9] Following the financial crisis in 2008 and the ensuing collapse in prices, some of those measures were relaxed, but the crisis was short-lived and oil prices rebounded to record high courtesy of OPEC cuts.

Since 2014, however, oil markets have been fundamentally reconfigured thanks to the shale revolution in the United States and which sowed the seeds for the current situation. As the U.S. tight oil boom commenced in earnest around 2010, it brought not only new supplies to the market but, just as important, much more flexible supplies. Traditionally, a conventional oil project may take seven to 10 years to convert investment into production. For tight oil projects, however, this time lag has shrunk to months, making production very price sensitive. Such a simple yet powerful feature has had major implications on global oil markets, established producers, and geopolitics; and it will continue to dictate market trends in the foreseeable future. The challenge of not only plentiful, but more flexible, oil supplies was so big that in 2016 OPEC assembled the biggest alliance in the history of the oil industry to agree on coordinated production cuts with non-OPEC producers, led by Russia. The alliance became known as OPEC+, which stopped the relentless pressure on prices and managed to set a floor on the price of oil. Tight oil, however, set the ceiling over the entire period of interventions, as it rebounded as soon as oil prices recovered.

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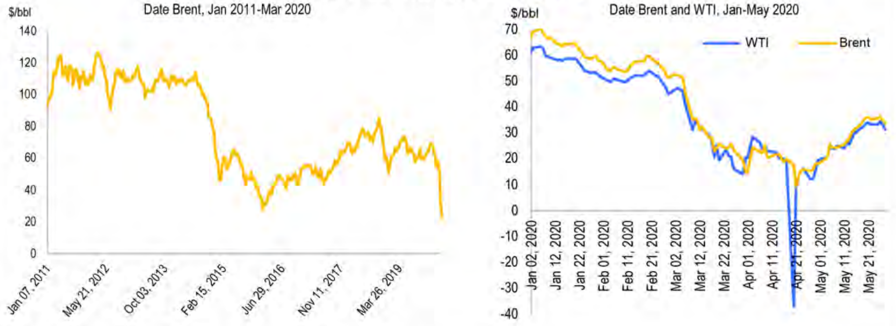
[8] As referred to by Wood Mackenzie in "Fiscal Storms Perspective" (2008).

[9] "Energy and Nationalism — Barking Louder, Biting Less," *The Economist*, Mar. 8, 2007.

Figure 5. Oil Price Evolution



Data Source: EIA, "Petroleum and Other Liquids: Spot Prices" (Sept. 14, 2020).

Since then and up to March 2020, prices continued to react upward to cuts and downward to increased shale production; however, this artificially induced volatility gradually diminished as prices moved into a well-defined corridor (around $60/bbl +/- $10/bbl) toward the end of the period (Figure 5). In February 2020, oil prices were back where they had been in December 2016, just when the first production cut of OPEC+ was announced, and despite substantial supply disruptions in key producers such as Iran and Venezuela.

The other important aspect to consider is that the crisis gave producers a glimpse of how the market will look when oil demand peaks, and as a result the oil market starts to shrink and low oil prices become the norm. In such a market, the low-cost producer always has the edge, while the high-cost producer is the first to leave the market.

In a low oil price environment, capital becomes scarce and pro-investment policy reforms are more evident as countries compete harder for global capital. In fact, such a trend is more evident since 2014; from the Americas to Europe and the Middle East, Africa, and Asia, governments have announced and implemented reforms designed to make their countries more attractive investment propositions than elsewhere. As the U.K. government clearly stated in a 2014 paper, "shifts in the global oil and gas landscape may make it harder to continue to attract global capital without substantial improvements in the fiscal and regulatory landscape."[10] The race can largely be expected to intensify, given prevailing market conditions.

Investment Trend

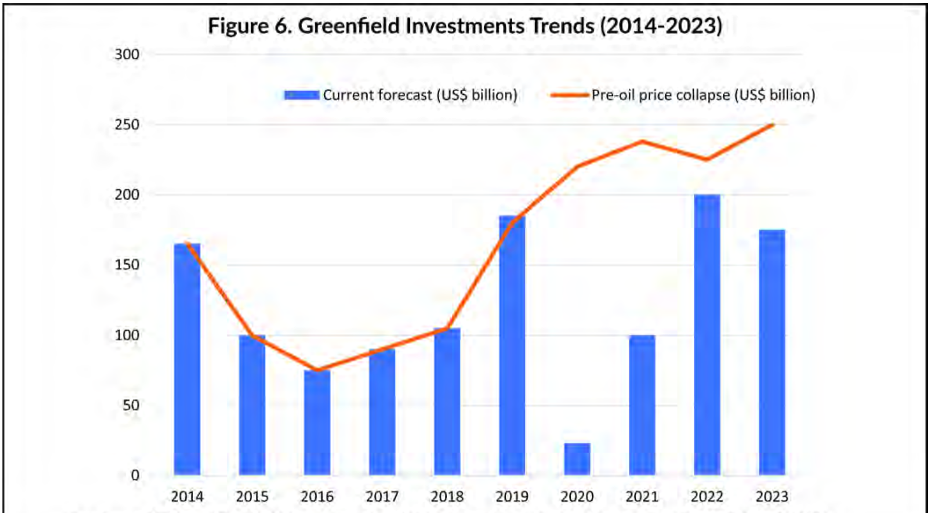
Typically, rising investment encourages host governments to believe that they can introduce a tax increase with little pain. Unexpected declines in investment may trigger the opposite response. Investment, however, is a function of several variables; chief among them is oil price in addition to cost, as well as the fiscal regime (particularly its international competitiveness and long-term stability) — all of which affect expectations about future returns. Following the collapse in oil prices in 2020, capital expenditure (capex) cuts of between US$85 billion[11] to US$120 billion[12] have been announced globally (figures 6 and 7).

As observed during the 2014-2017 downturn, sub-Saharan Africa is likely to witness the most significant capex cuts during the latest downturn due to the industry's high dependence on foreign investors for funding upstream projects, complex projects spanning multiple geologies, and high political and regulatory uncertainty (political risks) in some key producing countries. Some

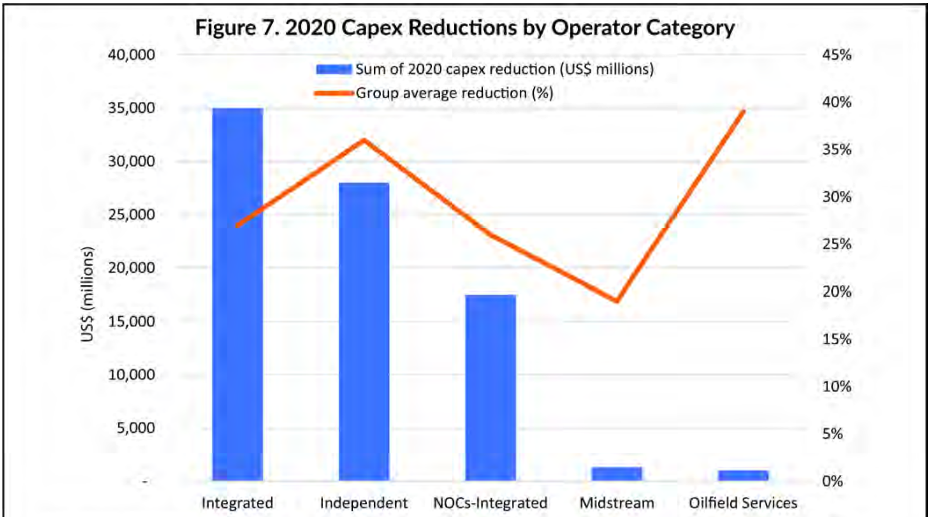
[10] HM Treasury, *supra* note 5.

