The US Gulf of Mexico Policy Initiatives: An Analysis of the Licensing and Fiscal Policies

Crystol Energy

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Abbreviations List

AIF	Additional Investment Factor
AMT	Alternative Minimum Tax
ANP	National Agency of Petroleum, Natural Gas and Biofuels
APS	Additional Payment to the State
ARF	Additional Royalty Factor
ATO	Australian Taxation Office
BOEM	Bureau of Ocean Energy Management
BRR	Basic Royalty Rate
BSEE	Bureau of Safety and Environmental Enforcement
Canada NL	Canada Newfoundland and Labrador (see comment page 57)
capex	Capital Expenditures
CAPP	Canadian Association of Petroleum Producers
CNH	National Hydrocarbons Commission
CFR	Code of Federal Regulations
CT	Corporate Income Tax/Corporation Tax
DOCD	Development Operations Coordination Document
DWRR	Deep-Water Royalty Relief
E&P	Exploration and Production
EC	Exploration Costs
ECI	Effectively Connected Income
EFTA	European Free Trade Association
EIA	Energy Information Administration
EITI	Extractive Industries Transparency Initiative
EMV	Expected Monetary Value
ENPV	Expected Net Present Value
FA	Field Allowance

FIRPTA	Foreign Investment in Real Property Tax
FDP	Field Development Plan
G&G	Geological and Geophysical
GOM	Gulf of Mexico
HSE	Health, Safety and Environment
IA	Investment Allowance
IDC	Intangible Development Costs
IEA	International Energy Agency
IOC	International Oil Company
IRC	Internal Revenue Code
IRR	Internal Rate of Return
IRS	Internal Revenue Service
LCF	Loss Carried Forward
MACRS	Modified Accelerated Cost Recovery System
MMS	Minerals Management Service
NCF	Net Cash Flows
NCS	Norwegian Continental Shelf
NPD	Norwegian Petroleum Directorate
NOC	National Oil Company
NOPTA	(Australia's) National Offshore Petroleum Titles Administrator
NOS	Notice of Sale
NPV	Net Present Value
OCS	Outer Continental Shelf
OGA	UK Oil and Gas Authority
OGTC	UK Oil and Gas Technology Centre
OML	Oil Mining License
ONRR	Office of Natural Resources Revenue

opex	Operating Expenditures
OPGGS	Offshore Petroleum and Greenhouse Gas Storage
OPL	Oil Prospecting License
PRRT	Petroleum Resource Rent Tax
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
R&D	Research and Development
RFES	Ring Fence Expenditure Supplement
ROR	Rate of Return
RRT	Resource Rent Tax
RSVs	Royalty Suspension Volumes
SCT	Supplementary Corporation Tax
SDL	Significant Discovery License
SENER	Mexico Secretary of Energy
SOO	Suspension of Operation
SOP	Suspension of Production
SPT	Special Petroleum Tax
UOP	Unit of Production basis
UK	United Kingdom
UKCS	United Kingdom Continental Shelf
VAT	Value Added Tax
WHT	Withholding Tax
WU	Work Units

Units and Currencies

AUD	Australian Dollars
Boe	Barrels of oil equivalent
bbl	Barrel
BRL	Brazilian Real
CAD	Canadian Dollars
GBP	British Pound
ha	Hectares
km^2	Square kilometer
m	Meters
mm	Million
mmbbls/d	Million barrels per day
mmboe	Million Barrels of Oil Equivalent
MXN	Mexican Pesos
NGN	Nigerian Naira
NOK	Norwegian Krone
/bbl	Per barrel
tcf	Trillion cubic feet
USD	United States Dollars

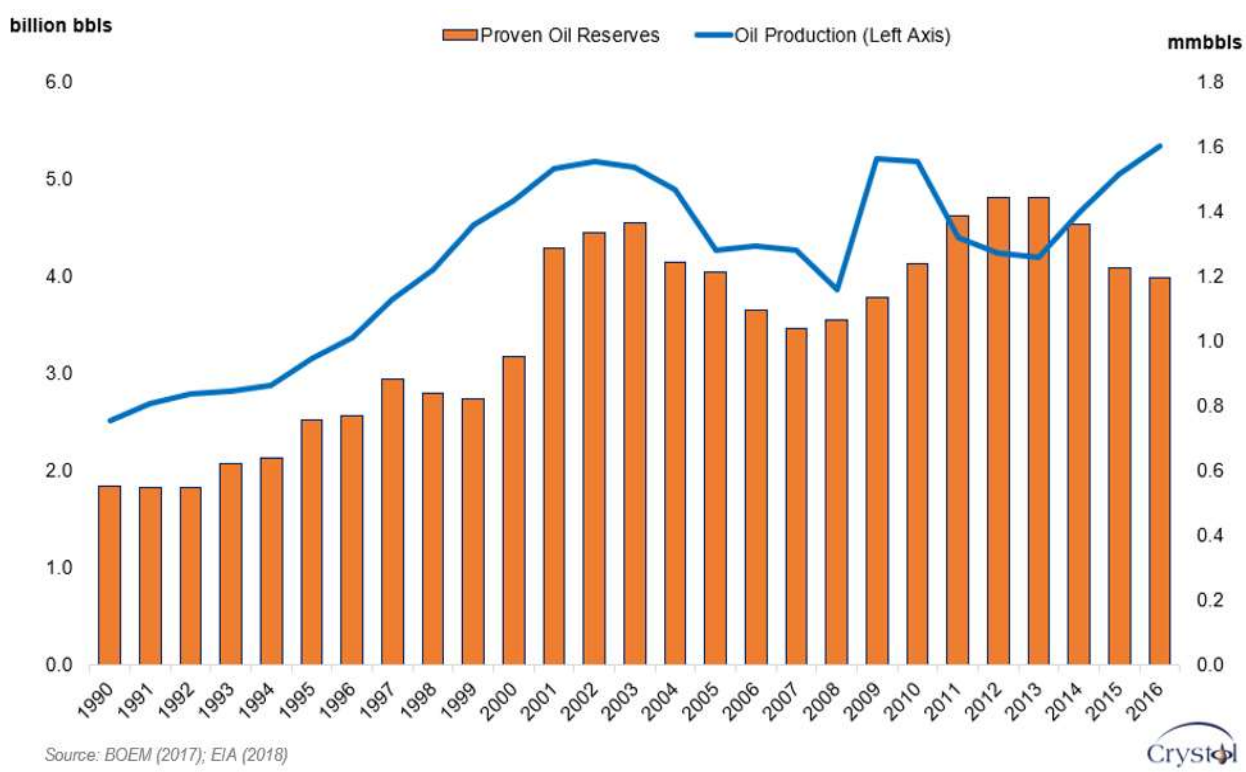
Executive Summary

The API contracted Crystol Energy to carry out a study into the current US GOM licensing and fiscal regime. The aim is to assess the regime's competitiveness and scope for reform to maintain the basin as amongst the most attractive global destinations for upstream investment, taking into consideration the mounting evidence that the US GOM has begun to lose its historic appeal due to a combination of its own basin maturity, the rise of US shale and competition from less mature basins such as Mexico and Brazil.

It may be difficult to articulate an immediate sense of crisis for the US GOM, given the rise in US GOM oil production in the last few years, the recent recovery in oil prices and a material cut in federal CT from 35 percent to 21 percent. Nevertheless, policy makers need to prepare for the onset of the basin's maturity, which, experience indicates, can swiftly accelerate through declining interest in exploration, falling investment and decommissioning of critical infrastructure.

The recent increase in US GOM oil production has been largely driven by the development of fields that were discovered many years ago and brought on stream 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.

US Gulf of Mexico Oil Production and Proven Reserves



In the longer term, if recent trends continue, the maturity of the US GOM will become increasingly more pronounced leading to negative consequences for the economies of the states bordering the GOM and the overall US energy scene.

Oil demand is facing many uncertainties, and for oil producers in increasingly competitive markets, history shows that the low-cost producer has always had the edge. Given the global nature of the industry, competition for domestic and international capital is also expected to intensify. This dictates a real sense of urgency for US policy makers to put in place policies that will ensure that the valuable GOM oil and gas resources are not to become economically stranded.

This study therefore takes a long-term view. Its overarching objective is to assess whether the current system, which may have well worked in the past, remains appropriate for a maturing province, in an increasingly competitive market. Using a combination of qualitative and quantitative analysis, the study evaluates the licensing and fiscal policies applicable to the US GOM and in competing offshore provinces – mainly: Angola, Australia, Brazil, Canada Newfoundland and Labrador, Mexico, Nigeria, Norway, Trinidad and Tobago and the United Kingdom (UK). The conclusions in this study are based solely on government and other public information and Crystol Energy's own expertise and analysis.

The study's main findings and recommendations are summarized below, first for the licensing then fiscal policy. The recommendations are intended to work within the system that is in place today - an evolutionary not revolutionary approach to avoid unsettling investors' sentiment.

Licensing Policy

Although no ideal licensing policy exists in practice, the analysis of the licensing terms and the results of recent licensing rounds in the US GOM and nine competing offshore jurisdictions reveal that the US is an outlier on several fronts. The US GOM licensing system is generally more rigid than elsewhere and should incorporate more flexibility in line with the needs of a maturing US Central and Western GOM.

The recommendations below are shaped to develop greater flexibility and improve the attractiveness of the US GOM licensing regime to investment by aligning it more with competing provinces. The suggested measures can also be implemented at little or no financial cost to the government and some can help in alleviating the administrative burden.

1. Bidders' list:

The US GOM is the only jurisdiction that applies a bidders' list although no evidence is found on the effectiveness of such a measure. Most of the other jurisdictions surveyed have an equally competitive market structure with no similar restrictions in place. The oil industry structure today is much more fragmented and much less concentrated today than in the 1970s when the bidders' list was introduced. It is unlikely that many large fields around the world would have been developed without joint ventures between the oil majors, a demonstrably successful mechanism for sharing the risk of large, high cost, technically challenging developments. As upstream exploration becomes more complex and companies operate in more challenging environments, restrictions on joint bidding can be counter-productive. The BOEM should therefore consider removing such a restriction.

2. **Complexity:**

The US GOM licensing system is more complex than in the other analyzed jurisdictions. It has the widest variation in exploration license durations, differing with several water depths. By comparison, most of the other jurisdictions assessed have one license duration for offshore and, where a distinction between water depth is made, it is typically between two categories: shallow and deepwater. The US might benefit from a more simplified approach, such as having only two types of lease: shallow and deepwater or even a unified duration for all offshore leases, irrespective of water depth.

3. **License duration:**

Only for licenses covering water depths higher than 1,600 m does the US GOM license length exceeds the average of the selected jurisdictions; all the other licenses in the US GOM fall below the average. The authorities should therefore consider aligning their lease duration with that of other competing offshore provinces. Furthermore, the duration of the US GOM exploration phase (primary term) for depths between 800 m and 1600 m is lower than the other depths, including shallower water. In practice, one would expect to see a longer duration for deeper water depths and shorter for shallow water; it simply takes longer to exploit deepwater acreage due to the greater costs and risks. If differentiation by water depth is maintained, the authorities should consider offering a single longer exploration lease duration for deepwater compared to shallow water. Of course, the risk is that the lease could be held for a longer period by an owner with no intention of exploring or developing the resource. The minimum work program requirement, however, would guard against such a scenario.

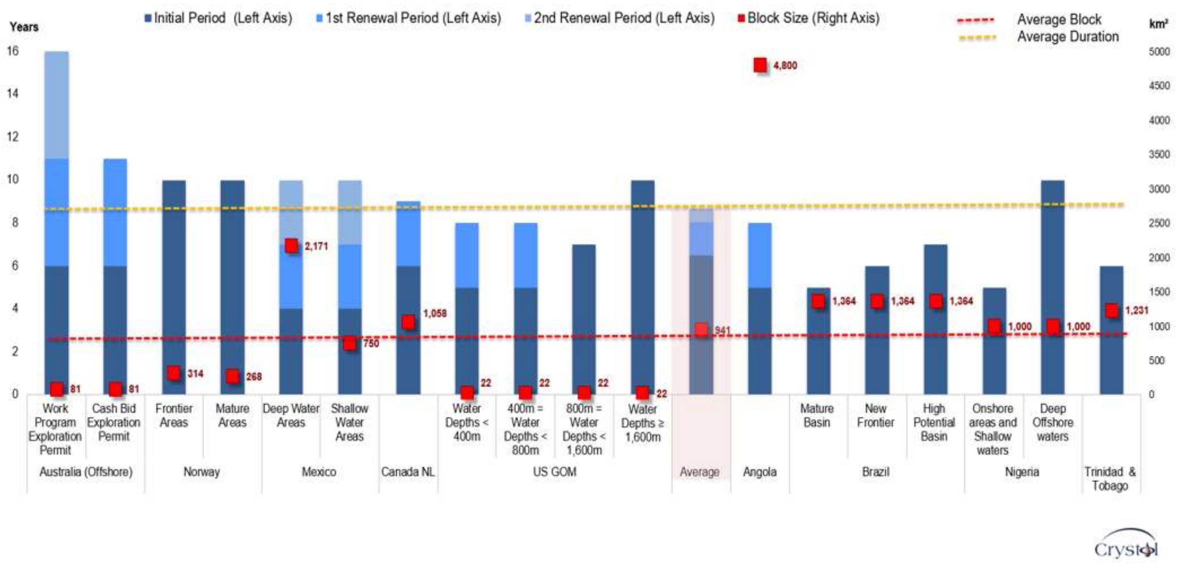
4. **Uncertainty:**

The US GOM system does not provide sufficient predictability, although investment is best encouraged by predictability. For instance, while the SOP and SOO can be granted for up to five years, the practice has been for one year or less. The system should therefore provide greater certainty and flexibility by, say, broadening the criteria for situations that qualify for lease suspensions to include the need to advance technology and gather additional seismic data. It could be also made more explicit as to what SOP and SOO outcomes can be achieved under what circumstances (e.g. what conditions need to be fulfilled to secure a five-year extension, four years and so on). As a basin matures, it tends to take longer to develop discoveries as they become smaller, more marginal and technically challenging.

5. **Block size:**

No relinquishment applies to the primary term renewal in the US GOM, most likely because the blocks are very small – in fact, the smallest among all the selected jurisdictions. Under current regulations, US authorities could consider leasing much larger individual blocks in deepwater, possibly with mandatory relinquishments (after say five years) to help make the blocks more attractive to investors.

Block Size and Exploration License Duration

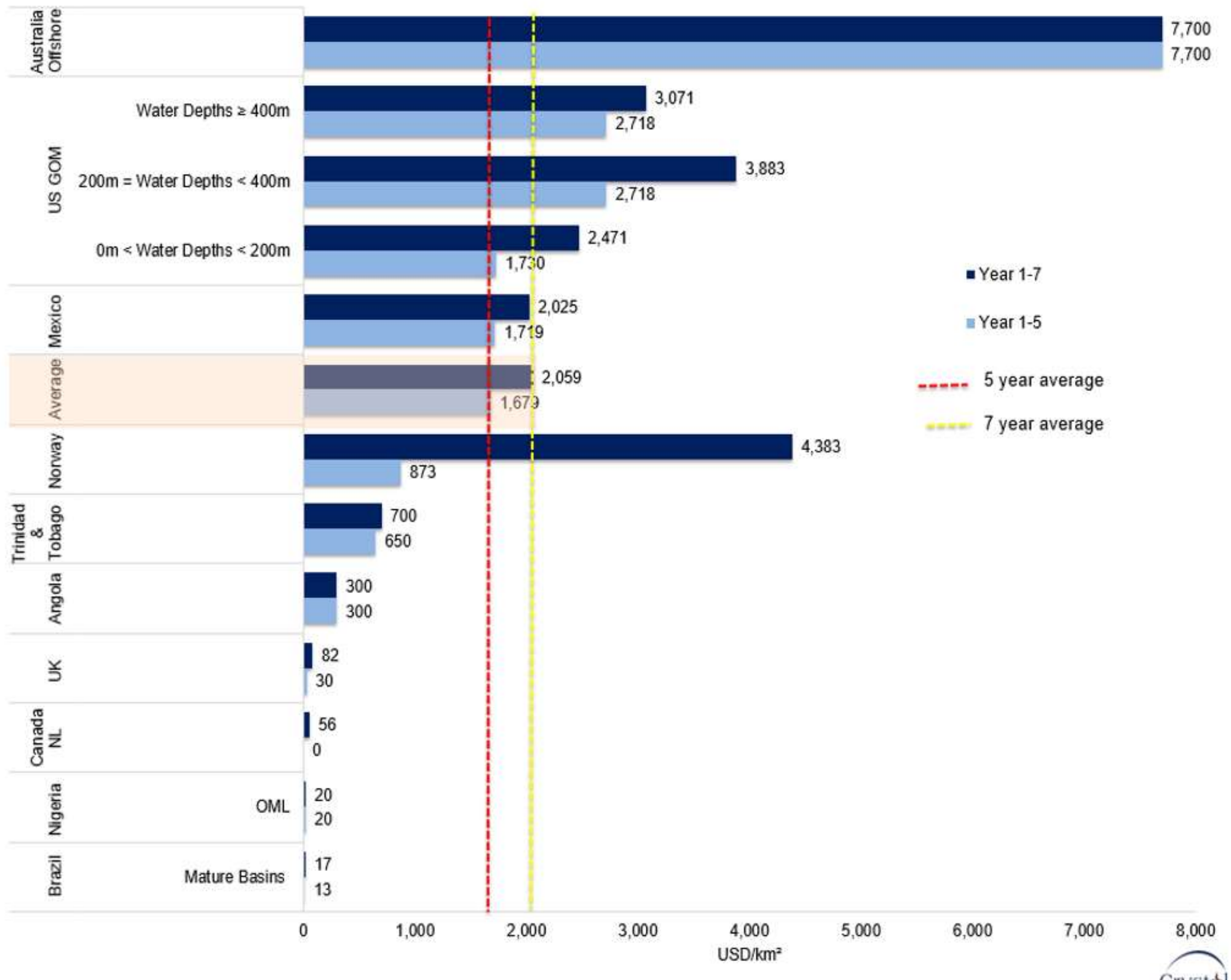


Source: ANP; Australian Government; BOEM; CNH; C-NLOPB; Federal Republic of Nigeria Ministry of Petroleum Resources; NPD; Sonangol; Trinidad & Tobago Ministry of the Attorney General and Legal Affairs, (2018). Note: The block size is the average size of the block ranges offered in each jurisdiction

6. Rental fees:

When considering the five-year average of the exploration phase for all the selected jurisdictions, the US GOM fees fall above the average, especially for leases covering water depth above 200 m, where the difference exceeds USD 1,000 per km². When the average is taken for the first seven years, the rental fee for all the leases in the US GOM exceeds the average, with the lease for water depth between 200 and 400 m nearly double the average rate. Furthermore, there is no clear rationale behind US GOM rental fees whereby leases between 200 and 400 m attract the highest fee from year six, while leases for shallow water (less than 200 m) have the lowest fee for the first five years. The US Government should consider, at the very least, aligning its rental fees with global norms. Some countries impose high rental fees, which can be waived if the investor carries out a specific work program, to encourage exploration activity. Such a 'carrot and stick' approach to lease rentals allows the government to impose high fees where little or no activity is taking place but offer the opportunity for the investor to have the fees waived or materially reduced where there is clear evidence of activity. It would probably be best to link the rentals to annual expenditure outcomes on each lease. License rentals are simply there to influence behavior and encourage activity, not as a primary source of government revenue.

Five and Seven Year Average Rental Fee



Source: Angola Petroleum Tax Law; ANP; BOEM; C-NLOPB; OGA (2018); EY (2017); Nigeria Petroleum Act (2004)

Fiscal Policy

Prima facie, the headline rates for US GOM look competitive and compelling, comprising just Royalty in the range 12.5 percent to 18.75 percent and federal CT 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 up-front 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 meaning that Government Take (total tax/total pre-tax cash flow) rises as profitability falls. Ideally, fiscal regimes should be progressive or neutral so that Government Take falls or remains static as profitability falls. Post-tax returns are significantly lower than pre-tax returns, rendering some profitable projects pre-tax into unprofitable post-tax, suggesting that they would not be developed.

The current US GOM fiscal regime is essentially a legacy regime shaped for the environment several decades ago when exploration programs could deliver a large number of highly profitable and volumetrically large discoveries. Competitor basins, both domestically and internationally, were not perceived as challenging the attractiveness of the US GOM as the leading destination for upstream investment. The fiscal regime has been amended frequently to preserve the high rates of Royalty when the economic evidence suggests that terms should have been improved to encourage the development of marginal fields. The regime is 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.

Fiscal analysis

The study ruled out any changes to the system of competitive bidding used to allocate licenses. The system has proved to be a highly successful element of the fiscal regime for many decades, raising over USD 255 billion (in real terms). The study takes the view that it is difficult for the industry to mount a coherent objection to such a system when it is entirely a matter for individual companies to determine how much they choose to bid, if at all.

Similarly, it is challenging, on the grounds of feasibility, to recommend further material changes to the basis of federal CT, in the light of the recent tax reform. In any event, with the CT rate now at 21 percent, any changes to the tax base are very diluted in terms of financial impacts. Nevertheless, the impact of uplift on capital costs has been evaluated along with immediate expensing of exploration costs.

The much-acclaimed Norwegian exploration tax refund approach has been investigated but it is important to remember that this benefit is simply a timing difference and would only be of benefit to those investors who are currently not in a tax paying position in the US GOM. The Norwegian mechanism simply refunds 78 percent of the exploration costs for an investor not currently tax paying; this is then recaptured once the investor becomes tax paying in Norway.

There would, however, be some value in current taxpaying investors having the ability to immediately expense exploration and appraisal costs 100 percent, as incurred. The impact of this in the US GOM would be relatively modest as the tax shelter is 21 percent compared to 78 percent in Norway. For the assumed exploration program of USD 300 million in this analysis, the projected benefit of such accelerated deprecation would be in the range USD 31 million to USD 39 million.

Arguably the most effective mechanism to encourage exploration, in terms of above ground frameworks, is a competitive, stable and profit-related fiscal regime rather than specific incentives for exploration alone. The latter is likely to result in the government taking a greater share of the exploration risk than of the underlying project reward - a situation the government may be unwilling to contemplate on a sustainable basis.

The analysis has therefore primarily focused on Royalty, the impact of the current regime and the potential reform options that could be considered.

The study concludes that the current regime is particularly damaging to small and economically marginal fields. Many projects which are economic pre-tax are projected to become significantly uneconomic post-tax due to the regressive impacts of the Royalty regime - deepwater projects particularly so given the higher 18.75 percent Royalty. The US authorities recognize the investment disincentive that the Royalty regime imposes and have devised, over the years, a complex tapestry 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. For example, the suspension volumes are, in principle, a very effective measure to improve the economic returns of marginal and small fields. Nonetheless, given that the relief is withdrawn once prices exceed USD 43/bbl, it is questionable whether this really features in investment appraisal decisions.

Similarly, having lower Royalty rates only in shallow water seems perverse when deeper waters have higher costs, longer lead times and higher development risk. Marginal fields can occur in any water depth but those in deepwater suffer a more onerous fiscal regime. The problem with the suspension volumes and lower Royalty rates is effective targeting; inevitably these reliefs will be granted to some highly profitable fields that do not require them, whilst more deserving projects may miss out. The solution is a Royalty framework that reflects underlying project profitability.

The study evaluated several Royalty options to ascertain what framework is most effective and reflective of underlying project profitability; these are summarized below:

Scenario	Description
1	Current US GOM fiscal regime with 12.5% Royalty
2	Current US GOM fiscal regime with 18.75% Royalty
3	Current US GOM regime with 18.75% Royalty and suspension volumes
4	Royalty rate determined by IRR (or ROR)
5	Current US GOM regime with Royalty calculated on net revenues
6	Current US GOM regime with Royalty deduction for capital costs
7	Current US GOM regime with uplift for CT at 25% with 18.75% Royalty
8	Current US GOM regime with uplift for CT at 50% CT with 18.75% Royalty
9	Current US GOM regime with exploration costs expensed

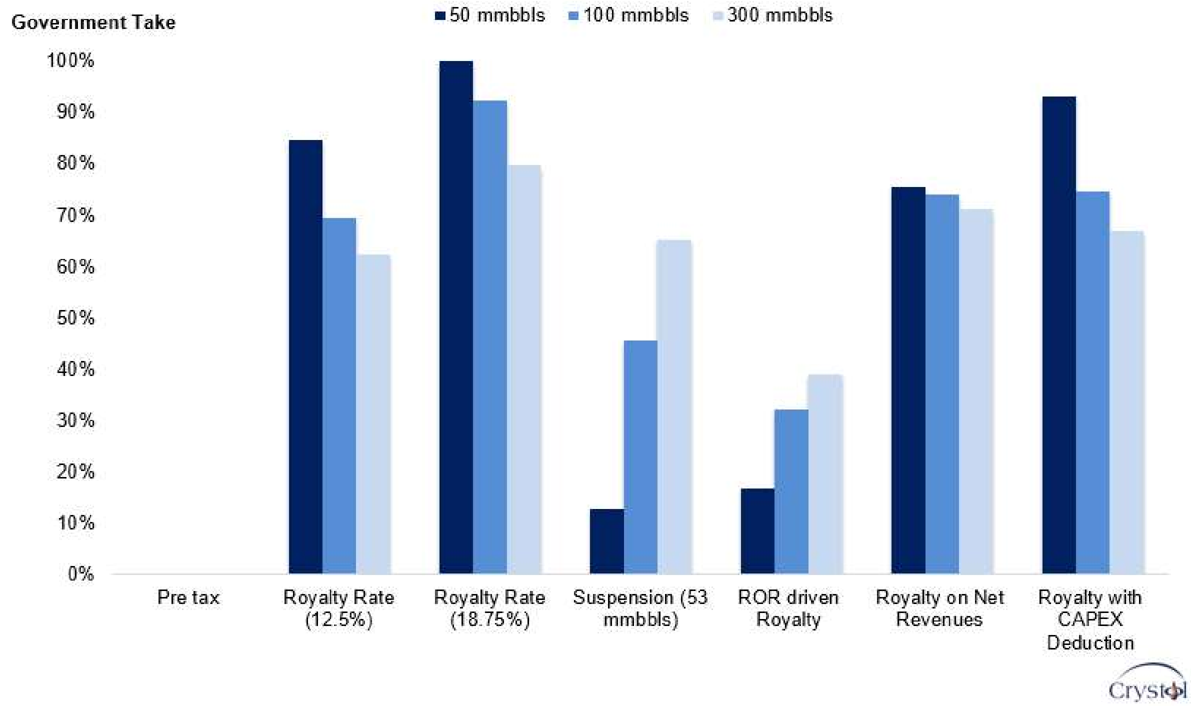
The projected outcomes for each of these in terms of Government Take from three different field sizes is illustrated in the following graphs at USD 50/bbl and USD 60/bbl oil price.

The analysis confirms the high levels of Government Take under the current regime and leads to the conclusion that the most effective Royalty regime is where the Royalty structure is determined by the realized post-tax ROR. As the project returns increase, so will the rate of Royalty. Also, under our proposed framework, the Royalty rate is zero until payback is secured and then rises in tranches to a top Royalty rate of 18.75 percent.

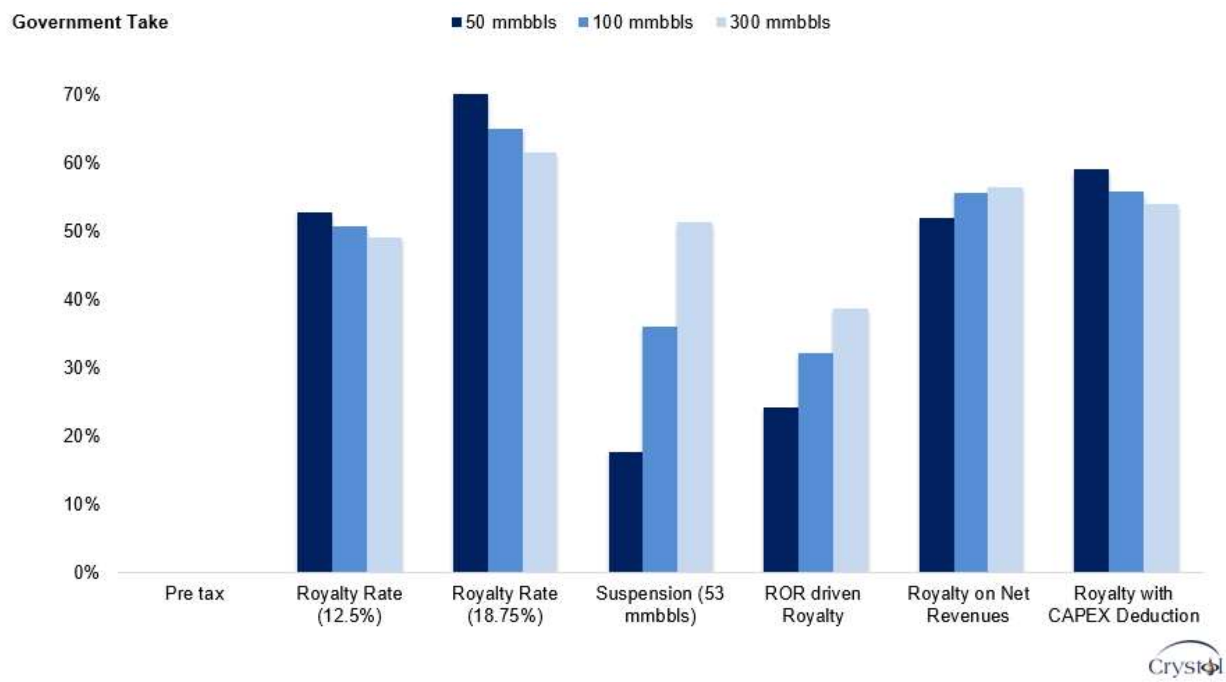
The clear impact of such a regime is that the overall tax regime flips from being regressive to progressive: the most profitable projects pay the highest Royalty and vice versa. The presumed effect of such a regime would be to encourage many marginal projects, those profitable pre-tax, to be developed that might otherwise remain stranded.

Furthermore, the analysis demonstrated that this profit-related regime significantly improves the EMV of future exploration. Such a regime may appear complex to implement and monitor, though there is extensive international experience of tax rates linked to project profitability, particularly in PSC regimes.

Government Take under Different Royalty Options at USD 50/bbl



Government Take under Different Royalty Options at USD 60/bbl



If this proposal is too radical, then the analysis concluded that an increase in the price threshold for suspension volumes would have similar effects though this does risk giving a large benefit to profitable projects that do not require such assistance.

Both the price withdrawal threshold and the quantum of the suspension volume would merit from further consideration to widen the range of applicability. For example, a linear tapered withdrawal of the suspension volume over a higher range of oil prices could be more effective. Other Royalty options such as permitting the deduction of operating costs from revenue before the application of the Royalty rate make the fiscal regime more neutral and less regressive but would not be as effective in assisting marginal fields as an ROR-determined Royalty.

The impact of uplift on capital investment has also been evaluated assuming rates of 25 percent and 50 percent. Once again, the projected impacts are diluted by the comparatively low rate of CT at 21 percent. The improvement to project NPVs ranges from USD 26 million (25 percent uplift) to USD 302 million (50 percent uplift) for the 50 mmbbls and 300 mmbbls projects, respectively. These outcomes are price independent and clearly the larger the capex spend, the greater the projected NPV benefit. It should be noted that countries, which allow uplift, do not normally allow tax relief for interest, which may be a concern to some investors.

The analysis also carried out some simple benchmarking of the US GOM fiscal regime with the UK (currently considered to be the most attractive upstream regime) and Mexico (due to its proximity). As expected, the UK has, by some margin, considerably more attractive terms for investors and there is little evidence of the fiscal regime preventing projects that are economic pre-tax from proceeding, with projected returns identical pre- and post-tax for marginal projects. The US GOM and offshore Mexico offer similar returns and a similar burden of Government Take. However, the potential for large or even giant discoveries in Mexico represents a unique selling point that US GOM cannot come close to emulating. At this stage of maturity, the US GOM ought to position itself to have a fiscal regime considerably more attractive than Mexico and more like the UK.

Fiscal analysis recommendations

The analysis supports the following recommendations for further dialogue and engagement between the industry and the authorities, with a view to improving to competitiveness of the US GOM fiscal regime.

1. Replace the existing Royalty regime with Royalty rates determined by realized project post-tax ROR. The precise structure would require further modelling and dialogue with the authorities to shape the details, but a good start would be zero Royalty until payback and then progressively higher towards a top rate of 18.75 percent.

2. If the above is too radical, then consider a restructuring of the suspension volume mechanism with a view to raising the price trigger, withdrawing the suspension volumes more gradually and revising the level of suspension volumes.

3. If both the above Royalty options are judged to be unachievable in the short term, then the rationale under the current regime for higher Royalty at greater water depths should be subject to rigorous scrutiny. This differentiation appears perverse and should be challenged on the basis of its potential distortionary impact. As the basin matures and developments become more marginal, irrespective of water depth, then royalty rates should be reduced.

4. Permit the immediate expensing as incurred (100 percent in year one) of all future exploration and appraisal costs to assist in improving the EMV outcomes from future exploration.

5. Consideration could also be given to the feasibility of a limited capital uplift of 25 percent to be applicable to investment on all future developments. However, we recognise the challenge of introducing such a measure given the benefit to industry of the recent headline rate reduction. This provision could be targeted by limiting the measure to future discoveries only but that risks disadvantaging existing undeveloped discoveries. We would regard this as a lesser priority than the proposals for Royalty reform.

6. Although the study evaluated some changes to the federal CT, any proposal that involves a change in federal tax law, including increased or accelerated R&D deductions, depreciation or tax credits or the introduction of a lower tax on income from patents is unlikely to be feasible given the comprehensive tax reform that was only enacted at the end of last year. It may, however, be possible to make changes at the state tax level in respect of onshore R&D activity.

1. Introduction

The US Gulf of Mexico (GOM) is one of the oldest producing oil and gas deepwater provinces in the world; it has gone through many cycles and witnessed numerous policy changes. These have been shaped to maintain the delicate balance between safeguarding the international competitiveness of the province for investment and generating an equitable share of revenues to the US federal Government. The future for the US GOM, however, is not like the past: the basin is maturing, and, if current trends continue, production will peak in the coming decades. The pace of the subsequent production profile will be largely dependent on the policy and regulatory framework.

Today, the mature US GOM is facing difficulties on multiple dimensions, mainly:

- the GOM itself being a high-cost/high-risk/deepwater investment region with long exploration and development life cycles;
- a complex regulatory system and a regressive fiscal regime – whereby Government Take, the share of government revenues from a project's net cash flows, falls as profitability rises and vice versa;
- the slowdown in investment courtesy of oil and gas price uncertainty;
- the return of the cost inflation cycle following the recent recovery in oil prices; and
- the looming decommissioning, which brings a whole new set of conditions to be catered for.

Of course, it is not all negative. The US GOM still contains billions of barrels in undeveloped oil and gas resources. The challenge is to ensure optimal economic recovery of these resources in the coming decades, accessing leading edge technology whilst taking advantage of the extensive network of existing infrastructure.

Some would argue that today there is no immediate need for action. After all, the US continues to make the headlines with its rapidly growing oil and gas production, overtaking other major producers such as Russia and Saudi Arabia, thanks to the shale revolution and production growth from the Outer Continental Shelf (OCS), particularly the GOM.

In the longer term, however, this optimistic picture is expected to change. If the maturity of the US GOM becomes increasingly more pronounced, it will likely lead to negative consequences for the economies of the GOM's states and overall US energy scene[1]. Oil demand is likely to face many uncertainties if aggressive environmental policies are pursued around the globe, improvements in energy efficiency are achieved and advancements in oil-alternative technologies are made. For oil producers in an increasingly competitive market, experience shows that the low-cost producer has always had the edge.

[1] For the economic contribution of US GOM, see for instance, the studies carried out by Calash and Northern Economics, and published by the American Petroleum Institute (API) in 2017, and the BOEM's Offshore Oil and Gas Economic Contributions (2017)

Given the global nature of the industry, competition for domestic and international capital is also likely to intensify. This dictates a real sense of urgency for US policy makers to put in place policies that will ensure that the valuable GOM resources are not economically stranded. US policy makers need to prepare for the onset of the basin's maturity which, experience indicates, can swiftly accelerate through declining interest in exploration, falling investment and decommissioning of critical infrastructure.

In the Executive Order 13795 of April 28, 2017 'Implementing an America-First Offshore Energy Strategy', the US Government acknowledges the need to maximize the efficient exploitation of its oil and gas resources, which are "important to a vibrant economy" and "national security". "It shall be the policy of the United States to encourage energy exploration and production, including on the Outer Continental Shelf, in order to maintain the Nation's position as a global energy leader and foster energy security and resilience for the benefit of the American people", the Executive Order asserts.

The objective of this study is to analyze whether existing US GOM licensing and fiscal policies support the achievement of such national aspirations or, on the contrary, hinder the exploitation of the increasingly difficult oil and gas resources. The study takes a long-term view, assessing whether the current system, which may have well worked in the past, remains appropriate for a maturing province, in an increasingly competitive market.

The study proceeds as follows. Section 2 provides an overview of the US GOM, its past and future production trends as well as emerging challenges. Section 3 assesses the licensing policies of the US GOM and as pursued in competing offshore provinces. The section appraises the main licensing terms and the outcomes of recent licensing rounds. Section 4 focuses on the fiscal instruments applicable to the US GOM, particularly the signature bonus, Royalty and federal Corporate Income Tax (CT) and compares them with terms found in other offshore jurisdictions. The section also models evolutionary options to improve the regime currently in place. Section 5 presents the recommendations based on the findings of the analysis.

The conclusions in this study are based solely on government and other public information and Crystol Energy's own expertise and analysis.

2. US Gulf of Mexico Overview

The US oil and gas industry is experiencing a renaissance in production that has transformed its domestic long-standing energy challenges and fundamentally altered global oil and gas market dynamics. After reaching a peak of 9.6 million barrels per day (mmbbls/d) in 1970, U.S. oil production shrank steadily for four decades. This inexorable decline was halted in 2009, when tight oil began to reach the market in large quantities. Similarly, in 2011, U.S. natural gas production exceeded its previous peak from 1973 and has continued on a new path of expansion. Concerns about energy security and reducing dependence on imports particularly from the Middle East - a top priority of successive US presidents since the first oil shock in 1973 - have been replaced by a more assertive global 'energy dominance' stance. In 2017, largely thanks to its unconventional oil and gas resources, the US became a net exporter of gas and is expected to become a net exporter of oil in the late 2020s, materially expanding its share of world oil production, which increased from 8.0 percent to 13.5 percent between 2007 and 2017.

This is the narrative that is much discussed and debated in international quarters. What seems to have been given less attention, however, is the other long-established producing provinces particularly the US GOM. Amid the shale hype and declining oil prices, interest in deepwater areas, such as the GOM, appears to have waned.

It is premature to be dismissive when such large unexplored and undeveloped resources remain to be exploited. The GOM still provides around 17 percent and 5 percent of total US oil and gas production respectively, with significant economic spillovers in terms of investment, job creation and taxes paid, to name but a few. Although US GOM gas production has been declining, oil production continues to surprise with new production records achieved on an annual basis since 2016.

The output increase has been largely due to the development of fields that were discovered many years ago and brought on stream during the preceding period of high oil prices between 2011 and 2014, which saw prices exceeding USD 110 per barrel (/bbl). A key difference between conventional (e.g. offshore GOM) and unconventional oil (e.g. onshore tight oil) is the lead time between making the initial investment and bringing the first production on stream. For conventional oil, this will take many years or even decades. With tight oil, however, the investment cycle is much shorter and the lead time has shrunk to months. So, today's conventional oil production is the result of exploration carried out at the turn of the century and investment decisions made years ago.

