OCS Study
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2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison

U.S. Department of the Interior
Bureau of Ocean Energy Management
Bureau of Safety and Environmental Enforcement
Bureau of Land Management

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2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison

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DISCLAIMER

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Contents

List of Figures

List of Tables

List of Abbreviations and Acronyms

$/bbl	Dollars per barrel
$/Mcf	Dollars per thousand cubic feet
ANP	National Petroleum, Natural Gas and Biofuels Agency of Brazil
AO	Angola
AOA	Angola Kwanza
AU	Australia
AUD	Australian dollar
bbl	barrel
Bcf	billion standard cubic feet
Bcf/d	billion standard cubic feet per day
Bcf/well	Billion standard cubic feet per well
boe	barrel of oil equivalent
Boe/d	barrel of oil equivalent per day
BOEM	Bureau of Ocean Energy Management
BR	Brazil
BRL	Brazilian Real
BSEE	Bureau of Safety and Environmental Enforcement
CAD	Canadian dollar
capex	capital expenditure
CFR	Code of Federal Regulations (U.S.)
CNPE	National Council of Energy Policy
CNH	National Hydrocarbons Commission of Mexico
CO_2	carbon dioxide
COFINS	social contribution for welfare programs
DOI	U.S. Department of the Interior
DRD	decommissioning relief deeds
DSA	decommissioning security agreements
DW	Deepwater
E&P	exploration and production
EIA	Energy Information Administration
EMV	expected monetary value
FID	final investment decision
FPSO	floating production, storage, and offloading vessel
GBP	British Pound Sterling
GDP	gross domestic product
GOM	Gulf of Mexico
HPHT	high pressure, high temperature
IOC	international oil company
IRR	internal rate of return
km^2	square kilometers

LNG	liquefied natural gas
LTBR	long-term bond rate
m	meters
Mcf	thousand standard cubic feet
MMbbl	million barrels
MMbbl/well	million barrels per well
MMboe	million barrels of oil equivalent
MMBTU	million British thermal units
MER	maximum efficient recovery
MPE	Ministry of Petroleum and Energy
MXN	Mexican peso
N/A	not applicable
NBP	National Balancing Point
NFW	new field wildcat
NL	Newfoundland and Labrador
NPV	net present value
No.	Number
NOC	National Oil Company
NOK	Norwegian Krona
NTL	Notice to Lessees
OCS	Outer Continental Shelf
OGA	Oil and Gas Authority - UK
OGUK	Oil and Gas UK
Opex	operating expense
PEPS	IHS Markit Petroleum Economics and Policy Solutions service
PIS	Social Integration Program Contribution
PP	proven & probable reserves
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
PRT	Petroleum Revenue Tax
PRRT	Petroleum Resource Rent tax
REPETRO	Brazil’s temporary import exemption regime
RFES	Ring fence expenditure supplement
RSV	Royalty Suspension Volume
SC	Supplementary Charge
SEC	U.S. Security Exchange Commission
TVD	true vertical depth
TVDSS	true vertical depth subsea
UK	United Kingdom
UKCS	UK Continental Shelf
U.S.	United States
USC	U.S. Code
USD	U.S. Dollar
WTI	West Texas Intermediate

Executive Summary

E.1 Introduction

The U.S. Department of the Interior (DOI) has undertaken an updated comparison of the oil and gas fiscal systems of other countries, U.S. states, and private lands to help ensure that oil and gas investment on Federal lands remains competitive with other jurisdictions and that the public is receiving fair return for Federal oil and gas resources.

Since the publication of DOI's 2011comparative assessment of the U.S. Federal oil and gas fiscal system, market conditions have changed, both in energy markets, specifically in the amount and type of oil and gas resources available, as well as in the activities of competing oil and gas suppliers around the world. With an increase in U.S. onshore supply, world oil and gas prices have fallen, and low prices have created challenges for governments' abilities to attract oil and gas investments to offshore regions. Legislative changes are also having an impact, particularly the end of the ban on the export of most U.S. crude oil products in 2015, and the 2017 changes to the Federal income tax.

This is the first of two reports prepared by IHS Markit. The first report compares other countries' offshore fiscal systems with the shallow and deepwater of the U.S. Gulf of Mexico (GOM). The second report will provide comparisons of other jurisdictions' fiscal systems with the systems used for Federal onshore leases and for offshore frontier areas.

The recent low oil price environment has resulted in different responses from industry as well as policy makers. In this report, we examine the industry and policy developments since 2011, with regard to fiscal terms and exploration and production (E&P) activity; conduct a comparative assessment of the U.S. Federal fiscal systems for the Gulf of Mexico and assess the performance of alternative fiscal systems.

E.2 Approach and Scope of Work

The comparative analysis of the Federal oil and gas fiscal gas fiscal systems for the GOM is comprised of two separate peer groups: shallow water and deepwater. The criteria for the selection of jurisdictions and oil and gas field sizes varied between the two groups depending on the challenges faced by the respective operating environments.

Shallow water peer group: The jurisdictions in this peer group were selected for their similarity with the U.S. GOM shallow water area, the maturity of the region, and the expected decline in infrastructure in the near future. Other criteria for selecting the peer groups include the following:

- Proven and probable (PP) reserve additions during the 2007-16 period
- Presence of a shallow water E&P sector
- Maturity of the province
- Anticipated spending for decommissioning of infrastructure through 2040.

The jurisdictions were assigned a relative score of 0-10, with a score of 10 representing the highest reserve additions, the most mature province, and the highest level of estimated spending for decommissioning through 2040. The six countries with the highest combined score, including the U.S. Gulf of Mexico, were selected for the shallow water peer group. See Table E-1 for the shallow water jurisdiction selection criteria.

Table E-1. Shallow water jurisdiction selection criteria

Jurisdiction	Reserve additions (2007-16)	Maturity of the province	Decommissioning activity planned	Shallow water sector	Total score	Selected countries
Brazil	10.00	8.31	1.60	Y	19.91	√
Norway	1.23	7.38	10.00	Y	18.61	√
United Kingdom	0.35	8.69	8.00	Y	17.04	√
United States	1.90	10.00	2.40	Y	14.30	√
Mexico	0.69	8.25	1.20	Y	10.14	√
Australia	1.20	6.85	1.60	Y	9.65	√

Source: IHS Markit

Deepwater Peer Group

Deepwater jurisdictions competing for investment with the U.S. GOM consists of the following:

- Established deepwater areas with significant reserve growth potential
- Emerging offshore provinces with major discoveries in recent years.

Table E-2 shows the deepwater jurisdiction selection criteria. The selection process considered similarities with regard to the following:

- Water depth
- Total vertical depth
- Technological challenges involved.

Table E-2. Deepwater jurisdiction selection criteria

Characteristics of discoveries (2008-2017)				
Item No.	Jurisdiction	Water depth (Meters)	Total vertical depth (Meters)	Average discovery size (MMboe)
1	U.S. GOM	400 – 3,000	2,331 – 10,685	100
2	Norway	217 – 1,425	4,183 – 7,811	40
3	Brazil	235 – 1,820	2,202 – 7,628	520
4	Angola	225 – 2,434	1,901 – 6,384	150
5	Mexico	225 – 3,008	3,040 – 6,943	90
6	Guyana	1,563 – 1,743	5,175 – 6,450	600
7	United Kingdom	252 – 1,288	2,334 – 4,475	35
8	Nova Scotia	1,095 – 1,172	3,400 – 3,758	170

The demarcation for deepwater is 200 meters (m).
MMboe = million barrels of oil equivalent
Source: IHS Markit

E.3 Fiscal and Contractual/Lease Terms

The countries included in the shallow and deepwater peer groups for this study vary widely in terms of the types of fiscal systems adopted and the nature and range of fiscal levies. The fiscal systems adopted by each jurisdiction reflect government policies, and the relative prospectivity and maturity of its respective offshore E&P sector. While the shallow water jurisdictions selected for this study are similar in terms of maturity, the underlying philosophy within each jurisdiction varies widely regarding the following:

- Licensing and award criteria
- Degree of control exercised by the state in decision making process

- Contractual mechanisms adopted
- Nature of taxes and quasi-fiscal levies
- E&P terms.

The deepwater peer group is even more diverse than the shallow water one, as it represents a combination of established and frontier basins. Different policies exist depending on the maturity of the basins, the resource potential, and the underlying national objectives and dependence on oil and gas resources. In addition to the cross-jurisdictional variation regarding contractual and fiscal terms, there are variations within the same jurisdiction with regard to applicable terms based on basin maturity and field economics.

Some jurisdictions, such as Angola, Brazil, and Mexico, have adopted more than one type of contract for the grant of rights in different areas or geological formations. From a revenue-sharing perspective, the same economic benefit can be achieved under any of the three major types of contracts—concessionary or royalty/tax system, production sharing agreements, and service contracts. The decision to adopt different contractual and fiscal systems reflects the respective government's decision related to the degree of control it wants to exert in the decisionmaking process. Often contractual systems based on prospectivity, location of the acreage, and technological challenges associated with exploration for and development of hydrocarbons.

E.4 Changes in Fiscal Terms

Resource nations were slow to react to the new reality of lower for longercrude oil prices. Resource holders, particularly the ones heavily dependent on oil and gas revenues, usually go through a four-stage process in reaction to lower oil prices (Figure E-1). The initial reaction is usually that of inertia and an unwillingness to act until absolutely necessary. While logic might dictate any subsequent policy changes should be investor-positive to retain investors' interest that is rarely the first response when there is real economic distress. In time, funding cuts and limited output growth tend to result in the easing of some E&P terms, particularly around conditions for new offerings. Figure E-2 shows the government actions taken and responses from 2001 to 2018.

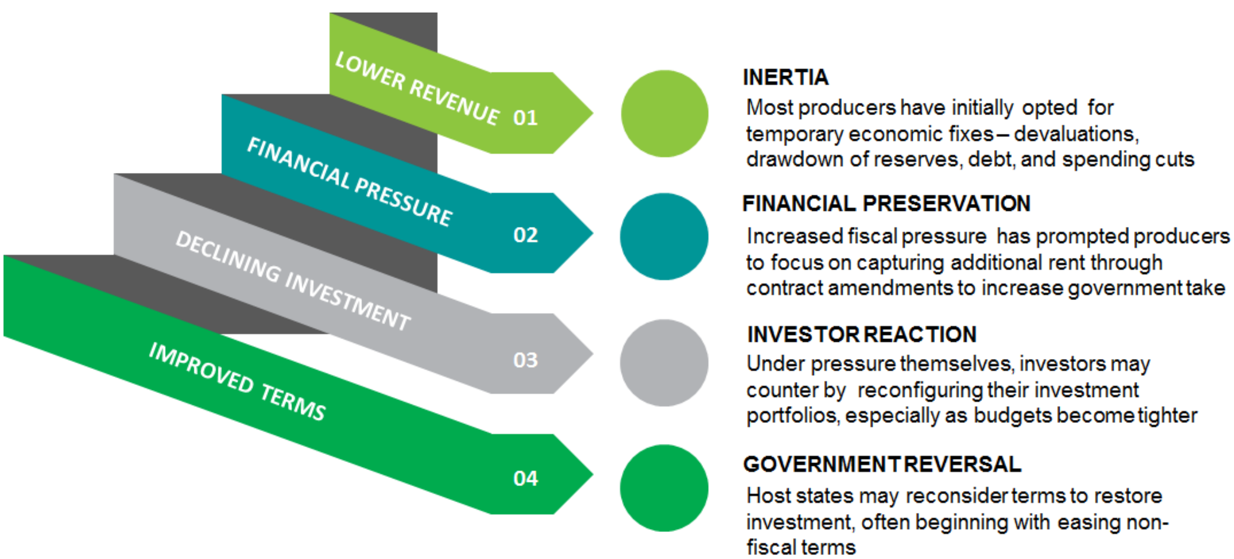


Figure E-1. Reaction stages: Typical government responses to oil price drops

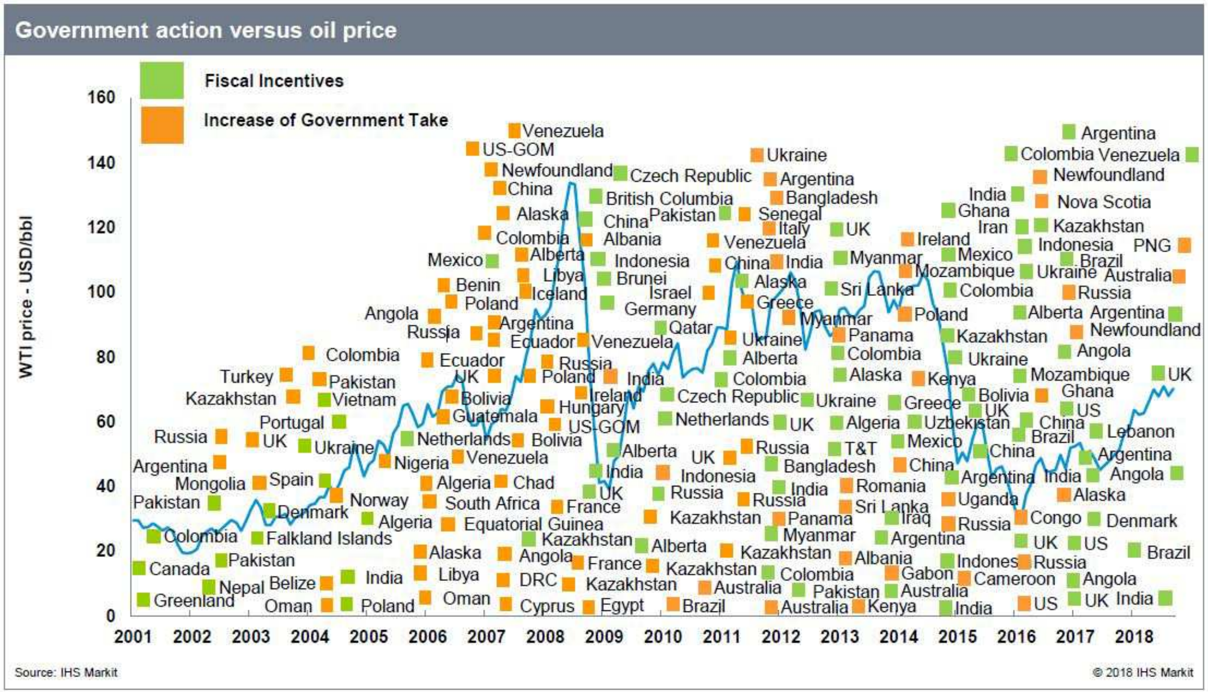


Figure E-2. Government action versus oil price

The market downturn that started in the second half of 2014 was accompanied by slow, often incremental changes to the government take. While there was substantial action taken by governments, especially in the 2016–2017 period, such actions were often in reaction to lackluster performance in the E&P sector and were often introduced in a piecemeal fashion rather than as part of a well thought-out plan. Some governments engaged in public relation campaigns to manage perception rather than meaningful revision of E&P fiscal terms. Often governments announced changes one to two years in advance of the restructuring and reform plans for the oil and gas sector, including the role of the national oil company.

However, some governments did take proactive action to compete for investments and launched a series of initiatives to accomplish that goal. Figure E-3 provides a snapshot of some of the key measures affecting oil and gas fiscal systems.

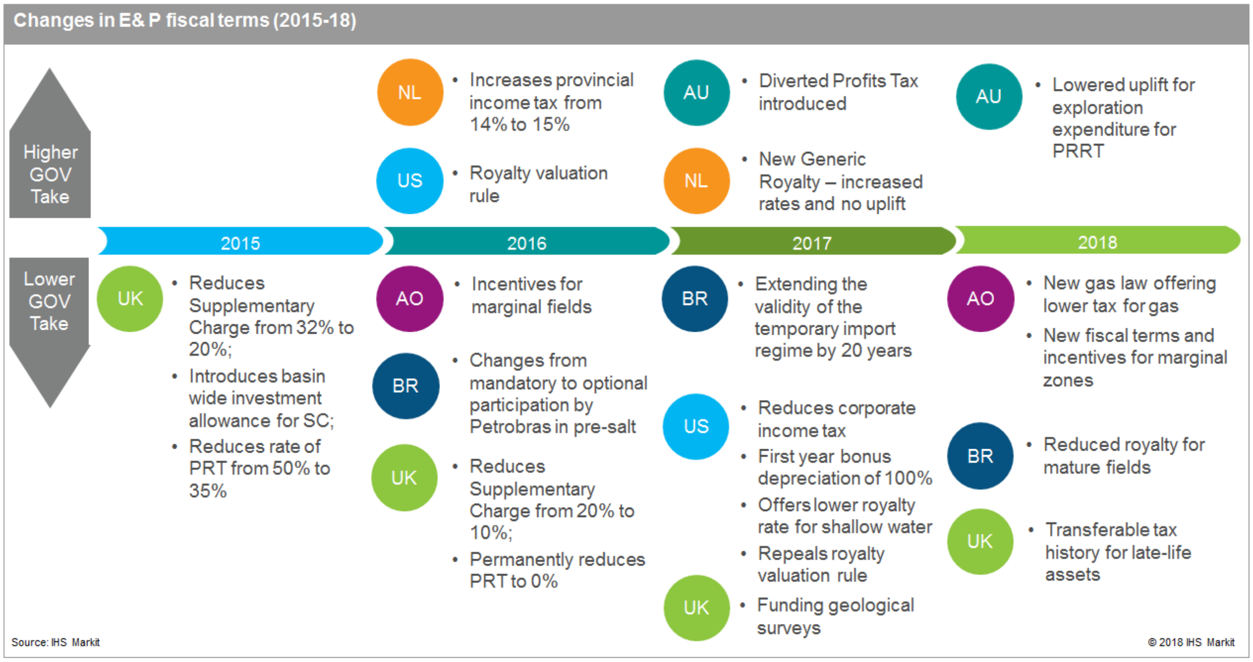


Figure E-3. Changes in E&P fiscal terms (2015–2018)

While all jurisdictions included in this study experienced significant declines in exploratory and appraisal drilling, the approaches followed in response to the decline differed. Table E-3 describes the approaches of the respective jurisdictions.

Table E-3. Government response to commodity price drop

Jurisdiction	Response to market changes and decline in exploratory activity			
	Took action to lower government take	Took action to increase government take	Conducted competitiveness review	No change
Angola	●			
Australia			●	
Brazil	●			
Canada - NL		●		
Guyana				●
Mexico	●			
Norway				●
United Kingdom	●		●	
United States GOM	●		●	

Source: IHS Markit

E.5 Comparative Analysis of Fiscal Systems

The study uses three oil and gas price and cost scenarios to assess the competitiveness of the Federal oil and gas fiscal system as well as the performance of fiscal system alternatives under different market conditions. A global market price is used for crude oil, and regional market prices are used for natural gas. For the sake of consistency, we used the IHS Markit base case crude oil and natural gas price outlooks for this study, given that Energy Information Association (EIA) does not provide outlooks for natural gas prices in Europe or Asia. See Figures E-4 to E-6 for the low, base, and high case price assumptions for crude oil and natural gas. The study uses a variance of minus 40% and plus 60% from the base case for the low and high case scenarios, respectively. The selection of crude oil prices for this analysis is not intended as a forecast, but rather reflects the relatively wide range between the high and low commodity price ranges that have prevailed in the past decade. The wide spread among the low, base, and high case is useful to analyze the performance of alternative fiscal systems under depressed and high commodity prices alongside the base case scenario, which is reflective of the current market conditions.

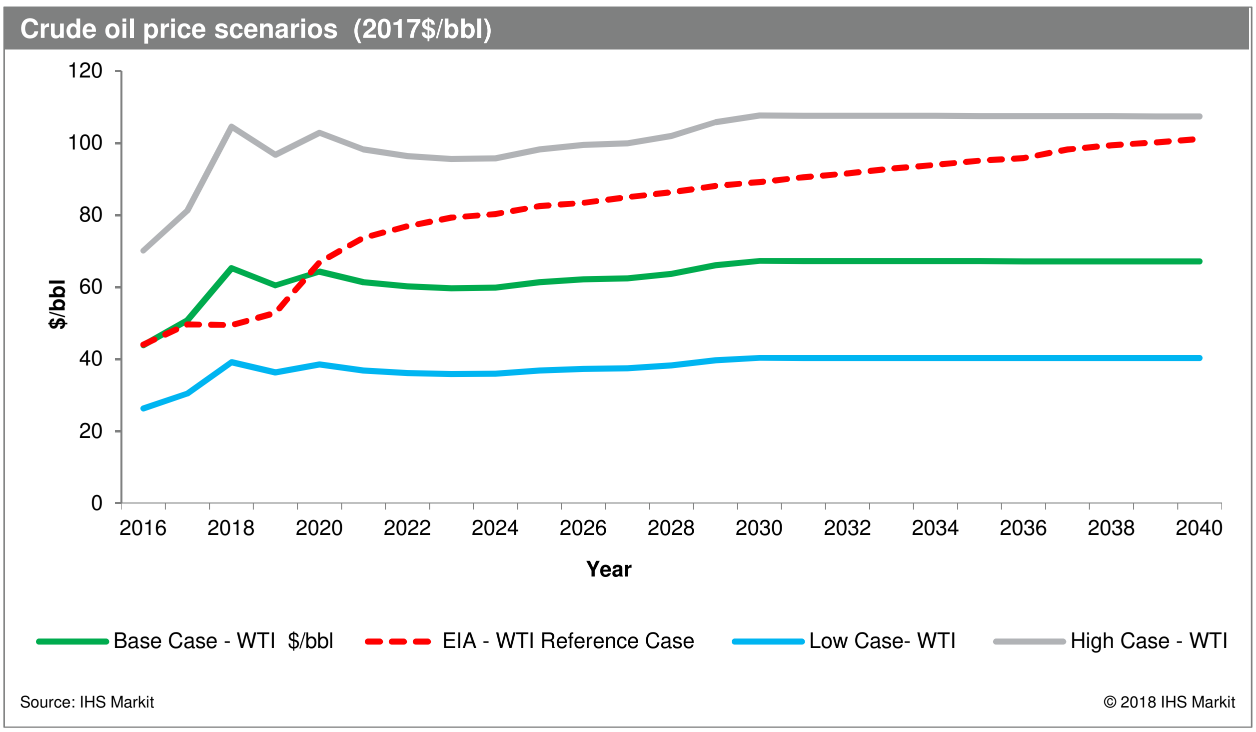


Figure E-4. Crude Oil Price Scenarios

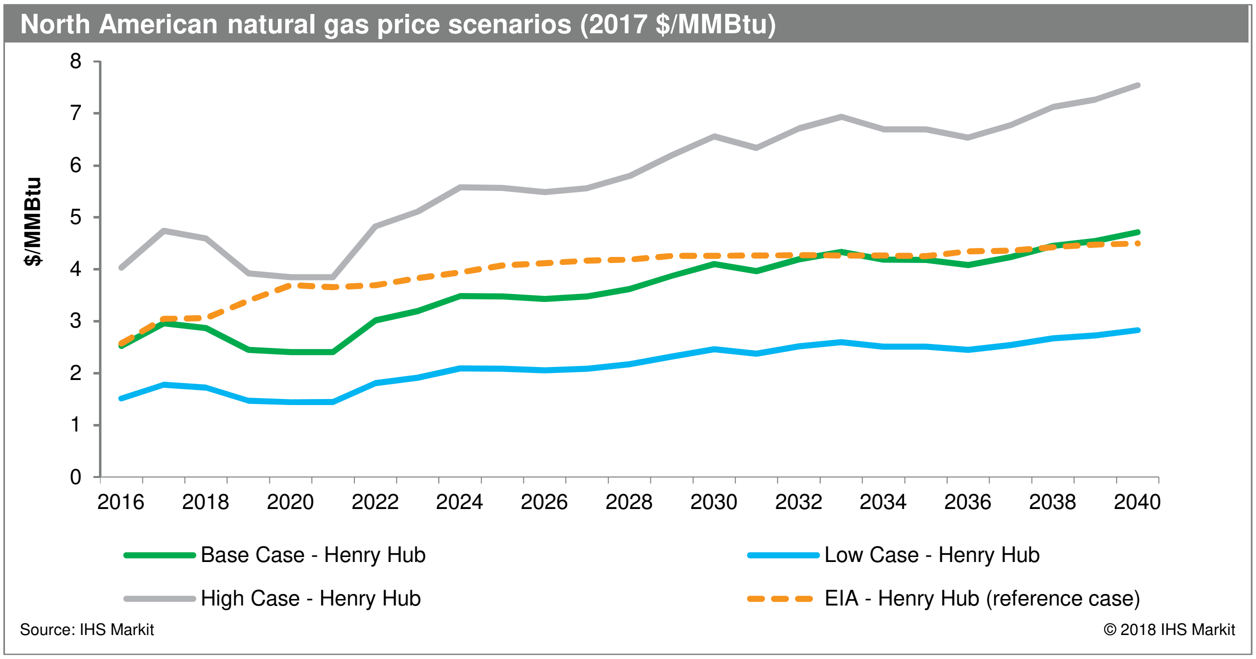


Figure E-5: North American natural gas price scenarios

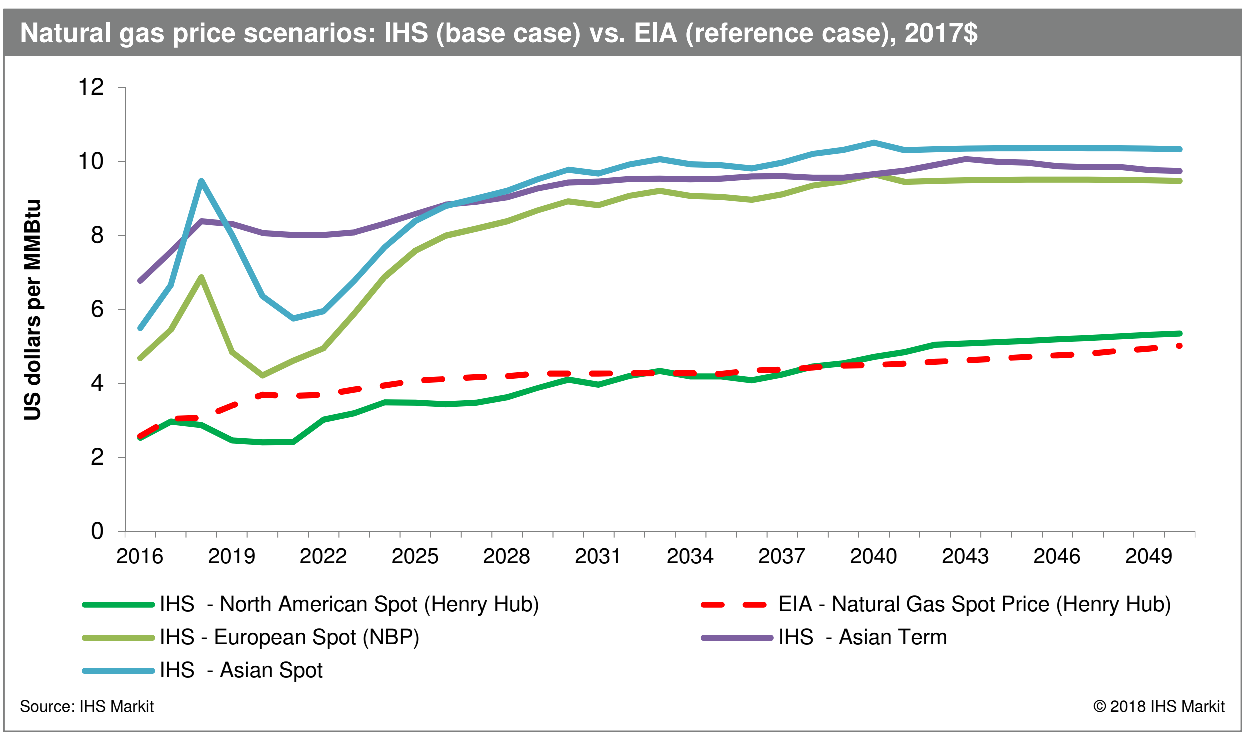


Figure E-6: Natural gas price scenarios: IHS (base case) vs. EIA (reference case), 2017$

Shallow Water Comparative Analysis

Both the range and the average government take for U.S. GOM shallow water areas in this study are significantly lower than the ones observed in the *2011 Comparative Assessment of the Federal Oil and Gas Fiscal Systems* (*2011 study*). Three factors contribute to this drastic change. First, the U.S. corporate income tax overhaul resulted in the tax rate declining from 35% to 21%. The second contributing factor is the reduction in general exploration and development costs that took place during the recent oil and gas downturn. The U.S. Federal fiscal system has an inverse relationship with project profitability; when profitability increases, government take declines. Lastly, the royalty rate for new leases in the GOM shallow water areas was lowered in 2017 from 18.75% to 12.50%. These factors combined resulted in a 22 percentage point drop in government take for shallow water projects in the GOM.

The government take for the U.S. GOM shallow water oil fields is among the lowest in the peer group, challenged only by the UK fiscal system, which has undergone significant transformation under the Maximum Efficient Recovery (MER) strategy adopted in 2014 (Figure E-7).

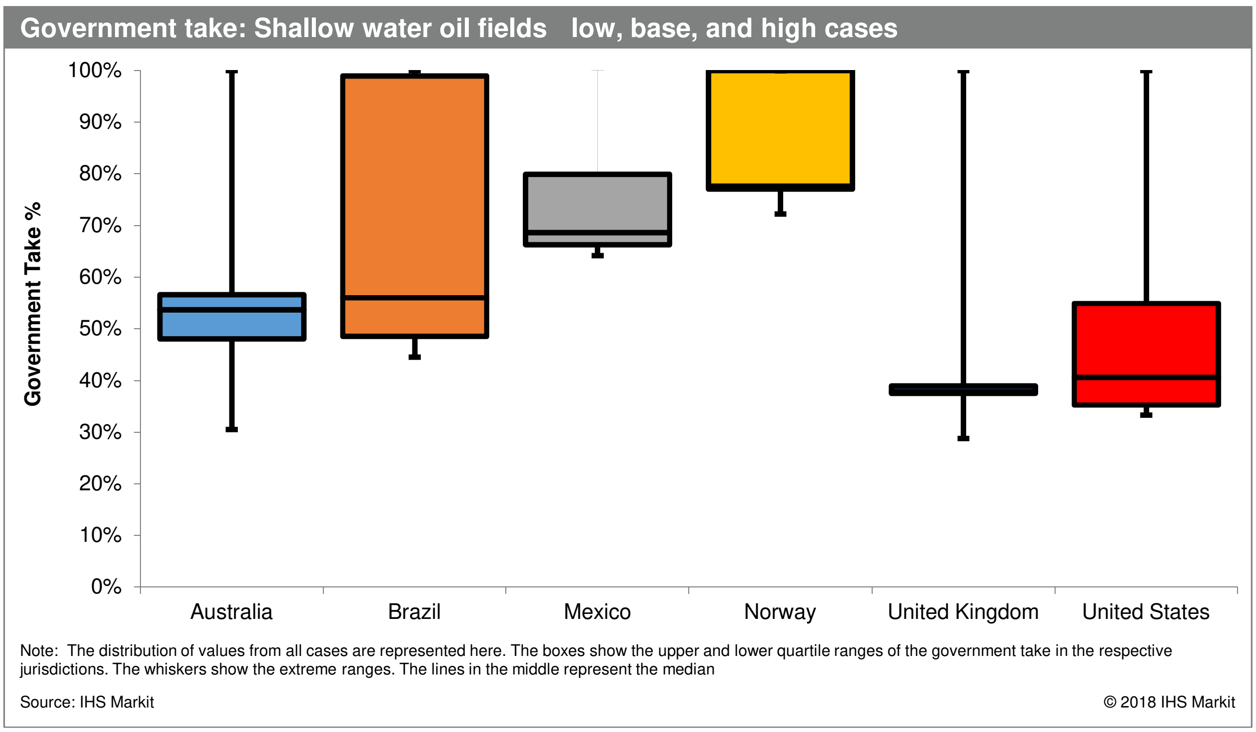


Figure E-7: Government take: Shallow water oil fields – low, base, and high cases

When accounting for the discounted share of barrel accruing to investors, the U.S. GOM shallow water fiscal system either leads or is in the top two within the peer group (Figures E-8 to E-10). This is largely due to the lower cost base for shallow water oil fields in the GOM. When the combined discounted share of the barrel of capital and operating expenditure is 50% or less, the U.S. fiscal system is the most competitive in the world. For projects with a higher per-unit cost structure, the government has a disproportionate share in terms of the before-tax cashflow. This is attributed to the regressive nature of levies, such as royalties and bonuses, which do not consider profitability. The investor cashflow for the 10 MMboe oil field is negative in the base case as is the case for the majority of the countries in the peer group. This reflects the marginal nature of such discoveries. On a stand-alone basis, such fields are not economic; however, they could be candidates for cluster development or the use of subsea tie-backs that connect new discoveries to existing facilities. The subsea tie-back technology is technically and economically viable and is becoming more widely used as companies turn attention towards previously untapped, less economically viable discoveries.[1]

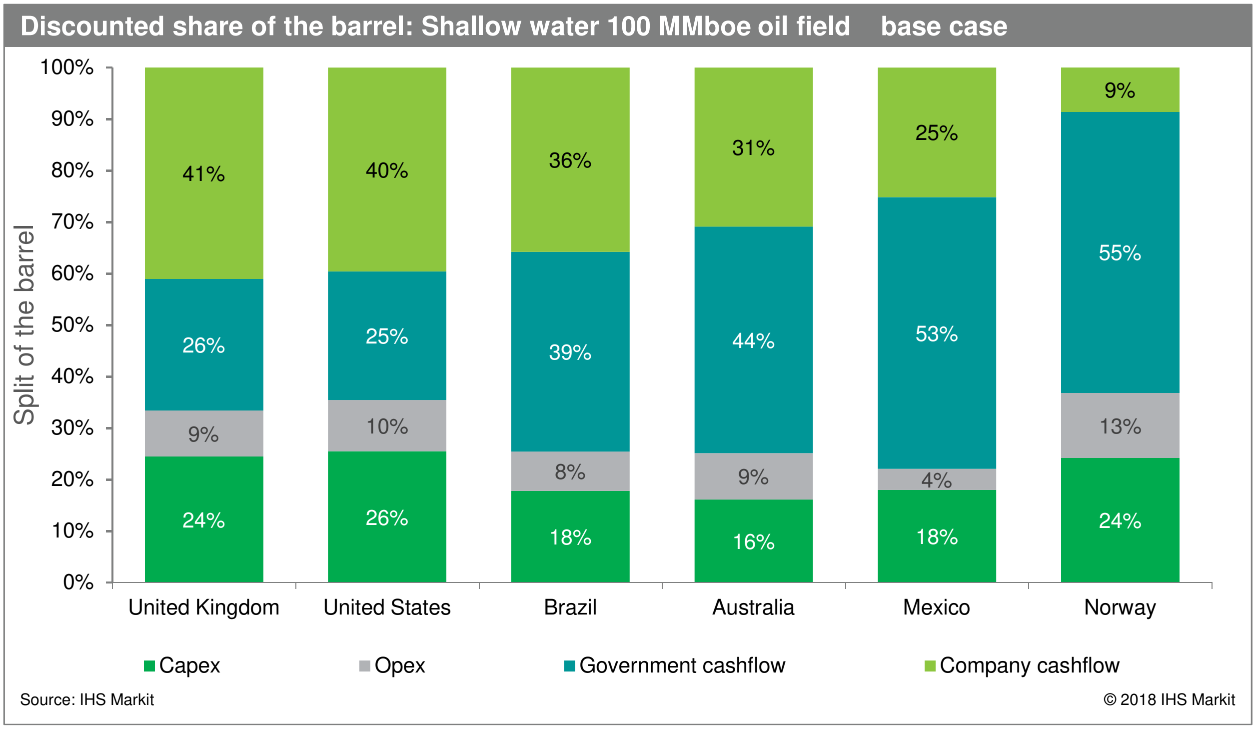


Figure E-8: Discounted share of the barrel: Shallow water 100MMboe oil field – base case

[1] For additional information, refer to the article Subsea Tieback Potential Grows as Priorities Shift, E&P (Hart Energy, 2016).

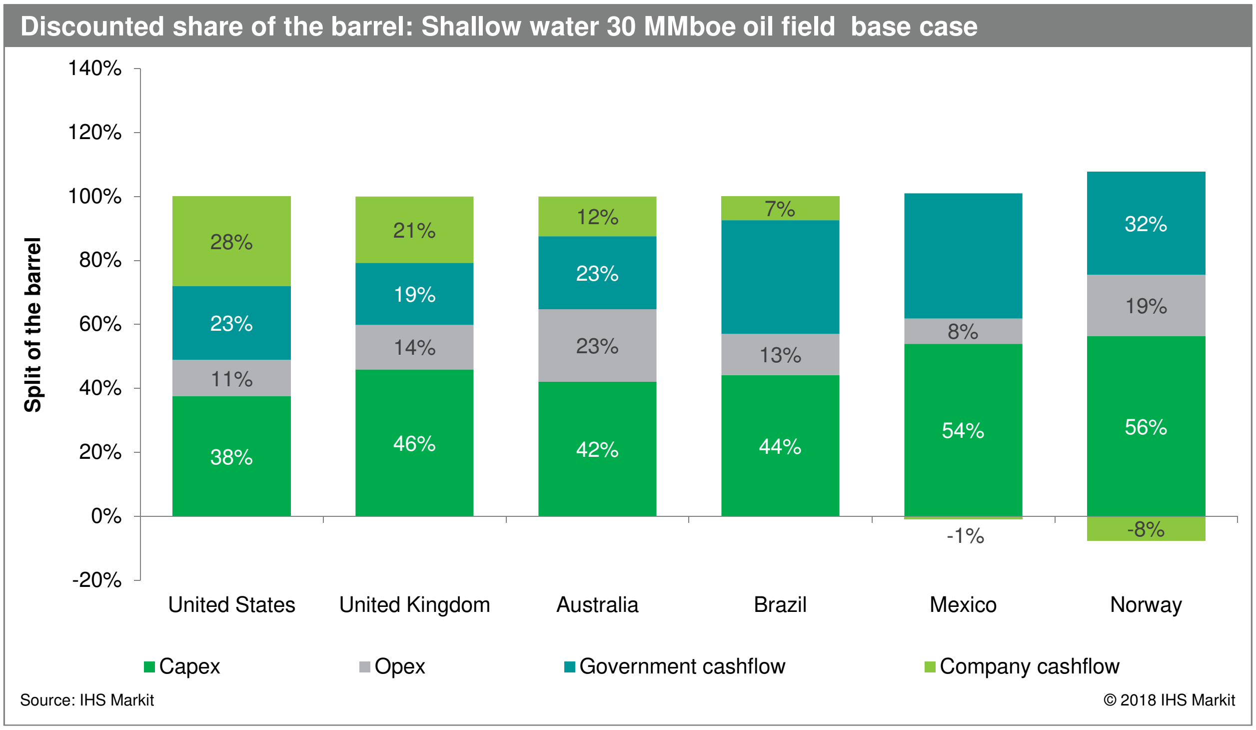


Figure E-9. Discounted share of the barrel: Shallow water 30MMboe oil field–base case

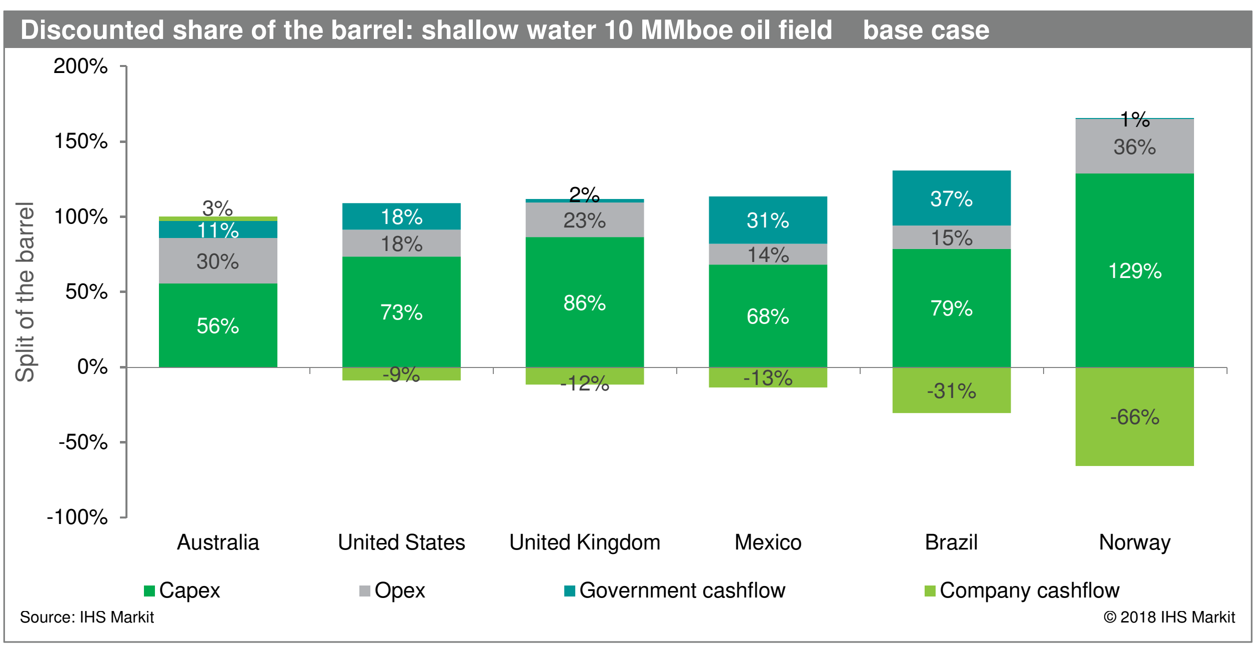
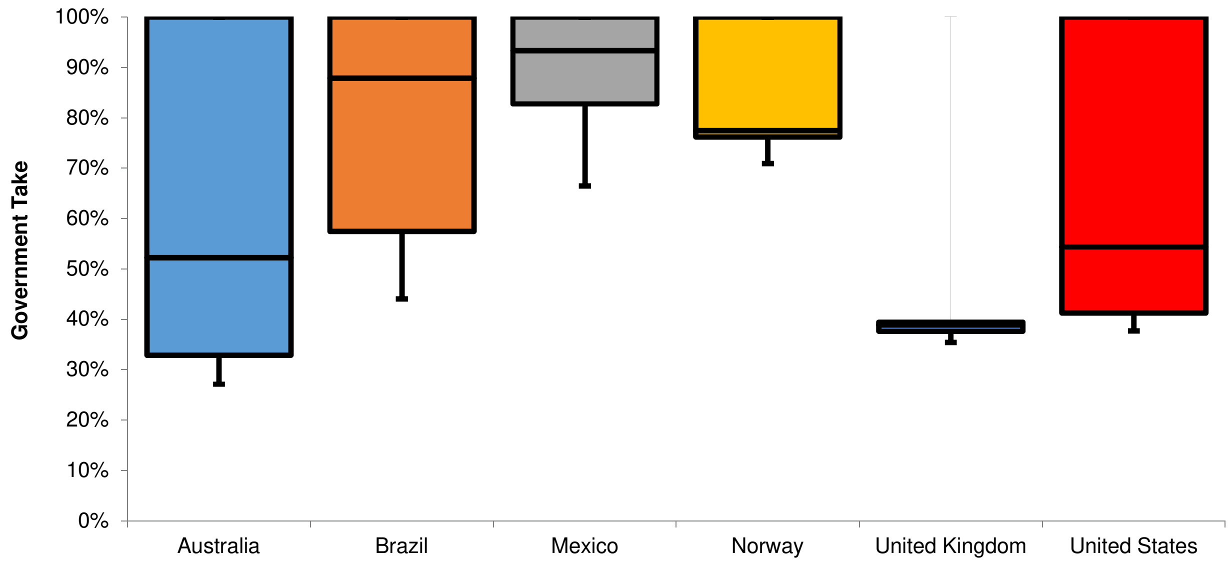


Figure E-10. Discounted share of the barrel of oil: Shallow water 30MMboe oil field–base case

The range of the government take for natural gas projects in the GOM is much wider than that of the oil fields. This is largely due to the marginal economics associated with natural gas production in the GOM. With a median government take of 54%, the U.S. competes with Australia for second place in the peer group (Figure E-11). The share of the discounted barrel shows the relatively high capital cost per unit associated with natural gas projects in the peer group and in the U.S. GOM (Figures E-12 to E-14). The discounted share of the barrel of the combined capital and operating expenditure in the U.S. GOM ranges from 73% to 100% in the base case.

Government take: Shallow water gas fields   low, base and high cases



Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median

Source: IHS Markit

Figure E-11. Government take: Shallow water gas fields – low, base and high cases

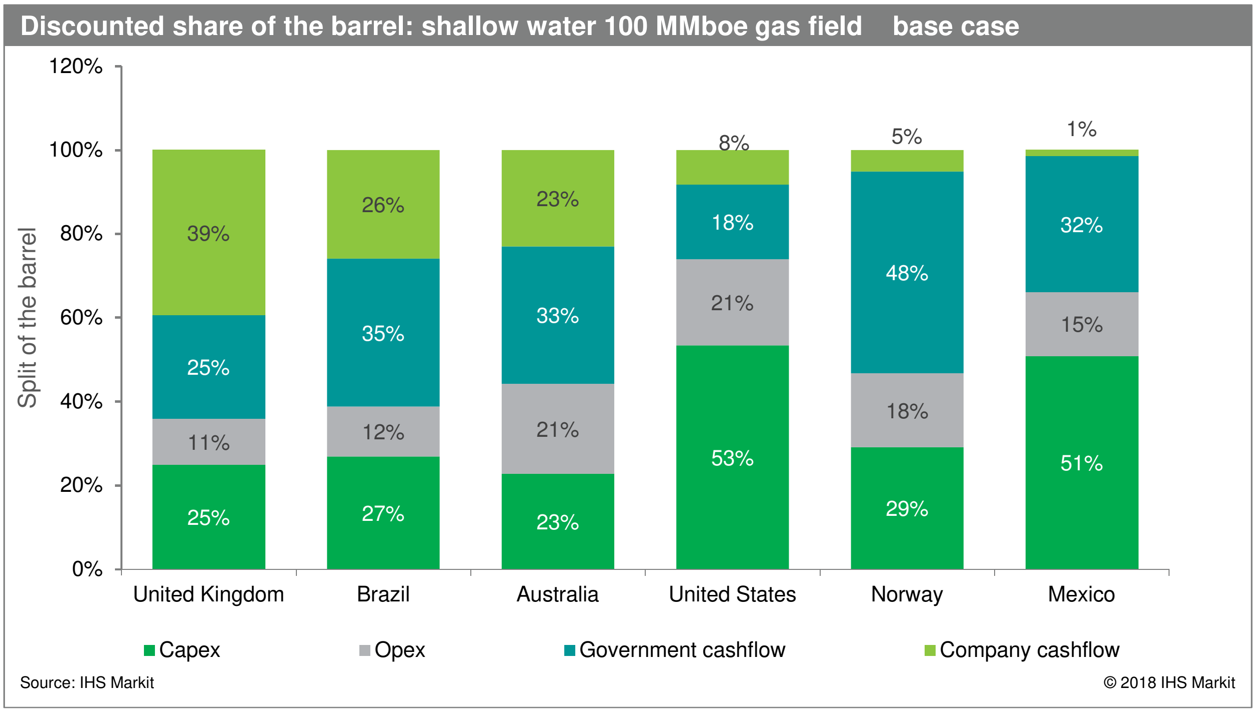


Figure E-12. Discounted share of the barrel: shallow water 100 MMboe gas field – base case

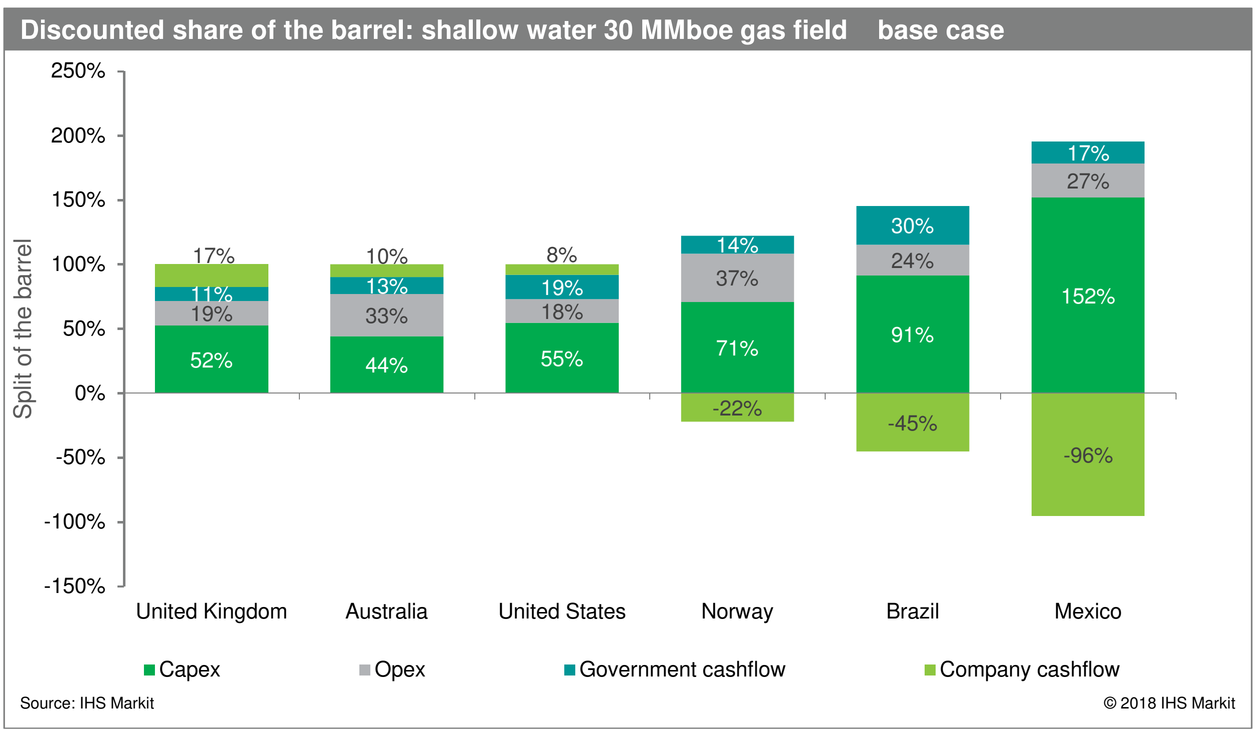


Figure E-13. Discounted share of the barrel: shallow water 30 MMboe gas field – base case

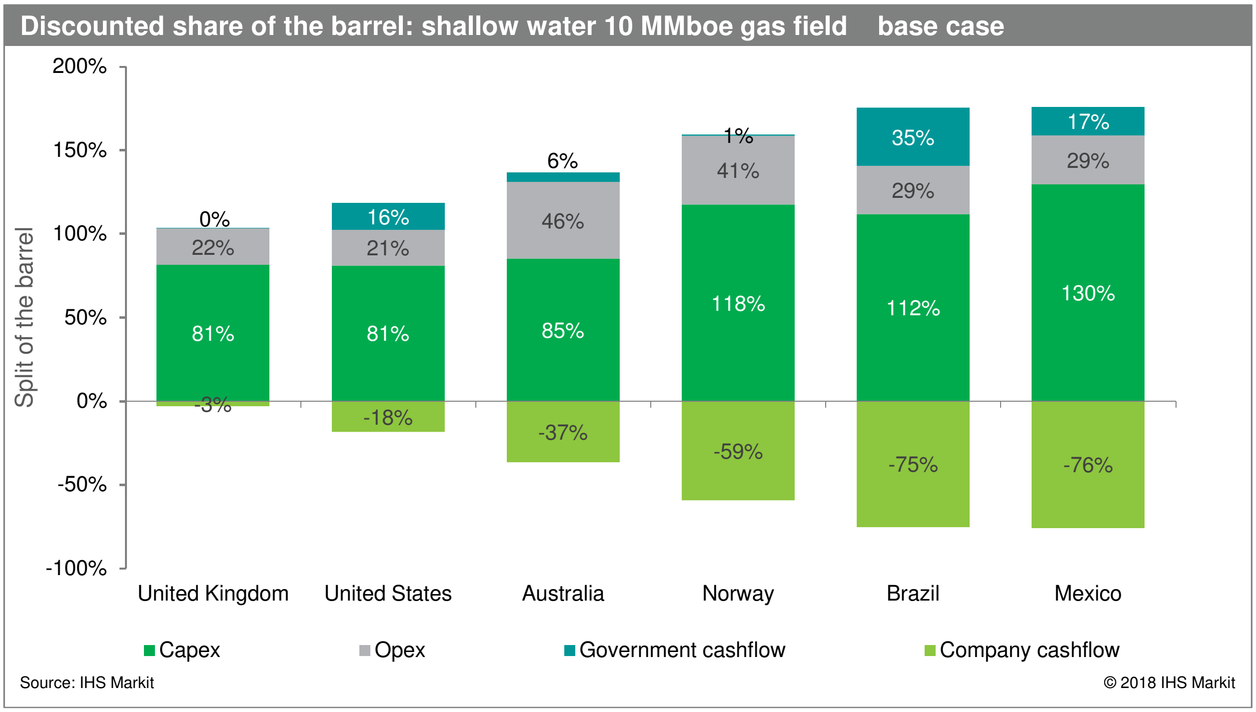


Figure E-14. Discounted share of the barrel: shallow water 10 MMboe gas field – base case

From an investor perspective, the U.S. GOM shallow water oil fields appear to be the most competitive in the peer group. With a 20% median internal rate of return (IRR), the U.S. edges the United Kingdom and Australia for the top position in the peer group (Figure E-15). The IRR for natural gas fields in the GOM also appears very competitive within the peer group (Figure E-16). However, the median IRR for both oil and gas is not representative of the actual investment environment in the GOM. The expected field sizes in the GOM are under 10MMboe, which is equivalent to the smaller field analyzed for this study. A lookback at the field discovery distribution in GOM shallow water since 2003 indicates that 96% of the discoveries are under 10MMboe (Figure E-17). The IRR for the 10MMboe oil and gas fields falls short of the generally applicable 15% investment threshold in the base case, suggesting the returns are not attractive enough to trigger investments.