[11] Offshore Technology, "Over $85bn of 2020 Forecast Expenditure Erased From Oil and Gas Sector" (Apr. 23, 2020).

[12] OilNow "CAPEX Cuts Hit US$120 billion Across 170 Companies — Guyana Offshore Pushes On" (May 12, 2020).

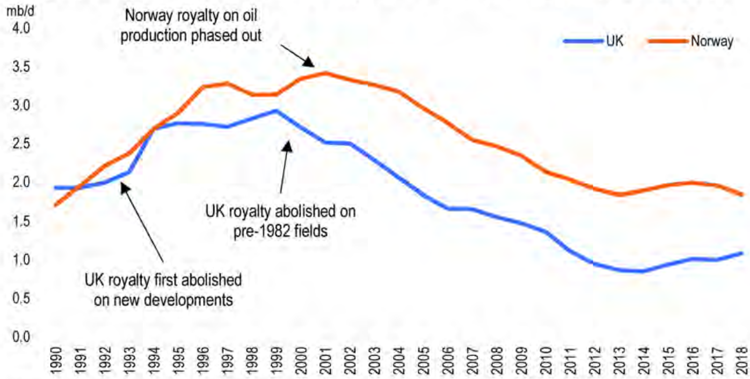


Data Source: OilNow, "Greenfield Investments Headed for Lowest Level Since 1970s — Rystad Energy" (May 30, 2020).



Data Source: Offshore Technology, "Over $85bn of 2020 Forecast Expenditure Erased From Oil and Gas Sector" (Apr. 23, 2020).

Figure 8. Oil Production in Norway and the United Kingdom, 1990-2018



Data Source: BP, "Statistical Review of World Energy" (2019).

industry sources estimate that the continent would be one of the worst regions for capex cuts and delays to discretionary spending,[13] estimated to be 33 percent (US$10 billion) for 2020, compared with cuts of 20 percent during the last downturn.[14]

While oil prices go beyond any government control, through the fiscal regime, which is one of the chief policy instruments within government control, the government can improve or worsen the attractiveness of the investment proposition in the country. The U.S. Gulf of Mexico (GOM) provides an interesting example. In the early 1990s, the GOM was declared a dead sea for exploration. To reverse that perception, the U.S. government introduced new fiscal incentives, through the Deep-Water Royalty Relief Act of 1995. Despite the then-low oil price, the region witnessed a remarkable jump in leases for deepwater — from 171 in 1995 to 620 in 1996, reaching a record high of 1,110 in 1997.[15]

Though not common, some governments introduce fiscal changes in favor of the industry, even during periods of high oil prices, if investment is struggling and causing a decline in production. In Algeria, for instance, auctions held between 2008 and 2011 revealed limited international interest. Hoping to rescue its economy by stimulating interest in new energy developments and to reverse the decline in the country's oil and gas production (which peaked in 2007 and 2005, respectively) the Algerian government revised its hydrocarbon law in 2013, providing tax incentives and relaxing some of the sector's otherwise strict regulations.

Production Life Cycle

At the beginning of the life of a basin, the host government has an incentive to provide an attractive fiscal regime to oil companies to encourage them to make the investment. Once commercial discoveries are made, the bargaining power shifts in favor of the host country that owns the (now-proved) resource, possibly promoting the introduction of a new law, or the amendment of an existing law, for the government to capture the upside of those discoveries.

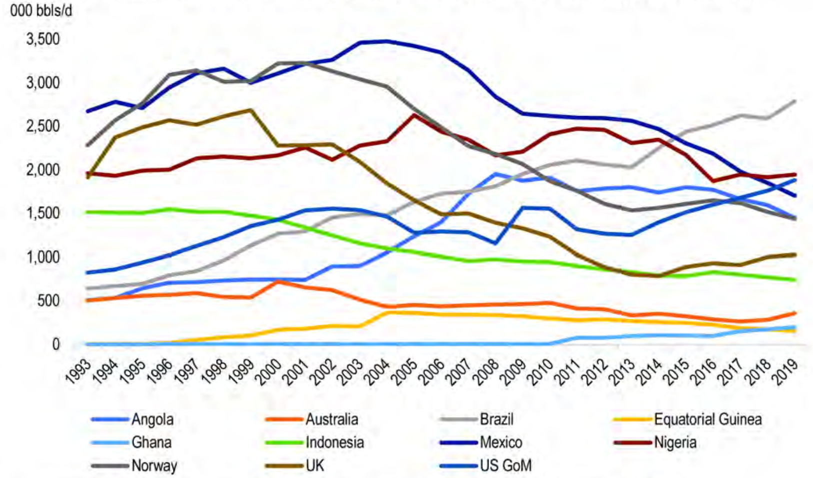
Following the gas discoveries made offshore Israel between 1999 and 2000, the authorities applied a moratorium on all offshore activities to amend existing regulations and fiscal regime accordingly. More than six years later, the sector was opened to new exploration, but with more restrictive terms. The government take was

[13] Alastair O'Dell, "Arrested Development in Africa," *Petroleum Economist*, Apr. 7, 2020.

[14] Mackenzie, "Africa Facing Steep Spending, Production Cutbacks," *Offshore Magazine*, Mar. 31, 2020.

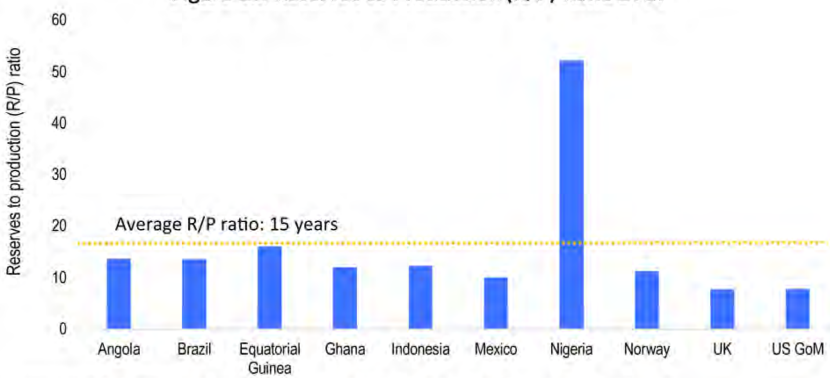
[15] Lesley D. Nixon et al., "Deepwater Gulf of Mexico 2009: Interim Report of 2008 Highlights," OCS report MMS-2009-016 (2009).

Figure 9. Crude Oil Including Lease Condensate Production (000 bbls/d)



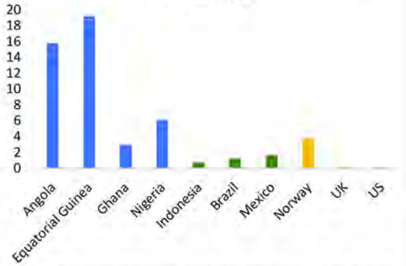
Data Source: EIA, "Petroleum and Other Liquids: Quarterly Petroleum and Other Liquids Production" (last accessed June 14, 2020).

Figure 10. Reserves to Production (R/P) Ratio 2017



Data Source: EIA, "Petroleum and Other Liquids: Quarterly Petroleum and Other Liquids Production" (last accessed June 14, 2020).