Furthermore, it is worth noting that while oil production has recently increased from US GOM, the magnitude of proven oil reserves has gone in the opposite direction, indicating that the reserves replacement is not being maintained (Figure 1).

When the oil price entered the 'low band' phase (Figure 2), many oil and gas projects were cancelled, others postponed indefinitely. The US GOM, a high-cost province where most of the production comes from deepwater, was no exception.

Figure 1: US Gulf of Mexico Oil Production and Proven Reserves

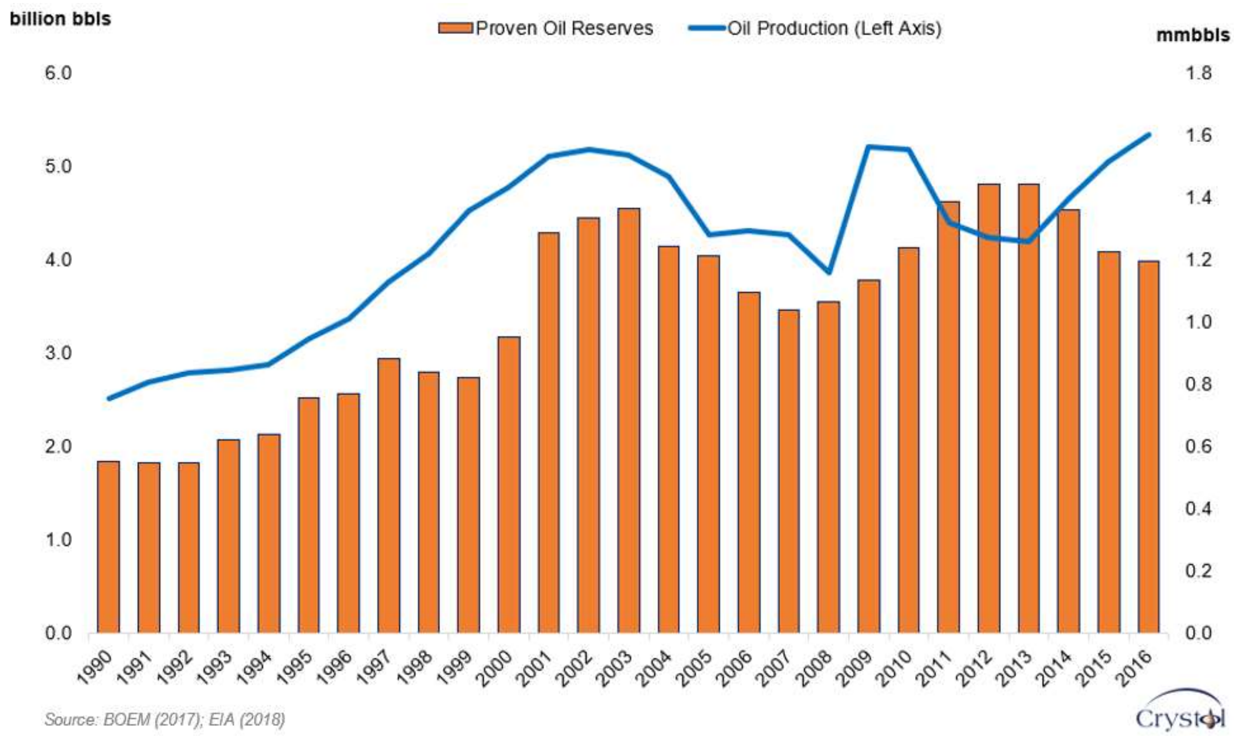
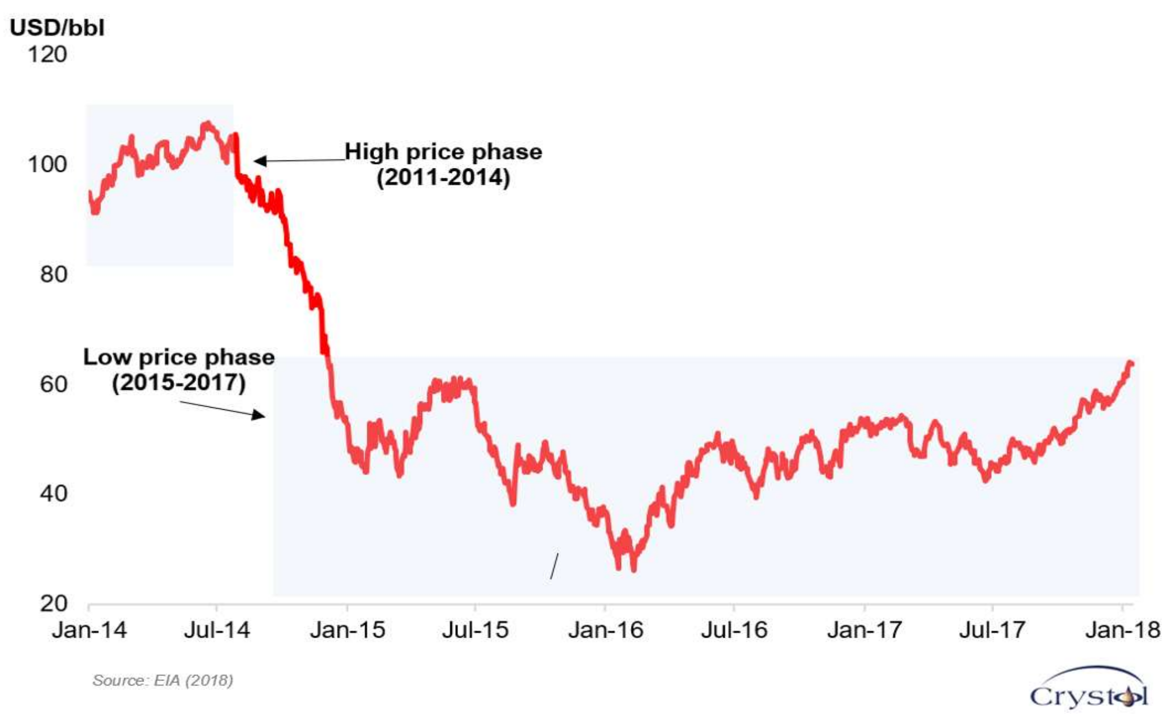
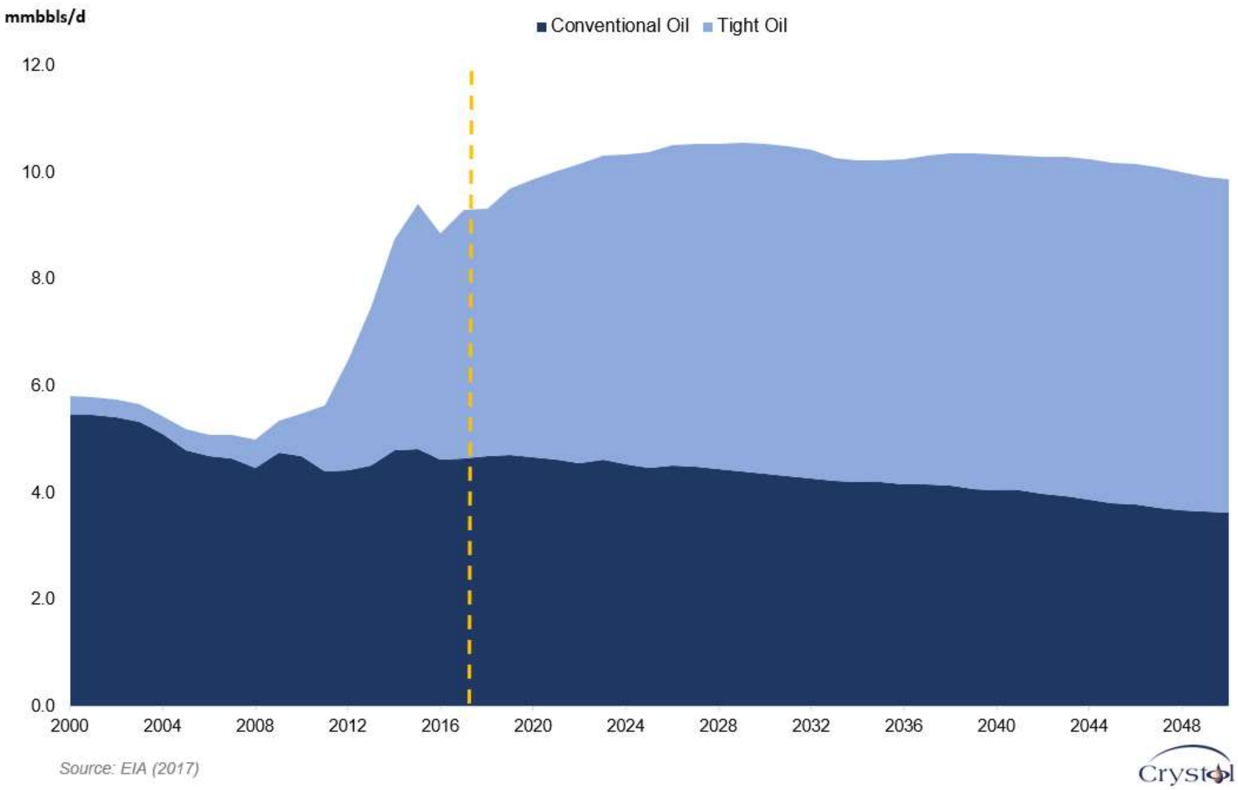


Figure 2: Oil Price (WTI): from High to Low



According to the US Energy Information Administration (EIA, 2016), decreasing profit margins and reduced expectations for a quick oil price recovery have prompted many US GOM operators to retreat from future deepwater exploration spending. Also, the industry has become and remains cash constrained. Whilst the oil price has shown some recovery through 2017 and 2018, the industry will likely maintain cautious investment levels due to fears of prices falling back to below USD 50/bbl again. These facts suggest that, if investment is not restored to levels of five years ago, the US GOM will start to mature, eroding the prospects for increasing exports and reducing dependence on imports, even if tight oil production is maintained (Figure 3).

Figure 3: US Conventional and Tight Oil Production (2000-2050)



As the International Energy Agency (IEA) states, in its 2017 World Energy Outlook, "if conventional project approvals do not pick up, then the surge in US tight oil would face the daunting task of compensating, largely on its own, not only for demand growth but also for the continual drain on supply caused by declining production from existing fields" (p. 96).

To maintain future production growth from conventional oil, investment needs to be encouraged today. The necessary investment to keep decline at bay, however, is far from assured, and the regulatory framework is important in making investment decisions. A combination of commercial and non-commercial factors comes into play when assessing the competitiveness and attractiveness of an oil and gas province. Investors seek to achieve reasonable returns at an acceptable level of risk. They compare the expenditures to be incurred with the potential rewards.

The evaluation looks at factors such as geological potential, commercial prospectivity, cost structure, political risks, and of course, fiscal terms. The end-result of this process permits opportunities to be ranked across the global portfolio.

In the current age of oil abundance and lower prices, governments around the world compete for international capital to increase production to safeguard and expand their share in an increasingly competitive market. Assets of national oil companies (NOCs) are being privatized, legislation revisited, and fiscal regimes revised, with the predominant intention of attracting more investment and improving the competitiveness of their country for international capital.

The success of the US GOM is a unique testament to the importance of government policy, which can outweigh the impact of factors that go beyond government control, such as the oil price. After a decline in activity in the 1990s, the US GOM was beginning to be viewed as a 'dead sea' for exploration. Yet activity recovered, following the introduction of the Deepwater Royalty Relief (DWRR) in 1995, which contributed to giving a new lifeline to the province and unlocking more of its potential. The US Government also provided decades of stability in the overall structure of the fiscal regime. This gave investors' confidence that retrospective tax increases were unlikely and that the GOM would continue to have one of the most competitive tax regimes in the world.

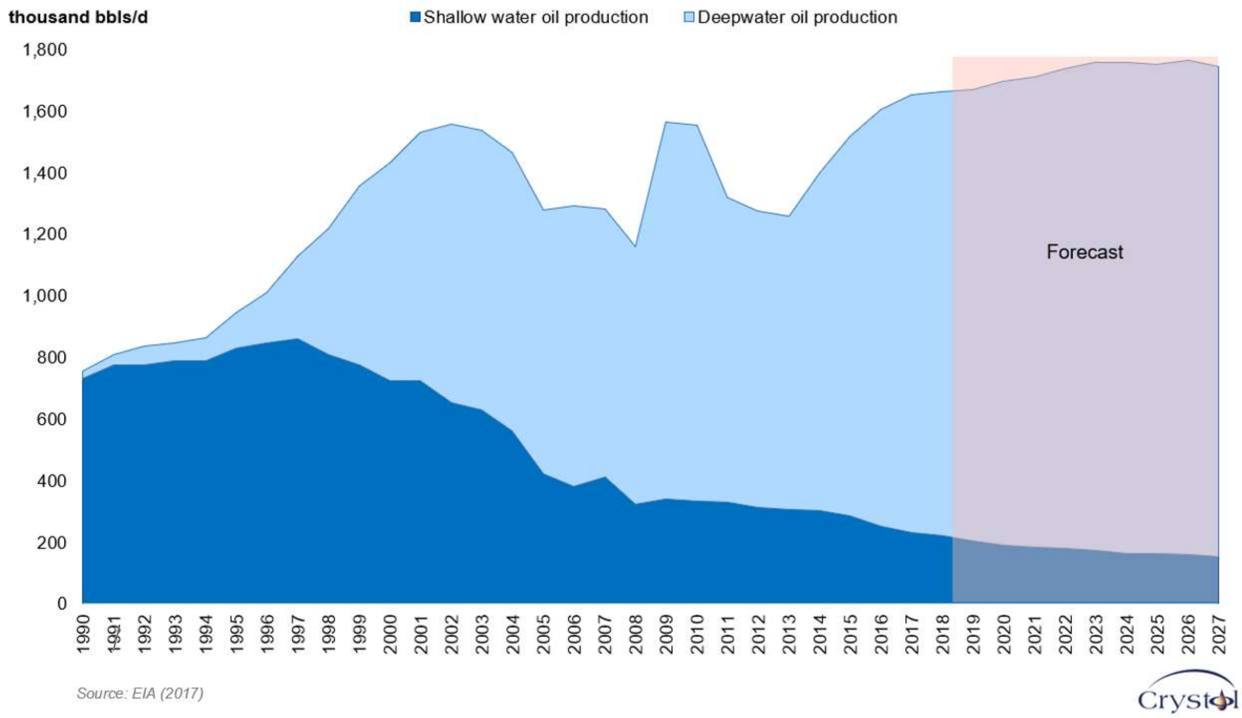
More recently, the US government introduced broad-based tax reform which should in principle boost activity across the country. The reduction in the headline CT rate from 35 percent to 21 percent will be shared by the oil and gas industry and should, in particular, benefit legacy production. It will also improve the economics of new developments, though for many of these, especially marginal projects, the regressive nature of the Royalty regime continues to be a major disincentive.

Today, the US GOM faces competition on two fronts: domestically and internationally. Within the US and lower 48, the GOM faces a major competitive disadvantage to shale, which benefits from low cost and low risk, with swift payback where a new well can deliver new production within months and payback within a year. In contrast, for deepwater which has become the main contributor to GOM production (Figure 4), the payback can be measured in years and even decades. Investors may increasingly take the view that the oil price outlook is too precarious to deliver the returns required over such a long period and turn their focus to those projects that can deliver a swifter payback.

Internationally, the competitive pressures are more complex. Looking at other Organization for Economic Co-operation and Development (OECD) countries, the US GOM offers more materiality than the UK and Australia but lags close competitors such as Mexico and Brazil, as well as Norway which also offers low risk returns[2] (Figure 5).

[2] Further discussed in Section Four

Figure 4: US Gulf of Mexico Oil Production: Shallow and Deepwater



One could argue that one of the most significant attractions of the US GOM to investors is the existing legacy of infrastructure, namely platforms, pipelines and processing terminals. This should make the exploitation of new discoveries more economic (particularly those too small to remunerate stand-alone development facilities). However, once this infrastructure begins to be removed, undeveloped resources risk being stranded[3]. This further highlights the importance of swift and accelerated development of remaining resources.

The clear focus of US policy should therefore be to optimize the extraction of domestic oil and gas resources, particularly in the GOM, whilst they can be economically extracted. The oil price will clearly be of critical importance, but it is beyond the influence of any actors. However, policy makers should be mindful that the long-term prognosis of the oil price is increasingly negative; on the one hand, there is an abundance of global oil resources, and on the other hand, environmental concerns and associated regulations are negatively affecting investors' sentiment. Without a more explicit emphasis on accelerating basin exploitation, there is, therefore, the growing risk that significant oil and gas resources will never be exploited.

The following sections will investigate whether the existing US GOM policies – first as related to licensing, then to the fiscal regime – can fulfil such a requirement, taking into consideration what is offered in competing offshore provinces, and, if not, what needs to be done to improve the investment climate in the US GOM.

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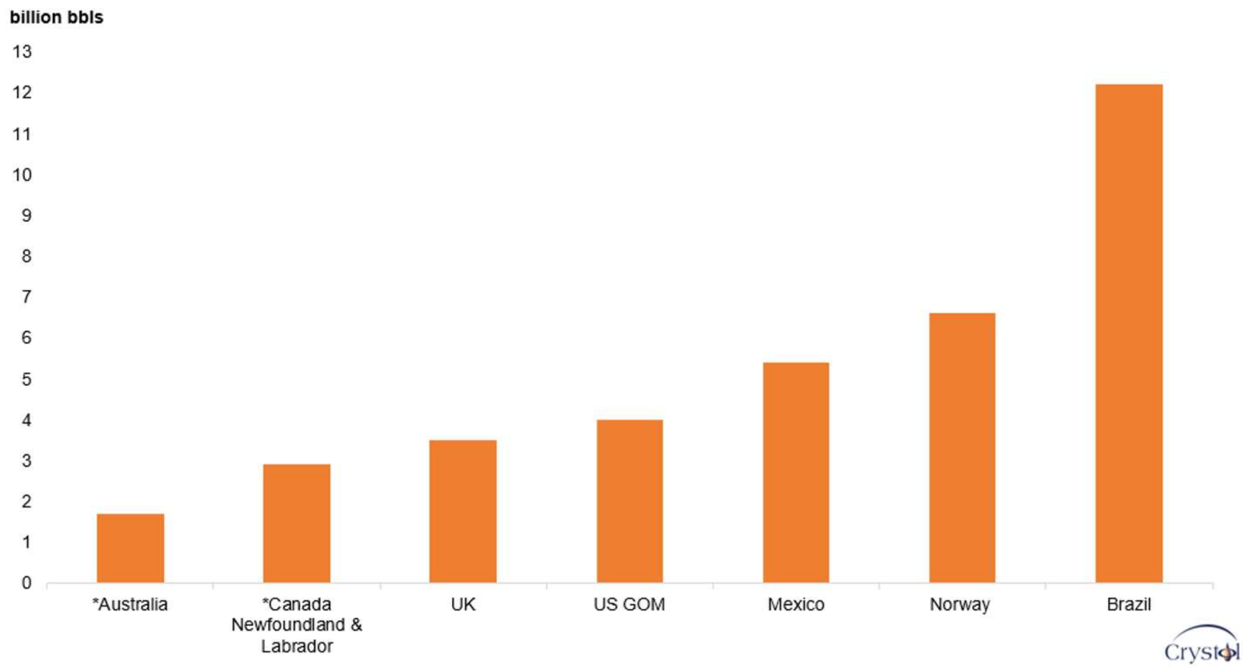
[3] Decommissioning deserves special attention given the size of the challenge ahead, though this goes beyond the scope of this study.

Figure 5: Offshore Proven Oil Reserves in Selected Countries



*Source: Australian Government; ANP; CNH; EIA; NPD; OGA (2018); CAPP (2017). Note: * latest data available is for 2014*

3. Licensing Policy

Although host governments can have different priorities for their oil and gas sector, they are aligned on core objectives such as maximizing recovery and production, establishing an internationally competitive industry and supporting the wider economy. The licensing policy is one of the most important tools that governments use to attract the most competent operators and maximize economic recovery.

The objective of this section is to analyze the licensing policy in the US GOM and compare it with those of nine jurisdictions with prominent offshore oil and gas sectors, to determine whether the US GOM is following best practice in all dimensions. The selected jurisdictions and their government objectives for the sector are listed in Table 1.

Table 1: Government Priorities for their Oil and Gas Industry

Jurisdiction	Key Government Priorities
US GOM	To allow for safe and responsible domestic oil and natural gas production to support economic growth and job creation and enhance energy security
Angola	To protect the national interest, promote the development of the employment market, protect the environment and the rational usage of petroleum resources and increase the country's competitiveness on the international market
Australia (Offshore)	To encourage petroleum exploration in Australia's offshore areas and to provide a stable, transparent and internationally competitive offshore exploration investment regime
Brazil	To establish of an industry with a significant number of players operating in each environment (pre-salt, conventional onshore and offshore), revitalize mature fields and increase exploration activity in frontier basins, following these principles: preservation of the national interest, promotion of the sustainable development, expansion of the job market, appreciation of the energy resources, protection of the environment, promotion of energy conservation, increment of gas use, promotion of free competition, sourcing of investments in energy production, and expansion of the country's competitiveness in the international market
Canada Newfoundland & Labrador	To be an internationally preferred location for oil and gas exploration and development driven by an innovative, sustainable, local industry that is globally competitive, environmentally responsible and maximizes benefits to the people of the province
Mexico	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
Nigeria	To create a market driven oil and gas industry and maximize production and processing of hydrocarbons
Norway	To ensure high value creation through efficient and environment-friendly management of Norway's energy resource. This should be done in the best interest of the Norwegian society
Trinidad & Tobago	To optimally exploit the country's hydrocarbon resources ensuring efficient administration to obtain the greatest returns to the country for the benefit of all citizens
UK	To maximize the economic recovery of the UK's oil and gas resources

Source: Australian Government Department of Industry, Innovation and Science; Government of Newfoundland and Labrador Department of Natural Resources; Government of the Republic of Trinidad & Tobago Ministry of Energy and Energy Affairs; National Agency of Petroleum, Natural Gas and Biofuels ANP; Norwegian Government Ministry of Petroleum and Energy; UK Oil and Gas Authority (2018); Federal Republic of Nigeria Ministry of Petroleum Resources (2017); Bureau of Ocean Energy Management (2016); Presidencia de la República México (2013); Republic of Angola Petroleum Activities Law (2004); National Agency of Petroleum, Natural Gas and Biofuels ANP (1997)

The section starts with a comparison of the licensing terms across these jurisdictions (Sections 3.1-3.4) then analyzes the results of licensing rounds carried out and concluded between 2016 and 2018 in these provinces (Section 3.5).

3.1. Allocation Method

All the selected provinces in Table 1 above use licensing rounds to allocate oil and gas rights, albeit with varying regularity and success. As of 2018, more than 50 licensing rounds are planned around the world. Brazil and Mexico are pursuing an aggressive licensing policy, having announced several rounds per year, after a moratorium of several years in the case of Brazil and a ban of decades in the case of Mexico.

Between 2008 and 2013, Brazil did not hold any licensing rounds. The decline in oil prices and the series of scandals embroiling its oil and gas sector negatively impacted industry activity. To reverse the declines in production and investment, Brazil introduced regulatory and fiscal energy reforms in 2015 and has since planned three rounds yearly, depending on opportunities such as marginal fields and pre-salt area (Box 1). A total of nine rounds are scheduled between 2017 and 2019. Mexico also adopted major energy reforms in 2013/14 which ended the 75 years of PEMEX monopoly and opened its oil and gas sector to international investment. Since then, four calls for bids are held every year, targeting different opportunities (e.g. shallow water, deepwater and onshore) with a total of three rounds (10 calls for bids) between 2014 and 2018[4].

Box 1: Brazil's Energy Reforms

Brazil's NOC, Petrobras, had a monopoly over upstream activities until 1999, at which time the policies shifted to a heavily regulated concessionary system.

Large discoveries in the Campos and Santos basins (hereafter referred to as pre-salt) in 2007 led Brazil to enact specific policies related to the pre-salt basins with the goal of maximizing societal impacts through significant government revenue. The new framework, under the umbrella legislation called the Pre-Salt Law, required Production Sharing Contract (PSC) and Petrobras as the sole operator.

A combination of the legislative burden of drafting of new laws, falling oil prices, and controversies surrounding Petrobras led to a moratorium on the award of new offshore licenses – said aspects culminated in a larger reform process that began in 2016 with the goal of facilitating Petrobras divestment and attracting international oil companies (IOCs) to invest in the country.

Licensing rounds are increasingly popular given that they are more transparent than direct or bilateral negotiations. They also build on the competitive instinct of oil and gas companies, usually resulting in a better outcome to host governments. For most of the provinces surveyed, this is the

[4] Each round has four calls for bids, e.g. Round 1 has the following calls for bids: 1.1, 1.2, 1.3 and 1.4.

only allocation method. Some countries, like Angola, revert to direct negotiations and out of round awards in case of an unsuccessful round. The UK can receive out-of-round applications although that is increasingly rare.

In most cases, the schedule for the licensing rounds is known in advance and the rounds are held on a regular basis. Of the analyzed jurisdictions, only Angola, Nigeria and Trinidad and Tobago held irregular rounds.

In the US, the leasing strategy is based on a five-year program announced by the Secretary of the Interior. The auctions are usually held on a yearly basis. In Canada Newfoundland and Labrador, the frequency depends on the opportunities on offer: For low activity, it is a four-year cycle. For high activity, it is a two-year cycle and for mature basins it is a one-year cycle. Norway holds two types of rounds, giving companies access to exploration acreage in both mature and frontier areas: 1) Numbered licensing rounds for the least explored parts of the shelf (frontier areas) usually every other year; and 2) Awards in predefined areas (APA) for mature areas that have been awarded in previous ordinary license rounds and relinquished, held yearly.

In contrast, Trinidad and Tobago announced a new bidding round in 2018, five years after the last round in 2013. Angola also experienced a gap of more than five years between licensing rounds. The last successful round was held in 2011. Interestingly, in the 2005/6 round, Angola received a record breaking signature bonus in the history of the international oil industry. But this has been hard to replicate since, because of a combination of above ground factors, with the oil price and government policies being the main causes (Box 2).

In Nigeria, the last bidding round was held in 2007. A new round focusing on marginal fields is planned for 2018, after years of delays. The decline in oil prices in 2008 and more importantly the publication of the draft Petroleum Investment Bill (PIB), which created a high level of fiscal uncertainty, discouraged investment. The governance part of the PIB was finally passed into law in 2017.

Box 2: Angola's Turn of Fortunes

Licensing Round 2005/06: Remarkable success

In the licensing round of 2005/06, Sonangol invited companies to bid for seven offshore blocks, including relinquished exploration areas of blocks 15, 17 and 18. Competition was intense with over 50 companies qualifying. Bidding was aggressive: Eni offered USD 902 million (nominal terms) for a 35-40 percent operated interest in Block 15/06. Blocks 17/06 (known as the golden block of deepwater Angola) and 18/06 received the highest signature bonus for a block in the history of the oil industry with Sonangol-Sinopec offering USD 1.1 billion for each block.

Licensing Rounds 2008 then 2010/11: Cancellation and last success to date

Angola announced a licensing round in 2007/08, hoping to replicate the success story of the previous round in 2005/06, but the round was cancelled. Another round was announced in 2010/11. The round was successful, but bidding was subdued compared to the previous round. The largest signature bonus was around USD 500 million and only 13 companies pre-qualified.

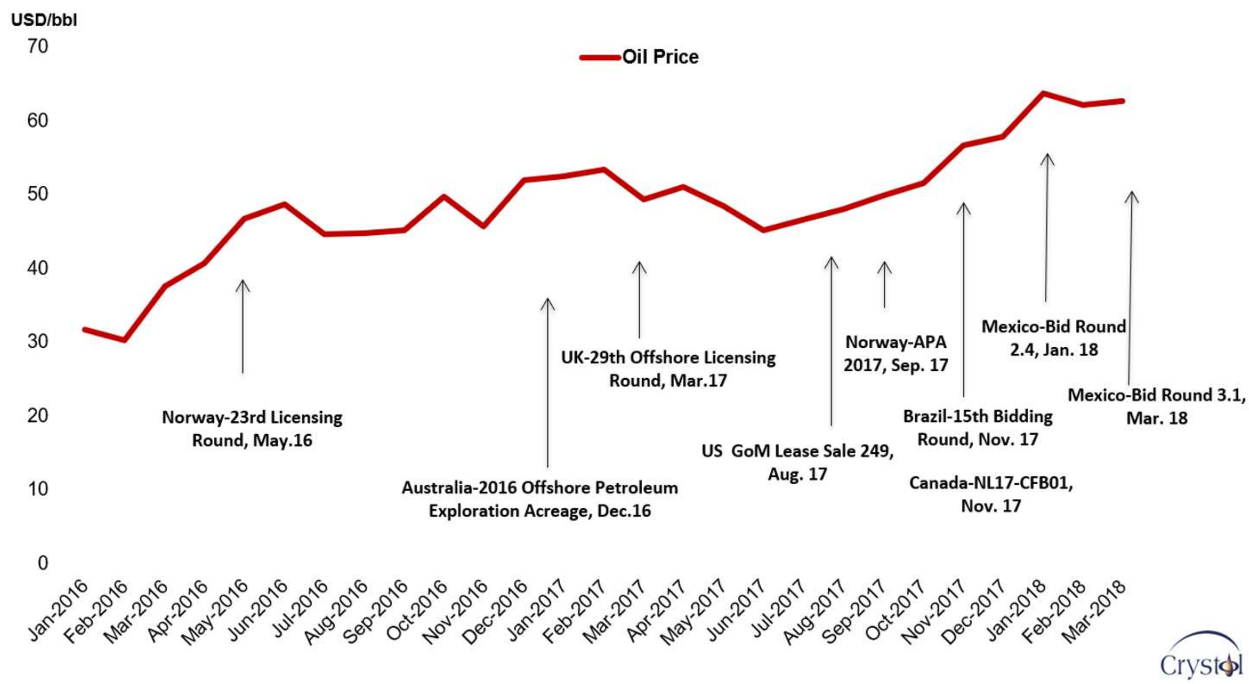
Several factors shape the outcomes of a licensing round - its success or failure in terms of attracting investment and aggressive bidding. The oil price is one of them.

Experience shows that during periods of high oil prices, companies bid more aggressively especially when competition is perceived as strong. Conversely, when prices fall, companies become much more selective reflecting cash flow and capital allocation constraints.

When licensing rounds are held around the same period, their outcomes indicate the extent to which factors other than the oil price influences investors' decisions. The license terms, which are analyzed in this section, play an important role along other decisive factors, such as the geological potential, the availability of, and access to, infrastructure and the fiscal regime[5].

The sections below focus on licensing rounds held and concluded in the selected jurisdictions between 2016 and 2018 (March), as shown in Figure 6. Other licensing rounds took place over the same period, but the awards are yet to be finalized.

Figure 6: Licensing Rounds 2016-2017 and Oil Price (Spot WTI)



Source: ANP, Australian Government, BOEM, CNH, C-NLOPB, EIA, NPD, OGA (2018)

[5] See Section 3.3

3.1. Restrictions

3.1.1. Bidders List

The US stands out in terms of imposing a restriction on joint bidders, where some companies are not allowed to place a joint bid. This goes back to 1975 when producers with international petroleum production greater than 1.6 mmbbls/d were prohibited from joining together in bids for federal offshore leases.

The rationale behind such a policy is to preserve competition. No evidence of the effectiveness of this policy, however, was found[6]. Besides, the restriction was introduced around the time of the heightened political rhetoric surrounding the dominance of the 'Seven Sisters'. Today, the structure of the oil industry is fundamentally more diverse and less concentrated from where it was in the 1970s. Experience from other countries also shows that competition can be maintained without such restrictions.

In its earlier days of offshore activity, Norway required that the companies applied for licenses individually, after which the authorities decided owner shares and operatorship, in an attempt to counter the market power of established alliances among companies. This so called 'forced marriage' policy was eventually abandoned and today group or joint applications are allowed, since such applications reduce application costs and result in consortia with members that are more aligned with each other[7]. If several companies apply as a group, the Norwegian government has the right to assess the composition of the group and recommended operator. Companies that apply individually may be added to a group or several companies that apply individually may be awarded ownership interests in the same license. The UK also practices similar discretion.

In Angola, the licensing rounds of 2005/06 and 2010/11 required bidders to submit their applications individually, indicating whether they wished to be operators and the share of the participating interest that they wanted to acquire in the blocks applied for. In this respect, joint bidding was restricted. The government would decide on the composition of the participating interests in each block and the operatorship. In the 2014 call for bid (though the round was later cancelled), the authorities allowed individual and joint bidding applications. Today the main restriction is that any company that wishes to carry out petroleum activities there may only do so together with the National Concessionaire, which is Sonangol, the national oil company (NOC). As such, all petroleum activities will have the mandatory participation of Sonangol.

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[6] Iledare and Pulsipher (2007), for instance, conclude that such a policy deserves no credit for maintaining competition in the OCS. On the contrary, the authors found that the imposition of joint bid restrictions can reduce bidding effectiveness for petroleum leases on the OCS. Similar conclusions were reached by: Watkins and Kirkby (1981), Mead et al (1984) and Mulholland (1984) who found no convincing evidence for the imposition of the ban in the first place.

[7] Tordo et al. (2009)

Some licensing rounds were also by invitation only; this was the case of the rounds focusing on pre-salt as the government believed that were not many companies with technical and financial capacity to exploit such opportunities[8].

It is unlikely that many large fields around the world, including the Brent field in the UK and the Groningen field in the Netherland, would have been developed without joint ventures between the oil majors (in these examples, between Shell and ExxonMobil). As upstream exploration becomes more complex and companies operate in more challenging environments, restrictions on joint bidding can be counter-productive.

3.1.2. Pre-qualifications

It is increasingly common for potential investors to first meet specific minimum criteria to be able to apply for a license. These requirements can vary with each licensing round and with the status of companies whether operators or non-operators.

Pre-qualification can safeguard host governments against participants not having the necessary financial and technological expertise to develop oil and gas projects and deal with emergencies such as spills. Most of the analyzed jurisdictions impose pre-qualifications, particularly for the operator, though in some jurisdictions they are more prescriptive (Table 2).

According to the Norwegian Petroleum Directorate (NPD), the introduction of prequalification criteria for operators and licenses from 2000, has been one of Norway's most successful licensing/policy reforms that has been implemented to secure the successful results in the licensing rounds (Box 2).

[8] A pre-salt reservoir is a layer of oil-bearing rock, positioned under a thick layer of salt. In Brazil, it is found in the Campos and Santos basins.

Table 2: Participation Criteria in Licensing Rounds

Jurisdiction	Prequalification Criteria/restrictions on participation
US GOM	Restricted bidders' list prohibiting some oil companies from jointly bidding on a lease. Operators must prove their ability to serve as operator
Angola	Companies who want to become associates of Sonangol must demonstrate their technical and financial capacity. Some rounds (pre-salt) are by invitation only. Pre-2014, companies applied individually. Call for bid 2014, companies could apply individually or as consortium
Australia (Offshore)	Pre-qualification for cash bid whereby interested companies should provide evidence of their technical and financial competence
Brazil	Pre-qualification takes place post-bid placing, on: legal, fiscal and labor compliance, economic, financial and technical capacity
Canada Newfoundland & Labrador	Bidders should conform to the terms and conditions provided in the call for bids
Mexico	Companies must demonstrate technical (at least three exploration and production (E&P) projects, capex in E&P of USD 1 billion for operators, and financial criteria (credit rating, net worth of at least USD 1 billion)
Nigeria	Companies must demonstrate technical and financial criteria
Norway	• Relevant technical expertise • Satisfactory financial capacity • Geological understanding of the area in question • Experience
Trinidad & Tobago	Legal, Financial, Technical, HSE and Local Content; All companies must pay the bid fee
UK	Financial capacity; technical capability and environmental matters

Box 3: Norway's Successful Policy Reforms[9]

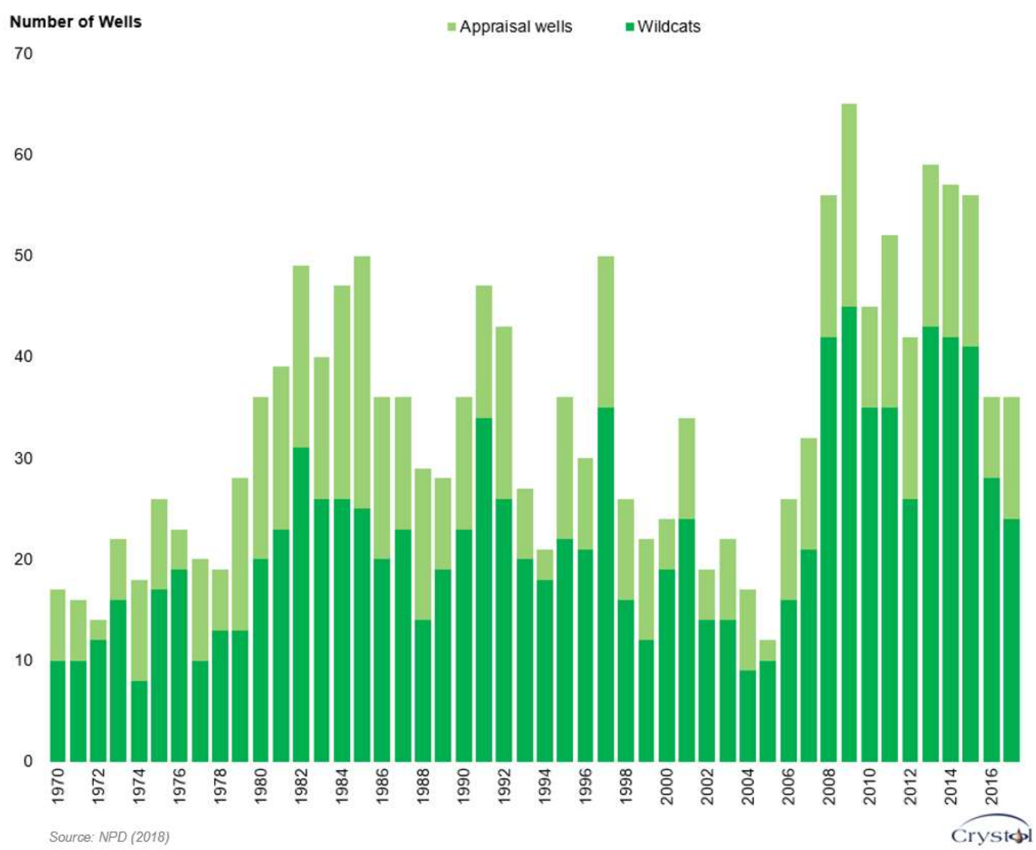
Norway's most successful licensing/policy reforms that have been implemented to get the desirable outcomes of the licensing rounds, in terms of exploration activity and diversity of players, include:

- Prequalification of operators and licensees from 2000
- APA rounds from 2003
- Refunding the tax value of exploration expenses from 2005

These measures were introduced following the period of low oil prices that marked the 1990s. The Norwegian Continental Shelf (NCS) has seen an increase in exploration activity since 2005 which has resulted in several profitable discoveries. Figure 7 shows the increase in exploration wells particularly since 2005, after reaching the lowest level in 2004/5 since the early 1970s.