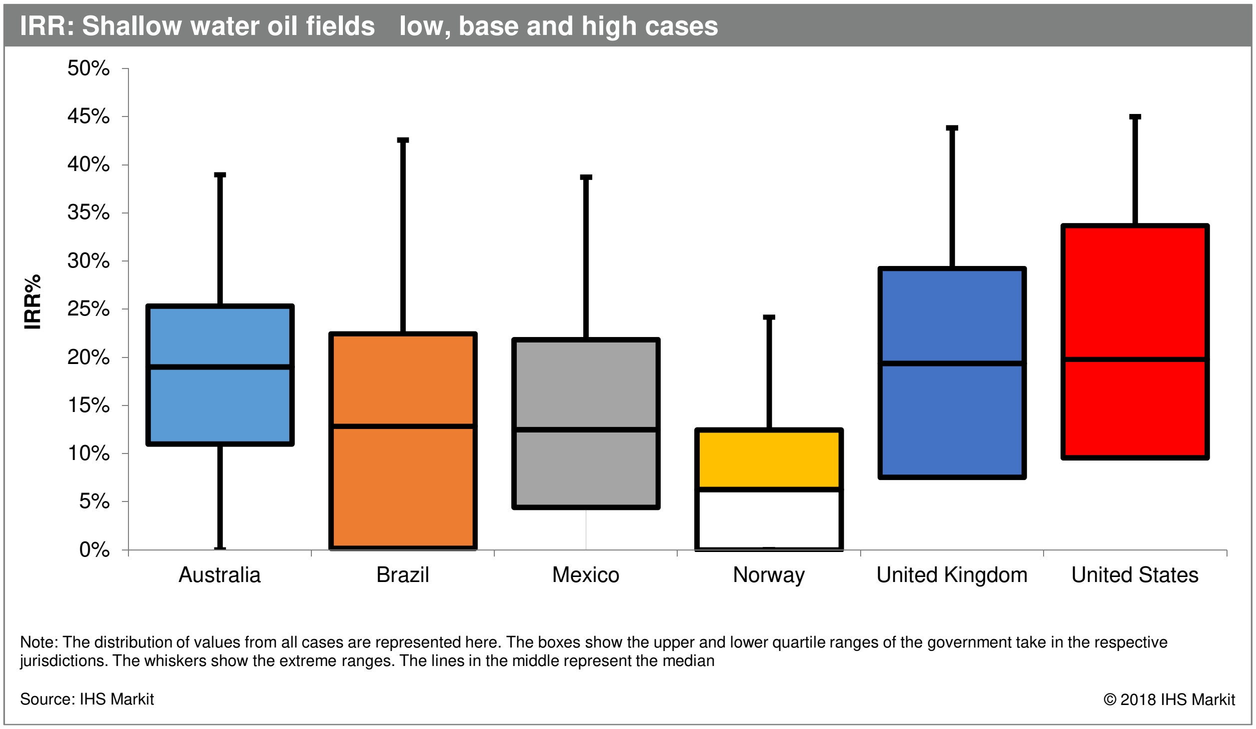


Figure E-15. IRR: Shallow water oil fields – low, base and high cases

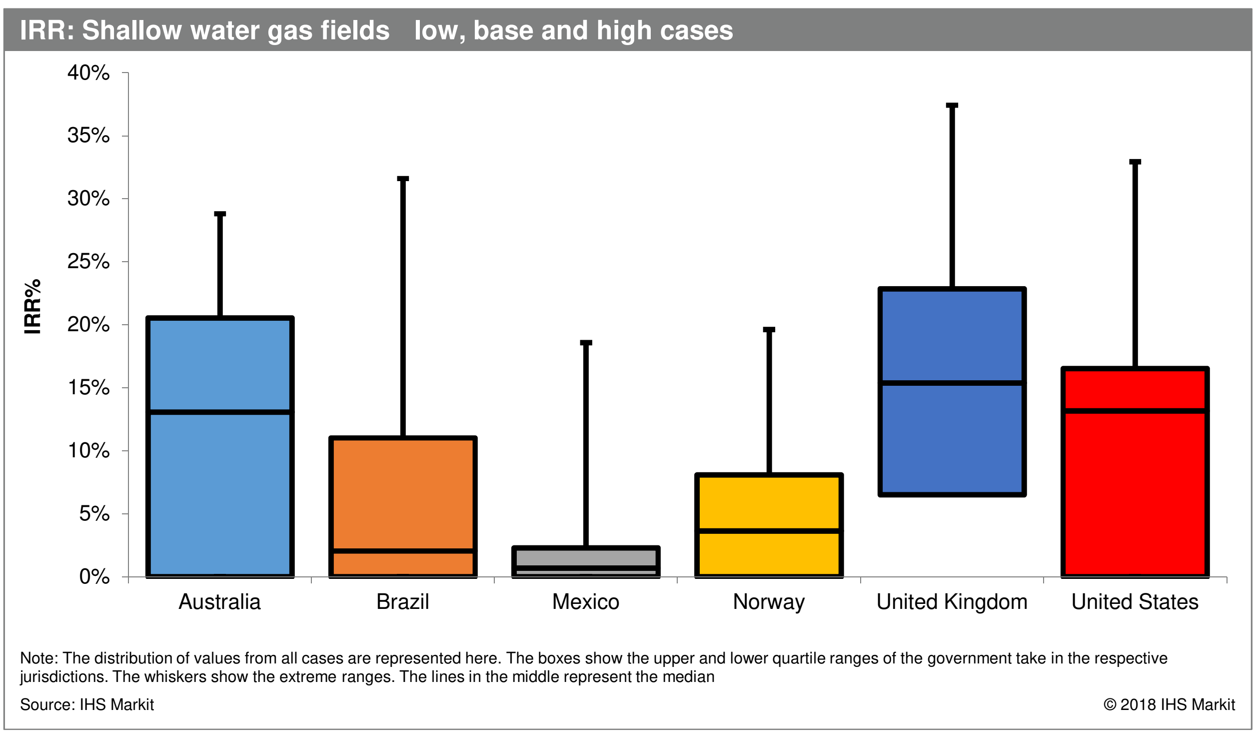
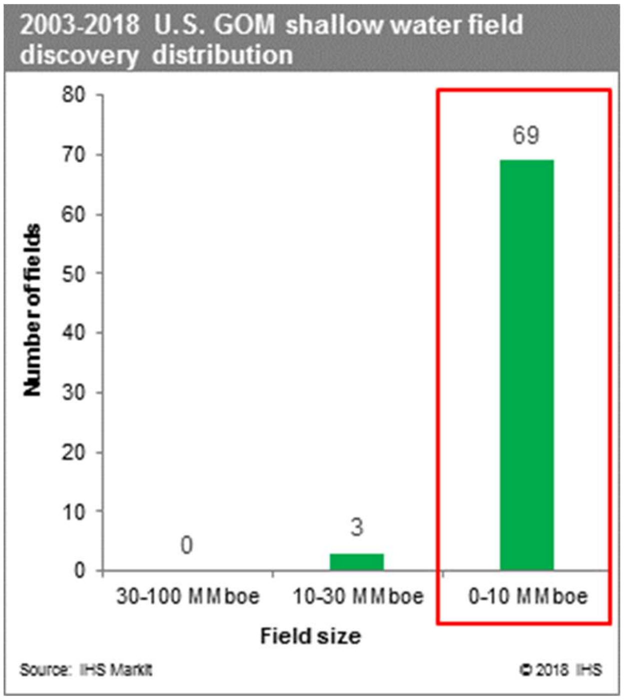


Figure E-16. IRR: Shallow water gas fields – low, base and high cases



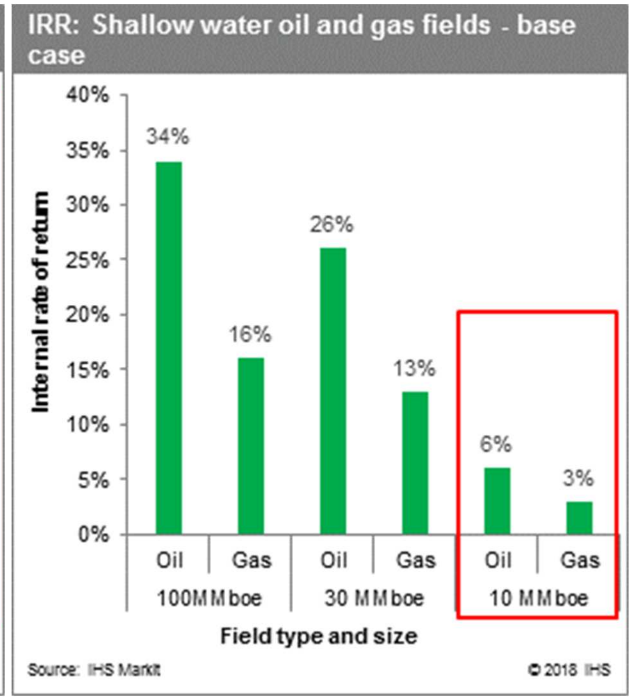


Figure E-17. U.S. GOM shallow water discovery distribution and investor IRR

When commodity prices are at current levels or higher (base and high case) the oil fields in U.S. GOM offer some of the highest values per barrel of oil equivalent compared to its peers (Table E-4). However, the value per unit in the U.S. GOM erodes quickly under a low-price environment. The regressive components of the U.S. fiscal system, such as royalties, can be detrimental to project economics when profit margins are low. Most members of the peer group face similar challenges under a low oil price environment. Jurisdictions with progressive fiscal system such as the United Kingdom, or mildly regressive ones such as Mexico, offer relatively higher values per barrel of oil equivalent under low commodity prices (low case).[2]

The value per barrel of oil equivalent of production from gas fields is often lower than that of oil fields due to lower prices for gas on an energy-equivalent basis, but also because gas reservoirs are often found at deeper depths and the per unit cost is higher. In the case of shallow water gas, the U.S. is not very competitive. Much of this is due to the depressed natural gas prices in the U.S. due to the increase in onshore unconventional production out of tight formations. On an NPV basis, U.S. natural gas projects on the continental shelf rank fourth in the peer group after the United Kingdom, Brazil, and Australia in the base case (Table E-4).

[2] While Mexico does rely on front-end loaded levies such as royalties, Mexico's sliding scale royalties significantly lessen the burden of low commodity prices.

Table E-4. NPV/Boe: Shallow water oil and gas fields

Jurisdiction	High case			Base case			Low case		
	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe
Crude Oil									
Australia	12.7	9.3	7.9	6.9	3.1	0.7	3.0	-2.8	-8.2
Brazil	17.7	11.7	2.2	9.0	2.0	-9.3	3.1	-4.9	-17.5
Mexico	18.4	7.7	3.1	9.6	-0.4	-5.0	3.8	-6.2	-14.7
Norway	4.8	1.4	-8.4	1.9	-1.9	-17.8	-0.1	-5.4	-31.6
United Kingdom	17.2	14.4	5.9	8.9	5.3	-4.0	3.3	-1.0	-14.0
United States	18.6	17.5	8.5	9.0	7.0	-2.3	2.6	-0.1	-10.6
Natural Gas									
Australia	7.5	6.3	3.3	3.2	1.5	-6.6	0.2	-4.6	-15.8
Brazil	9.8	-1.3	-6.8	4.1	-7.8	-14.8	0.3	-13.6	-21.9
Mexico	3.9	-8.0	-5.6	0.2	-13.4	-11.3	-2.0	-19.0	-15.6
Norway	3.1	-1.1	-5.9	0.9	-3.9	-12.2	-0.7	-9.3	-22.6
United Kingdom	12.3	8.7	5.1	6.2	2.1	-2.6	2.2	-2.8	-9.0
United States	5.9	6.9	3.6	1.0	1.1	-2.6	-2.8	-3.0	-7.9

Source: IHS Markit

Deepwater Peer Group

The U.S. GOM ranks third after the United Kingdom and Mexico under all three price scenarios, with 51% median government take for deepwater oil fields. However, the relatively wide range of government take for projects falling between the first and third quartile is an indicator of the high government take associated with low oil prices in the U.S. GOM (Figure E-18). When the entire range of government take is taken into account, Brazil, Guyana, and Mexico outperform the U.S.

As in the case of the shallow water projects, there is also a significant drop in the median government take relative to the *2011 study*—a 22 percentage point drop. This, too, is attributed to the lowering of the corporate income tax and the industry-wide cost reductions that occurred since the 2014 drop in commodity prices.

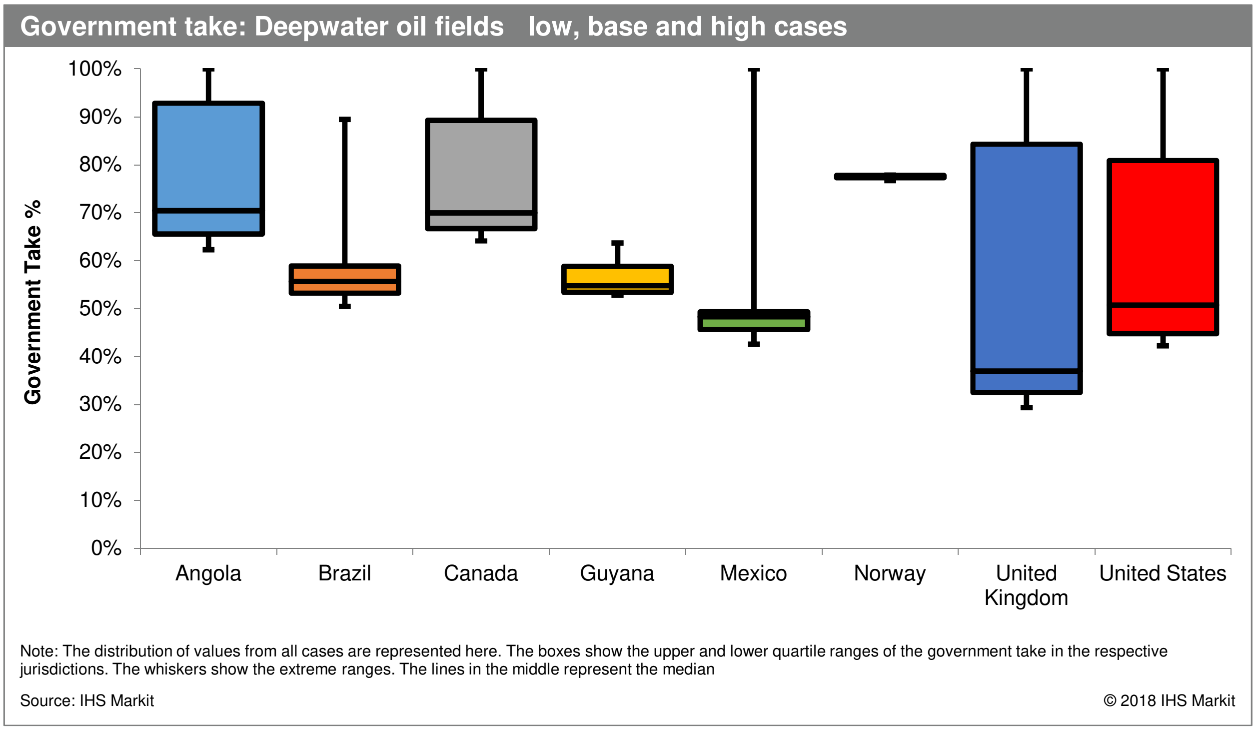


Figure E-18. Government take: Deepwater peer group versus U.S. Gulf of Mexico

When the discounted share of the barrel is considered for individual case results under the base case scenario, the U.S. ranks fourth with respect to the share of revenue accruing to investors. For both cases considered, the share of capital and operating costs in the U.S. GOM is approximately 60% of the overall discounted cashflow, with the government share being nearly double that of the share accruing to investors (Figures E-19 to E-20). The distribution of the discounted revenue betweeen the government and investors is somewhat evenly spread under the high case. Under the low case, the investor cashflow is negative as it is for the majority of the jurisdictions in the peer group.

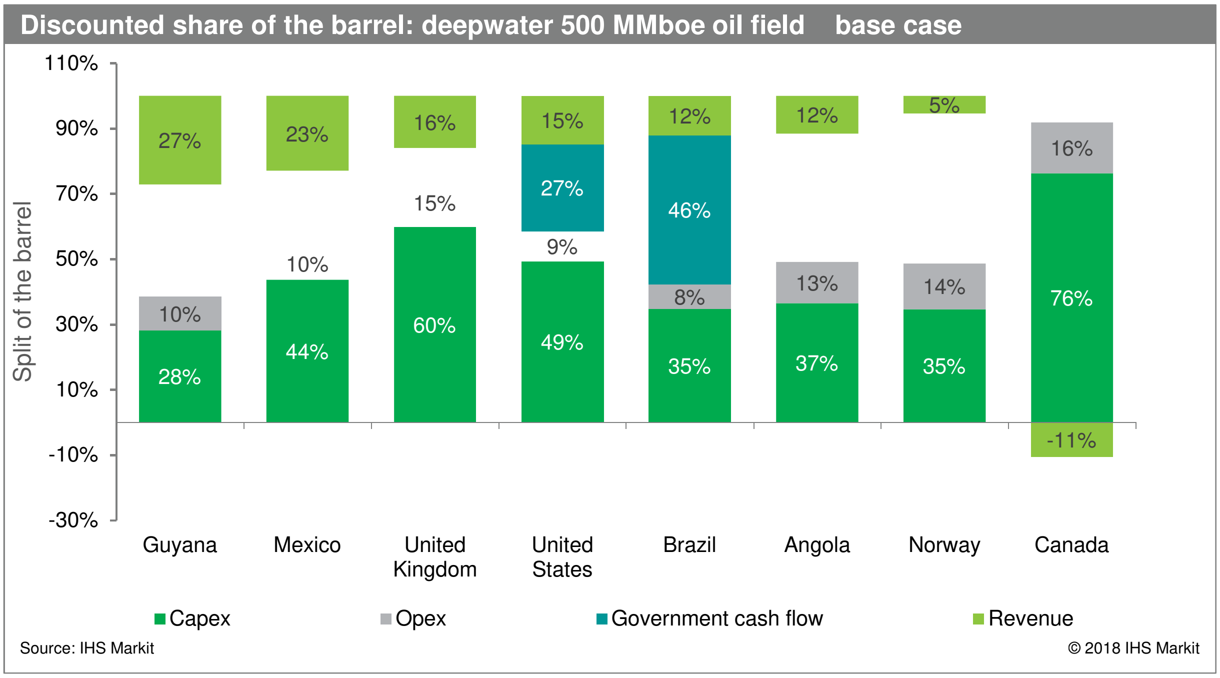


Figure E-19. Discounted share of the barrel: Deepwater 500MMboe – base case

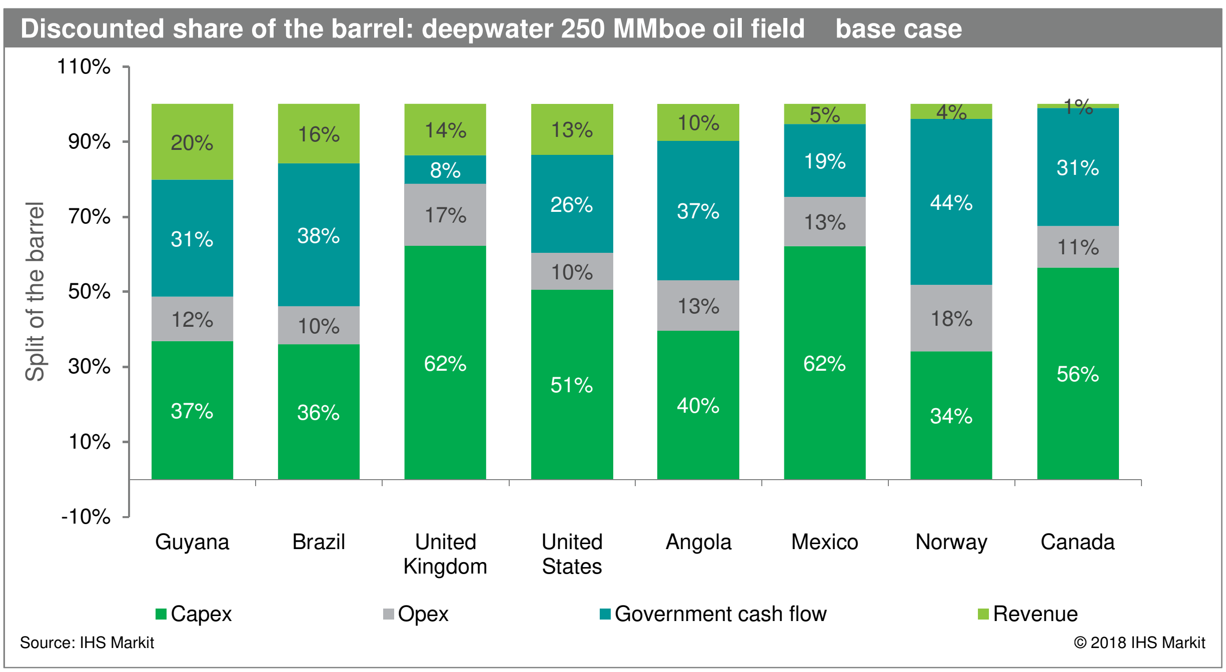


Figure E-20. Discounted share of the barrel: Deepwater 250MMboe – base case

The median government take for deepwater natural gas projects in the GOM is much higher than that for oil fields in the same region. Similar to shallow water natural gas projects , the cost structure for deepwater gas projects in the GOM pushes the government take towards the top of the peer group (Figure E-21). Two reasons account for this—the depth of the fields and the market prices in the U.S. Deepwater gas fields in the United States are located much deeer than in other jurisdictions. Natural gas projects in the Gulf of Mexico are also disadvantaged by the prevailing market prices in the U.S. when compared to projects in Europe and Asia where the natural gas market prices are more than double the U.S. natural gas price (Figure E-6).

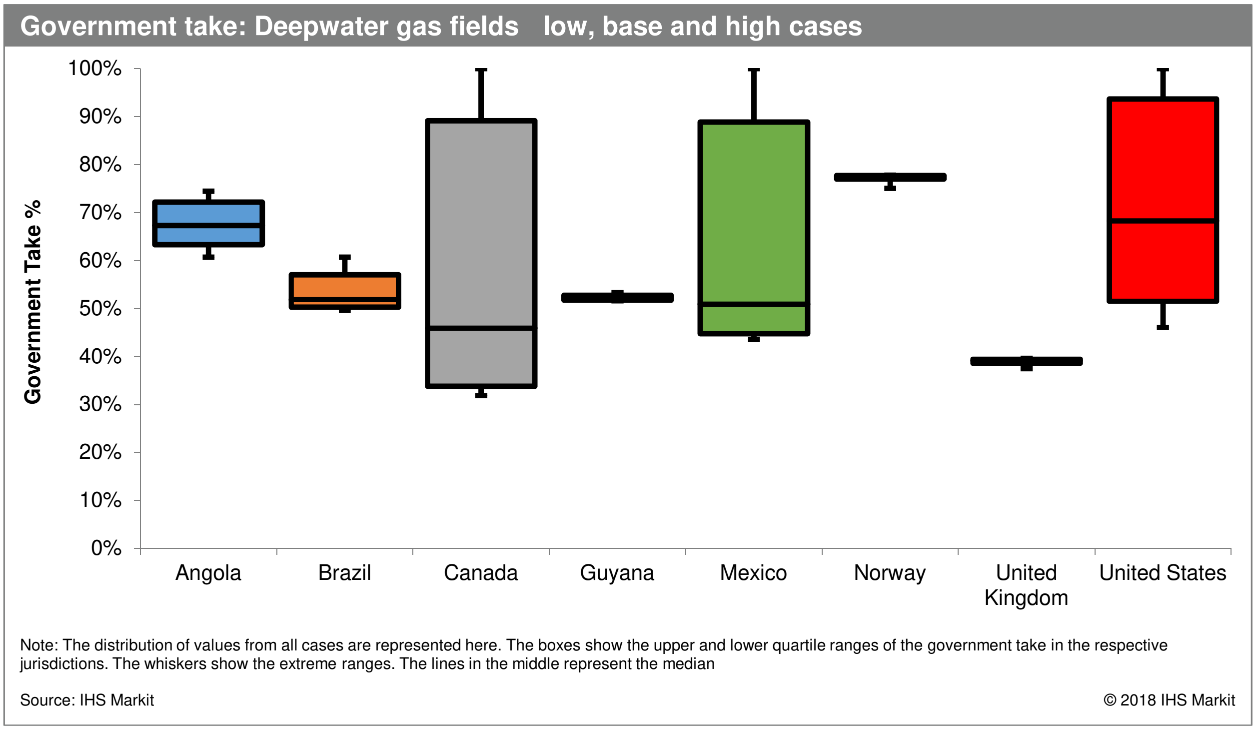


Figure E-21. Government take: Deepwater gas fields – low, base and high cases

The discounted share of the barrel analysis for deepwater natural gas fields shows North American natural gas projects at the bottom of the peer group when the share accruing to investors is considered (Figures E-22 to E-23). Similar to the U.S., Canada and Mexico are disadvantaged by prevailing natural gas markets in the region. The challenging economics for natural gas are attributed to market conditions rather than the design of the fiscal system. This is evident by the results of the high case, where the share of the discounted revenues accruing to investors is 18% and 26% for the 250MMboe and 500MMboe gas fields, respectively.

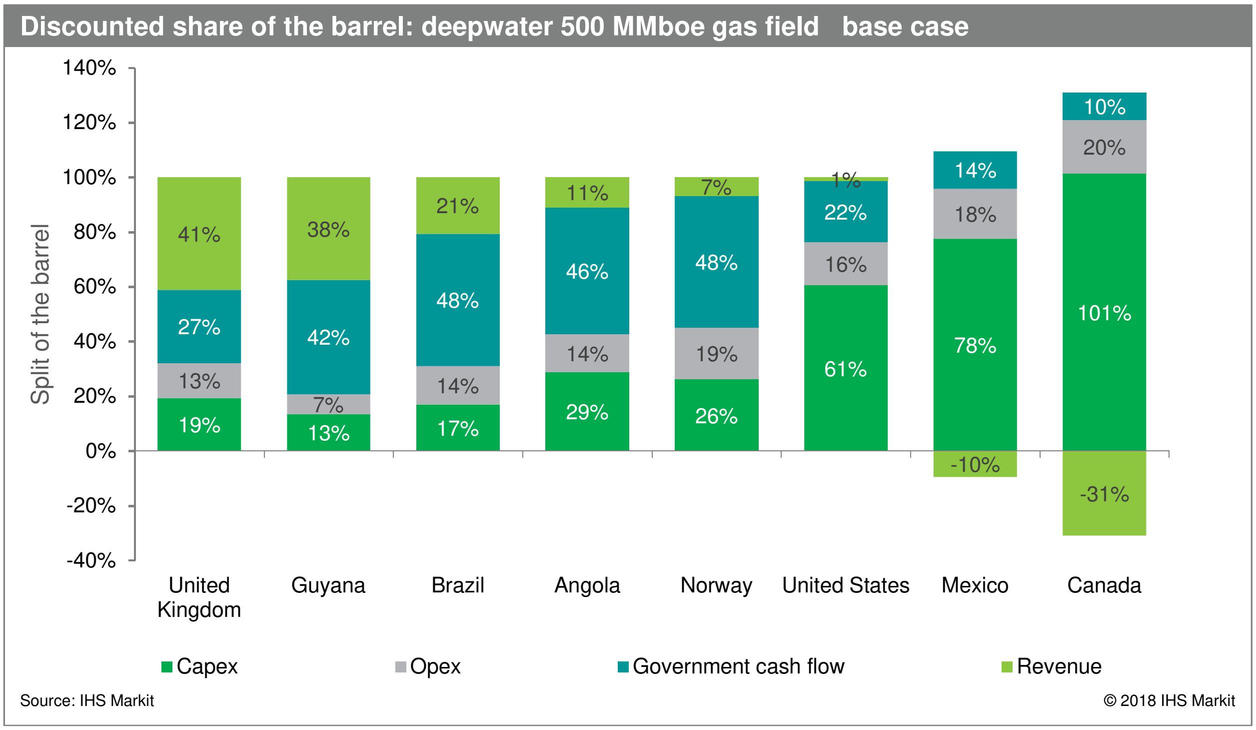


Figure E-22: Discounted share of the barrel: Deepwater 500MMboe gas field – base case

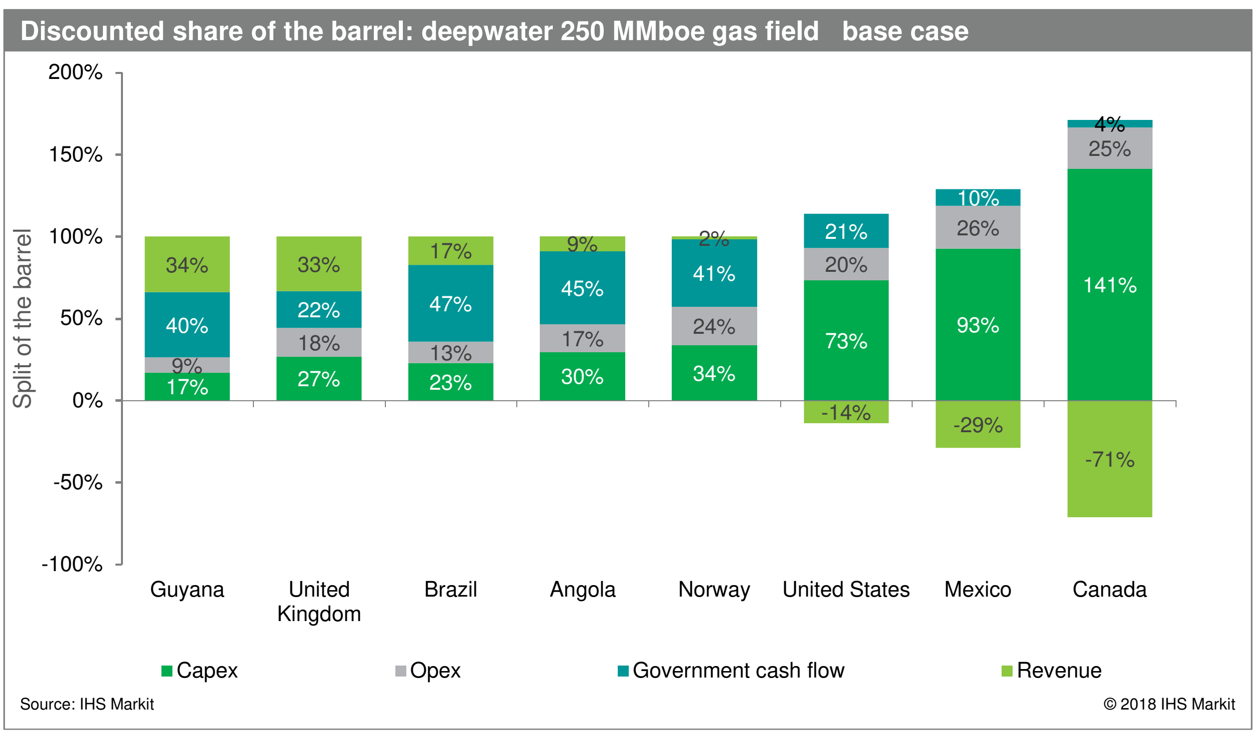


Figure E-23: Discounted share of the barrel: Deepwater 250MMboe gas field – base case

The U.S. GOM deepwater oil fields modeled for this study are representative of some of the future oil resource potential in the GOM. The oil fields have been modeled with a true vertical depth (TVD) of 28,000 feet, representative of the depths of the Lower Tertiary. The wells in the Lower Tertiary are some of the deepest in the world, averaging more than 20,000 feet of TVD, with significant technical challenges and low productivity. A significant portion of future U.S. GOM deepwater production potential lies in the Lower Tertiary (Figure E-24). The development of these deepwater oil resources is challenged under the base and low oil price scenario. Large Lower Tertiary discoveries have been recently returned to the government inventory since the economics do not make sense under current market conditions.

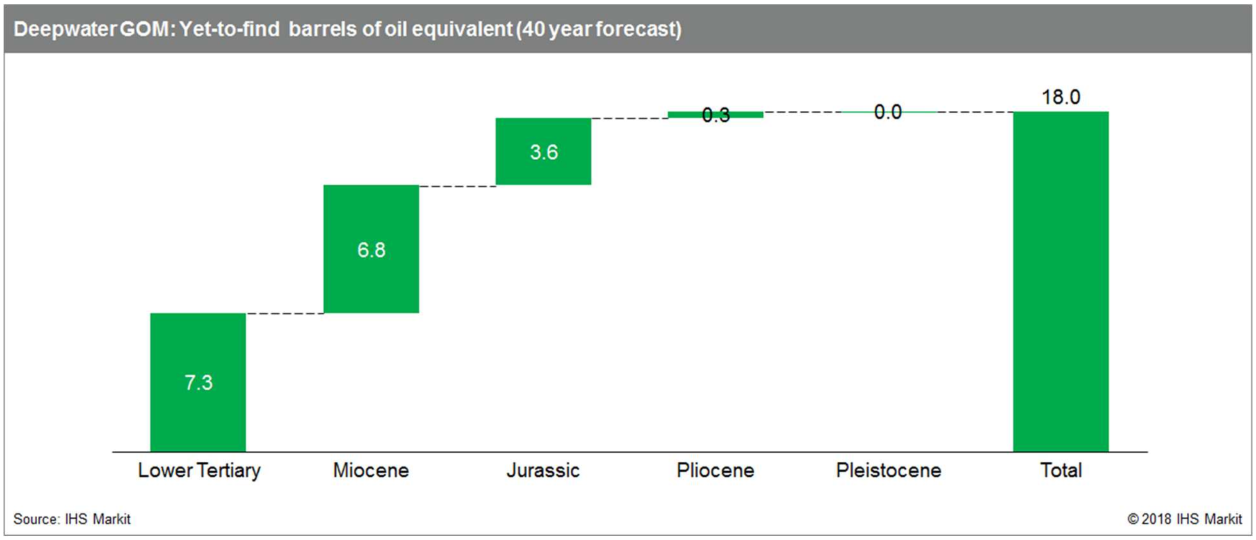


Figure E-24. Deepwater GOM: Yet-to-find barrels of oil equivalent (40 year forecast)

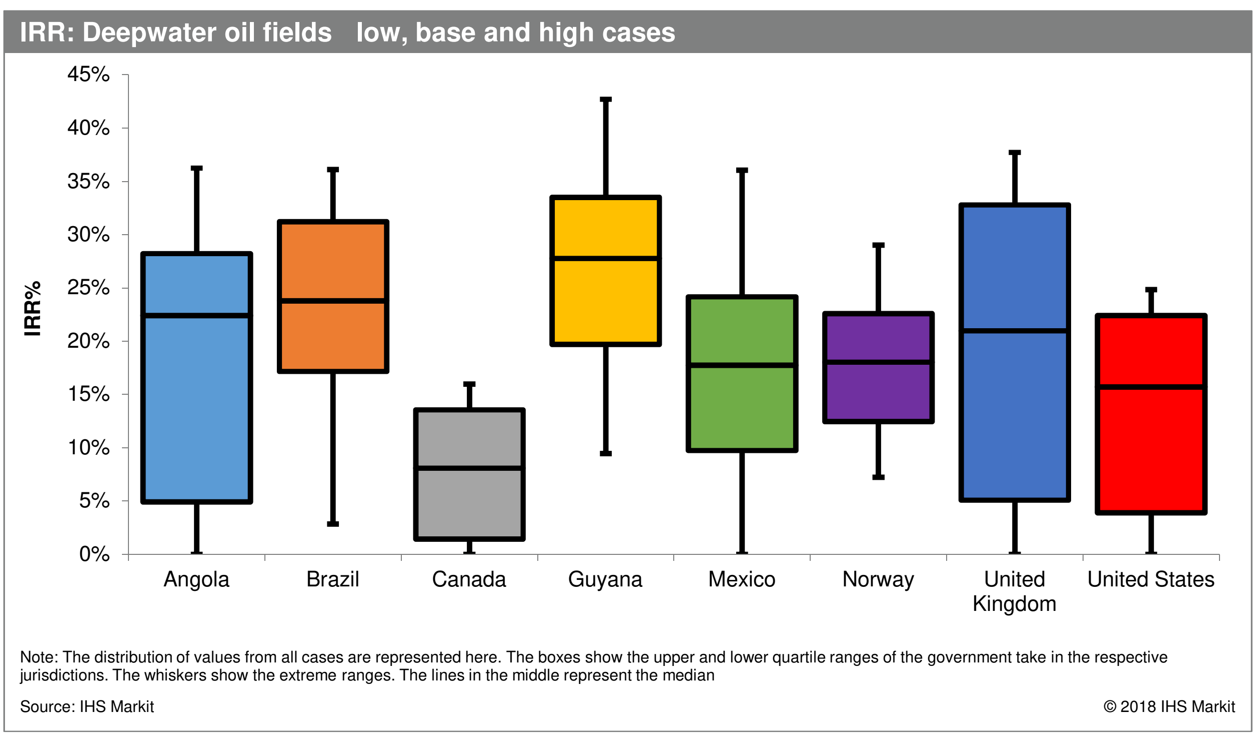


Figure E-25. IRR: Deepwater oil fields – low, base and high cases

The analysis of IRR for deepwater natural gas projects in the GOM mirrors the analysis of government take and the discounted share of the barrel, with U.S. slightly edging Mexico and Canada at the bottom of the peer group (Figure E-26). With a median IRR of 7%, deepwater natural gas projects in U.S. GOM are likely to face difficulty attracting investments.[3] As reiterated earlier in this report, the primary reason for the poor performance of natural gas projects[4] in the GOM are the low natural gas prices in North America.

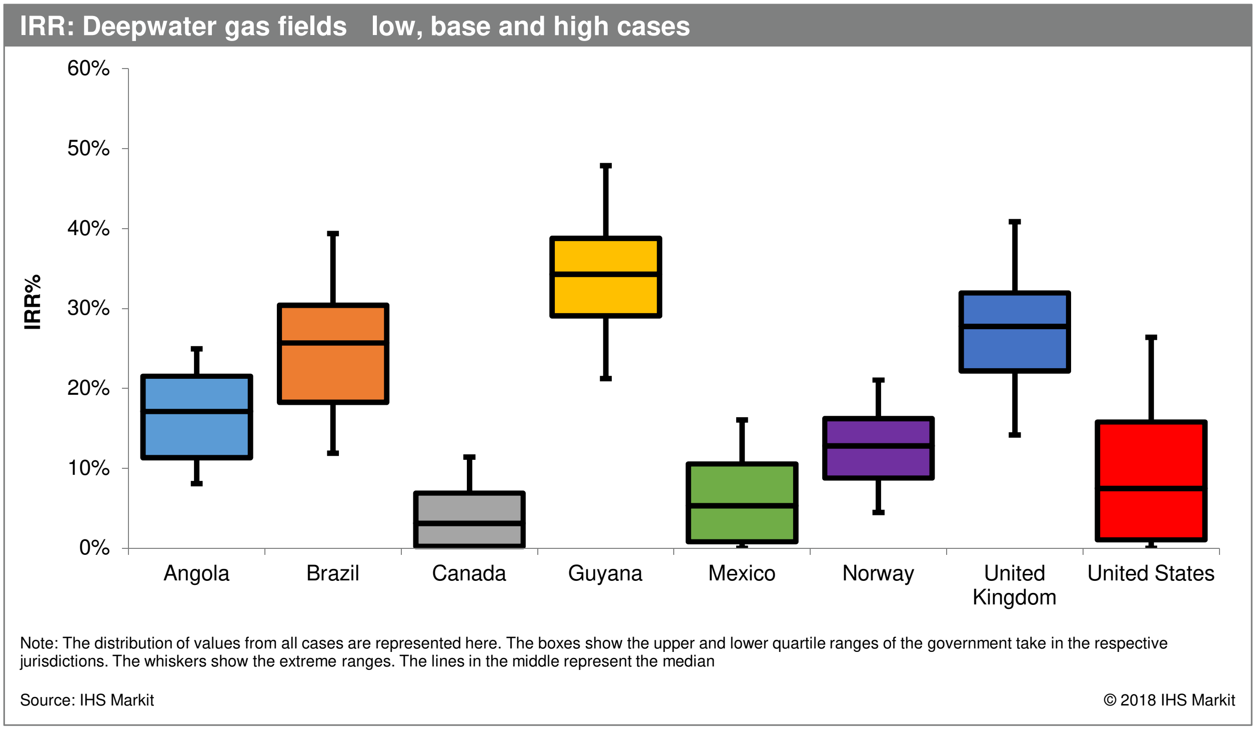


Figure E-26. IRR: Deepwater gas fields – low, base and high cases

Deepwater oil projects in the U.S. produce nearly half as much value per barrel of oil equivalent as Guyana and to some extent Brazil, but often perform better than Norway and Canada under all cases (Table E-5). Nonetheless, the deepwater oil fields analyzed in this study would attract investments under the base and high case. Despite the significant cost reduction that occurred since 2014, not all GOM projects are viable in a low oil price environment (low case).[5] The fields modeled for this study have negative net present value (NPV)/barrel of oil equivalent (BOE) in the low case, which means some of the Lower Tertiary projects may not be sanctioned in a low oil price environment—as shown by the low case in this study.

Some of the major oil companies are currently making investment decisions at $40/barrel (bbl) price despite the recovery of the commodity prices above $70/bbl by end of September 2018. This appears to be a strategy to manage costs and commodity price fluctuations in the future. According to Oil and Gas UK, Shell requires that any investments in upstream oil and gas projects break even at less than $40/boe, whereas BP is targeting 2021 as the year in which it brings down its break-even costs to $40/boe.[6]

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[3] Projects with an IRR below 15% are typically rejected when investment decisions are made.
[4] Projects yielding less than 15% IRR do not meet the investment threshold sought by most operators for deepwater projects.
[5] Projects with a negative NPV/boe are sub-economic and therefore rejected when investment decisions are made.
[6] Oil & Gas UK – Economic Report 2018.

Similar to the shallow water natural gas fields, the value per barrel of oil equivalent associated with deepwater gas fields in U.S. is nearly one-third of the value associated with oil fields in the GOM. The lower prices for gas on an energy-equivalent basis, and the significant disparity among natural gas prices in the U.S., Europe, and Asia (Figure E-6), contribute to the low ranking of the U.S. and other North American natural gas projects in the peer group.

Table E-5. NPV/Boe: Deepwater oil and gas fields

Jurisdiction	High Case		Base Case		Low Case	
	500 Mmboe	250 Mmboe	500 Mmboe	250 Mmboe	500 Mmboe	250 Mmboe
Crude Oil						
Angola	8.67	8.35	3.65	3.09	-1.84	-3.04
Brazil	13.1	10.8	6.3	3.5	1.6	-1.6
Canada	2.88	4.70	-1.83	0.24	-5.79	-3.22
Guyana	18.28	16.22	8.05	5.97	1.84	-0.15
Mexico	10.1	8.1	4.0	1.1	-0.2	-4.0
Norway	4.1	3.6	1.8	1.2	0.2	-0.5
United Kingdom	9.5	9.7	2.8	2.5	-2.8	-3.9
United States	9.0	10.8	2.5	2.8	-2.1	-2.8
Natural Gas						
Angola	5.44	5.22	2.23	1.87	-0.12	-0.58
Brazil	8.1	7.5	3.9	3.3	1.0	0.4
Canada	0.66	-1.55	-1.71	-4.23	-3.66	-6.95
Guyana	19.02	17.64	10.07	8.87	4.54	3.41
Mexico	2.6	0.8	-0.9	-2.7	-3.2	-5.8
Norway	2.3	1.9	0.8	0.2	-0.3	-1.1
United Kingdom	9.4	8.3	5.0	3.9	2.0	0.9
United States	3.7	2.3	0.1	-1.2	-2.6	-4.0

Source: IHS Markit

E.6 Alternative Fiscal Systems

Shallow Water Fiscal System Alternatives

The following fiscal system alternatives were analyzed for the shallow water areas (i.e. less than 200 meters) of the U.S. GOM:

Categorical royalty relief: This alternative applies to all leases in water depths less than 200m. A royalty suspension volume (RSV) of 5 MMboe is granted for each qualifying lease when oil prices are less than $85/bbl. For modeling purposes, we assume that a 10 MMboe field contains two leases, that a 30 MMboe field holds three leases, and a 100 MMboe field holds four leases. The 5 MMboe per-lease RSV is multiplied by the number of leases that comprise the field to get the total RSV for that field. The categorical royalty relief amounts are designed to offer a substantial benefit to help the government evaluate the maximum potential impact of fiscal terms. Table E-6 shows the categorical royalty relief for the RSV.

Table E-6. Shallow water categorical royalty relief – RSV volumes

Field size (MMboe)	Number of leases	RSV total (Leases x 5 MMboe)	Total % royalty free (low & base case)
100	4	20	20%
30	3	15	50%
10	2	10	100%

Source: IHS Markit

Sliding scale royalty: Lessees pay a variable royalty rate based on oil and condensate prices. Under this royalty alternative, only gas production is subject to the statutory royalty of 12.5%. This scale is intentionally more onerous than the current statutory minimum of 12.5% in shallow water in the GOM. Table E-7 describes the application of the shallow water sliding scale royalty for oil prices.

Table E-7. Shallow water sliding scale rates

Oil price ($/bbl)	Royalty rate (%)
< 50	12.5
50 to < 80	16.7
80 to < 105	20.0
> 105	22.5

Source: IHS Markit

Deepwater Fiscal System Alternatives

The following two alternative royalty systems were analyzed for GOM deepwater:

Lower royalty: This alternative lowers the royalty rate to the statutory minimum of 12.5%.

Higher royalty: This alternative increases the royalty rate to 20% and 22.5%.

Deepwater categorical royalty relief: This fiscal system alternative applies at the lease level for predetermined volumes in water depths greater than 200m. For modeling purposes, we assume that a 250 MMboe field has four leases and a 500 MMboe field has five leases. An RSV is granted per lease when the oil price is less than $85/bbl. Table E-8 shows the RSV available by water depth. The per-lease RSV is multiplied by the number of leases a field contains to get the total RSV applied to the hypothetical field. As with the shallow water categorical royalty relief, these royalty suspension amounts are designed to offer a substantial benefit to help the government evaluate the potential impact of fiscal terms.

Table E-8. Deepwater royalty relief suspension volumes

Water depth (meters)	Royalty suspension volume (MMboe)	Total RSV for 500 MMboe field (leases x RSV)	% Royalty Free 500 MMboe field (non-high case)	Total RSV for 250 MMboe field (leases x RSV)	% Royalty Free 250 MMboe field (non-high case)
200 to < 400	20	100	20%	80	32%
400 to < 800	40	200	40%	160	64%
800 +	60	300	60%	240	96%

Source: IHS Markit

Sliding scale royalty based on commodity price: In this royalty alternative, revenue from the gas stream pays the statutory minimum royalty of 12.5%. The oil price that determines the effective royalty rate is the sales price of crude oil or condensate. Table E-9 shows the application of the sliding scale royalty.

Table E-9. Deepwater sliding scale rates

Oil price ($/bbl)	Royalty rate (%)
< 50	12.5
50 to < 80	16.67
80 to < 105	20
> 105	22.5

Source: IHS Markit © 2018 IHS Markit

E.7 Comparative Analysis of Alternative Fiscal Systems

Shallow Water Alternatives

The categorical royalty relief analyzed in this study results in 50% and 100% effective reduction of the royalty volumes payable to the Federal government for the 30MMboe and 10MMboe fields modeled transforming the U.S. government take for the shallow water projects into the lowest among the peer group (low- to mid-20s in the base case)—perhaps the lowest in the world among jurisdictions that offer acreage for oil and gas investment.[7] Under the status quo, the government take for U.S. GOM shallow water projects is already low compared to the majority of the jurisdictions in the peer group—second lowest after United Kingdom (Figure E-27). With rates of return upwards of 20% under existing terms, a categorical relief of this nature may not be necessary for a 30MMboe oil field. The 10MMboe oil field becomes commercially viable under the base case. The 100% royalty relief, however is not sufficient to render the 10MMBboe economic under the low oil price environment (low case). The application of this alternative would, however, mean no revenue would accrue via royalties to the Federal government under the base and low case for such fields.

The U.S. GOM shallow water oil projects are already competitive from a government take and investor rate of return perspective. A decision whether a categorical royalty relief is necessary should not be pinned on the ranking of the U.S. among the peer group, but rather on what measures are necessary to make a category of investments commercially viable while maintaining an equitable share of project revenues between the government and investors. In this context, the relevant question is whether categorical royalty relief or discretionary relief would better serve the government's objectives in the U.S. GOM continental shelf area.

[7] A government take of 21-25% would rank the U.S. as the jurisdiction with the lowest government take among 148 fiscal system analyzed in the IHS Markit Petroleum Economics and Policy Solutions (PEPS) database.

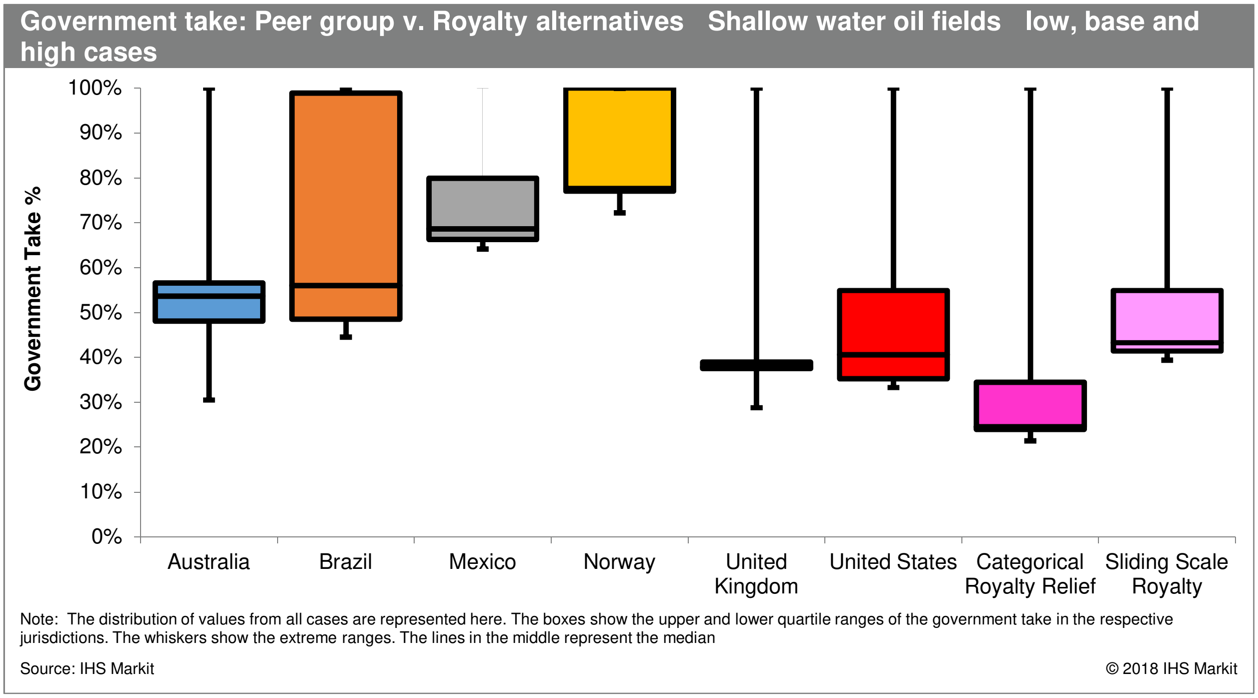

Figure E-27. Government take: Peer group v. Royalty alternatives - Shallow water oil fields – low, base, and high cases

Despite the effective 100% relief for 10 MMboe in this study, the categorical royalty relief is not sufficient to push investor rates of return for the small natural gas field sizes beyond the 10% rate of return threshold (Table E-10). This demonstrates that the challenges associated with natural gas projects in the U.S. GOM are not related to the fiscal system per se, but due to the market conditions in the U.S.

Table E-10. IRR: Shallow water oil and gas fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Crude Oil									
Australia	39%	25%	19%	31%	16%	11%	22%	1%	0%
Brazil	43%	22%	12%	32%	13%	0%	21%	0%	0%
Mexico	39%	16%	12%	31%	10%	4%	22%	2%	0%
Norway	24%	12%	3%	17%	6%	0%	10%	0%	0%
United Kingdom	44%	29%	16%	33%	19%	5%	22%	8%	0%
United States	45%	38%	19%	34%	26%	6%	20%	10%	0%
U.S. SW Categorical Relief	45%	38%	19%	37%	29%	10%	23%	14%	0%
U.S. SW Sliding Scale	43%	36%	17%	33%	25%	5%	20%	10%	0%
Natural Gas									
Australia	29%	21%	14%	21%	13%	0%	11%	0%	0%
Brazil	32%	9%	2%	22%	0%	0%	11%	0%	0%
Mexico	19%	1%	2%	11%	0%	0%	2%	0%	0%

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Norway	20%	8%	4%	13%	3%	0%	7%	0%	0%
United Kingdom	37%	23%	15%	28%	14%	7%	18%	2%	0%
United States	33%	27%	17%	16%	13%	3%	0%	0%	0%
U.S. SW Categorical Relief	33%	27%	17%	20%	17%	7%	0%	0%	0%
U.S. SW Sliding Scale	32%	26%	15%	15%	12%	2%	0%	0%	0%
Key: SW = shallow water									

Source: IHS Markit

Sliding scale royalties are usually designed to enable the resource holder to capture the project upside when profitability is high (during high oil prices) and provide relief when profitability decreases (during lower oil prices). The triggers for the sliding scale in this instance are crude oil prices—with royalty rates ranging from 12.5% to 22.5%. While this measure results in an increase of the government take for the U.S. GOM shallow water projects, it does not change the overall ranking of the U.S. among other jurisdictions in the peer group for oil fields (Figure E-26), except for the 10MMboe base case. In that case, the U.S. government take shifts from second to third-lowest in the peer group. Under this measure, the U.S. GOM oil projects on the shelf continue to remain competitive within the peer group. As expected, an increase in government take leads to reduction in investor rates of return. The IRR is reduced by one percentage point in the base case and two percentage points in the high case (Table E-10).

Overall, the impact of this fiscal system alternative is minimal on shallow water natural gas projects—since the royalty rate for natural gas is kept constant at 12.5%. Any change in government take or IRR results from the application of the sliding scale to liquids associated with natural gas production.

Deepwater Alternatives

Lower royalty rate: This alternative lowers the currently applicable 18.75% royalty rate to the statutory minimum of 12.5%. This alternative improves the competitiveness of the U.S. deepwater oil projects by lowering and narrowing the range of government take—thus reducing the degree of regressivity of the U.S. fiscal system (Figure E-28). With a median government take of 41%, the U.S. fiscal system has the lowest government take under the high case and second lowest next to United Kingdom under the base case. When the overall range of government take is considered under all three cases, the U.S. fiscal system is the most competitive in the peer group. It surpasses the United Kingdom under the low case scenario. Table E-11 shows the government take associated with standard and royalty rate alternatives.