Figure 11. Oil and Gas Contribution To GDP (%)



Notes: Developed countries (yellow), developing (green) and least developing countries (blue) as per IMF and UN classifications.

Data Source: World Bank, "Oil rents (% of GDP)" (last accessed June 15, 2020).

increased from around 50 percent to more than 60 percent accordingly. Similarly, the giant discoveries made in Guyana over the last few years have triggered calls for tightening the fiscal terms. The IMF, for instance, has recommended the government increase some of the tax rates to bring them more in line with what is observed internationally.

When a basin matures, however, the tax regime designed for basin opening ceases to be competitive, given that unit costs rise and discovered volumes decline. As the North Sea hit maturity, both the U.K. and Norwegian governments moved to solely profit-based fiscal regimes. The royalty was a key feature of both regimes from the beginning of their oil and gas exploitation in the 1960s. It remained in place as the basin production grew in the subsequent decades. However, as production growth started to slow down, the royalty was abolished in the early 2000s.[16] (See Figure 8.)

Government Reaction

The dynamics of the above three factors strongly suggest that fiscal changes can be expected following the pandemic. This is even more so in countries where production was in decline and investment was struggling even before the crisis, despite the availability of substantial reserves, indicating that above ground factors, primarily the fiscal regime and regulatory policies, were a deterrent — only to be worsened by the crisis. In such countries, calls for fiscal and regulatory regimes to be revisited are likely to intensify. However, in countries that implemented such reforms following the 2014 price decline, there may be less room for maneuver.

The analysis in this section focuses on the experience of 10 offshore producing provinces, both from OECD and emerging economies.

Case Studies Overview

Appendix 1 summarizes the key fiscal and regulatory changes adopted in the selected provinces following the oil price fall in 2014, then identifies the measures taken or announced after the 2020 price collapse. Except for Brazil and Ghana where oil production is rising, the remaining eight provinces are mature, whereby oil production peaked and is declining (Figure 9). Furthermore, except for Nigeria, the reserves to production (R/P) ratio across the provinces is less than 20 years (Figure 10).

In terms of economic contribution, oil and gas production and export remain the economic linchpin of most of the developing countries selected. In countries such as Angola, Equatorial Guinea, and Nigeria, the industry is a fundamental component of their industrial strategy and transition to an upper-middle-income state, acting as the lever to provide jobs and energy security.

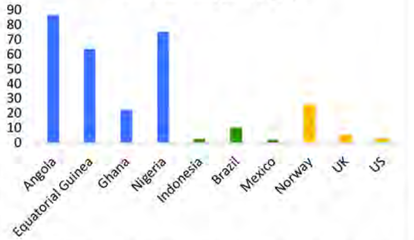
The rapid growth of the upstream oil and gas industry in many of these petroleum-producing countries is dependent on external foreign direct investments led by international oil companies (IOCs). In general, the OECD economies have more diversified economies, though the contribution of the oil and gas industry is highest in Norway compared to other selected developed economies (figures 11 and 12).

Underlying Conditions

In order to put the fiscal measures listed in the appendix in context, this section highlights the key factors in the selected provinces that triggered fiscal changes after the 2014 oil price collapse and

[16] In 1993 Norway abolished gas royalties.

Figure 12. Petroleum Contribution To Total Exports (%)



Notes: Oil rents are the difference between the value of crude oil production at world prices and total costs of production. Developed countries (yellow), developing (green) and least developing countries (blue) as per IMF and UN classifications.

Data Source: The Observatory of Economic Complexity, "Petroleum contribution to total exports (%)" (last accessed June 16, 2020).

that can affect the government's decision with respect to further changes following the 2020 crisis.

Angola

Following the financial crisis in 2008 and subsequent oil price recovery, several oil producers managed to resuscitate their industry. Angola, however, lagged. In 2018, oil production, which is largely concentrated in deepwater, reached its lowest level since 2007, as investment could not be maintained. In addition to high investment and operating costs, the total government take out of an oil project can exceed 90 percent, a share which is typically found in countries that sit on much bigger and lower cost reserves like Iraq. As a result, several discoveries have remained undeveloped.

Recognizing the challenge facing the industry and hoping to reverse production trend while boosting investment in exploration, President João Lourenço enacted several reforms as soon as he assumed office in 2017, including halving tax rates on small and marginal fields. Not surprisingly, the industry welcomed such a move; Italian oil company Eni attributed its field discoveries in 2018 and 2019 to these new measures. Interestingly, one of the goals under the new concession award strategy for 2019-2025 is to "increase competition within the industry and encourage a fair return on investments,"[17] though here too, "fair" needs to be defined.

Conscious of the current economic constraints, in June 2020, the government announced it would delay the launch of its licensing round originally scheduled for end of May 2020. Even when the rounds are relaunched, the record signature bonuses that Angola received in the bidding round of 2005-2006 would be simply inconceivable, as oil companies do not have a shortage of opportunities around the world.[18]

Brazil

Brazil is expected to be one of the most significant sources of oil supply growth in the next five years, along with Canada, Guyana, Norway, and the United States, in addition to OPEC members Iraq and the United Arab Emirates. Brazil owes this capacity to its pre-salt layers, which have been driving production growth. Following the discovery of its giant pre-salt fields in 2006, the government introduced a production-sharing agreement with tougher terms than the conventional concessionary system that applies in the rest of the oil sector.

In November 2019, the government held two licensing rounds related to pre-salt. Expectations were high, given the volumes on offer. Energy Minister Bento Albuquerque described one of the rounds as "the world's largest oil and gas tender," referring to the potential of revenues that would be generated from signature bonuses, amounting to around US$25.8 billion in addition to more than US$152 billion over the next 35 years.[19]

Volumes, however, proved to be insufficient for the eagerly anticipated bid round. The government received bids only from one consortium led by the national oil company, Petrobras, with minority equity for Chinese

[17] Gonçalo Falcão and Norman Nadorff, "Angola 2019-2025 New Concession Award Strategy," Mayer Brown (2020).

[18] In the licensing round of 2005-2006, competition was intense, with over 50 companies qualifying; the result of an aggressive bid-round was impressive. Italian Eni offered US$902 million for a 35 percent to 40 percent operated interest in one of the blocks. Two other blocks received the then-highest signature bonus for a block in the history of the oil industry, with Sonangol and China's Sinopec offering US$1.1 billion for each block.

[19] BnAmericas, "All Eyes on Brazil for Pre-Salt Tenders," Nov. 4, 2019.

partners, in addition to sole bids made by Petrobras.

The fiscal regime, in addition to complex regulations, were largely to blame. Authorities are aware of this shortcoming. "It is an awful system," Economy Minister Paulo Guedes was quoted saying,[20] while Albuquerque stated that the government learned a lesson and would adjust the rules of any future auction accordingly. The current market conditions, where oil prices are less than 60 percent their 2019 levels, will put an additional pressure on the Brazilian government to push ahead with fiscal and regulatory changes, particularly for pre-salt opportunities, in favor of investors.

Equatorial Guinea

Oil and gas production in Equatorial Guinea has declined by about 78 percent since 2010 (from 298,000 bbls/day to 156,000 bbls/day in 2019). Oil and gas output is projected to decline by an average of 6.3 percent from 2019 to 2024.[21] The government has taken several pro-investment initiatives since the 2014 downturn (some since 2006) to reverse the decline, improve the oil sector's outlook and support broader economic diversification drive.