Also, the number of companies active in the NCS has not only increased since, but also become more diverse. Norway is particularly attractive to small and medium sized new entrants as the Norwegian Government immediately refunds the tax relief (78 percent) associated with exploration drilling for any participant not in a tax paying position. The refund is clawed back when the participant becomes tax paying.

Figure 7: Appraisal Wells and Wildcats Spudded on the Norwegian Continental Shelf (1970-2017)



[9] Based on direct communication with the NPD

3.2. Application Fees

All the jurisdictions surveyed, except the US, impose an application or registration fee, which varies from as little as USD 1,752 per application in Canada Newfoundland and Labrador to USD 500,000 for an oil mining lease in Nigeria, covering exploration and production (Table 3).

The economic rationale for imposing such a fee is to cover costs related to running the licensing process and evaluating bids.

Table 3: Application/Registration Fee

Jurisdiction	Application Fee
US GOM	The US does not impose registration fees at the Federal level
Angola	USD 10,000
Australia (Offshore)	USD 5,775 (AUD 7,500)
Brazil	Participation fees vary from USD 18,700 to USD 57,500 (BRL 65,000 - BRL 200,000) depending on the contract area (deep vs shallow water)
Canada Newfoundland & Labrador	Issuance fee determined per round and per parcel: varying between USD 1,752 and USD 3,115 (CAD 2,250 and CAD 4,000)
Mexico	USD 18,000
Nigeria	Processing fee: USD 10,000 per block On an application for oil prospecting license: USD 10,000 On an application for an oil mining lease: USD 500,000
Norway	USD 16,000 (NOK 123,000) (APA 2017)
Trinidad & Tobago	Bid Fee paid on submission of the bid: USD 50,000
UK	USD 3,000 (GBP 2,100)

3.3. Biddable terms

The US, Canada Newfoundland and Labrador, Norway and the UK use a single biddable parameter, unlike the other jurisdictions which rely on a combination of variables.

Most countries allocate their acreage by work program where the winning investors commit to drill a number of wells or carry out seismic surveys. These commitments can sometimes be re-negotiated but this is rare. The US, Australia (for Cash Bid Exploration Permit) and Canada Newfoundland and Labrador (for a specific license) are the only jurisdictions among the selected cases for this study that do not include the work program in their assessment of the bid on offer:

- In the US, the bidder offering the highest signature bonus wins the bid (minimum pre-specified).
- In Australia and Canada Newfoundland and Labrador, bidders have two options:

- In Australia, the bid is based either on the work program bid for Work Program Exploration License or cash for Cash Bid Exploration License.
- In Canada, the cash bonus bid normally applies to parcels located in areas of proven oil and gas reserves (e.g. significant discovery and production licenses)[10]. For the Work Program Exploration License, the Work Program bid is expressed in terms of the amount of money the bidder commits to spend on exploration within the first period of the exploration license term (six years). The minimum is specified in each bid.

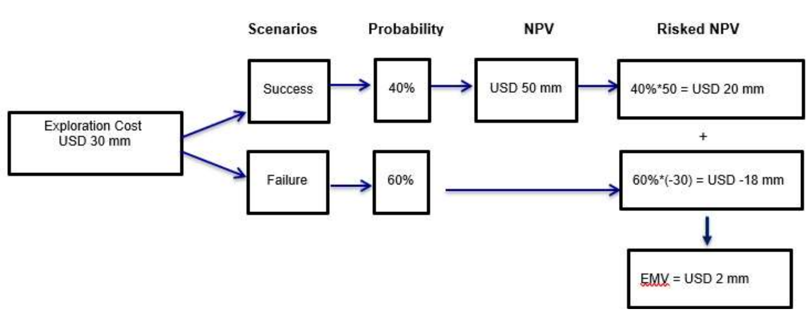
In the other jurisdictions where the signature bonus is used, it is part of the broader deal. In Angola, for instance, it accounts for 10 percent of the bid while the work program accounts for 80 percent; the rest is based on social contribution. In Brazil (concessionary system), the bonus accounts for 80 percent of the bid while the work program for 20 per cent. In Mexico and Trinidad and Tobago, the signature bonus is used to decide on the winner in case of tie (Table 4).

Several factors go into the determination of the lease bid by potential investors, with the key factors being: the geology, reservoir characteristics, technical assessment of whether oil or gas can be found, in what volumes, of what quality and whether they are likely to be economic to extract. This leads to an assessment of the expected monetary value (EMV) for the license being offered for lease (Box 4).

Box 4: Realized and Expected Value

The financial metric which is used to assess investment profitability is the Expected Net Present Value (ENPV) or EMV, also called risked NPV. At its simplest level, two scenarios are identified, exploration failure and exploration success, with probabilities assigned to each. For each scenario, the NPV is calculated. By multiplying each NPV by its associated probability and then summing for all scenarios, the EMV of a given event can be determined. The NPV is calculated by discounting the stream of revenues generated by the investment (cash inflows) less the present value cost of the investment (cash outflows). In other words, it is the sum of the discounted Net Cash Flows (NCF).

An NPV of zero means that the project's cash flows are just sufficient to repay the invested capital and to provide the required rate of return on that capital. If a project has a positive NPV, it generates a return that is greater than is needed to pay for the funds provided by the investors, hence is accepted. If a project has a negative NPV, it is generally rejected since it does not increase the firm's value. For an exploration project, the EMV is calculated as follows: $EMV = p_s NPV - (1-p_s)EC$ where p_s is the probability of success and *EC* represents the exploration costs. Just as is the case with NPV, investors also seek a positive EMV.



[10] Canada uses the concept of land parcel offshore instead of block.

There are, however, other more subjective factors in play, including but not limited to:

- Current and future oil and gas prices
- Drilling rates
- Fiscal regime and risk of future changes, favorable or unfavorable
- Financial health of the industry – is cash available for large bids?
- Competitive landscape – who are we bidding against?
- Competing exploration opportunities elsewhere in the country and overseas
- Discoveries nearby
- Technology improvements – real or anticipated
- Regulatory regime and future changes
- Strategic considerations – new basin access or imperative to build a position
- Proprietary information from existing lease holding and geological experience
- Recent failures to acquire acreage – outbid
- Recent large discoveries or conversely a run of exploration failures

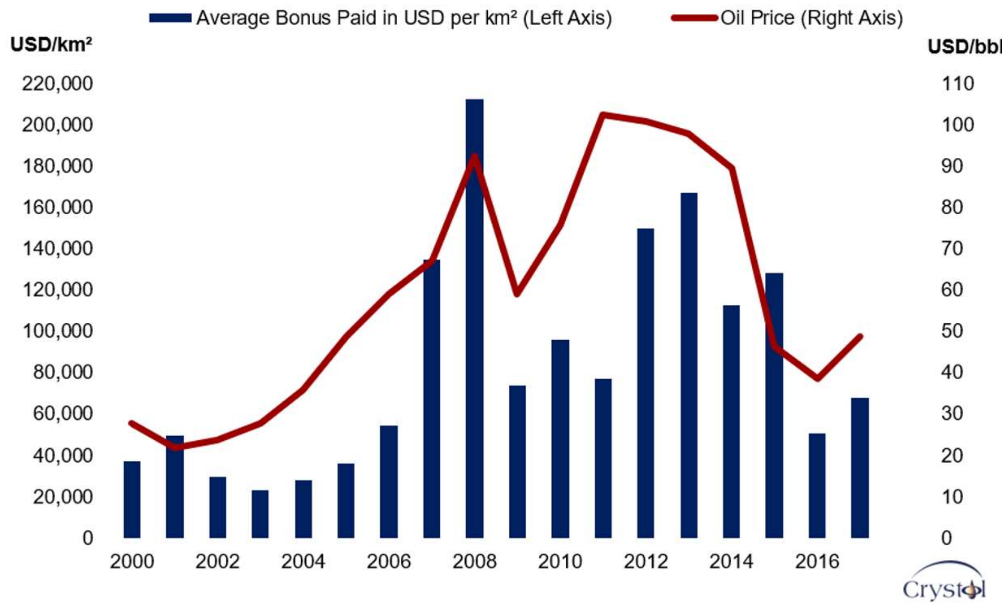
Typically, the EMV (and bonus bid) is usually much higher for a basin with proven reserves and infrastructure than for a new province where the commercial oil potential has not been proven. It is also higher for an expectation of oil rather than gas, since the value of the former tends to be higher for the same barrels of oil equivalent size. The discount rate is very important due to the long life of oil projects so any factors that impact investors' risk perception usually have a notable impact on the EMV and, thus, signature bonus levels. As the Angolan case showed (Box 1), the level of competition has had an additional impact on the magnitude of the bonus offered, while the more onerous the fiscal terms, the lower the lease bids and vice versa.

The size of the bid may also depend on the extent to which the fiscal regime is perceived to be stable. If investors believe the fiscal terms may tighten, then they tend to bid much less up front. Another critical factor is whether the signature bonus is an allowable deduction and over what period to compute future tax liabilities. The oil price normally plays a significant role in determining the bid value, given its direct impact on the expected returns from a project and existing cash resources of the bidder(s). Figure 8 below shows the positive correlation between the oil price and the average bonus paid in the US GOM[11]. Taking all these factors together will make the assessment of lease bids very difficult to predict. In theory, any investor will be prepared to bid up to their assessment of the EMV acreage potential.

From a government perspective, the signature bonus is a popular mechanism for generating upfront cash, long before any oil production starts. Once paid, the lease bid is a sunk cost and will not have any impact on the project economics of future developments, though it will have a material impact on the life cycle return to the investor from that basin. Nonetheless, an over-emphasis on collection of signature bonus revenues can have limitations. After all, money spent on bonuses is money not spent on exploration. In the long run, successful exploration and ensuing developments are likely to deliver much greater value for the state than signature bonuses.

[11] Further analyzed in Section Four.

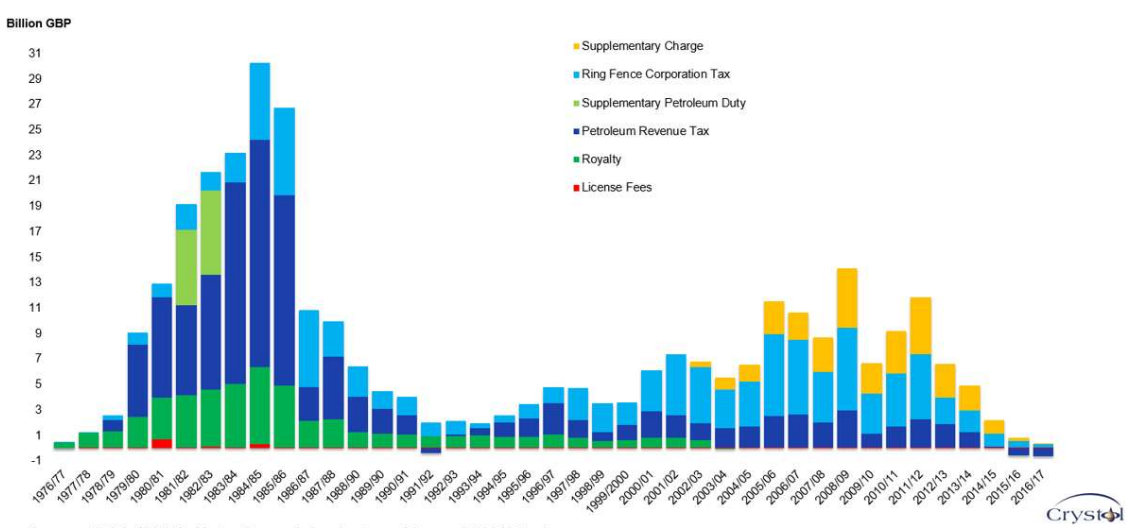
Figure 8: Oil Price and Average Bonus Paid in the US GOM per km²



Source: BOEM; EIA (2018). Note: Oil Price is dated WTI, estimated for 2018; Bonus and oil price in nominal terms

The UK, which relies solely on the work program to allocate the license, tested with some form of signature bonus which was embedded in the license fee. The bonus applied in the 4th round in 1971/72, 8th round in 1982/83 and 9th round in 1984/85 (Figure 9). The UK Government then abandoned the idea as it believed it was better to tax realized rent (through resource rent taxation) than anticipated rent (through signature bonus). The authorities also felt that money spent on bonus is money not spent on exploration.

Figure 9: UK Government Revenues from Oil and Gas Production



Source: OGA (2018). Note: On cash basis, in real terms 2016/17 prices

Sometimes companies offer a high signature bonus only to obtain the license and hope that other companies farm into the blocks and pay most of the bonus on their behalf. The 2005 licensing round Nigeria best illustrates this case, when most of the aggressive bidders defaulted on the bonus payment and only 17 bids out of 44 turned into contracts.

Table 4: Biddable Parameters in Selected Jurisdictions

Jurisdiction	Biddable terms
US GOM	Cash-bonus bidding: signature bonus (winner: highest paid), minimum threshold specified
Angola	• Cash bidding: Signature Bonus (10%); Work program (80%), contribution to Social programs (10%) • Different bidding parameters per block, varying with prospectivity
Australia (Offshore)	Two options for companies: • Work program bid, or • Cash bid
Brazil	• Signature bonus, local content (split into exploration and production phases) and minimum work program • According to the tender protocols for the 14th and 15th bidding rounds (2017), only the signature bonus (80%) and the Minimum Exploratory Program (PEM – 20%) are biddable
Canada Newfoundland & Labrador	• Cash Bonus Bid: expressed in terms of the dollar value a bidder is willing to pay to acquire a parcel. Normally applied for parcels located in areas of proven oil and gas reserves (e.g. significant discovery and production licenses) • Work Expenditure Bid: expressed in terms of the amount of money the bidder commits to spend on exploration within the first period of the exploration license term (6 years). This work expenditure bid is fully recoverable against work expenditure that qualifies as an allowable expenditure. Minimum: USD 8 million (CAD 10 million) in work commitments for each of the parcels in the Call for Bids NL18-CFB01 (2018)
Mexico	License Contracts Agreement: • Additional royalty factor (AR) • Additional investment factor (AIF) • Additional signature bonus payment is the main criteria for determining winning bids in the event of a tie between offers • Round 2.4 (Deepwater exploration, license contracts): awarding variables are Additional royalty rate + Additional investment (equivalent to the drilling of one or two wells during the contract's initial phase) • Contract awarded to the highest weighted value for the economic proposal (VPO) using the formula: • VPO = (Additional royalty rate + weighted value) * Additional investment factor
Nigeria	• Signature Bonus (~40%) • Local content participation and community development (20%) • Work program (~20%) • Production Bonus
Norway	Work program
Trinidad & Tobago	Government's profit share and minimum work program (post-2010); signature bonus in case of a tie
UK	Work program: if competition for the same acreage, the license is granted to licensee proposing to conduct the more onerous work program in the initial term of the license

3.4. Types of Permits

Typically, two types of lease/license/permit are found: one which is dedicated to exploration and appraisal, and another one to production.

3.4.1. Exploration License

Some countries like Angola offer non-exclusive prospecting licenses, which are dedicated to conducting seismic surveys and are of a short duration (around three years). In Mexico, Nigeria, Norway, Trinidad and Tobago, and the UK, such licenses are entitled 'exploration license' (Table 5).

The analysis below focuses on exploration licenses that give the exclusive right to their owners, irrespective of whether they are standalone exploration licenses (Australia, Canada Newfoundland and Labrador, and Nigeria) or part of the production permit, which grants the exclusive rights to exploration and production of petroleum in the area covered by the license. In this case, the exploration work program is carried out during the initial phase of the permit. In the US, the exploration license is carried out under the Primary Term of the lease (Table 6).

3.4.1.1. Duration and Terms

Where an exclusive right is given – whether as a standalone license or as part of the production license - the total duration allocated to the exploration phase varies, but is between four and ten years, the maximum period including the renewal.

Two countries, however, are the exception: Australia and the UK.

- Australia offers the longest exploration license, which can be up to 16 years in the case of the Work Program Exploration License but after the first six years, only 50 percent of the license area can be renewed for maximum two periods of five years each.

- The UK system has evolved after more than 40 years of experience. Following the formation of the Oil and Gas Authority (OGA), the upstream oil and gas industry regulator, in 2015, the UK government introduced a new type of licenses, the Innovate License, where the license duration is proposed by the applicant (Box 5).

Box 5: The UK's Flexible License Duration Approach

Like the older licenses that it replaced (Traditional, Promote and Frontier licenses), the Innovate License has three terms. The main difference is that the applicant proposes the duration for each, as long as it is in line with the terms below:

1. **Initial Term:** mainly for exploration but a licensee who moves fast enough and secured permissions would not be prevented from starting production during this phase. The Initial Term is subdivided into up to three phases, each with a specific work program:
   a. Phase A to carry out geotechnical studies and geophysical data reprocessing;
   b. Phase B to undertake seismic surveys and acquire other geophysical data; and
   c. Phase C for drilling.

   Phases A and B are optional and depend on the applicant's plan but every work program must have at least a Phase C.

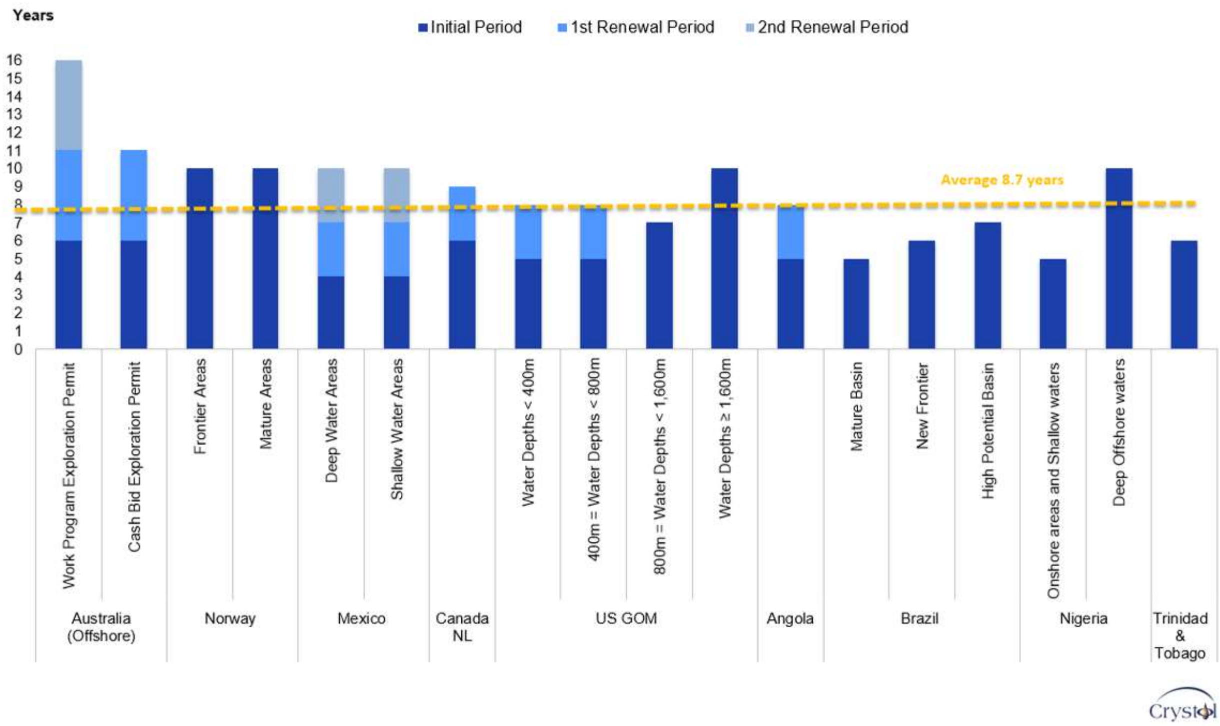
   The license expires at the end of its Initial Term unless the Licensee has completed the agreed work program and surrendered a fixed amount of acreage (usually 50 percent).
2. **Second Term:** Dedicated to the FDP; the license will expire at the end this term unless the FDP is approved.
3. **Third Term:** intended for production.

In some jurisdictions different opportunities have different durations. The US GOM has the widest variations, with the license duration depending on four different water depths. In Nigeria, the difference in duration depends on whether the field is onshore and in water depth below 200 meters (m) versus water depth above 200 m, whereby under the latter case the exploration license duration is double (ten instead of five years). A longer exploration license duration may be necessary in areas where exploration requires more time. The risk is that the lease could be held for a longer period by an owner with no intention of exploring or developing the resource. The minimum work program requirement, however, would guard against such a scenario.

The exploration permit is usually divided into several phases: an initial phase in addition to one or two renewals, where the renewal is conditional to delivering the minimum work program agreed on in the initial phase. In the US GOM, for the deepwater leases (more than 800 m water depth), however, there is only one primary term of ten years with no extension. As part of its energy reforms, Brazil also combined its previously two exploration phases of an initial four years then two years extension into one of five to seven years. In contrast, the UK, which currently has three phases, used to apply one phase to licenses granted up to the late 1980s.

A comparison of the total exploration phase duration among the selected jurisdictions is illustrated in Figure 10. The average period is 8.7 years. Only for licenses covering water depths higher than 1,600 m, the US GOM exceeds the average; all the other licenses in GOM fall below the average. Interestingly, the license covering water depth between 800 m and 1,600 m has the lowest total duration compared to the other GOM licenses, including in shallower water. All the other selected cases, excluding Angola, Brazil, Nigeria (onshore and shallow water) and Trinidad and Tobago, fall above the average. In Angola and Brazil, however, the license duration can be extended per individual agreements.

Figure 10: Maximum Exploration Phase Comparison



Source: ANP; Australian Government; BOEM; CNH; C-NLOPB; Trinidad & Tobago Ministry of the Attorney General and Legal Affairs; NPD; Sonangol (2018); Federal Republic of Nigeria Ministry of Petroleum Resources (2016)

Typically, the renewal of the first phase of the exploration license is subject to different conditions: it is usually the work program and in some cases the payment of a fee. Also, the renewal may not be granted for the full license area and part of the original area has to be relinquished. In Angola, the contractor pays a fee in the form of a negotiable bonus, for renewal.

In Australia, a fee also applies, and the license holder relinquishes 50 percent of the license area at the renewal. In Nigeria, the right holder relinquishes 50 percent of the area when converting the exploration license (OPL) to production license (OML), though this rule does not apply to blocks of less than 250 km². In Norway, all acreage not included in the field development plan (FDP) should be relinquished – a similar practice is followed in Mexico.

Some jurisdictions are more prescriptive with the relinquishment rule than others. In Trinidad and Tobago, for instance, the contractor should relinquish at least 30 percent of the original Contract Area, not later than the end of the first phase of the Exploration Period; at least 50 percent of the original Contract Area (inclusive of areas previously relinquished) not later than the end of the second phase of the Exploration Period; then all portions of the original Contract Area, no later than the end of the Exploration Period, excluding areas with production or appraisal.

In the US GOM, the lessee can relinquish the lease or any officially designated subdivision, by filing with the appropriate regional BOEM OCS office, a written relinquishment effective on the date it is filed. To avoid paying a full year's rental/royalty, the lease must be relinquished before its anniversary date.

In Angola, if the contractor relinquishes its rights before performing the seismic program, the contractor should pay Sonangol an amount equal to USD 30 million less USD 20,000 for each square km² of the seismic program concluded before relinquishment. Usually, all the area where no discovery is made is relinquished at the end of the exploration term, as is the case in Brazil and Canada Newfoundland and Labrador, for instance.

Table 5: Production License (Including Exploration) Terms

Jurisdiction	Duration and extension
Mexico	**License Contract for Extraction of Hydrocarbons (Deepwater)** • Initial Period: 35 years. Two extensions subject to contractor fulfilling all its obligations: • 1st Extension: up to 10 years or until the economic limit of the Development Areas, in case this last term is shorter. • 2nd Extension: up to 5 years or until the economic limit of the Development Areas, in case this last term is shorter Exploration carried out during the first 10 years: • Initial Period: maximum of 4 years • First Additional Exploration Period: 3 years subject to contractor fully meeting minimum work program during the initial exploration period, and agrees to drill one additional well • Second Additional Exploration Period: 3 years, there exist Appraisal Areas or Development Areas in the Contract Area at the time of the request and contractor agrees to drill one additional Well
Norway	**Production License**: • Initial period: up to 10 years. If granted for a shorter period of time, can be extended to up to 10 years. During this time, a specific work commitment shall be completed (e.g. seismic data acquisition and surveys and/or exploration drilling) • Renewal: When the initial period is over and the work commitment is completed, the licensees can apply for extension for a period as stipulated in the production license. In general, this period is up to 30 years (may be up to 50 years)
Trinidad & Tobago	**Exploration and Production License:** • Initial Period: 6 years • 1st Renewal: shall not exceed 25 years • 2nd Renewal: 5 years
UK	**Innovate License:** • Initial term for exploration with 3 phases A, B and C, each with a work program • Second term for FDP • Third term for production Flexible duration as proposed by the applicant

Table 6: Exploration and Production Licenses Terms

Jurisdiction	Exploration license	Production License
US GOM	**Primary Term (Min 5; Max 10 years):** 1-Water depths < 400 m, up to 8 years: • Initial Period: 5 years; Renewal: 3 years, subject to: lessee drills a well, in Initial Period, to a target below 25,000 feet or where the well is drilled but does not reach that depth for reasons beyond lessee's control 2- 400 = Water depths < 800 m, up to 8 years: Initial Period: 5 years; Renewal: 3 years subject to lessee spudding a well within the 5-year primary term of the lease 3- 800 = water depths < 1,600 m, up to 10 years: Initial Period: 7 years; No extension 4- Water depths =>1,600 m: • Initial Period: 10 years; No extension	• If a discovery is made within the Primary term, the lease is extended for as long as oil/gas is produced in paying quantities or approved drilling operations are conducted • The term of the lease may also be extended if SOO/SOP granted • 2017 decision: Lease remains in effect after cessation of production or other operations to 1 year compared to 180 days under older system (i.e. to maintain a lease, lessees have one year after the cessation of operations to apply for SOO, SOP or resume operations)
Angola	**Exploration license:** • Initial Exploration Phase: 5 years • Optimal Exploration Phase (renewal): 3 years, provided that the Contractor has fulfilled its obligations in respect of such Phase. A bonus for the extension of an exploration term is negotiable	• Initial period of 25-30 years following the declaration of a commercial discovery. Can be extended
Australia (Offshore)	**Work program exploration permit:** 6 years; 50% of area can be renewed for maximum 2 periods of 5 years each **Cash bid exploration permit:** 6 years that may be renewed for one period of 5 years **Retention lease:** 5 years with work program that may be renewed Fee for renewal of petroleum exploration permit and retention lease: USD 5,775	• Granted for life of field while producing • May be terminated if production ceases for more than five years
Brazil	**Exploration License:** • Mature Basin: 5 years • New Frontier: 6 years • High potential basin: 7 years May be extended depending on agreement	• Initial Period: 27 years, extendable with approval from the regulator (ANP) • Production should start in no more than 5 years, extendable at ANP's discretion, of the submission of declaration of Commerciality
Canada Newfoundland & Labrador	**Exploration License:** Max 9 years (2 consecutive periods, Period I (6 years) and Period II) **Significant Discovery License:** in force for so long as the relevant declaration of significant discovery is in force, or until a production license is issued	• 25 years or for such period thereafter during which commercial production continues. • Declaration of commercial discovery is a precondition to the issuance of the license • Where a Declaration of Commercial Discovery has been made but production has not commenced, the term of the relevant interest can be reduced to 3 years.
Nigeria	**Oil Prospecting License (OPL):** • Initial Period: maximum of 5 years (3+2) for onshore areas and shallow waters (water depths less than 200 m); maximum of 10 years (5+5) for deep offshore and inland basins, water depths more than 200m • No provision for renewal	**Oil Mining License (OML):** Only the holder of an OPL is entitled to apply for an OML but to apply for an OML, an OPL license holder will have had to find oil in commercial quantities (at least 10,000 bbls/day shallow water and 25,000 bbls/day for deepwater) • Initial Period: 20 years • Renewal for another 20 years

Below are additional practices that are unique to three jurisdictions: Australia, Canada Newfoundland and Labrador and the US GOM.

- **Australia Retention Lease:** Australia grants a 'Retention Lease' to the holder of an exploration permit or a production license where a discovery has been made that is not currently commercially viable but is likely to be within 15 years. The Retention Lease is a five-year title with work program; it can be renewed.

- **Canada Significant Discovery License:** In addition to the exploration license of maximum nine years (six plus three), Canada offers a special license called 'Significant Discovery License' (SDL), whereby if a drilling program results in a significant discovery (accumulation of hydrocarbons that has potential for sustained production), the interest owner is eligible for an SDL, which confers the same rights as that of an exploration license. The interest owner can continue to hold rights to a discovery area while the discovery is appraised, and commercially proven. The SDL is subject to rental fees applicable at ascending rates. The rentals become very high the longer the license is held, reaching more than USD 12,400 per km² once the license exceeds 16 years.

- **US GOM SOO and SOP:** Under certain criteria, the leaseholder can request a lease suspension, which extends the term of the lease by up to five years. All requests require the payment of a fee and must include the reason for the suspension, the length of time requested, and a reasonable activity schedule of work to initiate or restore production.

  Two types of suspension which can be either requested by the operator or directed by the regulator:

  - Suspension of Operations (SOO): Normally of short duration and granted on a case-by-case basis.
  - Suspension of Production (SOP): A lease that is about to exceed its primary term and is not yet producing will, upon request, be considered for an SOP if there is a demonstrated firm commitment to begin operations but could not be carried out because of factors that go beyond the operator's control. The SOP may be granted for up to five years, but the practice has been for one year or less.

  For requested SOO and SOP, the leaseholder is required to pay rental and minimum royalty for the granted suspension period.

3.4.1.2. Minimum Work Program Obligation

As Table 4 shows, in all the jurisdictions selected, except the US, the minimum work program to be carried out during the exploration phase is biddable.

In the US, during the primary term, lessees do not have a mandatory work program or deadlines for conducting exploratory or development activities, except when applying for an extension (for leases in water depths less than 800 m). In Canada, the work program should be fulfilled in Period I of the Exploration phase to transition to Period II, but no work program is required in Period II.

The minimum work program is typically a pre-requisite for renewing a license, transitioning from exploration to production permit or obtaining an exemption from the are rental fee as is the case of Norway (see section below). In Nigeria, the holder of an OPL is expected to start drilling operations within six months of the date of grant of the license with at least one well drilled each year commencing from the second year. An average of three wells (two in deepwater) shall be drilled through all the prospective zones in the relevant area to satisfy the minimum work obligations for an application for conversion of an OPL to OML.

3.4.1.3. Rentals/Area Fee

License or lease holders are required to pay a rental fee for the area covered by the license. The fee can be considered as an element of the fiscal regime, as is the case in Mexico, for example, where both a rental fee and a surface tax apply. In Australia, a flat fee applies which takes the form of an administration levy per permit, except for the Retention Lease and Production license where the levy is imposed per block. Both the Retention Lease and Production License command the same levy.

In both Canada Newfoundland and Labrador and Norway, the rental fee starts to apply several years following the initial award of the license. In the former, the fee applies during Period II of the license or after six years from the award; in the latter, it starts to apply from year five to seven. Also, in Norway, although the fee seems high on paper, in practice it is not that significant since exemptions apply, as follows:

- the Ministry can provide whole or partial exemption at its own discretion.
- No area fee is payable for areas that are being actively explored (initial period pursuing work program) or where there is production.
- Companies can also apply for exemption from the area fee if they submit a plan for development and operation or if extra exploration wells are drilled in addition to those required under the work program.
- It is also possible to apply for exemption if there is a lack of infrastructure in an area or if there is substantial ongoing work within the license.

In 2015, for instance, Norway generated a relatively modest total fee of USD 191,743 or 0.75 percent of total revenues generated.

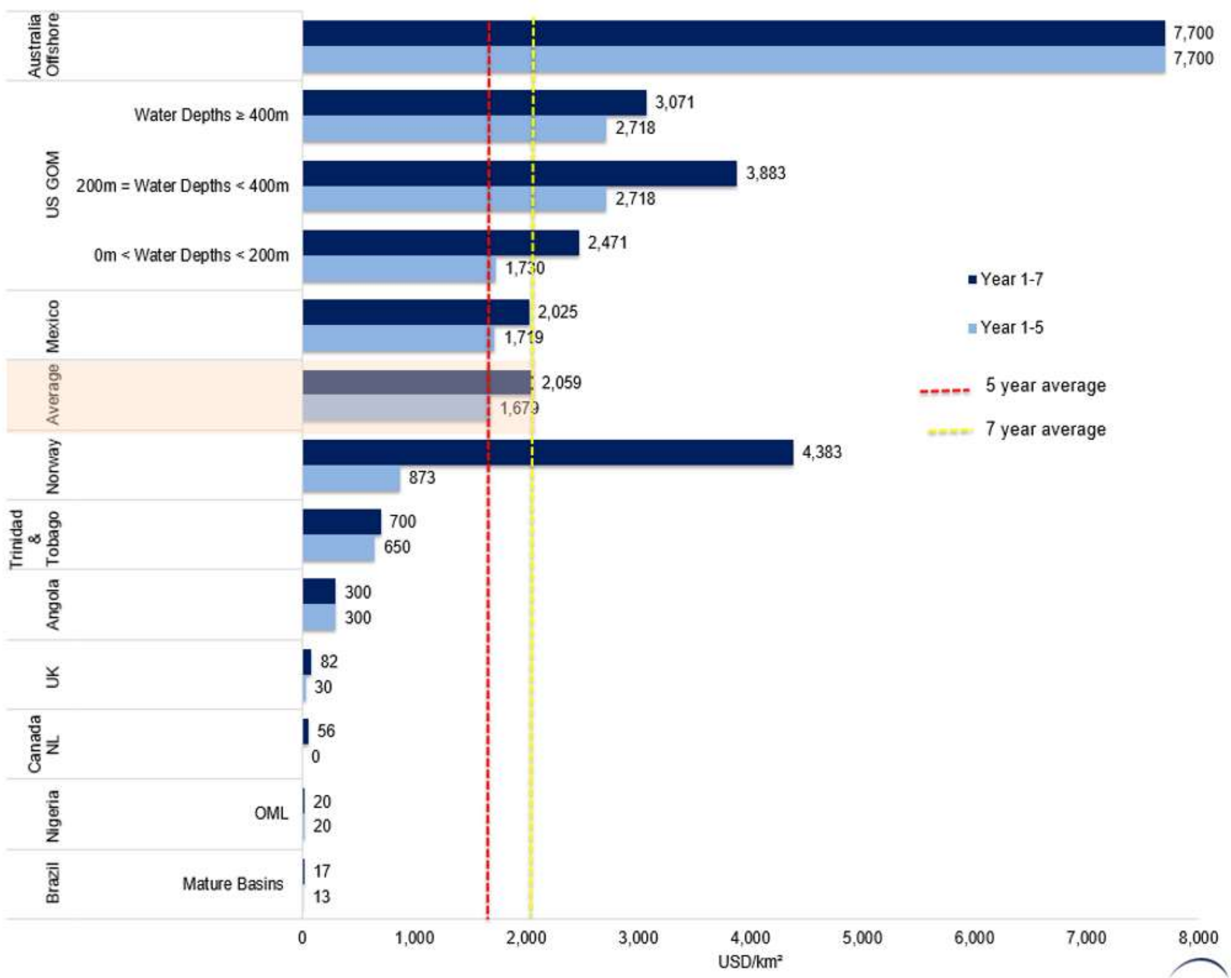
In the US GOM, the rental fee is limited to the primary term only. When production starts, the fee is replaced by the minimum Royalty. However, for requested SOO and SOP, the leaseholder is required to pay both the rental and the minimum Royalty for the granted suspension period. It is also interesting to see that the US imposes a higher rental fee on leases between 200 and 400 m water depth compared to the leases in shallower depths.

The US GOM offers one alleviation to leases with an eight-year primary term in water depths of less than 400 meters, whereby in such a case, if another well is spudded targeting hydrocarbons below 7,620 meters True Vertical Depth Subsea (TVD SS) after the fifth year of the lease, the rental rate is fixed at the rate in effect during the lease year in which the additional well was spudded.

When considering the five-year average of the exploration phase for all the selected jurisdictions, Mexico's rental fees, which combine an area fee and surface tax, fall in line with the average, while in Australia and the US GOM, they are above the average. For the US GOM, the difference is rather insignificant for leases covering water depth below 200 m but, for the other leases covering a higher water depth, the difference becomes notable at more than USD 1,000 per km².

When the average for the first seven years is considered, the rental fee for all the leases in the US GOM exceeds the average, with the lease for water depth between 200 and 400 m nearly double the average rate (Figure 11).

Figure 11: Five and Seven Year Average Rental Fee



Source: Angola Petroleum Tax Law; ANP; BOEM; C-NLOPB; OGA (2018); EY (2017); Nigeria Petroleum Act (2004)

Table 7: Annual Rental Fee per km^2

<table>
<tr><th>Jurisdiction</th><th>Annual Rentals per km^2 (unless specified otherwise)</th></tr>
<tr><td>US GOM</td><td><table>
<tr><th>Water Depth</th><th>Years 1-5</th><th>Year 6</th><th>Year 7</th><th>Year 8 +</th></tr>
<tr><td>0 to < 200</td><td>1,730</td><td>3,460</td><td>5,189</td><td>6,919</td></tr>
<tr><td>200 to < 400</td><td>2,718</td><td>5,426</td><td>8,154</td><td>10,873</td></tr>
<tr><td>400 +</td><td>2,718</td><td>3,954</td><td>3,954</td><td>3,954</td></tr>
</table></td></tr>
<tr><td>Angola</td><td>USD 300</td></tr>
<tr><td>Australia (Offshore)</td><td>Annual titles administration levy (set rate regardless of the size of the permit area):
• Work-bid petroleum exploration permit: USD 7,700 per title (AUD 10,000)
• Cash-bid petroleum exploration permit: USD 7,700 per title (AUD 10,000)
• Petroleum Retention lease: USD 15,400 per block (AUD 20,000)
• Petroleum Production license: USD 15,400 per block (AUD 20,000)</td></tr>
<tr><td>Brazil</td><td>• Exploration Phase:
- Blocks in High potential basins: between USD 79 to USD 474 (BRL 280 to BRL 1,683)
- Blocks in Mature basins: USD 13 (BRL 45)
- Blocks in New Frontier basins: USD 59 (BRL 210)
• Extension of the Exploration Phase: 100% increase of the value set for the Exploration phase
• Development Phase: 100% increase of the value set for the Exploration phase
• Production Phase: 900% increase of the value set for the Exploration phase</td></tr>
<tr><td>Canada Newfoundland & Labrador</td><td>1-Rentals applicable to the Exploration License (Period II):
• 1st year: USD 390 (CAD 5 per ha)
• 2nd year: USD 780 (CAD 10 per ha)
• 3rd year: USD 1,170 (CAD 15 per ha)
2- Rentals applicable to the SDL:
• Year 1-5: 0
• Year 6-10: USD 3,120 (CAD 40 per ha)
• Year 11-15: USD 15,600 (CAD 200 per ha)
• Year 16-20: USD 62,400 (CAD 800 per ha)</td></tr>
<tr><td>Mexico</td><td>Contractual Quota for Exploration Period (CQEP) (rental fee):
• Year 1-5, USD 769 (MXN 14,571)
• Year 6+, USD 1,839 (MXN 34,843)
Surface tax:
• USD 950 (MXN 18,000) during the exploration period for the Contract Area
• USD 4,012 (MXN 76,068) during the exploitation period for the Contract Area</td></tr>
<tr><td>Nigeria</td><td>Prospecting license: USD 10
Oil mining lease:
• Year 1-10, USD 20
• 11+, USD 15 until expiration of the lease and on renewal</td></tr>
<tr><td>Norway</td><td>• 1st year of application (usually from year 5 to 7) of license award: USD 4,365 (NOK 34,000)
• 2nd year of application: USD 8,729 (NOK 68,000)
• 3rd year until submission of FDP: USD 17,587 (NOK 137,000)</td></tr>
<tr><td>Trinidad & Tobago</td><td>• 1st Contract Year: USD 550 per km^2 (USD 5.50 per ha)
• 2nd Contract Year: USD 600 per km^2 (USD 6.00 per ha)
• 3rd Contract Year: USD 650 per km^2 (USD 6.50 per ha)
• 4th Contract Year: USD 700 per km^2 (USD 7.00 per ha)
• 5th Contract Year: USD 750 per km^2 (USD 7.50 per ha)
• 6th Contract Year: USD 800 per km^2 (USD 8.00 per ha)
Thereafter, minimum payment increases annually at 6% for unexpired term</td></tr>
<tr><td>UK</td><td>• Phase A: USD 21.3 (GBP 15)
• Phase B: USD 42 (GBP 30)
• Phase C: USD 213 (GBP 150)
On each subsequent date after the Initial Term:
• on the 1st such date: USD 426 (GBP 300)
• on the 2nd such date: USD 1,278 (GBP 900)
• on the 3rd such date: USD 2,556 (GBP 1,800)
• on the 4th such date: USD 3,835 (GBP 2,700)
• on the 5th such date: USD 5,539 (GBP 3,900)
• on the 6th such date: USD 7,243 (GBP 5,100)
• on the 7th such date: USD 8,947 (GBP 6,300)
• on the 8th such date: USD 9,800 (GBP 6,900)
• on the 9th such date, and subsequent such date: USD 10,653 (GBP 7,500)</td></tr>
</table>

3.4.1.4. Block Size

The block size varies significantly between jurisdictions and within the same jurisdiction. The US GOM offers the narrowest range of block sizes, whereas other jurisdictions give a wider range of the size of the blocks to be offered. Norway and the UK offer the widest range of blocks, which can be as small as 0.3 km² and 0.6 km², and as big as 566 km² and 267 km², respectively (Table 8).