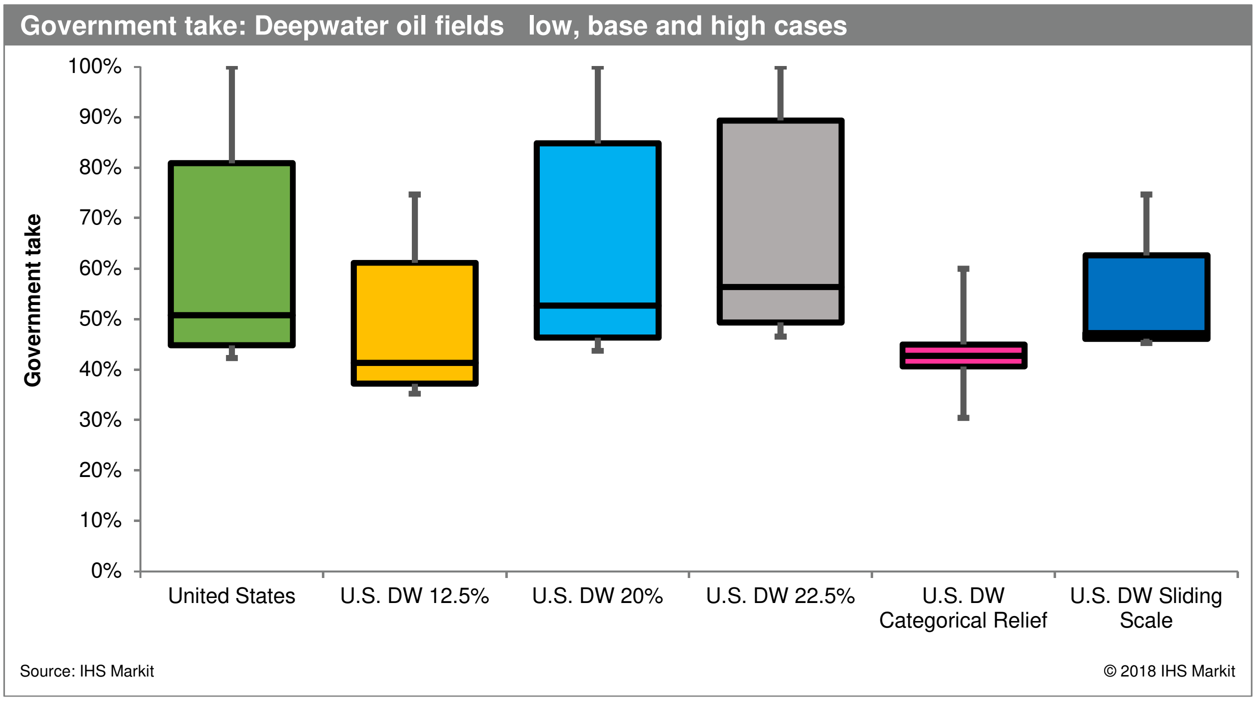

Figure E-28. Government take: Standard v. Royalty alternatives - Deepwater oil fields (low, base and high cases)

Table E-11. Government Take: GOM Deepwater oil and gas fields, standard v. alternative royalty rates

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Oil						
United States	43%	42%	52%	50%	91%	100%
U.S. DW 12.5%	36%	35%	42%	40%	67%	75%
U.S. DW 20%	44%	44%	53%	52%	95%	100%
U.S. DW 22.5%	47%	47%	57%	55%	100%	110%
U.S. DW Categorical Relief	43%	42%	40%	30%	60%	46%
U.S. DW Sliding Scale	46%	45%	48%	46%	67%	75%
Gas						
United States	46%	48%	62%	75%	100%	100%
U.S. DW 12.5%	38%	39%	48%	57%	100%	100%
U.S. DW 20%	48%	50%	65%	78%	100%	100%
U.S. DW 22.5%	51%	53%	70%	85%	100%	100%
U.S. DW Categorical Relief	46%	48%	46%	39%	100%	100%
U.S. DW Sliding Scale	40%	42%	50%	60%	100%	100%
Key: DW = deepwater						

Source: IHS Markit

The investor rates of return increase slightly (one percentage point) under this alternative (Table E-12). This measure however, is not sufficient to turn such fields into economic ones under the low case. The 250 MMboe oil field is sub-economic across all jurisdictions in the low case. In the water depths modeled in this study, reserves of 300MMboe or lower are considered marginal under the low oil price scenario. Except for the United Kingdom, all the deepwater oil fields modeled for this study are situated in ultra-deep waters. This is representative of the recent trends in exploratory drilling and discoveries made in the respective jurisdictions.

Table E-12. IRR: GOM Deepwater oil and gas fields, standard v. alternative royalty rates

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Oil						
United States	25%	25%	16%	16%	0%	0%
U.S. DW 12.5%	26%	26%	17%	17%	4%	3%
U.S. DW 20%	24%	25%	16%	15%	0%	0%
U.S. DW 22.5%	24%	24%	15%	14%	0%	0%
U.S. DW Categorical Relief	25%	25%	18%	19%	5%	6%
U.S. DW Sliding Scale	24%	24%	16%	16%	4%	3%
Gas						
United States	26%	17%	11%	4%	0%	0%
U.S. DW 12.5%	28%	19%	13%	7%	0%	0%
U.S. DW 20%	26%	17%	10%	4%	0%	0%
U.S. DW 22.5%	25%	16%	9%	3%	0%	0%
U.S. DW Categorical Relief	26%	17%	15%	9%	0%	0%
U.S. DW Sliding Scale	28%	19%	13%	6%	0%	0%
Key: DW = deepwater						

Source: IHS Markit

Although the government take for deepwater natural gas projects drops significantly under this alternative, the shift in the investor rate of return is not sufficient to reach the 15% hurdle rate that most investors seek for such projects (table E-12). This is in no way related to the fiscal system, but rather a result of the challenging economics for natural gas projects in the U.S. GOM and generally in North America. The fact that the deepwater gas projects yield robust rates of return (17%-28%) under the high case for both the standard and the 12.5% royalty alternative indicates that the problems are related to market prices rather than the fiscal system.

Higher royalty rate: The higher royalty alternatives of 20% and 22.5% have the potential to bring more revenue to the U.S. government without any change in the overall raking in the peer group. They also enhance the regressiveness of the U.S. fiscal system. The government take under the high and base case remains within a reasonable range of 44-57% (Table E-11). However, from an investor perspective, the internal rates of return remain the second lowest in the peer group (Table E-12). The deepwater oil fields in jurisdictions such as Angola and Norway that show much higher government takes than the U.S. GOM yield higher rates of return to investors. That is primarily due to their progressive (or neutral, in the case of Norway) fiscal systems that rely on measures of profitability for government revenue. The revenue accruing to the governments of Angola, Norway, and the United Kingdom is mostly back-end loaded (i.e., the government is sharing the revenue risk with investors).

Categorical royalty relief: The categorical royalty relief is the most impactful fiscal measure with regard to the range of government take in deepwater oil fields. While this measure eliminates almost entirely the regressivity of the fiscal system, it comes at the expense of offering 240MMboe and 300MMboe RSVs for the 250MMboe and 500MMboe oil fields, respectively—representing an effective 96% and 60% reduction in royalty entitlement to the government. From a government take ranking perspective, this measure does not change the already competitive position of the U.S. GOM oil projects in the peer group –second lowest government take after the United Kingdom under the base case. The categorical royalty relief has no impact on the high case because the categorical royalty relief does not apply when prices are above the $85/bbl threshold.

The substantial relief applied to the deepwater oil fields modeled for this study, does not result in significant increase in the IRR. A 96% royalty free volume on the 250MMBoe oil field only pushes the IRR by two percentage points in the base case (Table E-12). The investor rate of return for deepwater oil fields remains sub-economic under the low oil price scenario (low case), despite the substantial giveaway.

While the fields modeled for this study are not necessarily representative of the Lower Tertiary, the economics for the Lower Tertiary projects are going to be even more challenging[8]. Despite the large inventory of discovered resources in the Lower Tertiary, a sizeable share of potential volumes are still at the appraisal stage, making the play potential far from proven at the time of this report. This is largely due to development challenges such as tighter reservoirs, poor oil quality and lack of infrastructure compared to Miocene and Miocene Sub salt plays (Figure E-29). The Perdido Fold Belt and Outboard Lower Tertiary areas have already been reeling with a number of challenges such as:

- Well productivity that is estimated to be as much as 50% lower than in Miocene and Miocene Sub-salt reservoirs (see adjacent chart)
- High-pressure/high-temperature reservoirs (HPHT) resulting in more challenging and costly wells
- A lack of existing infrastructure
- The current absence of production technologies to produce at high pressures of up to 20,000 psi.
- Discoveries far from existing production hubs

[8] The total vertical depth of wells modeled for this study is similar to the Lower Tertiary, however, the well productivity and cost are more representative of the wider GOM ultra deepwater area.

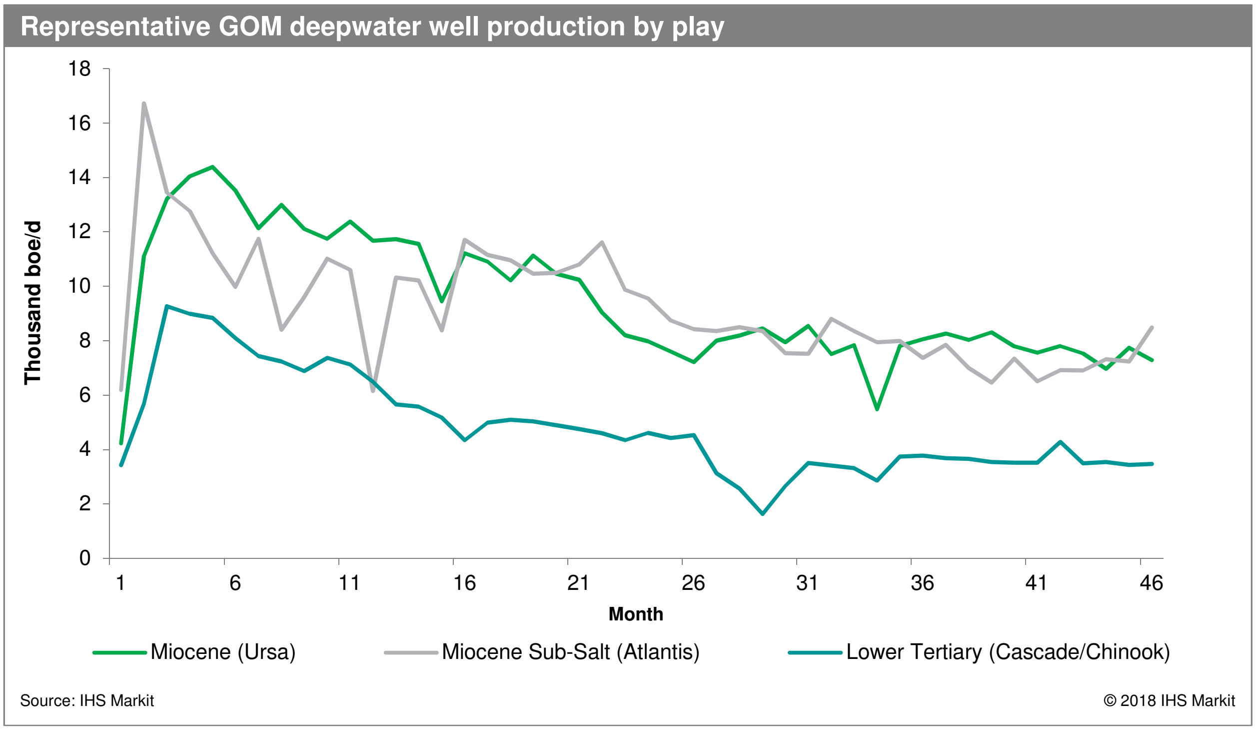

Figure E-29: Representative GOM deepwater well production by play

From an investor point of view, the internal rate of return (IRR) improves from 11% to 15% in the base case for the 500MMboe gas field; however, it is not able to push the 250MMboe across the 15% IRR threshold. The deepwater gas fields remain uneconomic in the low case under this royalty alternative. This proves once again that the challenges associated with natural gas projects are market challenges, rather than inherent in the fiscal system—not even a 50% and 96% royalty relief offered for the 500MMboe and 250MMboe gas fields respectively could render such fields economic.

Sliding scale royalty: The sliding scale royalty offers a more balanced approach by lowering the royalty rate and therefore revenue to the government when commodity prices are below \$80/bbl and \$50/bbl (effective royalty rates of 16.67% and 12.5%, respectively), and increasing the government share when commodity prices cross the \$80/bbl and \$105/bbl thresholds (20% and 22.5%, respectively). The range of the government take narrows significantly compared to the status quo, thus lessening the degree of regressivity of the fiscal system (Figure E-28). This measure results in increase of the government take by three to four percentage points for oil fields under the high case and a four percentage point rate reduction in the base case (Table E-11). The government take in the low case for deepwater oil fields drops significantly from 91% to 67% for the 500MMboe and from 100% to 75% for the 250MMboe. Despite the substantial drop in government take, the resulting increase in IRR is not sufficient to make these projects viable under this price scenario (Table E-12).

The sliding scale alternative is not designed to fluctuate with natural gas prices. Royalties for natural gas production remain flat at the statutory minimum of 12.5%. Such project experience a greater decline in the base case than oil projects, 9-12 percentage point drop due to the application of the statutory minimum royalty rate. What differentiates this alternative from the 12.5% alternative is the royalty applied on liquids. The impact of the sliding scale alternative in deepwater natural gas fields depends on the share of condensate and other liquids produced in associaiton with natural gas. Compared to the 12.5% alternative the sliding scale royalty for natural gas fields yields a slightly higher government take, 2-3 percentage point increase under the high and base case. Despite the improvements in IRR the deepwater gas projects remain uneconomic in the base and low case (Table E-12).

E.8 Discretionary Royalty Relief

To promote increased production or incentivize new projects that are otherwise uneconomic, BSEE may reduce or eliminate royalty under "end-of-life royalty relief" or "special case" relief programs. The purpose of these programs is to allow operators reasonable financial returns to increase ultimate recovery. The discretionary relief programs have had very limited use by lessees since the introduction of the Deepwater Royalty Relief Act of 1995. Only seven leases have benefited from discretionary royalty relief over the three decades this program has been in place, with the most recent approval occurring 17 years prior to the date of this report.[9] None of the approved discretionary royalty relief applications appears to be associated with the "end-of-life royalty relief" program.

End-of-Life Royalty Relief

The end-of-life royalty relief program is applicable to producing leases that are approaching the economic limit (i.e., have earnings that cannot sustain production under existing royalty rates) and relief would likely result in additional production. If approved, BSEE would grant a reduced royalty rate on the declining production.

The extension of a lease's life is important to increase the ultimate recovery of reserves. End-of-life royalty relief can be granted when royalty payments over a 12-month period exceed 75% of net revenues.[10] The royalty relief regulations issued by the DOI stipulate a reduction of 50% of the royalty payable on the relief volume.

The end-of-life royalty relief program does not appear to have been used by operators in the U.S. GOM. The requirement that royalty payments be in excess of 75% of the net revenue over a 12 month period could be placing a very high bar for qualification. By the time royalty revenue reaches 75% of the net revenue it may be too late in the field life for the operators to undertake any additional investment in relation to the said field. The application of the end-of-life royalty relief as prescribed by 30 Code of Federal Regulations (CFR) 203.50 was not successful in extending the field life for any of the hypothetical fields built for this study. The models used for this study indicate that the current structure of end-of-life relief has no visible or positive impact on the extension of the field life. This result is primarily due to the models' annual outputs which are not designed to capture the benefit of only a few months of effective relief. Perhaps the program might be improved by lowering the trigger ratio for the relief from 75% to 50% or lower. However, this would require a regulation change.

Special Case Relief

The special case relief is a discretionary relief granted by BSEE when existing programs do not provide adequate encouragement to increase production or development. Such leases must meet at least two of the following criteria:[11]

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[9] BOEM Data Center, Listing of Deepwater Royalty Relief Applications, web site last updated: 12-16-2018 03:00 AM(CST) https://www.data.boem.gov/Other/DataTables/RoyaltyReliefApplications.aspx
[10] 30 CFR § 203.52
[11] 30 CFR 203.80.

a. A royalty relief would allow recovery of significant additional resources
b. There is a substantial risk another lessee would not recover the resources
c. Valuable facilities exist on the lease which a successor would be unlikely to use
d. The lessee made substantial efforts to reduce operating costs, but it is too late to take advantage of other royalty relief programs
e. Circumstances beyond lessee's control preclude reliance on one of the existing royalty relief programs.

This study analyzes the case where the application for royalty relief meets the criteria of item a. and c. of the 30CFR 203.80 i.e. a royalty relief would allow recovery of significant additional resources, and valuable facilities exist on the lease which a successor would be unlikely to use.

Declining production sees little benefit from the current end-of-life royalty relief; the best hope for extending the useful life of existing assets is to find additional reserve volumes beyond the existing field profile. This means considering a special case relief to improve the economics of tying-back nearby discoveries to existing facilities to access new reserves. Investments that access significant additional reserves better supplement declining field incomes used to support the baseline field facility operations.

This special case relief is conditional upon the commitment of significant incremental investments, and lowers the royalty rate for the incremental reserves to half the applicable rate for the lease. The intention is to increase the ultimate recovery of reserves, while simultaneously increasing revenue to the government via royalties, since the incremental investment and its production keeps a field online for several more years. Overall, this should be beneficial to the government and investors. This type of relief results in an effective royalty rate reduction of 50% on additional reserves, and increase of baseline production by 3.7MMboe per field and extension of the life of assets by two and 5 years for shallow water and deepwater projects respectively. In the current environment when companies are focusing on shorter-cycle projects that can generate first cash within one to two years of development, the special case relief should serve as an incentive to add incremental reserves around existing facilities in the GOM.

E.8 Conclusion

The competitiveness of oil and gas investments in the U.S. GOM hinges on many factors, including the cost of exploration and development, prospectivity and the scale of the resource base, fiscal terms, and other regulatory and above-ground risk factors.

With respect to the exploration and development costs, the U.S. GOM and other offshore jurisdictions benefitted from the gradual cost cutting that has taken place since 2014. The increase in automation, efficiencies, use of artificial intelligence, and adaptive design changes by oil and gas companies, combined with cyclical cost factors that are sensitive to market conditions and fluctuate with changing oil prices, have resulted in a 38% to 41% decline in project costs for the shallow water and deepwater E&P sectors, respectively. These cost reductions are significant and have led to a recovery in project sanctioning in 2017 and 2018. As a result, most deepwater projects become cost competitive and close the gap with North American tight oil.

From a resource base perspective, the U.S. GOM is a mature province with significant undiscovered resource potential. However, there is steep competition with established oil and gas producers, such as Brazil, Mexico, Norway, and the United Kingdom, as well as frontier/emerging plays such as the Atlantic Margin play in Guyana. A significant portion of the U.S. GOM undiscovered technically recoverable resources lie in the Lower Tertiary formation with total vertical depth greater than 20,000 feet, HPHT reservoirs, lower well productivity, and substantially higher than average exploration and development costs. The comparative ease of producing resources offered by the discoveries in Brazil pre-salt polygon and Guyana deepwater basin gives these two jurisdictions a competitive edge over the U.S. and other countries included in this study. Brazil and Mexico have emerged in the past couple of years as the jurisdictions that have attracted significantly higher investment in their offshore sector via signature bonuses and work commitments.

The passage of the Tax Cuts and Jobs Act in December 2017 has transformed the U.S. Federal oil and gas fiscal system for the U.S. GOM into one of the most competitive fiscal systems in the world from an investor perspective. The U.S. ranks second or third-lowest in terms of government take within the peer groups selected for this study. In this race to compete for investments, the U.S. faces competition from jurisdictions, such as the United Kingdom, that have launched a comprehensive MER strategy that has resulted in adoption of policy solutions that address the maturity of the UKCS. However, the ability of the U.S. GOM sector to compete for investments will depend on measures other than government take. The return on investments, EMV, and resource potential will be key to investment decisions and project prioritization.

Evaluated on its individual merits and assuming the market prices reflect the base case scenario under this study, the current U.S. Deepwater GOM fiscal system offers conditions that should promote investment in oil exploration and development. However, compared with its peers, the U.S. projects for deepwater GOM rank below average based on their return on investment and EMV. The U.S. GOM rates of return are not as attractive as some of the jurisdictions in the peer group, notably, Guyana, Brazil, Angola, the United Kingdom, and Mexico, which offer rates of return above 20% under the base case scenario, compared to only 16% for the U.S. However, this study considers stand-alone projects only and the ability to tie-back to existing infrastructure provides an advantage to the U.S.

The U.S. GOM has a higher capital cost per unit than some of its peers, notably Brazil, Guyana, and Angola. The higher capex per barrel combined with a regressive fiscal system that does not account for profitability makes returns on investment very sensitive to low oil prices. The U.S. GOM fiscal systems for both shallow and deepwater areas yield sub-optimal results under a low oil price environment.

The deepwater oil fields in jurisdictions such as Angola and Norway that have much higher government takes than in the U.S. GOM yield higher rates of return to investors. That is primarily due to their progressive or neutral (in the case of Norway) fiscal systems that rely on measures of profitability for government revenue. The revenue accruing to the governments of Angola, Norway, and the United Kingdom is mostly back-end loaded (i.e., the government is sharing the revenue risk with investors).

Natural gas fields face significant challenges to drive offshore exploration and development on the shelf and deepwater areas of the GOM, even despite its relatively low government take. Potential natural gas projects are met with marginal or negative internal rates of return in the base case scenario, reflecting the value of current gas commodity prices. These projects also face stiff competition from the abundance of onshore natural gas supply from shale and associated gas. None of the fiscal system alternatives presented was sufficient to make most natural gas projects economic in this study, and thus it is unlikely any fiscal system changes can be made to reverse the declining natural gas trend at this time.

Between the two fiscal system alternatives considered for U.S. GOM shallow water, the sliding scale royalty alternative would result in more revenue accruing to the Federal government. Given the maturity of the shallow water areas and the expected field sizes—which are lower than some of the fields modeled for this study—the application of the sliding scale royalty alternative is likely to deter investment in the U.S. GOM shallow water area. While this alternative allows the government to capture the upside, it does not offer any relief for the downside. That is largely due to the floor set by the minimum statutory royalty of 12.5%. The floor for sliding scale royalties in most jurisdictions that adopt them—in this case, Newfoundland and Labrador and Mexico—is set much lower than the U.S. Federal fiscal system.

The categorical royalty relief considered for the U.S. GOM Shelf will make the U.S. fiscal system the most competitive in the world alongside the United Kingdom from a government take perspective. However, it will not significantly improve the ranking with regard to investor rate of return and EMV. Nevertheless, an aggressive royalty relief program can encourage the development of marginal fields and influence investment decisions for undeveloped discoveries. An alternative sliding scale royalty that lowers the royalty rate below the statutory minimum when commodity prices are low could be perceived as more balanced and neutral to investment decisions.

Out of the five fiscal system alternatives considered for the U.S. GOM deepwater areas the 20% and 22.5% royalty alternatives have the potential to generate more revenue for the Federal government, but increase the government take while projects are still sensitive to prices in the low and base price cases for both oil and gas. Given the gradual decline in exploratory and development drilling since 2003 in the GOM deepwater area an increase in royalty rate could further exacerbate the trend.

The 12.5% royalty alternative lowers the government take and increases the IRR in all cases, but not to the degree of categorical royalty relief in the low and base cases for oil and gas. Such measure is most impactful in the high price cases where these changes are the least helpful to project economics.

The sliding scale royalty offers a more balanced approach by lowering the royalty rate, and hence revenue accruing to the government, when commodity prices are less than \$80/bbl and \$50/bbl, and increasing the government share when commodity prices cross the \$80/bbl and \$105/bbl thresholds. The range of the government take among the various cases significantly narrows compared to the status quo, thus softening the degree of regressivity of the fiscal system. Similar to the sliding scale royalty for shallow water, the deepwater sliding scale preserves the statutory minimum rate. As such it is not able to render economic the deepwater projects under the low case.

Among the deepwater alternatives that improve the rate of return to investors, the categorical royalty relief is the most impactful one, but without regard to government take. The threshold price of \$85/bbl for categorical royalty relief gives the government its usual share when commodity prices are high, while marginal projects benefit from the relief in the base case and low-price environment. The deepwater gas fields remain uneconomic in the low case under this royalty alternative, proving once again that the challenges associated with natural gas projects are market challenges, rather than inherent in the fiscal system—not even a 50% and 96% royalty relief offered gas fields in this study could render such fields economic.

The categorical royalty relief, is based on water depth and provides similar relief to deepwater projects within the same water depth, regardless of the reservoir or play characteristics. Under this alternative Lower tertiary projects would be entitled to similar RSVs as Miocene projects. A more effective royalty relief policy could be designed to target the play or plays that need it most. Given the technological and commercial challenges faced by the Lower Tertiary discoveries a categorical royalty relief that targets investments in such a play may prove more beneficial to investors and government alike.

Overall, the U.S. GOM oil projects are competitive within the peer group with the shelf being the most competitive among the two for the fields considered in this study. Such projects offer competitive rates of return under base and high case scenarios. However, the U.S. GOM shelf is limited in terms of resource availability. With the expected field sizes matching the small reserve size under this study, the best hope for such projects on the shelf is reliance on existing facilities and infrastructure. The market conditions do not favor development of the small reserves in the U.S. GOM shelf on a stand-alone basis. With the wave of decommissioning continuing strong in the shelf—more than 100 structures being decommissioned each year—the establishment of efficient policy solutions that encourage such developments could be necessary.

1 Context and Scope

1.1 Background

In 2011, DOI published the study *"Comparative Assessment of the Federal Oil and Gas Fiscal System."* (2011 Study). The 2011 Study compared "the oil and gas systems that apply on federally owned offshore and onshore lands with oil and gas fiscal systems adopted by other countries that compete with the United States for investments in the oil and gas upstream industry."[12] Since that study was finalized, the oil and gas market has changed significantly with regard to the following:

1. The amount and type of the oil and gas resources available and the activities of oil and gas suppliers' around the world. The "shale revolution" has transformed the U.S. into a top producer of natural gas and crude oil. Production from tight oil and shale gas plays has currently overtaken conventional oil and gas production in the U.S. and is expected to push U.S. crude oil and condensate production to 14 million barrels per day (MMbbl/d) by 2025, with natural gas exports reaching 5 billion cubic feet per day by 2020 (IHS Markit base case outlook: Figures 1-1 – 1-4).

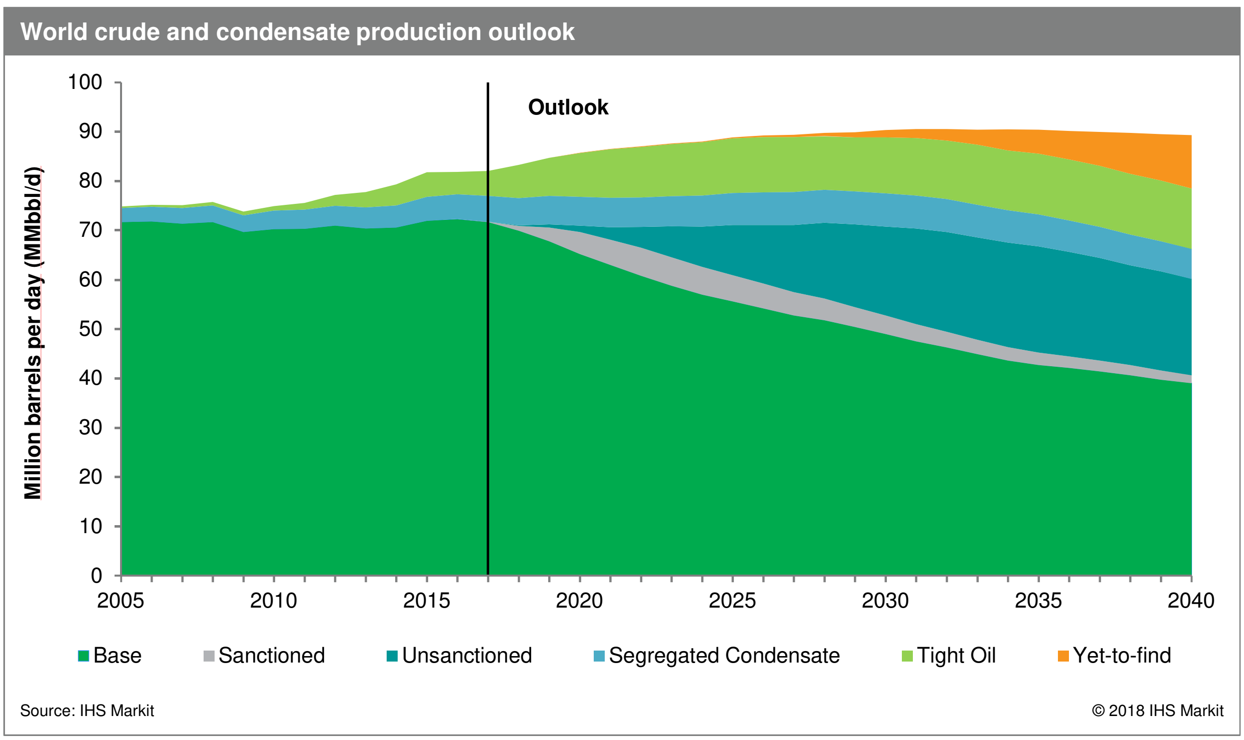

Figure 1-1. World crude and condensate production outlook

[12] Agalliu, I. 2011. Comparative assessment of the federal oil and gas fiscal systems. U.S. Department of the Interior, Bureau of Ocean Energy Management Herndon. VA. OCS Study, BOEM 2011-xxx. 300 pp.

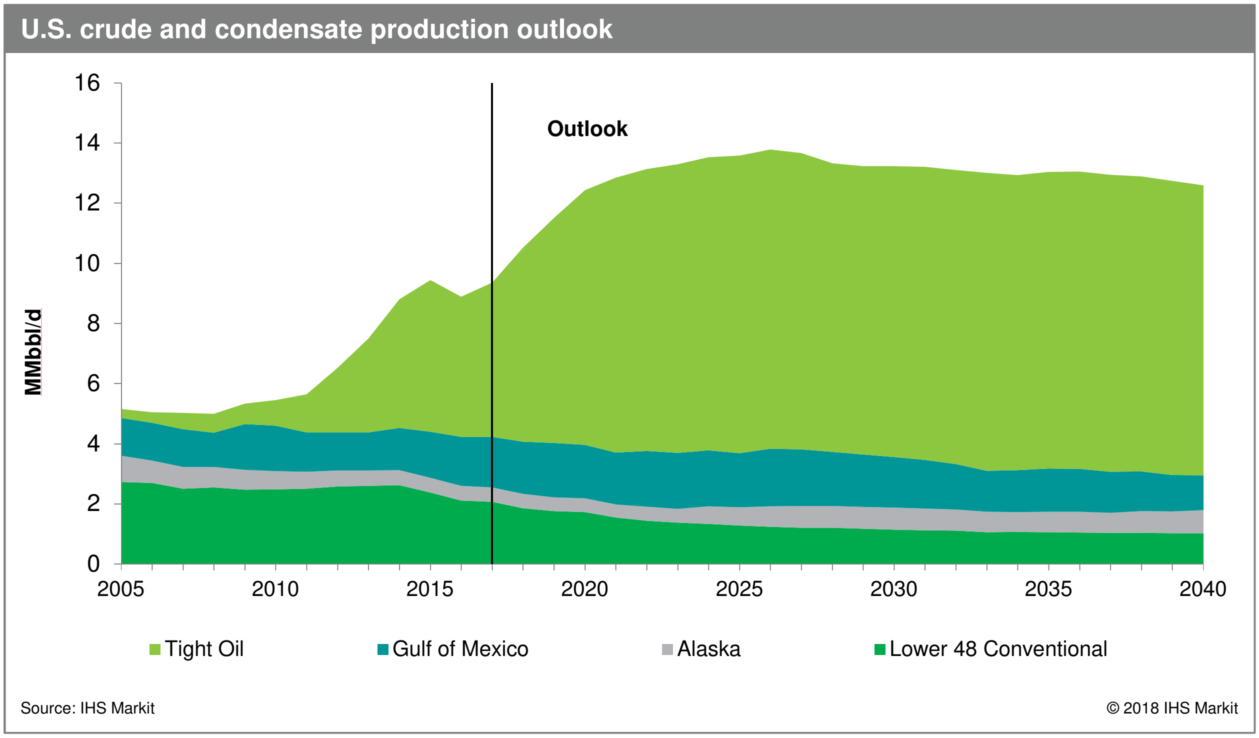

Figure 1-2. U.S. crude and condensate production outlook

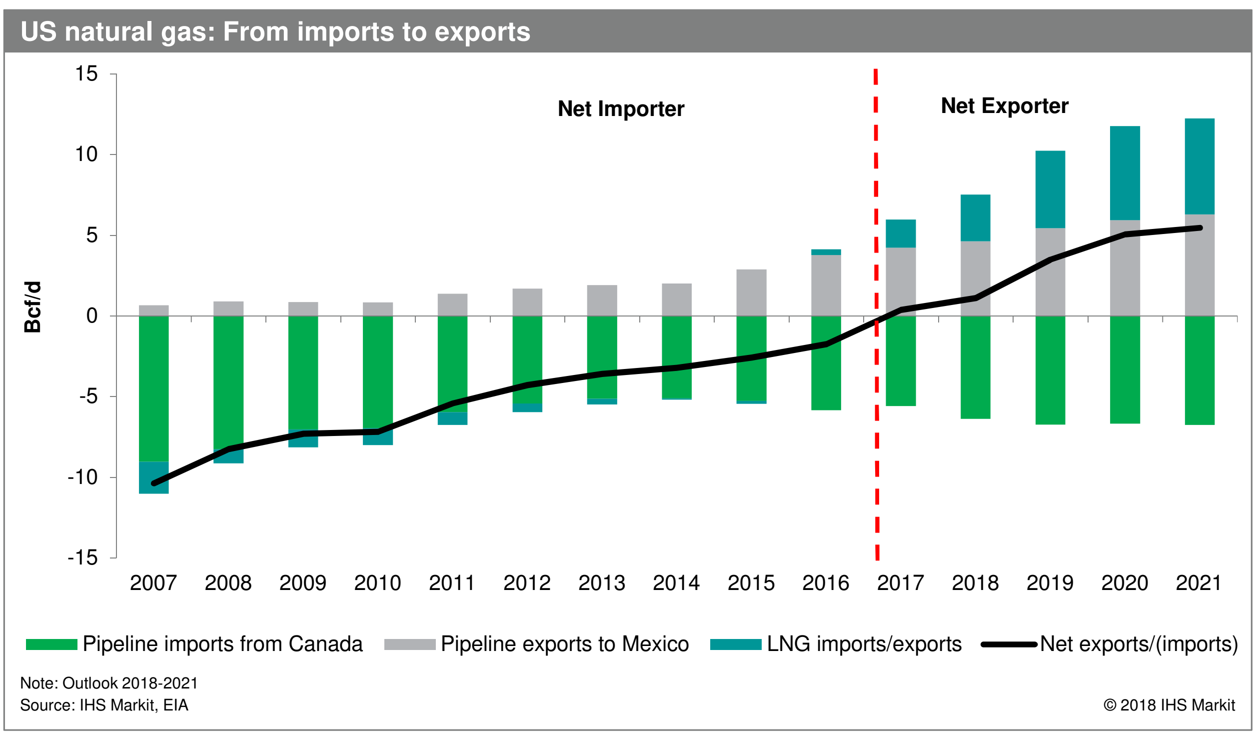

Figure 1-3. U.S. natural gas: From net importer to net exporter

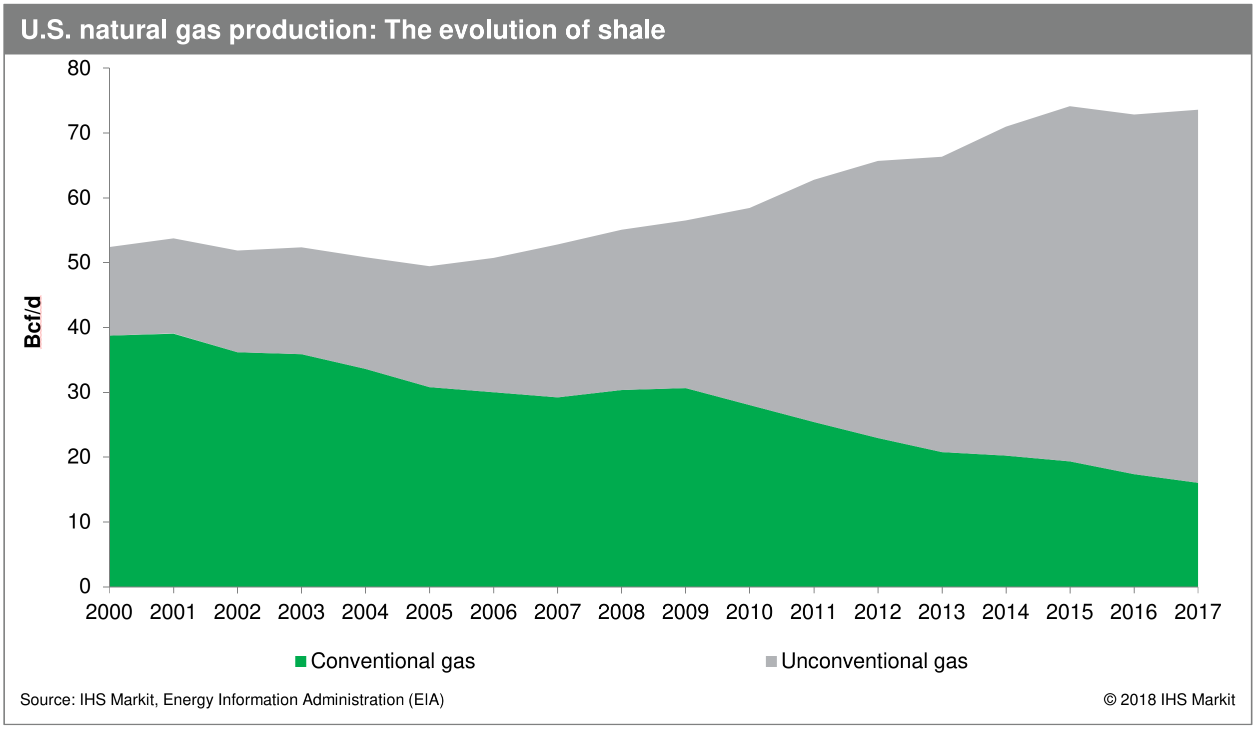

Figure 1-4. U.S. natural gas production: The evolution of shale

Despite this increase in overall U.S. oil and gas production, and the vast resources underlying the Federal lands, the growth of U.S. production has largely taken place on private land, or on split-estate properties where the Federal share is relatively minor, according to the Congressional Research Service.[13]

2. Dramatic shifts in commodity prices have led to a shift from long-cycle barrels to short-cycle barrels. Although the traditional exploration cycle typically exceeds five years from lease sale to first oil production, the emergence of tight reservoirs and advancements in the technology associated with their development have created the potential for sustainable development opportunities that are both short- and long-cycle.[14] Spending on exploration is decreasing in new frontier ventures and increasing in tight reservoirs in proven "Super Basins" and a select set of emerging basins with multiple stacked targets.

However, conventional barrels are not dead. IHS Markit research shows that under the base case scenario, net crude oil supply to 2030 is highly dependent on the sanctioning of conventional projects (Figure 1-5). The role the U.S. Gulf of Mexico will play in global supply growth depends on the competitiveness of such resources in the marketplace.

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[13] Federal lands are estimated to hold over 90 billion barrels of oil and 327 trillion cubic feet of natural gas of undiscovered technically recoverable (mean estimate) resources offshore, and 52 billion barrels of oil equivalent onshore. Congressional Research Service, "U.S. Crude Oil and Natural Gas Production in Federal and Nonfederal Areas", 2016.

[14] Short cycle barrels are projects that can generate profit within one to two years of development, or, in the case of new entrants, projects that progress to FID in less than three years. The typical deepwater project averages seven years to reach FID with exponentially more upfront investment.

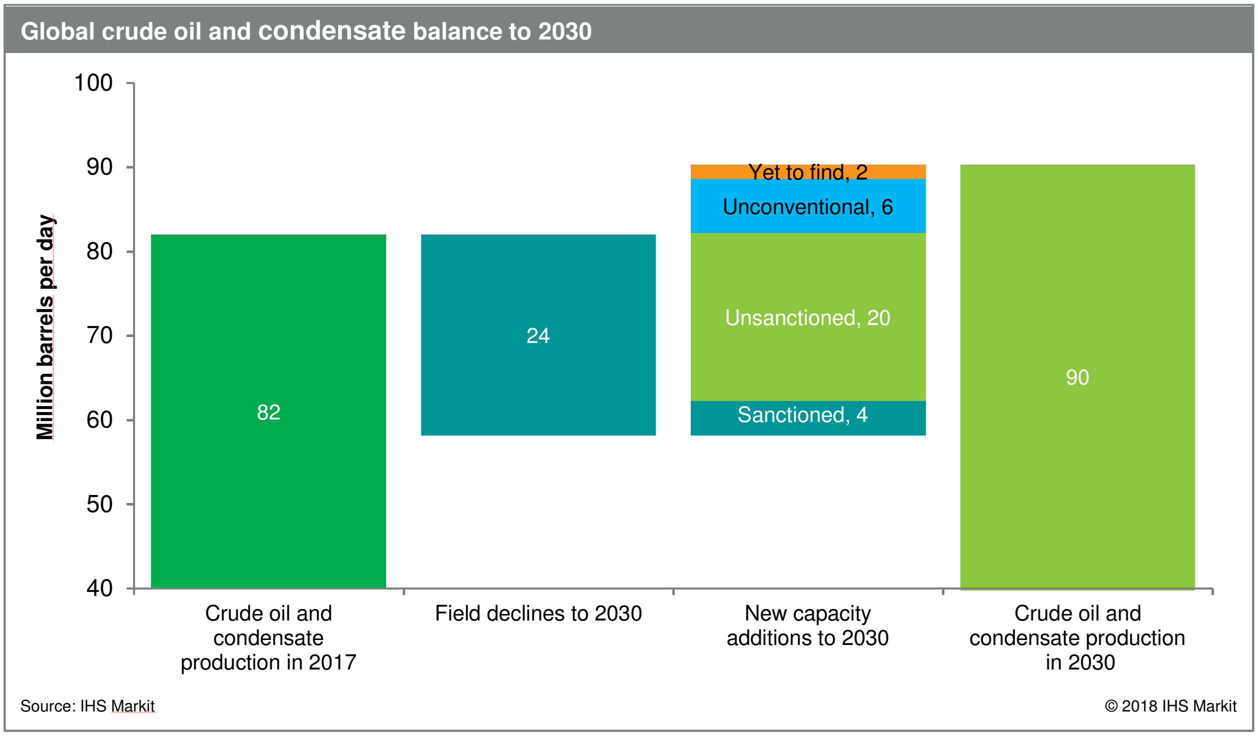

Figure 1-5. Global crude oil and condensate balance to 2030

3. In response to these market challenges, governments have taken measures to address their relative competitive position in the market place. Some governments, such as the United Kingdom and the province of Alberta, Canada, have been very proactive in adjusting terms to attract investments. Others have reacted more tepidly in response to disappointing results in licensing rounds, which has led to incremental changes in fiscal terms to attract investments. An understanding of the measures taken by other governments since 2014 is an important aspect of this study.

Two major domestic legislative changes have greatly impacted the oil and gas industry. The lift of the U.S. oil export ban at the end of 2015 provided a boost to the domestic oil and gas production in the U.S. Also, recent U.S. tax code changes resulted in a much lower corporate income tax rate (21% from 35%). This lower rate is expected to significantly reduce the amount of government take in the U.S. Federal system.

4. Due to the mature nature of the GOM, it is anticipated that a significant number of structures on the shelf will be decommissioned in the relatively near term. The effective decommissioning of offshore platforms, subsea wells, and related assets is one of the most important challenges facing the oil and gas industry today because associated costs are skyrocketing. IHS Markit study "Offshore Decommissioning" of September 27, 2016 estimated that the following could occur:[15]

- Decommissioning spending will reach 13 billion in U.S. dollars (USD) per year by 2040. Total expenditure from 2010 to 2040 will amount to USD210 billion.
- Europe will drive spending in the near term, as a substantial inventory of large offshore structures is removed, absorbing approximately 50% of global spending over the forecast period.

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[15] IHS Markit, "Offshore Decommissioning" September 27, 2016

- More than 600 sites are expected to be decommissioned in 2016–2021, with another 2,000 expected in 2021–2040.
- North America has by far the largest number of units to be decommissioned, but most structures are simple platforms with relatively low decommissioning costs.

This study describes and considers the significant changes in the oil and gas markets and changes in the oil and gas fiscal systems of other jurisdictions, in context of remaining US resources.

1.2 Approach and Scope of Work

1.2.1 Jurisdictional Selection and Field Sizes

This study analyzes two separate peer groups: shallow water and deepwater. The criteria used to select the appropriate jurisdictions and field sizes were informed by the challenges of the respective operating environments.

Shallow water peer group: The jurisdictions in this peer group were selected for their geologic similarity to the U.S. Gulf of Mexico shallow water area and the maturity of the region, as well as the expected loss of infrastructure in the near future. Other criteria for selecting the peer groups include the following:

- PP reserve additions during the 2007-2016 period
- Presence of a shallow water E&P sector
- Maturity of the province
- Anticipated spending for decommissioning of infrastructure through 2040.

Based on the above criteria, 25 countries were selected with the highest reserve additions offshore, and ranked on the combined set of criteria described above. While the data related to reserve additions is representative of the entire offshore region for the respective jurisdictions (not necessarily just the shallow water areas), reserve additions are important in terms of the level of E&P activity in the offshore sector. The jurisdictions were assigned a relative score of 0-10, with a score of 10 representing the highest reserve additions, the most mature province, and the highest level of estimated spending for decommissioning through 2040.

The six countries with the highest combined score, including the U.S. Gulf of Mexico, were selected for the shallow water peer group. These countries are identified in Table 1-1.

Table 1-1. Shallow water jurisdiction selection criteria

Jurisdiction	Reserve additions (2007-16)	Maturity of the province	Decommissioning activity planned	Shallow water sector	Total score	Selected countries
Brazil	10.00	8.31	1.60	Y	19.91	√
Norway	1.23	7.38	10.00	Y	18.61	√
United Kingdom	0.35	8.69	8.00	Y	17.04	√
United States	1.90	10.00	2.40	Y	14.30	√
Mexico	0.69	8.25	1.20	Y	10.14	√
Australia	1.20	6.85	1.60	Y	9.65	√
China	0.88	6.69	0.40	Y	7.97	
Angola	1.19	5.54	1.20	Y	7.93	
Malaysia	0.96	6.15	0.52	Y	7.63	
Mozambique	5.29	2.31	0.00	Y	7.60	
Nigeria	0.17	6.30	0.40	Y	6.87	
India	0.15	6.15	0.48	Y	6.78	
Egypt	0.88	5.77	0.00	Y	6.65	
Azerbaijan	0.31	5.45	0.08	Y	5.84	
Russia	0.75	4.92	0.01	Y	5.68	
Vietnam	0.00	5.31	0.20	Y	5.51	
Venezuela	0.05	5.46	0.00	Y	5.51	
Iran	0.78	4.45	0.00	Y	5.23	
Israel	1.05	0.92	0.00	Y	1.98	
Tanzania	0.98	0.77	0.00	Y	1.75	
Ghana	0.28	1.38	0.00	Y	1.67	
Falkland Islands	0.07	0.77	0.00	N	0.84	
Mauritania	0.19	0.62	0.00	N	0.81	
Senegal	0.32	0.15	0.00	N	0.47	
Guyana	0.07	0.00	0.00	N	0.07	

Source: IHS Markit

In making these selections, the IHS Markit's EDIN database was used that contains E&P exploration data for every country with E&P activity around the globe, as well as the IHS Markit 2016 Offshore Decommissioning Study.

Russia and the Caspian region has mostly newer infrastructure and the decommissioning rates there are expected to be much lower for the next few years. Older installations also exist in other regions, such as the Middle East, but because of their longer field life, these are expected to operate for many years to come.

While the U.S. Gulf of Mexico has by far the largest number of facilities to be decommissioned in the future, most structures are simple platforms with relatively low decommissioning costs. Norway and the United Kingdom are expected to incur much higher decommissioning costs than the U.S. GOM through 2040.

This study, unlike its predecessor in 2011,[16] relies on three hypothetical field sizes for oil and gas that apply across all the jurisdictions in the respective peer group. These fields have equivalent resources across each country, but each has a different cost to explore and develop based on the unique circumstances of each jurisdiction. In selecting the three field size cases, IHS Markit reviewed the field size distributions of the discoveries made in shallow water areas of the peer group between 2008 and 2017. As seen in Table 1-2 the field sizes for U.S. GOM in the past 10 years are under 10MMboe.

Table 1-2. Shallow water field size distribution over entire peer group

Field size (MMboe)	0 – 9	10 – 29	30 – 49	50 – 75	75 – 99	> 100
No of fields in peer group	86	76	45	16	14	19
No of fields in GOM	7	0	0	0	0	0

Note: MMboe equals million barrels of oil equivalent

Source: IHS Markit

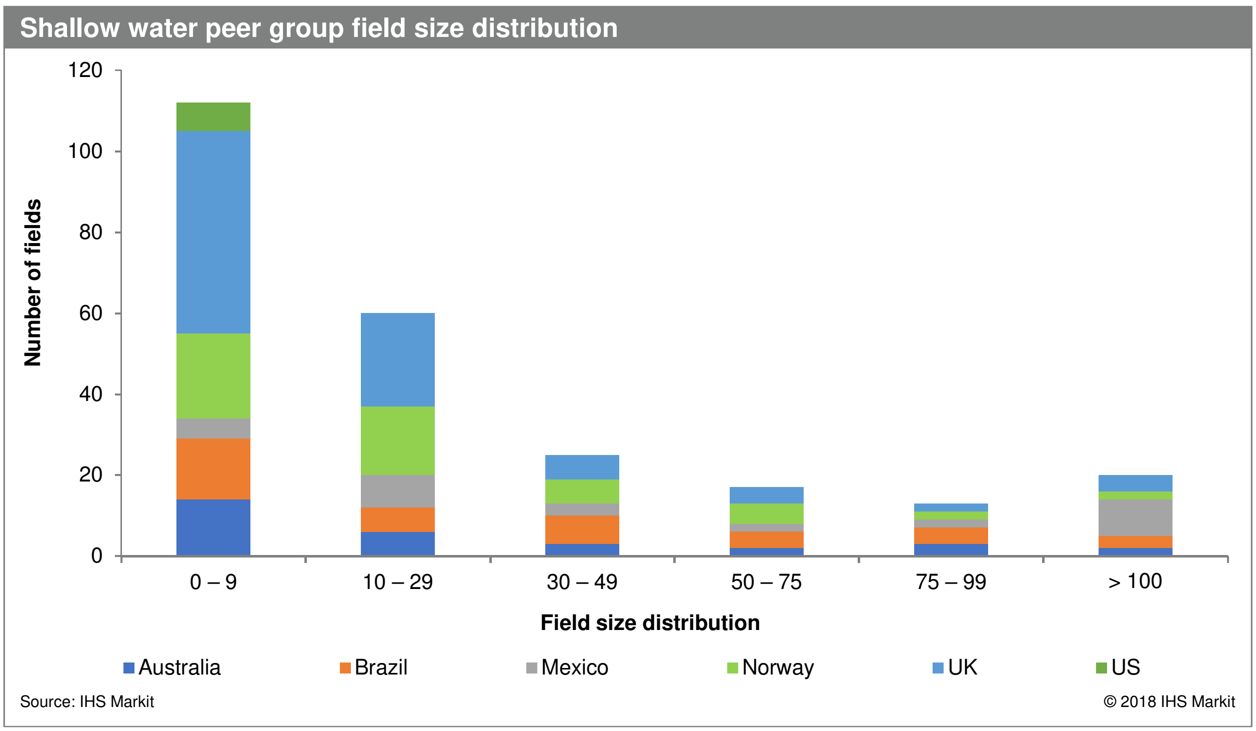

Figure 1-6. Shallow water peer group field size distribution

Upon review of the field size distributions, IHS Markit selected the following field sizes including both oil and gas systems with cost adjustments per each jurisdiction:

- 10 MMboe
- 30 MMboe
- 100 MMboe.

Deepwater Peer Group

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[16] The 2011 study "Comparative Assessment of the Federal Oil and Gas Fiscal System" relied on modeling actual field sizes from the respective jurisdictions.

The list of proposed deepwater jurisdictions competing for investment with the U.S. Gulf of Mexico consists of a mixture of the following:

- Established deepwater areas with significant reserve growth potential
- Emerging offshore provinces with major discoveries in recent years.

The selection process considered similarities with regard to the following:

- Water depth
- Total vertical depth
- Technological challenges involved.

While E&P activity in deepwater GOM has pushed boundaries to well depths of more than 10,000m, the total vertical depth of discovery wells drilled in other jurisdictions does not go that deep. Currently, the U.S is the only jurisdiction with deepwater wells drilled in depths greater than 8,000m. However, this aspect is addressed through cost adjustments that take into account the water depth, well depth, and other technical factors as described in the Exploration and Development Cost section of this report. Based on the above criteria, we selected the deepwater peer group shown in Table 1-3.

Table 1-3. Deepwater jurisdiction selection criteria

Characteristics of discoveries (2008-2017)				
No	**Jurisdiction**	**Water depth (Meters)**	**Total vertical depth (Meters)**	**Average discovery size (MMboe)**
1	U.S. GOM	400 – 3,000	2,331 – 10,685	100
2	Norway	217 – 1,425	4,183 – 7,811	40
3	Brazil	235 – 1,820	2,202 – 7,628	520
4	Angola	225 – 2,434	1,901 – 6,384	150
5	Mexico	225 – 3,008	3,040 – 6,943	90
6	Guyana	1,563 – 1,743	5,175 – 6,450	600
7	United Kingdom	252 – 1,288	2,334 – 4,475	35
8	Nova Scotia	1,095 – 1,172	3,400 – 3,758	170

Source: IHS Markit © 2018 IHS Markit

In selecting the three field size cases, IHS Markit reviewed the field size distributions of the discoveries made in deepwater areas of the peer group between 2008 and 2017. Table 1-4 shows the distribution of field sizes in all six jurisdictions combined.