Several elements of the fiscal regime are negotiable (including royalty, cost recovery ceilings, profit shares, and production bonuses). During the EG Ronda 2016 licensing round, minimum signature bonuses ranged from US$200,000 to US$5 million, as compared to US$2 million to US$10 million in 2014, and seven out of 12 companies bidding for the acreage were offered blocks.

Nonetheless, local content requirement has become more prescriptive as the government has sought to retain more value primarily through non-fiscal means. In December 2014, the government introduced new local content rules, which gave preference to local companies, with strong sanctions. The Ministry of Mines and Hydrocarbons maintains a list of eligible local companies to be invited to tender bids, and oil companies must send all requests for services to the ministry before hiring any service companies. Several international oil supply companies, including CHC Helicopters and Subsea 7,[22] have had their operating licenses revoked for flouting the new rules.

In February 2020, the government took an important step to convey its commitment to improving the transparency of the oil and gas sector in the country. It published its model and production contracts for the extractives industry for the first time, as part of a three-year IMF program announced in December 2019.[23]

The COVID-19 crisis, however, has had significant negative repercussions on the economy; after all, the oil and gas industry is the foundation of Equatorial Guinea's economy, accounting for about 60 percent of GDP and over 80 percent of exports value.[24] In an attempt to maintain investors' interest, the government has announced investment-friendly measures, including a two-year extension for all oil and gas licenses and exploration programs until 2021, as well as a waiver of fees for oil service companies in the country. Also, the government in June 2020 adopted new petroleum operations regulations (Regulation No. 2/2020) that include 10-year contracts for marginal and mature fields subject to five-year renewals. The new regulations are a key pillar of Equatorial Guinea's post COVID-19 recovery strategy to attract more foreign investment to the country.

Ghana

Ghana is a relative newcomer to the oil and gas industry. Its commercial production started in December 2010 following the discovery of the offshore Jubilee Field in 2007 by a consortium of IOCs. Crude oil production has provided a critical boost to the economy, accounting for 23 percent of total exports and 4.3 percent of GDP. Pre-COVID-19, the plan was to increase

[20] Marianna Parraga, Gram Slattery, and Marta Nogueira, "Big Oil Stuns Brazil in Back-To-Back Auction Flops," Reuters, Nov. 7, 2019.

[21] IMF, "Republic of Equatorial Guinea: First Review Under the Staff-Monitored Program — Press Release; and Staff Report," Country Report No. 18/310 (Nov. 2018).

[22] African Review of Business and Technology, "Equatorial Guinea Directs Cancellation of CHC Helicopter Contracts," (July 19, 2018); and Reuters, "UPDATE 1 — Equatorial Guinea Punishes Subsea 7 for Not Hiring More Locals," Nov. 22, 2018.

[23] IMF, "IMF Executive Board Approves US$282.8 Million Three-Year Extended Fund Facility Arrangement for Equatorial Guinea," Press Release No. 19/472 (Dec. 18, 2019).

[24] African Development Bank, "Republic of Equatorial Guinea: Country Strategy Paper 2018-2022" (July 2018).

production from 200,000 bbls/day to 400,000 bbls/day by 2024. The government has had a mixed response to the oil price collapse of 2014. On the one hand, the government took several initiatives to reform the industry with the aim to position Ghana as one of the top petrodollar investment destinations in West Africa. In this vein, a new exploration and production law [Petroleum (Exploration & Production) Act, 2016 (Act 919)] was enacted in 2016, replacing the 1984 law (PNDCL 84). This introduced competitive bidding, and in some instances, direct negotiations in the award of blocks, among others. Also, several laws were passed to enhance regulatory capacity, including data management, and health, safety, and environment. Following on from this, the government in 2018 launched the country's first-ever competitive licensing round to award various offshore blocks.

However, the fiscal terms were tightened, as the exploration risk in the country was deemed to be lower once the oil and gas potential was proven, resulting in a higher government take. As per the 2016 fiscal changes announced in the new exploration and production law and subsequent contracts, the regime includes a minimum 12.5 percent royalty for all new contracts, compared to the previous 5 percent to 12.5 percent royalty; a minimum 5 percent additional paying-state participation interest, compared to about 3.71 percent in the pre-Jubilee contracts; and the introduction of minimum US$250,000 signature bonus and production bonuses (all non-cost recoverable). Additionally, the capital gains tax rules have been strengthened — for example, a US$500 million capital gains tax claim by Ghanaian authorities stalled Total's acquisition of Occidental's (previously Anadarko) shares in the Jubilee and TEN oilfields.[25]

Such fiscal changes, along with other factors such as seismic data quality challenges and relatively small block sizes, contributed to the lack of interest in the country's first oil and gas licensing round, which ran from October 2018 to September 2019.[26] Fourteen pre-qualified companies were invited to bid for the five blocks on offer (three under competitive tendering and two under direct negotiations). However, only three companies (both local exploration and production companies and IOCs) submitted bids for just two of the competitive tender blocks. Negotiations of the petroleum agreement with the winners is currently delayed. Likewise, two major IOCs pulled out from the direct negotiations.

In response to COVID-19, the government in June 2020 announced plans to extend the exploration period for oil companies, although details are yet to be communicated. Also, there have been some proposals by industry representatives for the government to revise the exploration and production law and subsidiary legislation. Such a revision would seek, among others, to give oil companies the rights to explore beyond their earmarked production and development areas under the same tax terms as their original petroleum agreements, while also facilitating the tieback of several stranded marginal fields through greater area development plans to maximize economic recovery. Finally, there are calls by the industry for the government to delay its planned second competitive licensing round in 2020 targeted at offering both offshore and onshore oil blocks. This is due to the potential low interest caused by COVID-19 but also offers the government the opportunity to fix the seismic data challenges.

Indonesia

Indonesia's crude oil production has been on a decline from 1.4 million bbls/day in 2000 to 742,000 bbls/day in 2019, triggering a move toward relaxing the fiscal terms, especially when combined with a lower oil price environment. The significant decline in production also forced Indonesia to suspend its membership in OPEC in November 2016.[27]

The most significant recent change in the country's 50-year production history occurred in January 2017 when the government introduced a new form of production-sharing contract (PSC) — the gross-split PSC, replacing the 1966 PSC regime. This followed the expiration of some of

[25] Ekow Dontoh, "Total-Occidental's Ghana Deal Delayed by $500m Tax Claim," *World Oil*, Mar. 2, 2020.

[26] *See* Civil Society Licensing Round Monitoring Group, "Ghana's First Oil Licensing Round Monitoring Report" (2020).

[27] Fergus Jensen and Wilda Asmarini, "Net Oil Importer Indonesia Leaves Producer Club OPEC, Again," Reuters, Dec. 1, 2016).

these contracts and was driven by the government's desire to attract investment. Under the 2017 gross-split PSC model, the country abolished the cost-recovery system, which was the fulcrum of many PSCs — an indispensable feature of Indonesian PSCs since their inception in 1966 that became a template for several developing countries, replacing their royalty-tax (concession) arrangements in favor of PSCs. The gross-split PSC does not have a mechanism that allows contractors to recoup their investment (capex) costs, after which the remaining production would be shared with the state. Therefore, capex required for operations would be entirely funded by the IOCs at their sole risk. Operating costs are allowed as deductible expenses against the corporate income tax.

The gross-split PSC model introduced two elements applicable on a field-by-field basis: a base split for gas production, 52 percent government and 48 percent investor (previously 70-percent government share); and base split for oil production, 57 percent government and 43 percent investor (previously 85-percent government share). These base splits will be adjusted by progressive elements such as "variable" components (field location, field type, crude type, reservoir depth, availability of infrastructure) and "progressive" components (tied to benchmarked Indonesian crude oil price).