Table 8: Range of Block Sizes Offered in km²

Jurisdiction-Licensing Round	Size in km²
Norway-APA 2017, Sep. 2017	0.3 to 428
UK-29th Offshore Licensing Round, Mar. 2017	0.6 to 267
Norway-23rd Licensing Round, May 2016	0.6 to 566
US GOM-Lease Sale 249, Aug. 2017	20.23 to 23.31
Australia-2016 Offshore Petroleum Exploration Acreage, Dec. 2016	35 to 85
Brazil-15th Bidding Round, Nov. 2017	586 to 1,373
Mexico-Bid Round 3.1, Mar. 2018 (Shallow water)	600 to 961
Canada-NL17-CFB01, Nov. 2017	732 to 1,383
Mexico-Bid Round 2.4, Jan. 2018 (Deepwater)	1,853 to 3,254

Source: ANP; Australian Government; BOEM; CNH; C-NLOPB; NPD; OGA (2018)

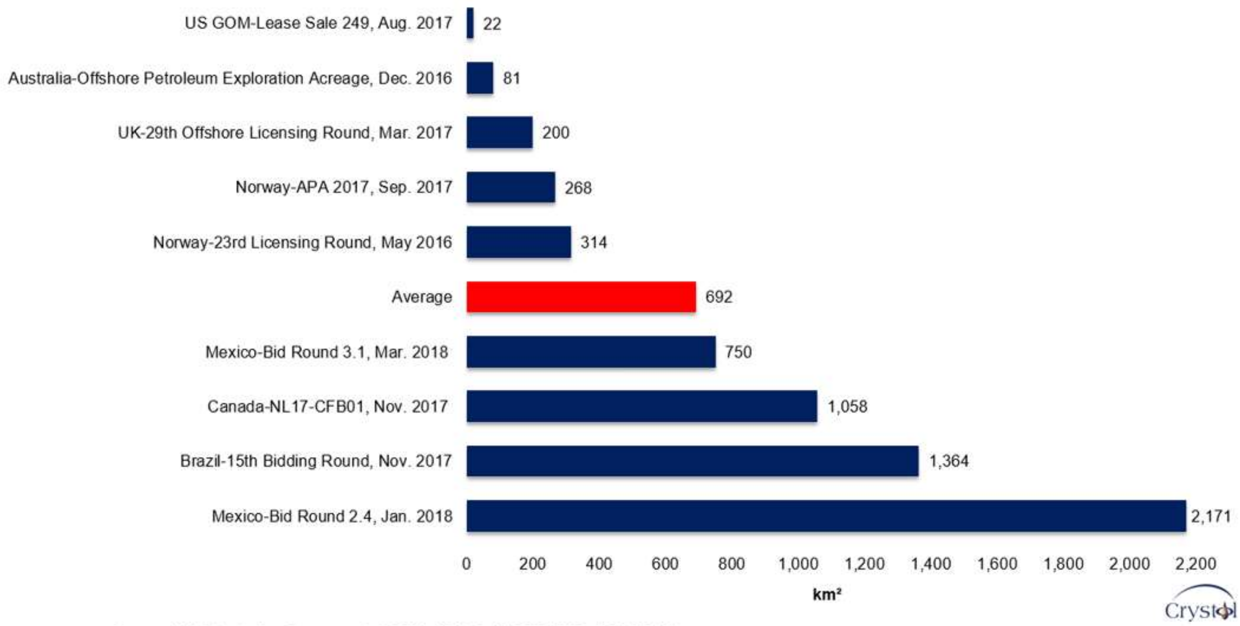
Looking at recent rounds held in the jurisdictions surveyed, one finds the largest blocks in Mexico and the smallest in the US (Figure 12). During Mexico's deepwater Round 2.4, the blocks offered covered an area averaging 2,171 km² per block, compared to 780 km² for shallow water (Round 3.1). By comparison, the US GOM offered the smallest block area, covering an average of 22 km² per block.

In addition to the US GOM, Australia, the UK and Norway offer blocks which fall below the average, while Brazil, Canada and Mexico are above.

The block size should take into consideration any applicable rental fee. In general, companies have preferred to acquire larger blocks. In Mexico, however, a larger block size will result in higher surface rent and tax. For instance, for the first year of exploration, an average block in Mexico would attract a staggering USD 3,731,949 in surface rent and tax. In Norway, that figure is also high at USD 1,169,820 but it can be waived. The relinquishment rule should also be considered (see Section 3.4.1.1).

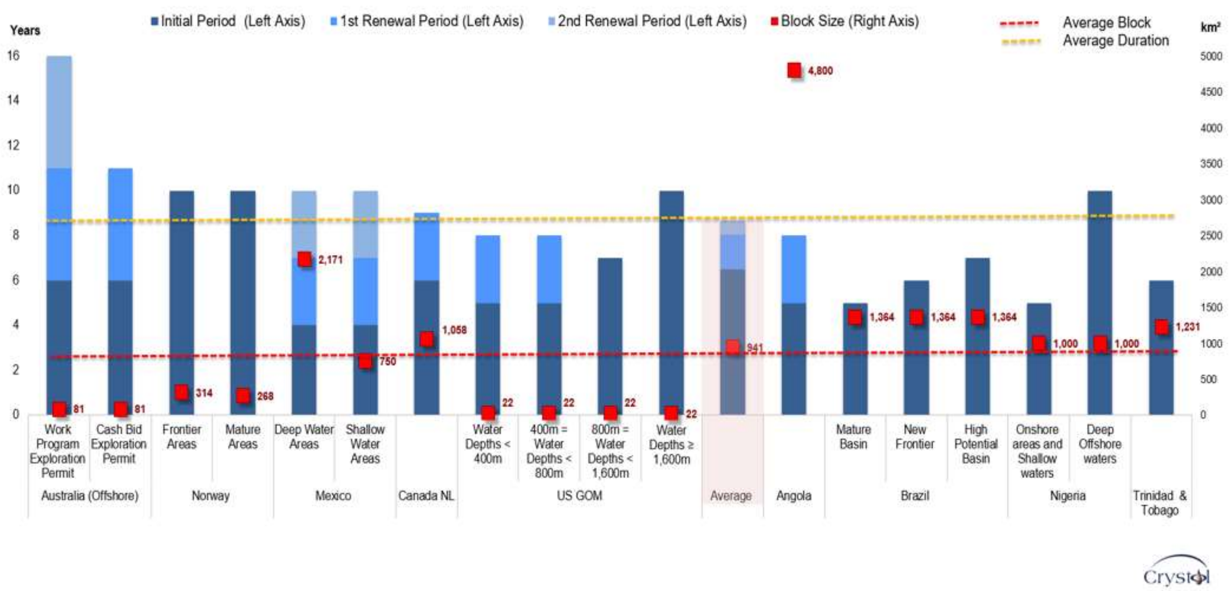
When the block size is assessed along the license duration, the US GOM becomes a clear outlier, particularly for licenses covering water depth between 800 and 1,600 meters (Figure 13). The US GOM offers the smallest block size compared to the selected jurisdictions and a relatively short exploration term (Primary term). In Australia, where block sizes are also small compared to the other jurisdictions (81 km²), they are still nearly four times those found in the US GOM and they have an exploration license with either 11 or 16 years duration.

Figure 12: Average Size of Blocks Offered in km²



Source: ANP, Australian Government, BOEM, CNH, C-NLOPB, NPD, OGA (2018)

Figure 13: Block Size and Exploration License Duration



Source: ANP; Australian Government; BOEM; CNH; C-NLOPB; Federal Republic of Nigeria Ministry of Petroleum Resources; NPD; Sonangol; Trinidad & Tobago Ministry of the Attorney General and Legal Affairs, (2018). Note: The block size is the average size of the block ranges offered in each jurisdiction

The US authorities can issue a lease larger than 23.31 km^2 (5,760 acres) if it is found that a larger area is necessary for reasonable economic production[12]. While discretion in this area is somewhat limited, the US authorities could consider offering larger leases, particularly in deepwater and possibly with shorter lease terms (less than 10 years) to make the leases more attractive to investors and promote quicker development.

3.5. Comparison of Licensing Rounds

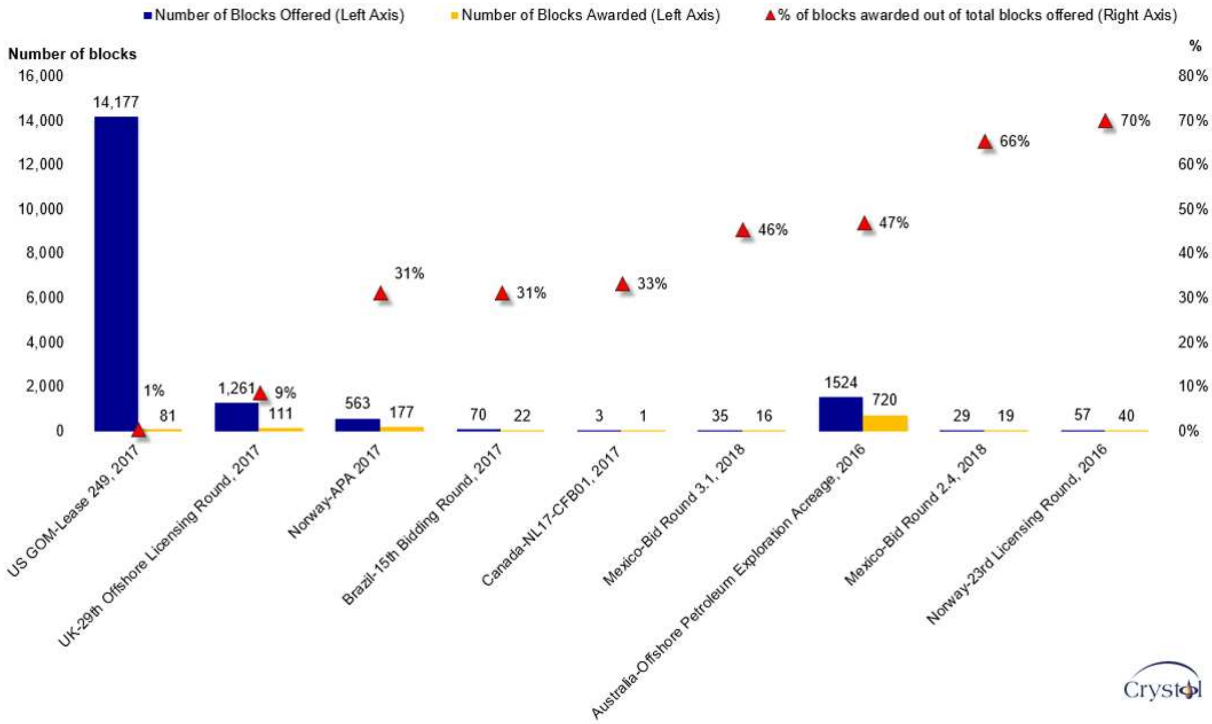
The above terms can help to explain the outcomes of the recent licensing rounds held in the surveyed jurisdictions between 2016 and 2018, excluding Angola, Nigeria and Trinidad and Tobago since no rounds were held over that period.

3.5.1. Blocks and Acreage Awarded

In absolute terms, the US GOM Lease Sale 249 offered the largest number of blocks (14,177) but awarded only 90 (or less than one percent), while Australia Offshore Petroleum Exploration Acreage 2016, which offered 1524 blocks, awarded the largest number of blocks (720 or more than 47 percent). Norway's 23rd licensing round and Mexico's deepwater Bid Round 2.4 outperformed their peers, awarding 70 and 60 percent of their blocks respectively (Figure 14). Mexico's deepwater is expected to hold a significant potential as it remains largely unexplored compared to other deepwater areas in the world. These proportions, however, should be treated with caution as some countries follow more targeted lease sales, typically resulting in higher percentage of allocation than those that do not follow such a targeted strategy.

[12] See 43 U.S.C. § 1336(b)(1) (authority to issue larger leases if "the Secretary [of the Interior] finds that a larger area is necessary to comprise a reasonable economic production unit"); 30 C.F.R. § 556.308 (BOEM regulation implementing same).

Figure 14: Blocks Offered and Awarded



Source: ANP; Australian Government; BOEM; 2018; CNH; C-NLOPB; NPD, OGA (2018)

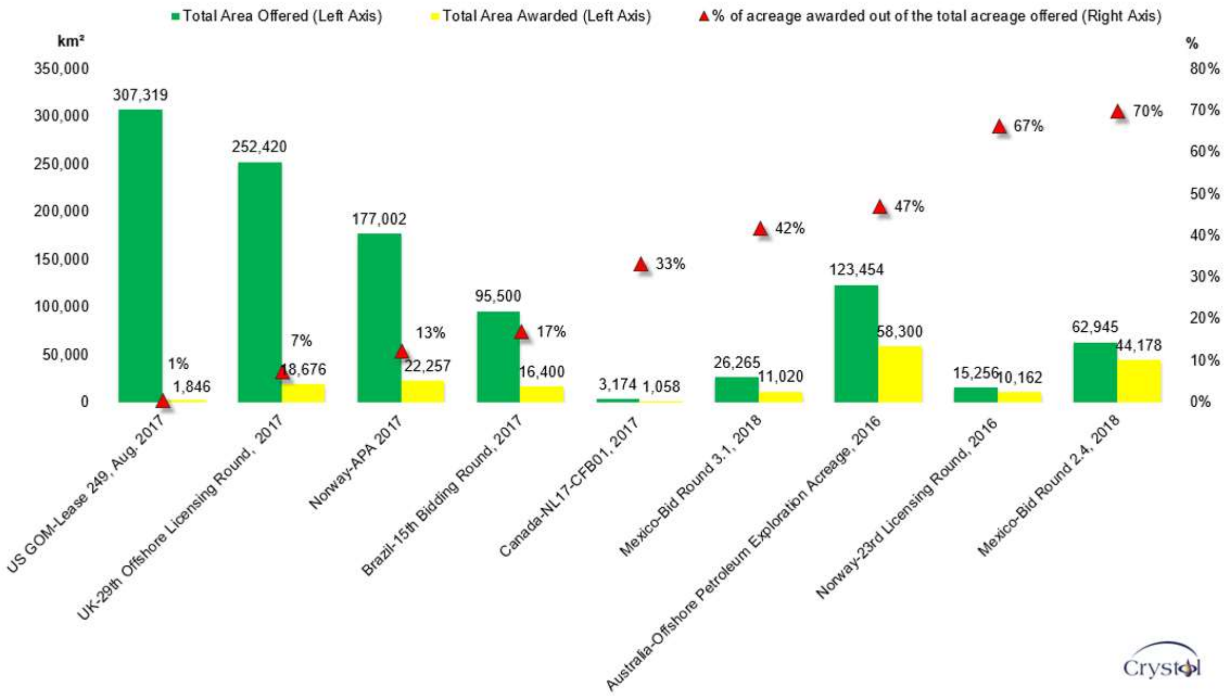
In terms of acreage offered, the US GOM dominates with 307,319 km² of acreage offered during the Lease sale 249 in August 2017, followed by the UK 29th Offshore Licensing Round (252,420 km²) and Australia (123,454 km²).

Canada Newfoundland and Labrador offered the least acreage with a total of 3,174 km² during the NL-17-CFBO1 licensing round launched in November 2017. Canada, however, managed to award 38 percent of the total acreage offered. By comparison, in the US GOM less than one percent of the total acreage offered was awarded, while in the UK the figure was less than 8 percent (Figure 15).

Mexico, with more targeted licensing rounds, awarded the biggest proportion of its acreage during the deepwater Bid Round 2.4 on January 2018 where 70 percent of the total area offered was awarded. The total acreage offered in that round was 20 percent of what US GOM offered. An equally outstanding result was recorded in Norway, with the 23rd licensing round focusing on frontier areas in May 2016 and which awarded 67 percent of the acreage, compared to 13 percent from APA 2017 (Figure 15).

The outcome of these licensing rounds can reflect the relative geological potential and investors' expectations of value. Mature areas, such as the US GOM and those covered by the UK 29th and Norway's APA rounds, are a good example where such a potential is presumed to be limited, and investors showed less appetite accordingly. In contrast, countries like Brazil and Mexico as well as frontier areas in Norway can offer more substantial and exciting opportunities, as they are much less explored.

Figure 15: Total Acreage Offered and Awarded in km²



Source: ANP; Australian Government; BOEM; 2018; CNH; C-NLOPB; NPD, OGA (2018)

3.5.2. Signature Bonus

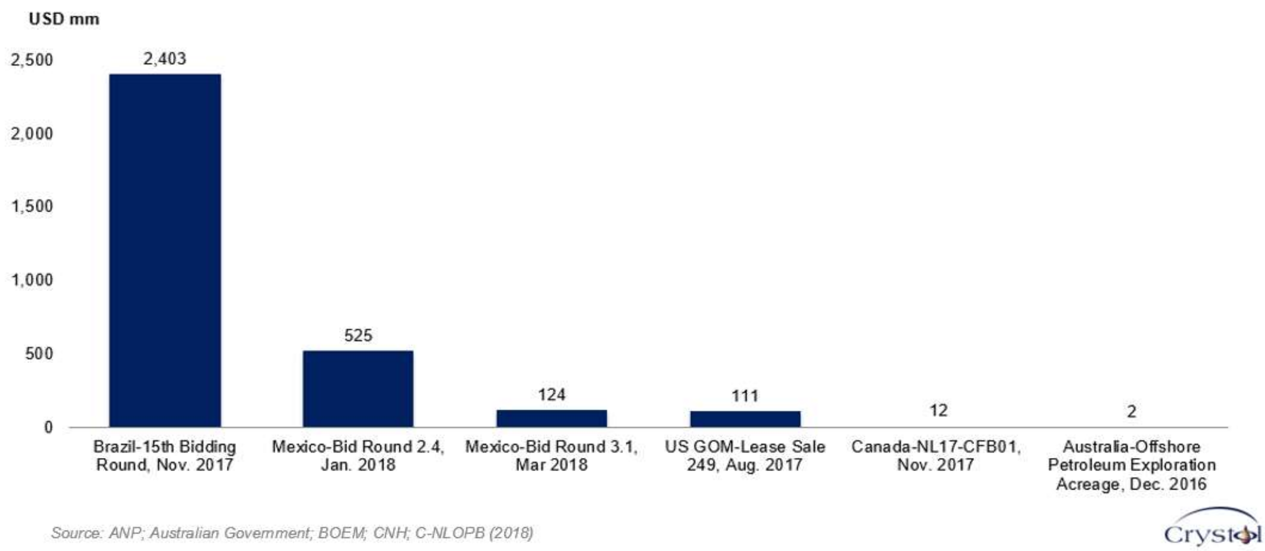
As Section 3.3 shows, in Australia, Brazil, Canada Newfoundland and Labrador, Mexico and the US GOM, the signature bonus is biddable. Brazil's 15th licensing round, announced in November 2017, attracted the highest total bonus bid - both in terms of aggregate figure (more than USD 2.4 billion) and on a per km² basis (USD 150,000), even though Brazil awarded only 17 percent of its total acreage offered (Figure 16). The total bonus bids in the US GOM Lease Sale 249 account for less than 5 percent of what Brazil received.

In recent years, Brazil has emerged as a leading offshore basin, securing the greatest investment appetite from the international oil industry. Competition for basin access and building acreage banks has been sustained and intense. Brazil's 15th licensing round's success is due to several factors. First, there is the geological attraction; the country is less heavily explored than elsewhere, potentially offering significant opportunities, especially when combined with the right fiscal and regulatory terms. Second, the government introduced several regulatory and fiscal reforms in 2015/16, including the reduction in the Royalty rate of up to five percent, simplification of the exploration phase[13] and extension of the contract duration also played a key role. The government also eased the local content requirement which used to impose a heavy burden on investors.

[13] See Section 3.4.1.1. For contracts awarded in the 11th and 12th licensing rounds, Brazil extended the exploration phase by two years.

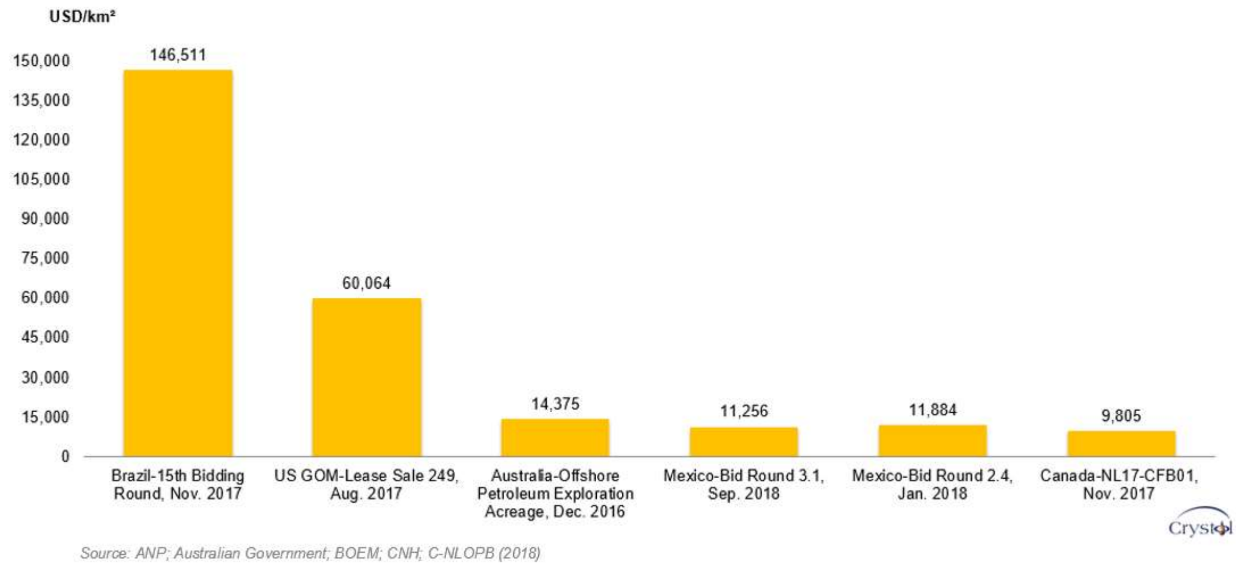
Australia's 2016 Offshore Petroleum Exploration Acreage came last, with over USD 2 million (mm) of total bonus bid paid. The round is the first cash-bid auction to result in the award of a permit, since cash-bid auctions were reintroduced in 2014. Only six blocks out of the 1524 blocks offered were for cash bidding; Australia relies more on the work program bid to award its licenses.

Figure 16: Total Bonus Bid in USD



In terms of the average bonus bid paid per km², the US GOM Lease Sale 249 performed better; it attracted the second highest value after Brazil's 15th licensing round, and five times more than what Mexico received (Round 2.4) (Figure 17). However, the signature bonus paid per km² in Brazil was more than double what was paid in the US GOM, knowing that in Brazil, the bonus is one of several biddable parameters, while in Mexico, it is only paid in the case of a tie between two bids.

Figure 17: Average Bonus Bid per km²



3.6. Licensing Policy Summary

This section analyzed the licensing policy in the US GOM and compared it with those of nine jurisdictions with prominent offshore oil and gas sectors, to determine whether the US GOM is following best practice in all dimensions. The analysis reveals that the US GOM is an outlier on several fronts, namely:

- It is the only jurisdiction that applies a bidders' list, though there is no evidence of the effectiveness of such a measure. Most of the other jurisdictions surveyed have an equally competitive market structure with no similar restrictions in place. Instead, they rely on technical and financial pre-qualification requirements.

- It has the widest variation in exploration license durations, varying with several water depths. By comparison, most of the other jurisdictions have one license duration for offshore and where a distinction between water depth is made, it is typically between shallow and deepwater.

- The duration of the US GOM exploration phase (Primary term) for depths between 800 m and 1600 m is lower than the other depths, including shallower water. In practice, one would expect to see longer duration for deeper water depths.

- It applies special circumstances to SOO and SOP, where the latter can be granted for up to five years, but the practice has been for one year or less. Also, for SOO and SOP, the leaseholder is required to pay rental and minimum royalty for the granted suspension period. The closest to this arrangement can be found in Australia (with the Retention Lease) and

Canada Newfoundland and Labrador (with the SDL), which apply in the case of a discovery. In the former case, the lease is granted when a discovery is not currently commercially viable but is likely to be so within 15 years; the lease requires a work program to be carried out and its terms can be renewed subject to a fee. In Canada's case, the interest owner can continue to hold rights to a discovery area while the discovery is appraised, and commercially proven. The SDL is subject to rental fees applicable at ascending rates.

- In terms of lease duration, only for licenses covering water depths greater than 1,600 m, the US GOM exceeds the average of the analyzed jurisdictions; all the other licenses in the US GOM fall below the average.

- No relinquishment applies to upon renewal in the US GOM most likely because the blocks are very small – in fact, the smallest among all the selected jurisdictions.

- During the primary term, lessees do not have a mandatory work program or deadlines for conducting exploratory or development activities, except when applying for an extension. In all the other jurisdictions selected, a minimum work program must be carried out and is typically biddable (in some jurisdictions, it is the only biddable parameter).

- There is no clear rationale behind US GOM rental fees: Leases between 200 and 400 m attract the highest fee from year six, while leases for shallow water (less than 200 m) have the lowest fee for first five years.

- When considering the five-year average of the exploration phase for all the selected jurisdictions, the US GOM rental fees are above the average. The difference is insignificant for leases covering water depth below 200 m but, for the other leases covering a higher water depth, it is more than USD 1,000 per km². When the average is taken for the first seven years, the rental fee for all the leases in the US GOM exceeds the average, with the lease for water depth between 200 and 400 m nearly double the average rate.

- The results of recent licensing rounds reveal that the US GOM is not as attractive to investors as less explored areas such as Brazil and Mexico. For instance, the US GOM captured the second highest signature bonus per km², after Brazil, and five times more than Mexico. However, the US GOM relies solely on the signature bonus to award licenses, while in Brazil, the bonus per km² was more than double what was paid in the US GOM, even though in Brazil the bonus is not the only biddable parameter. In Mexico, the bonus is paid only to resolve a tie between two bids.

4. Fiscal Policy Analysis

The objective of this section is to evaluate the US GOM upstream fiscal regime, in order to identify the fiscal characteristics that impact investment opportunities. The analysis carries out a qualitative and quantitative assessment of the current US GOM fiscal regime and identifies potential fiscal reform options for consideration. The study recognises that any major structural changes to the fiscal regime, such as replacing Royalty with a generic resource rent tax, would risk unsettling investors and almost certainly discourage investment in the short-term. The challenge is therefore to work within the regime in place today, an evolutionary not revolutionary approach.

Prima facie, and by simply focusing on marginal tax rates, the US GOM probably ranks as one of the most economically attractive territories in which to invest, especially with the Administration's recent decision to reduce the headline CT rate from 35 percent to 21 percent. However, when fundamental basin differentiators such as costs, capital exposure, payback and regulatory risk are assessed, the US GOM looks materially less attractive given the very large water depths, up front lease bonus payments and high finding and development costs, long lead times and regulatory burden.

The conventional measure of marginal tax would show that the US GOM has recently experienced a marginal tax rate of typically 43 percent after Royalty and federal taxes[14]. Following the latest tax reforms, this will fall to around 30 percent: in headline terms, no other established oil and gas province comes close. For example, Norway is typically 78 percent and the UK 40 percent on similar measures. The low tax burden seems, on the face of it, highly attractive for the industry and that may well be true for some legacy projects. The risk, however, is complacency; historically, basin maturity has bitten hard and swiftly. The fiscal regime in the US GOM today is attractive for harvesting cash flow from legacy producing assets and highly profitable new projects but less so for embarking on new exploration with high cost development, as this section will demonstrate.

The analysis delves beneath the headline rates to assess the actual fiscal burden for new projects and investigates whether the current regime is working for the full range of investment opportunities. It addresses questions such as: How can exploration activity be encouraged through the fiscal regime? Is the fiscal regime causing projects that are economic pre-tax to become uneconomic post-tax and what measures can minimize or eradicate this impact? The section further examines practical specific tax incentives that have been introduced in mature and maturing offshore basins, to identify what could be appropriate for the US GOM; how they could be modified and shaped to meet the specific challenges of the province; what bespoke incentives should be considered for GOM and how would they be structured.

The analysis is carried out as follows. Section 4.1 undertakes a qualitative assessment of the key components of the US GOM fiscal regime, namely: the lease payment, Royalty and CT, in order

[14] The marginal tax rate is the amount of tax paid on an additional dollar of income.

to identify the aspects that could be sensibly addressed. Section 4.2 presents the modelling work whereby nine scenarios are thoroughly assessed. Section 4.3 provides the recommendations.

Throughout, experiences from other countries are considered to illustrate practices elsewhere and lessons that can be learnt for the US GOM. It is always helpful, when designing a fiscal regime and or considering improvements to it, that the experience of other fiscal regimes is considered. There is no such thing as a perfect fiscal regime though the search continues to create one. Fiscal regimes need to respond to the geology, maturity, cost structure, competitive pressures and government priorities.

4.1 Structure of US Fiscal Regime

4.1.1. Lease Payments

One of the most enduring features of the US system for awarding leases is the reliance on cash bids to determine exploration license awards. As the analysis in Section 3 shows, a minority of oil and gas provinces choose to allocate exploration licenses exclusively by competitive cash bids. The strongest practitioners are found in North and South America, specifically the US, Canada and Brazil. The signature bonus can work effectively as a rent-capturing mechanism as long as there is sufficient competition and in a basin with proven commercial hydrocarbon potential.

One of the reasons for the durability of the US cash bidding process must be its success, from a government perspective. Since the 1950's, the US Government has collected USD 82.8 billion (nominal) in lease bids. In real terms (2018 USD), this is over USD 255 billion. The vast majority of this is attributable to US GOM, the remainder being in Alaska and other OCS areas. With such a major source of revenue for the government, it is hardly surprising that the government is eager to license other regions of the US OCS. Sums of this magnitude make the lease bidding system one of the fundamental aspects of the US upstream fiscal regime along Royalty and CT. With the recent reduction in the federal tax rate, lease bonus payments represent, with Royalty, the main rent collection mechanism.

In many respects, the lease payments enable the US Government to capture the economic rent upfront. It is then a matter of hindsight whether or not the lease or 'rent payment' collected an appropriate amount of the anticipated 'rent', from too much or all of the rent in the event the lease was unproductive or too little in the event of a very large profitable discovery.

Figure 18: US Annual Bonus Receipts from Outer Continental Shelf Lease Sales 1968-2017

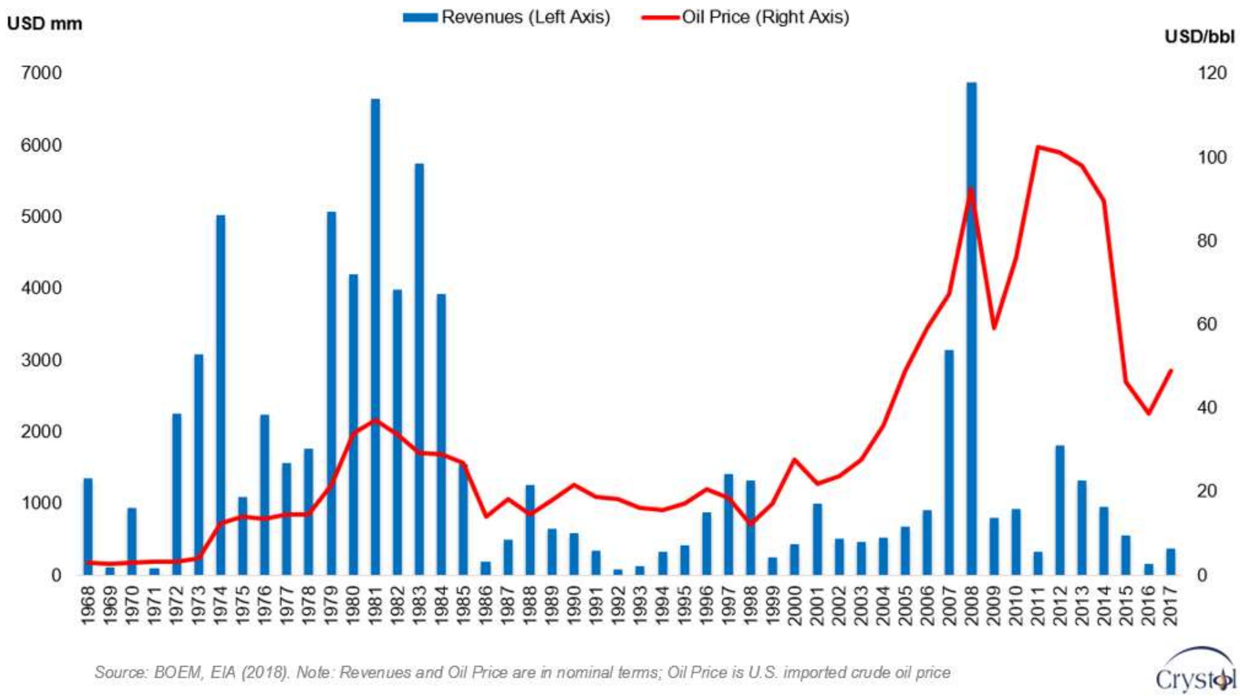


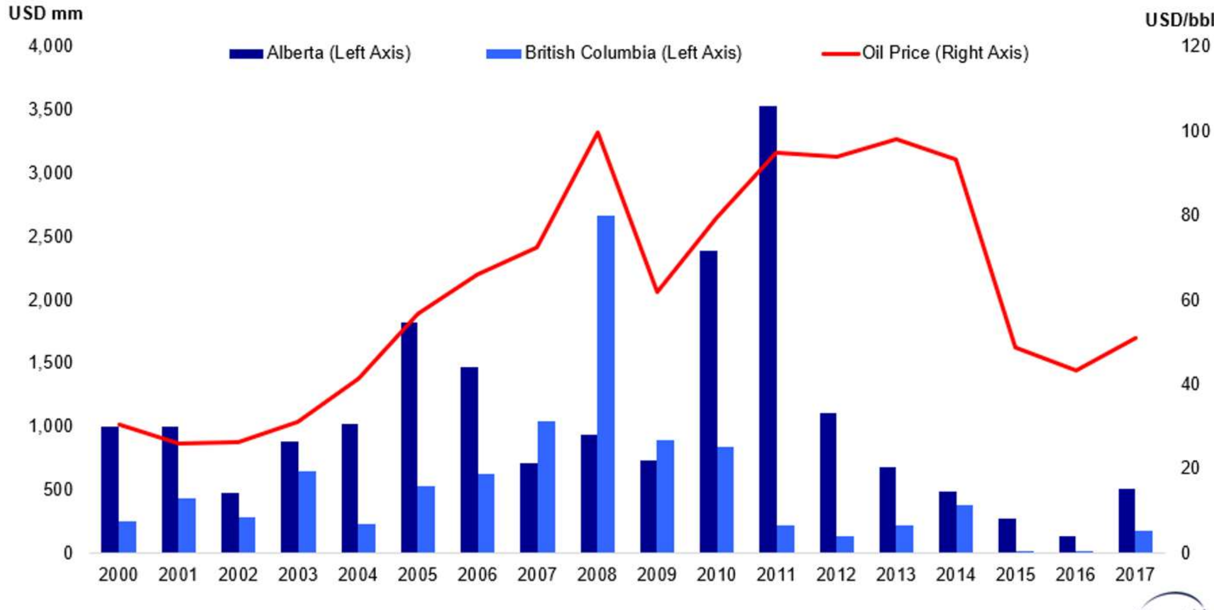
Figure 18 demonstrates the volatile nature of the annual revenue derived from the lease sales, largely reflecting changes in oil prices.

For comparison, Figure 19 below illustrates the lease payments collected in Alberta and British Columbia between 2000 and 2017. Like the US GOM, the payment profile is strongly correlated with oil prices and basin maturity. In all of these basins, the fall in bid payments following the collapse in the oil price in 2014 is pronounced.

Additionally, the oil industry's interest is switching to other more volumetrically prolific provinces. For example, in the last two years, Brazil has collected USD 3.5 billion in upfront lease bids as investors pursue the potential of the pre-salt plays.

Much like the US, the rational for having a biddable signature bonus in Brazil is to capture rents through maximizing immediate revenues (Box 6). Brazil's fiscal package which relies on the signature bonus and a Special Participation Payment to accrue economic rents seems to be sufficient to elicit investment in deepwater areas as the results of bid Round 15 suggest (Section 3).

Figure 19: Alberta and British Columbia: Annual Bonus Receipts (2000-2017)



Source: Government of British Columbia and Alberta (2017); EIA (2018). Note: Oil price is dated WTI Spot Price FOB

Box 6: Capturing the Economic Rent in Brazil

Brazil's concessionary fiscal regime is composed primarily of the following elements:

- The signature bonus is one of the biddable parameters, the other being the work programme (local content related commitments were previously part of the bid), but a minimum signature bonus is assigned to each block.
- The royalty rate is a fixed 10 percent for oil and gas with the possibility of reduction to a minimum of 5 percent in the case of marginal fields.
- The Special Participation Payment is levied at the project level and the rate is a function of production value, production year, location and profitability. The tax base is similar to that of CT but its structure seems to be overly complicated and not effectively targeting project profitability. It has a sliding scale based on many proxies for economic rent, including daily rate of production, location, and production year, further creating regulatory compliance costs.
- The CT rate is 34 percent and capital deductions are calculated using either units of production or 10 years straight line.