Table 1-4. Deepwater field size distribution over entire peer group

Field size MMboe	< 50	50 - 99	100 - 249	250 - 499	500 - 749	750 - 999	1,000 - 1,999	> 2,000
Fields in peer group	155	44	37	13	5	2	6	6
Fields in GOM	56	12	11	4	5	0	0	0

Source: IHS Markit © 2018 IHS Markit

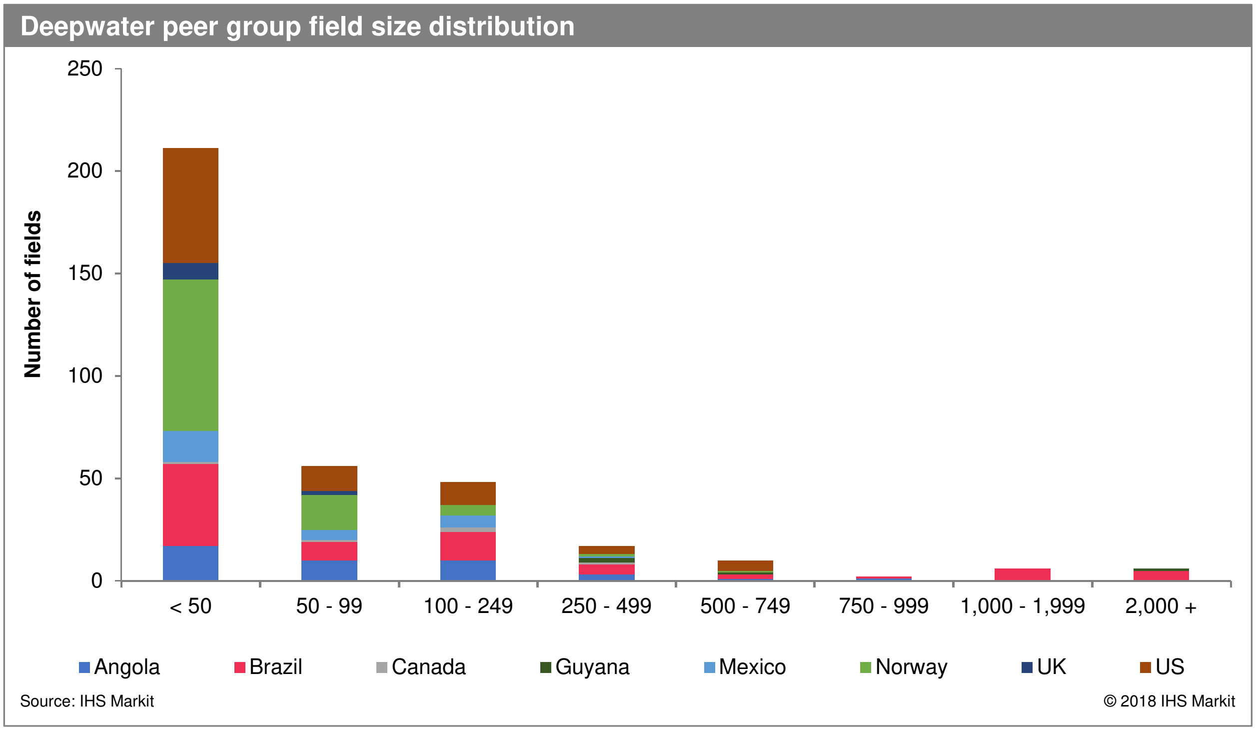

Figure 1-7. Deepwater peer group field size distribution

Upon review of the field distributions, IHS Markit selected the following deepwater field sizes for both oil and gas systems with cost adjustments for each jurisdiction:

- 50 MMboe
- 250 MMboe
- 500 MMboe.

1.2.2 Exploration and Development Cost and Price Scenarios

This study relies on typical exploration and development costs in each jurisdiction to account for differences in water depths, total vertical depth, well productivity, regional capital and operating costs, environmental or other regulatory compliance, and transportation costs.

Exploration well costs estimates were prepared for each reserve case for each jurisdiction. These estimates consider the water depth and reservoir depth characteristics for each jurisdiction while also accounting for rig type, local rig rates, and expected drilling times. The economic metrics calculated incorporate exploration success rates for each jurisdiction, which are based on the total number of discoveries since 2008 found in IHS Markit databases divided by the total number of new field wildcats drilled in that same time period. The chance of success calculated for each jurisdiction was used as a risk element in the models prepared for this study. The profiles modeled consider the exploration success rate in each jurisdiction. The NPV/boe, IRR and government take metrics in this study consider a full-cycle profile by grossing-up the cost of exploratory wells to include the average number of wells drilled per discovery. The expected monetary value (EMV) metrics in this study consider the risk involved when drilling a single exploration well to evaluate the decision operators make when investing in exploration. Appraisal costs are also included in each model. They are grossed-up on the same basis as the exploration cost in the full-cycle models, but apply an 80% chance of success of appraisal. Appraisal costs are considered in this way for all metrics.

The development concepts are assessed for each reserve case for each jurisdiction to reflect the respective environments and the types of platforms and facilities typically used. The selection of deepwater development concepts considers water depth, environmental conditions, local hazards, and common practices. Thus, the deepwater development concepts used for each jurisdiction are diverse and include gravity-based platform systems; semi-submersibles; floating production, storage, and offloading (FPSO) vessels; spar buoys; and near shelf subsea tie-backs to a fixed-shelf platform. Likewise, the existence of local infrastructure in each respective jurisdiction was taken into consideration to tie in most of the shallow water facilities and pipelines. The development concepts also take into account the level of existing infrastructure, existing and potential market locations, and the density of offtake capacity, which influence the amount of capital and operating expenses required to develop and produce a field.

IHS Markit's proprietary tools and databases are the basis for this analysis. The cost modeling software QUE$TOR™ was used to generate the full-cycle development cost models for this study. QUE$TOR™ is the world's leading software solution for new oil and gas project cost analysis, and is the industry standard tool for cost evaluation and concept optimization of new oil and gas field developments. QUE$TOR™ has been benchmarked against actual project costs and is continuously updated to reflect the latest changes in technology. QUE$TOR uses primary input data including recoverable reserves, gas and liquid ratios, reservoir depth, and water depth. It leverages IHS Markit basin data to generate a production profile that supports the development of concept and design flow rates.

Additionally, IHS Markit leveraged the data from IHS Markit products EDIN and ENERDEQ to determine the expected development parameters for each field model. EDIN is a global database of international E&P activity including the data for deep water U.S. Gulf of Mexico. ENERDEQ is a database that also tracks E&P activity for the U.S. shelf, onshore U.S., and onshore Canada. EDIN and ENERDEQ also provide data in the form of a geographical information system (GIS) allowing for the determination of distances and proximities to pipelines, platforms, markets, and other terminals.

The study uses three oil and gas price and cost scenarios in its economic models.[17] A global market price is used for crude oil and regional market prices are used for natural gas. For the sake of consistency, we used the IHS Markit base case crude oil and natural gas price outlooks for this study, given that the EIA does not provide outlooks for natural gas prices in Europe or Asia. See Figures 1-6 and 1-7 for IHS Markit and EIA price crude outlooks to 2050. See Figures 1-8 to 1-10 for the low, base, and high case price assumptions for crude oil and natural gas The study uses a variance of minus 40% and plus 60% from the base case for the low and high case scenarios, respectively. The selection of crude oil prices for this analysis is not intended as a forecast, but rather reflects the relatively wide range between the high and low commodity price ranges that have prevailed in the past decade.

[17] Economic models built for this study use a 10% real discount rate.

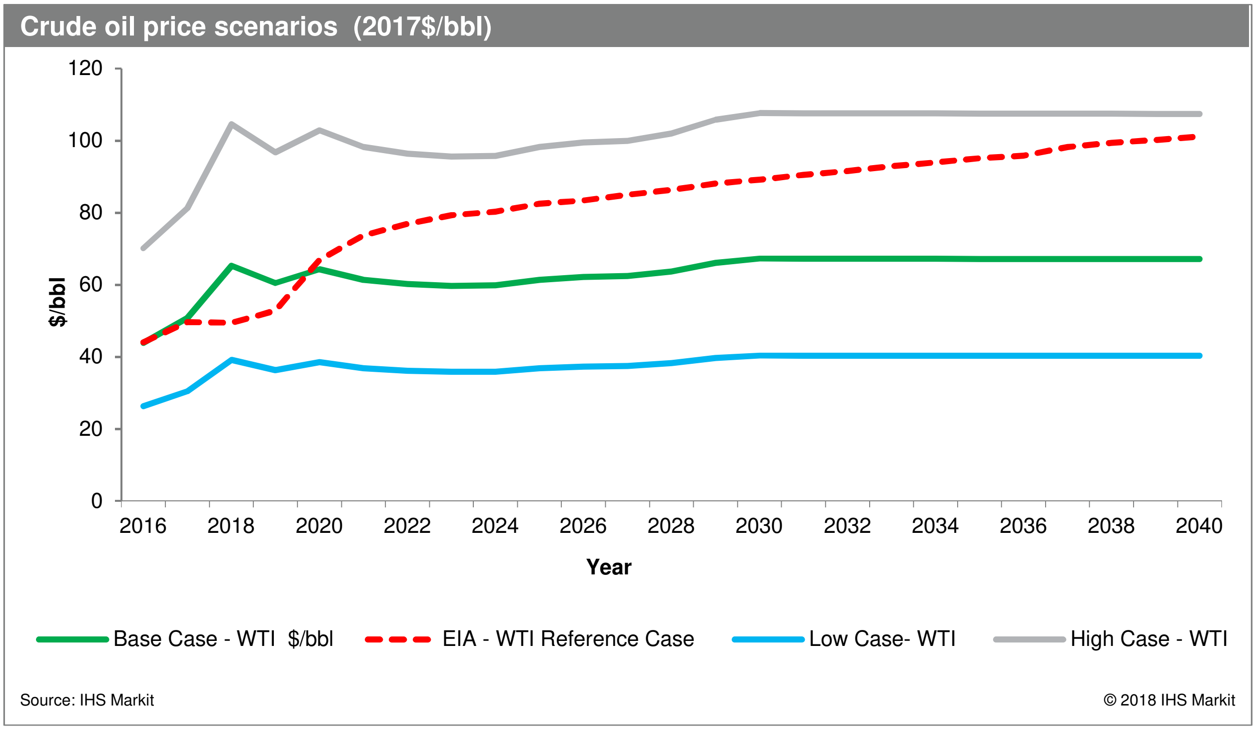

Figure 1-8. Crude oil price outlook: IHS (base case) vs. EIA (reference case), 2017$

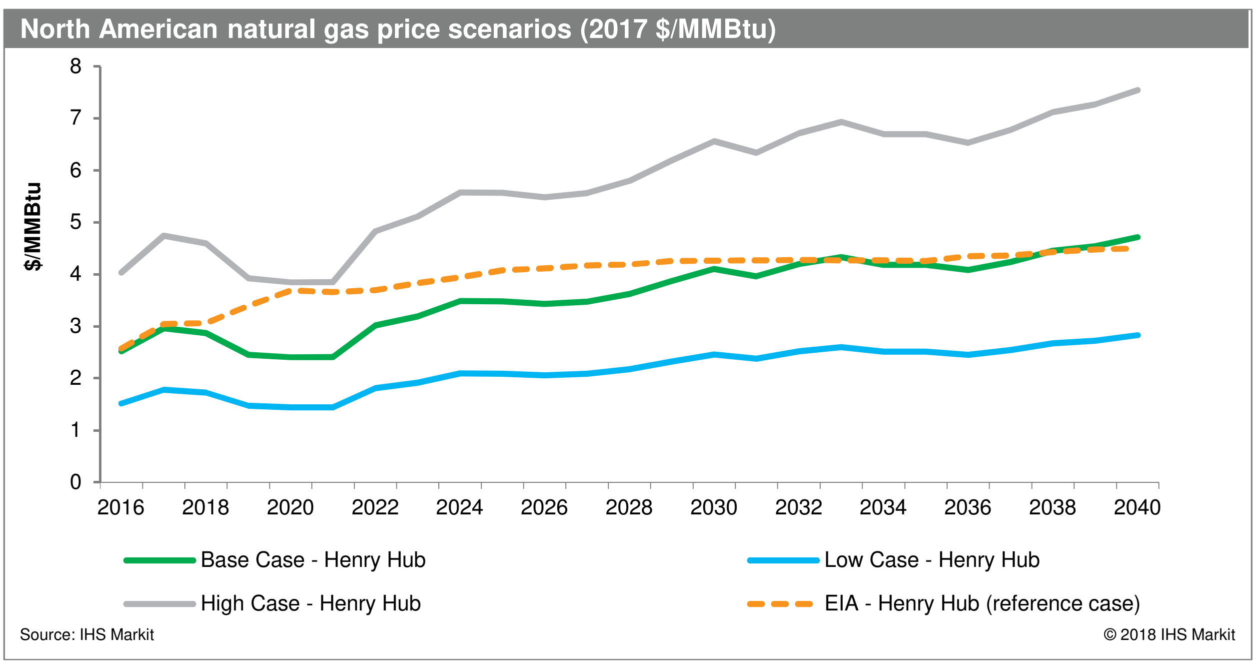

Figure 1-9: North American natural gas price scenarios

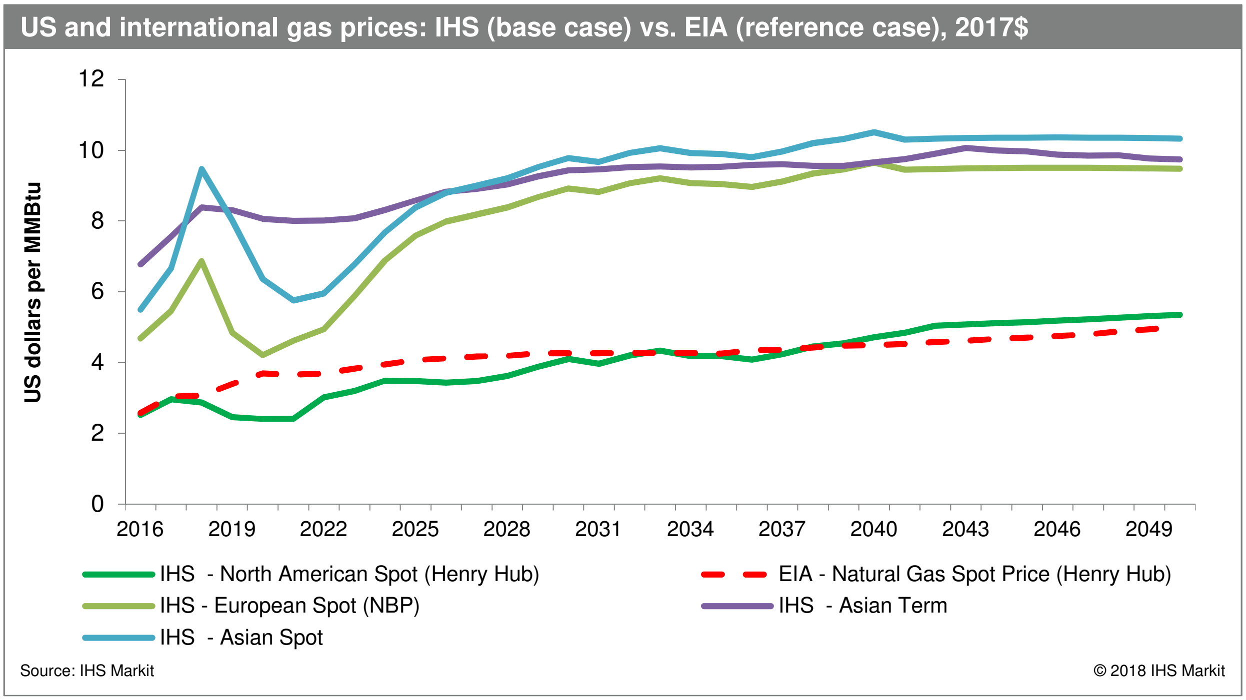

Figure 1-10. U.S. and international gas prices: IHS (base case) vs. EIA (reference case), 2017$

1.2.3 Organization of the Report

This report is organized into seven chapters.

Chapter 2 provides a qualitative assessment of fiscal, contractual, and lease terms applicable in the respective jurisdictions; acreage award criteria such as signature bonuses; work commitments and other factors; and E&P terms.

Chapter 3 examines the current E&P landscape, highlighting trends in licensing activity, exploration, yet-to-find resource potential, and exploration and development costs. Furthermore, this chapter provides an explanation and discussion of the policy decisions made by various jurisdictions, and provides insights on the competitive landscape in the future.

Chapter 4 analyzes trends in fiscal terms since the drop of commodity prices in 2014. The chapter focuses on changes in fiscal terms and industry response, as well as the policy initiatives to incentivize exploration, encourage investment in unsanctioned discoveries, late-life-asset strategies, and financial responsibility for decommissioning.

Chapter 5 provides a comparative analysis of fiscal terms such as government take, internal rate of return, NPV per barrel of oil equivalent, and expected monetary value. Fiscal systems are ranked on the basis of each individual metric.

Chapter 6 provides a detailed analysis of the fiscal systems alternatives for the U.S. shallow and deepwater Gulf of Mexico. This chapter examines the impact of each alternative fiscal system on the various indicators developed for this study, as well as any shift in ranking among the respective peer groups.

Chapter 7 finalizes the study’s conclusions.

2 Characteristics of Fiscal Systems Reviewed

2.1 Fiscal and Contractual/Lease Terms

The countries included in the shallow and deepwater peer groups for this study vary widely in terms of the types of fiscal systems adopted and the nature and range of fiscal levies. The fiscal systems adopted by each jurisdiction reflect government policies, and the relative prospectivity and maturity of its respective offshore E&P sector. While the shallow water jurisdictions selected for this study are similar in terms of maturity, the underlying philosophy within each jurisdiction varies widely regarding the following:

- Licensing and award criteria
- Degree of control exercised by the state in decisionmaking process
- Contractual mechanisms adopted
- Nature of taxes and quasi-fiscal levies
- Exploration and production terms.

The deepwater peer group is even more diverse than the shallow water one, as it represents a mixture of established and frontier basins. Different policies exist depending on the maturity of the basins, the resource potential, and the underlying national objectives and dependence on oil and gas resources. In addition to the cross-jurisdictional variation regarding contractual and fiscal terms, there are variations within the same jurisdiction with regard to applicable terms based on basin maturity and field economics.

Some jurisdictions, such as Angola, Brazil, and Mexico, have adopted more than one type of contract for the grant of rights in different areas or geological formations. From a revenue-sharing perspective, the same economic benefit can be achieved under any of the three major types of contracts—concessionary or royalty/tax system, production sharing, and service contracts. The decision to adopt different contractual and fiscal systems reflects the respective government’s decision related to the degree of control it wants to exert in the decisionmaking process with respect to areas that vary considerably in terms of prospectivity, terrain, and technological challenges associated with exploration for and development of hydrocarbons.

This chapter provides an overview of the contractual and fiscal terms applicable in the countries selected for the international comparison. A more detailed description of the terms by jurisdiction and type of contract is provided in Appendix A.

2.1.1 Types of Contractual and Fiscal Systems

The **concessionary or royalty/tax system** as referred to in this report is the oldest and the most widely used contractual type in the world. It has been adopted to allocate oil and gas leases by 121 countries at one point in time or another.[18] Under this system, the contractor carries the investment risk and acquires the title to all the hydrocarbons produced – usually at the wellhead. State revenues are derived from the levy of fees, rentals, bonuses, and royalties, and the various taxes applicable in the respective jurisdiction. The royalty and tax rates are generally specified in legislation and are the same for all investors, so there is no negotiation on the fiscal terms of the agreement. However, variations to the rule do apply. One example is when royalty is specified in the lease sale terms; it then becomes a contractual instrument, as in the case of U.S. Gulf of Mexico. Another example is when companies are required to offer an additional royalty to the state as a bid variable, as in the case of Mexico deepwater areas. The early leases signed offshore Newfoundland and Labrador also consisted of contractual royalties that were negotiated individually with

[18] Information has been assembled from a historical evolution of contract terms within IHS Markit PEPS service.

project proponents. The Canadian province, however, has moved away from that practice and has adopted a generic royalty regime that applies to all new oil and gas investments offshore.

In its purest form, royalty tax agreements consist of royalty and tax; in practice, wide variations exist. For instance, royalty may not always be a component of the fiscal regime, as in the case of the United Kingdom and Norway. In other cases, additional petroleum-specific levies and surcharges may apply, as in the case of Australia, Brazil, Norway, and the United Kingdom. What determines the type of system is the nature of rights granted, rather than the fiscal instruments adopted.

Production sharing contracts/agreements (PSCs/PSAs) are contractual rights to explore for and produce hydrocarbons within a specified area. This system has been used by 99 jurisdictions either as the only contractual mechanism available or as one of the options available to investors in the particular jurisdiction.[19] These agreements allow the government to share in the production and profits after costs have been deducted. Unlike the royalty/tax arrangements, in this type of contract, investors are not entitled to all hydrocarbons produced. Title to an investor's share of costs and profit passes at the delivery point, as defined in each respective agreement.

Like royalty/tax agreements, fiscal systems applicable under a PSA are rarely found in their pure form, consisting only of cost recovery, profit sharing, and income tax. Modern day PSAs are more complex and are often considered hybrids, as they typically adopt some elements from the royalty/tax system. It is quite common for modern day PSAs to include royalties, even though such contracts grant no ownership rights to hydrocarbons produced.[20] Brazil, Mexico, and Guyana are among the jurisdictions that incorporate royalties into their PSAs.

Service contracts and risk service contracts (RSC) are contractual mechanisms usually adopted by jurisdictions where the country's constitution prohibits investors from acquiring the title to hydrocarbons produced. However, exceptions apply in cases where these types of contracts are offered as one of the alternatives in the respective jurisdiction. Angola and Mexico offer RSCs alongside other contractual types. However, neither of these agreements has been incorporated in this analysis, as they are very limited and not widely used in Angola deepwater or Mexico offshore. These agreements have been used by 15 countries worldwide, either in their pure or hybrid form.[21] Under these types of contracts, particularly RSCs, investors carry all the risk and are repaid a service fee based either on a rate of return or on the volume of hydrocarbons produced. As with PSAs, the fiscal instruments used by these types of contracts often borrow from royalty/tax or the PSA regime. Table 2-1 shows the types of contractual and fiscal systems applicable in the respective jurisdictions analyzed in this comparative analysis.

Table 2-1. Contractual and fiscal systems adopted in shallow and deep water

Country	Contractual/fiscal system		
	Shallow water	Deepwater	Geological formation
Angola	PSA and RSA	PSA and RSA	-
Australia	Royalty/tax	Royalty/tax	-
Brazil	Royalty/tax	Royalty/tax and PSA	Post-salt v. pre-salt

[19] Ibid.
[20] Royalties are payments to the owner of mineral rights (i.e., the sovereign in the case of international jurisdictions), in exchange for ownership rights over hydrocarbons produced. When adopted under PSA, royalties lose their legal nature and become simply an instrument of taxation.
[21] See footnote 5.

Country	Contractual/fiscal system		
	Shallow water	Deepwater	Geological formation
Canada – NL	Royalty/tax	Royalty/tax	-
Guyana	-	PSA	-
Mexico	PSA	Royalty/tax	-
Norway	Royalty/tax	Royalty/tax	-
United Kingdom	Royalty/tax	Royalty/tax	-
United States	Royalty/tax	Royalty/tax	-

Source: IHS Markit

Brazil is the only jurisdiction among the ones selected for this study where the type of contract applicable is determined by the geological formation, rather than location. As the pre-salt polygon's significant resource potential became evident in the mid-to-late 2000s, the government of Brazil decided to adopt the production sharing regime for the pre-salt area to exert greater control over E&P investment decisions related to this area.

2.1.2 Key Components of Government Take

Fiscal systems evolve over time and often reflect the stage of the development of the oil and gas sector and shifting priorities and national policies. The recent changes introduced in the U.S. Gulf of Mexico and the United Kingdom reflect the mature nature of the basin. The design of the fiscal system reflects the sharing of risk between the government and the investors. Given the uncertainty of what lies underneath the ground, the associated risk is surrounding the revenue each party can generate within a certain fiscal design and the uncertainty surrounding the receipt of that revenue.[22] The components of government take generally fall into the following categories:

- Production-based levies
- Income- or profit-based levies
- Other fiscal and quasi-fiscal instruments.

This section examines some of the main fiscal instruments used in the fiscal systems covered in this study. Table 2-2 identifies some of the key fiscal instruments used by the respective jurisdictions. Additional levies and allowances apply to each of the countries reviewed. High-level summaries of the respective fiscal and contractual terms are shown in Appendix A.

[22] Tordo, Johnston, and Johnston, Countries' Experience with the Allocation of Petroleum Exploration and Production Rights, 12.

Table 2-2. Key fiscal instruments

Fiscal system	Bonus	Royalties	Corporate income tax	Special petroleum tax	Profit sharing	State participation
Angola – PSA	●			●	●	●
Australia – Royalty/tax	●		●	●		
Brazil – PSA	●	●	●		●	●
Brazil – Royalty/tax	●	●	●	●		
Canada NL – Royalty/tax		●	●			
Guyana – PSA	●	●			●	
Mexico – PSA		●	●		●	
Mexico – Royalty/tax		●	●			
Norway – Royalty/tax			●	●		●
UK – Royalty/tax			●	●		
U.S. GOM – Royalty/tax	●	●	●			

Source: IHS Markit

2.1.2.1 Production-Based Levies

Royalty is payable to the government or national oil company under royalty/tax fiscal systems and production sharing regimes. They are a means used by governments to generate revenue upfront. As such they are regressive in nature (i.e., government take has a reverse relationship with project profitability). The basis for royalty payments varies among jurisdictions. The most common types include flat-rate royalties and sliding scale royalties.

Flat-rate royalties: Usually levied as a percentage of production or of the proceeds from the sale of hydrocarbons. Allowances for transportation of crude oil and natural gas to liquid markets, as well as processing of natural gas often apply. A high, flat-rate royalty exacerbates the regressive nature of this levy as the royalty is applied at the same percentage regardless of the profitability of the field. Flat-rate royalties have been adopted by Brazil, Guyana, and the U.S.

Sliding scale royalties: They are designed to enable the resource holder (i.e., the government) to capture the upside when revenues increase and soften the burden on investors when revenues decline. The basis for sliding scale royalties can be as follows:

- **Production thresholds:** Levied on a gross or incremental basis when production reaches specified thresholds.
- **Commodity price:** Based on a formula that fluctuates with commodity prices. Separate rates and price thresholds are set for crude oil and natural gas. Of the jurisdictions surveyed in this study, Mexico is the only one that has adopted this type of royalty.
- **Net revenue:** Based on project cost recovery and profitability with progressive royalty rates linked to the ratio of cumulative revenue over cumulative project costs, referred to as the R-factor. This is the system adopted by the provinces of Newfoundland and Labrador.

Royalties tend to increase the marginal cost of extracting oil and gas and can discourage the development of marginal fields, leading to early abandonment of producing oil and gas assets. Hence, some jurisdictions such as the United Kingdom and Norway have abolished royalties altogether. Others tend to lower them in the case of marginal fields—Brazil is a case in point. The U.S. also has a discretionary royalty relief—end-of-life royalty relief—for late-life assets and a special case relief when the existing royalty relief programs do not provide adequate encouragement to increase production or development.

Royalties are usually tax deductible under both production sharing and concessionary systems. Under a production sharing system, royalty is not a recoverable cost for profit sharing purposes. Table 2-3 contains the range for royalties levied in each jurisdiction.

Table 2-3. Offshore royalty rates

Jurisdiction	Royalty rate
Angola	-
Australia	-
Brazil	10%
Canada - NL	1–50%
Guyana	2%
Mexico	7.50–16.5%
Norway	-
United Kingdom	-
United States	12.5–18.75%

Notes: Newfoundland and Labrador offshore royalty is levied on net revenues, as opposed to gross proceeds applicable for other jurisdictions. The gross proceeds royalties do, however, allow for deduction of transportation costs for oil and gas.

Source: IHS Markit

2.1.2.2 Income or Profit-Based Levies

Income tax: This is the most common levy and often not specific to the oil industry. A few jurisdictions, however, exempt the oil industry from the generally applicable corporate income tax and impose a petroleum income tax instead. Among the jurisdictions selected for this study, Angola adopts this approach, subjecting oil and gas investments to petroleum income tax as opposed to the general corporate income tax (Table 2-4). Revenue accruing to the government under this mechanism is deferred by allowances for operating expenses and depreciation. Incentives such as accelerated tax depreciation, depletion allowances, and tax credits are often part of the fiscal systems. Examples of incentives provided by the jurisdictions reviewed include the following:

- **First-year allowances:** Enables corporations to deduct up to 100% of the cost of qualifying capital expenditures made during the year the equipment was first purchased. Among the jurisdictions surveyed, the United Kingdom and U.S. offer such allowances.
    - **UK first-year allowance:** Introduced under the Finance Act of 2002, it provides a 100% allowance for "first-year qualifying expenditure" for E&P activities in the North Sea. First-year allowances include the following:
        - Plant and machinery
        - Mineral exploration and access.
    - **U.S. first-year bonus depreciation:** Introduced under the Tax Cuts and Jobs Act, it provides a 100% deduction in the first year that the property was acquired for qualified property acquired and placed in service after September 27, 2017, and before January 1, 2023.
- **Accelerated depreciation:** Usually allows for a more accelerated rate of depreciation than book or financial depreciation.

- **U.S. accelerated depreciation:** A double-declining balance method of depreciation is applied to tangible capital spent depending on the number of years of life expected from the asset or depending on the asset class category in which the capital item falls. Double-declining balance is a form of accelerated depreciation.

- **Treatment of Tangible Cost:** Tangible costs are depreciated or expensed in most regimes and can be described as asset that have a useful life or monetary value that exceeds one year. The duration of depreciation is often based on the useful life of the asset, but can be prescribed by tax code in some cases.
    - **U.S. treatment of tangible costs:** The U.S. applies a double-declining balance method of depreciation which is applied to tangible capital spent depending on the number of years of life expected from the asset or depending on the asset class category into which the capital item falls. According to the Internal Revenue Service, the double-declining balance method applied is called the Modified Accelerated Cost Recovery System and is used to recover the basis of most business and investment property placed in service after 1986. A half-step or half-year phase shift is applied to the annual depreciation amounts to account for mid-year spending.
    - **UK treatment of tangible costs:** The UK does not distinguish between tangible and intangible costs. Most oil and gas exploration and development capital costs are expensed.
- **Treatment of Intangible Cost:** Intangible costs are expenditures on items that have a useful life of less than one year. Often these are services or consumables, but can include much of a well's cost. These costs include exploration and intangible development drilling costs. Intangible drilling costs as a percentage of drilling costs vary widely.
    - **U.S. treatment of intangible costs:** In the U.S., intangible costs are generally expensed in the year they are incurred. There are some limitations that apply to certain company structures. Intangible costs may also be capitalized at the election of the taxpayer.

Table 2-4. Nominal income tax rates (peer group)

Jurisdiction	Nominal income tax rate
Angola	50%
Australia	30%
Brazil	34%
Canada - NL	30%
Guyana	40%
Mexico	30%
Norway	23%
United Kingdom	30%
United States	21%

Note 1: In the case of Guyana, the income tax liability of the oil and gas investors is discharged by the state out of the state's share of profit oil.

Note: 2 The applicable income tax rate for Angola and the United Kingdom is different from the generally applicable corporate income tax rate in the respective jurisdictions. The corporate income tax rate in the United Kingdom for the 2018 tax year was 19%. However, income from oil and gas activities in the North Sea is ring-fenced and taxed at 30%. In Angola, the corporate income tax rate is 30%; however, income from oil and gas exploration and production activities is subject to a petroleum income tax of 50%.

Source: IHS Markit

Special petroleum taxes: Such taxes are usually levied in addition to income tax and are designed to provide the government with a share of the upside of revenue from oil and gas investments. Similar to income tax, they are back-end loaded and shift the revenue risk to the government. They can be levied on the same basis as income tax with additional credits or allowances, as in the United Kingdom, Norway, and Australia, or they may be linked to production volumes and applied at progressive rates on net revenue before income as is the case of Brazil. Table 2-5 shows the range of special petroleum taxes in the jurisdictions covered in this study.

Table 2-5. Nominal additional petroleum tax rates (peer group)

Jurisdiction	Nominal additional petroleum tax rate
Angola	-
Australia	40%
Brazil	10%-40%
Canada - NL	-
Guyana	-
Mexico	-
Norway	55%
United Kingdom	10%
United States	-

Source: IHS Markit

Special petroleum taxes often have the same tax basis as the corporate income tax, with some additional allowances specific to such taxes. Notable incentives or allowances for special petroleum taxes include:

- **Field or basin allowances:**
    - **UK basin-wide investment allowance:** Shields an amount equal to 62.5% of capital expenditure of corresponding taxable income from the supplementary charge. This allowance is granted in recognition of the significant capital costs of North Sea projects.
    - **UK cluster area allowance:** Operates alongside the basin-wide investment allowance. Cluster area allowance is equal to 62.5% of the qualifying expenditure in relation to a cluster (ultra-HPHT discovery, which may contain more than one discrete field). Expenditure that already qualifies for cluster area allowance does not qualify for basin investment allowance.
- **Uplift for capital and operating expenditure:**
    - **Norway uplift for development costs:** Currently applied at 5.3% over four years (for a total of 21.2%) on development costs, resulting in depreciation at a rate of 121.2%.
    - **Australia uplift for capital and operating expenditure:** Exploration expenditure are uplifted at the long-term bond rate (LTBR) plus 15%, while general project expenditure is uplifted at LTBR plus 5%. The uplift is applied annually on the un-deducted cumulative expenditure from previous years. For 2018, the LTBR for PRRT was 2.7%.

Profit sharing mechanisms: This fiscal instrument is often used with PSAs and provides for the sharing of profits between the government and investor after recovery of allowable costs. To minimize revenue risk for the government, a cost recovery ceiling generally applies. This instrument is an implicit royalty that ensures that the government gets a share of the revenue upfront. Profits may be shared on sliding scales based on production volumes, rate of return, or revenue-cost ratio. When designed as a resource rent tax (for example, when profits are being shared between the government and the investor after the project has reached a specified rate of return), this levy shifts all the revenue risk to the government. Table 2-6 provides the indicative cost recovery ceilings and share allocated to the host government under the respective production sharing systems.

Table 2-6. Production sharing mechanisms (peer group)

Jurisdiction	Cost recovery ceiling	Government profit share
Angola	50%	20-70%
Australia	-	-
Brazil	65%	12-75%
Canada NL	-	-
Guyana	75%	50%
Mexico	60-80%	24-65%

Jurisdiction	Cost recovery ceiling	Government profit share
Norway	-	-
United Kingdom	-	-
United States	-	-

Source: IHS Markit © 2018 IHS Markit

The following profit sharing mechanisms were adopted by jurisdictions included in this study:

- **Sliding scale based on IRR:** Adopted by Angola and Mexico for shallow water acreage
- **Sliding scale based on crude oil price and daily production volumes:** Adopted by Brazil for pre-salt areas
- **Flat rate:** Adopted by Guyana.

Special allowances may apply to cost recovery provisions. In the case of Angola, a 20% uplift is applied to recovery of development costs, effectively resulting in 120% recovery of such costs.

State participation: This is an instrument used by governments that wish to share in the revenues from upstream projects, exercise greater control over natural resources, and facilitate transfer of technology and knowledge by taking an equity interest in the upstream oil and gas investment. This type of participation can be either on a working interest basis (where the government, through the national oil company, pays its share right from the start) or on a carried interest basis (where the investor carries the national oil company through exploration and sometimes through development also). In the latter case, the government pays its share of exploration and/or development costs through proceeds from its profit share. Table 2-7 shows the range and type of state participation.

Table 2-7. State participation

Jurisdiction	State Participation	Type of Interest	Timing of Participation
Angola	20%	Carried	Discovery
Australia	-	-	-
Brazil	30%	Working interest	Exploration
Canada NL	10%	Working interest	Exploration
Guyana	-	-	-
Mexico	-	-	-
Norway	20-33.6%	Working interest	Exploration
United Kingdom	-	-	-
United States	-	-	-

Source: IHS Markit © 2018 IHS Markit

2.1.2.3 Other Fiscal and Quasi-Fiscal Instruments

Governments capture revenue from oil and gas investments through various other fiscal and quasi-fiscal instruments. Additional levies observed in this comparative analysis include the following:

Taxes on profits transferred abroad: Australia's diverted profits tax falls in this category. It applies to profits of multi-national corporations that transfer profits generated in Australia and send them to offshore jurisdictions.

Carbon tax: Norway and Canada have adopted taxes/policies that target greenhouse gas emissions. Norway's system consists of a tax on carbon dioxide (CO_2) emissions from the continental shelf. The Canadian government introduced the Pan-Canadian Framework on Clean Growth and Climate Change, which requires all provinces to have carbon pricing initiatives by 2018. However, the governments of

Newfoundland and Labrador have yet to introduce carbon pricing mechanisms for oil and gas projects at the time of this study.

Bonuses and other fees: This category includes quasi-fiscal instruments such as bonuses, rentals, training, research and development, social contribution, and environmental fees.

- **Signature bonuses**: Adopted by jurisdictions where a cash bonus is a bid factor. They are non-recoverable costs under production sharing regimes. More information on bonuses payable is included in Section 2.2, Acreage Award Criteria, of this report.
- **Training fees**: Usually offered as a payment for training of national government staff involved in the supervision and administration of petroleum agreements. Training fees are less common than signature bonuses. Angola and Guyana adopted training fees in their respective PSAs. Such payments are usually associated with the exploration period, typically around USD300,000. In exceptional cases, as in the case of Angola, they extend to the production period.
- **Rental**: Annual rental payments apply in the majority of the jurisdictions surveyed. They usually apply during the exploration phase; however, exceptions to the rule apply, for example in Mexico and the United Kingdom, rentals are payable during the production period.
- **Research and development:** Angola and Brazil are among the jurisdictions that adopted this type of levy. In the case of Angola, the fees are paid during the first four years of the contract and range from USD75 million to 100 million annually. Such a fee is applied to funding the Sonangol Research and Technology Center. In Brazil, the fee is payable during the production period and consists of 1% of gross revenues from oil and gas production. Up to 50% of the fee is dedicated to universities and research and development institutes in Brazil.
- **Social contribution:** A negotiable/biddable fee is offered as contribution for social projects in Angola. In Brazil, however, the social contribution fees take the form of a tax, and are not specific to the oil and gas industry. Social contribution for welfare programs (COFINS) is levied at 7.6% of gross revenue, whereas Social Integration Program Contribution (PIS) is levied on gross revenues at a rate of 1.65% and used to fund unemployment and insurance programs.
- **Environmental fees:** Newfoundland and Labrador levy fees for an Environmental Studies Research Fund that is established annually and varies by region. For 2018, such fees ranged between USD0.31 and 0.54 per hectare. In Guyana, the contractor is required to contribute USD300,000 annually towards environmental and social projects to be agreed upon with the Minister.

2.2 Acreage Award Criteria

Governments allocate oil and gas E&P rights primarily through two types of systems: (1) a competitive bidding process and (2) an open-door or direct negotiation. Sometimes a combination of the two is used, where competitive bidding is followed by direct negotiation. Competitive bidding, a transparent process with clearly defined award criteria, is the most common form of allocating E&P rights worldwide. Out of the nine countries selected for the international comparison in this study, eight rely on a competitive bidding process. Guyana and recently Brazil are the only jurisdictions among those analyzed in this study that have adopted the open-door policy.[23]

[23] Brazil's open-door policy is in addition to regular licensing rounds scheduled for standard and pre-salt areas.

Open-door policy: Under this system, governments do not always set predefined deadlines for submission of bids, and the award criteria are often undefined and are not known to market participants in advance.[24] The model contract sets forth the basic terms for the agreement and acts as a first offer.[25] The model contract also sets forth the negotiable aspects of the E&P rights, often fiscal terms such as royalty, cost recovery, profit sharing, bonuses, and work commitments. This acreage allocation system has received a lot of criticism for its lack of transparency.

Competitive bidding: The competitive bidding process usually falls into two categories:

1. Discretionary allocation: In this system, the government is allowed some discretion in the award of E&P rights. Adopted by the United Kingdom and Norway, this system allows the government to consider the applicant's ability to comply with the goals sought to be obtained in the specific licensing round.
2. Auctions: In this system, acreage is awarded to qualified bidders solely on the basis of competitive sealed bids. A set of fixed and variable bid criteria are established in advance, with the award going to the highest bid.

Although the licensing policies adopted by the majority of jurisdictions surveyed fall within the two broad categories of competitive bidding process, their approaches differ with respect to frequency of licensing process and award criteria. Table 2-8 shows the licensing process adopted by each jurisdiction.

Table 2-8. Allocation systems for award of exploration and production rights

Jurisdiction	Allocation System			Licensing Frequency
	Open Door	Competitive Bidding		
		Discretionary Allocation	Auction	
Angola			●	Irregular
Australia		●	●	Annual
Brazil	●		●	Annual
Canada - NL		●		Annual
Guyana	●			Irregular
Mexico			●	Annual
Norway		●		Annual
United Kingdom		●		Biennial
United States GOM			●	Biannual

Source: IHS Markit

The frequency of licensing rounds and the extent of areas offered in each jurisdiction reflect each government's policies regarding the development of their natural resources. Generally, the jurisdictions surveyed license acreage pursuant to regular pre-determined schedules, although Angola and Guyana are exceptions to the rule. As an emerging oil and gas province, Guyana is still in the process of defining its policy. In this early stage, there has been no formalized process for issuance of oil and gas rights. Angola, on the other hand, as a member of the Organization of Petroleum Exporting Countries, has policy objectives that differ from the objectives of the other jurisdictions analyzed in this study. Unlike the U.S., the UK,

[24] Tordo, Silviana, David Johnston, and Daniel Johnston. "Countries' Experience with the Allocation of Petroleum Exploration and Production Rights: Strategies and Design Issues." World Bank Working Paper No. 179.
[25] Smith E., Dzienkowski J., Anderson O. et al, International Petroleum Transactions, 2nd Ed. 2000, p 394.

Australia, and other regimes where government policies tend to balance expeditious development of the oil and gas resources with environmental safeguards and receipt of a fair share of the revenues for the nation, Angola's oil and gas policy focuses on revenue maximization for the state and the national oil company. This policy has often led to irregular offerings of acreage with periods of high and low investments. On a few occasions, Angola has withdrawn acreage from licensing rounds when commodity prices dropped. Table 2-9 lists the oil and gas licensing objectives of the jurisdictions analyzed in this study.

Table 2-9. Oil and gas licensing objectives

Jurisdiction	Licensing objective
Angola	To maximize the economic interests of the State and of Sonangol as concessionaire and investor.[26]
Australia	To create a policy framework that expands Australia's resource base, increases the international competitiveness of the resources, and improves the regulatory system consistent with principles of environmental responsibility and sustainable development.[27]
Brazil	Ensure rational use of the country's resources to accomplish the following:[28] • Preserve the nation's and consumer's interests • Foster expansion of energy resources • Protect the environment • Ensure supply of oil by-products nationwide • Increase the country's international competitiveness.
Canada – NL	Canada: To promote an open, competitive tax and investment regime for energy resource development. NL: - Up until recently, NL's objectives were as follows: • Secure an attractive rate of return • Give preference to local business and employment in operations • Maintain a controlled rate and manner of development. However, the new land tenure system introduced by NL seeks to expedite development of oil and gas resources.
Guyana	To balance multiple competing interests of public and private entities, and enable growth of the sector while supporting the efficient, safe, and orderly development of energy resources while minimizing the environmental footprint of the sector. [29]
Mexico	To increase oil and gas production, and increase reserves whilst encouraging investment and more employment opportunities.[30]
Norway	To generate the greatest possible values from the resources on the Norwegian shelf in the best interest of the Norwegian society.[31]
UK	Maximizing the economic recovery of hydrocarbon resources whilst ensuring a fair return on those resources for the nation. A 'fair return' implies that a share of the profits should be retained for the nation, whilst ensuring returns on the private investment needed to exploit these resources is sufficient to make extraction activity commercially attractive.[32]

[26] IEA, Angola, Towards an Energy Strategy, 2006, p82.
[27] Tina Hunter, *Review of the Australian Petroleum Sector: Submission to the Australian Productivity Commission*, (2009). Canvassing the following key objectives of the regulatory framework related to development of oil and gas resources in Australia: (1) Offer high levels of certainty to investors and other stakeholders about their rights and responsibilities and the process of decision making: (2) Provide a highly competitive operating environment, in an economic sense, (3) Ensure good stewardship of the environment and community interests, (4) Allow industry to respond confidently to international challenges and seize international trade and investment opportunities.
[28] Petroleum Law (Law 9,478/97)
[29] Government of Guyana, Draft National Energy Policy of Guyana, Report 2, Greenpaper, p16.
[30] SENER, Five Year Plan for Exploration and Production of Oil and Gas Bids 2015-2019.
[31] Ministry of Petroleum and Energy, Facts 2014: The Norwegian Petroleum Sector, 2014, p5.
[32] HM Treasury: Review of the oil and gas fiscal regime: call for evidence, July 2014, p16.

Jurisdiction	Licensing objective
U.S. – GOM	Goals of the Outer Continental Shelf Lands Act include the following:[33] Promotion of expeditious and orderly development of the outer continental shelf (OCS) resources, subject to environmental safeguards, in a manner that maintains: competition and national needs, receipt of fair market value for the lands leased and the rights conveyed, equitable sharing of developmental benefits and environmental risks among the various regions.

Source: IHS Markit

In awarding acreage to oil and gas investors, the countries surveyed rely on one or more bid variables. Across the board, signature bonuses and work commitments are the most commonly used variables, followed by state profit share in the case of PSAs. Table 2-10 shows the bid variables applicable in each jurisdiction.

Table 2-10. Acreage award criteria

Fiscal system	Cash bonus	Work commitment	State profit share	Social contribution	Additional royalty	Additional investment factor	Tie-break bonuses
Angola – PSA	●	●	●	●			
Australia – Royalty/tax	●						
Brazil – PSA	●		●				
Brazil – Royalty/tax	●	●					
Canada NL – Royalty/tax		●					
Guyana – PSA	●		●				
Mexico – PSA			●			●	
Mexico – Royalty/tax					●	●	●
Norway – Royalty/tax		●					
UK – Royalty/tax		●					
U.S. GOM – Royalty/tax	●						

Source: IHS Markit

2.2.1 Cash Bonus Bidding

Cash bonuses guarantee the resource holder revenue regardless of the success or failure of exploration efforts. As such, they contribute to the regressivity of the fiscal system. They are used frequently in awarding acreage in areas with high probability of success and/or sufficient information available.[34] The range of bonuses payable varies widely among the jurisdictions surveyed, as well as within the areas offered in each jurisdiction. Brazil's pre-salt area has by far attracted the highest signature bonus payments per block, as well as on a per square kilometer (km^2) basis. Bonuses payable in other jurisdictions, including Brazil's post-salt area, on average range between USD400/km^2 and 75,000/km^2. Table 2-11 lists the bonus amounts payable in recent licensing rounds in the respective jurisdictions, along with the average lease sizes awarded and the average amount paid per km^2.

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[33] Outer Continental Shelf Lands Act, 43 U.S.C. 1331 *et seq*

[34] Tordo, Johnston, and Johnston, Countries' Experience with the Allocation of Petroleum Exploration and Production Rights, 19.

Table 2-11. Bonus payments

Fiscal system	Bonus (MM USD per contract/lease)	Block sizes (km^2)	Average $/km^2
Angola – PSA	10 - 400	3,500 – 7,500	40,000
Australia – Royalty/tax[35]	4	10,000	500
Brazil – PSA	100 – 15,000	700 - 880	1,250,000
Brazil – Royalty/tax	26 - 90	700 - 850	75,000
Canada NL – Royalty/tax	-	1,200 – 3,700	
Guyana – PSA	18	6,000 – 17,000	1,000
Mexico – PSA	-	300 – 1,000	
Mexico – Royalty/tax	-	300 – 3,200	
Norway – Royalty/tax	-	100 – 3,800	
UK – Royalty/tax	-	100 – 2,300	
U.S. GOM – Royalty/tax	0. 144 - 25	23.3	46,000

Source: IHS Markit

Bonuses have been payable in Mexico's licensing rounds only as tie-breakers for winning bids.

2.2.2 Work Commitments

Under work program bidding, companies commit to carry out a specified work program during the initial and subsequent phases of the exploration period. In some jurisdictions, work program bidding is associated with a minimum expenditure commitment that can be claimed by the resource holder in case the investor fails to carry out part of or the entire proposed work program. Usually the work commitments involve seismic acquisition and processing in the early stages of exploration period with a drill-or-drop provision for the later stages of the exploration phase. In Mexico, the government specifies the minimum work program, however, the companies are expected to offer additional work commitments in the form of an investment factor as one of the bid variables for deepwater acreage. Work commitment bidding usually requires the resource holder to offer much larger areas than the ones offered in the U.S. Gulf of Mexico. More information on work commitments in each jurisdiction is included in Appendix A.

2.2.3 Other Bid Factors

2.2.3.1 State Profit Share

Under production sharing systems, profit sharing is frequently used as a bid factor. State profit share alone or combined with a cost recovery ceiling is a significant source of revenue for resource holders under production sharing systems. Licensing systems utilizing PSAs in the jurisdictions covered in this study (e.g., Angola deepwater, Brazil deepwater pre-salt areas, Guyana deepwater, and Mexico shallow water) included state profit share as a bid variable. See Table 2-6 for further information on the range of state profit share offered in each jurisdiction.

[35] In the case of Australia, cash bonus bidding is limited to a few blocks per licensing round. The majority of the acreage is offered under work commitment bidding.

2.2.3.2 Additional Royalty

Under this approach, the investor offers the resource holder a biddable royalty in addition to the statutorily prescribed royalty rates. This mechanism is not very common. Among the jurisdictions reviewed, Mexico is the only one that adopts this approach for deepwater acreage.

2.3 Exploration and Production Terms

2.3.1 Block Sizes

A major factor in determining the pace of E&P activity is the size of acreage offered to individual investors. In frontier areas, the size of the blocks tends to be larger. As more information is gained through seismic and other drilling activity, governments tend to reduce the size of the blocks offered. For example, Mexico's government offers larger lease blocks in its deepwater areas than in its shallow water areas. From a government perspective, smaller blocks enable more E&P activity to occur simultaneously. Governments often correct for large block offerings through intermittent relinquishment obligations that allow them to re-license the relinquished areas. Table 2-12 includes information on range of block sizes in each jurisdiction.

Table 2-12. Size of exploration blocks

Fiscal system	Range of block sizes (km^2)	Average block size (km^2)
Angola – PSA	3,500 –7,500	5,000
Australia – Royalty/tax[36]	6,400 – 10,000	8,000
Brazil – PSA	700 - 880	800
Brazil – Royalty/tax	700 - 850	800
Canada NL – Royalty/tax	1,200 – 3,700	2,260
Guyana – PSA	6,000 – 17,000	12,000
Mexico – PSA	300 – 1,000	540
Mexico – Royalty/tax[37]	300 – 3,200	2,000
Norway – Royalty/tax	100 – 3,800	500
UK – Royalty/tax	100 – 2,300	250
U.S. GOM – Royalty/tax	23.3	23.3

Source: IHS Markit

2.3.2 Contract Duration

The timeframe allowed for exploration activities by the jurisdictions in the shallow water peer group ranges from 5 years[38], in the case of U.S., to 16 years, in the case of Australia. On average, such contracts are

[36] In the case of Australia, cash bonus bidding is limited to a few blocks per licensing round. The majority of the acreage is offered under work commitment bidding.
[37] On March 2, 2017, Mexico's Energy Ministry (SENER) issued an update to the Five-Year Licensing Plan, 2015-2019, which had been originally published in October 2015. Under the revised plan, Mexico intends to standardize future block sizes to 1,000 km^2 for deepwater and 400 km^2 for shallow water areas.
[38] The OCS Lands Act provides that "[a]n oil and gas lease issued pursuant to this section shall…be for an initial period of five years; or not to exceed ten years where the Secretary finds that such longer period is necessary to

awarded for an 8-year period, with an initial period of 3–5 years.[39] The majority of the jurisdictions have a cap on the duration of the production period, with the exception of Australia and the U.S. where the production period extends for the useful life of the field—or as long as oil and gas is produced in paying quantities. Table 2-13 contains information on E&P periods for the shallow water peer group.

Table 2-13. Shallow water contract duration

Shallow water	Exploration period				Production period	
	Initial period	1st extension	2nd extension	3rd extension	Initial period	Extension
Australia	3	3	5	5	field life	
Brazil	4	4			27	
Mexico	4	2			20	5
Norway	10				30	20
United Kingdom	4	4			18	
United States - (water depth < 400m)	5	3			field life	
Note: The additional three-year period for United States is only in the case of ultra-deep wells.						

Source: IHS Markit

Some jurisdictions tend to offer longer contract periods for deepwater versus shallow water areas. The U.S. has adopted different initial exploration periods depending on water depth. For water depths less than 1,600m, the extension of exploration period from the initial terms of five or seven years is contingent on the drilling of an exploratory well. This approach helps ensure more diligent exploration and is aligned with the drill-or-drop approach used by other jurisdictions in this peer group. Under the drill-or-drop approach, companies are required at a certain stage of the exploration period to either drill a well or relinquish the entire lease/contract. The drilling of a well in such case is a pre-requisite to proceeding with additional phases of the exploration period. Table 2-14 provides a summary of E&P periods for deepwater acreage.

Table 2-14. Deepwater contract duration

Deepwater	Initial exploration period	Extension of exploration period	Initial production period	First extension of production period	Second extension of production period
Angola	5	3	25	-	-
Brazil	4	4	27	-	-
Canada - NL	6	3	25	field life	-
Guyana	7	3	20	10	-
Mexico	4	2	16	10	5
Norway	10		30	20	-
United Kingdom	4	4	18	-	-

encourage exploration and development in areas because of unusually deep water or unusually adverse conditions." 43 USC 1337(b).

[39] Initial period under international E&P contracts is not the same as the primary terms in the U.S. The term exploration period would be the international equivalent for the primary term. The exploration period quite often is subdivided into an initial period and subsequent extensions.

Deepwater	Initial exploration period	Extension of exploration period	Initial production period	First extension of production period	Second extension of production period
United States - (water depth 400-800m)	5	3	field life	-	-
United States - (water depth 800-1,600m)	7	3	field life	-	-
United States - (water depth 1,600m +)	10		field life	-	-

Source: IHS Markit

2.3.3 Relinquishment Obligations

Host governments can impose mandatory relinquishment requirements upon completion of each exploration phase and again at the end of the exploration period to ensure that acreage is not locked up for an extended period of time with little to no investment. This allows the host government to reoffer acreage to future investors and encourage a higher level of activity in the petroleum sector. Relinquishment obligations vary among jurisdictions.