Under the new system, by transferring the capex risk, companies would be forced to be more efficient with their capital (for example, reduce capex savings on projects) while both the government and industry enjoy the upside through the progressive adjustment elements. The changes are supposed to bring more certainty to government oil and gas revenues, as they would not be affected by cost recovery. The regime would also be more efficient and simpler to administer as it eliminates the cost recovery approval by the state.

Mexico

In 2013-2014, Mexico went through an internally controversial process to end the 75-year monopoly of its national oil company, PEMEX, and open up its oil industry to private sector investment, with the swift decline and maturity of its once-prolific onshore basin, engendering a more pragmatic approach. The reforms aimed to attract foreign investment, particularly in deepwater and shale reservoirs, while maintaining a sufficient level of government revenue from the sector. A progressive fiscal system and a series of licensing rounds open to IOCs were implemented to achieve these goals. Mexico organized an average of four licensing rounds yearly, attracting a variety of bidders, including international oil majors.

Many licenses have been awarded on the basis of the new fiscal regimes, where one structurally resembles a PSC and the other a concessionary model (licensing), and different fiscal structures apply, varying with the opportunities on offer. The fiscal regime contains several progressive features, despite the use of royalties as a key element of rent collection. When considering the fiscal structure as a package, the Mexican system effectively captures economic rents for the government through the progressive additional royalty (assuming that there is sufficient competition, since it is biddable) while providing a relatively low tax burden on marginal projects. By being profit-based, the additional royalty is effectively a non-distortionary mechanism, but at the expense of simplicity.

The reforms, however, have not produced the increase in production, discoveries, and, subsequently, revenues Mexico was hoping for, and the government, under the leadership of President Andrés Manuel López Obrador, who was elected in 2017 and was never a fan of the 2013-2014 reforms, threatened to revisit the terms of existing contracts and suspended further bid rounds in 2018 until 2022.

There are a couple of things to consider with respect to the Mexican experience. First, indeed, on the face of it, the reforms did not make any difference to Mexico's production, which has continued to decline. This is partly because not enough time has passed since the contracts were awarded for the investments to be converted into production. Second, companies are partly to blame for the frustration; after making a discovery, they frequently trumpet its potential long before a full appraisal can give a more realistic picture about how much of the discovered resources can be actually produced and by when. With such announcements, companies typically target the financial community but forget about the heightened expectations they arouse in the host country's wider population, setting the stage for tension if those expectations are not met. The risk is much higher in a country like Mexico, which entered the new oil era with so much hesitation. Finally, it is believed that some companies overbid the royalty element to win the license only to request its downward revision later on.

Following the COVID-19 crisis, the direction of travel in Mexico is unclear, as politics — not economics — may play an important role.

Nigeria

Nigeria's oil production has been on an overall declining trend since 2010 and its oil reserves have plateaued and started to fall in recent years. This by no means indicates that Nigeria is running out of opportunities; on the contrary, its deepwater potential largely remains untapped. The exploration and development of such resources, however, will not be cheap.

For years, Nigeria has been juggling the idea of changing its fiscal terms for upstream oil and gas. The main argument put forward is that the aim is to improve the competitiveness of the fiscal regime from an investment perspective while securing a fair share to the government. In reality, it seems that the latter objective is the main driver — not surprisingly, given the government's substantial dependence on oil revenues. Furthermore, there is a widespread feeling in the country that the government lost significant revenues because of an obsolete law. The problem, however, is that modernizing legislation that governs the sector has proven to be a highly controversial task, and to date remains a work in progress. At the time of writing, the government is debating a new bill that is supposed to pass this year and introduce new fiscal terms.

From a fiscal point of view, the Nigerian system scores poorly: a high government take combined with regressive instruments, especially high royalty rates, and frequent fiscal changes (whether debated or introduced). Some bills were introduced only to be rejected after many years of discussions. The Petroleum Industry Bill, for instance, was introduced in 2008 to establish a more modern, transparent, and competitive legal, fiscal, and regulatory framework for the Nigerian petroleum industry. The bill, however, went through numerous revisions and became the subject of intense debate among various stakeholders. Furthermore, the fiscal regime is unnecessarily complex: It is a tapestry of different structures and rates, with special focus on royalties, which, in turn, varies with terrain, water depth, oil price, and oil and gas production — all a poor proxy of profitability.

The frequency of the fiscal changes proposed and/or implemented strongly suggests a structural weakness in the fiscal regime that prohibits it from adapting automatically to evolving oil industry related conditions, both domestically and internationally. This is largely because the regime has lacked progressivity; a progressive regime can better stand the test of time and cope with volatile oil and gas prices, unlike a regressive regime.

At the time of writing, the Petroleum Industry Fiscal Bill (PFIB) has yet to be approved and passed into law. The bill was drafted before the collapse in oil prices in 2020 and its final form, if passed this year or next, is likely to be different from what was originally drafted.

Norway

The basic ingredients of the Norwegian fiscal regime have remained broadly unchanged for decades despite high price volatility and the onset of declining production. The fiscal regime is entirely profit-based, and as of January 2020 comprised state tax (23 percent) and special petroleum tax (55 percent), aggregating to 78 percent. Depreciation is six years straight-line as costs are incurred. With such a high tax burden, there is no imperative for the Norwegian government to raise the tax rate as oil prices increase since most of the upside is captured by the fiscal regime in any event. With the fiscal regime being profit related, the state has remained reluctant to lower the tax burden at periods of low prices, especially because it has proved difficult for the industry to demonstrate that the fiscal regime alone is preventing projects from proceeding. The Norwegian fiscal regime is based on the "one size fits all" model, so taxation is levied at the "basin level" with no ring fences of field-specific taxation or allowances. The only specific incentives are uplift on capital costs and an exploration tax credit.

It is important to note that Norway, like many OECD countries in recent years, has lowered its corporate rate to ensure its non-oil sector remains internationally competitive. However, to maintain the stability of the regime, the Norwegian government increased the special petroleum tax rate in similar steps but in the opposite direction. A tax credit for exploration costs is allowable for those investors not in a current-tax paying position, helping to ensure a level playing field whether tax paying or not for exploration decisions.

The severity of the COVID-19 crisis led the government to consider a small fiscal package to support the industry during the crisis. The change seems to be taking the fiscal regime one step closer to that of the United Kingdom, with the rapid recovery of capex. However, it is understood that the overall government take will remain at 78 percent.

United Kingdom

The United Kingdom has the world's most mature basin but the adaptive fiscal measures the government has taken has sustained the attractiveness of the province to international investment. The U.K. probably features the most attractive fiscal regime of any mature basin. Although the U.K. is often cited as the basin with the most unstable upstream fiscal regime in the world, this is not necessarily as damning as it might sound, as over the decades the overall fiscal burden in the U.K. has remained consistently lower than in many other provinces, including Norway (though it has to be acknowledged that the fields in the U.K. sector are smaller and more mature than in Norway). The enduring priority of government policy has been to maximize current production to minimize the import bill for oil and gas and contribute to security of supply. The fiscal regime has always been regarded as an enabler of this policy.