In economic terms, the lease payment in the US provides the government with large upfront revenues often decades before any oil or gas begins to flow. Royalty and federal income tax receipts come much later in the investment cycle.

For many leases, the exploration efforts may yield no commercial discoveries, so the government will have received an up-front windfall while the investors will just incur losses from the lease payment and the unsuccessful exploration expenditure.

For these reasons, the lease payments are an integral and fundamental part of the US GOM fiscal regime. Looking just at Royalty and federal income tax regime alone gives a very misleading picture of the fiscal burden faced by investors.

It is difficult for the industry to mount any convincing argument to remove the lease bidding system and replace it with a system which, say, allocates acreage by work program, as it is entirely in the hands of the investors how much they choose to bid for a particular lease and when they wish to bid, if at all. From an economic perspective too, once the lease bid has been paid, it becomes a sunk cost and places no part in the subsequent assessment of future EMVs and drilling decisions. Indeed, perversely, the available future tax relief on the prior lease payment may provide an economic enhancement to the forward EMV and development decision economics.

Inevitably, if the lease bidding system was removed, this would require the US authorities to put in place new fiscal instruments that raised a comparable level of revenue on an NPV basis. This would probably have to be in the form of a resource rent tax (RRT) that would introduce considerable complexity into the existing fiscal regime, creating distortions between legacy leases that do not have this burden and new leases that do. It would be a challenge to design such a regime that did not risk discouraging investment rather than encouraging it.

Given the above assessment and deeply ingrained feature of the lease bidding system, this study does not propose any reforms to the current bonus bid system in the US GOM.

4.1.2. Exploration Incentives

Exploration incentives have proved to be a difficult topic amongst policy makers for many decades as there are no straightforward incentives that can be implemented without the risk of them being regarded as costly, complex, distortionary or a subsidy. In many respects, the best incentive to encourage exploration activity is, apart from the obvious geological attraction, a competitive and stable fiscal regime combined with enabling license terms. The US GOM has many of these ingredients, but not all.

As discussed earlier in this report, the US continues to operate a system of allocating acreage to the highest cash bidder, while many countries allocate acreage according to a committed ‘work program’, ensuring exploration activity occurs in a pre-determined time frame.

One of the economic features of the bonus system is that, once paid, the bonus has no further impact on forward project economics and investment decisions unlike Royalty and other ingredients in the fiscal regime. The tax relief on the upfront lease payment is eligible to be recovered from future cash flows and will for investors, with no legacy production and on-going tax shelter, serve to increase the value of future developments.

Furthermore, a large bonus payment may well act as an incentive to accelerate the lease exploitation so as to begin the process of earning a return on the upfront outlay. Nevertheless, it can be asserted that the bonus system reduces the amount of funds that could be devoted to exploration drilling[15].

Taken together with the Royalty and federal tax rates, the bonus system makes the US fiscal regime less competitive than might otherwise be the case. After all, the level of Government Take on acreage, secured via a competitive bid, that ultimately proves unproductive will be 100 percent.

The fact that the bonus is paid upfront, often decades before production commences, has a significant impact in depressing life cycle returns in the GOM. Bonus bids are, of course, reflective of the fiscal regime itself and the underlying geological potential. A more onerous fiscal regime would be expected to depress bonus bids and vice versa.

One radical approach could be, for example, to reduce or eliminate the Royalty burden on new leases. Whilst obviously reducing the Royalty yield, the US Government could still emerge better off through the resulting increase in upfront lease bids and higher tax revenues from developments proceeding that would have otherwise been stalled due to the high Royalty burden. This, however, would probably be difficult to prove to the satisfaction of policy makers wedded to the long-standing policy of leased bids.

4.1.2.1. The Norwegian Approach

A fundamentally different approach is taken in Norway, one which is often cited as an example of best practice that other oil and gas provinces should emulate. The essence of the Norwegian approach is that investors which are not in a current tax paying position are entitled to an immediate refund of 78 percent of their exploration costs: the 78 percent tax rate applied to the exploration costs is simply the current aggregated rate of the Special Petroleum Tax (SPT) and State Tax (ordinary company tax rate). When and if such an investor becomes tax paying, they cannot claim a deduction for the exploration cost.

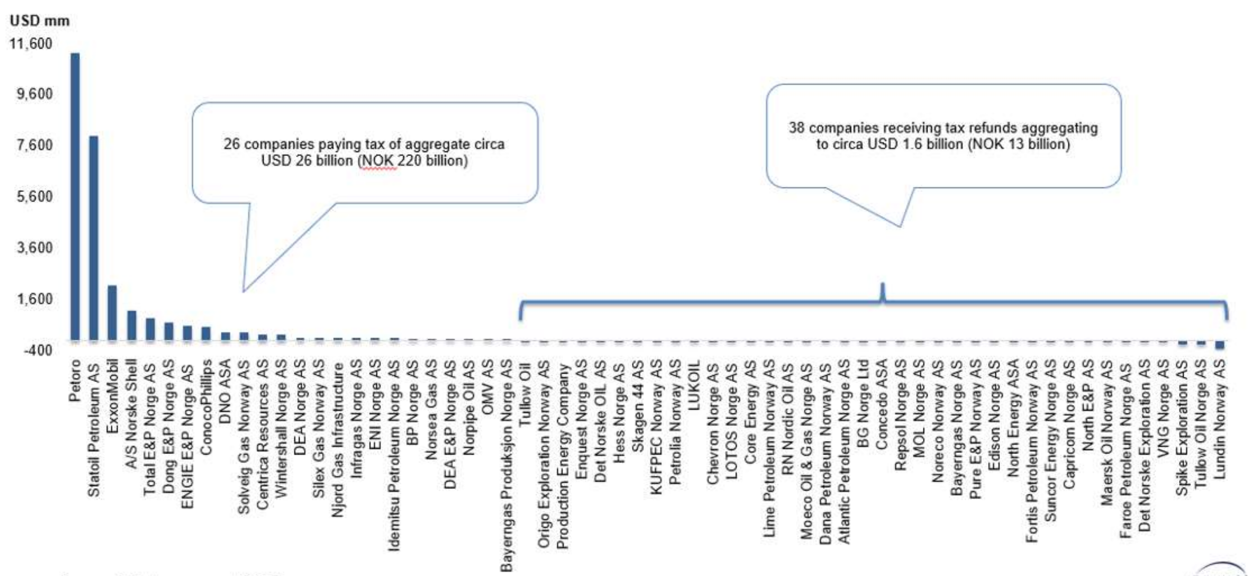
The scheme only applies to exploration costs, not subsequent appraisal costs. It is also of no incremental benefit to an investor who is currently tax paying. The benefit is essentially a timing difference enabling investors to secure immediate tax relief rather than wait until new developments come on stream and commence tax payments. For an investor who never makes a commercial discovery and ultimately leaves the basin, the payment by the state could be categorised as a subsidy in that specific circumstance. It is therefore no surprise that the relief is subject to constant attacks by stakeholders outside the industry, with the most recent one being an investigation by the European Free Trade Association (EFTA) following a referral from Bellona, a Norwegian environmental lobby Group in August 2017. Bellona is asserting that this system of

[15] Signature bonuses generally are not permitted as cost recoverable items in PSC though they are allowable as a deduction against CT.

reimbursing exploration costs represents an illegal State subsidy under EFTA rules. It is expected that EFTA will provide a ruling on this matter by the end of 2018.

The Norwegian system of exploration refunds was introduced in 2005 and so far, the Norwegian State has reimbursed over USD 12 billion (Figure 20). In 2015, the refund aggregated to USD 1.7 billion. Whilst this seems a large figure, the annual tax yield from the petroleum sector exceeded USD 27 billion in the same year, net of the refund, so a relatively small proportion of the total annual tax yield.

Figure 20: Norwegian Upstream Tax Payments 2015



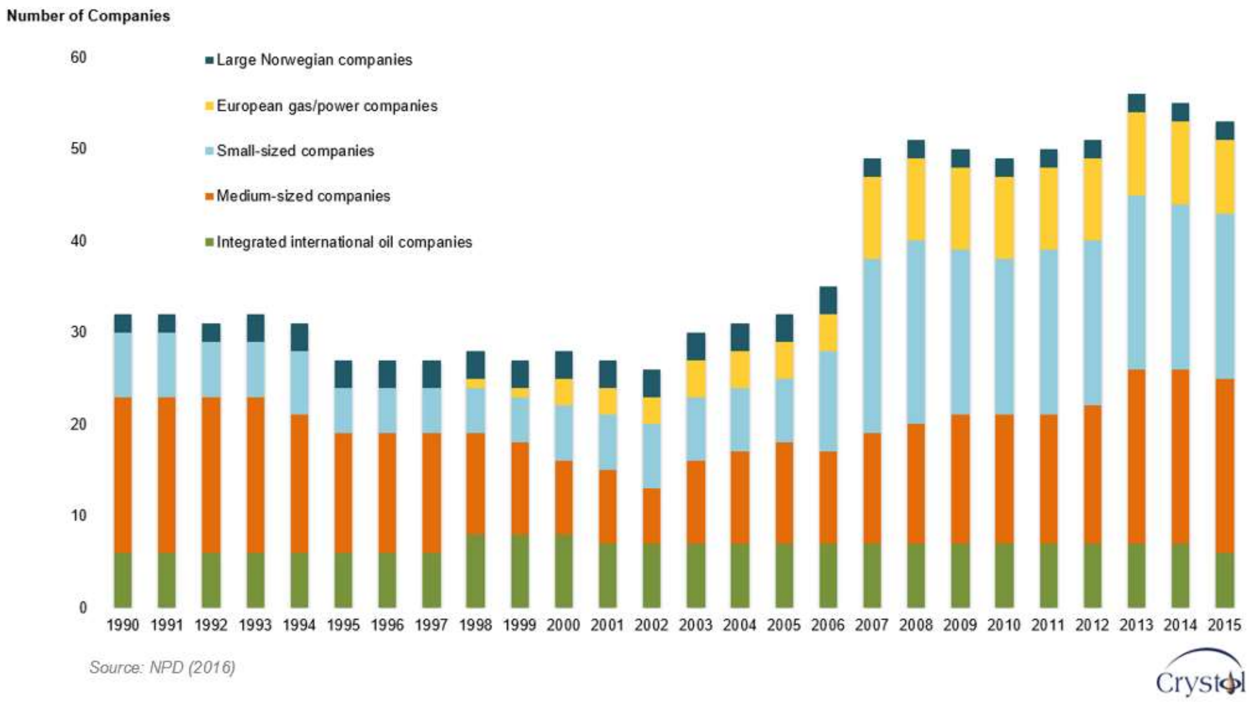
Source: EITI Norway report (2015)

The Norwegian Government strongly supports the measure as it encourages new entrants into Norway. Figure 21 shows the increase in the number and diversity of players post 2005. Smaller and mid -sized companies have been more likely to drill prospects that larger companies regard as not material or not a corporate priority.

One of the best ways to boost exploration activity is to encourage a large number and variety of participants. By sharing the burden of exploration risk amongst a wider number of participants and thereby with a large number of geologists, sooner or later one of them may well support a decision to drill a well.

A similar system, if introduced in the US, would be of little benefit to established players in the GOM, except to those companies which are not in a tax paying position. The cost to the government would be considerably less than in Norway as the applicable tax rate would be 21 percent not the 78 percent as in Norway. However, at that low rate it would arguably provide less leverage to the exploration decision.

Figure 21: Number of Companies on the Norwegian Continental Shelf



There is also the question of the overall coherence with the wider US tax system and its interaction with the lease bonus arrangements. For example, it might seem somewhat inconsistent to request investors to pay cash upfront to secure a lease and then for the government to return most of the proceeds to the investors to fund a share of their exploration costs. There is also the risk of distortion; if the exploration refund only applied to new leases, then holders of legacy leases might feel aggrieved that exploration on their acreage is in effect being discouraged.

No other countries have followed the Norwegian lead in providing reimbursement of exploration costs, though many, at the behest of the industry, have reviewed the potential of such an arrangement. In the UK, for example, there is no such direct exploration incentive; companies, however, not in a tax paying position with carried forward losses, are permitted to increase such losses by 10 percent per annum for a maximum period of ten years (previously six years but increased to ten in 2013). This is the so-called Ring Fence Expenditure Supplement (RFES). Companies still have to wait until they become tax paying before they can realise any cash benefit from the allowance.

It is questionable whether the state should be taking the bulk of the exploration risk in such an explicit fashion. Norway, however, has a long history of state participation and control in the oil and gas sector. Both through its large equity ownership of Equinor (formerly Statoil) and its 100 percent ownership of Petoro (the entity managing its direct state ownership), the Norwegian Government continues to directly and indirectly own the majority of oil and gas assets in Norway and is the majority participant in future exploration activity. Seen through this lens, the exploration refund is complimentary to the enduring state oversight, ownership and stewardship of oil and gas activity.

Since the bulk of the reward (78 percent marginal tax rate) accrues to the government, then the state continues to be comfortable in taking the bulk of the risk. If future exploration is the subject of increased tax relief and or incentives, at a significant cost to the US Government, then it is unlikely that the current fiscal regime would remain unaltered. If the US Government assumes a greater share of the risk, then it might insist on a greater share of the reward.

What other options might be available? The most obvious are changes to the treatment of exploration costs for relief against CT. There is much merit in permitting exploration and appraisal costs to be expensed as incurred rather that relieved on a unit of production basis (UOP). This could be augmented further by introducing uplift (development incentive) on such costs. This is the approach taken under the recently constructed Mexico fiscal regime whereby USD 100 million of exploration costs secure a tax deduction of USD 125 million (assuming 25 percent uplift rate).

As a note of caution with the CT rate now at 21 percent, the impact of such changes to depreciation will be modest, though the lower rate does have the advantage of making the changes more affordable from a government perspective. Uplift is fairly uncommon in fiscal regimes generally, perhaps due to its cost. If the CT rates are high, then the uplift will be a relatively expensive component of the fiscal regime.

4.1.3. Corporate Income Tax

The 2017 US tax reform lowered the headline federal CT from 35 percent to 21 percent; from one of the highest rates in the OECD to amongst the lowest. This significantly increases the value of both producing and yet to be developed oil and gas accumulations in federal waters.

The tax rate is, undoubtedly, only part of the story; the composition of the tax base is equally important to the rate itself. For the upstream sector, the depreciation terms are not particularly generous taking around six years to fully depreciate Intangible Development costs (IDC's) from when entering service. By comparison, the UK permits capital costs to be depreciated 100 percent as incurred plus uplift of capital costs against elements of CT.

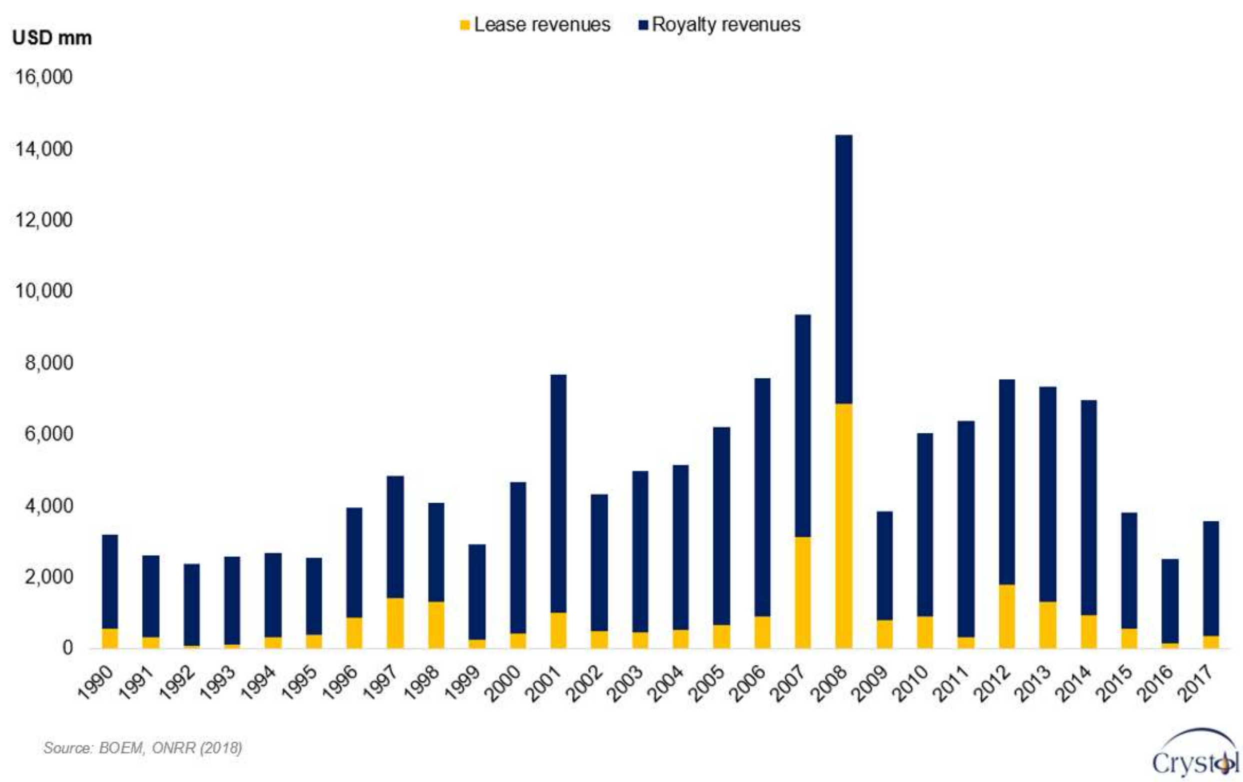
Given the low tax rate and complexity of the US tax code, however, this study does not propose any specific tax changes to the existing regime for determining CT liabilities which would have impacts on other US industries. This would make enabling legislation difficult politically. Instead, the study evaluates possible 'bolt on' measures such as uplift and expensing of exploration costs to assess the potential impact of these measures and on the basis that these changes could be implemented without upsetting the integrity of the wider CT system. That said, pragmatically given the scale of the recent tax cut and the increase in oil prices, the political appetite for further fiscal changes to the CT regime just for the oil and gas sector must be limited at least in the short-term[16].

[16] See Appendix I for a review of an incentivized technology development program with associated data sharing and tax credits.

4.1.4. The Royalty Regime

Along with the competitive lease bonus system, Royalty represents the key 'rent' collection mechanism in the US OCS in general, and GOM in particular (Figure 22). Indeed, across the US oil and gas sector, there is a long tradition of Royalty levies going back to when the oil industry was in its infancy. Cumulative Royalty (1990 to 2017) payments derived from the US OCS exceed USD 193 billion (mod).

Figure 22: US Outer Continental Shelf Lease and Royalty Revenues (nominal)



The US Royalty rates are high by global standards with most new leases (except shallow water) subject to a rate of 18.75 percent. Furthermore, the Royalty regime has evolved into a very complex tapestry of rates, reliefs and allowances. The legacy today, combined with the frequency of changes, confirms the considerable challenges facing policy makers to shape a Royalty regime that is appropriate for a very large range of resource and economic outcomes.

The key variables that policy makers have continually changed are: the Royalty rate itself, the rate applicable at various water depths and the suspension volumes (the amount of production that can be initially produced free of Royalty). To the extent changes have been made, they tend to be prospective and not retrospective so there is a legacy of different royalty terms dependent upon when the lease was awarded. The authorities also have the discretion to waive the Royalty liability towards the end of the field life when it is clear that the Royalty burden may precipitate early cessation of production. The current Royalty policy is based on the presumption that deepwater deposits are more profitable than shallow water so they typically attract a higher Royalty rate and are denied access to suspension volumes. In many respects, this policy differentiation has questionable foundations, as marginal projects can be found in any water depth and, if anything, deeper water means higher costs, longer lead times and higher risk.

The suspension volumes are potentially a very important mechanism as they assist in accelerating payback and minimise the tax burden in the early years of the project's life. However, the volumes in question can only be arbitrary in nature as they are based on exploration success and uncertain forecasts of the oil price that is likely to prevail when such projects enter production. Inevitably, the suspension volumes will be too low for many marginal fields and too high for many more profitable fields.

In terms of practical value, the fact that the suspension volumes do not apply when the oil price exceeds circa USD 43/bbl means that this provision has little economic value in today's environment when conducting economic appraisal.

The problem with the suspension volume as an incentive is that the suspended volumes are worth progressively more as oil prices increase hence the rationale for the government to withdraw the benefit at higher prices. To this extent, the incentive is poorly targeted, and subject to changes in the arbitrary oil price threshold, as the current provision in the US GOM illustrates, whereby the suspension volume is withdrawn when oil prices are above a certain threshold (though one can argue that USD 43/bbl is hardly a high price).

But even this is a blunt instrument as the oil price threshold is binary – one may just miss it or just make it. It would arguably be better targeted if there was a tapering provision whereby the volumes were linearly reduced within for example a USD 20/bbl price band (say from $43/bbl to $63/bbl). A Royalty structure which explicitly links the burden to underlying project profitability is a more intellectually coherent approach, but to date has proved to be elusive to policy makers in the GOM.

In some circumstances, the suspension volume is per lease not per field within the lease so whilst the first development will benefit from the suspension volume a subsequent development on the same lease would not. This clearly has the potential to create significant distortions to the flow of investment. However, given the relatively small size of each leased block, it is unusual to have more than one development per lease.

Some shallow water leases have had their Royalty rate reduced to 12.5 percent reflecting the assumption that the basin is mature, developments are now small and with marginal economics. The problem for policy makers is that oil field economics do not fit into neat categories so marginal fields can be found in deepwater and shallow water alike, and highly profitable fields can be found in all water depths.

The evidence suggests that shaping an enduringly stable Royalty regime remains elusive. It is clear from the frequency of changes that policy makers are attempting to use Royalty as proxy for an RRT but Royalty, as typically structured, is simply inadequate for this task.

By its very nature, Royalty is a regressive tax imposed on revenues not profits; in other words, the Government Take falls as oil price and profitability rises and vice versa. From an academic perspective, the most appropriate fiscal regimes have progressive tax instruments whereby the Government Take rises with high prices and profitability. Of course, nobody is suggesting that a new RRT should be introduced to GOM to replace Royalty; this could seriously destabilise investors' confidence and would almost certainly, in the short-term, discourage investment. Rather, the challenge in terms of fiscal policy is to work with the grain of what is in place today and shape changes to the Royalty to make the overall fiscal regime:

- less regressive;
- automatically respond to changing profitability;
- not require continual government intervention;
- stable across a range of price outcomes;
- stable as the basin matures catering for smaller field sizes and higher unit costs;
- minimize distortions – projects that are economic pre-tax remain so post tax; and
- minimize discretionary powers – providing more certainty and predictability.

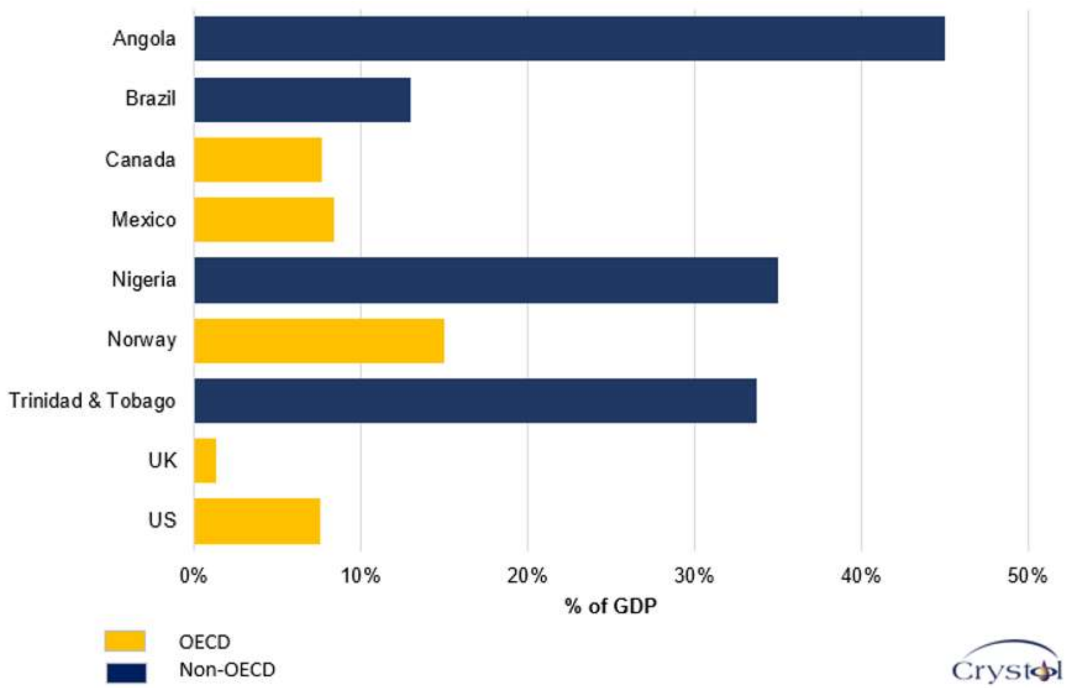
4.1.4.1. Available Royalty Structures

Royalty has long been a key feature of most fiscal regimes particularly in the early years of basin development. It has undeniable attractions which include its ease of design, collection and predictability; fundamentally, it delivers revenue to the state as soon as production commences. In this respect, Royalty serves a clear purpose in the early years of basin exploitation. Once significant production is established, however, rent collecting mechanisms are best designed to tax profits and not revenues.

Royalty is particularly popular in developing countries which often lack the sophisticated institutional tax collection administrations necessary to administer a CT regime. Royalty fits the bill as a key 'rent' collection instrument often in conjunction with a PSC, which is commonly found in developing countries where upfront cash and ease of collection are essential.

In contrast, in the OECD, oil revenues tend to be less critical as they contribute to a smaller part of the economy (Figure 23). Also, in the OECD, the government can rely on CT as there is a sophisticated institutional mechanism for its administration, which is often weak in developing countries.

Figure 23: Oil and Gas Sector Economic Contribution in Selected Countries



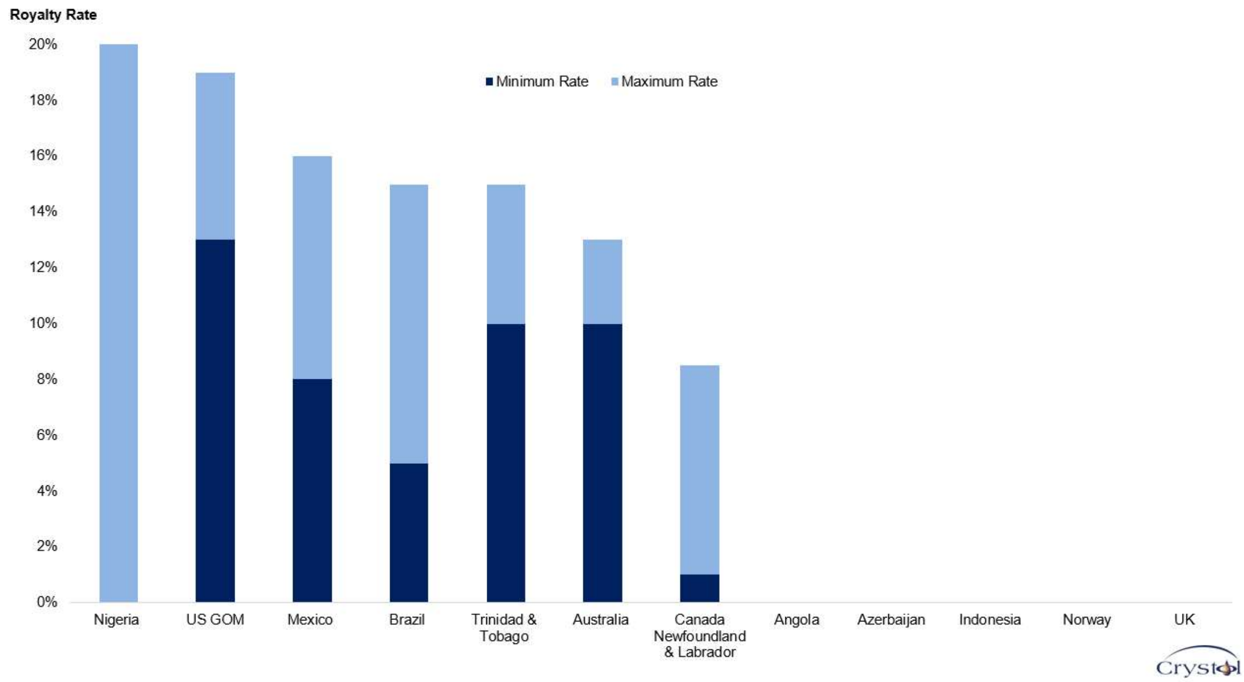
Source: ANP; Norwegian Petroleum (2018); API; OPEC Statistical Bulletin; OECD Economic Surveys; UK Energy Statistics in Brief (2017); Natural Resources Canada (2016-2017)

Despite these advantages, Royalty carries several drawbacks which outweigh its benefits particularly as its rates increase. Fundamentally, it is not profit related and can deter some projects, which are profitable on a pre-tax basis, from proceeding. Premature cessation of production typically occurs unless the Royalty burden is progressively relieved as fields mature.

From the perspective of fiscal design, the Royalty makes the fiscal regime regressive. The most effective and efficient fiscal regimes are broadly neutral or progressive with changes in profitability.

Before considering potential changes to the GOM Royalty regime, it is instructive to review what typical options are in place in other jurisdictions. Figure 24 below shows the Royalty rates in a selection of leading producers, including the US GOM's close neighbours. Note that mature basins such as the UK and Norway abolished the Royalty decades ago.

Figure 24: Selected Royalty Rates



Governments can select from the following options when designing their fiscal regime:

1. **No royalty**: Many countries do not have Royalty or have abolished it in phases. For example, in the UK, Royalty was abolished for new developments in 1983 and for all fields in 2003. Those countries that used to have Royalty but then progressively abolished it, moved to a wholly profits based regime with other rent collecting fiscal instruments that cushion the revenue cost of abolition to the state. Both the UK and Norway are in this category, with marginal tax rates between 40 percent and 78 percent respectively. Many countries with PSC regimes have no explicit Royalty but have it by other mechanisms, for example a limit on cost oil can serve a similar purpose by ensuring a flow of Profit Oil (which is shared between the host government and the contractor) as soon as production commences. Angola, Azerbaijan and Indonesia fall into this category. An outright Royalty abolition in the US would be hard given that other tax instruments are limited to federal income tax (21 percent) and lease bids. In theory, Royalty abolition would engender higher lease bids for acreage, but it would be difficult to assess whether or not this would lead to higher eventual government revenue.

2. **Royalty holidays**: Similar to the current US system of suspension volumes, a fixed quantity of initial production is exempt from Royalty. This particularly helps smaller fields but is somewhat arbitrary in nature. The benefit would flow to all fields irrespective of profitability and is worth more as prices rise. It would tend to benefit smaller fields the most as a greater proportion of their production will be Royalty exempt.

3. **Sliding scale Royalty linked to production**: Such an option can help to shorten the payback period and extend a field's life by avoiding premature field closure. Nigeria applied such a system, in addition to varying the Royalty rate by water depth. Nonetheless, since the size of production is a poor proxy of profitability, such a structure typically benefits small fields most, not necessarily those that are most marginal, thereby making the regime more regressive. There can also be undesirable side effects whereby, a project may be engineered to avoid production rates spiking into the top or higher tiers of Royalty.

4. **Royalty linked to price**: The Royalty rate can be linked to oil and/or gas prices within a defined band giving a minimum and maximum rate; Alberta oil sands' Royalty regime is one example (see Section 4.1.4.2). This sounds simplistic but creates hard edges as the Royalty rate changes. With oil price volatility the Royalty rate could be changing on a continuous basis, upwards and downwards. Adjustments need to be made for the quality of the actual crude produced relative to a reference blend (say Brent) price. However, there will always be some projects that are marginal even at high prices, so triggering a high Royalty rate via a price mechanism also has its limitations as it does not take the cost into consideration

5. **Royalty linked to rate of return (ROR) or Internal Rate of Return (IRR)**: This option has the most intellectual appeal but can be at the risk of complexity. The Royalty rate can be formulaically linked to the actual project level ROR earned to date, or within specific bands (for example: zero or a very low rate until payback has been secured, then with progressive steps upwards as the measured return increases). Such a system ensures that the Royalty burden is explicitly tied to the underlying profitability of the project. The Royalty rate could also be linked to an R factor - the ratio of cumulative pre or post tax receipts to cumulative expenditures ensuring that the Royalty rate begins to decline as the field matures and approaches the end of field life. Both Canada Newfoundland and Labrador (Table 9) and Mexico (Additional Royalty, see Section 4.1.4.2) adopt this approach.

Table 9: Canada Newfoundland and Labrador Royalty Mechanism

R-factor	Basic Royalty Rate for Oil
First Oil to R < 0.25	1%
0.25 ≤ R < 1	2.5%
1 ≤ R < 1.25	5%
R ≥ 1.25	7.5%
R-factor = (cumulative gross sales revenue and incidental revenue less cumulative transportation costs less cumulative basic and net royalty paid to prior month) ÷ (cumulative pre-development, capital & operating costs)	
Basic royalty = (gross sales revenue - transportation costs) x BRR	

Source: Generic Offshore Royalty Regime (2017)

6. **Level of Royalty rates**: the rates of Royalty applicable around the world vary considerably. A rate of 12.5 percent is close to the norm with most in a band of 10 to 15 percent for oil and lower rates for natural gas. In Brazil's 15th licensing round, the royalty rate was fixed at 10 percent for oil and gas with the possibility of reduction to a minimum of 5 percent in the case of marginal fields. The GOM rate of 18.75 percent (except for shallow water) is high by global standards but not perhaps in the wider context of US CT at 21 percent.

7. **Royalty calculation**: Like any tax instrument, the devil is in the detail when it comes to the calculation of the Royalty base, which is equally important as the Royalty rate. Most conventionally, the base is the wellhead value, but some regimes permit certain costs to be deducted prior to the application of the relevant rate. If operating costs and certain depreciated capital costs can be deducted from the revenues subject to Royalty, then the Royalty is effectively converted into a more profit related tax, dramatically reducing the yield and making the regime more neutral in nature, aligning Government Take with profitability.

8. **Royalty credit**: Typically, any Royalty liability is taken as deduction in the computation of CT. Alternatively, the Royalty may be taken as a credit against the CT liability, which materially reduces the economic burden. However, much the same effect can be secured by having a lower rate in the first instance.

9. **Hybrid**: The above structures are not mutually exclusive; a Royalty regime can be devised in a way that combines features from a number of these alternatives.

It cannot be definitely concluded that any one of these structures is superior to others. Such an assessment depends upon different factors, including: other elements of the fiscal regime, the basin's economics, geology and maturity, and the government's priorities.

4.1.4.2. Specific Country Experience with Royalty

To complement the above discussion on the structures of Royalty, it is instructive to review the experience of selected countries with regard to Royalty policy.

Experience in the North Sea, Alberta and Mexico confirms that there is no perfect design solution. There are almost as many Royalty regimes as there are countries. The specific Royalty regime depends on several parameters, such as: the basin's geology and maturity, water depth, cost structure, government need for revenue, and tax administration competence. The Royalty regimes themselves are rarely static with continued evolution of rates and allowances to ensure the basin remains competitive and economic extraction of resources is maximized.

a. The North Sea (UK and Norway)[17]

The North Sea is often cited as a good basin to benchmark and compare the fiscal experience as it is 'writing the script' as to how the government and industry should best steward oil and gas resources in a maturing basin. Both the UK and Norway had Royalty as a key feature of their fiscal regime from the beginning of their oil and gas exploitation in the 1960's. The Royalty remained in place as the basin production grew in the subsequent decades.

The UK Government made an early move to abolish Royalty first for new oil developments back in 1982, whilst leaving it in place for legacy production. Royalty was abolished for new gas fields a few years later in 1988. Royalty was finally abolished for all production in 2002, though this was accompanied by an increase in CT and a move to 100 percent depreciation for capital expenditures. Although, as a package, the measures were revenue raising, they did convert the UK fiscal regime uniquely to a cash flow tax regime based entirely on taxing profits not revenues whereby no tax is payable until project payback has been secured and the pre-tax and post-tax internal rate of return (IRR) are the same. The UK Government was then able to confirm that no projects were prevented from proceeding due to the tax regime. Norway followed the UK example very closely, abolishing the Royalty for new developments in 1986 and phased out for legacy production from 2000.

The drivers behind the changes were in large measure an acknowledgement of the strength of the industry's advocacy which focused on the:

- simplification of a complex tax regime and of its administration;
- advantages of a wholly profit based fiscal regime;
- recognition of basin maturity, with rising unit costs and falling discovery sizes;
- need to encourage exploration and development of marginal fields while extending the life of mature fields and associated infrastructure;
- reality of a hiatus in new development coming forward for approval after the 1982 oil price collapse.

Royalty abolition was made possible in the North Sea by the existence and continuation of other 'Rent' collection mechanisms within the prevailing fiscal regimes. With the Royalty removed in stages, the net impact on government revenues in both the UK and Norway was very limited. In the UK, Royalty abolition was financed by an increase in the CT, which more than compensated for the revenue cost. In Norway, with the marginal tax rate standing at 78 percent, the overall cost to the government of Royalty abolition was modest.

[17] A more detailed description of the UK and Norwegian fiscal regimes is provided in Appendix I.

b. Canada: Alberta Oil Sands

The Province of Alberta has grappled with the appropriate Royalty regime for decades with a history of frequent changes and multiple reviews. Alberta's experience is symptomatic of a fiscal regime that does not have an explicit RRT and relies on Royalty (and to a lesser extent lease bonus payments) for this purpose, like GOM. It should be remembered, however, that the resource base (onshore, oil sands) is very different to GOM, so comparisons have limitations. But it is the policy challenges, fiscal design and political dynamics that are of most interest.

Following the oil price collapse in summer 2014, Alberta carried out a fiscal review in 2016 with little in the way of substantive change emerging. However, the review did include a well-articulated defence of the current regime which is of comfort to the industry in presaging a period of fiscal stability, at least until the next review.

Alberta is interesting as the Royalty regime represents one of the more globally sophisticated attempts to link the Royalty burden to underlying project profitability and oil prices. In essence, the regime splits the project Royalty burden into two phases:

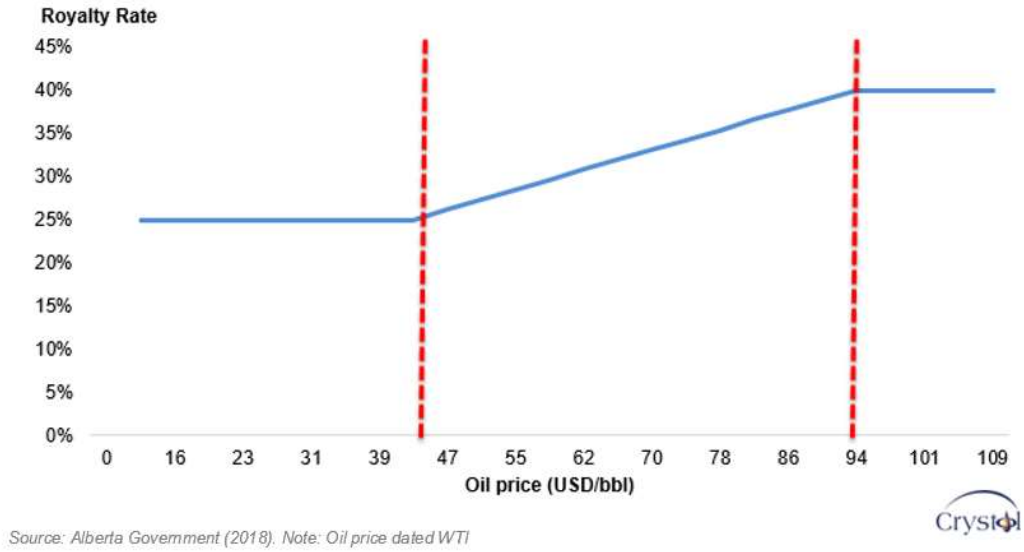
1. Pre-project payback or payout: The Royalty rate increases linearly from 1 to 9 percent depending upon the WTI oil price (Figure 25).