A common practice is for an investor to be required to relinquish 25–50% of its contract area upon conclusion of the first or second phase of exploration, with the remainder of the contract area (excluding the area it intends to develop under an approved development plan) being relinquished at the end of the exploration period. Such practice is necessary to help ensure diligent development, especially given the size of the acreage covered under a license or PSA internationally. The U.S. does not impose any relinquishment obligations, largely due to the relatively small size of the blocks in the Gulf of Mexico. Table 2-15 provides a high-level summary of relinquishment obligations in each jurisdiction.

Table 2-15. Relinquishment obligations

Jurisdiction	Exploration period			
	End of initial period	End of 1st extension	End of 2nd extension	End of exploration period
Angola	-	-		Relinquish all areas except development area
Australia	-	50%	50% of remaining area	50% of remaining area until a minimum of 16 blocks is reached
Brazil	-	-		Relinquish all areas except development area
Canada - NL	-	-	-	n/a
Guyana	20%	-	-	-
Mexico	50%			Relinquish all areas except development area
Norway				Relinquish all areas except development area
United Kingdom	-	25%	-	50% of original area must be relinquished
United States	-	-	-	-

Source: IHS Markit

2.3.4 Domestic Market Obligations

Domestic market obligations are provisions contained in hydrocarbon legislation, oil and gas contracts, or concession agreements that require the contractor to sell a prorated portion of their production in the domestic market in case of a shortfall. Such obligations are usually not problematic when the contract or the legislation in force provides for international market value for hydrocarbons subjected to the domestic market obligation. The provision can become burdensome, and is an indirect means of taxation, when the investor is required to sell the crude oil or natural gas below market prices. The domestic market obligations found in some of the jurisdictions included in this analysis do not appear to impose any obligations to sell below market prices. Table 2-16 provides a high-level summary of domestic market obligations.

Table 2-16. Domestic market obligations

Jurisdiction	Domestic market obligations	Cap on amount supplied	Market value
Angola	Yes	Up to 40% of total production	Yes
Australia	No	-	-
Brazil	Yes (only in emergency)	-	Yes
Canada - NL	Yes	-	Yes
Guyana	Yes	Prorated - not to exceed contractor profit share	Yes
Mexico	No	-	-
Norway	Yes	-	Yes
United Kingdom	No	-	-
United States	Yes	20% of production to be delivered to small refineries	Yes
Note: The DOI has not reserved offshore production for small refiners since 2009			

Source: IHS Markit

2.3.5 Decommissioning and Abandonment Requirements

2.3.5.1 Regulatory Requirements

U.S. law and lease terms prescribe for oil and gas operators to decommission their assets once the productive life of the asset such as a platform, well, pipeline, or other structure has ended. BSEE, who oversees abandonment activities, defines decommissioning as the process of ending oil and gas operations and returning the lease or pipeline right-of-way to a condition specified by regulatory requirements.[40] This is important since this same area or space may need to be used by other entities for operations. Additionally, the abandonment procedure ensures that wells are plugged and pipelines are removed or cleaned so that hydrocarbons are not released into the environment.

Decommissioning of idle structures older than three years is typically required by BSEE. A structure is deemed no longer useful for operations, "idle", if it has not been used in the past five years for operations associated with the exploration for or the development and production of oil, gas, sulphur, or other mineral resource or as infrastructure to support such operations.[41] The U.S. Gulf of Mexico shallow water was home to 662 idle structures in 2017.[42] The majority of these structures are likely candidates for decommissioning.

Non-producing platforms can present serious safety and environmental risks. Such structures may not be subject to frequent maintenance, resulting in deterioration and potential structural failures or serious damage by hurricanes. Inactive platforms are more susceptible to being toppled by hurricanes and could

[40] The Bureau of Safety and Environmental Enforcement, November 5, 2018, https://www.bsee.gov/what-we-do/research/tap-categories/decommissioning
[41] Notice to Lessees (NTL) No. 2010-G05 "Decommissioning Guidelines for Wells and Platforms"
[42] Ibid.

cause environmental damage to aquatic life through release of hydrocarbons to the surrounding waters or damage operating infrastructure.

The jurisdictions analyzed in this study have provisions in place that relate to the following:

- Obligation to carry out decommissioning and abandonment activities
- Financial security for decommissioning
- Tax treatment of decommissioning costs.

Country policies vary with regard to entities that may be required to carry out the abandonment obligation, the required financial security, and the tax treatment of abandonment costs. Table 2-17 provides a summary of decommissioning requirements of the selected offshore jurisdictions.

Table 2-17. Decommissioning requirements

Jurisdiction	Obligation to carry out decommissioning	Financial security	Tax treatment of decommissioning cost
Angola	Contractor	There is no provision for financial security.	Abandonment costs are classified as operating (production) costs to be recovered, when cumulative production represents less than • 50% of reserves under 50MMboe • 30% of recoverable reserves between 50-100MMboe • 20% of reserves above 100MMboe. Amounts calculated on a unit-of-production basis are payable to the national oil company on a quarterly basis.
Australia	• Titleholder or • Former titleholder	Financial security requirements for decommissioning obligations fall within the general financial assurance regime that governs all activities.	Expenditure associated with abandonment is deductible as incurred.
Brazil	Concessionaire	• Letter of credit • Sinking fund	Abandonment costs are deductible for income tax purposes.
Canada – NL	Operator	N/A	Abandonment costs may be written off in the year incurred and are classified as operating expenditure.
Guyana	Contractor	N/A	Abandonment costs are treated as operating costs and recovered on a unit-of-production basis from the period when the abandonment program and budget is approved.
Mexico	Contractor	The contractor must establish an 'abandonment trust' ('trust') when declaring commerciality. The trust will be jointly controlled by Mexico's National Hydrocarbons Commission (CNH) and the contractor at a bank designated by a	Abandonment costs are determined on a unit-of-production basis and are deductible for income tax and cost recovery.

Jurisdiction	Obligation to carry out decommissioning	Financial security	Tax treatment of decommissioning cost
		financial Mexican institution authorized by CNH.	
Norway	Licensee	MPE may demand the provision of financial security when awarding a license and at any time thereafter. Typically, this may take the form of a parent company guarantee, but other forms of security may also be requested.	Expenses for the abandonment of wells, and the removal of installations and pipelines, are deductible at the time such expenses are incurred, but no deduction is permitted for future abandonment expenses.
United Kingdom	• Operator of installation • License holder • Any party to a joint operating agreement (JOA) • Anyone who has an ownership interest in the installation [43] Any corporation controlling or controlled by those entities.	Security in the form of the following: • Letter of credit • Parent company guarantee • Third-party guarantee • Insurance • Decommissioning trust fund. Industry has developed decommissioning security agreements (DSAs). Under a DSA, each participant agrees to deposit cash or a form of security into a trust that will pay the costs of decommissioning when this obligation is due.	
United States	Lessee	BOEM may determine that additional security to cover decommissioning costs is necessary to ensure compliance with the lessee's decommissioning obligations. That determination is based on an evaluation of the lessee's ability to carry out present and future financial obligations as demonstrated by: financial capacity, projected financial strength, business stability, reliability, and record of compliance with laws, regulations, and terms. A third-party guarantee and the establishment of a lease-	Deductions for abandonment costs may only occur when the expenditure has been made (i.e., there can be no tax deductions for abandonment provisions during the producing life of the asset).

[43] The Secretary of State has the power to effectively 'claw back' former licensees' liabilities and to pursue these parties for decommissioning costs.

Jurisdiction	Obligation to carry out decommissioning	Financial security	Tax treatment of decommissioning cost
		specific abandonment account may be accepted by BOEM for the purpose of meeting decommissioning obligations.	

Source: IHS Markit © 2018 IHS Markit

2.3.5.2 Global Decommissioning Market

The global offshore decommissioning market currently has a value of approximately USD2.5–3.0 billion per year and is rapidly growing. The decommissioning market is experiencing strong annual growth, while E&P capex have dropped sharply since 2014. As such, the decommissioning market currently represents approximately 1.5–2.0% of overall offshore E&P capex. IHS Markit expects the decommissioning market to continue to outpace the general exploration and production market, reaching 3.3% of offshore E&P capex in 2020 and just under 5% in 2040.

There are several phases in the decommissioning market. The first phase, which has been ongoing for the past 15–20 years, is the decommissioning of simpler shallow water structures, particularly those in the Gulf of Mexico. Industry is currently entering the next phase, which is the decommissioning of structures in deeper waters that were put in place during the 1970s to early 1980s. IHS Markit expects this phase to plateau during the next decade and begin to decline towards the end of that period, owing both to the slowdown in offshore development activity in the second half of the 1980s and to the delay that occurred before the next industry cycle gathered steam again in the early 2000s. The decommissioning of many of the high-cost, gravity-based structures, particularly in the North Sea, will also add to the decline. IHS Markit expects decommissioning spending to increase as we head into the 2030s, when structures installed during the last two decades will start to add to decommissioning demand.

As depicted in Figure 2-1, the relative age of the topsides in operation varies across regions. The North Sea and Europe have a particularly large share of aging infrastructure. Other regions such as South America and the Russia and Caspian region have newer infrastructure, and the decommissioning rates there are expected to be much lower over the next few years. Total installed topsides tonnage is on the brink of plateauing, owing to the ongoing removal of a large number of facilities.

Historically, the Gulf of Mexico has by far been the busiest region in terms of the number of fixed (or other) decommissioned platforms, mainly because of the large number of smaller caisson and well protector platforms that have been installed in shallow water. Approximately 4,000 of those platforms have been decommissioned, while less than 2,000 are still in place today. A large number of facilities were decommissioned between 2008 and 2012, as requirements to plug wells and remove structures became more stringent, in part resulting from the particularly severe hurricane seasons of 2004–2008. The decommissioning activity in the U.S. Gulf of Mexico is still ongoing at more than 100 structures per year.

The units that have been decommissioned in the Gulf of Mexico and the majority of those that are expected to be decommissioned in the coming years primarily constitute smaller, shallow water units with weights generally well below 1,000 tons and seldom above 1,500 tons, with a decommissioning cost in the range of USD1.0–1.5 million. In comparison, the decommissioning of the Brent field in the North Sea involves 22,500-ton topsides and a 180,000-ton substructure, and is expected to cost about USD2 billion to remove. As such, even though North America represents by far the largest region in terms of the number of decommissioned units, the European region currently represents the largest share in terms of offshore decommissioning spending.

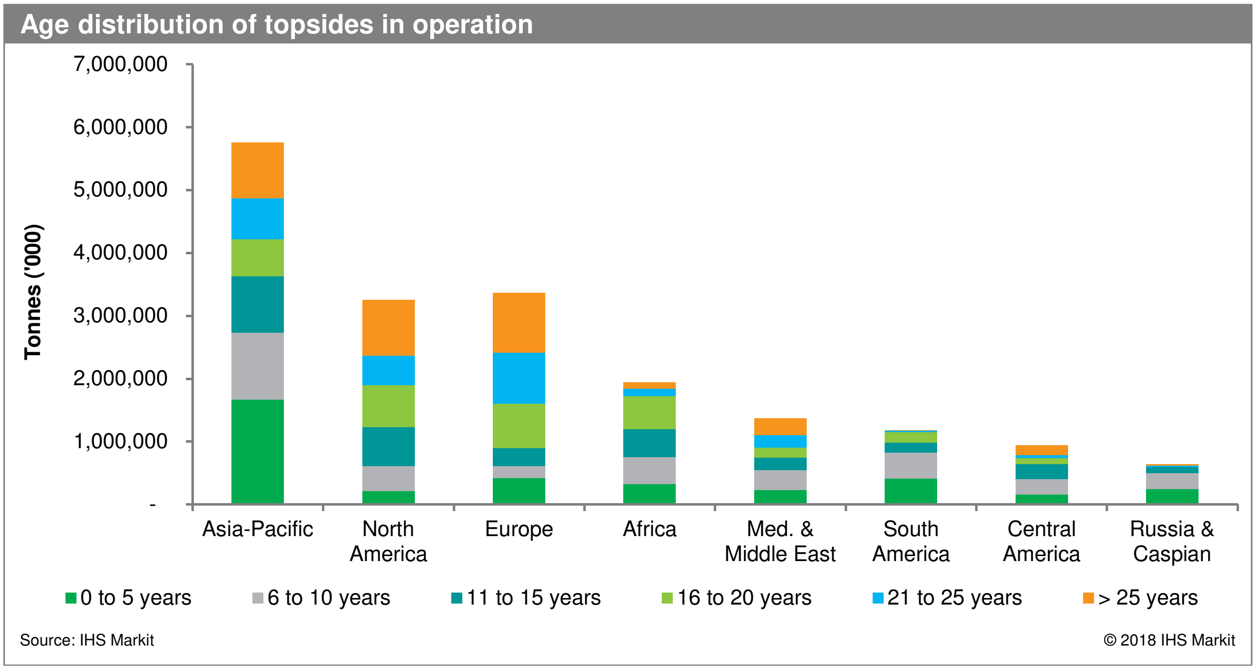

Figure 2-1. Age distribution of topsides in operation

IHS Markit expects global decommissioning spending to reach USD13 billion per year by 2040 (Figure 2-2). Total spending from 2010 to 2040 will amount to USD210 billion. In the near term, Europe will be the biggest spender, as major offshore structures are removed from the North Sea, absorbing approximately 50% of global spending through the forecast period.

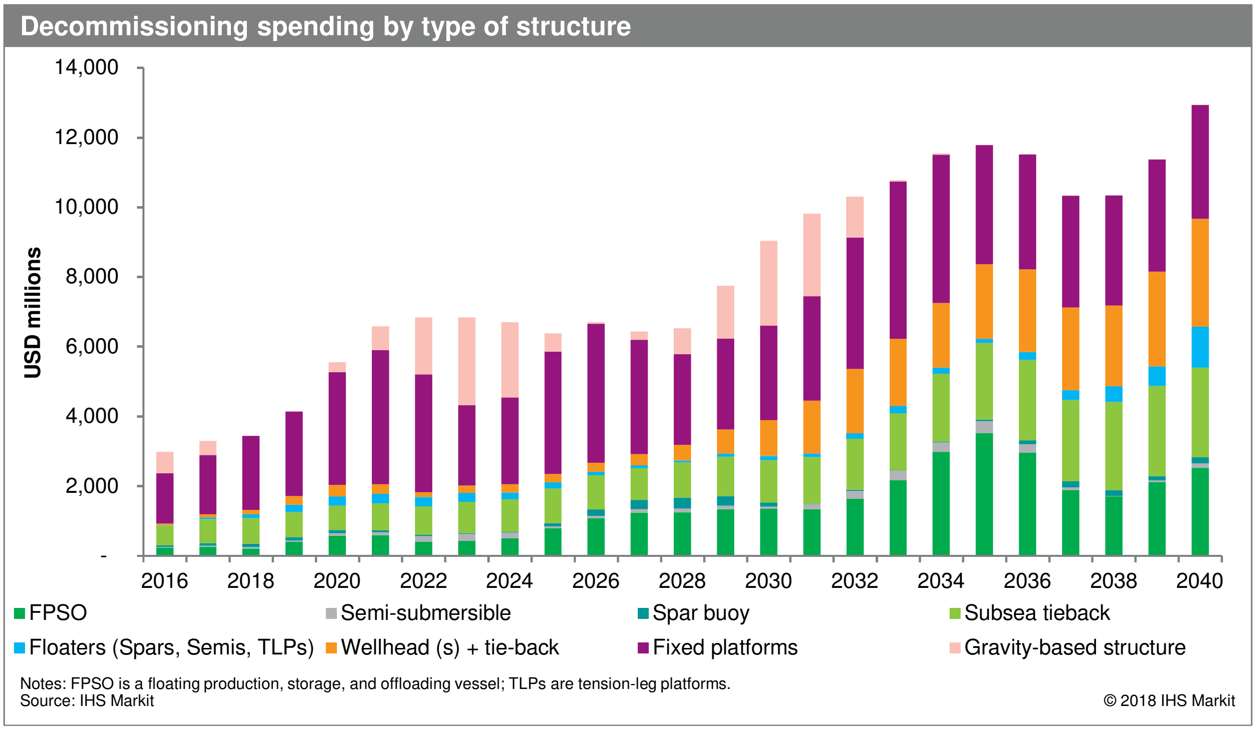

Figure 2-2. Decommissioning spending by type of structure

3 Exploration and Production Activity Overview

3.1 Exploration and Development Activity

Offshore new field wildcat[44] (NFW) drilling was one of the most impacted drilling programs in the upstream sector in the wake of the oil price collapse. Offshore wildcat drilling fell by almost 43% from 2014 to 2016. Thus far in 2018, the recovery in NFW drilling has accelerated slightly, 15% on an annualized basis (Figure 3-1).

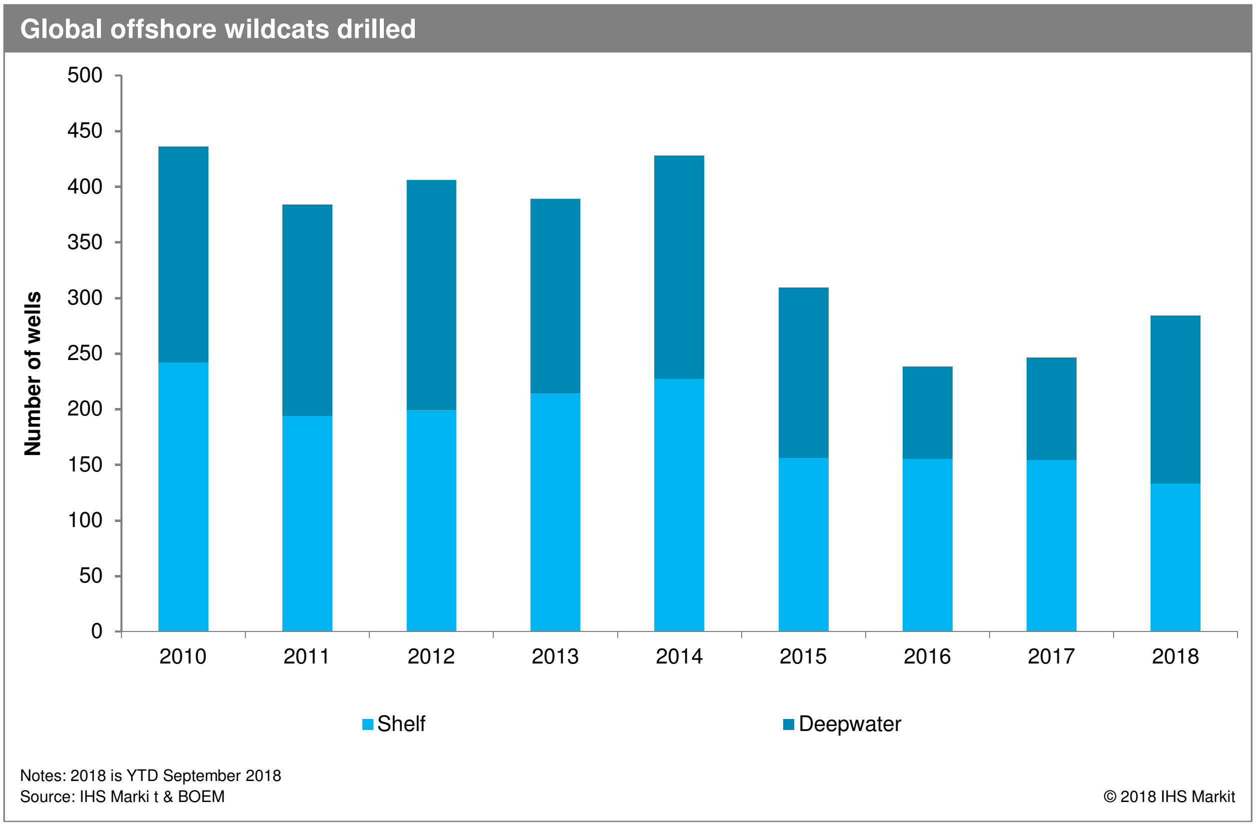

Figure 3-1. Global offshore wildcat wells drilled

The countries in this study comprise nearly 50% of the global NFW drilling offshore. In this peer group, NFW offshore drilling in 2018 is up 85% from 2017—well above the 2013 levels (Figure 3-2). U.S. offshore NFW wells make up 23% of the NFWs drilled in the peer group both in shallow and deepwater areas.

[44] New field wildcats are exploratory wells targeting a geological structure or other type of hydrocarbon trap that has not previously produced oil or gas. These wells are usually drilled in new areas to identify new prospective areas or plays. Consequently, new field wildcats are generally far away from existing field infrastructure. In this study, exploratory drilling and new field wildcat drilling are used interchangeably.

Deepwater drilling represents the bulk of the NFW wells drilled, representing 60% of the total NFW wells drilled in the peer group since 2010 and 74% of the NFW wells drilled in 2018. This is a strong signal of the deepwater resource potential within the peer group (Figure 3-2).

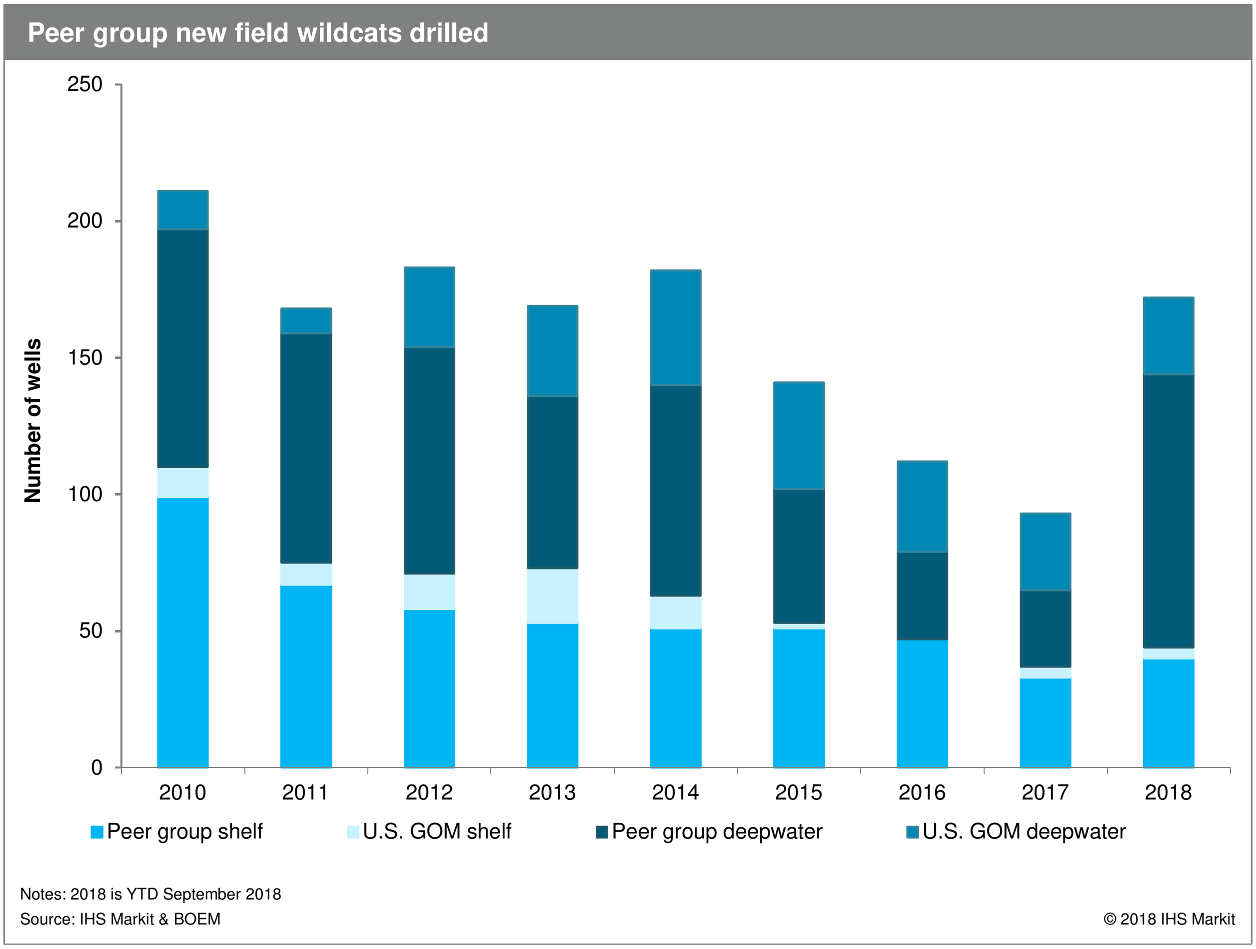

Figure 3-2. Peer group new field wildcats drilled

Global offshore development drilling has continued on a downward trend since 2015—with wells drilled to date in 2018 representing a 57% decline from the peak in 2015 (Figure 3-3). A similar trend can be found within the jurisdictions selected for this study, with the U.S. Gulf of Mexico shelf suffering the sharpest decline among the peer group in 2015 at 83% from the 2014 levels (Figure 3-4). Peer group development drilling has fared better than global development drilling in 2018—with wells drilled as of September 2018 representing 130% increase from 2017 levels. Development drilling in U.S. Gulf of Mexico shelf and deepwater areas has not yet shown signs of recovery at this time. Wells drilled in 2017 and to date in 2018 represent a 41% decline from the peak in 2014.[45]

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[45] The 2018 data represents wells drilled as of the end of September 2018.

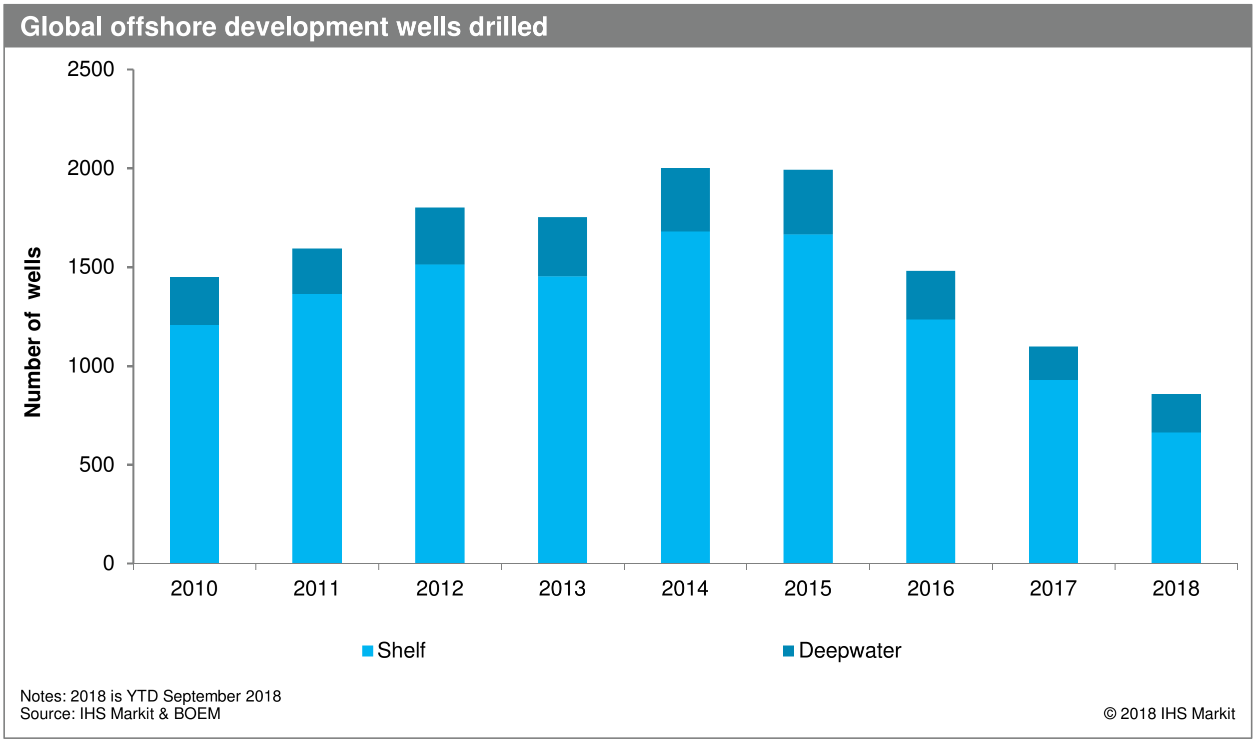

Figure 3-3. Global offshore development wells drilled

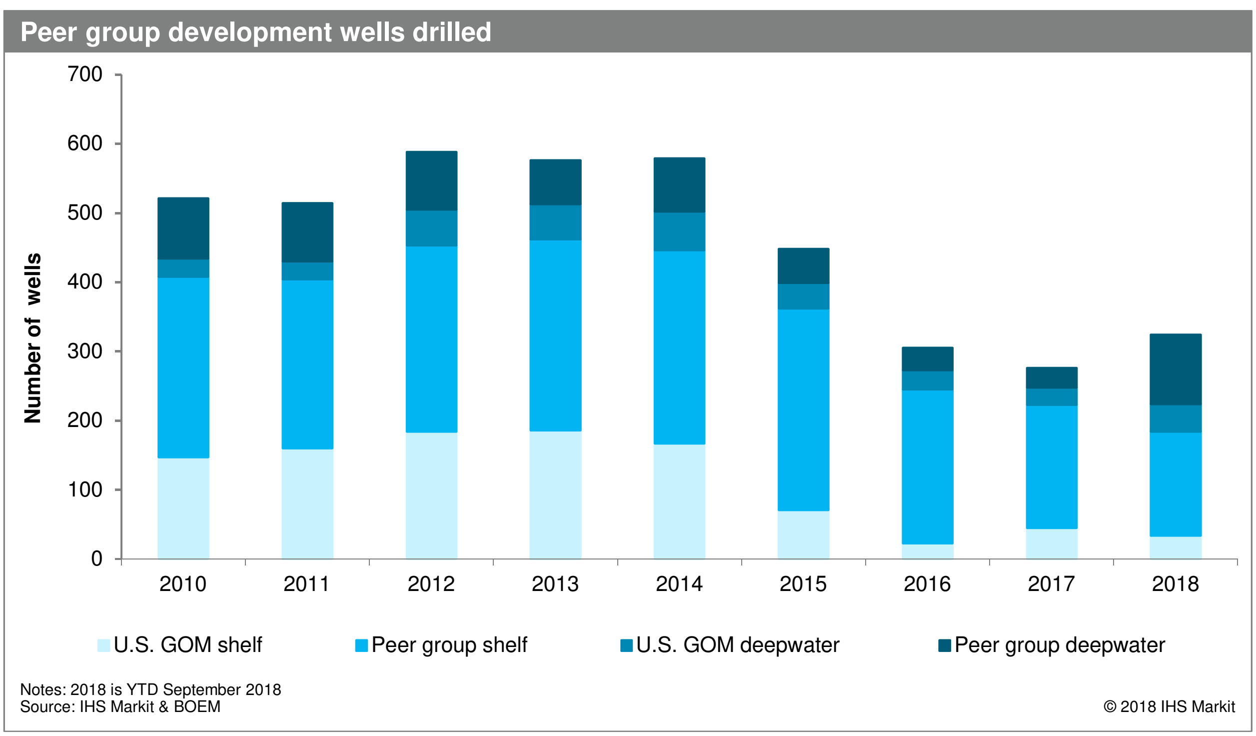

Figure 3-4. Peer Group Jurisdictions: Development wells drilled

Exploration and development drilling in U.S. GOM shelf areas has experienced a dramatic decline since 2003 (Figure 3-5). This is symptomatic of the maturity of the U.S. GOM shallow water region, rather than the drop in commodity prices.

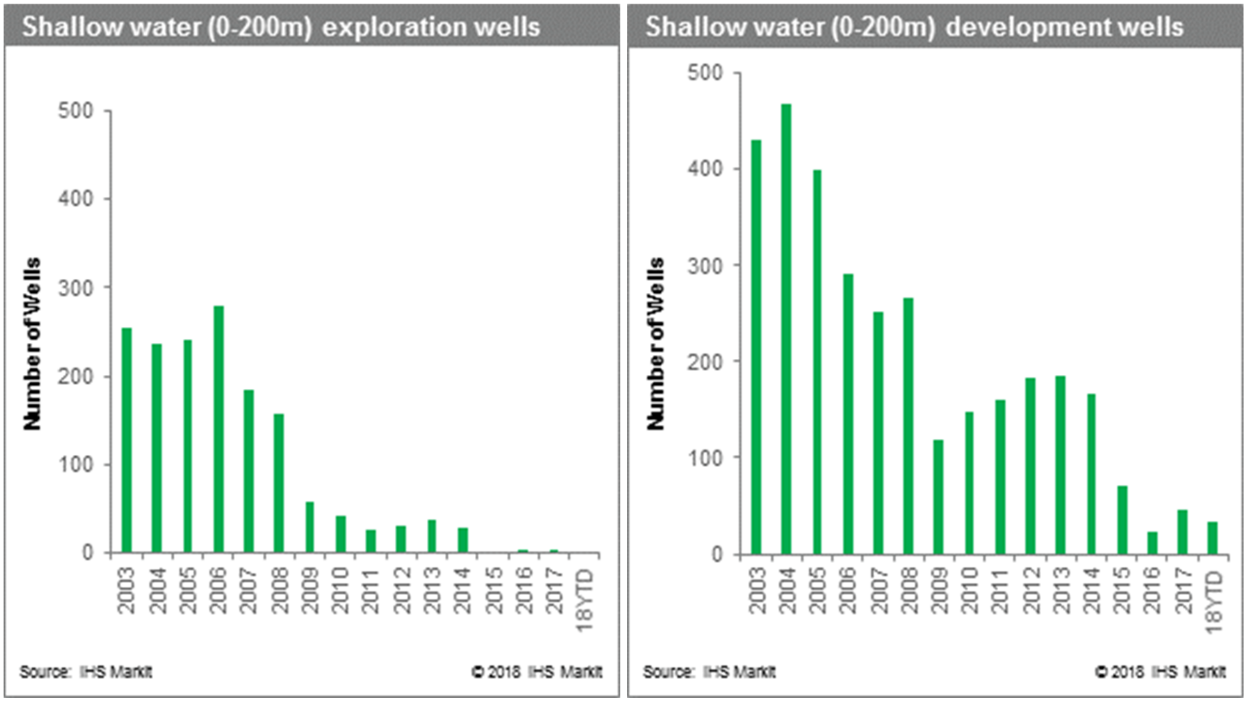

Figure 3-5: U.S. GOM shallow water exploration and development wells (2003-2018YTD)

Exploration and development drilling in the U.S. GOM deepwater areas has been on a gradual decline since 2003 (Figure 3-6). While the decline in 2010-2011 period is attributed to the slow pace of permitting after Macondo oil spill, overall the decline in development drilling is attributed to the technical challenges and low productivity of the Lower Tertiary play, which holds nearly 40% of the yet to find reserves of the U.S. GOM.

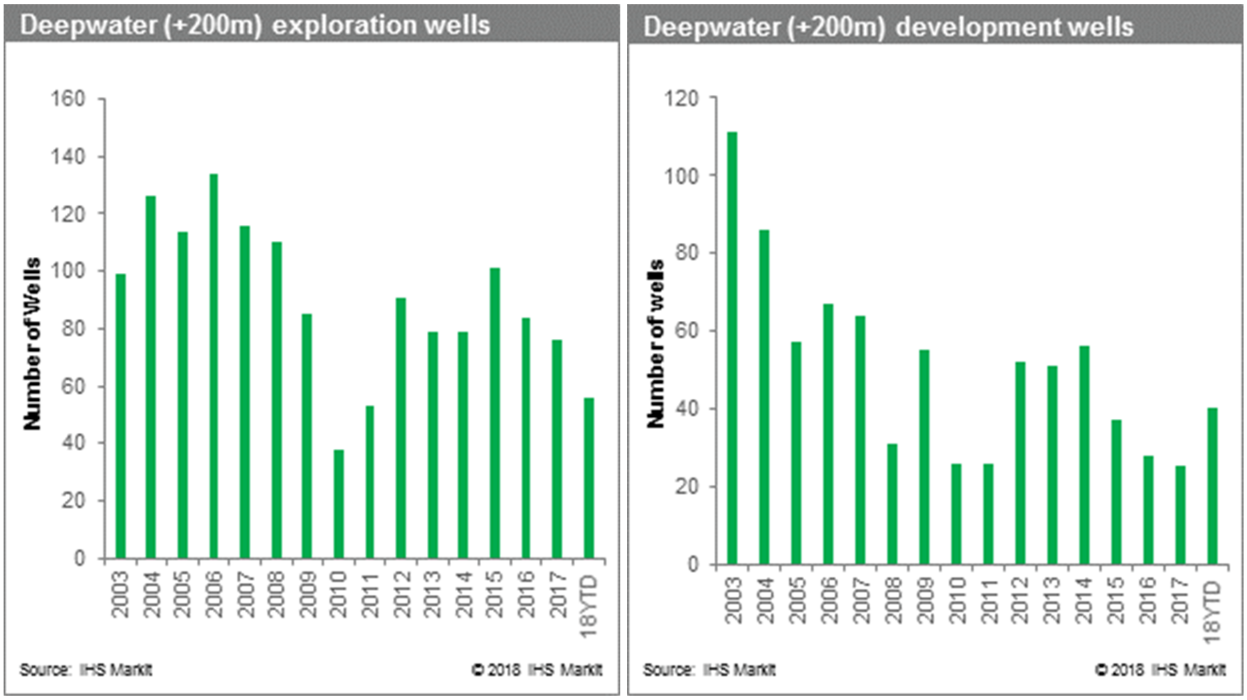

Figure 3-6: U.S. GOM deepwater exploration and development wells (2003-2018YTD)

Deepwater E&P activity is showing signs of recovery. In 2017, global offshore projects (not restricted to the peer group) have sanctioned 919,000 bbl/d, of which 628,000 bbl/d are in ultra-deepwater and 291,000 bbl/d are in deepwater (Figure 3-5). Year-to-date data as of September 2018 shows that 754,000 bbl/d have been sanctioned, 76% of which are in deepwater. Historically, the fourth quarter has the largest sanctioning activity; therefore, a strong close in sanctioned capacity is anticipated in late 2018. Figure 3-7 depicts the volumes sanctioned in key international deepwater and ultra-deepwater projects excluding the "Gulf 6" (Saudi Arabia, Iran, Iraq, Qatar, Kuwait and the United Arab Emirates). The 2018 numbers include 69,000 bbl/d from the Vito project in the U.S. GOM deepwater. Of the sanctioned projects, the U.S. GOM comprise 9%.

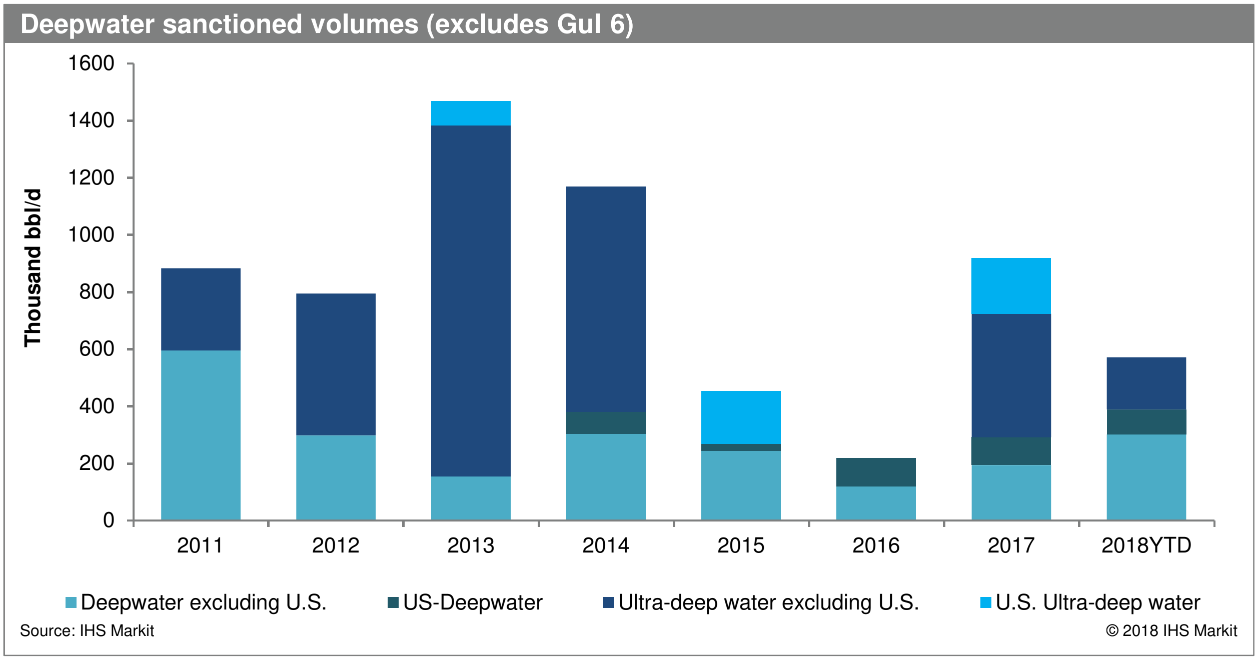

Figure 3-7. Deepwater sanctioned volumes for selected countries

Licensing activity during the downturn has not followed the same patterns as exploratory and development drilling. Licensing activity is largely dependent on the following factors:

- the frequency with which governments offer acreage,
- the number of blocks, being offered
- the relative prospectivity of the area, being offered
- cost of entry, and
- contractual and fiscal terms on offer.

In jurisdictions where the cost of entry is low—where there are no signature bonuses involved—investors tend to acquire acreage with the hope of being able to resume activity once commodity prices bounce back. The UK in particular has benefitted significantly due to a combination attractive fiscal terms, low cost of entry, and flexible license duration (Figure 3-8).

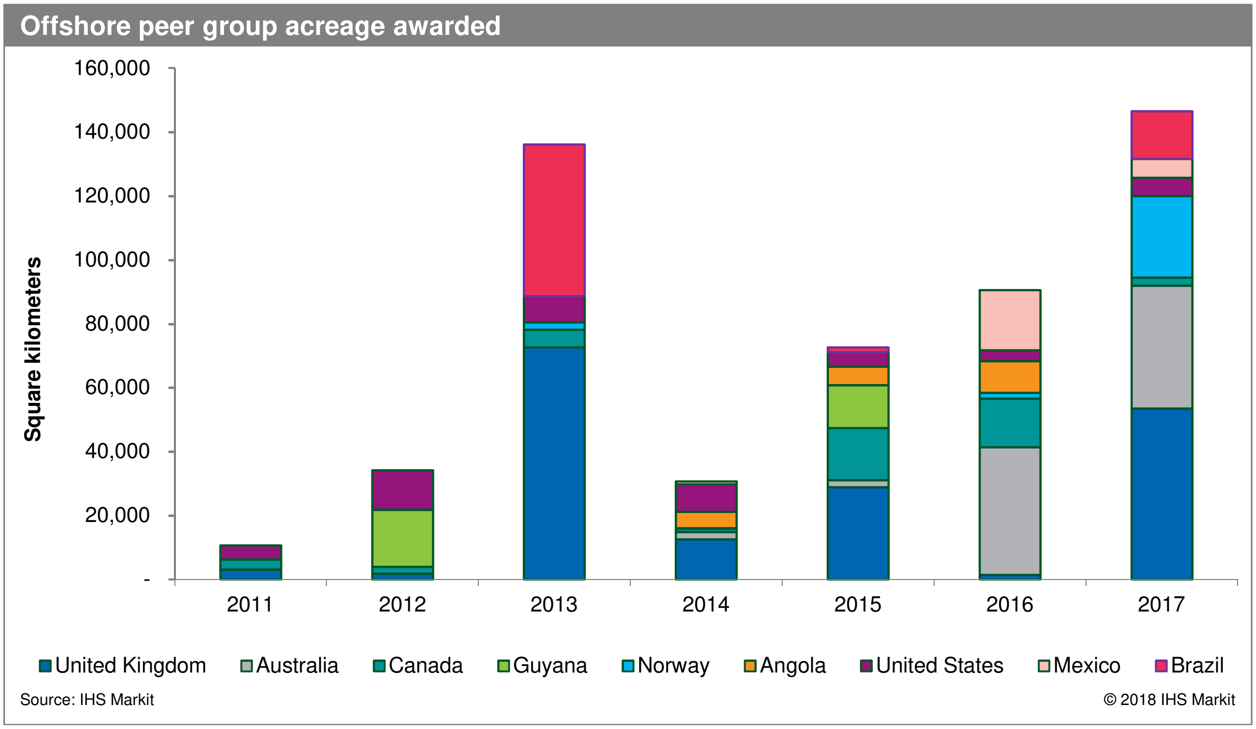

Figure 3-8. Offshore peer group acreage awarded

The success of licensing rounds cannot be measured solely by the amount of acreage leased. A combination of factors that usually align with bid award criteria are a better measure of success. Amounts collected via signature bonuses as well as those committed for exploration investment are often better indicators of licensing round performance. This is especially true when evaluating the performance of licensing rounds in Brazil and Mexico. The acreage on offer in each licensing round in Mexico is much more limited than in other jurisdictions, such as Australia, the United Kingdom, and the U.S. When the exploration commitments are taken into account, whether in monetary terms or in actual seismic activity or exploratory drilling, the Brazil and Mexico licensing rounds are considered very successful. A review of the licensing rounds/lease sales held in 2017 and 2018 (Table 3-1) in the peer group shows Brazil as the most successful by far among the peer group in terms of dollars committed via signature bonuses and work commitments, attracting nearly 60% of the commitments made in the peer group (Figure 3-9).

Table 3-1. Licensing Rounds and Lease Sales Concluded in 2017-2018

Jurisdiction	2017 Calls for bids / licensing rounds	2018 Calls for bids / licensing rounds
Angola	N/A	N/A
Australia	2016 Exploration Acreage Release	2017 Exploration Acreage Release
Brazil	ANP 14 and 4th Presalt bid rounds	ANP 15 and 5th Presalt bid rounds
Canada - NL	NL17-CFB01	NL 18-CFB01 and NL 18-CFB02
Guyana	N/A	N/A
Mexico	Round 2.4	N/A
Norway	23rd Licensing Round	24th Licensing Round
UK*	29th Licensing Round	30th Licensing Round
U.S.	Sale 249	Sale 250 and 251
Note 1: Mexico's 2018 Deepwater round was cancelled.		

Source: IHS Markit

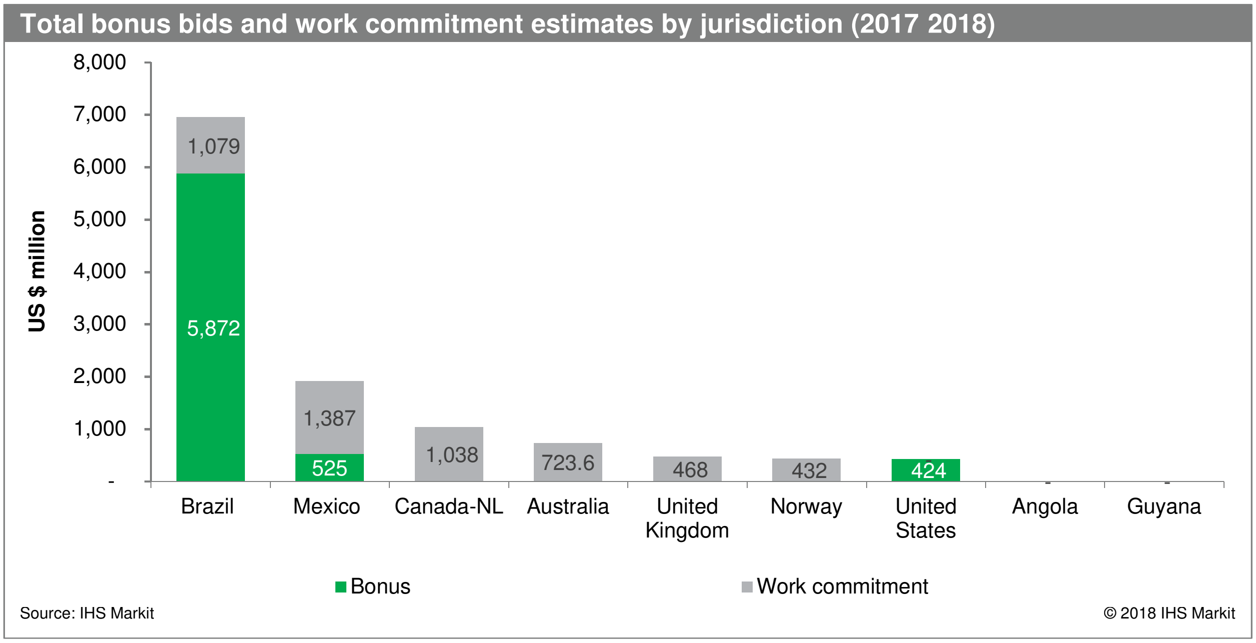

Figure 3-9. Total bonus bids and work commitment estimates by jurisdiction (2017-2018)

3.2 Assessment of Offshore Undiscovered and Undeveloped Resource Potential

Only a portion of total offshore oil and gas resources has been discovered, and an even smaller portion is currently under production. Technological advances and new exploration will help facilitate development of currently undiscovered or uneconomic resources. Often, fields that are not currently economic will become economic later when technology advances or market conditions improve. This chapter provides a high-level overview of yet-to-find resources likely to be developed within the next 40 years. IHS Markit calculated yet-to-find volumes of oil and gas for main basins or well-known plays. The objective of this analysis is to give an approximation of the undiscovered and undeveloped resource potential at the country level. In this context, yet-to-find resources at country levels represent the summation of the resources in the main basins included in the analysis. See Appendix E for the basins selected for the yet-to-find assessment.

Mature oil and gas regions, such as the U.S. Gulf of Mexico Shelf and the North Sea, are well understood geologically, and much of the future production from these areas will come from already producing fields. Brazil has the greatest upside potential, but currently has limited production owing to the relatively low levels of exploration and development activities that have taken place in the basin. Mexico has a large deepwater yet-to-find pool that has recently been the object of Round 2 focusing on the Campeche Deep Sea basin.

Under the base case, opportunities exist for development in deepwater basins that have had limited development, as well as the mature oil and gas regions. Yet-to-find resources make up almost 50% of the deepwater hydrocarbon endowment in Brazil and one-third of the hydrocarbon endowment in the U.S. Gulf of Mexico deepwater area. Other deepwater areas with significant yet-to-find potential include Guyana, Mexico, and Angola. (Figures 3-11 and 3-12).

Most of the undiscovered volumes in the U.S. Gulf of Mexico deepwater are located in the Lower Tertiary Miocene and Jurassic plays (Figure 3-10). There are five core plays in the deepwater U.S. GOM—Plio/Pleistocene, Miocene, Miocene sub-salt, Lower Tertiary, and Jurassic. The focus of most material new field exploration is in the Lower Tertiary, Miocene sub-salt, and Jurassic plays. Companies have moved into these three growth plays as technologies have advanced, allowing for increases in water and drilling depths.

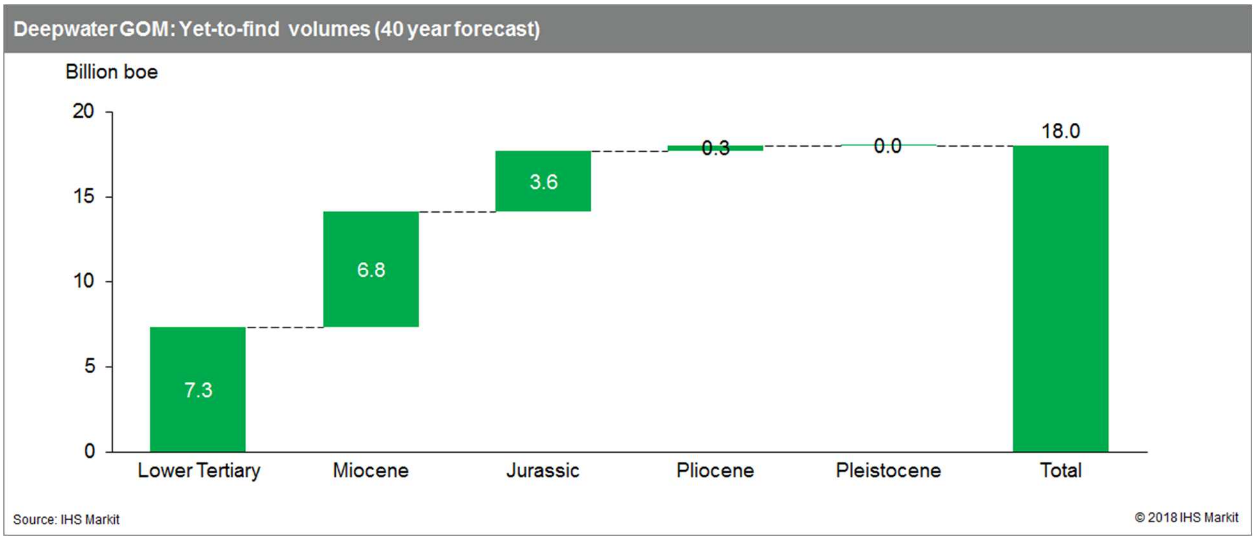

Figure 3.10. U.S. Deepwater GOM: Yet-to-find volumes (40 year forecast)

Other important deepwater basins/plays in the peer group are the Santos pre-salt play in Brazil, the Guyana Basin Stabroek play, the lower cretaceous sands of the Barents Sea Basin in Norway, and the pre-salt Aptian reservoirs of the Angola Lower Congo Fan and the pre-salt Aptian carbonate reservoirs of the Angola Kwanza basin.