Following the oil price collapse in 2014, the supplementary charge tax has been reduced in a series of reductions to 10 percent, but the differential remains: 40 percent for the oil industry versus 19 percent for the rest. In part, the U.K. government has been able to justify the differential treatment by virtue of the more favorable treatment of capital allowances for the oil industry alone. The 2002 fiscal reform, which introduced the supplementary charge tax (and removed the royalty, from 2003, from the dwindling band of fields developed pre-1982 still paying it) also heralded the introduction of 100 percent capital allowances (replacing a much slower form of depreciation). From this point forward, no project in the United Kingdom would pay any tax until payback had been reached. The outcome is that pretax project initial rate of return remains the same posttax. Subsequently, it is difficult to assert in the U.K. that tax is preventing projects from proceeding. The industry is currently lobbying for additional tax reliefs; it is unlikely that these would be granted, but such a strategy may protect the industry from potential tax increases.

U.S. Gulf of Mexico

The recent increase in GOM oil production has been largely driven by the development of fields that were discovered many years ago and brought onstream during the preceding period of high oil prices. Also, the magnitude of proven oil reserves has gone in the opposite direction, suggesting that the reserves' replacement is not being maintained. In the longer term, if recent trends continue, the maturity of the GOM will become increasingly more pronounced.

The headline rates for the GOM look competitive and compelling, comprising just royalties in the range 12.5 percent to 18.75 percent and federal corporate tax at 21 percent. As a result, the marginal tax rates are amongst the lowest of any major global oil and gas province — in the range 31 percent to 36 percent. However, these headline rates disguise many key features that erode the apparent competitiveness. Lease bonus payments are a material component of the fiscal regime which, due to their upfront nature, materially erode life cycle returns. Additionally, the rate of depreciation of costs is relatively slow by global benchmarks. The royalty burden at up to 18.75 percent serves to make the fiscal regime very regressive. The regime is also a complex tapestry of rates, reliefs, and allowances, symptomatic of the difficulty in designing a universal royalty regime suitable for a range of prices, field sizes, and commercial potential.

A detailed study by Crystol Energy found that the current regime is particularly damaging to small and economically marginal fields.[28] Many projects that are economical pretax are projected to become significantly uneconomical posttax due to the regressive impact of the royalty regime — deepwater projects particularly so, given the higher 18.75 percent royalty. The U.S. authorities recognize the investment disincentive that the royalty regime imposes and have devised, over the years, a complex system of reliefs and allowances to ameliorate the most damaging aspects. However, this does not go far enough, with many of the reliefs largely ineffective or applied on an inconsistent basis. The study recommended a royalty framework that reflects underlying project profitability. The COVID-19 crisis may provide the catalyst for a modification in that direction.

Direction of Fiscal Travel

The above analysis confirms the inherent fiscal instability in the oil and gas sector, with the prominent roles of oil prices, investment, and production trends as the main drivers of fiscal changes. Other factors include the dependence of an economy on oil revenues; politics also play a role, albeit more muted. Even in the world's most stable fiscal regime — that is, Norway's — changes have been implemented to adapt the regime to changes in local and international conditions. The Norwegian experience shows that no fiscal regime is cast in stone, but changes can be made while maintaining the same overall government take. The Norwegian government puts high priority on fiscal stability, partly justifying its higher take, especially as compared to their neighbor across the North Sea.

Apart from this fundamental difference between Norway and the United Kingdom, both countries share several fiscal characteristics, with the most notable one being the reliance on solely profit-based regimes. The suggested changes in Norway post-COVID-19 brings their regime closer to the United Kingdom's by activating a key tool that is probably more powerful than lower tax rates: rapid capex recovery, which in turn shortens the payback period.

The "neighborhood" effect is typically strong, especially if countries are at similar levels of economic development, but also with respect to the oil and gas industry. A tax increase in one country, for instance, may be swiftly followed by copy-cat increases among its neighbors, especially if the perception takes hold that the changes have had little adverse impact on investment and competitiveness. The neighborhood effect may work in reverse, but the process is much slower and needs a collapse in investment to provide the catalyst. The fiscal reforms in Angola, for instance, may well affect the type of changes Nigeria will consider as the latter revisits its fiscal terms primarily to boost investment.

The way the regime is designed will also impact the need and type of changes made. Profit-based regimes have long proven their superiority to revenue-based regimes: the government's share increases or decreases with profitability and thereby automatically adjusts to changes in a wide range of conditions, unlike regressive regimes where the government's share varies inversely to profitability and needs continuous tinkering for the regime to adapt to changing conditions. Investment typically favors progressive regimes, even with higher government share. That said, properly designed regressive instruments such as royalties are an important source of revenues, especially for poorer nations and regions. In this respect and in line with the recommendation of the OECD on durable extractive contracts, a desirable fiscal regime includes both progressive and regressive elements, but more weight should be given to the former to ensure overall progressivity of the regime. A fiscal regime that "is progressive overall will help to align the interests of the host government and the investor."[29]

Furthermore, headline tax rates are misleading. In this respect, international comparison on this basis alone should be treated with caution. For instance, the GOM has a marginal tax rate of around 30 percent after royalty and federal taxes (though this varies across projects): in headline terms, no other established oil and gas province comes close.

[28] Crystol Energy, "The U.S. Gulf of Mexico Policy Initiatives: An Analysis of the Licensing and Fiscal Policies" (Aug. 6, 2018).

[29] OECD "Guiding Principles for Durable Extractive Contracts," at 15 (2019).

However, the GOM fiscal regime is highly regressive, as it largely relies on signature bonuses and relatively high royalty rates.

Looking further ahead, overall there seems to be consistency in the direction of travel: The prevailing mood is that the industry is going through a difficult cycle and an alleviation of the fiscal and regulatory burden may be needed. The reaction of host governments will differ, as will the measures that might be or are introduced and the speed at which they will be pursued.

Host governments, especially those in emerging economies, are usually slow to react to the new reality of low crude oil prices. This was the case during the 2014 downturn and is likely to be so with the 2020 downturn. For those countries that are heavily dependent on oil and gas revenues to meet budgetary needs, this can even take much longer (and sometimes lead to counterproductive increases in government take) to mitigate the revenue shortfalls. It is inevitable that a sustained downturn in oil prices will continue to force revisions to fiscal terms, albeit delayed.

Experience from the 2014 oil price downturn shows that governments are slower at relaxing the fiscal terms, compared to tightening them when prices increase. It also indicates that governments attempt to soften the regulatory burden before considering pursuing fiscal changes (see, for instance, the measures announced by Equatorial Guinea in 2020) for several reasons, chief among them that regulatory changes do not necessarily translate into loss of financial returns to the authorities. Also, some contracts may be restricted by fiscal stabilization provisions, thereby limiting the scope of fiscal changes.[30] Another common reaction is the suspension of licensing rounds (such as in Indonesia and Brazil) for fear of lack of interest.

Furthermore, some of the fiscal changes made during the 2014 downturn are yet to fully manifest in many countries — most producer countries were just about recovering from the last downturn only to be hit by another. In this respect, developing oil and gas producers in particular do not have much room for maneuverability, especially on the fiscal front.

The collapse in oil prices in 2020 is likely to accelerate pro-investment reforms considered in recent years in most countries. That may well be the case in Brazil, for instance, especially following the disappointing results of the pre-salt bidding rounds in autumn 2019 and given the overall policy direction of the existing administration. However, in other countries, changes may go in the opposite direction, and host governments might take a more aggressive stance toward private investment.

In Mexico, for example, the pro-investment reforms implemented during periods of high prices have been criticized for not delivering the promised increase in output. In this case, the government may not be easily convinced of the need for a further relaxation of the fiscal terms despite the current challenging market conditions.