Figure 25: Oil Sands Royalty Rate (Gross)

Source: Alberta Government (2018). Note: Oil price dated WTI

2. Post project payout: The Royalty burden is the higher of the above calculation and an additional calculation based on net revenues. This additional calculation is based on a Royalty rate of 25 to 40 percent (determined by oil price) as applied to net revenues (Gross revenues less operating costs) (Figure 26).

Figure 26: Oil Sands Royalty Rate (Net)



The Alberta structure represents an attempt to make the Royalty burden more reflective of the underlying project profitability although it uses the oil price as a proxy rather than the actual project realised returns. The post payback change in the Royalty structure makes the Royalty much more akin to a profit-based tax by allowing operating costs as a deduction against gross revenues.

c. Mexico

Offshore Mexico is the closest competitor to the US GOM in terms of deepwater oil opportunities at scale. The country is contiguous to the US GOM and is considered to offer similar volumetric potential though it is almost completely unexplored.

Mexico is also a relative newcomer to international investment as until very recently, the basin was closed to international investors for 75 years. In 2013/14, it went through an internally controversial process to end the 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. Many licenses have been awarded on the basis of new fiscal regimes, where one structurally resembles a PSC and the other a concessionary model (licensing) [18].

[18] Mexico applies several fiscal structures and regimes: licensing, PSC and Association. This study focuses on the licensing regime which has been applied to the two deepwater bid rounds (Round 1.4 and 2.4) and is more applicable to the US context.

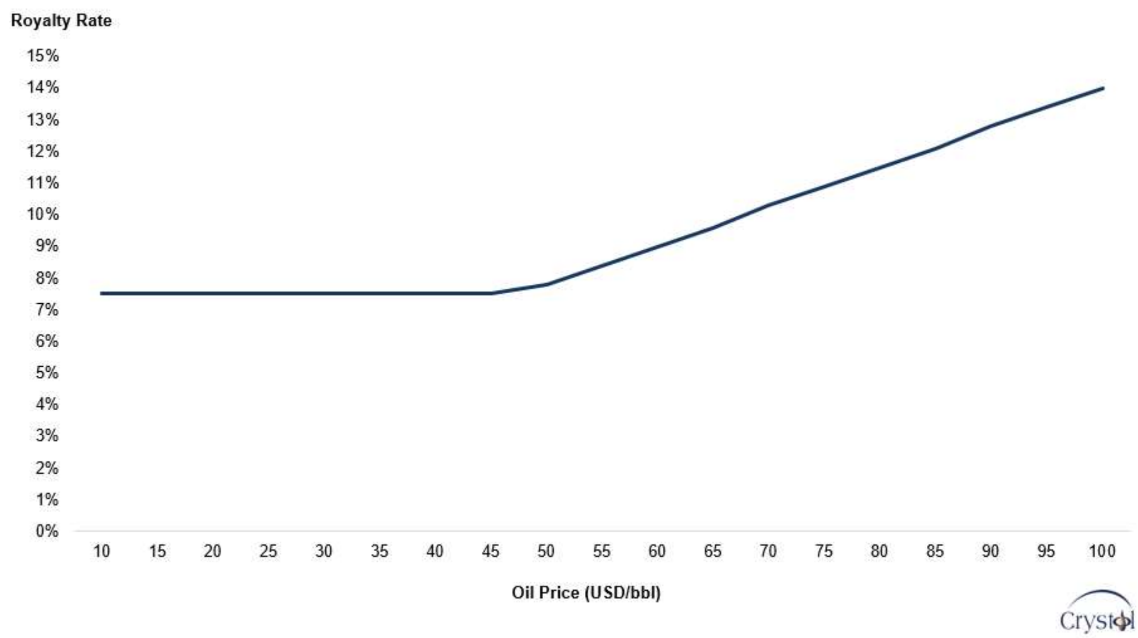
Under the licensing arrangement, the Royalty is used as a key element of its rent collection ambition. Two types of Royalty apply: the base Royalty which is determined by the oil price, and the Additional Royalty, which is biddable and is R-factor based.

The base Royalty rate applies as follows:

- It is flat at 7.5 percent for prices below a threshold price of USD 48/bbl (threshold increases with inflation).

- Above the threshold, it increases linearly with price based on a simple formula (12.5 percent of the oil price plus 1.5 percent). So, at USD 100/bbl for example the Royalty rate is 14 percent (Figure 27).

Figure 27: Mexico Royalty Regime



The profit-based Additional Royalty, which is dependent on post-Royalty (but pre-CT costs), also has two components with the total Additional Royalty being the sum of the two:

1. The first component is the biddable portion, which is constant and reflects a minimum Additional Royalty. Deepwater licensing rounds - Round 1.4 and 2.4 - set minimum and maximum rates for this at 3.1-5.0 percent and 20 percent respectively, with different minimum rates applying to specific basins.

2. The second component is a somewhat complicated progressive royalty that incorporates R-factor (ratio of cumulative net revenues to costs[19]) and CRO (ratio of current period net cash flow to gross revenue). The rates for the second component increase continuously with R-factor and CRO – the rate is 0 percent until the R-factor is greater than or equal to 2.00.

When considering the fiscal structure as a package (Box 7), it effectively captures economic rents for the government through the progressive Additional Royalty (assuming that there is sufficient competition[20]) while providing a relatively low tax burden on marginal projects. By being profit-based, the Additional Royalty is effectively a non-distortionary mechanism.

A downside to the Additional Royalty structure is the lack of simplicity. The interaction between the CRO and R-factor is rare in the industry. While the use of R-factor is common, it is possible that Mexico is the first country to implement a structure that combines the R-factor with a measure that captures current period cash flow (the CRO). The complexity leads to its fiscal impact being difficult to understand without detailed modelling and evaluation over a range of scenarios.

Nevertheless, incorporating the CRO has commendable features, specifically that it protects against a common complaint of R-factor based systems, which goes as follows: Since the R-factor measures cumulative profitability, it does not sufficiently reflect current period cash flow deficiencies coming from declines in commodity prices and costs during the production phase (e.g. maintenance or capital expenditures, such as enhanced oil recovery costs). The use of the CRO causes the progressive element of the Additional Royalty to be 0 if current period cash flow is negative, regardless of the R-factor level.

[19] Net revenues allow deductions for surface fees and royalties but not CT.

[20] For a system that requires competition to capture rent, it is important that investors have maximal (geological and fiscal) information during the bidding process.

Box 7: Overview of Mexico's Licensing Fiscal Regime

Why did the Government enact new policies?

Mexico enacted a series of policies aimed at incrementally liberalizing its entire energy system in 2014. Prior to reforms, PEMEX had a monopoly on extraction activities, serving two primary state functions: employment and government revenue through transfers to the federal treasury. However, partly because of these goals, PEMEX had become uncompetitive, with unfeasible employment practices and pension liabilities, and unable to explore and develop deepwater and shale basins due to inadequate investment in human capital and modern technologies. The reforms hoped to attract foreign investment 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 the IOCs were implemented to achieve these goals.

Licensing Regime Fiscal Structure

- The licensing regime put forth in Round 1.4 and 2.4 includes surface payments, a base royalty, an additional biddable royalty, no exemption for VAT or CT, and no requirement for PEMEX participation.
- Surface payments are in line with those levied in the US GOM.
- The base oil and non-associated gas royalty increases from 7.5 percent and 0 percent (respectively) with price, reaching roughly 14 percent at a price of USD 100/bbl, while the associated gas royalty is only 1 percent to encourage marketing rather than flaring of associated gas.
- The VAT rate is 14 percent without refund during the exploration or development periods, creating a sizable timing penalty to the investor.
- Payments into a decommissioning fund begin from the start of production and are deductible for calculation of CT, R-factor, and CRO. These deductions lower the barriers to entry and increase the NPV of deductions.
- The CT rate is 30 percent with depreciation of one year for exploration and four years for development expenditures. CT is ring-fenced around upstream operations. In the near-term, companies will not be in tax paying positions and, thus, not be able to immediately use exploration and development deductions. This creates a potential barrier to entry in the medium-term as companies paying taxes will effectively have lower exploration and development costs, all else equal. Additionally, allowing CT deductions for payments into the decommissioning fund lowers the fiscal burden for non-tax payers.

4.1.4.3. Royalty Reform Options

From the above review and analysis, it is clear that as a rent collection mechanism, the Royalty has serious limitations, summarized as:

- taxing revenues not profits;
- ignoring costs and the underlying profit or rent that can be taxed;
- delaying project payback;
- regressive - Government Take falls as profit rises and vice versa; and
- accelerating cessation of production – economic reserves are left unrecovered.

However, it must be recognised that the Royalty has a long-standing attraction as a fiscal instrument and its popularity in fiscal regimes remains undiminished both for oil, gas and precious minerals alike. Its main attractions include the following:

- simple to collect;
- simple to predict;
- difficult to avoid; and
- provides early revenues to the state.

For the US GOM, it is simply too radical today to propose its abolition or material reduction as it remains the principle rent collection mechanism along with the lease bonus payments. Royalty abolition would almost certainly engender higher lease bonus bids, although it is very difficult to assert whether the increase in bids collected would match the loss of future Royalty on an NPV basis. Furthermore, it is unlikely that the authorities would be willing to conduct such an experiment. The recent cut in the federal tax rate also makes the arguments for Royalty reform and any material reduction in yield all the harder to articulate.

Virtually every (concessionary) upstream fiscal regime in the world has 'rent' collection mechanisms in place, either a Royalty, RRT or both. The only known exception is in the UK where, between 1993 and 2002, the fiscal regime for new fields was simply the CT levied on the same basis as all other Industries. But even this regime, 'the Holy Grail' of upstream taxation, failed to endure once oil prices started to recover at the turn of the century, and was retroactively changed in 2002 with permanently higher levels of CT for the oil industry going forward.

In the long-term, continued basin maturity, intensifying global competition for capital, and falling real oil prices due to structural changes in the supply/demand dynamics are expected to strengthen the argument for reducing and removing the Royalty burden.

So, the challenge facing policy makers and investors is to shape modifications to the Royalty regime which can mitigate its disadvantages. Inevitably these design challenges revolve around making the Royalty burden more reflective of the underlying profitability of projects. In this respect, the study adopted the following guiding design principles to assess the alternatives:

- Link the Royalty rate(s) to project economic characteristics;
- Link the Royalty thresholds to economic milestones (e.g. payback, discounted payback, and securing minimum IRR);
- Minimizing complexity and promoting predictability and transparency;
- Go with the grain of the existing Royalty rates – standard Royalty of 12.5 percent with top rate (as today) of 18.75 percent; and
- Provide two or three design options consistent with the above.

Given these guiding principles, the following options emerge:

- **Option 1: Link the Royalty Rates to IRR (or ROR)**

Under this option, the Royalty rate is linked to project economic characteristics, primarily the post-tax IRR, as per Table 10 below.

Table 10: Royalty Rate by IRR Tranches

Project IRR Tranche	Royalty Rate
Tranche 1	0% until project payback has been reached
Tranche 2	5% until IRR of 5% (real) has been reached
Tranche 3	12.5% until IRR of 10% (real) has been reached
Tranche 4	18.75% once project IRR of 10% (real) has been reached

The project IRR is computed on a rolling annual basis (this could be made shorter, say quarterly or biannual). Once the triggers (or tranches) are reached, the new Royalty rate applies from the start of the next accounting period in which the trigger was reached. The project IRR is also computed on a project 'stand-alone' basis including lease bonus payments (where applicable) plus all exploration and appraisal costs pertaining to the project in question. Dry hole costs from unsuccessful exploration on the lease may be included in the above calculation. If two or more projects are undertaken from the same lease, then the subsequent projects cannot include any costs already included in the IRR calculation for the first project to avoid double counting. Each project has its own IRR calculation to determine the applicable Royalty rates over time.

- **Option 2: As Option 1 but with high Royalty kick out trigger**

One of the drawbacks of the current US GOM regime and Option 1 above is the potential for a high Royalty rate of 18.75 percent to be triggered and then remain applicable until cessation of production. This risks causing the field to be uneconomic when, on a pre-Royalty basis, economic production can still be sustained. There is a provision in the current regime for a dialogue with the authorities leading to a discretionary reduction in the Royalty rate; it would, however, be preferable if a lower Royalty burden could be automatically triggered once the field is mature.

One option would therefore be for the Royalty calculation to switch to a net revenue basis once annual production has declined to less than 20 percent of the highest annual production reached in prior years and that at least 70 percent of the original estimate of reserves have been recovered. From this point forward, the Royalty would be charged at 25 percent of net revenues (Gross revenues less operating costs). This switch would be at the option of the producers; fields with very poor economics which never triggered high Royalty rates may prefer to remain on the prevailing regime linked to IRR. The above numbers are just for illustration, more detailed dialogue and modelling would be required to settle on appropriate trigger points.

Given that this benefit occurs late in field life it is unlikely that the impact this arrangement would be very visible in project economics given the impact of discount rates, but it can be a discussion point between the industry and government.

- **Option 3: As Option 1 but with linear progressions of the Royalty rates**

A further variation of Option 1 above is to have the Royalty rates change every accounting period as the IRR changes. The initial tranche of zero Royalty until payback would remain as would the top tranche of 18.75 percent, but between these two boundaries the Royalty rate would continuously change.

In NPV terms, Option 3 would be costlier to the industry but might have more appeal with the authorities. It would, however, be more complex to administer with the Royalty rates continually changing to several decimal places.

- **Option 4: Rates linked to oil prices**

This option assumes the oil price is a good proxy for project profitability although it is far from exact as costs are ignored. Given the high volatility in oil prices this option will result in a regime of constantly changing Royalty rates. The lags in measurement may cause difficulties for producers if the Royalty rate is adjusted only annually or biannually. A sudden fall in the oil price may leave a high Royalty in place at times of very low prices until the next adjustment kicks in.

- **Option 5: Royalty levied on net revenues, not gross revenues**

By limiting the Royalty burden to net revenues (gross revenues less operating costs), the Royalty becomes profit related and more neutral.

This structure has the benefit of ensuring the Royalty burden adapts not only to price changes but also to profitability, and automatically falls as the field approaches cessation of production. Clearly, the rate will fall to zero once operating costs equal revenues unlike many of the alternative structures.

4.2. Modelling and Analysis

As the earlier discussion shows, the most realistic fiscal policy reform options for the US GOM are those targeting Royalty. The economic analysis presented in this section compares and contrasts various option for reforming this instrument in the GOM. The ambition is to create a new

Royalty regime which links the Royalty burden to the project profitability, which is progressive in nature. This may come at the expense of simplicity. First, a description of the modelling methodology is provided and then, analysis of reform options and recommendations are made.

4.2.1. Economic Assumptions

Crystol Energy constructed a model for the GOM to test the impact of the current regime and identify potential modifications to it. For this purpose, three typical model fields (50, 100, and 300 million barrels (mmbbls)) have been shaped to cover the range of volumetric outcomes that might be encountered.

The model fields have been developed on the basis that they can be found in either deep - or shallow water and that they are marginal pre-tax. The objective is to show how the regime can be improved to allow the development of such marginal fields as these are primarily the types of projects that may remain undeveloped without policy reform.

Two oil price scenarios have been modelled, namely USD 50/bbl and USD 60/bbl, both in real terms. Whilst experience suggests that the oil price will continue to spike above and below this range in the short-term given the OPEC cuts and geopolitical tensions especially in the Middle East, we believe that this price bandwidth is a reasonable assumption of long-term oil prices in the coming decades. Note that the modelling does not assume first oil on any project before 2023, so it is the oil price from this date forward that is relevant to the economic analysis.

The modelled projects have the following assumptions:

- Different development costs: development wells cost USD 150 mm each and 5 wells in the 50 mmbbls project, 10 in the 100 mmbbls, and 30 in the 300 mmbbls (resulting in roughly USD 14.5/bbl real terms)
- Different peak production rates of 15, 25, and 70 thousand bbl per day (no gas production) with an 8 percent decline rate after reaching peak production, and production beginning in year 6, 7, and 8 from lease payment, respectively.
- Total exploration costs are USD 300 mm for each project and spaced out equally over three years. An upfront lease bonus payment of USD 50 mm for each project has been assumed taking pre-development costs to USD 350 mm in total.

All costs are funded through company cash flows, meaning no debt.

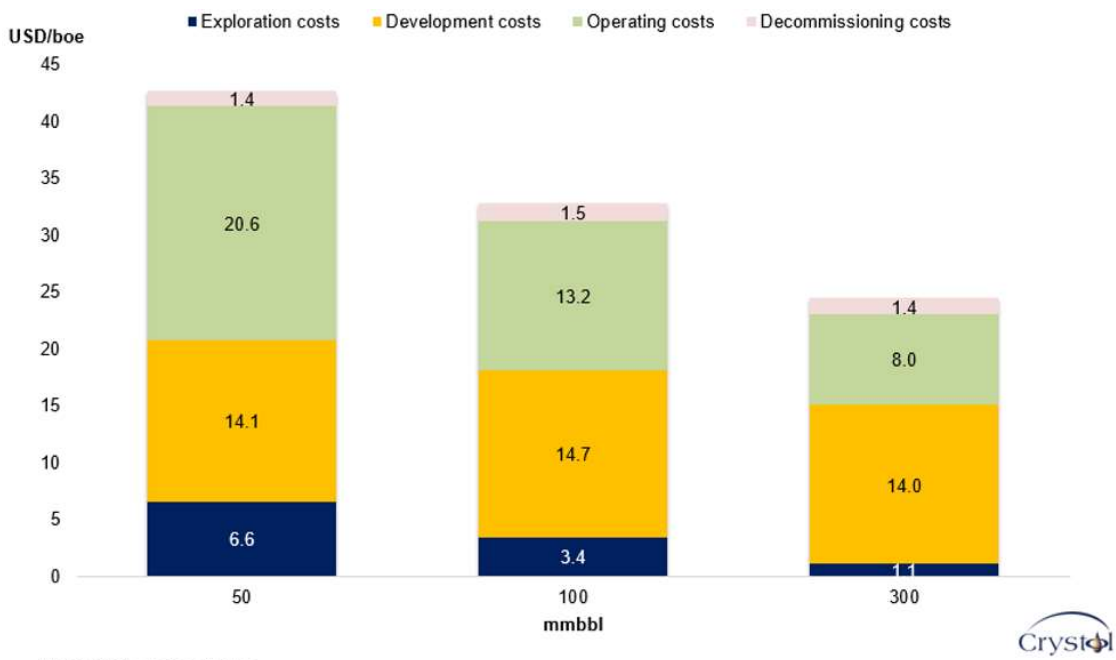
The breakdown of the unit costs is illustrated in Figure 28. The projects were then calibrated to have the same 14 percent pre-tax return (when excluding exploration and lease payment costs) at USD 50/bbl oil price.

In all the post-tax results tables below, the Royalty and CT numbers are undiscounted aggregate revenues and are the same for both the life cycle and Development economics cases[21]. The data

[21] The Table shows the individual taxes for the Development economics only

on payback reflects discounted payback and in the case of development economics, the payback from the year of development commencement (rather than the start of the project). The development economics exclude prior exploration and lease costs but include the forward tax relief attributable to these costs.

Figure 28: Breakdown of Unit Costs



Note: USD/boe is in real terms

We have not shown metrics illustrating capital efficiency such as for example (NPV/I) but this could be a decisive factor for many investors when considering capital allocation at times of constrained capital budgets. The US GOM projects modelled are quite capital intensive and this could negatively impact their global ranking position within company project portfolios beyond the NPV and IRR metrics presented below.

4.2.2. Pre-Tax Economics

The projected pre-tax economic outcomes at both USD 50 and USD 60 real oil prices for these projects are illustrated in Table 11. Values are presented for both life cycle and forward development economics.

Life cycle returns are shown on an un-risked basis throughout and include both the up-front lease payment and the subsequent exploration expenditure, aggregating to USD 350 mm. Development economics assume these costs are sunk. In all cases, NPV's are discounted from 1/1/2018 and at 7.5 percent real terms.

Table 11: Pre-Tax Economic Outcomes

Field sizes	mmbbls	**50**	**100**	**300**
Oil price (real)	**$/bbl**	**50**	**50**	**50**
Life cycle returns				
IRR	%	4.3%	8.5%	11.8%
NPV	$ mm	(151)	96	1,125
Development economics				
IRR	%	13.7%	13.9%	14.0%
NPV	$ mm	158	406	1,435
Oil price (real)	**$/bbl**	**60**	**60**	**60**
Life cycle returns				
IRR	%	9.0%	12.3%	15.3%
NPV	$ mm	79	475	2,145
Development economics				
IRR	%	22.0%	19.3%	18.1%
NPV	$ mm	389	785	2,454

The pre-tax development economics are just commercial at USD 50 and quite healthy at USD 60. Life cycle returns, which are un-risked, look sub-marginal at USD 50 and just commercial at USD 60, though the 50 mmbbls development has poor returns under both price scenarios.

Nine scenarios, summarized in Table 12, were modelled. The detailed results and analysis are illustrated below.

Table 12: Modelled Tax Scenarios

Scenario	Description
1	Current US GOM fiscal regime with 12.5% Royalty
2	Current US GOM fiscal regime with 18.75% Royalty
3	Current US GOM regime with 18.75% Royalty and suspension volumes
4	Royalty rate determined by IRR
5	Current US GOM regime with Royalty calculated on net revenues
6	Current US GOM regime with Royalty deduction for capital costs
7	Current US GOM regime with uplift for CT at 25% with 18.75% Royalty
8	Current US GOM regime with uplift for CT at 50% with 18.75% Royalty
9	Current US GOM regime with exploration costs expensed

4.2.3. Current US GOM Fiscal Regime for Shallow Water

The modelling assumptions for the current fiscal regime are as follows:

- Royalty: 12.5 percent, assuming water depth of below 200 m
- Federal Income tax at 21 percent
- Suspension volumes but this benefit is withdrawn for prices above USD 43/bbl real
- 80 percent of development costs are IDC's as depreciated on an accelerated basis (70 percent in the first year, 6 percent annually over the following five years)
- Lease and exploration costs depreciated on a UOP basis.

Table 13 summarizes the projected outcomes for the current fiscal regime economics at both USD 50 and USD 60/bbl price.

Table 13: Post-Tax Current GOM Regime (Royalty 12.5 percent)

Field sizes	mmbbls	50	100	300
Royalty rate	%	12.5%	12.5%	12.5%
Oil Price (real)	$/bbl	50	50	50
Life cycle returns				
IRR	%	0.2%	5.1%	8.5%
NPV	$ mm	(287)	(186)	231
Payback	Years	n/a	n/a	14
Government Take	%	n/a	n/a	83.9%
Development economics				
IRR	%	8.6%	9.8%	10.4%
NPV	$ mm	24	124	542
Payback	Years	13	14	14
Government Take	%	84.6%	69.5%	62.3%
Royalty	$ mm	332	637	2,011
CT	$ mm	27	260	1,356
Oil price (real)	$/bbl	60	60	60
Life cycle returns				
IRR	%	4.6%	8.4%	11.5%
NPV	$ mm	(127)	76	936
Payback	Years	n/a	22	17
Government Take	%	n/a	94.9%	58.8%
Development economics				
IRR	%	15.7%	14.4%	13.9%
NPV	$ mm	184	386	1,246
Payback	Years	8	9	10
Government Take	%	52.7%	50.8%	49.2%
Royalty	$ mm	398	764	2,413
CT	$ mm	125	446	1,947

The main points to note are the relatively poor life cycle economics under both oil price scenarios. Development economics remain marginal even at high prices. The discounted Government Take (Total tax/pre-tax cash flow) is high under most development outcomes, with the regressive effect (highest take at lowest prices) plain to observe.

This assessment provides a more realistic view of the fiscal burden in US GOM and contrasts with the low 'headline' marginal tax rate of 31 percent (12.5 percent Royalty) or 36 percent (18.75 percent Royalty). High Royalty rates tend to engender very regressive fiscal regimes with high levels of Government Take under circumstances where field economics are marginal and unit extraction costs are high. The Royalty receipts are considerably higher than the revenues from federal CT under all circumstances, particularly so at low prices and when discounted. The impact of the tax regime is to lower development IRR's by 4 to 5 percent.

The projected life cycle returns indicate that exploration in the GOM does not look attractive unless high oil prices are assumed, and high volumetric outcomes are a realistic probability. Bearing in mind that the returns illustrated are un-risked; a typical chance factor of 50 percent would render the EMV distinctly negative[22] (See Section 4.2.10).

4.2.4. Current US GOM Fiscal Regime with 18.75 percent Royalty

This scenario repeats the earlier exercise but for projects in water depth higher than 200 m where the Royalty applies at 18.75 percent, which has expected consequences of depressing returns further and increasing Government Take sharply. On a pre-tax basis at an oil price of USD 50/bbl, all three projects were just commercial. However, the imposition of 18.75 percent Royalty depresses the IRR's by up to 8 percent and the three projects are sub commercial. Government Take ranges from 55 percent to 95 percent for the development economic cases (Table 14).

It is therefore difficult to avoid the conclusion that the GOM Royalty regime is designed for very large low cost discoveries in an era of sustained high prices which are able to carry the burden of the high Royalty. That may have been the prevailing reality in the first decade of the 21st century but is questionable whether this is now appropriate in the face of emerging challenges arising from basin maturity.

Table 14: Current US GOM Regime with 18.75 Percent Royalty

Field sizes	mmbbls	50	100	300
Royalty rate	%	18.75%	18.75%	18.75%
Oil Price (real)	$/bbl	50	50	50
Life cycle returns				
IRR	%	-	3.8%	7.4%
NPV	$ mm	(342)	(279)	(19)
Payback	Years	n/a	n/a	n/a
Government Take	%	n/a	n/a	n/a
Development economics				
IRR	%	5.9%	8.1%	9.1%
NPV	$ mm	(32)	31	291
Payback	Years	n/a	18	17
Government Take	%	n/a	92.4%	79.7%
Royalty	$ mm	498	955	3,016
CT	$ mm	(7)	193	1,148
Oil price (real)	$/bbl	60	60	60
Life cycle returns				
IRR	%	2.9%	7.1%	10.3%
NPV	$ mm	(194)	(36)	635
Payback	Years	n/a	n/a	19
Government Take	%	n/a	n/a	72.7%
Development economics				
IRR	%	12.8%	12.6%	12.4%
NPV	$ mm	116	275	945
Payback	Years	9	11	11
Government Take	%	70.2%	65.0%	61.5%
Royalty	$ mm	597	1,146	3,620
CT	$ mm	84	367	1,697

[22] See Section 4.2.10

4.2.5. Current US GOM Regime with Suspension Volumes

In this scenario, a prevailing Royalty of 18.75 percent with a suspension volume of 52 mmbbls is assumed. Under the current fiscal regime, the suspension volumes do not apply if, in any year, the oil price exceeds around USD 43/bbl. In reality, this price threshold is so low it does little to promote investment. Most GOM projects have been simply not viable much below USD 50/bbl and many have required a price considerably above that level so the benefit of suspension volumes as currently applicable would be expected to rarely support an investment appraisal decision.

The following assumption has therefore been modelled whereby the suspension volumes apply provided the price of oil price is less than USD 61/bbl (close to recent average annual price levels). The results in Table 15 below demonstrates the effectiveness of this measure.

Table 15: Current Regime with Suspension Volumes

Field sizes	mmbbls	50	100	300
Royalty rate	%	18.75%	18.75%	18.75%
Oil Price (real)	$/bbl	50	50	50
Life cycle returns				
IRR	%	3.5%	6.3%	8.4%
NPV	$ mm	(172)	(90)	186
Payback	Years	n/a	n/a	25
Government Take	%	n/a	n/a	87.9%
Development economics				
IRR	%	13.8%	12.0%	10.3%
NPV	$ mm	138	220	497
Payback	Years	9	10	14
Government Take	%	12.8%	45.6%	65.4%
Royalty	$ mm	5	463	2,524
CT	$ mm	97	297	1,251
Oil price (real)	$/bbl	60	60	60
Life cycle returns				
IRR	%	7.7%	9.9%	11.5%
NPV	$ mm	10	192	882
Payback	Years	n/a	18	17
Government Take	%	n/a	70.2%	61.2%
Development economics				
IRR	%	21.4%	17.1%	14.0%
NPV	$ mm	320	502	1,192
Payback	Years	6	8	10
Government Take	%	17.7%	36.1%	51.4%
Royalty	$ mm	7	555	3,029
CT	$ mm	208	491	1,821

As expected, the suspension volume removes the Royalty from the 50 mmbbls field size case, transforming the projected economic outcomes: The pre and post-tax returns are now very similar. The impact remains material but proportionately less significant for the larger field sizes.

In many respects increasing the price threshold of applicability would be a relatively simple change to make by the US authorities though perhaps their concern would be that legacy fields already in production would see a considerable benefit they do not require.

Any increase in the oil price threshold for suspension volumes would need to be targeted for future developments only. There is also the question of the suspension volume quantum itself, why 52 mmbbls? Inevitably this will always be a somewhat arbitrary amount, after all why not 40 million or 60 million, and highlights the inherent limitations of this mechanism compared to others.

4.2.6. Royalty Determined by IRR

In this scenario, the applicable Royalty is determined by the achieved post-tax IRR on the development project. The Royalty rate changes according to achieved IRR thresholds in real terms as follows:

- Royalty rate of 0 percent until payback in real terms is secured
- Royalty rate of 5 percent until IRR reaches 5 percent
- Royalty rate of 12.5 percent until IRR of 10 percent secured
- Royalty rate of 18.75 percent thereafter.

The Royalty rate in any year is determined by the achieved project IRR up to and including the prior year's cash flow. In the example presented, the relevant IRR excludes the costs of the exploration program, which could be included as an alternative design configuration.

The logic of this structure is to link the Royalty burden explicitly to the underlying profitability of the project in question. Other variations to this concept could also be considered such as Royalty based on R-factor or permitting the Royalty rates in the above structure to be biddable by investors. One of the advantages of this structure, however, is its predictability and certainty of applicability.

This mechanism ensures more precisely that the damage to marginal fields' pre-tax returns from the fiscal regime is minimized. The projected difference between pre and post-tax returns for the development economics is small; typically, less than a 2 percent drop and at its narrowest for the smallest fields.

Note that Government Take for the development economics is in quite a narrow band from 17 to 39 percent, but it is projected to rise with more profitable projects. Under the current regime with 18.75 percent Royalty, the projected Government Take is never below 61.5 percent and typically considerably above. Projected life cycle returns are also much improved to the extent that exploration begins to look economically attractive (Table 16).

Table 16: Internal Rate of Return Driven Royalty

Field sizes	mmbbls	50	100	300
Royalty rate	-	Determined by IRR		
Oil Price (real)	$/bbl	50	50	50
Life cycle returns				
IRR	%	3.3%	7.0%	10.1%
NPV	$ mm	(178)	(36)	564
Payback	Years	n/a	n/a	19
Government Take	%	n/a	n/a	54.3%
Development economics				
IRR	%	13.6%	12.8%	12.3%
NPV	$ mm	132	275	874
Payback	Years	9	10	11
Government Take	%	16.7%	32.3%	39.1%
Royalty	$ mm	33	215	1,143
CT	$ mm	91	349	1,541
Oil price (real)	$/bbl	60	60	60
Life cycle returns				
IRR	%	7.2%	10.2%	12.9%
NPV	$ mm	(16)	223	1,196
Payback	Years	n/a	17	15
Government Take	%	n/a	63.6%	46.6%
Development economics				
IRR	%	20.9%	17.4%	15.6%
NPV	$ mm	295	533	1,507
Payback	Years	6	7	9
Government Take	%	24.2%	32.1%	38.6%
Royalty	$ mm	116	930	2,953
CT	$ mm	185	401	2,026

4.2.7. Royalty Calculated Based on Net Revenue

The analysis for this Royalty option assumes a Royalty rate of 18.75 percent but levied on net revenues, not gross revenues. Such an assumption makes the Royalty more profit related and is only payable on the margin between gross revenues and operating costs.

As Table 17 shows, this option is projected to significantly improve the project economics, compared to the current GOM regime, but is less effective in reducing the tax burden on marginal projects than the alternative of linking Royalty to achieved IRR's or having suspension volumes available, principally because the Royalty is liable from the first year of production provided revenues exceed operating costs.

This option, however, has the considerable advantage of reducing the Royalty burden as the field matures; Royalty will be progressively squeezed out of the tax burden as revenues decline towards the level of operating costs.

There are potential half way measures when it comes to defining the revenue base for the application of the Royalty rate. For example, early in the life of the UK regime, Royalty was levied on the basis of wellhead value (not landed value). Thus, transport and initial treatment costs were deductible for the purposes of determining wellhead values on which Royalty was levied; this included a depreciation element equivalent to 70 percent of platform costs.

Table 17: Royalty on Net Revenues

Field sizes	mmbbls	50	100	300
Royalty rate	%	18.75%	18.75%	18.75%
Oil Price (real)	$/bbl	50	50	50
Life cycle returns				
IRR	%	0.7%	4.8%	8.0%
NPV	$ mm	(272)	(205)	102
Payback	Years	n/a	n/a	28
Government Take	%	n/a	n/a	95.4%
Development economics				
IRR	%	9.3%	9.5%	9.7%
NPV	$ mm	39	105	412
Payback	Years	12	14	15
Government Take	%	75.6%	74.1%	71.3%
Royalty	$ mm	292	703	2,532
CT	$ mm	37	246	1,250
Oil price (real)	$/bbl	60	60	60
Life cycle returns				
IRR	%	4.7%	8.0%	10.8%
NPV	$ mm	(124)	38	756
Payback	Years	n/a	24	18
Government Take	%	n/a	n/a	67.1%
Development economics				
IRR	%	15.9%	13.8%	13.0%
NPV	$ mm	187	349	1,067
Payback	Years	8	10	11
Government Take	%	52.0%	55.6%	56.5%
Royalty	$ mm	391	894	3,136
CT	$ mm	127	420	1,799

4.2.8. Royalty with Capital Costs Deduction

A further variation to the computation of Royalty is to permit depreciated capital costs to be deducted from the annual revenue stream before the application of the Royalty rate. In this scenario, the capital costs are depreciated on a UOP basis, though other mechanisms could be employed. Like the scenario above, the attraction of this option is it permits the authorities to retain the headline Royalty rates currently in place.

In terms of materiality, as Table 18 shows, the projected NPV of the 300 mmbbls developments would be increased by USD 181 mm under both oil price scenarios, compared to the current GOM regime with 18.75 percent Royalty. Government Take remains regressive with price but less steeply.

The fact that this option, like uplift, is price independent makes it less attractive to policymakers. At high prices, it is more difficult to justify the necessity of such a structure. High cost projects or those poorly executed with large CAPEX overruns would benefit more than lower cost alternatives. In the early years of the development of the North Sea, the UK tax regime permitted the offset of depreciated capital costs against Royalty. This practice ceased when Royalty was abolished.

Table 18: Royalty with CAPEX Deduction

Field sizes	mmbbls	50	100	300
Royalty rate	%	18.75%	18.75%	18.75%
Oil Price (real)	$/bbl	50	50	50
Life cycle returns				
IRR	%	-	4.8%	8.2%
NPV	$ mm	(299)	(207)	161
Payback	Years	n/a	n/a	26
Government Take	%	n/a	n/a	90.1%
Development economics				
IRR	%	8.0%	9.5%	10.1%
NPV	$ mm	11	103	472
Payback	Years	14	14	15
Government Take	%	93.2%	74.6%	67.1%
Royalty	$ mm	374	717	2,336
CT	$ mm	19	243	1,291
Oil price (real)	$/bbl	60	60	60
Life cycle returns				
IRR	%	4.0%	7.9%	11.1%
NPV	$ mm	(151)	36	816
Payback	Years	n/a	24	18
Government Take	%	n/a	n/a	64.3%
Development economics				
IRR	%	14.7%	13.8%	13.3%
NPV	$ mm	159	347	1,126
Payback	Years	8	10	11
Government Take	%	59.1%	55.9%	54.1%
Royalty	$ mm	474	908	2,939
CT	$ mm	110	417	1,840

4.2.9. Uplift on Capital Costs

Uplift is a percentage applied to capital costs whereby the increase is eligible for a deduction against federal income tax. So, for capital expenditure of USD 100 mm, a 25 percent uplift would result in an additional deduction of USD 25 mm against federal income tax. This would be worth USD 5.25 mm under the current CT rate of 21 percent. Table 19 reflects an uplift of either 25 percent or 50 percent applied to the development costs. The uplift rate is applied to capital costs incurred in each year and the uplift CT deduction is spread equally over four years. The uplift benefit is independent of oil prices and ranges in value from USD 23 mm (50 mmbbls field, 25 percent uplift) to USD 260 mm (300 mmbbls field, 50 percent uplift). Clearly, the more is spent on capex, the larger the benefit, which may have unintended consequences.

The projected IRR is typically increased by around 1 to 2 percentage points relative to the current regime. Uplift is quite a common feature of fiscal regimes around the world though the percentage varies considerably. A rate of 50 percent is at the high end of what might be observed; a rate around the 25 percent level would be more realistic as a target outcome.

The value of the uplift is dependent on the applicable percentage, when it can be claimed and the prevailing rate of CT. In considering this option, it should be noted that uplift typically replaces tax relief for interest on borrowing, which may be of greater benefit to some investors but is not modelled here.

Table 19: Uplift on Capital Costs

Field sizes	mmbbls	50	100	300
Royalty rate	%	18.75%	18.75%	18.75%
Oil Price (real)	$/bbl	50	50	50
Development economics				
IRR	%	5.9%	8.1%	9.1%
NPV	$ mm	(32)	31	291
Uplift	%	25%	25%	25%
IRR	%	7.0%	9.0%	9.9%
NPV	$ mm	(9)	76	421
Delta NPV	$ mm	23	45	130
Uplift	%	50%	50%	50%
IRR	%	8.2%	10.0%	10.7%
NPV	$ mm	14	121	551
Delta NPV	$ mm	46	90	260
Oil price (real)	$/bbl	60	60	60
Development economics				
IRR	%	12.8%	12.6%	12.4%
NPV	$ mm	116	275	945
Uplift	%	25%	25%	25%
IRR	%	14.1%	13.6%	13.3%
NPV	$ mm	139	319	1,075
Delta NPV	$ mm	23	44	130
Uplift	%	50%	50%	50%
IRR	%	15.4%	14.6%	14.2%
NPV	$ mm	162	364	1,205
Delta NPV	$ mm	46	89	260

4.2.10. Expected Monetary Values

The returns to exploration have been calculated using some simple EMV analysis. The EMV is the sum of the risked post-tax cost of failure (USD 150 mm = one exploration well plus lease bonus) plus the risked value of the success case. The chance factor (probability of success) is assumed at 40 and 50 percent. In the event of failure, it is assumed that the lease is relinquished and the USD 150 million of costs can be expensed at that time.

The projected EMV outcomes for the current regime, assuming shallow water Royalty of 12.5 percent, are illustrated in Table 20. The EMV results demonstrate negative outcomes except for the 300 mmbbls project. A discovery in excess of 100 mmbbls would be necessary, on our assumed cost structure, for exploration to be encouraged.