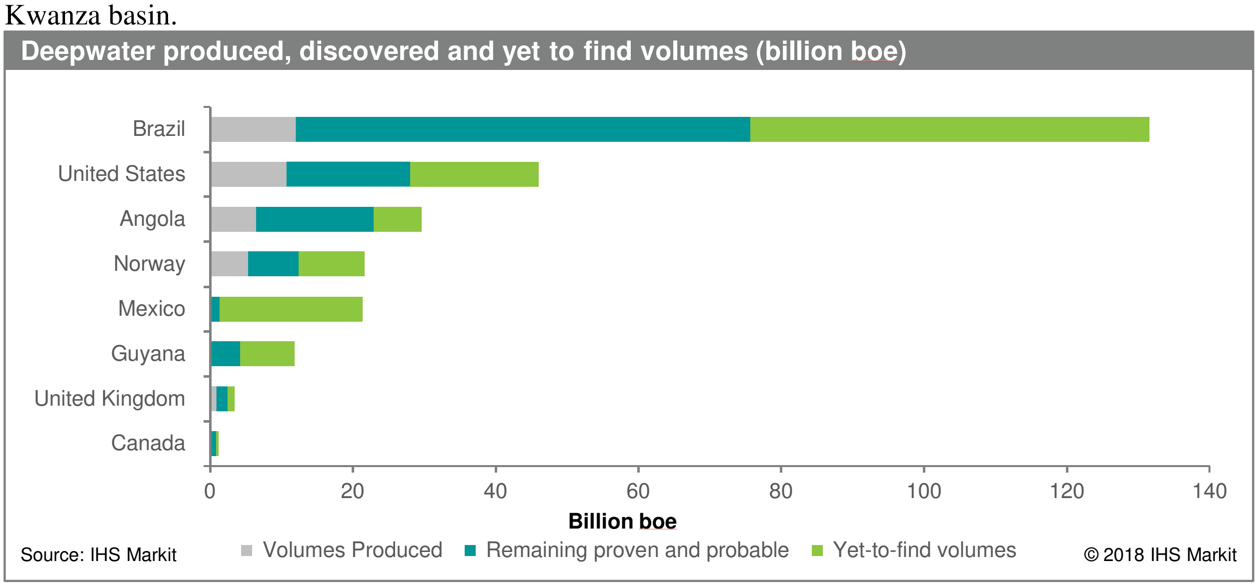

Figure 3-11. Deepwater produced, discovered and yet-to-find volumes

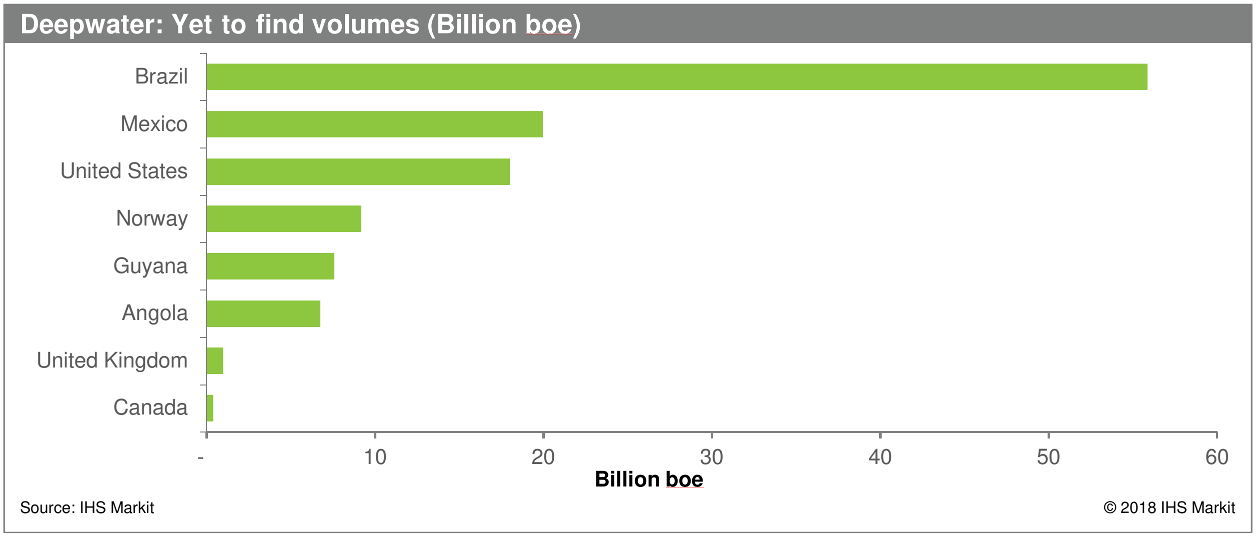

Figure 3-12. Deepwater yet-to-find volumes

Shallow water basins have much lower yet-to-find potential. The Gulf of Mexico and North Sea regions have been producing for 60+ years. The U.S. Gulf of Mexico shelf basis is by far the most mature with relatively low remaining recoverable reserves. Australia has the greatest hydrocarbon yet-to-find potential in shallow waters in the Carnavon, Browse and Bonaparte basins. Mexico, Norway, the United Kingdom, and U.S. Gulf of Mexico all have lower yet-to-find volumes as a reflection of their maturity (Figure 3-13 and 3-14).

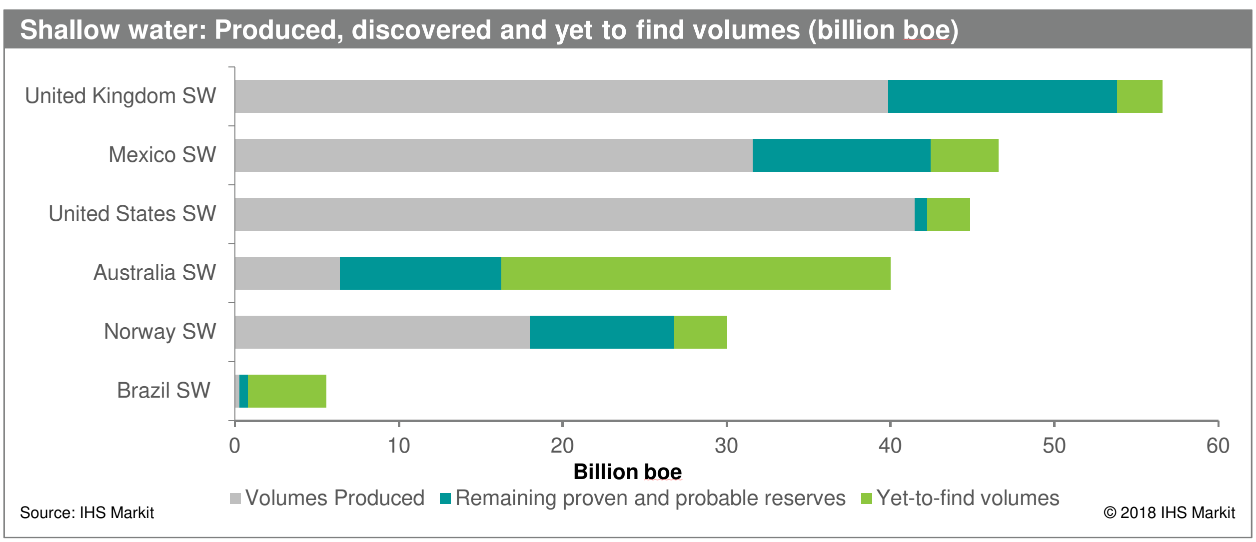

Figure 3-13. Shallow water produced, discovered and yet-to-find volumes

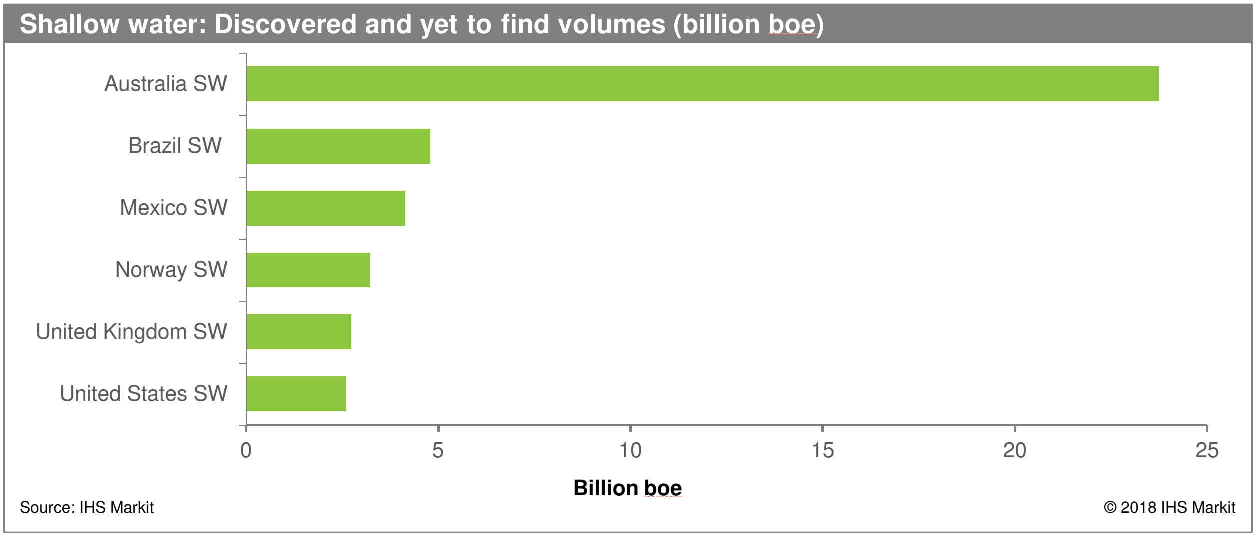

Figure 3-14: Shallow water yet-to-find volumes

Volumes yet to be found in the shallow waters of the U.S. GOM are likely to lie in small size discoveries as historical data shows. Fields under 10 MMboe made up 97% of the discoveries over the past 15 years in the U.S. GOM shallow waters (Figure 3-15).

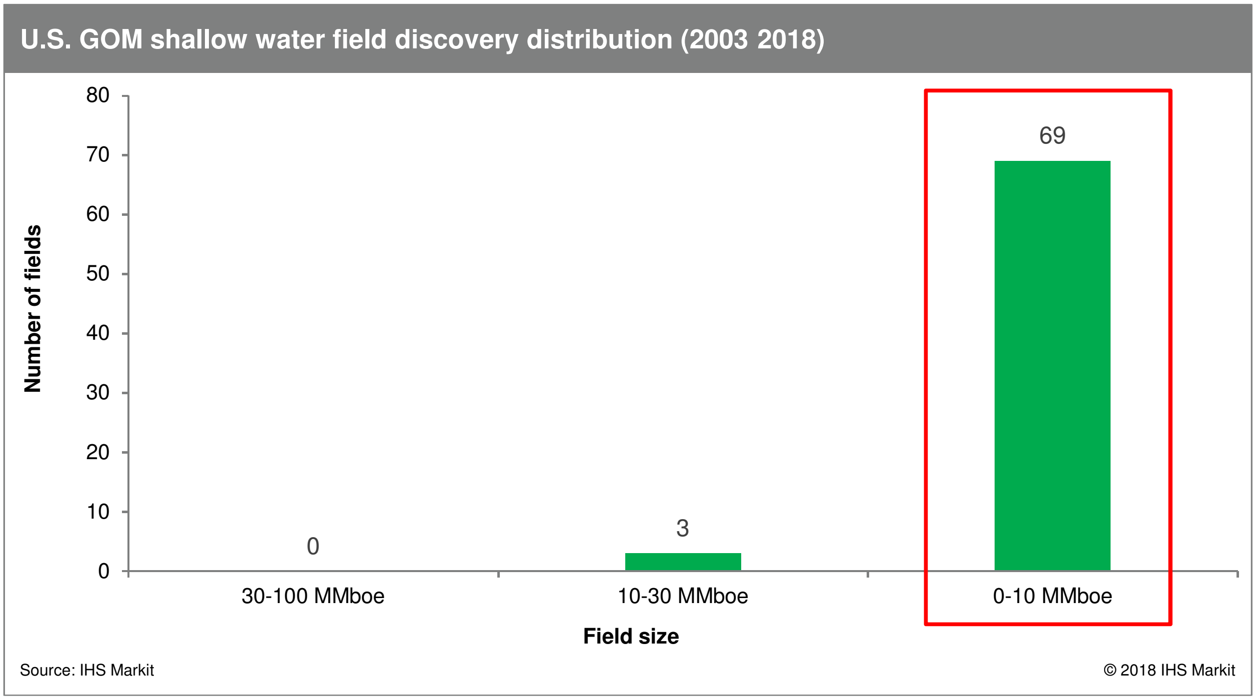

Figure 3-15. U.S. GOM shallow water field discovery distribution (2003-2018)

3.3 Exploration and Development Costs

The oil industry has adapted to the lower price environment that has existed since the oil price collapse in late 2014. Operators have adapted to these lower prices by reducing their capital costs and lowering operational costs, which has reduced the break-even prices for offshore oil and gas developments. The industry has generally shifted focus from exploration and large-scale developments to the optimization of existing projects and the use of phased, repetitive, and smaller-scale developments that can generate cash flow quickly and contribute towards a gradual field development.[46] GOM lessees have been targeting areas close to existing infrastructure that could host subsea tie-backs if discoveries are made. Using existing processing capacity yields savings for the operator and can make projects economic that would be uneconomic under a stand-alone basis.

Certain costs associated with offshore development are cyclical, such as equipment and labor rates, meaning they are sensitive to market conditions and will fluctuate with changes to oil prices. Other cost reductions require operator-initiated changes, such as increased automation, efficiencies, use of artificial intelligence, and design changes. Additionally, a focus on reducing costs over the life of a field through improved reliability, product availability, and maintenance has contributed to reduced costs. Operators have also focused more on the development of fields in clusters. Newly discovered fields could be developed as satellite tie-backs to existing platforms, which allows for the sharing of infrastructure and personnel. This new design works well for deepwater projects where capital costs are higher, as this allows for smaller

[46] Asmar B, Structural cost reductions: The industry savior, IHS Markit, August 2018.

fields to be developed that could have been too costly to develop as a stand-alone development.[47] While this is a trend, especially in the Gulf of Mexico, deepwater fields studied in this report are modeled as stand-alone facilities.

Costs mostly differ through their elasticity to external factors – such as market fluctuations –, and their natural structural components – such as concepts and complex options.[48] Concept design, a key structural factor for development costs, is influenced by a variety of factors drawing from the geophysical properties of the reservoirs being developed. Key characteristics such as reservoir depth, water depth, and well productivity drive concept choices and therefore create costs differences between cases. Within the study peer group, large variances exist in reservoir depths. For example, the U.S. deepwater 500 MMboe oil case has a TVD of 28,393ft, the deepest reservoir depth of the whole peer group, and nearly twice the peer group TVD average of 14,238ft. This drives higher costs for this jurisdiction when compared to the peer group. Guyana, with a TVD at 13,500ft, is below the peer group average contributing to better economic performance.

Costs for deepwater projects declined by 40% between the third quarter of 2014 and the first quarter of 2017 (Figure 3-16). Deepwater projects have benefitted from a severe overcapacity of offshore equipment and services in the sector brought about by the anticipation of growth in the sector in the past decade that did not fully materialize. As E&D activity has recovered, costs are beginning to increase again.

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[47] Ibid.

[48] Concepts can be semi-submersibles, spars, tension leg platforms etc. Complex refers to the association of fields components and of satellite fields usually to optimize the use of certain type of facilities.

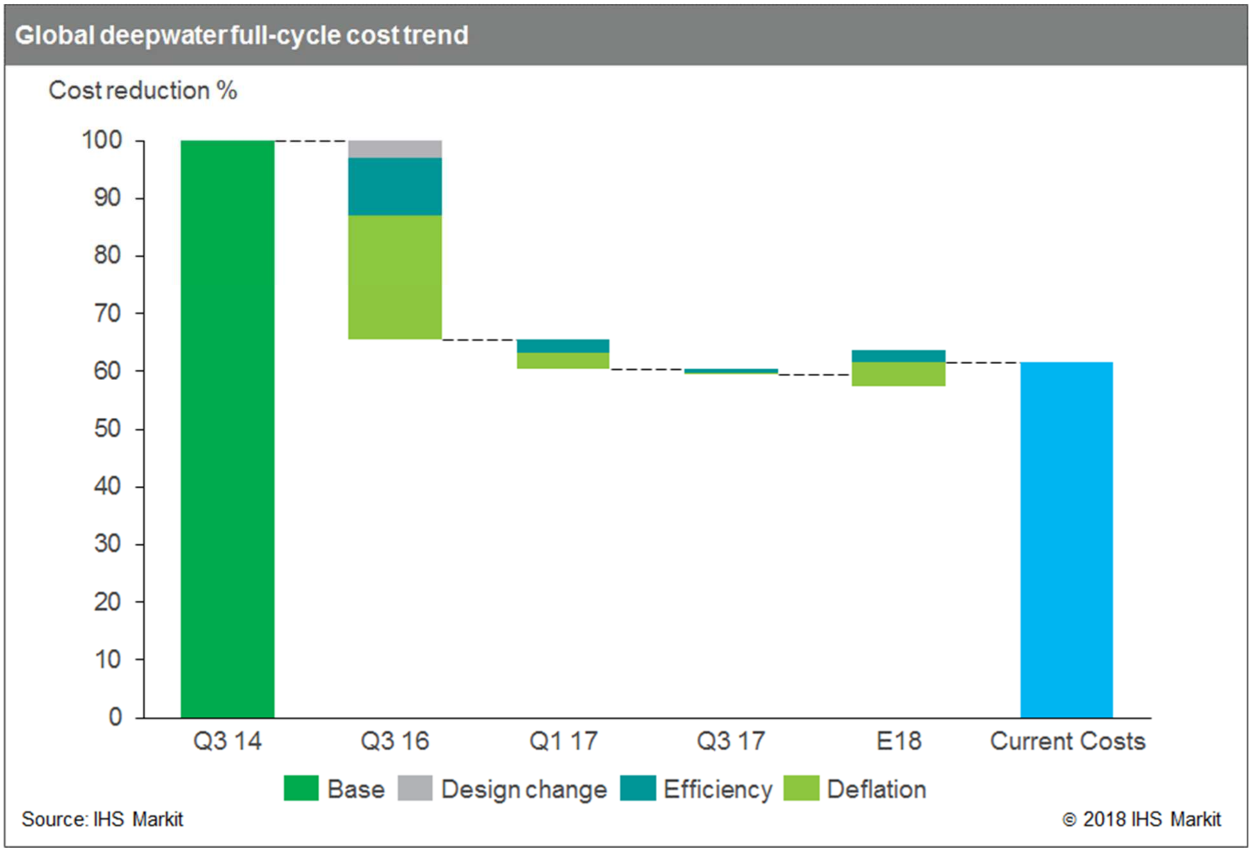

Figure 3-16. Global deepwater full-cycle cost trend

Shallow water projects have also seen similar cost reductions, but these cost reductions have had less of an impact in break-even prices owing to the simpler designs and shorter life cycles of shallow water projects (Figure 3-17).

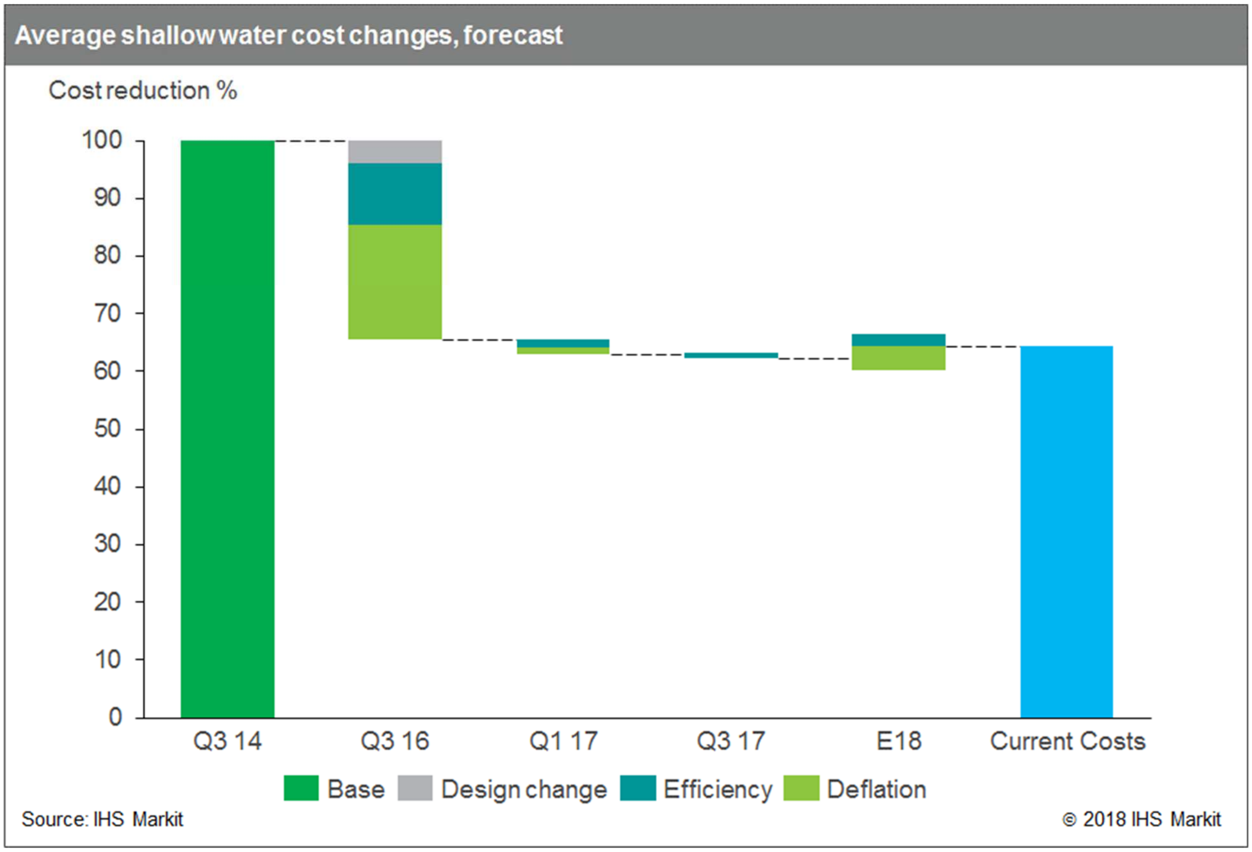

Figure 3-17. Average shallow water cost changes, forecast

IHS Markit estimates that global average upstream costs bottomed out in 2017 and have started to increase in 2018. However, IHS expects that the neither prices nor costs will increase significantly over the next ten years. According to IHS Markit estimates, the full-cycle, break-even cost to develop new oil projects globally inched up nearly 5% in 2018, from a global average of $42/bbl in 2017 to $44/bbl in 2018.[49]

When considering the role of U.S. Gulf of Mexico in the total global supply to 2030, it remains competitive from a break-even perspective. On average, U.S. Gulf of Mexico break-even prices are slightly lower than the North Sea break-even prices; however, the formations with the highest resource potential in U.S. GOM have greater costs and as such higher break-even prices (Figure 3-18). Figure 3-18 shows the cost curve of the global crude oil supply to 2030 for new projects from selected areas, representing more than 80% of total global supply from new projects.

[49] The full cycle breakeven cost shown here represents the global average, including onshore. Singh A, Asmar B, Moore S, Global Oil: Cost curve through 2020 shows only marginal inflation from 2017, IHS Markit, June 2018.

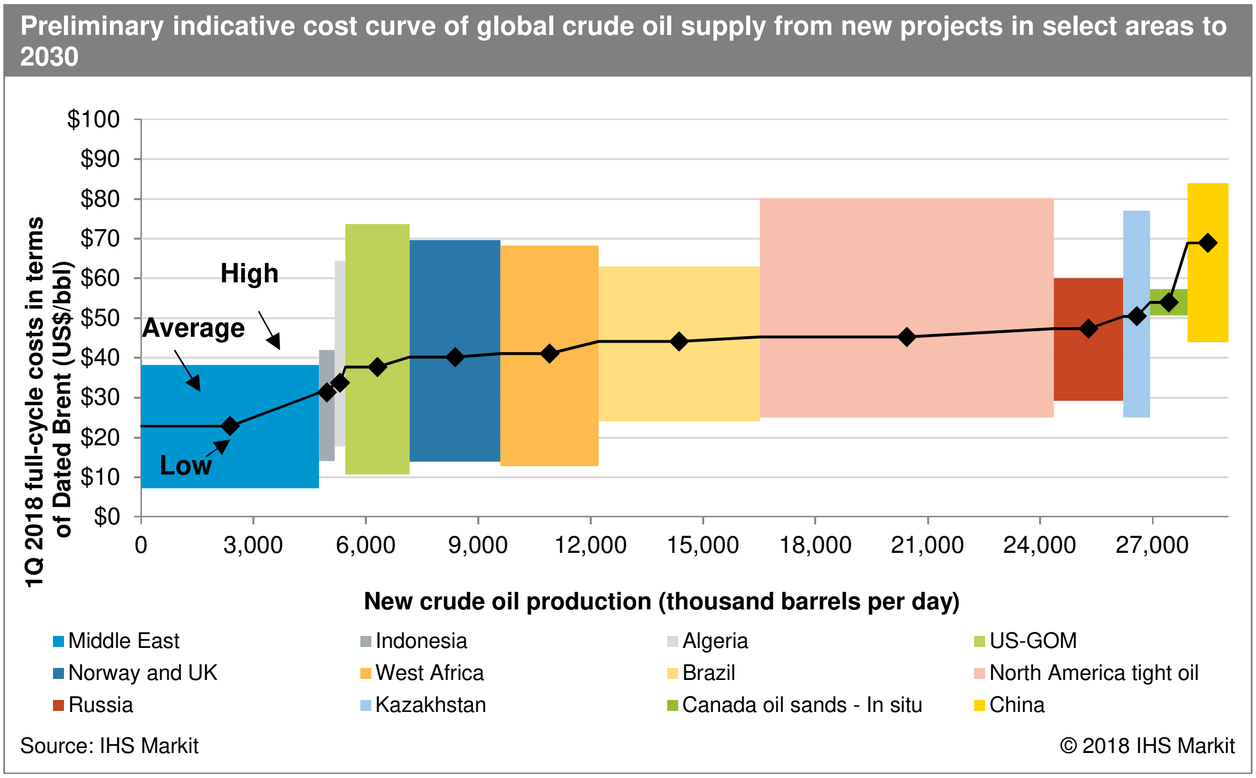

Figure 3-18. Preliminary indicative cost curve of global crude oil supply from new projects in select areas to 2030

4 Trends in Fiscal Terms since 2014

4.1 Changes in Fiscal Terms

Since the publication of DOI's comparative assessment of the U.S. Federal oil and gas fiscal system in 2011, significant changes have taken place, including oil and gas markets, the amount and type of oil and gas resources available, and the activities of competing oil and gas suppliers around the world. With an increase in U.S. onshore supply, global oil and gas prices have fallen, and low prices have created challenges for governments' abilities to attract oil and gas investments to offshore regions. Legislative changes are also having an impact, particularly the 2015 end of the ban on exporting of most U.S. crude oil products, and the 2017 changes to the U.S. Federal income tax.

Since 2014, the oil and gas industry has restructured to adapt to the low oil price environment, which has shifted from a "lower for longer" mentality to a potential "new norm" mentality.[50] This restructuring has forced the oil industry to adopt structural and cyclical cost reductions which have resulted in the following:

- A 41% decline in deepwater costs since 2014, with cyclical costs accounting for 60% of the decline and structural costs accounting for the remaining 40%
- A 38% overall decline in shallow water costs since 2014, with cyclical costs accounting for 55% of the decline and structural costs accounting for the remaining 45%[51]

IHS Markit defines cyclical costs as costs that are sensitive to market conditions and can fluctuate rapidly. These costs usually include equipment and labor rates and are tracked by IHS Markit Upstream Capital Cost Index and Upstream Operating Cost Index.

Structural cost changes, however, can occur due to factors other than market conditions. They can result from efficiency gains, design changes, and technological advances, such as automation, digitization, and drone utilization.[52]

Resource nations, on the other hand, were slow to react to the new reality. Resource holders, particularly those heavily dependent on oil and gas revenues, usually go through a four-stage process in reaction to a lower oil price (Figure 4-1). The initial reaction is usually that of inertia and unwillingness to act until absolutely necessary.[53] While logic might dictate any subsequent policy changes should be investor-positive to retain investors' interest, this is rarely the first response when there is real economic distress. In time, funding cuts and limited output growth tend to result in an easing in some E&P terms, particularly those for new offerings.[54]

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[50] Asmar B, Structural cost reductions: The industry savior, IHS Markit, August 2018.
[51] Ibid.
[52] Ibid.
[53] IHS Markit PEPS Oil and Gas Risk Service, Zones of vulnerability: Mapping where down-cycle risks live on, August 2018.
[54] Ibid.

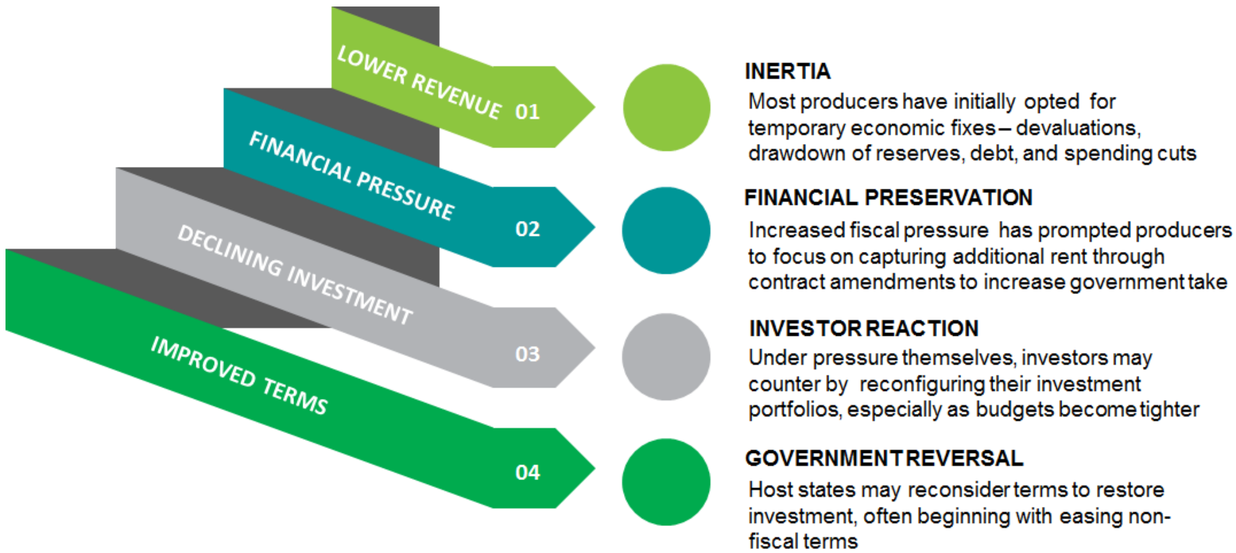

Figure 4-1. Reaction stages: Typical government responses to oil price drops

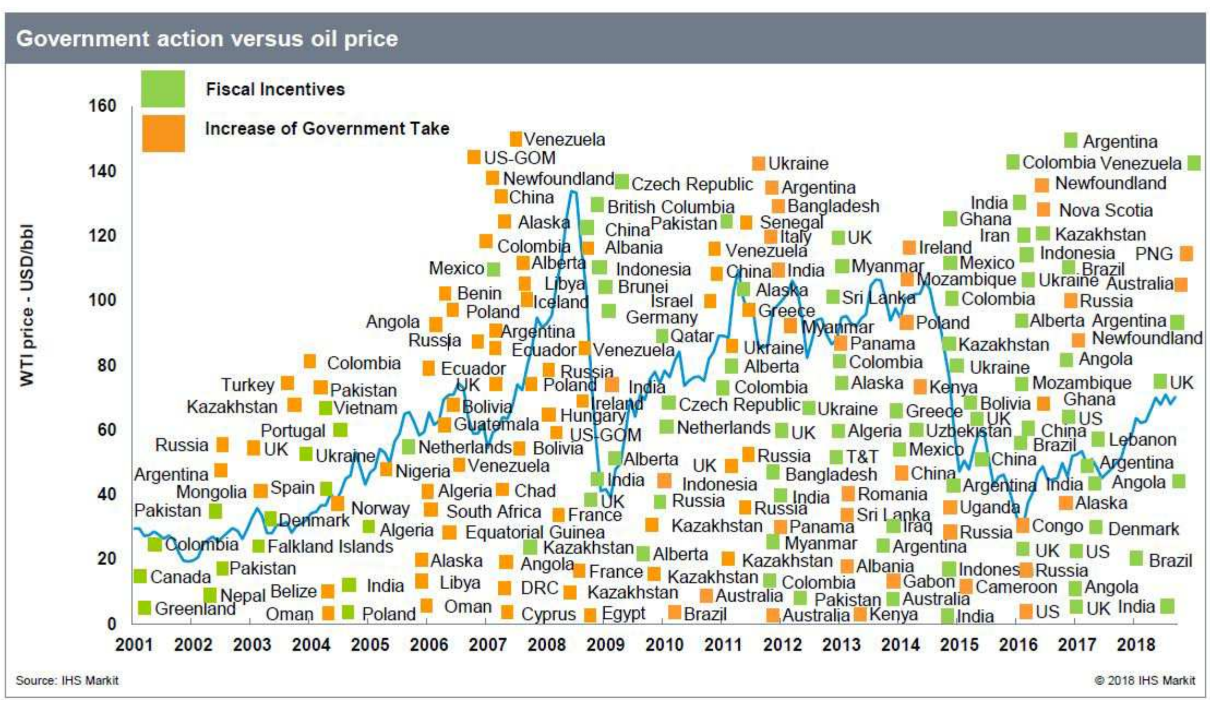

Figure 4-2. Government action versus oil price

The market downturn that started in the second half of 2014 was accompanied by slow, often incremental changes to the government take (Figure 4-2). While governments made changes—especially in the 2016–2017 period—with few exceptions, such actions were often in reaction to lackluster performance in the E&P sector and were often introduced in a piecemeal fashion, rather than as part of a well thought-out plan. Some governments engaged in public relation campaigns to manage perception rather than enact meaningful changes to oil and gas fiscal terms. Often countries would announce plans to reform and restructure the oil and gas sector, including the role of the national oil company, a year or two in advance of the actual change.

However, some governments did take proactive action to compete for investments and launched a series of initiatives to accomplish their goals. In this section, we examine the changes in fiscal terms implemented by the jurisdictions in the shallow and deepwater peer groups following the 2014 oil price collapse. Figure 4-3 provides a snapshot of some of the key measures that affect the oil and gas fiscal systems.

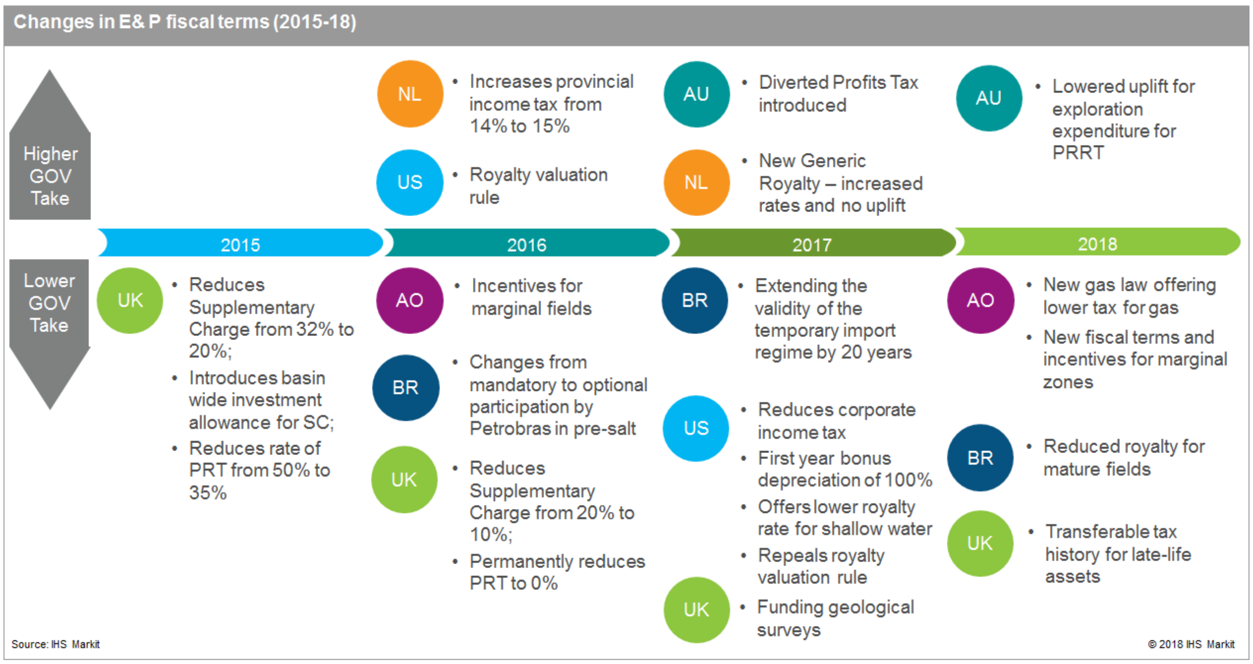

Figure 4-3. Changes in E&P fiscal terms (2015–18)

While all jurisdictions included in this study experienced a significant decline in exploratory and appraisal drilling, their approaches to respond to the decline differed. Table 4-1 summarizes the approaches of the respective jurisdictions.

Table 4-1. Government response to commodity price drop

Jurisdiction	Response to market changes and decline in exploratory activity			
	Took action to lower government take	Took action to increase government take	Conducted competitiveness review	Stayed the course
Angola	●			
Australia			●	
Brazil	●			
Canada - NL		●		
Guyana				●
Mexico	●			
Norway				●
United Kingdom	●		●	
United States GOM	●		●	

Source: IHS Markit

Guyana and Mexico were in the process of awarding their first acreage when the downturn occurred, so neither the initial terms introduced nor the adjustments made during their first licensing rounds are analyzed in this study, since the initial terms were only ever in draft form. In the case of Norway, the corporate income tax was reduced from 28% to 23%, which was followed with a 5% increase in the special petroleum tax (i.e., 50–55%), to maintain the balance of the government take for the oil and gas industry. Therefore, there is no analysis of actions taken by Norway, Mexico, or Guyana in this section.

4.1.1 Going with the Trend

4.1.1.1 Angola

Lower oil revenue since 2014 has exposed the structural inefficiencies, spiraling costs, and rising debt at Angola's national oil company, Sonangol. Angola's primary fiscal balance went from a 9% surplus in 2011 to a nearly 5% deficit in 2015. Historically strong gross domestic product (GDP) growth (nearly 8% in 2012) fell sharply, with the economy contracting in 2016 before growing only 1.1% in 2017 (Figure 4-4). Upstream investment in Angola stalled as international oil companies (IOCs) pulled back from both the costly deepwater projects that constitute the majority of the country's base and from new source production.[55] Exploratory and appraisal drilling declined from a total of 26 wells in 2014 to just one appraisal well in 2017 (Figure 4-5).

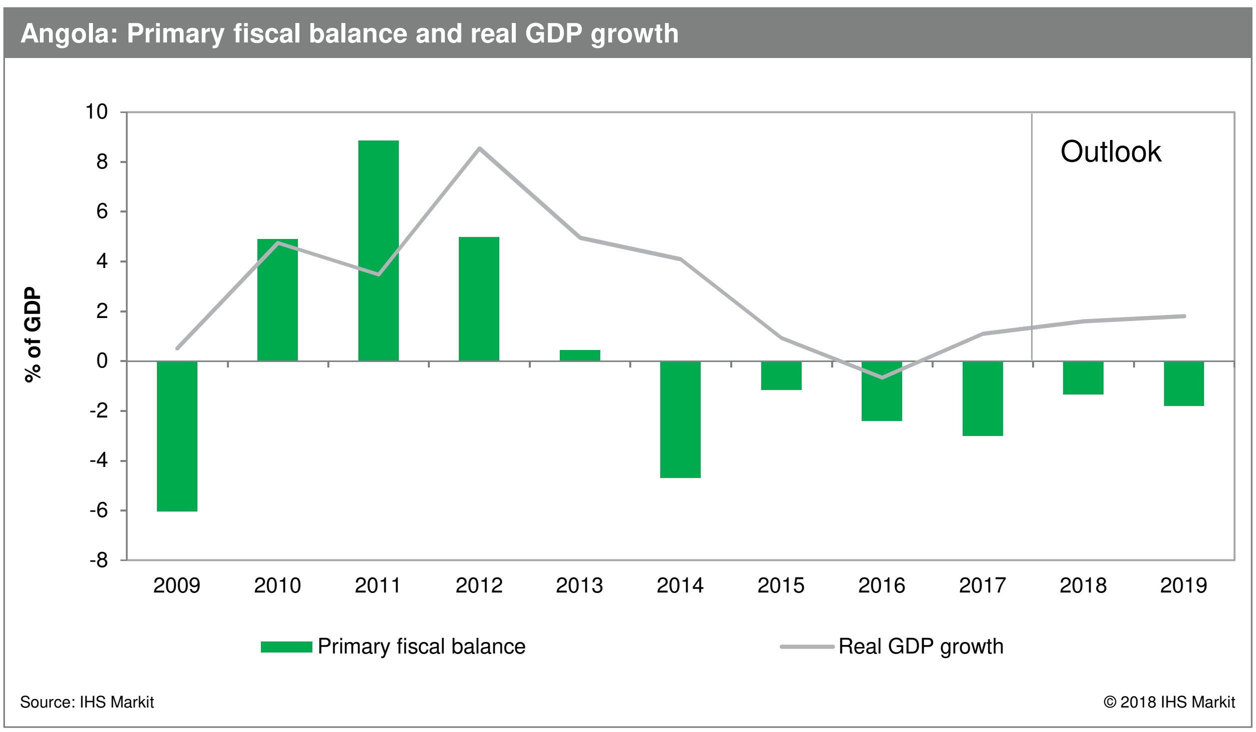

Figure 4-4. Angola: Primary fiscal balance and real GDP growth

[55] Bruce Roderick, DeLucia Chris, Sonangol: Government Drivers, IHS Markit, April 2018.

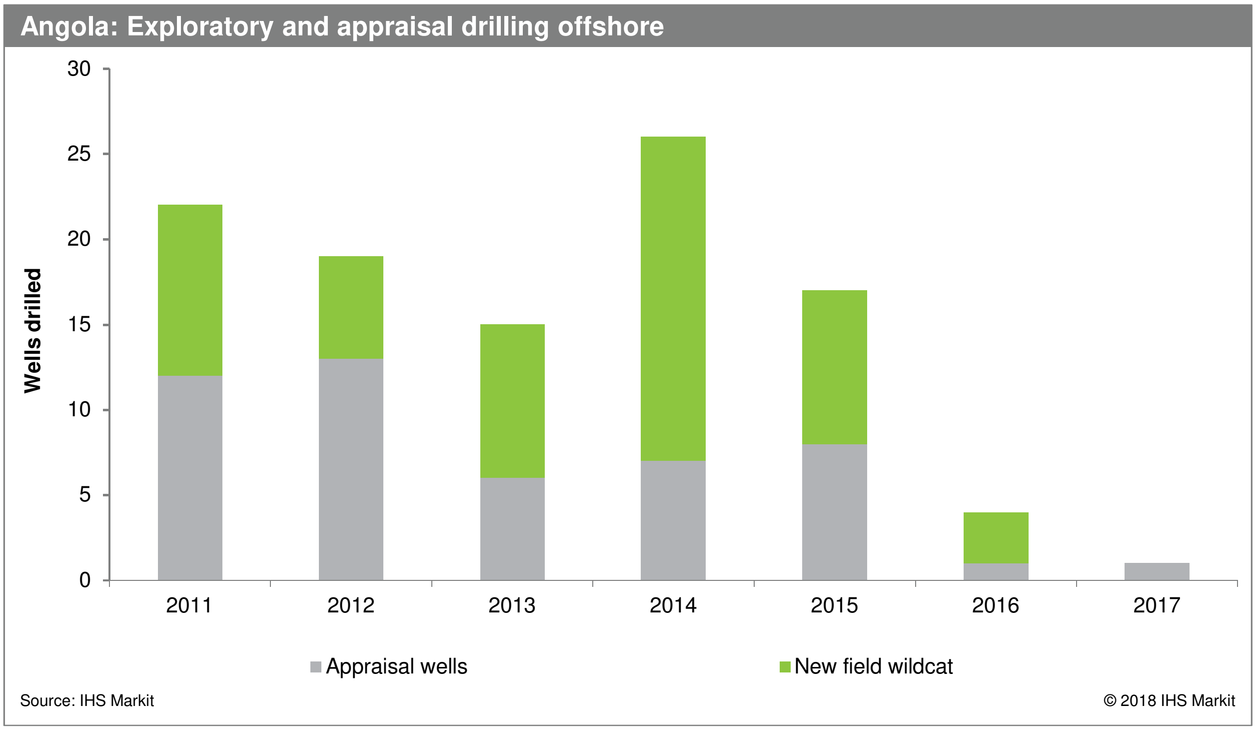

Figure 4-5. Angola: Exploratory and appraisal drilling (2011–2017)

The government has set the following priorities for the upstream oil and gas sector:

- **Enact contractual and fiscal changes to promote development of discovered resources, including new terms for natural gas:** The current government is continuing with the previous regime's pragmatic and flexible approach to contractual terms amid lower oil prices and challenging project economics since 2014. PSCs with foreign IOCs are being renegotiated on a case-by-case basis to reduce break-even project costs, while Angola is offering several incentives to upstream investors, including improved cost recovery for near-field exploration in existing contract areas and incentives for marginal field development. A contract regime conferring ownership of gas resources to foreign investors—under consideration for more than a decade—will probably be introduced in 2019 while a new model contract for frontier onshore exploration is also being drafted.
- **Formulate and enact legislative updates facilitating hydrocarbon sector institutional reform:** A working group commissioned by President Lourenço was given an April 2018 deadline to reconsider oil sector institutional reforms planned by his predecessor in 2016. The group favors a more thorough but more challenging approach to reform: shifting Sonangol's concessionaire role to a new regulator (the state firm would have retained this role under the previous plan) and abandoning plans to form an advisory Higher Council, thereby reducing decisionmaking bottlenecks.
- **Promote new exploration in established and frontier areas:** There have been no successful bid rounds since the 2011 pre-salt round, and a large swathe of the acreage awarded in 2011 has been handed back to the government because of disappointing drilling results and worsening economics for new deepwater developments.

Since the downturn in commodity prices, Angola has taken the following actions that have impacted upstream fiscal terms:

Contract renegotiations: During 2015 and 2016, Angola entered into a series of negotiations with existing holders of exploration acreage to improve project economics and influence investment decisions.

Marginal field incentives: In 2016, Angola introduced incentives for marginal fields, which were later improved in 2018. Such incentives apply to the following:

- Reserves less than 300 MMbbl
- Water depths greater than 800m
- Revenues for the state less than USD10.5/bbl
- Revenues for the oil companies less than 21/bbl
- An after-tax internal rate of return of less than 15%
- Geologically complex fields with more than 300 MMbbl, which may be considered marginal if the internal rate of return is less than 15%.

The incentives for marginal fields included the following:

- Reduction in the petroleum production tax for association agreement (joint ventures) and RSC from the generally applicable 20% rate to 10%
- Establishment of income tax rate at 25% versus 50%
- Depreciation of exploration and development costs over 3 years
- Set the cost recovery ceiling for the first 4 years at 80% and at the standard 65% thereafter
- Establishment of an investment premium of 20%.

4.1.1.2 Brazil

The reforms that were implemented during the 2016–2018 timeframe in Brazil were spurred by: (1) the Lavo Jato (Car Wash) corruption scandal that involved, among others, the president and Petrobras leadership; (2) the deterioration of Brazil's fiscal accounts since 2012, marked by general government fiscal deficit widening from approximately 2% of GDP to a record high of 10% of GDP in 2015; (3) the decline in E&P drilling (Figure 4-6); and (4) the 2014 drop in oil prices.

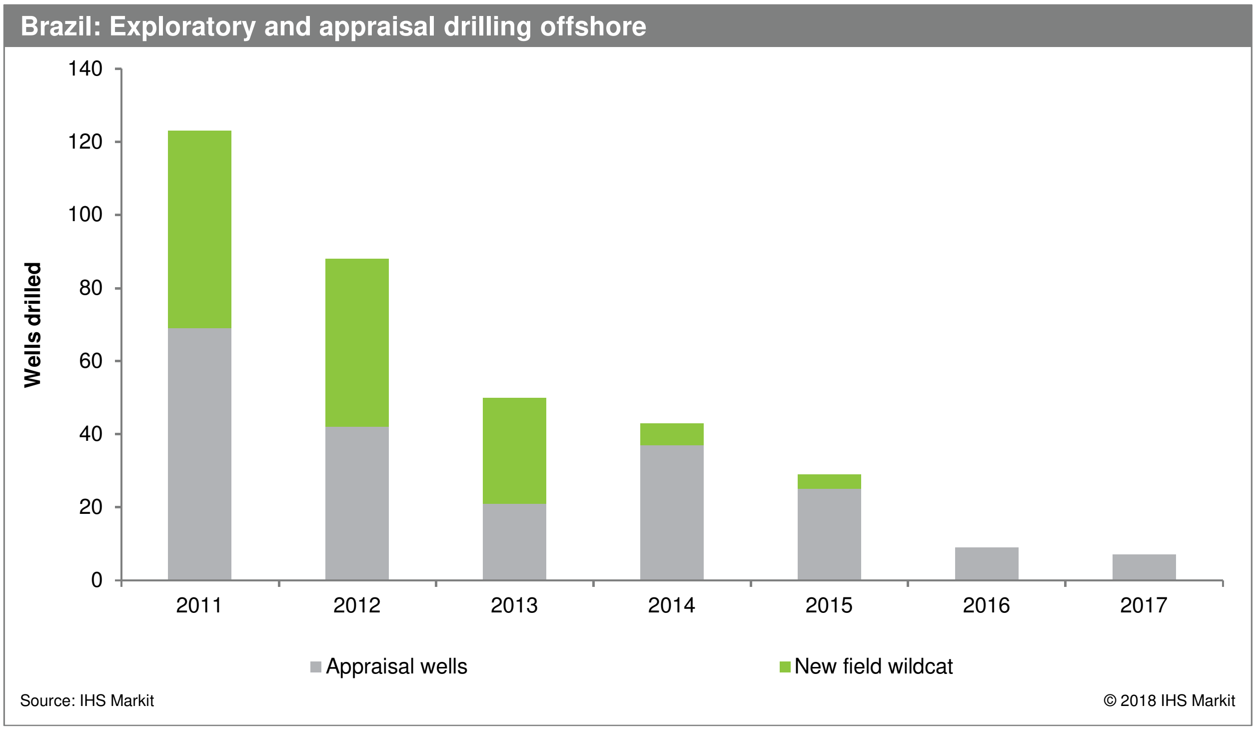

Figure 4-6. Brazil: exploratory and appraisal drilling (2011–17)

The reforms implemented by Brazil after this series of events had the following stated objectives:[56]

- **Achieve self-sufficiency in crude oil production:** Growth in oil production over the past two decades has enabled Brazil to meet the government's long-held goal of crude self-sufficiency.
- **Prioritize pre-salt development**: The Temer Administration has granted IOCs unprecedented access to new pre-salt acreage via bid rounds. Brazil held two pre-salt bid rounds in 2017 and two more in 2018. The government has also included blocks adjoining the pre-salt polygon in concession (royalty/tax) bid rounds. This compares to the award of just one pre-salt block by the Rousseff Administration, during the 2011 to 2016 timeframe.
- **Boost exploration through more frequent bid rounds**: In June 2017, the National Council of Energy Policy (CNPE) published Resolution No. 17/2017, setting out the government's hydrocarbon E&P policy priorities. These included maximizing the recovery of in-place resources, quantifying Brazil's hydrocarbon potential, expanding exploration activity, and promoting the monetization of existing reserves — all while protecting national interests.
- **Balance the role of the National Oil Company (NOC)**: The Temer Administration recognized that heavy reliance on Petrobras for upstream activity and investment is not conducive to the optimal and efficient development of Brazil's hydrocarbon resources.

[56] Kerr Juliette, Larson Dave, Petróleo Brasileiro S.A. (Petrobras): Government Drivers, IHS Markit, July 2018.

As a result of the reforms taken, the following changes were introduced that impact the oil and gas fiscal terms.

Elimination of Petrobras mandatory participation: Petrobras' mandatory participation requirement for pre-salt areas was amended in 2016 to provide for "option to participate" rather than "mandatory" participation. The mandatory Petrobras participation in the pre-salt areas had resulted in a rather slow pace of leasing of pre-salt acreage in Brazil. The government was often forced to suspend plans for licensing rounds in pre-salt when Petrobras did not have the financial resources to commit to new investments.

Relaxation of local content: Local content requirements that resulted in significant cost overruns and schedule delays were relaxed in 2017.

Extension of REPETRO regime: Brazil's temporary import exemption regime (REPETRO) was extended for an additional 20 years and permanent import incentives were introduced in 2017.

Lowering of royalty rates for mature fields: On September 24, 2018 the government issued National Petroleum, Natural Gas and Biofuels Agency of Brazil (ANP) Resolution 749/2018 that reduces the royalty rates on incremental production for mature fields as follows:

- small producing mature fields pay a 5%-rate on any incremental production
- large producing mature fields pay a regressive rate from 7.5% to 5% on any incremental production
    - incremental production higher than 50% of the production profile pays a 5%-rate
    - incremental production lower than 50% of the production profile pays a 7.5%-rate

The regulation defines 'mature field' as a field with historical production equal to or greater than 25 years, where the cumulative production represents at least 70% of its proven reserves. The mature fields are grouped into two categories, as follows:

- **Small producing field** is an onshore field that has always had production equal to or less than 5,000 boe/d, or an offshore field that has always had production equal to or less than 20,000 boe/d.

- **Large producing field** is an onshore field that produces more than 5,000 boe/d or an offshore field that produces more than 20,000 boe/d.

4.1.1.3 United Kingdom

Since 2014, the United Kingdom has taken significant measures to improve the competitiveness of its offshore oil and gas sector and has been the country to most aggressively work to attract investment within the peer group. The changes that were introduced during the 2015 to 2018 timeframe were a result of various consultation processes that had started before the 2014 decline in oil prices. The UK North Sea sector was considered to have a very unstable fiscal regime and relatively high government take. Production has been on the decline (Figure 4-7) despite the various field allowances introduced by the government in recent years to encourage investment.