Politics will also have a say, especially when combined with an important role of the oil and gas industry to local economy. U.S. President Trump, in a tweet in April 2020, promised to "make funds available so that these very important companies and jobs will be secured into the future. . . . We will never let the great United States Oil & Gas Industry down." Thanks to the shale revolution, the United States moved from being a net oil importer to a net exporter, from being solely the world's largest oil consumer to also becoming the world's largest producer, with significant economic and political implications. It is therefore not surprising to see the current administration keen on protecting the oil and gas industry. With the presidential elections looming, gaining the support of such a large political base and of the states that are shaped by it adds to the interest.

Conclusion

COVID-19 and the subsequent "Great Lockdown" have profoundly disrupted the oil and gas industry, causing a collapse in oil prices and the subsequent cancellation of several oil and gas projects, as well as severely affecting the supply chain and disrupting revenues and macroeconomic policy management in producer countries. There are significant risks and

[30] For analysis, see Mansour and Nakhle, *supra* note 3.

uncertainties concerning the duration and magnitude of the pandemic's effects on the global economy; the impact on the oil and gas industry; and the fiscal and regulatory initiatives that producer countries can enact to sustain oil and gas investments, production, and revenues.

This paper analyzed whether host governments might revisit their upstream fiscal regime following the COVID-19 crisis and if they do, what measures they are likely to adopt. The analysis focused on 10 major offshore provinces both from OECD and emerging markets, which are considered in direct competition for international capital. These provinces share similar commercial and technical challenges but government fiscal responses to collapse in oil price tends to differ, depending on several factors, including the way the fiscal regime is designed, the health of the industry before the collapse, and the degree of economic dependence on oil revenues.

The analysis reveals the following:

- Fiscal instability is inherent to the oil and gas sector, with a long list of factors driving fiscal change. In the more immediate term, oil prices, investment, and production trends will play a key role in pushing fiscal changes and shaping their direction. Other factors include the dependence of an economy on oil revenues and the "neighborhood" effect. Politics also play a role, albeit a more muted one.
- Overall, there seems to be consistency in the direction of travel in the near future. The perception is that the industry is going through an unprecedented cycle and an alleviation of the fiscal and regulatory burden may be needed to sustain investment, production, and revenues. However, the reaction of host governments will differ, as are the measures that might be introduced and the speed at which they will be pursued. The longer low oil prices prevail, the higher the pressure to accelerate fiscal reforms is, especially if investment remains subdued.
- Host governments, particularly those in developing economies, are usually slow to react to collapses in oil prices (especially as compared to their reaction when prices increase). Furthermore, governments typically attempt to soften the regulatory burden before considering pursuing fiscal changes, since the financial implications on their coffer is lower.
- Some governments started to review their fiscal terms before the COVID-19 crisis hit the world economy and subsequently the oil industry. The review was often driven by a decline in activity. Under current circumstances, it might be accelerated to avoid worsening an already challenging pre-crisis situation. However, not all governments will be convinced of the need to relax their fiscal terms, especially those that are more dependent on oil revenues and where resource nationalistic politics play a central role.
- A competitive fiscal regime does not necessarily imply low tax rates. Evidence shows that such regimes are often unstable. Simple measures such as a focus on swift payback and recovery of capital spending can hold equivalent or even greater appeal to investors, as do low headline tax rates. Similarly, profit-based instruments are much more likely to engender investment than front-loaded, revenue-based instruments, such as royalty and signature bonuses, and are characteristically more stable.
- The way the regime is designed will affect the need for, and type of, changes to be made. Profit-based regimes have long proven their superiority to revenue-based regimes. Investment typically favors progressive regimes even with higher government shares. That said, regressive instruments such as royalties — when properly designed and implemented — are an important source of revenues, especially for poorer nations and regions. In this respect, a desirable fiscal regime includes both progressive and regressive elements, but more weight should be given to the former to ensure overall progressivity of the regime.

Appendix 1. Review of Regulatory and Fiscal Changes

Country	2014-19 fiscal and regulatory changes	2020 fiscal and regulatory changes (including proposals)

Angola	• Major oil and gas industry restructuring process with amendment to the 2004 Petroleum Law, including the creation of the National Oil Gas and Biofuels Agency (ANPG) as national concessionaire and exclusive holder of the mineral rights for oil and gas exploration and production (previously held by Sonangol)
	• 50 oil and gas blocks planned to be auctioned between 2019 and 2025
	• New fiscal terms and incentives for marginal fields introduced in 2018[1]
	  • Reduction in petroleum production tax from 20% to 10% for marginal fields (less than 300 million barrels of reserves) or those not economically viable due to lack of infrastructure
	  • Reduction in petroleum income tax on marginal fields from 50% to 25%
	• New fiscal incentives for natural gas exploration, production, and commercialization:
	  • 5% gas production tax (10% for oil); 25% associated gas income tax (same as for oil) and 15% non-associated gas income tax for proven reserves smaller than 2 trillion cubic feet (tcf)[2]
		• Delay of the onshore licensing round covering blocks in the lower Congo and Kwanza basins[3]

Brazil	• Petrobras no longer the sole operator for pre-salt (Law No 13,365/2016)
	• Publication of multi-year bid round plan covering both concession assets and pre-salt areas up to 2021 (CNPE Resolutions 10/2017 and 10/2018)
	• Legal, tax and regulatory reforms (2017), including:
	  • Royalty reduction[4] — up to 5% on incremental production of mature fields. The default royalty rate is 10%
	  • Petrobras as operator (with a minimum of 30% stake) of a formed consortium for exploration bid blocks under the PSC regime (Law No. 13,365 /2016)
	  • Special customs regime for importation and exportation of goods for E&P Activities including suspension of federal import taxes (Law 13,586/2017)
	For 2017-2019, nine bidding rounds
		• Suspension of 17th oil and gas licensing round reportedly to offer 130 blocks across five basins[5]
		• Published proposals for new Decommissioning Regulatory Instrument (ANP Resolution 817/2020) which streamlines regulatory rules on decommissioning — single decommissioning plan submission to ANP and environment agency; simplification of field transfer rules from one company to the other, allowing extension of the useful life of the fields and improving recovery factors[6]

Appendix 1. Review of Regulatory and Fiscal Changes *(Continued)*

Country	2014-19 fiscal and regulatory changes	2020 fiscal and regulatory changes (including proposals)

Equatorial Guinea	• EG Ronda 2016 licensing round offering 17 offshore and onshore blocks with largely favourable (negotiable) fiscal terms
	• Most contract parameters are negotiable since the 2006 and 2014 licensing rounds
	  • Royalties — negotiable rates (minimum 13% since 2006) with negotiable daily production rates (10%-16% previously in 1998)
	  • Cost recovery limit — negotiable cost recovery ceilings net of royalty (since 2006 and 2014); and based on negotiable cumulative production rates; previously 60% ceiling on cost recovery (1998)
	  • Profit share — negotiable; split previously based on contractor's pre-tax rate of return (1998)
	  • Signature bonus: Reduction in 2016 minimum value ranging from US$200,000-US$5 million as compared to US$2-US$10 million (2014)
	  • Production bonuses — negotiable
	  • State participation — minimum 20% carried interest (since 2006); revised from 15% in 1998)
	• Seven out of 12 companies bid including Ophir Energy, Clontarf Energy, among others[7] but Fortuna FLNG development FID delayed due to low oil prices[8]
	• Introduced prescriptive local content regulations and national participation in the oil and gas sector law (Ministerial Order no. 1/2014)[9]
	  • New local content clauses, provisions for capacity building in new petroleum agreements
	  • Preference to local companies in the award of services contracts.
	  • Strong sanctions regime — operating licenses revoked for breach of provisions especially by supply chain companies[10]
		• Two-year extension for all oil & gas licenses and exploration programmes until 2021[11]
		• Waiver of fees for oil service companies in the country[12]
		• The government in February 2020 published its model and some production contracts for the extractives industry for the first time[13]
		• Other reforms include an asset-declaration regime applicable to all senior government officials aimed at reducing political corruption to strengthen investor confidence
		• Adoption of new Petroleum Operations Regulations (Regulation No 2/2020) to attract more foreign investment to the country as key pillar of Equatorial Guinea's post-COVID-19 recovery strategy[14]
		  • Clarifies rules on marginal and onshore fields (the former now defined as having produced 90% of its proven hydrocarbon reserves)
		  • Marginal and mature fields would benefit from new 10-year contracts subject to five-year renewals[15]
		  • Other incentives for investments in deep and ultra-deepwater acreages
		  • Prohibition of gas flaring