If the same analysis is repeated but replacing the fixed Royalty with Royalty determined in accordance with project IRR's (as discussed above) the projected outcomes are materially improved (Table 21). The revised EMV's with the enabling Royalty structure demonstrate that the 100 mmbbls project outcome is now commercially viable with a positive EMV of USD 21 mm (40 percent chance factor) at USD 60/bbl; in fact, the break-even price for this case is USD 56/bbl. The EMV's for the 300 mmbbls project are now materially more robust. The 50 mmbbls project remains below the water line but this project was barely economic on a pre-tax basis before the application of risk. The fiscal regime is not responsible for its lack of commerciality. Changing the Royalty regime to make it more profit related demonstrates that such actions can significantly increase the attractiveness of GOM exploration.

Table 20: EMVs with 12.5 percent Royalty

Field sizes	mmbbls	**50**	**100**	**300**
Royalty	%	12.5%	12.5%	12.5%
Oil price (real)	$/bbl	50	50	50
EMV				
Chance factor	%	40.0%	40.0%	40.0%
EMV	$ mm	(183)	(144)	23
EMV				
Chance factor	%	50.0%	50.0%	50.0%
EMV	$ mm	(200)	(151)	58
Oil price (real)	$/bbl	60	60	60
EMV				
Chance factor	%	40.0%	40.0%	40.0%
EMV	$ mm	(119)	(39)	305
EMV				
Chance factor	%	50.0%	50.0%	50.0%
EMV	$ mm	(121)	(20)	410

Table 21: EMV with ROR Royalty

Field sizes	mmbbls	**50**	**100**	**300**
Royalty	-		By ROR	
Oil price (real)	$/bbl	50	50	50
EMV				
Chance factor	%	40.0%	40.0%	40.0%
EMV	$ mm	(140)	(84)	156
EMV				
Chance factor	%	50.0%	50.0%	50.0%
EMV	$ mm	(147)	(76)	224
Oil price (real)	$/bbl	60	60	60
EMV				
Chance factor	%	40.0%	40.0%	40.0%
EMV	$ mm	(75)	21	409
EMV				
Chance factor	%	50.0%	50.0%	50.0%
EMV	$ mm	(65)	54	540

4.2.11. Exploration Costs Expensed as Incurred

To help improve the life cycle returns and EMV's the option of expensing exploration costs as incurred has been evaluated. Under the current US GOM regime, these costs are relieved on a unit of production basis resulting in very slow timing of relief.

However, with a CT rate of 21 percent, this change, which by its nature is just a timing difference, is projected to have only a modest impact. On a risked basis this change is projected to improve the above EMV's by USD 15 to 20 mm, which is unlikely to be transformative. The fiscal proposals in respect of Royalty are much more material.

Some USD 300 mm of exploration costs have been assumed in the modeling while the benefit of immediate relief varies from USD 31 to 39 mm. The benefit is expected to be more for the larger fields as under a UOP basis for depreciation and a later start to production, it takes longer to secure the relief under the current regime than for the smaller fields. The improvement in life cycle returns is very modest at less than 0.5 percent (Table 22).

Table 22: Exploration Costs Expensed as Incurred

Field sizes	mmbbls	50	100	300
Royalty	%	18.75%	18.75%	18.75%
Oil price (real)	$/bbl	50	50	50
Life cycle returns				
IRR	%	-	3.8%	7.4%
NPV	$ mm	(342)	(279)	(19)
Exploration costs expensed				
IRR	%	4.7%	4.0%	7.6%
NPV	$ mm	(311)	(244)	20
Delta NPV	$ mm	31	35	39
Oil price (real)	$/bbl	60	60	60
Life cycle returns				
IRR	%	2.9%	7.1%	10.3%
NPV	$ mm	(194)	(36)	635
Development economics				
IRR	%	3.3%	7.5%	10.6%
NPV	$ mm	(163)	0	674
Delta NPV	$ mm	31	36	39

4.3. Discussion

It is evident from the preceding analysis that the current US GOM fiscal regime, whilst superficially attractive on paper, principally due to the perceptions of the low marginal tax rate, is in practice very regressive in character.

Under the current regime, Government Take is typically 52 to 95 percent at USD 50/bbl, and 44 to 64 percent at USD 60/bbl for the projects modelled. For small and medium size fields and or those with high costs, the impact of the current Royalty framework is to render many of the projects sub marginal at low prices, even though they are commercial on a pre-tax basis.

As can be observed from the alternative Royalty structures evaluated, there is the potential to change the fiscal regime into a more progressive character, reducing the Royalty burden for small or marginal fields whilst retaining it for the more profitable projects.

To make these observations clearer, a series of comparative graphs are included below.

1. **Figures 29-31 are projected for USD 50/bbl and covering NPV, IRR and Government Take. These are for the development economics cases.**

Figure 29: Summary NPV's Development Economics at USD 50/bbl

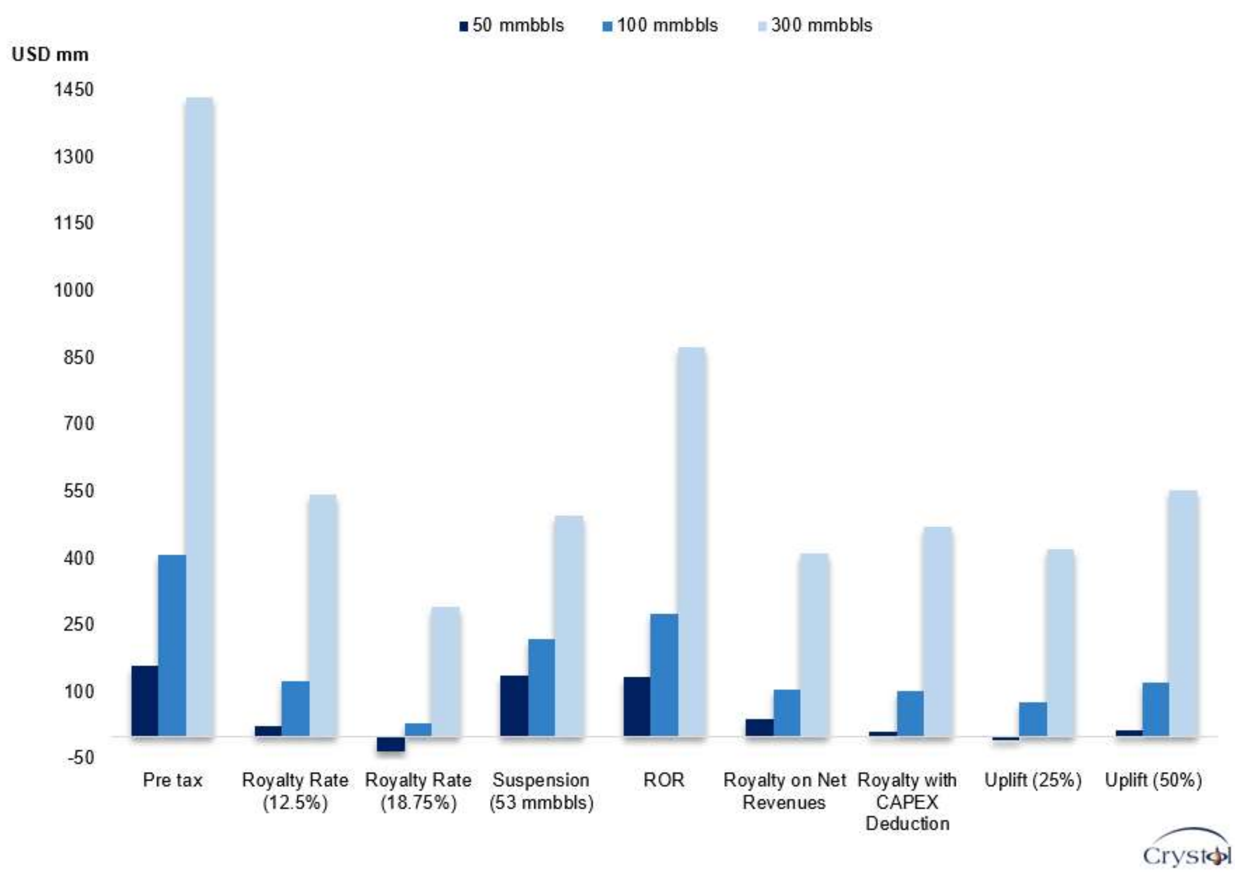


Figure 30: Summary IRR Development Economics at USD 50/bbl

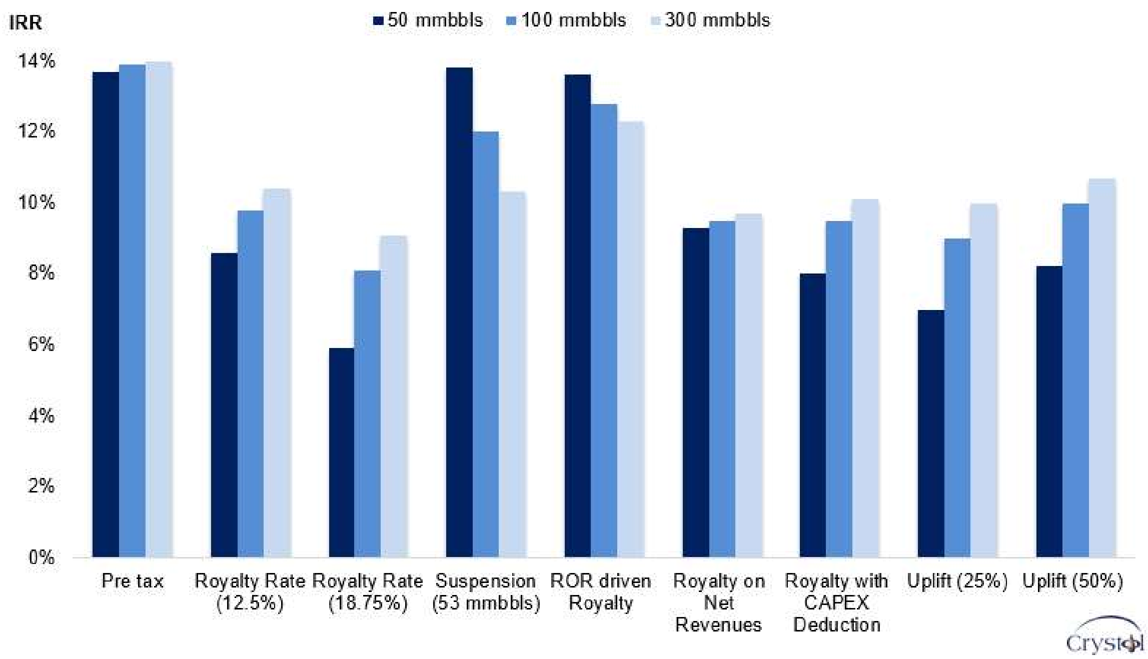
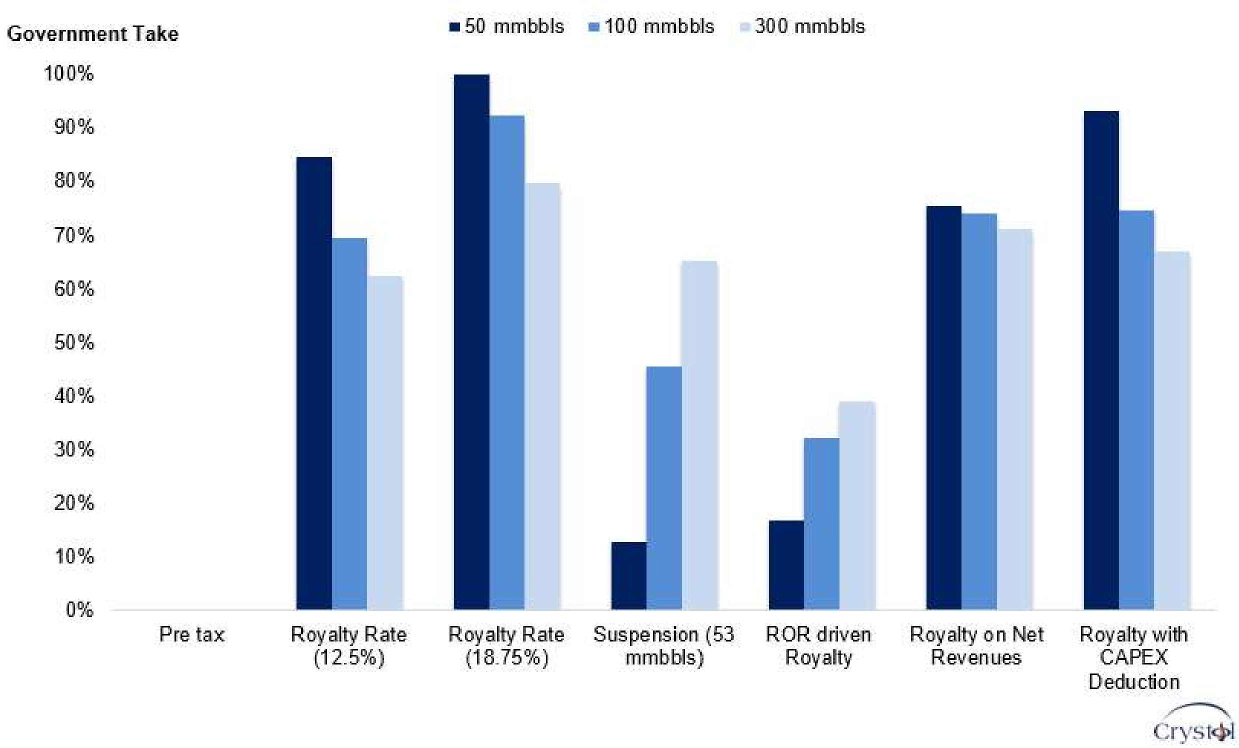


Figure 31: Summary Government Take at USD 50/bbl



2. Figures 32-34 are repeated projections for the USD $60/bbl oil price.

Figure 32: Summary NPV's Development Economics at USD 60/bbl

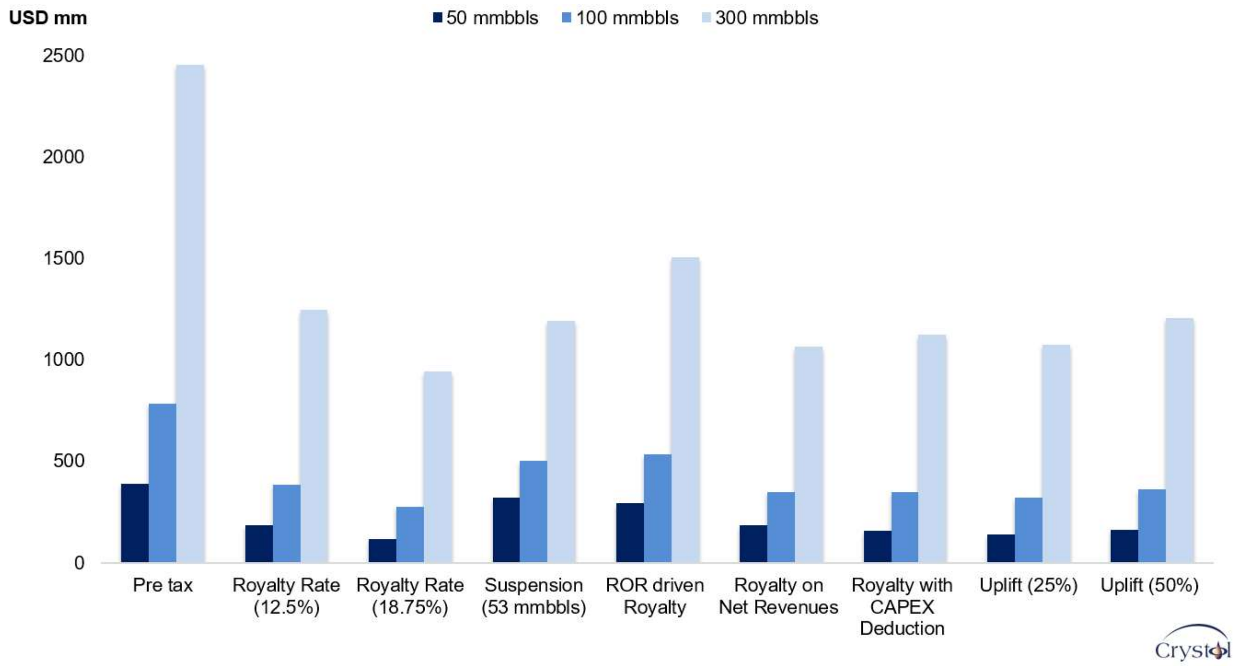


Figure 33: Summary IRR Development Economics at USD 60/bbl

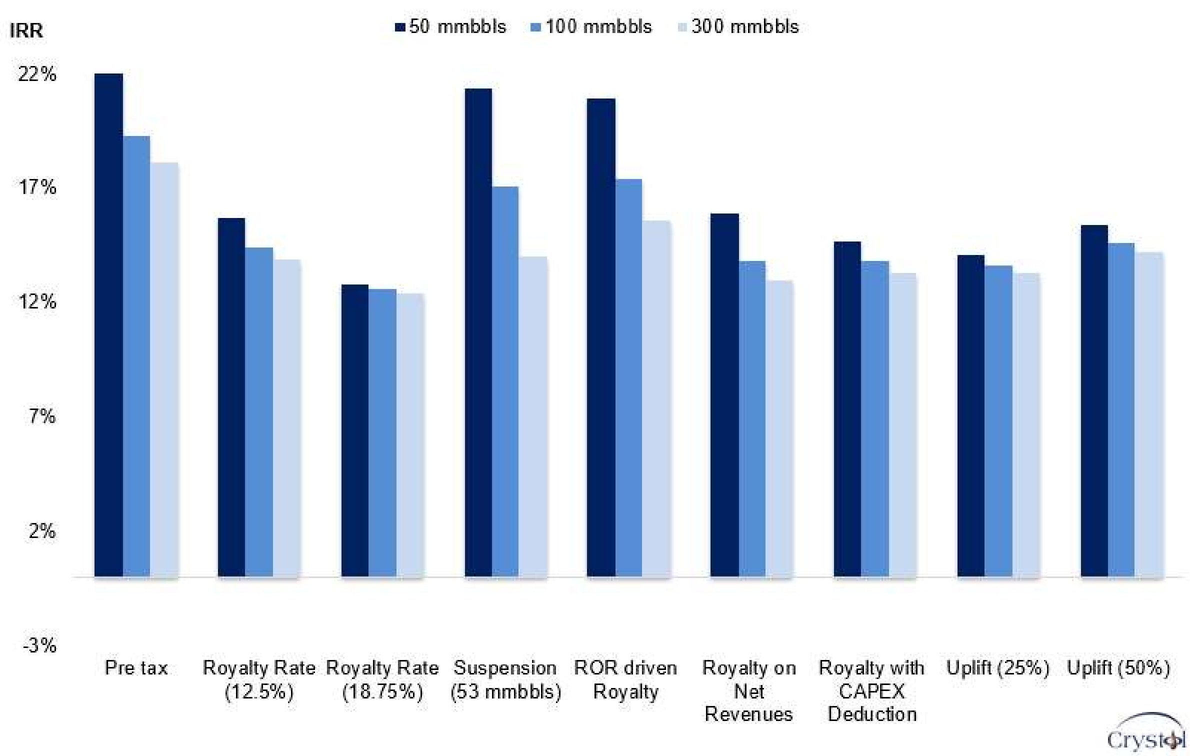
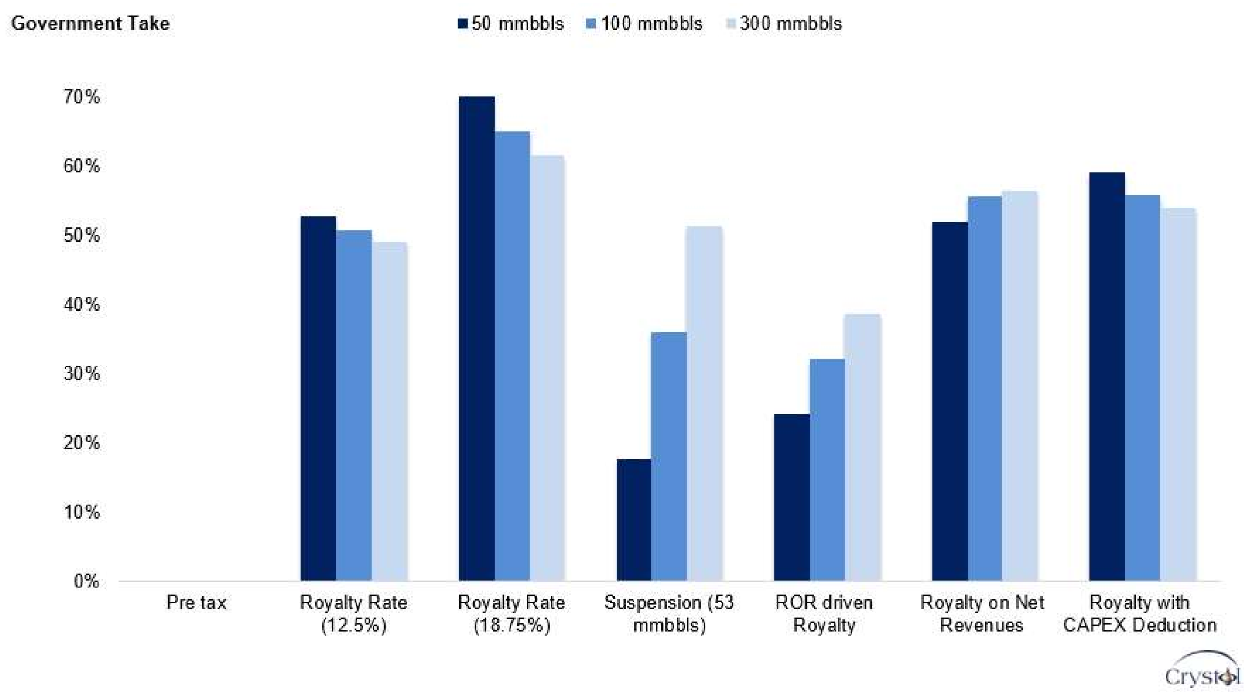


Figure 34: Summary Government Take at USD 60/bbl

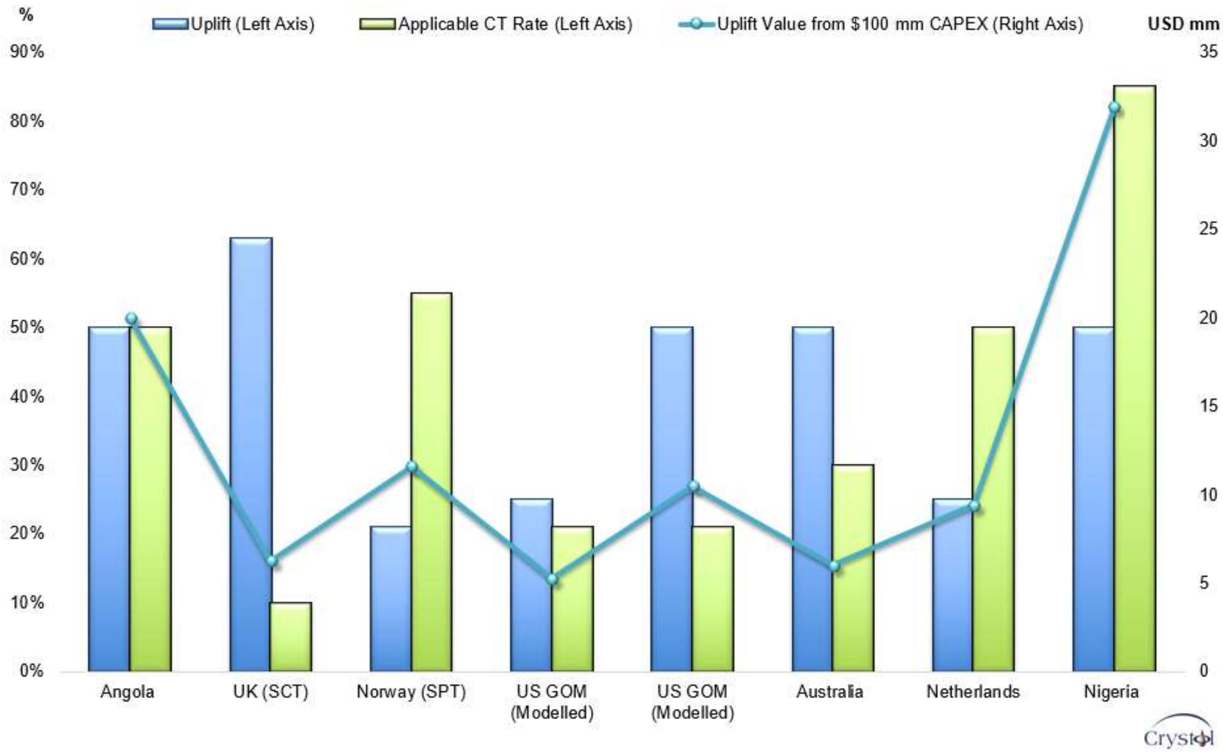


3. Figure 35 illustrates the impact of uplift on capital costs

In this case, the projected impact of a possible GOM uplift at 25% and 50% is compared with the impact of uplift in selected countries where the incentive is present. The figure shows the uplift rate, the CT rate against which it is relieved and the undiscounted value of the uplift from USD 100 mm of CAPEX.

In the UK and Norway, the uplift (called Investment Allowance in the UK) can only be relieved a specific element of the corporate tax regime not its entirety. Where uplift is present in PSC regimes, like Angola and Nigeria, the uplift becomes part of cost oil and potentially secures relief at the highest rate of Government Profit oil in addition to the prevailing rate of CT.

Figure 35: Uplift on Capital Costs Country Comparison



4. Figures 36 and 37 illustrate the price and cost sensitivities.

Figures 36 and 37 illustrate the projected impact on Government Take as price and costs change for the 100 mmbbls project, assuming Royalty at 18.75 percent**.** The pre-tax return is shown on the horizontal axis (where Government Take is zero).

The sensitivities bring out the features emphasized in the discussion, in particularly the regressive nature of the current US GOM regime compared to the UK and potential fiscal options to remedy this behavior. The UK regime is relatively neutral in terms of Government Take.

Figure 36: Government Take, Price Sensitivity (100 mmbbls)

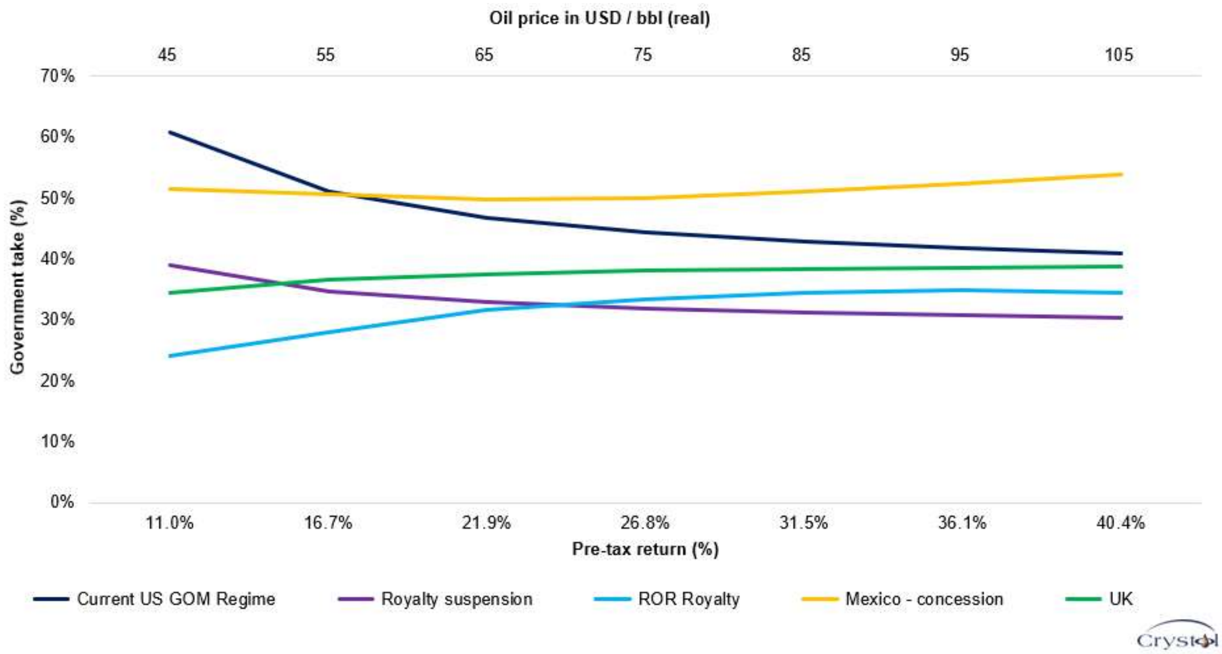
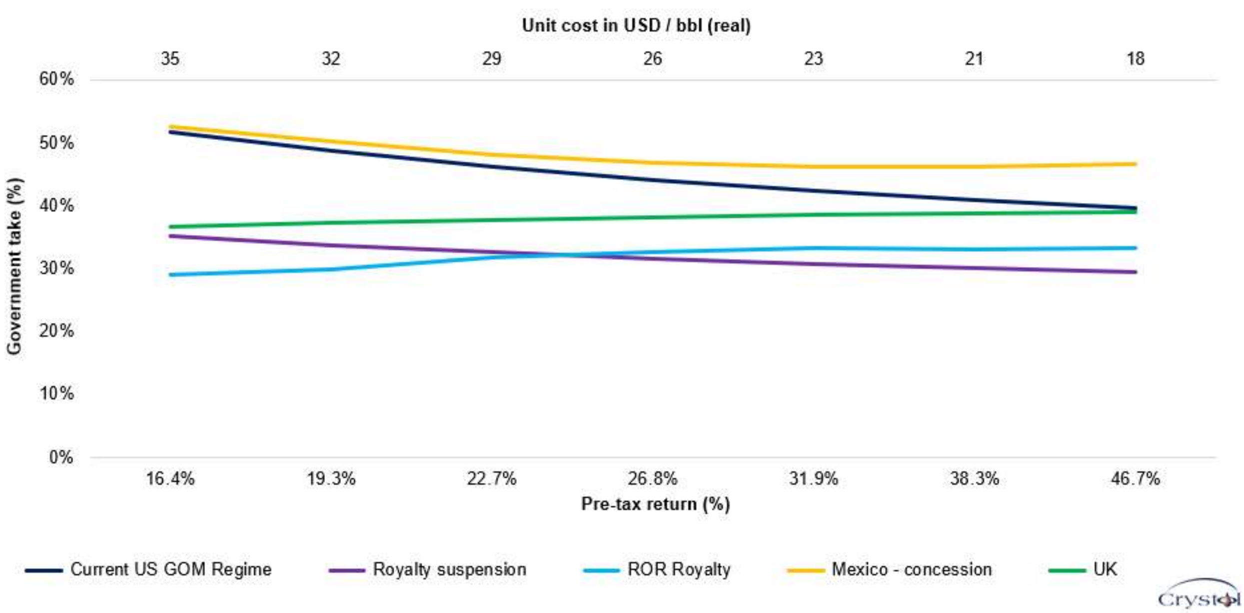


Figure 37: Government Take, Cost Sensitivity (100 mmbbls, USD 60)



4.4. International Comparison

The study further evaluated the current US GOM regime against two other offshore basins; namely Mexico and the UK. The former is chosen by virtue of the fact that its offshore basin is contiguous with the US GOM and represents an obvious and direct competitor, given the close proximity, shared geology and newly liberalized market in Mexico. The UK is selected due to its position as the world's most mature basin and the adaptive measures the UK Government has taken to sustain its attractiveness. The UK also currently features the most attractive fiscal regime of any material basin.

The Mexican regime modelled is based on Bid Round 2.4 (deepwater). The base rate for the Additional Royalty was set at a minimum of 3.1-5 percent for Round 2.4 depending on the location of the block; 4 percent (the average minimum) is assumed for this base rate. In reality, this biddable parameter functions as a rent capturing mechanism and is significant for more profitable prospective projects (many bids reached the 20 percent maximum rate in Round 2.4). Additional assumptions include:

- the company is not in a tax-paying position,
- depreciation of development is four years straight line,
- no VAT is modelled, and
- no signature bonus.

The UK fiscal regime for new developments is now relatively simple. The aspects that were modelled are:

- CT rate of 30 percent plus the Supplementary Corporation Tax (SCT) of 10 percent (40 percent in total),
- depreciation of capital costs 100 percent as incurred,
- exploration costs expensed as incurred,
- Uplift of 62.5 percent of project costs offset against SCT only from first production, and
- investor is tax paying.

The UK fiscal regime operates as a cash flow tax. No tax is payable until payback is reached, and the 62.5 percent uplift ensures that post tax IRR's are slightly higher than pre-tax IRR's.

4.4.1. International Comparison Results

Tables 23 and 24 illustrate the projected comparative economic outcomes. Table 16 shows the EMV's for the three field sizes assuming a 50 percent chance factor.

The UK is in a league of its own with only the 50 mmbbls project at USD 50/bbl failing to return a positive EMV. Both US GOM and Mexico deliver poor outcomes in all cases except for the 300 mmbbls field at high prices.

Mexico looks less attractive than US GOM as the failure case outcomes in the EMV calculation do not secure any tax relief unlike in GOM where it is assumed the investor is tax paying. Mexico, however, is perceived to be more attractive given its immaturity and potential for very large discoveries. The fiscal regime in both Mexico and US GOM risks leaving high risk exploration prospects undrilled and many marginal and medium sized discoveries undeveloped.

Table 23: GOM, UK and Mexico EMVs

Field sizes	mmbbls	50	100	300
Royalty	%	18.75%	18.75%	18.75%
Oil price (real)	$/bbl	50	50	50
Chance factor	%	50.0%	50.0%	50.0%
EMV				
US GOM	$ mm	(228)	(197)	(67)
Mexico	$ mm	(194)	(175)	(115)
UK	$ mm	(44)	38	370
Oil price (real)	$/bbl	60	60	60
Chance factor	%	50.0%	50.0%	50.0%
EMV				
US GOM	$ mm	(154)	(75)	261
Mexico	$ mm	(123)	(64)	167
UK	$ mm	25	152	676

As Table 24 below shows, the development economics confirm the stand out returns expected for the UK and the relatively low and stable levels of Government Take which displays moderately progressive features rising from a low of 22 percent (low price, low volumes) to 36 percent (high price, high volumes). In contrast, the projected returns for Mexico and US GOM are quite similar, with the latter slightly ahead. In both cases, Government Take is very high and strongly regressive (Figure 38).

The clear competitive advantage of the UK fiscal regime gives an indication of the wide disparity between it and the US GOM and direction of travel that GOM may need to follow if basin activity is to be sustained. Mexico's fiscal terms appear more onerous than US GOM (based on the terms evaluated, although other license rounds may offer more attractive returns), particularly at low volume outcomes.

However, offshore Mexico is relatively unexplored and its recent opening to foreign investment has created real momentum amongst investors. The offshore exploration potential has been considered very attractive, creating intense competition that the Mexican Government is successfully exploiting.

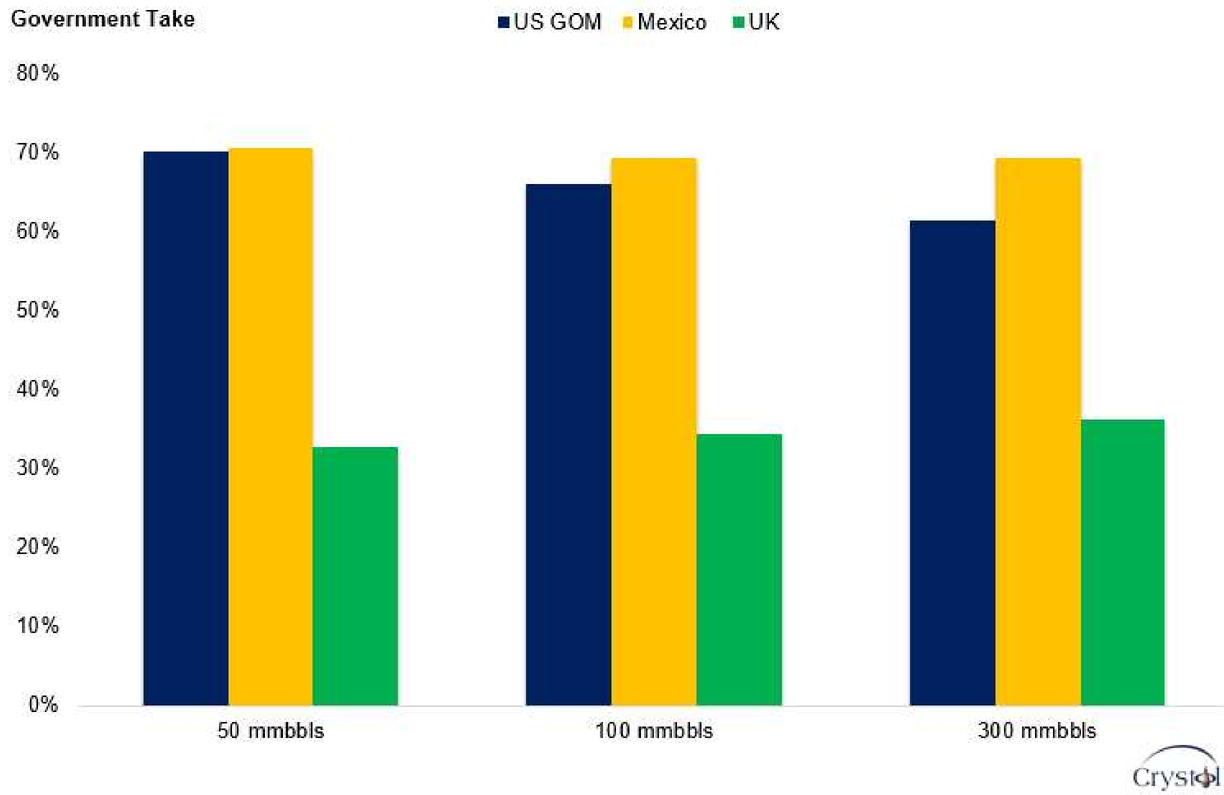
At this stage, it is too early to judge whether or not Mexico is likely to emerge as a strong and enduring competitor to the US GOM, however the early indications are that Mexico is capturing sustained interest from the major oil companies. The early license rounds have already delivered commitments to drill 138 exploration wells. The Mexican authorities believe that the acreage awarded in the more recent licensing rounds could bring up to USD 100 billion in new investment in the long-term. As a relatively immature offshore basin, Mexico offers the potential for large discoveries in contrast to US GOM where future discovery sizes have been on an established downward trend. Under these circumstances, Mexico could attract investment that might otherwise have been channelled towards opportunities in the US GOM.

Recognising the maturity of the US GOM, characterized by the trend towards smaller discovery sizes, higher unit costs and increasing exploration risk then the fiscal terms need to be much more attractive than Mexico and ultimately closer to the UK.