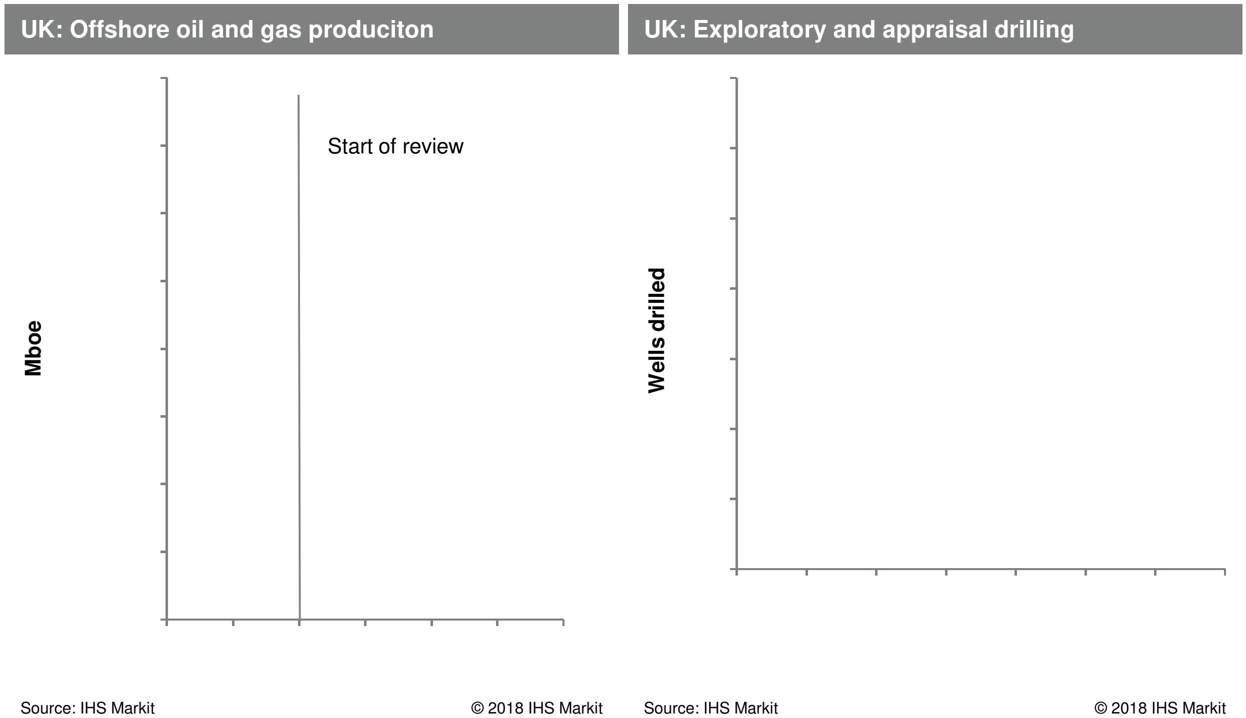

Figure 4-7. UK: E&P activity (2011-17)

In June 2013, the United Kingdom's Secretary of State for Energy and Climate Change asked Sir Ian Wood to conduct an independent review of the oil and gas recovery in UK continental shelf, with specific emphasis on maximizing economic recovery. The Wood review was completed in 2014 and made several recommendations, including the establishment of a Maximum Economic Recovery (MER) strategy. Following the recommendations of the Wood review, Her Majesty's Treasury published "*Review of the oil and gas fiscal regime: Call for evidence*," in July 2014.[57] The *Call for Evidence* sought, among others, the establishment of a working group that would look at "the overall shape and structures of the ring fenced regime … to ensure that it remains fit for purpose over the basins remaining lifetime, reflecting the economics of the basin as they change."[58] The group was specifically tasked to consider, among other things, the following:

- The overall competitiveness of the UK oil and gas fiscal regime
- Whether the tax rates and allowances reflected an appropriate balance of risk and reward between industry and the government
- Whether the fiscal regime should reflect the differing economics of oil and gas in the North Sea
- The pros and cons of the field allowances system that had been put in place in recent years and the principles that should inform changes to the regime in the future.

In 2015, a series of consultations followed the Wood Report and the *Call for Evidence*. The UK government took concrete action that resulted in the following policy initiatives:

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[57] HM Treasury. 2014. 'Review of the oil and gas fiscal regime: Call for evidence,' UK.GOV.
[58] Ring fenced income refers to income from oil and gas activities in North Sea. Such income is ring fenced around the North Sea sector and is taxed at 30% versus the general corporate income tax of 19%.

Supplementary charge rate reduction: In 2015, the UK government reduced the rate of the supplementary charge (SC), a levy specific to the oil and gas industry, from 32% to 20%. The rate of the SC was further reduced from 20% to 10% in 2016.

Petroleum Revenue Tax (PRT) rate reduction: The rate of the PRT was initially reduced from 50% to 35% in 2015. This measure affected existing oil and gas leases that were awarded before 31 of December 1992. PRT on post-1992 developments had been abolished in March 1993. In 2016, the UK government took further steps to permanently reduce PRT to 0%.

Introduction of new investment allowance: In 2015, the government introduced a basin-wide investment allowance that replaced the existing field allowances. The new measure was intended to encourage investment and reduce complexity for investors. The allowance covers capital expenditure and other investment expenditure, including leasing costs and operating costs that add value to a field, as well as tariff income. The allowance shields an amount equal to 62.5% of qualifying capital and investment expenditure of corresponding taxable income from the supplementary charge.

Introduction of cluster area allowance: The cluster area allowance was introduced to encourage the development of near-field exploration. It operates alongside the basin investment allowance and is equal to 62.5% of the qualifying expenditure in relation to a cluster (a HPHT discovery, which could contain more than one discrete field). Expenditures that already qualify for cluster area allowance do not qualify for basin investment allowance.

Ring fence expenditure supplement (RFES): This mechanism allows investors who are not in a position to generate taxable income——and therefore deduct qualifying exploration costs—to carry forward those costs, accruing at a rate of 10% (compensating for the loss in real terms value). The number of accounting periods (i.e., years, not necessarily consecutive) for which this could occur has been increased from six to ten by Section 47 of Finance Act 2015 and its Schedule 11.

Government funding of seismic surveys: The government provided £20 million of funding for seismic surveys in 2015/2016 and an additional£20 million in 2016/2017. The results of the survey are made available without charge. This effort provides industry with better data on prospects in the UKCS, helping to boost offshore exploration and encourage investment in under-explored areas.

Decommissioning relief deeds: Measures on decommissioning relief were introduced in the Finance Act of 2013, giving the government statutory authority to sign contracts with companies operating in the UKCS to "provide assurance on the relief they will receive when decommissioning assets."[59] On September 3, 2013, the UK government announced that it would enter into 'legally-binding contracts' termed "Decommissioning Relief Deeds" (DRDs) that purport to guarantee future tax relief on decommissioning costs.

DRDs are essentially bilateral agreements made with the UK government amounting to "contracts for difference on the future tax code." It is understood that DRDs establish a reference amount—to "crystalize" the regime of tax relief available for decommissioning, as at the time of the enactment of Finance Act of 2013—that qualifies for tax relief "in perpetuity". This is to allow the DRD holder to claim any shortfall from the government if this amount is not achieved through the taxation system.

DRDs provide for two potential scenarios, as follows:

[59] Finance Act 2013, ss.80-85.

- Where a DRD holder is meeting another's decommissioning costs, the DRD guarantees relief at a rate of 30% regarding income tax and 20% regarding surcharge. The level of relief regarding PRT will be the same as that which the defaulting party would have received (or "greater, from their own tax history"); and
- Where a DRD holder is meeting its own liabilities for decommissioning, the DRD guarantees relief "aligned to the rate of tax paid" (as well as access to relief regarding PRT if PRT is abolished).

The stated aim of the government's introduction of DRDs is that they act as a disincentive to potential changes in the future regarding treatment of decommissioning costs. They are thus an instrument of "last-resort" and there is an expectation that they will not need to be relied upon.

Transferable tax history for decommissioning: In late 2017, the UK government announced a mechanism unique to income tax and the petroleum industry: transferable tax history. This is designed to allow purchasers of UKCS assets to deduct decommissioning costs paid by previous licensees where the purchaser has not generated enough tax history to deduct such costs as determined in a costed decommissioning plan.

For deals that are completed on or after November 1, 2018, the government intends that some of the historical tax paid for given oil and gas fields be made available to successive licensees when assets are sold. This will allow purchasers to claim greater decommissioning relief by offsetting costs against a potentially larger pool of previously-paid tax. It is also the government's intention that the complexity of deals for acquiring UKCS late-life assets be reduced, facilitating continuing activity, consistent with the MER policy.

4.1.1.4 United States

While the U.S. has seen boom in oil and gas activity despite the economic downturn, growth of U.S. production has largely taken place on onshore private lands, or on split-estate properties where the Federal share is relatively minor, despite the vast resources underlying the Federal lands.[60] The drop in commodity prices led to a shift towards short-cycle barrels, leading to a reduction in deepwater exploration activities. While the industry has benefitted from certain actions taken by the U.S. government, not all were designed to assist the oil and gas sector.

The following key legislative and administrative measures have affected the U.S. Federal fiscal systems:

Changes to royalty valuation rule: In August 2017, the DOI repealed a royalty valuation rule issued by the previous administration in 2016. The 2016 rule sought, among other things, to reform the approach to valuation of oil and gas royalty by eliminating transportation and processing allowances. The rule faced opposition and litigation challenges prior to its effective date of January 1, 2017. The DOI repealed the rule on the following grounds:

- The Rule had "a number of defects that make certain provisions challenging to comply with, implement, or enforce." Such defects would, among other things, compromise the Office of Natural Resources Revenue's (ONRR) mission to collect and account for royalties and would "impose a costly and unnecessary burden on the Federal and Indian lessees."
- The rule would "unnecessarily burden the development of Federal oil and gas… beyond the degree necessary to protect the public interest or otherwise comply with the law."

[60] Congressional Research Service, "U.S. Crude Oil and Natural Gas Production in Federal and Nonfederal Areas", 2016.

- ONRR expects to conduct further internal assessment and analysis and lead the development of a new valuation rule with input from the reestablished Royalty Policy Committee.

Lowering of the royalty rate for GOM shallow waters: In Lease Sale 249, held in August 2017, BOEM offered a royalty rate of 12.5% for new shallow water leases in GOM. GOM sales held in previous years had included an 18.75% royalty rate for such leases. This lower shallow water royalty rate was also offered in Lease Sale 250, held in March 2018, and Lease Sale 251, held in August 2018. (GOM)

Reduction of the corporate income tax: The most significant recent change that has affected U.S. oil and gas producers was the passage of the Tax Cuts and Jobs Act in December 2017. This Act (Section 13001) changes the corporate income tax rate in the U.S. from a maximum of 35% to a flat rate of 21%, effective January 1, 2018.

First-year bonus depreciation: The Tax Cuts and Jobs Act increases the bonus depreciation percentage from 50% to 100% for qualified property acquired and placed in service after September 27, 2017, and before January 1, 2023. The bonus depreciation percentage for qualified properties that a taxpayer acquired before September 28, 2017, and placed in service before January 1, 2018, remains at 50%. The Tax Cuts and Jobs Act provides for a five-year phase down of the 100% depreciation starting on January 1, 2023.

Elimination of loss carry back: The Tax Cuts and Jobs Act also amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act provided that 100% of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years. Section 13302 of the Tax Cuts and Jobs Act amended the statute to allow a deduction for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80% of taxable income computed without regard to the deduction allowable under 26 U.S.C. Section172. Such loss can be carried forward indefinitely, but there is no longer a carry back option.

4.1.2 Going Against the Trend

4.1.2.1 Australia

In response to the downturn in crude oil prices and declining revenue from the Petroleum Resource Rent tax (PRRT), the government of Australia conducted a review of the PRRT in 2017. The government's mandate for this review was to do the following:

- Examine the design and operation of the PRRT
- Consider the impact of previous decisions on Commonwealth revenue
- Make recommendations, based on international experience, on future tax, excise, and royalty arrangements that are related to revenue adequacy, efficiency, equity, complexity, regulatory costs, and the impact on the industry.[61]

In 2017 and 2018, the government of Australia took measures to increase the government take from oil and gas activities offshore.

Introduced Diverted Profits Tax: A Diverted Profits Tax, introduced in April 2017, applies to profits of multi-national corporations that transfer profits generated in Australia and send them to offshore

[61] Australian Government: Petroleum Resource Rent Tax Review, April 2017, 10.

jurisdictions. The levy applies at a fixed rate of 40% to Australian companies that are part of a multi-national group with gross global income of over AUD1 billion.

Introduced changes to PRRT: In an effort to increase revenues from the oil and gas sector, on November 1, 2018, the government of Australia introduced changes to PRRT that reduce the amount of uplift applicable to exploration expenditure. The government hopes to raise an extra AUD6 billion in revenue over the next 10 years by changing the uplift for PRRT. Exploration expenditure incurred by projects before July 1, 2019, will still be deducted at the current uplift rate of the long-term bond rate (LTBR) +15 percentage points. However, after July 1, 2019, the rate will fall to LTBR+5 percentage points.

4.1.2.2 Canada – Newfoundland and Labrador

Oil and gas investments in the province have been affected by the following measures that were introduced during the 2016-2017 period:

Provincial Income Tax increase: In 2016, the provincial income tax rate was increased from 14% to 15%.

Introduction of new Generic Royalty Regime: In November 2017, the Province of Newfoundland and Labrador released offshore royalty regulations that replace the previous royalty regime with a new generic offshore royalty that applies to all projects moving forward. The new regulations introduced the following changes that resulted in an increase of the government take:

- Eliminated the previously-applicable return allowance and uplifts on eligible costs
- Set the maximum for net revenue royalty to 50% versus 35% applicable previously.[62]

4.2 Industry Response

The impact of changes to fiscal terms is not always immediately measurable in terms of investment in the offshore oil and gas sector. The majority of the changes in fiscal terms have occurred in the past couple of years, and there has not been sufficient time to observe whether changes in industry behavior can be definitively attributed to the respective governments' policy decisions. Additionally, the metrics for measuring industry reaction could be different in each jurisdiction, based on the characteristics of the policy measures introduced, as well as the types of investments targeted in each country.

The degree of change in fiscal terms also plays a role as to how the industry reacts—usually the greater the impact on project economics, the more emphatic the industry response, whether positive or negative. Figure 4-8 shows the degree of change of government take in the respective jurisdictions. The average field sizes selected for this study were used to generate the difference in government take. The change in government take for mature fields has not been captured in Brazil, as the models for this study were not designed as mature fields. The other policy changes introduced in Brazil during 2016 and 2017 relate more to access to acreage and reducing cost of doing business (i.e., exemption from import duties, softening of local content requirements.). The change in Petrobras' mandatory participation requirement contributes more to access to pre-salt acreage by IOCs rather than government take. Petrobras participation is on a working interest basis in the pre-salt acreage and therefore does not affect the government take.

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[62] Under the 2003 Regulations, tier I incremental royalty was 20% and tier II was 10% for a maximum incremental royalty of 30%. Under the 2017 Regulations net royalty starts at 10% when the recovery factor equals 1.0 and rises to a maximum of 50% when the recovery factor is 3.0 or more.

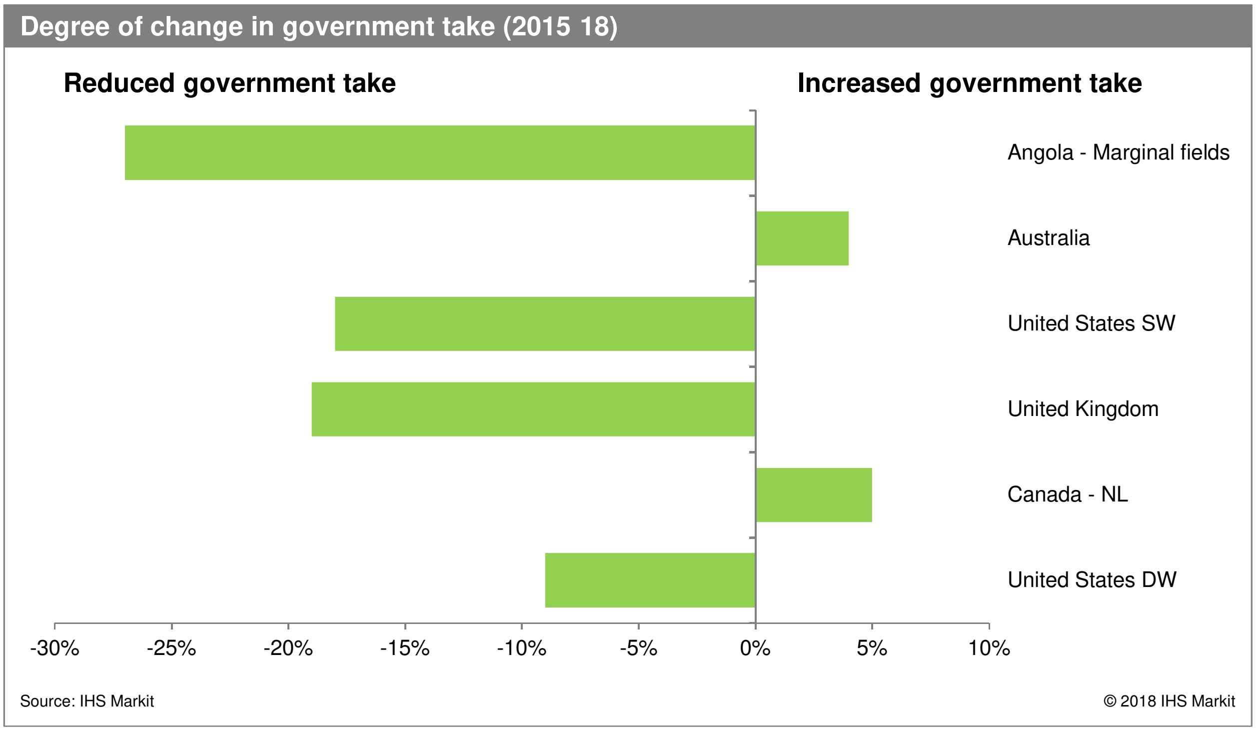

Figure 4-8. Degree of change in government take (2015-2018)

The UK and U.S. GOM shallow water fiscal systems have had the most impactful measures affecting future investments in their respective oil and gas sectors—the changes introduced by Angola do not apply to all investments. This is largely driven by the maturity of the respective offshore areas in the U.S. and UK. The changes introduced by Australia, which come into effect in 2019, occurred when the economic analysis for this report was completed. Thus, the economic indicators for Australia are based on the terms in force in 2018.

4.2.1 Impact of Measures in the United Kingdom

The changes that resulted in lowering the government take have been very well received by the industry in the United Kingdom. The Oil and Gas UK (OGUK), an association of the oil and gas producers, was very supportive of the MER Strategy in its *2018 Economic Report* and states that "… the sector has become more competitive and the foundations are being laid to add a generation of productive life to the basin."[63] The *2018 Economic Report* further states that the latest regulatory and fiscal changes in the United Kingdom have helped position the UKCS as one of the leading destinations for investment.[64] According to the OGUK, the industry found the UKCS to be in a good position to "compete against the most attractive comparable basis for access to investment in terms of overall returns," across each of the following factors that are key to competitiveness[65]:

- Total costs from exploration through development operations and ultimately decommissioning
- The scale of the resource base and prospectivity opportunities

[63] Oil & Gas UK – Economic Report 2018.
[64] Ibid.
[65] Ibid.

- The availability of infrastructure to service the projects
- The fiscal competitiveness of the basin
- The regulatory competitiveness
- The ability to secure access to finance
- The capability of the supply chain to service demand
- The people skills to manage and execute projects and ongoing operations.[66]

The MER UK strategy appears to have boosted industry confidence attractiveness and future stability of investment environment in the UKCS. The production levels displayed in Figure 4-8 show a reversal of the production decline, subsequent to the introduction of fiscal measures. The measures introduced by the United Kingdom target existing investments as well as future investment. The increase in production levels, at a time when commodity prices were in free fall, is an indication of the effectiveness of the fiscal measures introduced and the industry enthusiasm about the policies implemented by the UK government. The full impact of policy decisions on exploratory drilling is usually measured after passage of a three- to four-year period. New field wildcat and appraisal well drilling reached bottom in 2016, with 24 wells combined—this was followed by an uptick in drilling in 2017 (Figure 4-8). While this is well below the 60-well mark in 2012, the reversal of the decline indicates confidence in the oil and gas sector in the UK. Similar trends appear when licensing activity is taken into account. The acreage awarded in 2017 (54,000km^2) is four times greater than the acreage awarded in 2014 (13,000km^2) – before the MER strategy was developed and changes to fiscal terms were introduced.

4.2.2 Impact of Measures in Brazil

In Brazil, the new administration of Michel Temer was able to halt and reverse the downward trend in oil and gas activity by implementing significant reforms. The fiscal and regulatory reforms that were instituted in 2017 provided the IOC with more open access to the highly prospective pre-salt areas and lowered the cost of doing business in Brazil. This led to very aggressive acquisition campaigns by oil companies in Brazil for deepwater acreage, especially in the pre-salt plays. Contract activity dominated in 2017, with three successful licensing rounds. The level of interest in the three licensing rounds for 2018 was very high. The best measure of industry confidence in policies introduced by the government in Brazil are the signature bonuses paid in recent licensing rounds and the production sharing volumes offered to the government. The amount received by the government via signature bonuses in 2017 was quadruple the amount received in 2013—Brazilian Real (BRL) 3.4 billion in 2017 (USD850 million) from royalty tax concessions and an additional BRL6.15 billion (USD1.54 billion) from pre-salt PSAs versus BRL1.48 billion (USD370 million) in 2013. According to ANP, the country's oil and gas regulator, the production sharing volumes offered to the government for the six pre-salt areas in 2017 correspond to an additional BRL200 billion (USD50 billion) over the life of these projects.[67]

4.2.3 Impact of Measures in the U.S.

Though the fiscal measures introduced by the U.S. government have played a significant role in the reduction of the government take in the U.S., it is difficult to assess the impact that the corporate income tax change and the royalty rate reduction have had on development activities. As previously stated, it typically takes three to four years to assess the full impact that policy decisions have on exploratory drilling. The only metric to consider is the leasing of acreage in the U.S. GOM. In 2016, the acreage awarded in the

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[66] Ibid.
[67] ANP, Opportunities in the Brazilian Oil and Gas Industry: Ongoing Actions and 2018-2019 Upcoming Bidding Rounds, January 2018.

Gulf of Mexico hit the lowest level for the period considered in this study. The leasing activity gradually recovered in 2017 and 2018—reaching 6,500km^2 in 2018, almost double the 2016 levels of 3,340 km^2 (Figure 4-10). It is difficult to assess to what extent the policy measures have contributed to the reversal of the decline in leasing activity. The gradual increase from 2017—the year in which fiscal measures were introduced—to 2018 does not appear to be as significant as one would expect given the 9 and 18 percentage drop in government take for deepwater and shallow water areas, respectively (Figure 4-9). The heightened competition from Brazil and Mexico—holding three to four licensing rounds per year—perhaps has had a role in the tepid recovery of the U.S. GOM leasing activity.

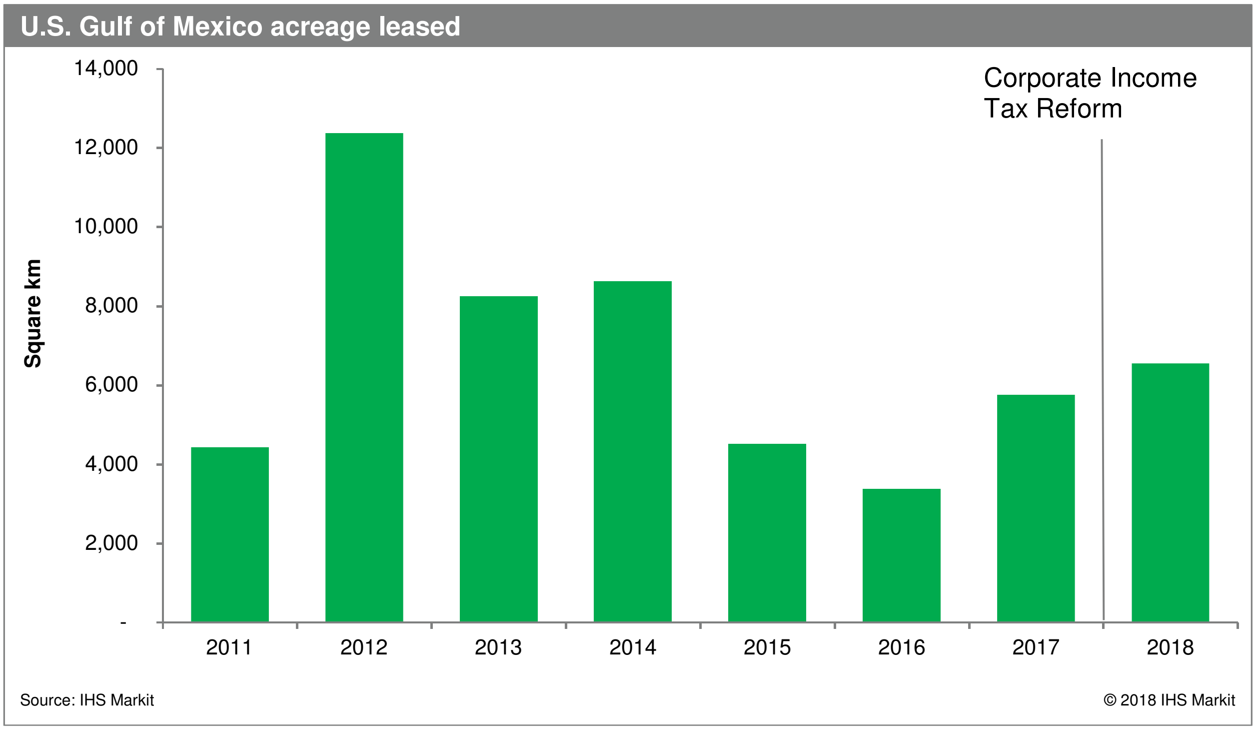

Figure 4-9. U.S. Gulf of Mexico acreage leased

Since the corporate income tax change affects both existing and future investments, perhaps a better indicator of its impact in the future would be the trend in final investment decisions (FIDs) and sanctioned volumes. The data to date (Figure 3.5) does not show any discernible trend in the U.S. GOM regarding sanctioned volumes. However, the fourth quarter historically sees the largest sanctioning activity, and data for the fourth quarter of 2018 are not available to analyze in this report.

Development drilling, on the other hand, has picked up significantly in 2018 versus 2017 in deepwater GOM. The year-to-date data for 2018 is quite promising – marking a 60% increase over 2017 (Figure 4-10). Should this trend continue, U.S. deepwater development drilling will probably come close to 2014 levels by the end of 2018. While the price recovery may have a role to play in activity pick up, the same trend is not occurring on the shelf, where the decline from 2014 levels is very dramatic (80%)—despite the significant drop in government take. The decline in government take for projects on the shelf is double that for deepwater projects. This is an indication that the competitiveness of the U.S. GOM oil and gas sector hinges on more than just government take.

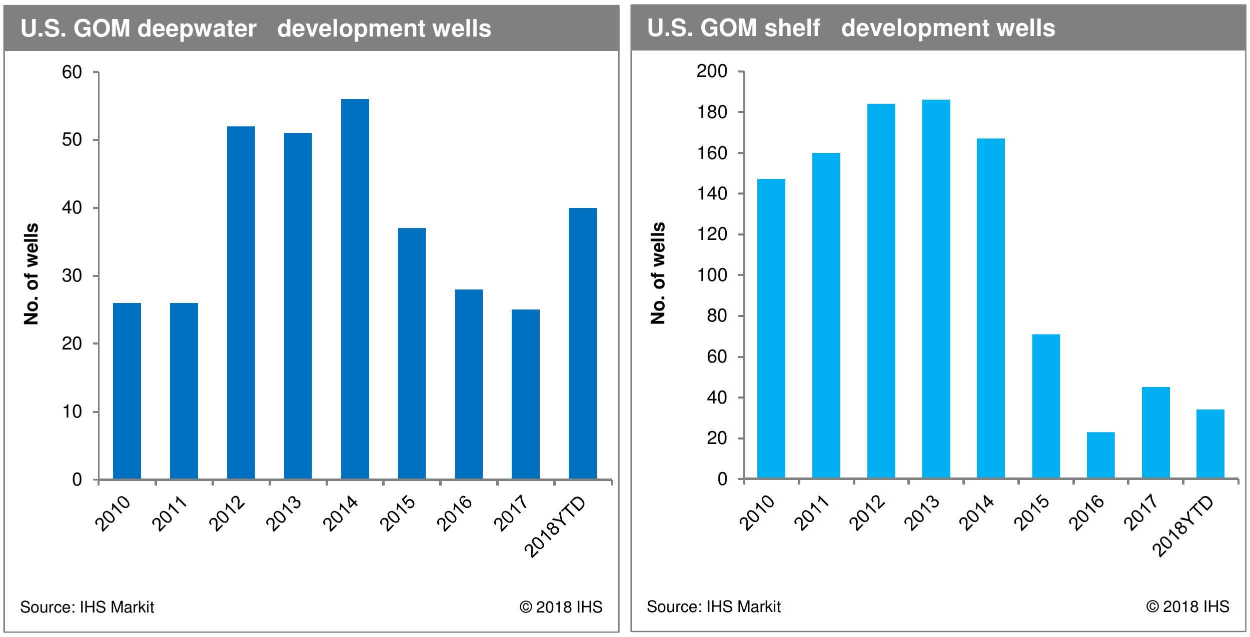

Figure 4-10. U.S. Gulf of Mexico development drilling

4.2.4 Impact of Measures in Canada

The changes to the generic royalty regulations introduced by the government of Newfoundland and Labrador in November 2017 resulted in an increase of the government take for already high cost developments offshore. From a licensing activity perspective the measure does not appear to have deterred investment. After a lackluster performance in 2017, licensing activity in 2018 picked up significantly with the award of over 10,000km^2 of exploratory acreage and work commitments of US$ 1,027 (Figure 4-11).

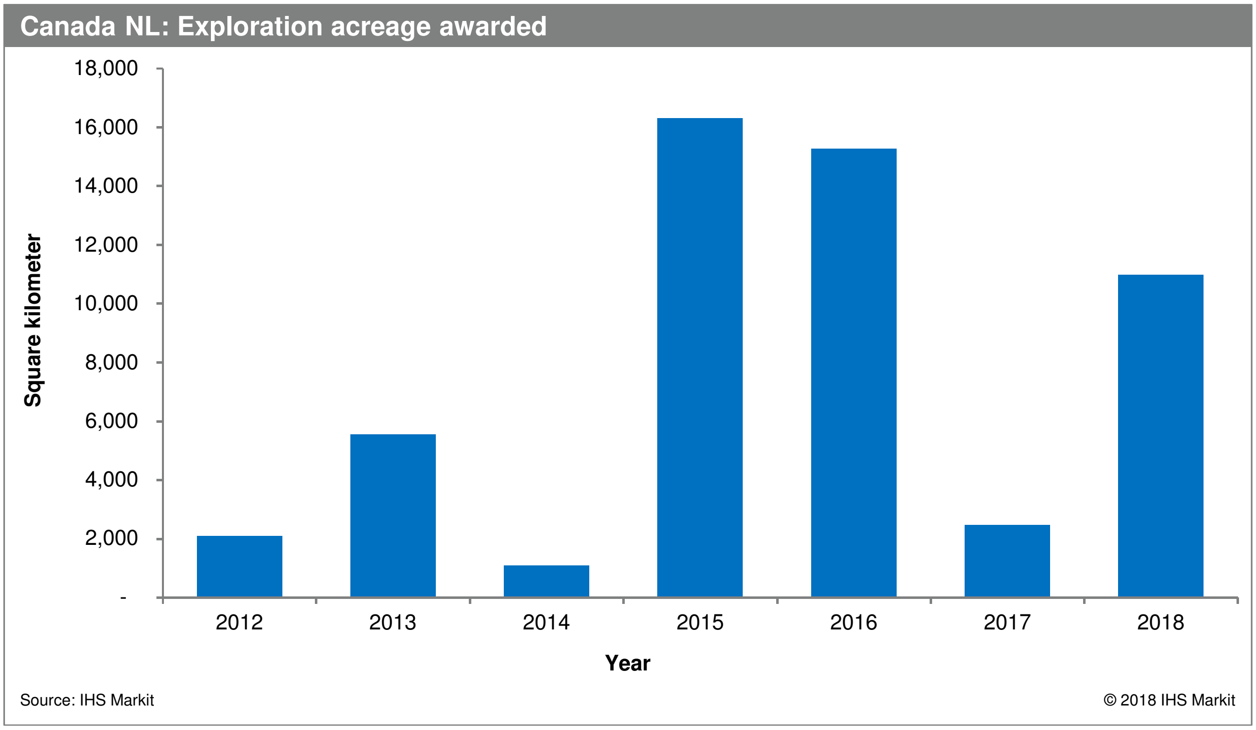

Figure 4-11. Canada-NL: Exploration acreage awarded

4.2.5 Impact of Fiscal Measures in other Jurisdictions

The impact of changes in government take introduced in Angola and Australia is difficult to quantify or support with data for the following reasons:

- The to the legislation occurred during the writing of this report or within 6 month period preceding it, and there is no information on E&P activity subsequent to the implementation of the changes—the changes to the PRRT legislation in Australia were announced in November 2018, and the introduction of terms for marginal fields in Angola occurred in April 2018.
- The jurisdiction does not offer acreage on a regular basis and there has been no opportunity to assess the industry interest in a licensing round—Angola does not hold regular licensing rounds. In fact, there has been no licensing round offshore since 2011.

5 Comparison and Ranking of U.S. Fiscal System

5.1 Approach

Our comparative analysis of the Federal GOM fiscal systems ranks the selected jurisdictions by government take, IRR, NPV/boe and EMV. Each of the field models used in this study and their economic metrics were considered under three price scenarios: base case, high case, and low case. The base case assumes the current oil and gas price planning outlook and uses WTI for oil and local hubs for gas. The high case is 160% of the base case and the low case is 60% of the base case. The price streams are provided in the methodology in Chapter 1 (Figures 1-8 to 1-10). All metrics, prices, and costs are modeled in real terms using 2018 U.S. dollars.

Government take: This metric is often used by host governments when comparing their fiscal system against those of other nations. Government take is a general term used to describe the share of revenues that accrues to the government over the life of an E&P project. The calculation of government take in this study includes the share of revenues accruing to federal governments through royalties, taxes, and other fiscal and quasi-fiscal levies such as regulatory fees or NOC carry. Government take in this report is defined as the Federal government's percentage of pretax project net cash flow on an undiscounted basis. The calculation below is used to determine government take:

$$\boldsymbol{Government\ t\ \ ke = 1 - \left(\frac{Contr\ \ ctor\ C\ \ sh\ Flow}{Contr\ \ ctor\ Gross\ Revenue - Contr\ \ tctor\ OPEX - Contr\ \ ctor\ CAPEX}\right) \times 1}$$

For fiscal systems where NOC participation is required, the government take only considers the project revenue, costs, and government revenues related to the operator's share of equity in the license.

In addition to government take, this study also looks at discounted "share of the barrel" which shows how one barrel of oil is split between government and investors in each jurisdiction. This analysis shows in percentage terms what portion of revenues are spent in discounted capital and operating costs versus the discounted revenue accruing to the government and investor separately.

Internal rate of return: Investor IRR expresses the discount rate that would generate an NPV of zero when applied to the investor's net cash flow after all levies and taxes (and after direct state participation, where relevant)[68]. The investor IRR is the rate at which the sum of the project's discounted cash outflows equals the sum of the project's discounted inflows. Companies usually set internal IRR target rates, or thresholds, for investment decisions. Projects with an IRR lower than the target rate, or threshold rate, are not typically pursued. IRR thresholds are unique to each company and they tend to be greater for higher risk exploration versus lower risk development projects. Threshold rates of return greater than 18% are quite common for deepwater oil and gas projects.

The IRR, however, has some limitations, and, as a result, is never referenced and utilized as the sole evaluation criterion.[69] One of the main limitations of the IRR is its inability to help evaluate incremental

[68] Agalliu, I. 2011. Comparative assessment of the federal oil and gas fiscal systems. U.S. Department of the Interior, Bureau of Ocean Energy Management Herndon. VA. OCS Study, BOEM 2011-xxx, 300pp.
[69] Mian, M.A. "Projects Economics and Decision Analysis, Volume 1: Deterministic Models", 2002.

investments. It assumes reinvestment of interim cash flows in projects with equal rates of return. When a project's interim cash flows are reinvested at a rate lower than the calculated IRR, the IRR approach overstates the annual equivalent rate of return. Another issue with the IRR indicator is that a single project can have more than one rate of return when cash flow switches from positive to negative and turns positive again. While the IRR is easy to understand as a metric, it could lead one to believe that a smaller project with a shorter lifecycle is preferable to a larger project that will eventually generate more revenue. To avoid this downfall, oil and gas companies use various economic indicators (including those described below) to compare and evaluate opportunities.

Net present value per barrel of oil equivalent (NPV/boe): NPV/boe shows the amount of value in today's terms that each barrel of oil equivalent of entitlement production[70] will generate for the operator on a full-cycle basis including dry holes, appraisal, development, and abandonment. The NPV/boe enables comparisons between different projects across a larger spectrum of investments. One main limitation of the NPV/boe is that it does not allow one to understand the initial size of the investment or its embedded risk. An NPV of $5/boe could be generated by either a project requiring billions of dollars of investment or a smaller project requiring several hundreds of millions of dollars invested. Therefore, NPV analysis is often done in parallel with the EMV analysis.

The NPV is the difference between an operator's discounted cash inflows and its discounted cash outflows. For a project NPV is calculated on a full-cycle basis and discounted back to the period of first expenditure on a mid-year basis,[71] which is 2019 in the IHSM models. The NPV is also referred to as 'present worth' as it looks at the present value of the project's economic streams. The calculation below is used to determine NPV:

$$\boldsymbol{NPV = \sum_{t=1}^{n} \frac{net\ c\ \ sh\ flow\ \ t\ t}{(1 + discount\ r\ \ te)^\wedge t}}$$

Where t is the time -period and n is the project life in years.

The discount rate used in the NPV calculation is often described as the 'hurdle rate' or the 'minimum acceptable rate of return'. When making investment decisions, different companies use different discount rates depending of their average cost of capital and the risk assessment inherent to the investment opportunity. Usually, an investment project will be approved if its NPV is positive. Any project or field with a negative NPV after taxes is considered sub-economic.

The NPV per barrel of oil equivalent is the ratio of the NPV, as defined in the equation above, divided by the total hydrocarbon production corresponding to the same period in barrels of oil equivalent.

$$\boldsymbol{NPV\ per\ boe = \frac{1}{P} \sum_{t=1}^{n} \frac{net\ c\ \ sh\ flow\ \ t\ t}{(1 + discount\ r\ \ te)^\wedge t}}$$

Where P is the total hydrocarbon production over the same period expressed in barrels of oil equivalent.

[70] Entitlement production is all equity production to the operator net of royalty volumes for concession contracts. In PSCs, entitlement production is the sum of cost oil, cost gas, profit oil, and profit gas net to the operator

[71] All cash inflows and outflows are allocated to the middle of the year to approximate even spending and discounting throughout a year

In this study, we use a real 10% discount rate for all cases and all jurisdictions. The discount rate used for this study represents the cost of capital and does not account for political risk, or any other above-ground risks. The cost of capital varies among companies—smaller companies tend to have a greater than 10% cost of capital, due to their financial capability and the riskier nature of projects they tend to pursue.[72] Comparative analysis studies of this nature use the same discount rate across all jurisdictions and all projects for the sake of consistency.[73] They do not distinguish between shallow and deepwater, although companies could use a higher discount rate for deepwater projects, greater than 15%. This approach is also consistent with the U.S. Securities and Exchange Commission (SEC). The SEC requires public companies to use a 10% discount for their filings, no matter where their investments are located.[74]

Expected monetary value (EMV): The EMV represents the weighted average of possible monetary streams multiplied by their respective probability of occurrence. This metric is used as a proxy for the investor decision to drill an exploration well since it attempts to include the risk involved in making an investment while also providing a value in absolute terms.

The calculation below is used to determine EMV:

$$\boldsymbol{EMV\ project = P(success) * NPV(success) + \big(1 - P\ (success)\big) * NPV\ f\quad ilure}$$

When making investment decisions, operators will select the projects with the highest EMV. The EMV adds another dimension to the NPV as it introduces the cost of failure events (dry holes), and therefore provides a fuller cash exposure than the simple NPV.

The main weakness of the EMV is that it addresses averages rather than ranges. Nonetheless, EMV is a very useful metric for decision makers. The EMV analysis is important for this study as it incorporates the probability of success based on exploration success rates achieved in their respective jurisdictions, thus giving a fuller appreciation of the prospectivity challenges associated with each jurisdiction.

5.2 Comparative Analysis of Oil and Gas Fiscal Systems

The analysis of shallow water fiscal systems includes three field sizes, to provide a comprehensive set of results. The 100 MMboe case is not indicative of the type of field that one might discover in the shallow water in the U.S. GOM, but demonstrates what is available globally and represents the competition for shallow water GOM projects.

The 30MMboe case is more representative of a shallow water GOM field, but still would be a rare condensate or oil find. The 10MMboe case is more typical of recent discoveries on the shelf in the U.S. GOM. All fields discovered since 2008 in the GOM shallow water area have had estimated reserves of less than 10MMboe.

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[72] Alberta at a Crossroads, Royalty Review Advisory Panel Report, 2016.

[73] The same approach was used in comparative analysis conducted for the government of Alberta, Newfoundland and Labrador, Ireland, and others.

[74] See Rhett G. Campbell, "Valuing Oil and Gas Assets in the Courtroom," presented at the American Institute of Business Law in conjunction with the Oklahoma Bar Review and the Conference on Consumer Finance Law, February 7-8, 2002.

The quantitative analysis for deepwater areas includes two field sizes—250 MMboe and 500MMboe. A 50MMboe field analysis was also conducted, but the results are not depicted in the quantitative analysis, since all projects were uneconomic under the base case as stand-alone projects. In reality, these 50MMboe fields would more likely be developed as satellites to existing fields and infrastructure. The fields analyzed for deepwater are representative of the fields likely to be found in deepwater GOM.

For modeling purposes, these fields are developed as stand-alone projects, to provide an apples-to-apples comparison with the peer group; not all countries have the cost-cutting infrastructure that the U.S. GOM possesses, and this should be kept in mind when considering these results. A notable exception is made for the 10MMboe field in shallow water, as it was uneconomic under all price cases[75] when developed as a stand-alone project. To produce an effect to help determine the efficacy of the alternative fiscal systems, the 10 MMboe field was analyzed as a satellite tie-back, in order to significantly reduce its development costs and make the project viable in the high oil price scenario.

5.2.1 Shallow Water Comparative Analysis – Government Take

Both the average and the range of government take for U.S. GOM shallow water areas in this study are significantly lower than take estimates observed in the *2011 Study*. Three factors contribute to this drastic change. First, the U.S. corporate income tax overhaul resulted in a tax rate reduction of 35% to 21%. The second contributing factor is the reduction in general exploration and development costs that took place during the recent oil and gas downturn—the U.S. Federal fiscal system has an inverse relationship with project profitability (i.e., when profitability increases, government take declines). Lastly, the royalty rate for new leases in GOM shallow water areas was reduced in 2017 from 18.75% to 12.50%. All these factors combined have resulted in 22 percentage point drop in government take for shallow water projects in the GOM compared to the 2011 study.

As a result of these fiscal system changes, the government take for the U.S. GOM shallow water oil fields is among the lowest in the peer group, challenged only by the UK fiscal system, which has undergone significant transformation under the MER strategy adopted by the government in 2014 (Figure 5-1).[76]

[75] Had IRR below 10%.
[76] The boxes in Figure E-7 show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median.

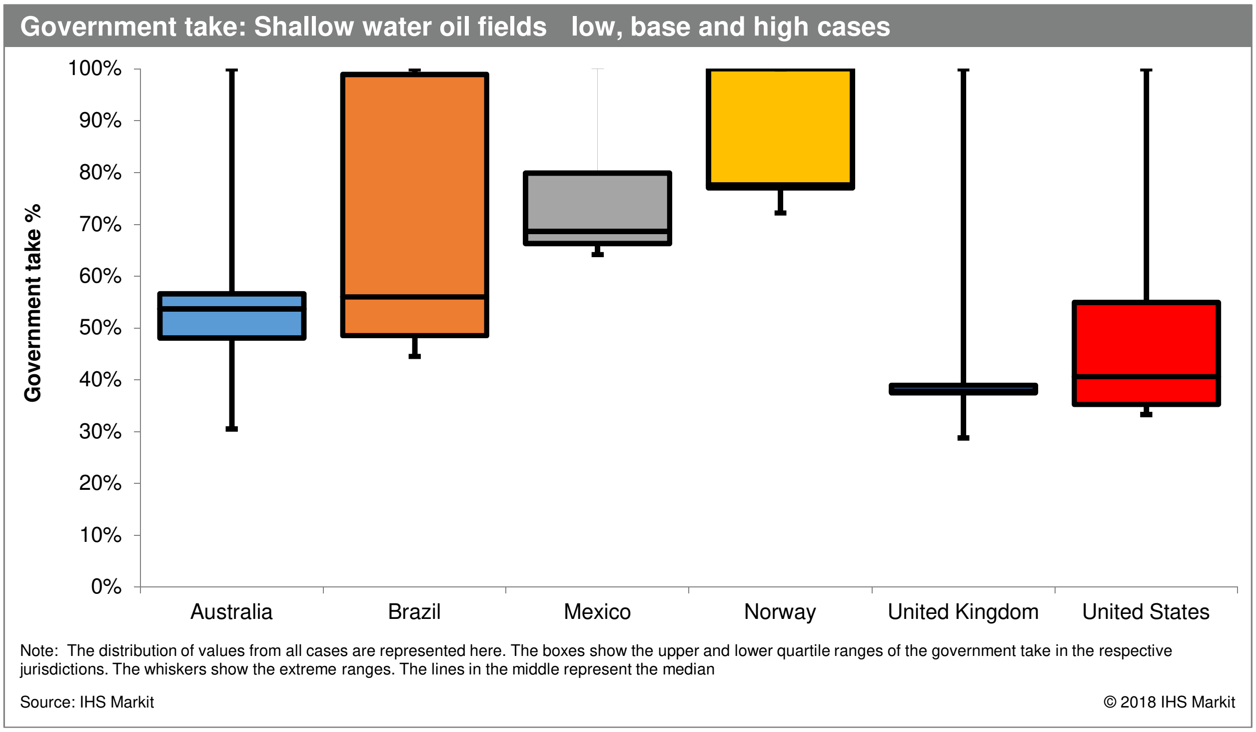


Figure 5-1: Government take: Shallow water oil fields – low, base and high cases

Table 5-1. Government take: Shallow water oil fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Australia	57%	54%	48%	55%	47%	30%	52%	83%	100%
Brazil	45%	49%	62%	47%	56%	100%	52%	99%	100%
Mexico	66%	69%	72%	64%	68%	80%	64%	86%	100%
Norway	78%	77%	72%	78%	76%	100%	77%	100%	100%
United Kingdom	39%	39%	38%	39%	38%	29%	37%	30%	100%
United States	33%	34%	41%	35%	38%	62%	41%	55%	100%

Source: IHS Markit

When taking into account the discounted share of the barrel, the U.S. GOM shallow water fiscal system either first or second for the share of the revenue accruing to investors (Figures 5-2 through 5-4). This is largely due to the lower cost base for shallow water oil fields in the GOM. When the combined discounted share of the barrel of capital and operating expenditure is 50% or less, the U.S. fiscal system is the most competitive in the world. For projects with higher per-unit cost structure, the government shares disproportionately in the before-tax cash flow, this is because of the regressive nature of levies; royalties and bonuses that do not scale accordingly and do not take profitability into account. The investor cash flow for the 10MMboe oil field is negative in the base case, as is the case for most of the countries in the peer group, reflecting the marginal nature of discoveries of this size. On a stand-alone basis, these fields are not economic; however, they may be candidates for cluster development or the use of subsea tie-backs that connect new discoveries to existing facilities. The subsea tie-back technology is technically and economically-viable and is being more widely used as companies focus on previously untapped, less economically-viable discoveries.[77]

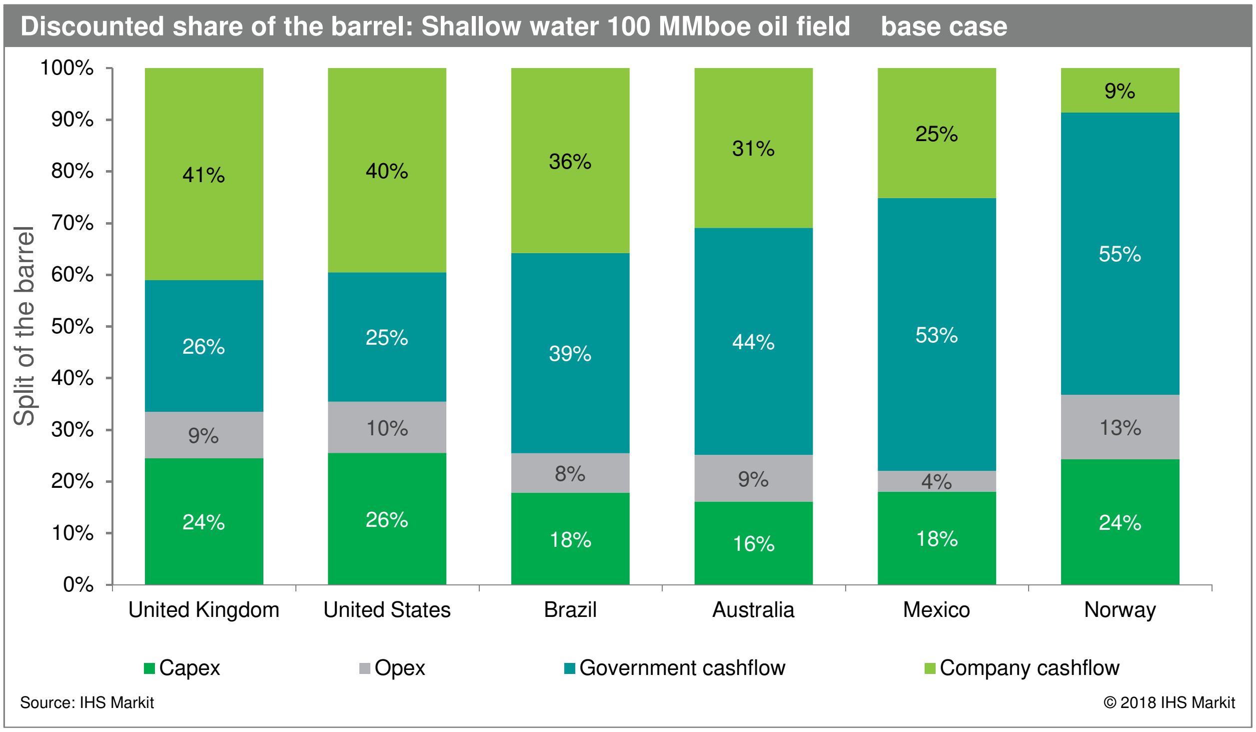


Figure 5-2: Discounted share of the barrel: Shallow water 100MMboe oil field – base case

[77] Subsea Tieback Potential Grows as Priorities Shift, E&P, Hart Energy, 2016.

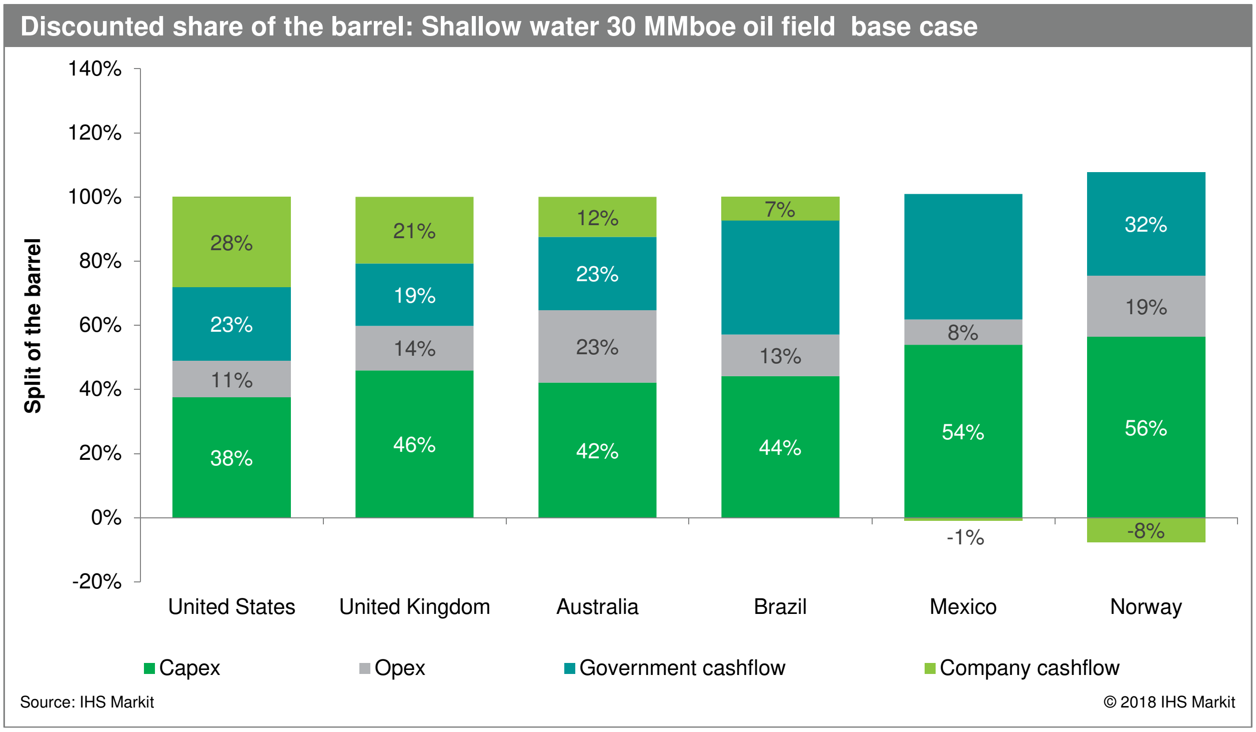


Figure 5-3. Discounted share of the barrel: Shallow water 30MMboe oil field–base case

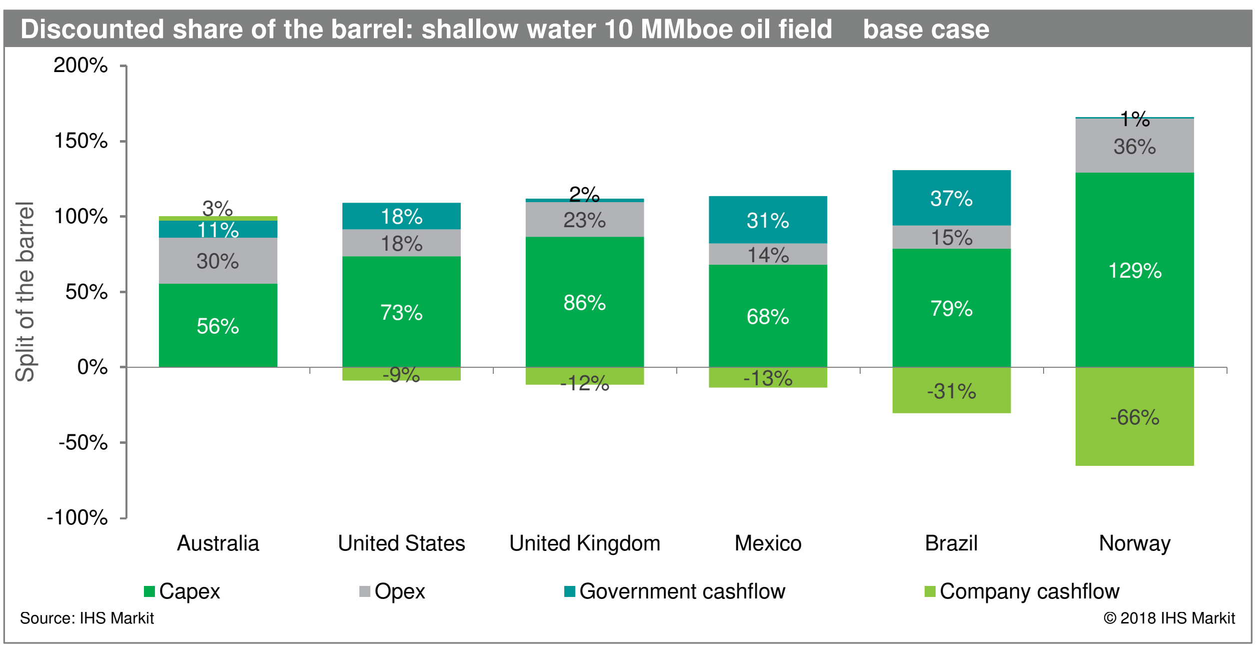


Figure 5-4. Discounted share of the barrel: Shallow water 10MMboe oil field–base case

The range of the government take for natural gas projects in the GOM is much wider than that of the oil fields. This is largely due to the marginal economics associated with natural gas production in the GOM. With a median government take of 54%, the U.S. competes with Australia for second place in the peer group (Figure 5-5, Table 5-2).