Ghana	• Launch of Ghana's first competitive licensing round in late 2018 based on new Exploration and Production Act, 2016 (Act 919) with increased government take
	  • Minimum 12.5% royalty compared to previous 5%-12.5% royalty
	  • Minimum 5% additional paying state participation on top of existing 15%
	  • New minimum US$250,000 signature and production bonus
	• Increased local content and local participation terms via the implementation of local content law passed in 2013 (for example, at least 5% equity participation of an indigenous Ghanaian company in a petroleum license other than the national oil company (GNPC)
		• Government announced a proposal to extend exploration period for oil companies due to COVID-19[16]
		• Proposals to revise the Exploration and Production Act, 2016 (Act 919) and the Petroleum Exploration and Production General Regulations, 2018 (LI 2359) giving E&P companies rights to explore beyond their original production and development[17] areas as part of marginal field development strategy and greater area development plans

Appendix 1. Review of Regulatory and Fiscal Changes *(Continued)*

Country	2014-19 fiscal and regulatory changes	2020 fiscal and regulatory changes (including proposals)

Indonesia	• Removal of exploration taxes, value-added tax on imported goods and land tax on oil and gas (2016)[18]
	• Gross split PSC model with no cost recovery applicable for conventional blocks (Regulation No 8/2017)[19]
	  • Base split for gas production: 52% government: 48% investor (previously 70% government split)
	  • Base split for oil production: 57% government: 43% investor (previously 85% government split)
	  • Onetime 5% uplift to the Contractor's split if their plan of development moves from exploration and development to production phase[20]
		• No formal announcements made yet on fiscal and regulatory changes mitigate the impact of COVID-19 and falling oil prices

Mexico	• Passage of various legislations from 2014 onwards to effect the 2013 reform programme governing legal, contractual and licensing frameworks
	  • Oil and gas revenue law; PEMEX law; E&P law
	  • Main aim: "To produce more hydrocarbons at lower cost, allowing private companies to complement Pemex's investment through contracts for oil and gas exploration and extraction; and to achieve better results through competition in refining, transportation and storage"
	  • Different fiscal packages introduced depending on opportunities
	• Several licensing rounds were held on a yearly basis since the reforms were introduced.
	• However, in December 2018, the government cancelled any new licensing rounds until at least 2022
		• No formal announcements made yet on fiscal and regulatory changes to mitigate the impact of COVID-19 and falling oil prices
		• However, there is a proposal to:
		  • Reform PEMEX's hydrocarbon production sharing payments (represents 80% of PEMEX's fiscal burden)[21]
		  • Fiscal relief decree — reduce PEMEX profit-sharing rate/duty from 65% to 58% and 54% in 2020 and 2021 respectively.[22] This would help mitigate the impact of falling oil prices on PEMEX's balance sheet and liquidity Heavily indebted PEMEX's credit rating was downgraded to junk status by Fitch and Moody's in April 2020[23]

Nigeria	• Amended 1999 PSC in 2018[24]
	  • Introduced a flat 10% royalty for oil and condensates for all deep offshore in waters greater than 200 metres water depth fields (previously 0%-12% based on water depth)
	  • 7.5% flat royalty for oil and condensates at frontier or inland basin (10% under the previous Act)
	  • Additional price-based royalty ranging from 0% to 10% if oil is between US$0 and US$150/bbl
	• More frequent reviews of fiscal terms legislated
	• Drafted two bills to revise the fiscal terms primarily for concessionary terms:
	  • National Petroleum Fiscal Policy Draft (NPFP) in 2017
	  • Petroleum Industry Fiscal Bill (PFIB) in 2018
		• At the time of writing, PFIB (2018) is under review
		• Major oil fields bid round delayed

Appendix 1. Review of Regulatory and Fiscal Changes *(Continued)*

Country	2014-19 fiscal and regulatory changes	2020 fiscal and regulatory changes (including proposals)
Norway	• Reduction in total uplift from 22% in 2016 (5.5 % per year for four years starting with the investment year) to 21.6% (2017), 21.2% (2018), 20.8% in 2019 (5.2 % per year for four years from the date of expenditure) • Reduction in Corporate Income Tax (CIT) marginal rates from 25% (2016) to 24% (2017), 23% (2018) and 22% (2019) • Increase in Special Petroleum Tax (SPT) marginal rates from 53% (2016) to 54% (2017), 55% (2018) and 56% (2019)	• Marginal rate of tax maintained at 78% (CIT, 22%; SPT, 56%) • Introduced 24% uplift (6% per year) for capex[25] • Change to tax write-off rules allowing E&P companies to frontload investments more quickly, thereby deferring tax payments until later years[26] • Replaced linear depreciation allowance scheme for investments spread over six years with immediate deduction against SPT for capital expenditure • E&P companies can claim payment from the State of the tax value for any uncovered loss and unused uplift arisen in the 2020- and 2021-income years.[27] The tax repayments are irrespective of what type of costs in the petroleum activities • These proposals are applicable for the next two years (2020-2021) to E&P companies operating in Norway
United Kingdom	• Zero-rated Petroleum Revenue Tax (PRT) and reduced Supplementary Charge (SC) from 20% to 10% in 2016. The net effect of this change is that the effective marginal rate in the Continental Shelf (UKCS) is 40%, which is one of the lowest in the world[28] • Ring Fence Expenditure Supplement (RFES) which increases losses carried forward value from one accounting period to the next by a compound 10% a year for a maximum of 10 years • Basin wide investment allowance for Supplementary Charge • Transferable Tax History (TTH) mechanism effective November 2018 for late-life assets, allowing companies selling UKCS license interests to transfer some of their tax payment history to buyers. Buyers can offset their decommission costs fields against the TTH.[29] TTH also grants PRT relief when a seller retains decommissioning liability[30] • Government-funded geological surveys to improve prospectivity	• Some proposals among industry groups including tax repayment for trading losses and deduction for finance costs on the SCT as done with Ring Fence Corporation Tax (RFCT)[31]
United States	• The US Congress in December 2017 enacted changes to the US federal income tax system, which primarily includes a reduction in the CIT rate from 35% to 21% • Considerations for reforming the fiscal regime that applies to US GOM, to improve its international competitiveness[32]	• No formal commitment yet on fiscal and regulatory changes • President Donald Trump announced his intent to provide further federal level fiscal relief/ financial aid to the upstream industry[33]

Appendix 1 Footnotes

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