Table 24: GOM, UK and Mexico Development Economics Comparison

Field sizes	mmbbls	**50**	**100**	**300**
Royalty rate	%	18.75%	18.75%	18.75%
Oil Price (real)	$/bbl	50	50	50
Life cycle returns IRR				
US GOM - current regime	%	-1.6%	3.8%	7.4%
Mexico	%	0.1%	4.1%	6.9%
UK	%	6.2%	10.0%	12.5%
Development economics IRR				
US GOM - current regime	%	5.9%	8.1%	9.1%
Mexico	%	6.1%	7.5%	8.1%
UK	%	16.0%	15.0%	14.3%
Development economics NPV				
US GOM - current regime	$ mm	(32)	31	291
Mexico	$ mm	(35)	3	122
UK	$ mm	123	287	951
Government Take				
US GOM - current regime	%	n/a	92.4%	79.7%
Mexico	%	n/a	99.2%	90.0%
UK	%	22.0%	29.2%	33.7%
Oil price (real)	$/bbl	60	60	60
Life cycle returns IRR				
US GOM - current regime	%	2.9%	7.1%	10.3%
Mexico	%	3.8%	7.0%	9.4%
UK	%	11.2%	13.8%	15.9%
Development economics IRR				
US GOM - current regime	%	12.8%	12.6%	12.4%
Mexico	%	12.0%	11.4%	11.1%
UK	%	24.6%	20.2%	18.0%
Development economics NPV				
US GOM - current regime	$ mm	116	275	945
Mexico	$ mm	108	224	688
UK	$ mm	262	515	1,563
Government Take				
US GOM - current regime	%	70.2%	65.0%	61.5%
Mexico	%	70.5%	69.3%	69.4%
UK	%	32.7%	34.4%	36.3%

Figure 38 : Benchmarked Government Take



4.5. Summary

The objective of this section is to evaluate the US GOM upstream fiscal regime, to identify the fiscal characteristics that impact investment opportunities. The analysis in this section demonstrates the following:

- Exploration in the US GOM struggles to be attractive unless large discoveries can be made in shallow water. The 300 mmbbls case is the only discovery size, amongst the three modelled, capable of delivering a positive EMV, assuming a typical exploration success rate of circa 40 percent.

- The current US GOM fiscal regime acknowledges the onerous nature of the Royalty burden by having lower Royalty rates in shallow water and suspension volumes at times of low prices. However, the precise mechanisms are too restrictive to be effective in encouraging GOM activity. The suspension volume-trigger at USD 43/bbl renders this provision essentially of little practical value; this analysis indicates that it would need to be raised to nearer USD 60/bbl to be more effective. Also, the application of the 12.5 percent Royalty rate to shallow water only is almost perverse; deeper water generally implies higher costs and more challenging economics. If anything, deeper water should be equally, if not more deserving, of a lower Royalty rate. Perhaps the provision is a legacy from the days when deepwater exploration could yield very large discoveries but with the onset of basin maturity those outcomes have been increasingly scarce. These are very powerful mechanisms to blunt the impact of Royalty, but the authorities are reluctant to widen the spectrum of applicability due to the implications for revenue. The mechanisms have very sharp edges and this analysis indicates that it would be more appropriate if there were some tapering provisions to smooth the transition of applicability.

- The evaluation carried out in this study suggests that the simplest measure is to simply increase the price threshold at which the suspension volumes are withdrawn or have a taper mechanism whereby the suspension volumes were banded according to the oil price; say in a range from USD 45 to 65/bbl. Applying the suspension volume of 53 mmbbls across the board is projected to have a noticeable impact on the economics and for the smaller fields represents 'de facto' Royalty abolition, price threshold permitting.

- Formulaically linking the rate of Royalty to achieved project IRR thresholds has the greatest intellectual appeal as self-evidently the most profitable fields will face the greatest Royalty burden and vice versa. This might appear quite a complex mechanism but the linking of tax rates to project IRR is common in PSC regimes, so there is a wealth of experience that can be tapped into when and if detailed legislation or regulations were prepared. The specific bands and rates can be changed to match policy objectives in the US GOM. Indeed, they could be biddable along with the lease bonus payment though this would complicate the award procedure. It could be argued that such a policy option simplifies the regime as the existing tapestry of Royalty reliefs could be abolished for new leases. A ROR driven Royalty can be designed to be effective at all oil prices, water depths, field sizes and cost structures.

- A further structural alternative was also evaluated where the 18.75 percent Royalty is payable on net revenues. Again, this makes the Royalty more profit related and less regressive. Indeed, the graphs of Government Take shown above illustrate that the take is projected to be remarkably neutral under this fiscal option and conforms to a narrow band across the development sizes: 71 to 67 percent at USD 50/bbl and 52 to 57 percent at USD 60/bbl. One of the advantages of this option is that the Royalty burden will automatically fall as the field ages to the point where it is eliminated once operating costs are equal to revenues. This would not require any discretionary intervention by the authorities to lower the Royalty rate to prolong field life as is currently the case.

- For the US GOM, the Royalty abolition is unlikely ever to be politically feasible in the medium term given the absence of any RRT, which places boundaries as to what is politically acceptable in the context of Royalty reform. Within the next two decades, there may be an increasingly compelling argument to abolish Royalty if faced with increasing maturity and falling real oil prices, but we are not there yet particularly given the very recent fall in the federal Tax rate.

- Beyond Royalty, changes to cost depreciation are likely to have a modest impact due to the comparatively low CT rate of 21 percent. The simplest fiscal option is to consider an uplift on capital costs which would complement the existing depreciation provisions. The modelling has evaluated a 25 and 50 percent uplift rate spread over four years. Some regimes have introduced capital uplift provisions (notably in the North Sea) mainly to compensate for the slow train depreciation reliefs that typically apply in many jurisdictions; often the uplift is regarded as a proxy compensation for financing costs. The benefit is independent of oil prices, so it is not especially well targeted and risks giving a benefit to fields that may not require it. Also, it can reward poor project execution because cost overruns will benefit from the uplift. In the examples evaluated, the uplift is projected to be worth from USD 46 to 260 mm across the three projects (based on a 50 percent uplift). The benefit is halved for uplift at 25 percent and behaves linearly as the uplift percentage is varied.

5. Conclusion and Recommendations

The objective of this study is to assess whether the existing regulatory and fiscal framework in the US GOM, which has worked well in the past, is suitable for a mature province in a global and increasingly globally competitive market.

The analysis focused, first, on the licensing policies then on the fiscal policies, and in both cases, as applicable to the US GOM and in competing offshore provinces. Below are the main recommendations based on the findings of the analysis. These recommendations are intended to work within the system that is in place today - an evolutionary not revolutionary approach to avoid unsettling investors' sentiment.

5.1. Licensing Policy

The analysis of the licensing terms and the results of recent licensing rounds in the US GOM and competing offshore jurisdictions reveals that the US is an outlier on several fronts. The licensing system is generally more rigid than elsewhere and should incorporate more flexibility that is more suitable to a maturing province. The results of recent licensing rounds reflect the relative geological potential and investors' expectations of value. In mature areas such as the US GOM, such a potential is increasingly perceived as limited, unlike less explored areas in Brazil and Mexico, for instance.

The recommendations below are shaped to develop greater flexibility and improve the attractiveness of the system to investment by aligning it more with competing provinces. They can also be implemented at little or no financial cost to the government and some can alleviate the administrative burden.

1. The US GOM is the only jurisdiction that applies a bidders' list although no evidence is found on the effectiveness of such a measure. Most of the other jurisdictions surveyed have an equally competitive market structure with no similar restrictions in place. As upstream exploration becomes more complex and challenging, restrictions on joint bidding can be counter-productive. The US authorities should therefore consider removing such a restriction.

2. The US GOM licensing system is more complex than in the other analyzed jurisdictions. It has the widest variation in exploration license durations, varying with several water depths. Most of the other jurisdictions assessed have one license duration for offshore. If a distinction between water depth is made, it is typically between two categories, shallow and deepwater. One therefore wonders whether such a differentiation is needed and whether a more simplified approach could be introduced, such as using only two types of lease – for shallow and deepwater, or even unifying the license duration.

3. Also, in terms of license duration, only for licenses covering water depths higher than 1,600 m, does the US GOM license length exceed the average of the selected jurisdictions; all the other licenses in the GOM fall below the average duration. The authorities should therefore align their lease duration with that of other competing offshore provinces. Furthermore, the duration of the US GOM exploration phase (primary term) for depths between 800 m and 1600 m is lower than the other depths, including shallower water. In practice, one would expect to see longer duration for deeper water depths and shorter for shallow water. If differentiation by water depth in license duration is maintained, one alternative can therefore be to offer two types of license duration – a shorter one for shallow water and a single longer one for deepwater. A longer exploration license duration may be necessary in areas where exploration requires more time. Of course, the risk is that the lease could be held for a longer period by an owner with no intention of exploring or developing the resource. The minimum work program requirement, however, would guard against such a scenario.

4. In terms of rental fees, when considering the five-year average of the exploration phase for all the selected jurisdictions, the US GOM fees fall above the average. When the average is taken for the first seven years, the rental fee for all the leases in the US GOM exceeds the average, with the lease for water depth between 200 and 400 m nearly double the average rate. Furthermore, there is no clear rationale behind US GOM rental fees whereby leases between 200 and 400 m attract the highest fee from year six, while leases for shallow water (less than 200 m) have the lowest fee for first five years. The US Government should consider at the very least aligning its rental fees with global norms, especially given that the fees are not the principle revenue collection mechanism for the authorities. Some countries impose high rental fees, which can be waived if the investor carries out a specific work program. This is one approach to encourage exploration activity. There is some logic in a 'carrot and stick' approach to lease rentals. For example, the government can have high rentals where little or no activity is taking place but present the opportunity for the investor to have the rentals waived or materially reduced where there is clear evidence of activity. It would probably be best to link the rentals to annual expenditure outcomes on each lease. License rentals are simply there to influence behavior and encourage activity not as a primary source of government revenue.

5. During the primary term of the lease, lessees in the US GOM do not have a mandatory work program, except when applying for an extension. In contrast, in all the other jurisdictions selected, a minimum work program must be carried out and is typically biddable. In some cases, the work program is the only biddable parameter.

6. The US GOM system does not provide sufficient certainty, given that investment is best encouraged by predictability. For instance, although the SOP and SOO can be granted for up to five years, the practice has been for one year or less. The system therefore needs to provide greater certainty and flexibility by, say, broadening the criteria for situations that qualify for lease suspensions to include the need to advance technology and gather additional seismic data. It could be made more explicit as to what SOP and SOO outcomes can be achieved

under what circumstances. As a basin matures, it tends to take longer to develop discoveries as they become smaller, more marginal and technically challenging.

7. No relinquishment rule applies upon renewal of the primary term in the US GOM, most likely because the blocks are very small – in fact, the smallest among all the selected jurisdictions. The US authorities could consider leasing much larger individual blocks in deep water with mandatory relinquishments (after say five years) to help increase interest from investors.

5.2. Fiscal Policy

The conclusions from the fiscal analysis are that the current US fiscal regime requires reform to meet the dual challenges of basin maturity and competition from more attractive basins both domestically and internationally.

The fiscal regime is a legacy from earlier in the century when it worked well to facilitate the exploration and development of large, low unit cost discoveries. Falling discovered volumes and more marginal developments require a more profit related fiscal structure. The recommendations are as follows:

1. Formulaically linking the rate of Royalty to achieved project post-tax IRR thresholds has the greatest intellectual appeal as self-evidently the most profitable fields will face the greatest Royalty burden and vice versa. Linking the tax rates to project IRR is common in PSC regimes, so there is a wealth of global experience that can be tapped into when and if detailed legislation or regulations were prepared. The specific bands and rates can be changed to match policy objectives in the US GOM. It could be argued that such a policy option simplifies the regime as the existing tapestry of Royalty reliefs could be abolished for new leases. A ROR driven Royalty can be designed to be effective at all oil prices, water depths, field sizes and cost structures.

2. If the ROR mechanism above proves too complex or fails to secure widespread support, then reforming the current ‘Suspension Volume’ system could be considered. The evaluation carried out in this study suggests that, as currently structured, the suspension volume system is ineffective in encouraging new investment, as not many exploration decisions are likely to assume a price as low as USD 43/bbl (the price level at which the relief is withdrawn). Therefore, the simplest reform is to materially increase the price threshold at which the suspension volumes are withdrawn or have a taper mechanism whereby the suspension volumes were linearly reduced according to the oil price; say in a range from USD 45/bbl to USD 65/bbl. The quantum of the suspension volume itself would benefit from review as to whether this amount, currently 52 mmbbls, remains appropriate

3. The current Royalty rate differentiation between shallow water and deep water is counter intuitive and should be reviewed. If anything, deepwater should attract a lower Royalty rate than shallow water and not vice versa due to the fundamentals of cost structure, lead times and risk. On the presumption that marginal fields can occur in any water depth, there is an argument for a single Royalty rate across the US GOM of 12.5 percent.

4. Uplift on capital expenditure for CT has been modelled as a potential fiscal option but we find it difficult to recommend this as a priority option for reform. The recent reduction in the Federal

CT weakens the argument for any further fiscal concessions in this area and in any event the impacts will have little leverage against a tax rate of 21 percent. There is also the argument that the government ends up rewarding investors for poor project execution if cost overruns occur.

5. Exploration incentives similar to the 'Norwegian' model would be of no benefit to any investor in a current CT paying position, as the Norwegian incentive is simply a timing difference to ensure non-tax payers are not placed at an economic disadvantage to current tax payers. There is however merit in considering the immediate expensing of all exploration and appraisal expenditure against CT in the year it occurs. This would give some modest encouragement to exploration activity through an increase in EMV's.

6. Although the study evaluated some changes to the federal CT, any proposal that involves a change in federal tax law, including increased or accelerated R&D deductions, depreciation or tax credits or the introduction of a lower tax on income from patents is unlikely to be feasible given the comprehensive tax reform that was only enacted at the end of last year. It may, however, be possible to make changes at the state tax level in respect of onshore R&D activity. The industry could work with industry-friendly states such as Texas and Louisiana to set up a cash incentive or grant scheme on total R&D expenditure in respect of projects approved by an expert commission, with the level of incentive limited to payroll taxes on employees engaged on such projects in the state. The commission would own the rights to the intellectual property developed and would make it freely available. Universities as well as companies could apply for grants[23].

[23] See Appendix II

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Appendix I: The North Sea Experience

The North Sea provides a useful example of governments, particularly UK and Norway, responding in very different ways to the challenges of a maturing basin.

A. Norway:

The Norwegian fiscal regime is the very model of both simplicity and fiscal stability. The basic ingredients of the 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 2018 comprises state tax (23 percent) and SPT (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 State to raise the tax rate as oil prices increase as 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. 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, the former is taken as 5.3 percent per annum spread over four years or 21.2 percent in aggregate. This benefit is only allowable against the SPT base. These rates are for 2018; some slight adjustments take place year on year (to keep the benefit value constant) as Norway lowers its state tax rate. The net effect is that for each USD 100 mm in capital expenditure, a Norwegian investor will reduce his tax liability by USD 90 million (90 percent). Prior to May 2013, the uplift was 30 percent giving an equivalent tax saving of USD 93 mm (93 percent). Clearly with such high levels of relief, there is a risk of gold plating and the Norwegian Government has historically taken most of the hit from project cost overruns (a very frequent outcome). Hence, the modest reduction in uplift from 2013, though this still remains a very attractive relief.

It is important to note that Norway, like many OECD countries in recent years, has lowered its CT rate to ensure its non-oil sector remains internationally competitive. In 2013, the State tax rate was 28 percent; since then, it has been lowered in four steps to its current rate of 23 percent which takes effect from January 2018. Notably the Norwegian Government has denied any benefit of this lower rate to the upstream sector by increasing the SPT rate in similar steps but in the opposite direction. So, over the same period, the SPT rate increased from 50 percent to 55 percent. It is expected that this policy to continue as and when the state tax rate is reduced in the coming years.

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. Perhaps one of the important distinguishing features of Norway is the very strong role the government continues to play both directly and indirectly. The government remains the majority investor across the basin, owning 100 percent ownership of Petoro and, also, large equity position in Equinor[24] (67 percent). The government is involved in nearly all the production assets and has dominant equity positions in most future developments. Equinor as the leading basin operator continues a key role in driving basin activity. This stable 'state' stewardship position has engendered a less volatile investment history than in the UK and more muted advocacy activity

[24] Formerly Statoil

by the industry in promoting fiscal change. Norway with its small population has low domestic consumption of oil and gas and in consequence is a major exporter. Like most countries in this position there is less urgency to maximize and accelerate production and more emphasis on long-term outcomes. The fiscal regimes for net petroleum exporting countries tend to less favourable than those for importing nations.

B. The UK:

In contrast to Norway, the UK is often cited as the basin with the most unstable upstream fiscal regime in the world. This is not necessarily as damming as it might sound as over the decades the overall fiscal burden in the UK has remained consistently lower than in Norway. But has needed to be, fields in the UK sector are smaller and more mature than in Norway. The UK has no state actors; the outcomes are entirely dependent on private sector decisions. Apart from a very brief period from the late 1990's until the mid-2000's, the UK has remained a net importer of oil and gas. 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.

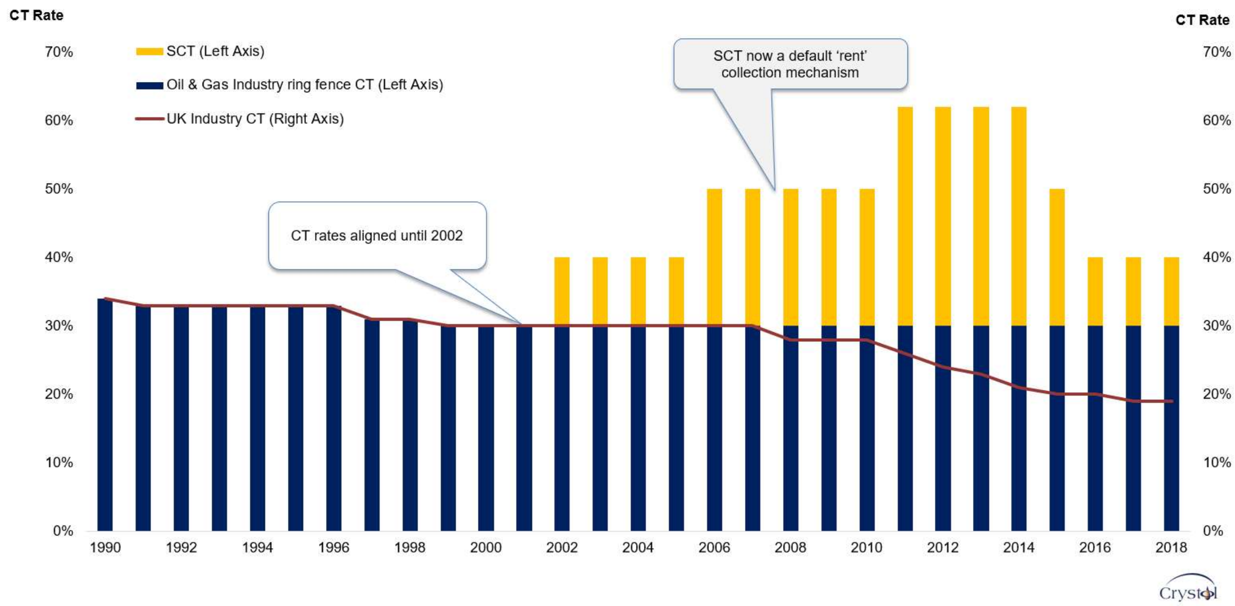
Unlike Norway and US GOM, the UK has over many decades favored field-based taxation, though with varying degrees of applicability. The UK introduced a RRT in 1975 called Petroleum Revenue Tax (PRT) and it remained the foundation of the UK tax regime for many decades. The raison d'être for the UK approach was a recognition of the very wide disparity in underlying profitability of individual fields across the basin. The PRT mechanism ensured that marginal field's paid little if any PRT whilst large profitable fields paid substantial amounts. With its associated reliefs PRT proved a very effective tool in capturing 'rent' across the basin. However, maturity hit the UK relatively early and, by 1993, PRT was abolished for new developments (along with Royalty).

The collapse in the oil price in the mid 1980's, along with high levels of taxation (marginal rates comparable with Norway), caused a rapid decline in basin exploration and development. From 1993 until 2002, the UK enjoyed a very attractive fiscal regime for new developments, with the tax burden being the same as the rest of UK industry, namely CT. At the time of PRT abolition in 1993, the CT rate was 33 percent; by 2002 it had fallen to 30 percent. These low tax rates engendered an activity renaissance and UKCS reached peak production in 2000.

The first decade of the new century heralded a period of frequent tax changes and a rising tax burden for the UKCS. A new tax was introduced in the UK in 2002: the supplementary corporation tax (SCT), at a rate of 10 percent, doubling a couple of years later to 20 percent. The SCT is calculated in the same way as CT except that deductions for interest expense are not permitted. In 2011, the SCT rate was increased further to 32 percent. By this time, the headline tax on new developments had risen from 30 percent to 62 percent in less than ten years, essentially tracking increases in the oil price. Over the same period, the rest of UK industry has seen its CT rate fall from 30 percent in 2007 to 19 percent today: so, from parity with the wider industry in 2000 to a material gulf today between the tax rate on the oil industry and that applicable to the rest of the business sector.

Following the oil price collapse in 2014, the SCT 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 UK Government has been able to justify the differential treatment by virtue of the more favourable treatment of capital allowances for the oil industry alone. The 2002 fiscal reform which introduced SCT (and removed 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 UK would pay any tax until payback had been reached. The outcome is that pre-tax project IRR remains the same post tax. Subsequently, it is now very difficult to assert in the UKCS that tax is preventing projects from proceeding.

Figure 39: UK CT Rates for Upstream



There is perhaps a lesson here for the GOM: if the industry wants a special treatment in the form of incentives for capital allowances, say uplift or swifter depreciation, the government may wish to pay for it by introducing a special rate of federal income tax or federal tax supplement just for the oil industry. Also, if the government policy is to reduce CT for the industry generally, matching global trends in tax competition, they may wish to ensure the oil and gas sector does not share in this benefit, particularly if the CT is a key 'rent 'collection mechanism without any obvious substitute. This is a risk in the US GOM given the recent fall from 35 percent to 21 percent in the CT rate. If like in the UK, such a CT rate distinction is made between the oil industry and others via a higher rate or supplement it will be very difficult to remove. Indeed, it gives the government the freedom to increase the supplementary rate with oil prices and turn such an instrument into a proxy RRT.

Whilst the attention of fiscal policy in the UK focussed on new developments, it should be noted that the legacy fields, securing development consent prior to 1993, remained subject to PRT. The marginal tax rate for these older fields remained in a narrow band of around 70 percent to 75 percent. In 2015, the rate of PRT was reduced to zero; no fields are paying PRT into the future, but the tax remains in existence and will need to for many decades to come in order for investors to claim PRT tax relief on future decommissioning expenditure.

The UK Government proceeded to soften the blow of the SCT tax rate by introducing a series of targeted field specific fiscal incentives - a move back towards field-based taxation. These came into force in 2009 and were centred on a new field specific allowance called 'Field Allowance'

(FA), this exempted a specific quantity of project revenues (up to GBP 500 mm though typically much lower) from SCT provided certain criteria were satisfied.
The allowance was taken equally over the first five years of field production. It permitted all the costs of the field in question to secure SCT relief at up to 62 percent whilst a fixed quantity of the revenues was exempt from SCT and were taxed at just 30 percent. Over a few years, an increasing number of fields began to qualify for this allowance, new categories were introduced each year. The ambition of the government was to target the FA at the most deserving cases, typically marginal fields which had atypical characteristics such as heavy oil, deepwater, and high costs.

The FAs were introduced to cover the following categories of new developments, including:

- Deepwater gas fields
- High reservoir temperature and pressure (HPHT fields)
- Heavy oil fields based on Viscosity and API criteria
- Small fields
- Deepwater oil fields
- Shallow water gas fields

It is fair to say that the government soon recognised that this direction of travel was seriously flawed. Industry lobbying intensified with the general view that the selection criteria were so flexible that pretty much any field just missing out could lobby government officials to get the criteria relaxed. If a field was reasonably unique, then the government could be persuaded to designate a new FA category just for that field. By 2015, around eight different FA's were introduced. The FA system became highly distortionary; developments with a FA progressed those failing to attract one were shelved until and FA could be secured. It also proved time consuming to administer, the above qualifying criteria tend to have sharp edges, so a field could just miss out on a FA by a few degrees Celsius or a few metres of water depth or reservoir pressure.

In 2015, the government replaced the FA system with a new investment allowance, which was simpler to administer and applied to all new investment on the UKCS. From April 2015, all new investment secures an Investment Allowance (IA) equivalent to 62.5 percent of the investment; this is then used to reduce the revenues liable to SCT. This appears to be a high percentage but by limiting its relief to SCT only (where the rate is 10 percent) the cost to government revenues is modest. So, for an investment of USD 100 mm, the value benefit of the 62.5 percent uplift is USD 6.25 mm.

As of today, the UKCS continues to struggle with the legacy of the oil price collapse. Reductions in the overall tax burden have helped to keep the basin competitive but the perception of the fiscal regime is one of continuing fiscal instability and endemic complexity. The basin now delivers very little in terms of tax yield with many leading basin operators having amassed significant carried forward losses which will take years to absorb. Decommissioning costs estimated at up to USD 100 billion and shared approximately 50/50 between the government and industry will most likely ensure that government tax revenues from the upstream sector will soon become structurally negative for the foreseeable future. Any spikes in the oil price say above USD 80/bbl to USD 90/bbl would probably trigger increases in the rate of SCT so the risk to fiscal stability remains. As is the case in most hydrocarbon producing basins, the fiscal regime is under permanent review.

Lessons that can be drawn from the North Sea experience:

- Avoid complex fiscal incentives that risk introducing distortions
- Avoid fiscal incentives based on physical criteria
- Avoid fiscal incentives that encourage industry lobbying
- Investment is best encouraged by certainty and predictability.
- Pleading for special incentives within the CT code risks the creation of a separate but higher tax rate for the upstream industry.
- Both the UK and Norway have taken explicit steps to prevent their upstream Industries from capturing any benefit from recent reductions in the level of CT. There is a risk that such policies are contagious.
- One size fits all preferable to field-based taxation, the latter encourages or makes it easier to introduce a RRT.
- Oil importing nations tend to have more attractive fiscal regimes than exporters. If the US were to become a net exporter the fiscal dynamics might become unfavourable.
- A Norwegian style fiscal regime requires Norwegian levels of state ownership.
- Very high levels of capital expenditure relief risk 'gold plating' and the government funding a disproportionate share of cost overruns.

Appendix II: Incentivizing technology development program with associated data sharing and tax credits

Although the study evaluated some changes to the federal CT, any proposal that involves a change in federal tax law, including increased or accelerated R&D deductions, depreciation or tax credits or the introduction of a lower tax on income from patents is unlikely to be feasible given the comprehensive tax reform that was only enacted at the end of last year. Such changes are therefore not considered in this appendix. It may however be possible to make changes at the state tax level in respect of onshore R&D activity.

European Union experience

The EU has a specific program supporting research and innovation called Horizon 2020, with a budget of around EUR 70 billion to spend over the period 2014-2020. The program has three themes – Excellent Science, Industrial Leadership and Societal Challenges. It provides funding through grants to individuals or groups for research projects, support to public-private partnerships, and other instruments supporting research and innovation in SMEs.

In September 2017, the Directorate-General for Research & Innovation of the European Commission published a report on how to make R&D tax incentives most effective. The report recommended:

- targeting incentives towards new and small companies that are more in need of funding than large companies,
- providing cash grants or refunds of tax that assist all innovators not just those paying corporate income tax,
- linking cash incentives to payroll taxes rather than CT, as those who spread knowledge tend to be employees moving between companies,
- incentivizing total R&D spend, not incremental over a historic baseline, as the latter can often encourage innovators to 'game the system', and
- making incentives easy and quick to administer by having a 'one stop shop' for R&D project approvals.

The UK Experience

The UK R&D Expenditure Credit Scheme provides a cash grant equal to 11 percent of qualifying R&D expenditure. The grant is limited to the payroll taxes paid in respect of employees working on the approved R&D project.

How Does the US Compare?

At the federal level, there is a 20 percent tax credit on qualifying R&D expenditure incremental to a baseline of prior expenditure. Making a claim takes a significant amount of time and effort, and there is no provision for a cash refund or grant to companies that are not paying CIT. The value of the credit has however gone up as a result of the reduction in federal income tax rate from 35 percent to 21 percent and this would not have been the case if the incentive had been in the form of a tax allowance rather than a tax credit.

The state of Louisiana has a 30 percent R&D tax credit, but it is also based on incremental rather than total expenditure and is not refundable. Texas appears to have no such incentive regime at present although it has been debated by the legislature in the past.

Recommendation

As changes in Federal tax legislation are difficult, it is proposed that the industry works with industry-friendly states such as Texas and Louisiana to set up a cash incentive or grant scheme on total R&D expenditure in respect of projects approved by an expert commission, with the level of incentive limited to payroll taxes on employees engaged on such projects in the state. The commission would own the rights to the intellectual property developed and would make it freely available. Universities as well as companies could apply for grants.

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Dr Carole Nakhle is the founder and CEO of Crystol Energy. An Energy Economist, she specializes in international petroleum contractual arrangements and fiscal regimes; upstream oil and gas regulations; petroleum revenue management and governance; energy policy, security and investment; and world oil and gas market developments.

With a unique breadth of experience, Carole has worked with oil and gas companies, governments and policy makers, international organizations, academic institutions and think tanks, globally. She is active on the Governing Board of the Natural Resource Governance Institute and Advisory Board of the Payne Institute at the Colorado School of Mines. She is a program advisor to the Washington based International Tax and Investment Centre, and regular contributor to Geopolitical Intelligence Services and the Executive Sessions on the Political Economy of Extractive Industries at Columbia University in New York. She is also involved in the OECD Policy Dialogue on Natural Resource-based Development and lectures at the Blavatnik School of Government at Oxford University, University of Surrey in the UK, and Saint Joseph University in Beirut. She has designed and delivered multiple professional training courses on oil and gas economic, fiscal and regulatory issues to government officials and industry players in different regions.

Carole is a respected and regular contributor to the global debate on energy matters, with numerous articles in academic journals, newspapers and magazines to her credit, as well as being a prominent speaker at international industry conferences. She has reviewed studies, books and reports for leading publishing houses and consulting firms and is an avid and regular commentator on energy in the international media. She has appeared on Al Arabiyya, Al Jazeera, the BBC, CNBC, CNN, among others. She is the Executive Editor of Newsweek special edition ‘The Future of Innovation in the Oil and Gas Industry’ and member of the Editorial Board of the Journal of World Energy Law & Business.

She is the author of two widely acclaimed books: Petroleum Taxation: Sharing the Wealth published in 2008, re-printed in 2012, and used as primary reference in leading universities and industry training courses; and Out of the Energy Labyrinth (2007), co-authored with Lord David Howell, former Secretary of State for Energy in the UK. She contributed chapters to leading publications (e.g. Petroleum Fiscal Regimes: Evolution and Challenges’, in The Taxation of Petroleum and Minerals: Principles, Problems and Practice, published by the IMF in 2010), prepared educational reports to shape policy making (e.g. ‘Oil & Gas Parliamentary

Guide' for the Lebanese Parliament; 'Iraq's Oil Future: Finding the Right Framework').

In 2007, Carole founded the not-for-profit organization 'Access for Women in Energy', with the aim of supporting the development of women within the energy sector.

Carole has worked on energy projects in more than 40 countries and has been on exploratory visits to the Arctic and North Sea. Given her highly regarded independent views, she is repeatedly approached by governments and institutions around the world to review oil and gas policies, legislation, fiscal regimes and regulations and to recommend policy changes and/or solving related stalemates. In 2017, she gave evidence to the International Relations Committee at the UK Parliament on oil markets and the transformation of power in the Middle East and implications for the UK policy. In 2017, she received the Honorary Professional Recognition Award from the Tunisian Minister of Energy, Mines & Renewable Energy.

RAYMOND HALL

Raymond Hall has over 35 years' (29 years with BP) experience in the oil and gas industry in a variety of senior commercial, planning and advocacy roles. Most recently, he acted as Aberdeen based manager of upstream fiscal economics and advocacy covering commercial, economics and government relationships for BP. He was responsible for negotiations with governments in respect of shaping competitive fiscal terms to assist BP investments and defending against damaging tax changes.

Ray project-managed a range of successful industry initiatives to implement fiscal incentives in the UK and overseas regimes. He has practical extensive experience in commercial negotiations, strategic planning, economic evaluation and modelling in multiple jurisdictions. Throughout his career, Ray has participated in industry initiatives to promote fiscal investment incentives with a special focus on the UKCS.

He is a respected industry player in shaping fiscal strategy, having acted as the lead participator in industry work groups examining decommissioning, investment and exploration initiatives. In 2000, he was appointed by the Department of Trade and Industry (DTI) as co-chairman of the Economic Advisory Group (EAG), which draws together a cross section of industry, contractors, academics, and government to support 'PILOT' and provide advice/analysis to the government on the UKCS economic issues. He chaired the EAG until 2007 when its role was superseded by Oil & Gas UK.

In 2003, he was selected by UK Industry peers to manage a cross industry task force assembled to engage with HM Treasury (UK) for lower tax burden on tariff receipts; the team successfully secured Petroleum Revenue Tax (PRT) exemption on all new tariff business. He also played a chief role in shaping industry response to the 2002 introduction of SCT including attendance at Downing Street meetings and fronting industry press conferences.

He also led BP advocacy team, which engaged with HM Treasury (UK) to secure changes to the High Pressure High Temperature (HPHT) Field Allowance in 2009; the changes ensured that a number of BP discoveries qualified for the Field Allowance. He represented BP in cross industry project to shape and educate Iraqi officials in the options for implementing a new fiscal regime for post-Saddam Iraq. In 2006, he assisted BP Alaska in responding to proposed adverse tax changes and appeared in front of live televised legislative committee (in Juneau) as BP tax expert giving evidence and answering probing questions from legislators.

Ray acted as Chairman of the Oil and Gas Producers Association Energy Strategy Task Force from 2006 to 2010. In this capacity, he was actively engaged in an extensive dialogue with officials in the UK and EU Commission to shape EU energy policy and assist with the implementation of EU emissions trading scheme. Between 2005 and 2017, he served as member of the organizing committee of the International Petroleum Tax Conference in Oslo.

Ray authored the first Industry Economic Report for the UKCS and gave oral evidence to House of Commons Select Committee investigating energy policy for UKCS.

NATE VERNON

Nate Vernon worked in the Tax Policy Division of the IMF, specializing in the modelling and analysis of fiscal issues relating to oil, gas, and mining. While at the IMF, he maintained and led projects to improve the Fiscal Analysis Resource Industries (FARI) model, a project-level, discounted cash flow model employed on IMF technical assistance and research of extractive industries. He has an extensive experience providing technical assistance on tax policy reform and revenue forecasting in many jurisdictions with substantial offshore hydrocarbon assets, including Ghana, Mozambique, Timor-Leste, and Trinidad and Tobago. Said work included the modelling of over 70 national oil and gas fiscal regimes and involved the integration of revenue forecasts into macroeconomic and fiscal frameworks.

Nate also worked considerably on several IMF working papers. He led the modelling work for a paper examining tax preferences for US shale oil and gas and helped develop a general equilibrium model to quantify the fiscal and welfare impacts of various environmental tax policies – the general equilibrium model was later instrumental in multiple published papers and the IMF's related technical assistance work. He has also consulted on oil and gas fiscal analysis for Crystol Energy, the IMF, NRGI, and OpenOil.

He was an intern within the Energy and Natural Resources Business Group at the European Bank for Reconstruction and Development (EBRD), where he was part of the team negotiating terms for a loan to a project financed utility-scale solar power plant in Jordan; a role, which involved financial modelling, and a series of negotiations. He also led an EBRD initiative on renewable energy licensing policy, which included the authorship of an internal paper on relevant policy tradeoffs – analysis cantered around Monte Carlo simulations that quantified risk-sharing between power producers and off takers.

Nate is attending the Harvard Kennedy School where he is earning a Master in Public Policy with a concentration on development. His thesis is on public policy options to attract foreign direct investment in Kaduna State, Nigeria.

Reviewers

JIM ROBERTSON
(B.Acc CA CTA FCMA)

Jim qualified as a Chartered Accountant with Price Waterhouse in 1981 and joined Shell the same year. He had nine different tax and finance roles in Shell and lived in London, The Hague, Kuala Lumpur, Aberdeen and Houston, where he was VP Tax Americas until his retirement at the end of March 2017. In Shell Finance, he had global responsibility for promoting professional qualifications and for communications in diversity and inclusion. He was also a founder member of the Finance Social Investment Network which connected staff to voluntary organizations that would benefit from their finance skills and experience.

Jim is a Chartered Tax Adviser and Fellow of the Chartered Institute of Management Accountants. He is chair of the academic board of the Advanced Diploma in International Tax of the UK Chartered Institute of Taxation. Jim is also a Senior Fellow of the International Tax and Investment Center which is a non-profit research and education foundation based in Washington DC, a member of the Professional Development Curriculum Committee of the Tax Executives Institute and its Chief Tax Officer group, a member of the conference committee of the Norwegian Petroleum Association and a board member of the Houston branch of the International Fiscal Association. In June 2017, he became chair of the new Scottish Tax Policy Forum, a joint venture between the Institute of Chartered Accountants of Scotland (ICAS) and the Chartered Institute of Taxation. Jim is a member of the ICAS Scottish Taxes Committee and joined the ICAS Governing Council in 2016.

Jim's previous responsibilities included membership of the UK Oil Industry Taxation Committee steering group, the UK Offshore Operators Association fiscal committee and chair of the UK royalty committee. He was on the Professional Development Curriculum Committee of the Tax Executives Institute and chair of the Oil and Gas Tax Executives Group. His speaking engagements have included Global Tax Trends at the CIS Fiscal Conference in Kazakhstan, Transfer Pricing and Enhanced Taxpayer Relationships at the NPF in Oslo, Managing Taxes at the Universities of Milan, Aberdeen and Edinburgh, Permanent Establishments at the Asia Development Bank conference in New Delhi, Learning and Development at the American Accounting Association in Atlanta and various seminars on cooperative compliance, offshoring/migration of tax work, transfer pricing, tax accounting and oil and gas tax.

PROFESSOR ALEXANDER G. KEMP

Professor Kemp is currently Professor of Petroleum Economics and Director of Aberdeen Centre for Research in Energy Economics and Finance (ACREEF) at the University of Aberdeen, UK.

For many years, he has specialized in his research in petroleum economics with special reference to licensing and taxation issues and has published over 200 papers and books in this field.

He was a specialist adviser to the UK House of Commons Select Committee on Energy from 1980 to 1992 and also in 2004 and 2009. From 1993 to 2003 he was a member of the UK Government Energy Advisory Panel. In May 1999, Professor Kemp was awarded the Alick Buchanan-Smith Memorial Award for personal achievement and contribution to the Offshore Oil and Gas Industry.

Professor Kemp is a Fellow of the Royal Society of Edinburgh. He was awarded the OBE in 2006 for services to the oil and gas industries. He was a Member of the Council of Economic Advisers to the First Minister of the Scottish Government from 2007 – 2011. In June 2011, Professor Kemp was appointed a member of the Scottish Energy Advisory Board to the Scottish Government.

He has written The Official History of North Sea Oil and Gas, which was published in 2011 in 2 volumes. In March 2012, Professor Kemp received the Lifetime Achievement Award at the Society of Petroleum Engineers Offshore Achievements Awards ceremony. In September 2013, Professor Kemp was appointed a member of the Independent Oil and Gas Expert Commission by the Scottish Government. Its report was published in July 2014. In June 2015, Professor Kemp received a Lifetime Achievement Award and was inducted into the Hall of Fame at the “Press and Journal” Gold Awards event. In November 2015, Professor Kemp was appointed by the New Zealand Government to be a member of its Petroleum Resource Allocation Advisory Group.