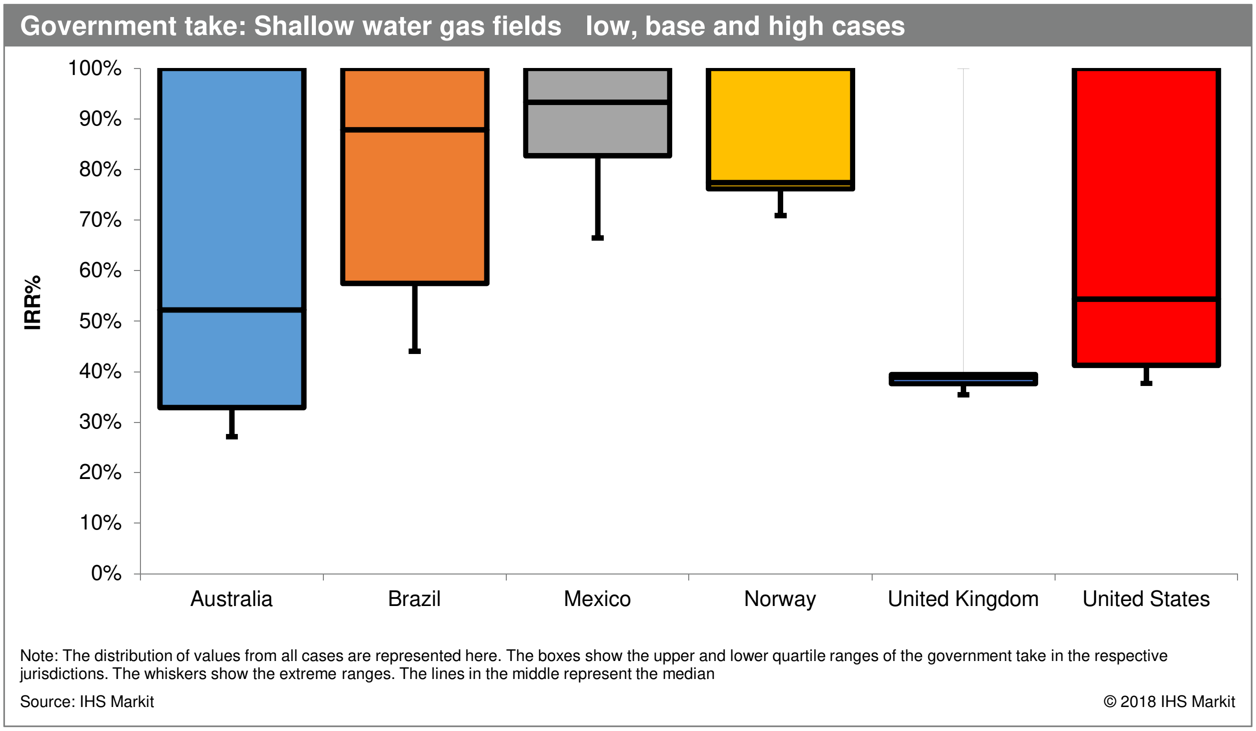


Figure 5-5. Government take: Shallow water gas fields – low, base and high cases

Table 5-2. Government take: Shallow water gas fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Australia	56%	51%	33%	52%	30%	100%	27%	100%	100%
Brazil	44%	58%	88%	47%	100%	100%	57%	100%	100%
Mexico	66%	93%	84%	67%	100%	100%	83%	100%	100%
Norway	78%	77%	73%	77%	71%	100%	76%	100%	100%
United Kingdom	39%	39%	39%	39%	37%	35%	38%	58%	100%
United States	39%	38%	41%	54%	50%	73%	100%	100%	100%

Source: IHS Markit

The discounted share of the barrel shows the relatively high capital cost per unit associated with natural gas projects in the peer group and in the U.S. GOM (Figures 5-6 to 5-8). The combined share of capital and operating expenditure in the U.S. GOM ranges from 73% to 102% in the base case. This is largely due to the fact that the fact that the price for a barrel of oil equivalent of natural gas production in the U.S. GOM is about half the market prices in Europe and Asia—hence the costs make up a larger portion of the limited revenue stream.

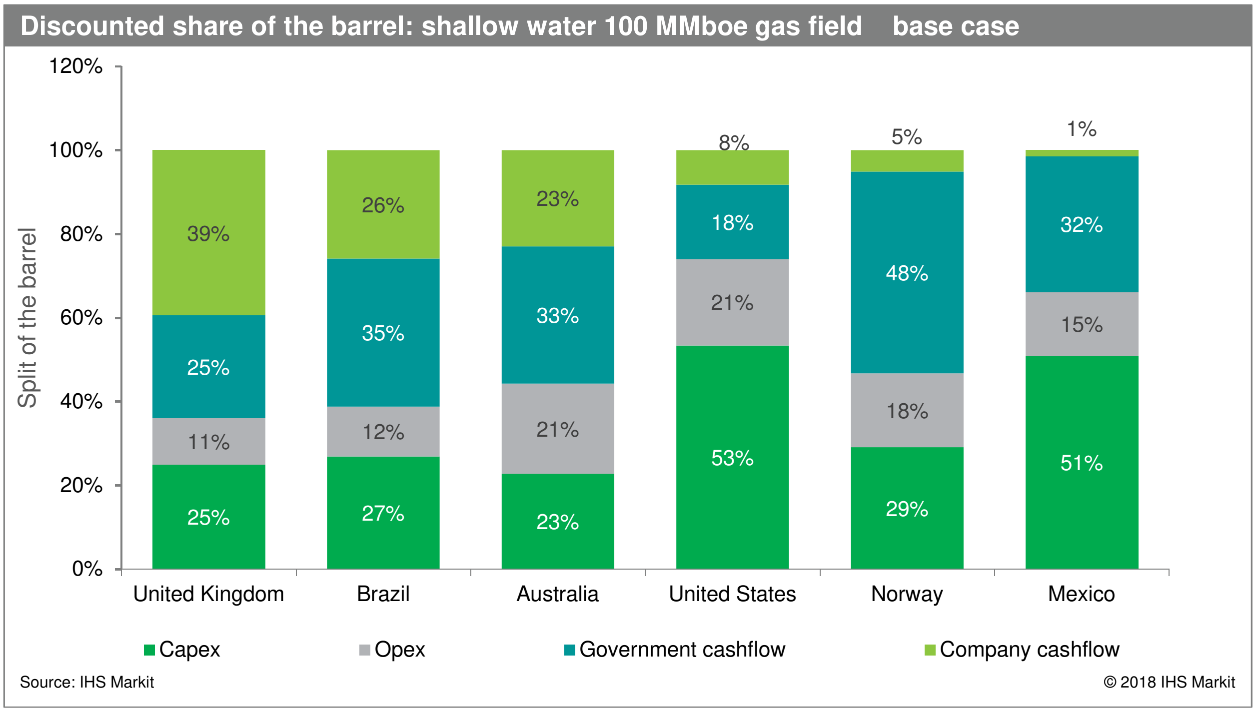


Figure 5-6. Discounted share of the barrel: shallow water 100MMboe gas field – base case

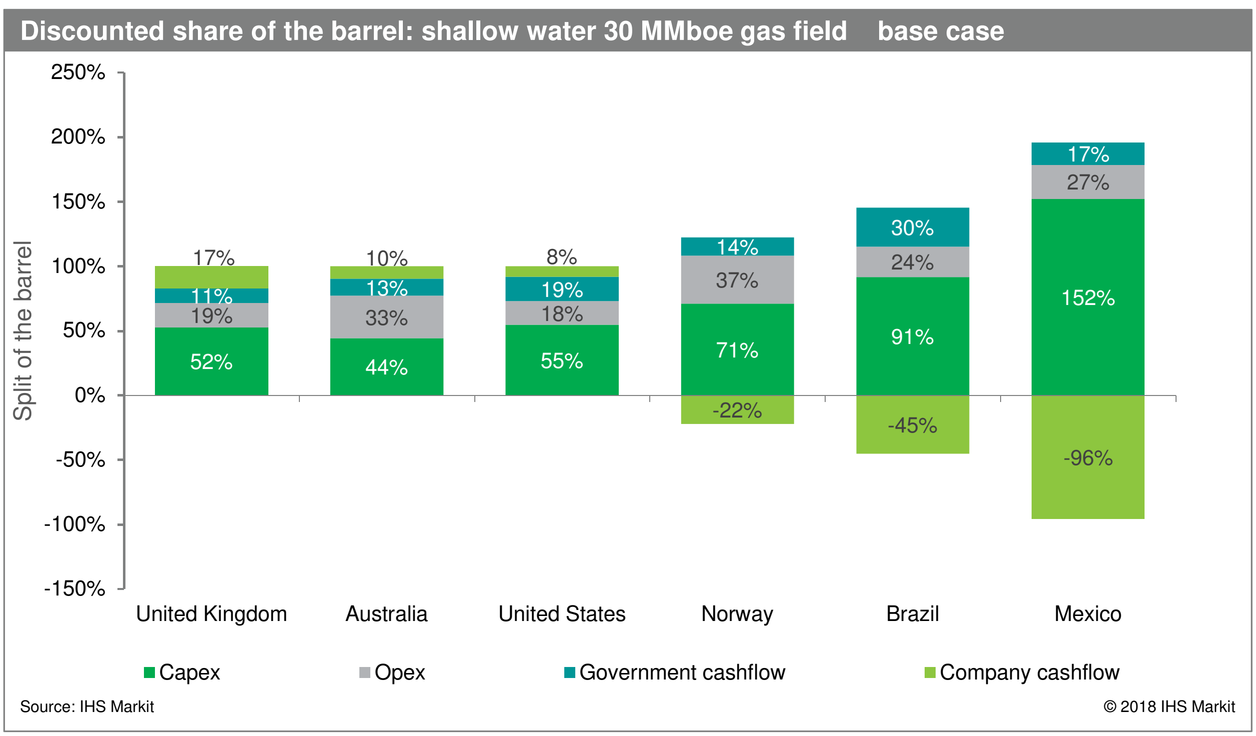


Figure 5-7. Discounted share of the barrel: shallow water 30MMboe gas field – base case

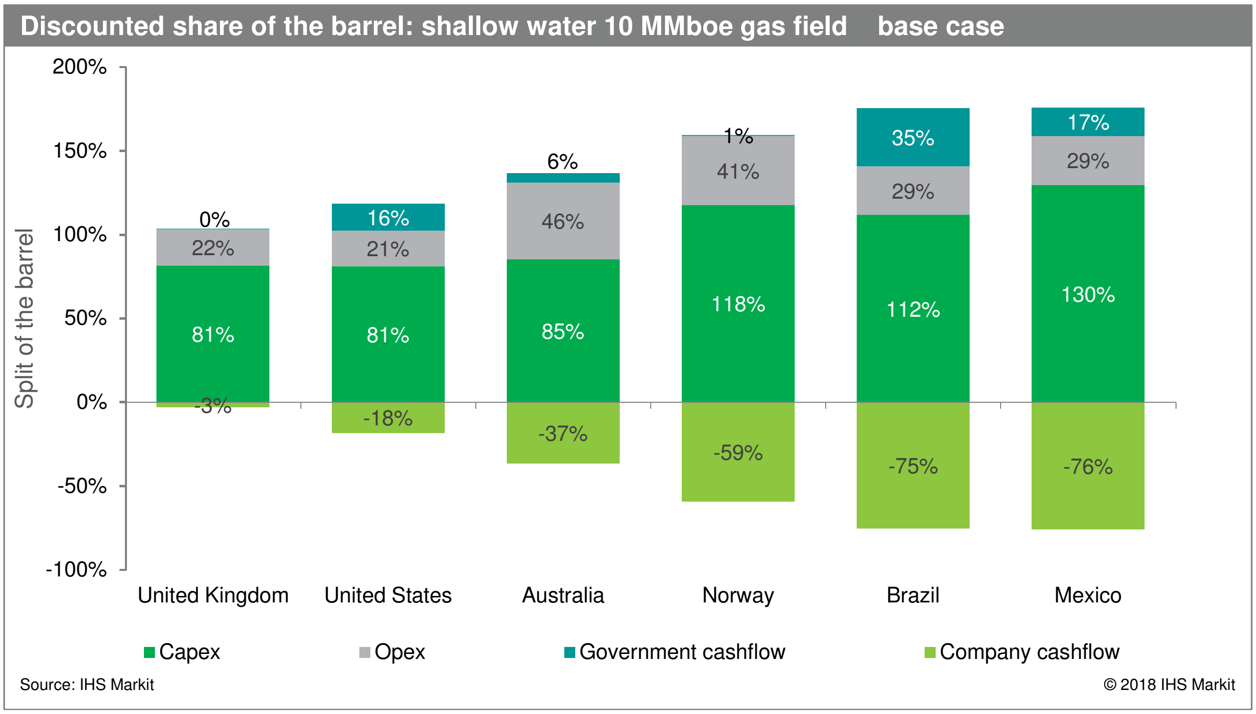
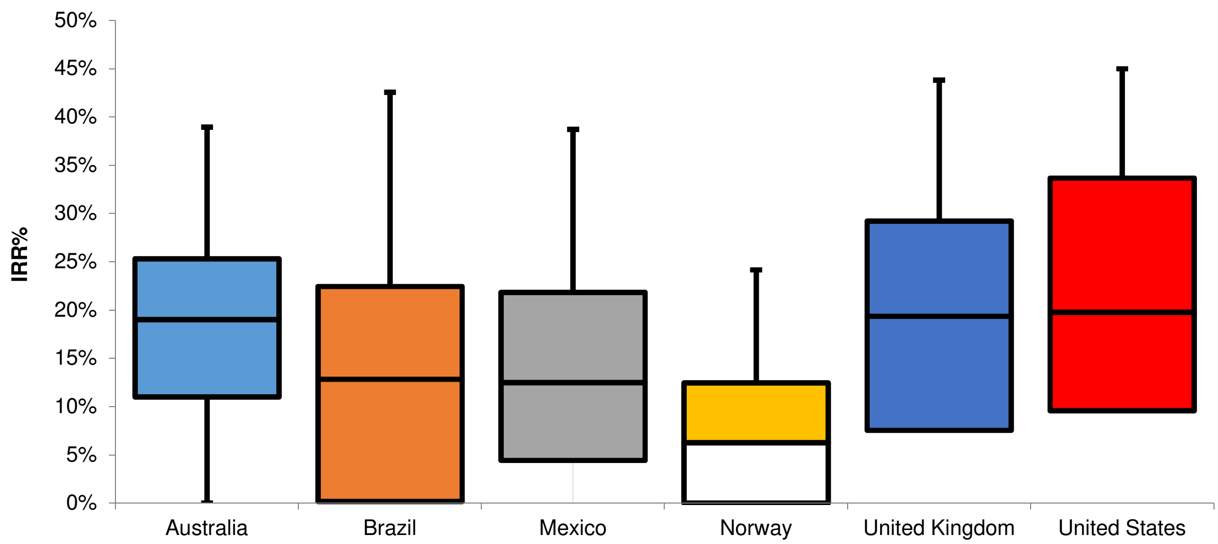


Figure 5-8. Discounted share of the barrel: shallow water 10MMboe gas field – base case

5.2.2 Shallow Water Comparative Analysis – Investor Rate of Return (IRR)

From an investor perspective, the U.S. GOM oil fields in the shelf are the most competitive in the peer group. With a 20% median IRR, the U.S. edges the United Kingdom and Australia for the top position in the peer group (Figure 5-9, Table 5-3). The IRR for natural gas fields in the GOM is also very competitive within the peer group (Figure 5-10). However, investments for natural gas in the GOM are competing in the domestic market rather than the international market. The abundance of lower cost sources of supply from shale gas and tight oil present a significant challenge for natural gas development in the GOM.

IRR: Shallow water oil fields low, base and high cases

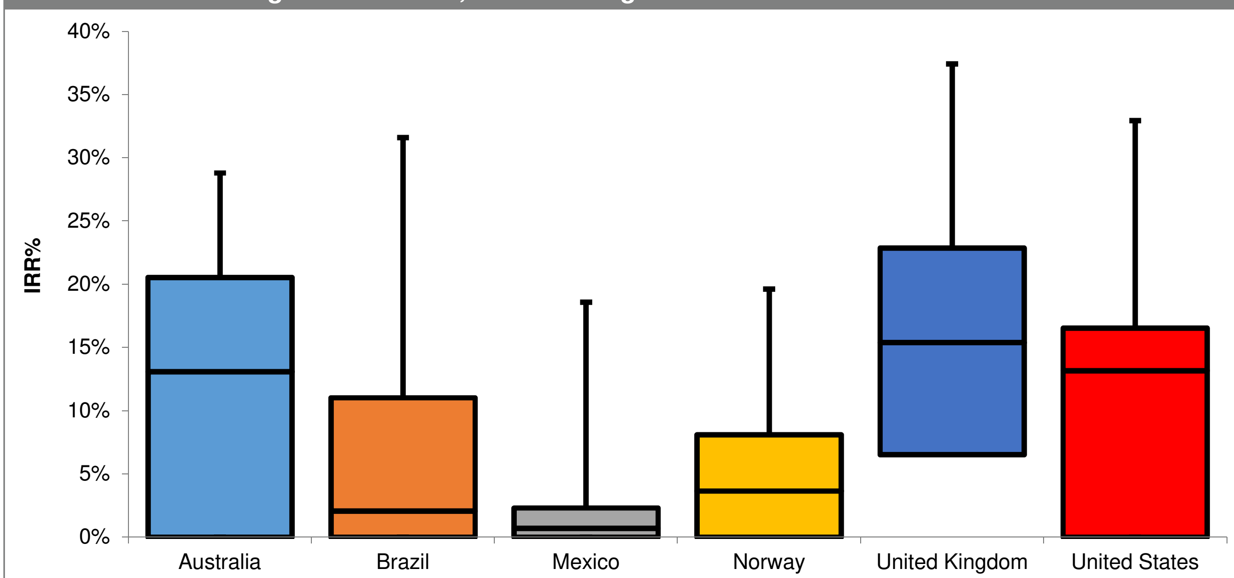


Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median

Source: IHS Markit

Figure 5-9. IRR: Shallow water oil fields – low, base and high cases

IRR: Shallow water gas fields low, base and high cases



Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median

Source: IHS Markit

Figure 5-10. IRR: Shallow water gas fields – low, base and high cases

Table 5-3. IRR: Shallow water oil and gas fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Crude Oil									
Australia	39%	25%	19%	31%	16%	11%	22%	1%	0%
Brazil	43%	22%	12%	32%	13%	0%	21%	0%	0%
Mexico	39%	16%	12%	31%	10%	4%	22%	2%	0%
Norway	24%	12%	3%	17%	6%	0%	10%	0%	0%
United Kingdom	44%	29%	16%	33%	19%	5%	22%	8%	0%
United States	45%	38%	19%	34%	26%	6%	20%	10%	0%
Natural Gas									
Australia	29%	21%	14%	21%	13%	0%	11%	0%	0%
Brazil	32%	9%	2%	22%	0%	0%	11%	0%	0%
Mexico	19%	1%	2%	11%	0%	0%	2%	0%	0%
Norway	20%	8%	4%	13%	3%	0%	7%	0%	0%
United Kingdom	37%	23%	15%	28%	14%	7%	18%	2%	0%
United States	33%	27%	17%	16%	13%	3%	0%	0%	0%

Source: IHS Markit

5.2.3 Shallow Water Comparative Analysis – Net Present Value per BOE (NPV/Boe)

When commodity prices are at current levels or higher (base and high case) the oil fields in U.S. GOM offer some of the highest values per barrel of oil equivalent compared to its peers (Table 5-4). However, the value per unit in the U.S. GOM erodes quickly under a low-price environment, as do the rest of the peer group. The regressive components of a fiscal system, the U.S. flat royalty rate for example, can be detrimental to project economics when profit margins are low. Most members of the peer group face similar challenges under a low oil price environment. Jurisdictions with progressive fiscal system such as the United Kingdom, or mildly regressive ones such as Mexico, offer relatively higher values per barrel of oil equivalent under low commodity prices (low case).[78]

The value per barrel of oil equivalent of production from gas fields is often lower than that of oil fields due to lower prices for gas on an energy-equivalent basis, but also because gas reservoirs are often found at deeper depths and the per unit cost is higher. In the case of shallow water gas, the U.S. is not very competitive. Much of this is due to the depressed natural gas prices in the U.S. from the flux of onshore unconventional production out of tight formations. U.S. natural gas projects on the shelf rank fourth in the peer group after United Kingdom, Brazil, and Australia in the base case (Table 5-4).

[78] While Mexico does rely on front-end loaded levies such as royalties—Mexico's sliding scale royalties significantly soften the burden of low commodity prices.

Table 5-4. NPV/Boe: Shallow water oil and gas fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Oil									
Australia	12.7	9.3	7.9	6.9	3.1	0.7	3.0	-2.8	-8.2
Brazil	17.7	11.7	2.2	9.0	2.0	-9.3	3.1	-4.9	-17.5
Mexico	18.4	7.7	3.1	9.6	-0.4	-5.0	3.8	-6.2	-14.7
Norway	4.8	1.4	-8.4	1.9	-1.9	-17.8	-0.1	-5.4	-31.6
United Kingdom	17.2	14.4	5.9	8.9	5.3	-4.0	3.3	-1.0	-14.0
United States	18.6	17.5	8.5	9.0	7.0	-2.3	2.6	-0.1	-10.6
Gas									
Australia	7.5	6.3	3.3	3.2	1.5	-6.6	0.2	-4.6	-15.8
Brazil	9.8	-1.3	-6.8	4.1	-7.8	-14.8	0.3	-13.6	-21.9
Mexico	3.9	-8.0	-5.6	0.2	-13.4	-11.3	-2.0	-19.0	-15.6
Norway	3.1	-1.1	-5.9	0.9	-3.9	-12.2	-0.7	-9.3	-22.6
United Kingdom	12.3	8.7	5.1	6.2	2.1	-2.6	2.2	-2.8	-9.0
United States	5.9	6.9	3.6	1.0	1.1	-2.6	-2.8	-3.0	-7.9

Source: IHS Markit

5.2.4 Shallow Water Comparative Analysis – Expected Monetary Value (EMV)

In each of the modeled cases, the shallow water of the U.S. GOM shelf provides some of the highest value per exploration well drilled when compared to its peers for oil fields (Table 5-5). However, this is not necessarily the case in reality, as the U.S. GOM shelf area is the most mature one among the peer group. The fields selected for this analysis are representative of the entire peer group, not necessarily of the U.S. GOM shelf. These results show that the economics of the U.S. fiscal terms are very competitive, but the U.S. problem lies with the available supply. There is still potential for material discoveries in shallow water in Mexico but the same potential is not found on the U.S. side of the GOM. The oil fields expected to be found in shallow waters in the U.S. GOM are in the order of 10MMboe rather than 100MMboe. Over the past 15 years 96% of the fields discovered in shallow waters in GOM were below 10MMboe.

Like shallow water oil fields, the U.S. GOM is highly unlikely to attract much exploration investment for natural gas when commodity prices are low. Even in the base case, which reflect recent market conditions, the U.S. GOM is not likely to compete for investment in natural gas exploration with unconventional oil and gas development from tight reservoirs in North America.

While the EMV values appear robust, the 10MMboe field, the one most likely to be found on the shelf is viable on a stand-alone basis only under the high case both for oil and gas. However, such fields could be potential candidates as additional reserves to existing facilities using subsea tie-back technology. Therefore, efficient policy solutions to preserve and extend the life of some of the ageing infrastructure on the shelf are important to maximize the recovery of resources in the U.S. GOM.

Table 5-5. EMV: Shallow water oil and gas fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Oil									
Australia	386.0	77.0	16.7	202.4	17.7	-4.9	80.5	-27.0	-25.9
Brazil	578.2	112.9	4.5	290.8	16.8	-27.1	98.2	-48.1	-49.5
Mexico	326.4	64.3	14.0	211.0	19.5	-1.8	97.0	-16.3	-18.9
Norway	166.3	6.3	-30.4	59.3	-29.4	-51.1	-11.7	-62.1	-76.3
United Kingdom	623.5	135.5	15.5	318.7	46.6	-15.2	115.5	-12.5	-42.0
United States	503.5	141.2	22.1	239.2	54.8	-7.8	65.4	-2.5	-28.9
Gas									
Australia	217.2	46.5	1.3	83.5	2.8	-21.1	-4.3	-37.7	-42.9
Brazil	326.7	-15.7	-23.3	134.6	-77.5	-48.6	6.2	-126.7	-65.3
Mexico	95.6	-34.1	-6.3	18.1	-75.3	-18.8	-41.5	-109.2	-31.5
Norway	105.7	-20.8	-28.1	23.0	-47.7	-44.1	-33.8	-88.6	-70.5
United Kingdom	465.7	96.1	16.1	231.5	21.0	-12.2	74.2	-33.0	-33.9
United States	188.5	64.2	10.8	25.6	6.4	-9.9	-92.3	-33.8	-25.3

Source: IHS Markit

5.2.5 Deepwater Comparative Analysis – Government Take

U.S. GOM ranks third after United Kingdom and Mexico under all price scenarios with 51% median government take for deepwater oil fields. The relatively wide spread range of government take for projects falling between the first and third quartile is an indicator of the high government take associated with low oil prices in the U.S. GOM (Figure 5-11). When the entire range of government take is considered, Brazil, Guyana, and Mexico outperform the U.S (Table 5-6).

As in the case of the shelf projects, there is also a significant drop in the median government take relative to the *2011 study*—22 percentage point drop. This, too, is attributed to the lowering of the corporate income tax and the industry-wide cost reductions that occurred since the 2014 drop in commodity prices.

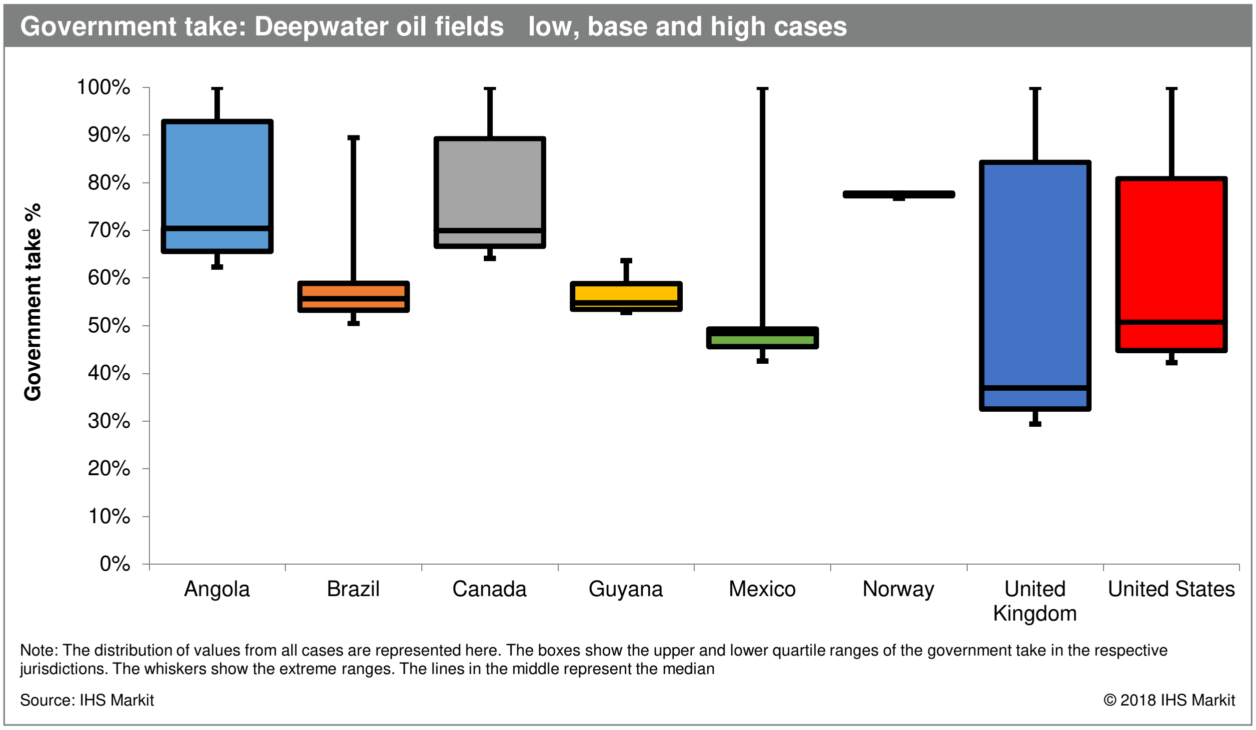


Figure 5-11. Government take: Deepwater oil fields – low, base, and high cases

Table 5-6. Government take: Deepwater oil fields

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Angola	71%	70%	64%	62%	100%	100%
Brazil	53%	50%	53%	58%	59%	89%
Canada	64%	72%	68%	66%	100%	95%
Guyana	53%	53%	54%	55%	60%	64%
Mexico	45%	48%	43%	49%	49%	100%
Norway	78%	78%	78%	78%	77%	77%
United Kingdom	37%	37%	31%	29%	100%	100%
United States	43%	42%	52%	50%	91%	100%

Source: IHS Markit

When the discounted share of the barrel is considered for individual case results under the base case scenario, the U.S. ranks fourth with respect to the share of revenue accruing to investors. For both cases considered, the share of capital and operating costs in the U.S. GOM is around 60% of the overall discounted cashflow, with the government share being nearly double the share accruing to investors (Figures 5-12 to 5-13). The distribution of the discounted revenue between the government and investors is somewhat evenly spread under the high case. Under the low case, the investor cashflow is negative as it is for the majority of the jurisdictions in the peer group (Appendix D).

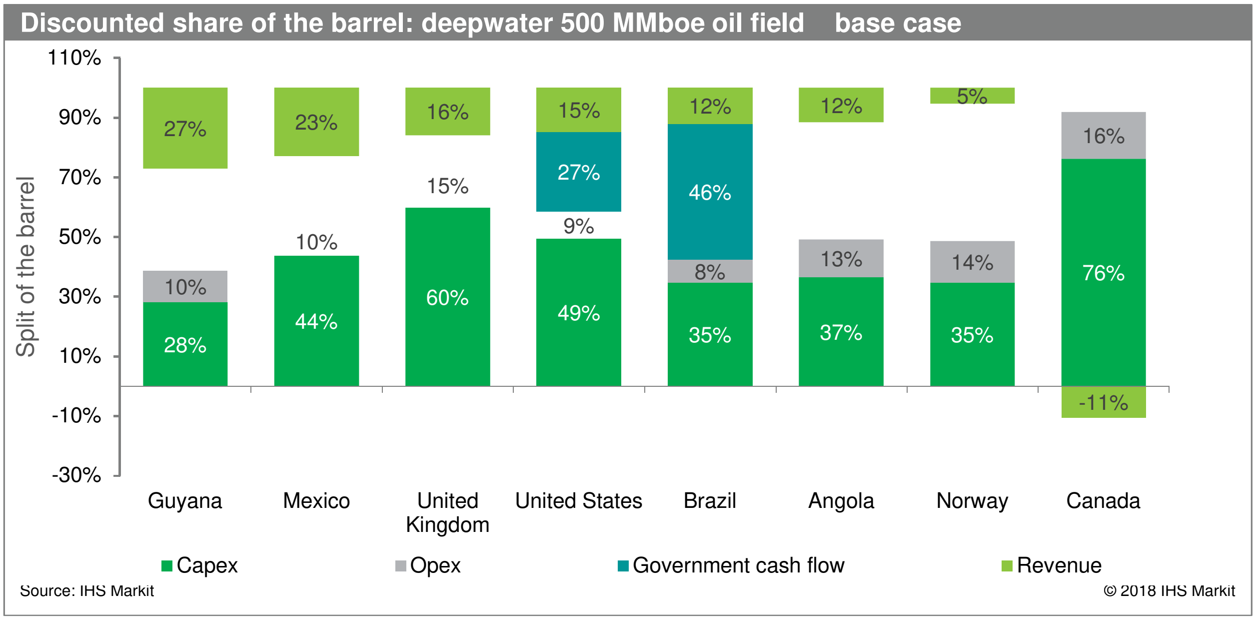


Figure 5-12. Discounted share of the barrel: Deepwater 500MMboe oil field – base case

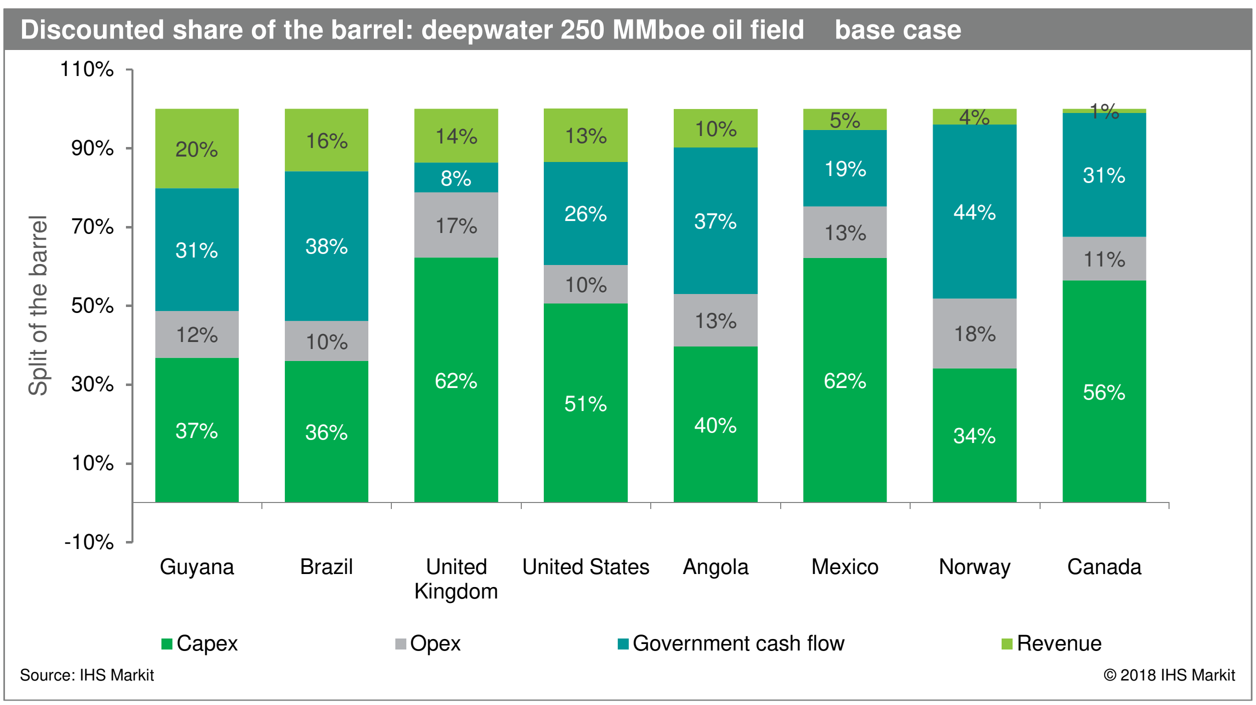
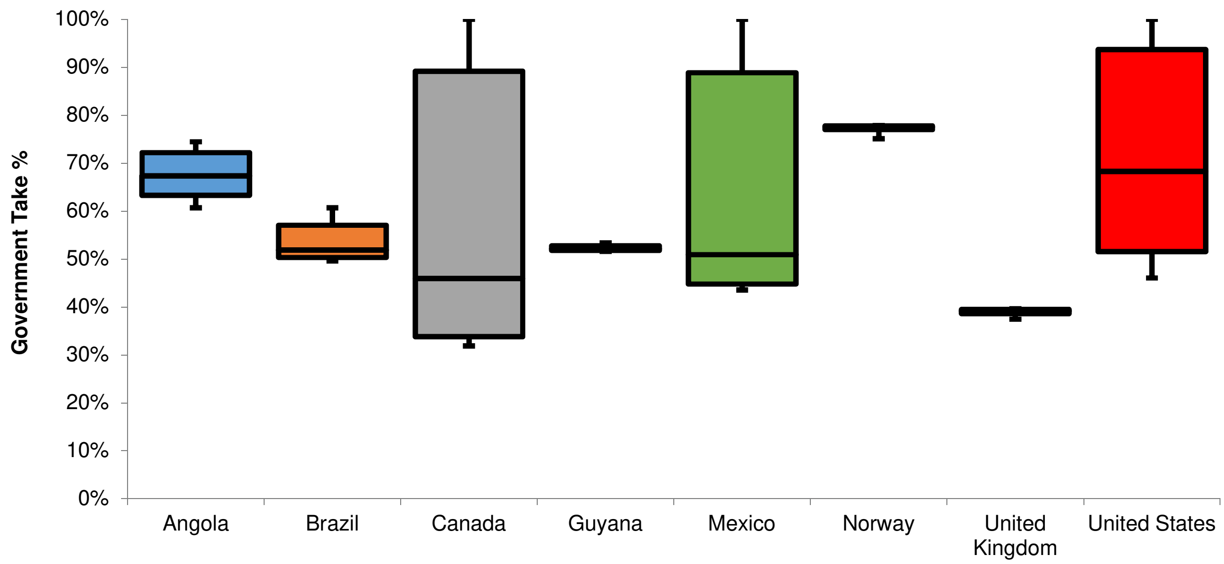


Figure 5-13. Discounted share of the barrel: Deepwater 250MMboe oil field – base case

The median government take for deepwater natural gas projects in the GOM is much higher than that for oil fields in the same region. Similar to natural gas projects on the shelf, the cost structure for deepwater gas projects in the GOM pushes the government take towards the top of the peer group (Figure 5-14, Table 5-7). Natural gas projects in the GOM are disadvantaged by the prevailing market prices in the U.S. when compared to projects in Europe and Asia where the natural gas market prices are more than double the U.S. natural gas price (Figure 1-10).

Government take: Deepwater gas fields low, base and high cases



Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median

Source: IHS Markit

Figure 5-14. Government take: Deepwater gas fields – low, base and high cases

Table 5-7. Government take: Deepwater gas fields

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	500	250	500
Angola	74%	74%	67%	68%	61%	62%
Brazil	50%	50%	51%	52%	59%	61%
Canada	32%	33%	35%	57%	100%	100%
Guyana	52%	52%	52%	52%	53%	53%
Mexico	44%	46%	44%	55%	100%	100%
Norway	78%	78%	78%	77%	77%	75%
United Kingdom	40%	39%	39%	39%	38%	37%
United States	46%	48%	62%	75%	100%	100%

Source: IHS Markit

The discounted share of the barrel analysis for deepwater natural gas fields shows North American natural gas projects at the bottom of the peer group based on the revenue accruing to the investors (Figures 5-15 to 5-16). Similar to the U.S., Canada and Mexico are disadvantaged by the prevailing natural gas markets in the region. The challenging economics for natural gas is a result of the market conditions rather than the design of the fiscal system. This is evident by the results of the high case where the share of the discounted revenues accruing to investors is 18% and 26%, compared to -14% and 1% in the base case, for the 250MMboe and 500MMboe gas fields respectively.

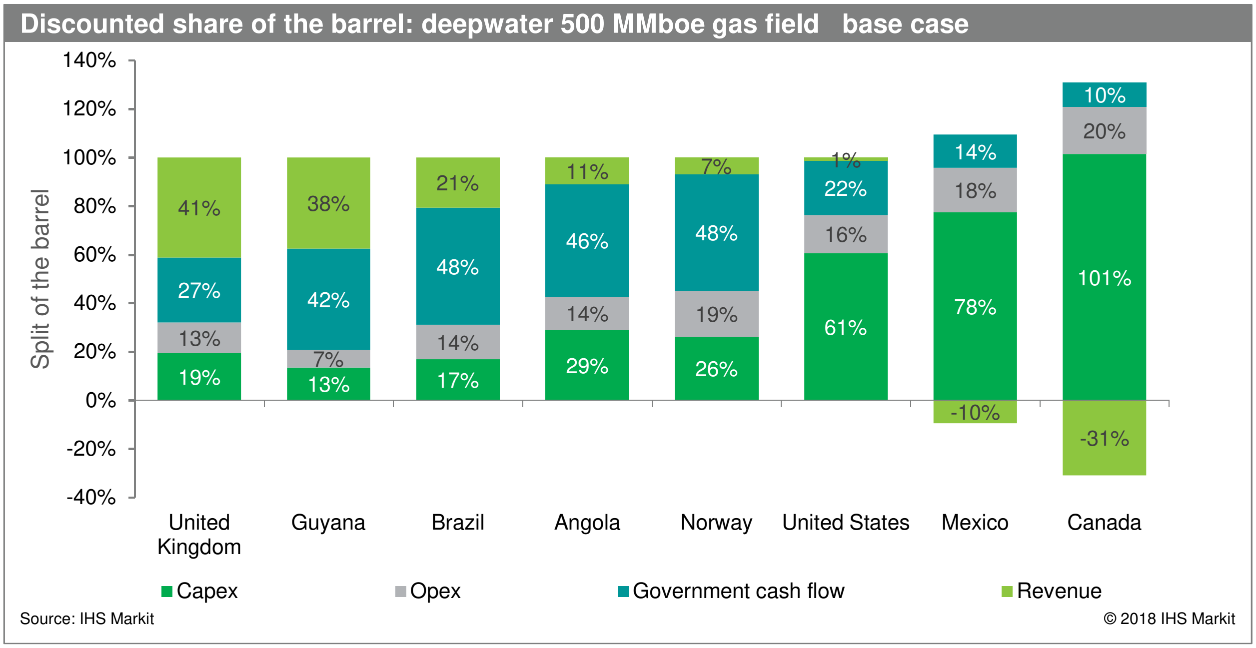


Figure 5-15: Discounted share of the barrel: Deepwater 500MMboe gas field – base case

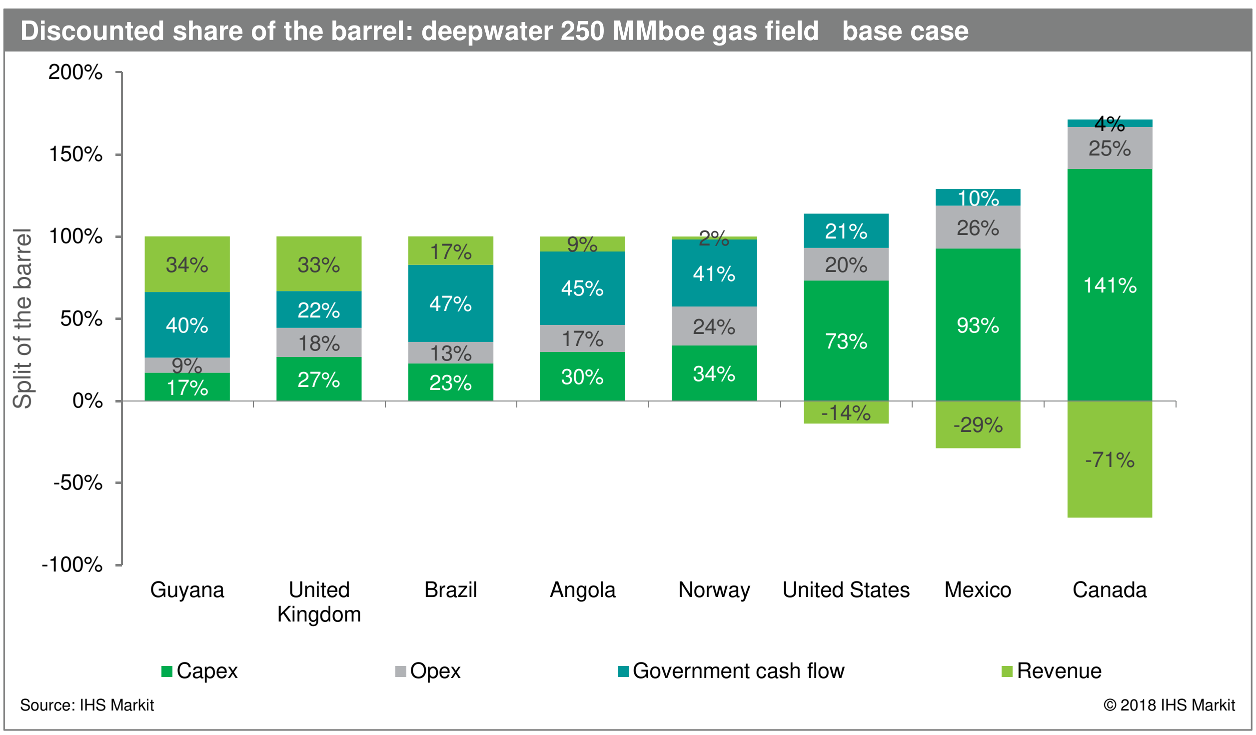


Figure 5-16: Discounted share of the barrel: Deepwater 250MMboe gas field – base case

5.2.6 Deepwater Comparative Analysis – Internal Rate of Return (IRR)

With a median IRR of 16%, deepwater oil fields in the U.S. GOM offer reasonable rates of return to oil and gas investors. However, these deepwater oil fields face tough competition from all the countries in the peer group, except for Canada (Figure 5-17). This should not be a problem in an environment where competition for exploration acreage is high, i.e. there is an abundance of capital available for investment and limited opportunities to invest. However, in an environment where financial resources are tight and the focus shifts from long-cycle deepwater projects to quick-to-first-oil barrels, prioritization of investments could disadvantage the GOM.[79]

The U.S. GOM deepwater oil fields modeled for this study are representative of some of the future oil resource potential in the GOM. The oil fields have been modeled with a true vertical depth (TVD) of over 28,000 feet, representative of the depths of the Lower Tertiary. The wells in the Lower Tertiary are some of the deepest in the world, averaging more than 20,000 feet of TVD, with significant technical challenges and low productivity. About 40% of future U.S. GOM deepwater production potential lies in the Lower Tertiary. The development of these deepwater oil resources is challenged under the base and low oil price scenario. Large Lower Tertiary discoveries have been recently returned to the government inventory since the economics do not make sense under current market conditions.

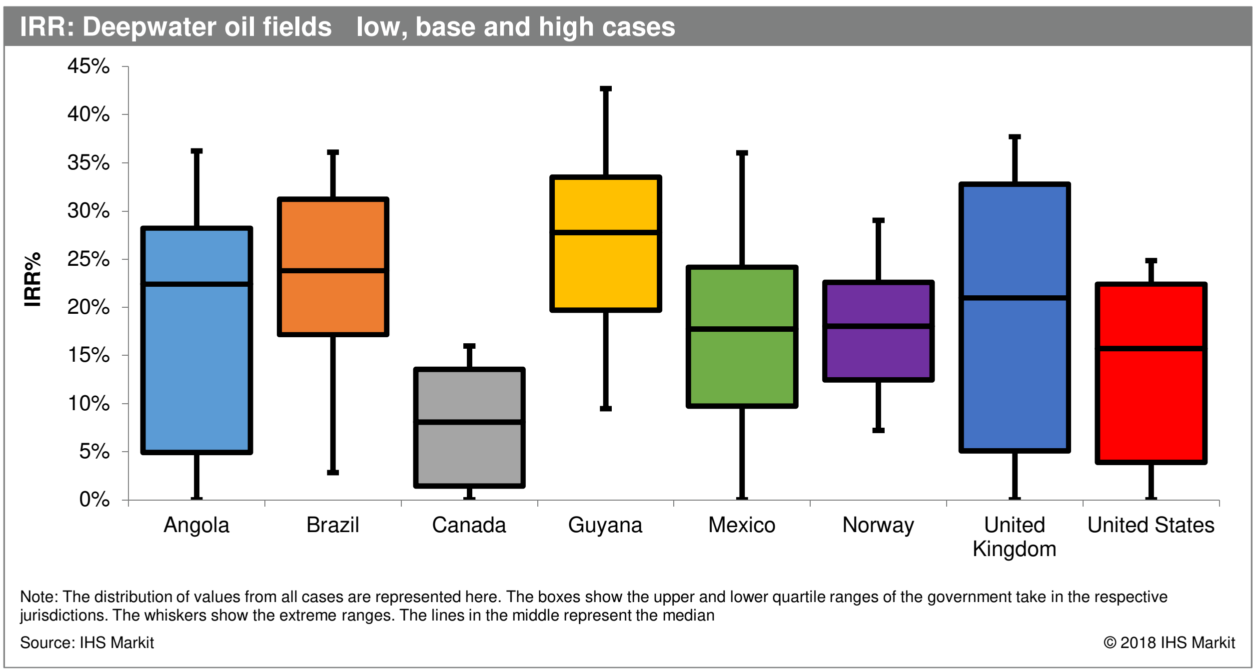


Figure 5-17. IRR: Deepwater oil fields – low, base and high cases

The analysis of IRR for deepwater natural gas projects in the GOM mirrors the analysis of government take and the discounted share of the barrel, with U.S. slightly edging Mexico and Canada at the bottom of the peer group (Figure 5-18, Table 5-8). With a median IRR at 7% deepwater natural gas projects in U.S. GOM are likely to face difficulty attracting investments.[80] As reiterated earlier in this report, the primary reason

[79] IHS Markit has identified 5 billion short-cycle-barrels in overlooked areas outside North America.

[80] Projects with an IRR below 15% are rejected when investment decisions are made.

for the poor performance of natural gas projects in the GOM are the low natural gas prices in North America rather than the fiscal system.

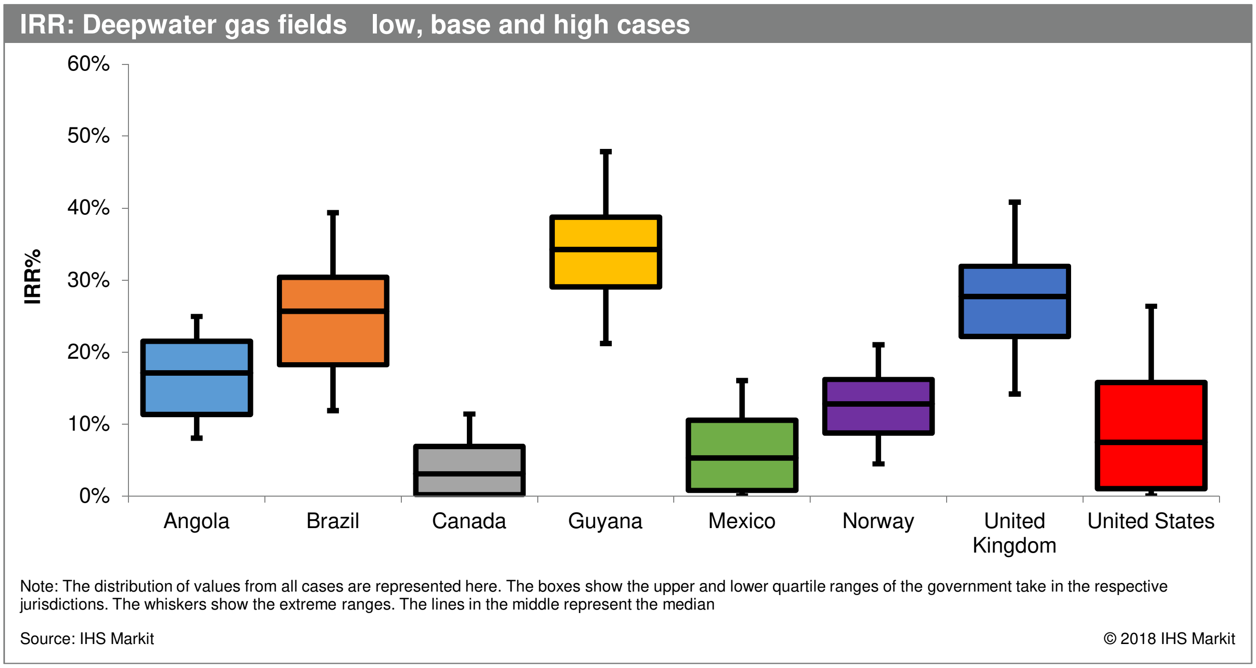


Figure 5-18. IRR: Deepwater gas fields – low, base and high cases

Table 5-8. IRR: Deepwater oil and gas fields

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	500	250	500
Oil						
Angola	36%	29%	25%	20%	0%	0%
Brazil	36%	32%	27%	20%	16%	3%
Canada	15%	16%	6%	10%	0%	0%
Guyana	43%	34%	32%	23%	18%	9%
Mexico	36%	23%	25%	12%	9%	0%
Norway	29%	23%	21%	15%	11%	7%
United Kingdom	38%	36%	22%	20%	0%	0%
United States	25%	25%	16%	16%	0%	0%
Gas						
Angola	25%	23%	18%	16%	10%	8%
Brazil	39%	31%	29%	22%	17%	12%
Canada	11%	7%	5%	1%	0%	0%
Guyana	48%	38%	39%	30%	29%	21%
Mexico	16%	12%	7%	3%	0%	0%

Norway	21%	17%	15%	11%	8%	4%
United Kingdom	41%	32%	32%	24%	22%	14%
United States	26%	17%	11%	4%	0%	0%

Source: IHS Markit © 2018 IHS Markit

5.2.7 Deepwater Comparative Analysis – NPV/Boe

Deepwater oil projects in the U.S. produce nearly half as much value per barrel of oil equivalent as Guyana, and to some extent Brazil, but perform often better than Norway and Canada under all cases (Table 5-9). Nonetheless, the deepwater oil fields analyzed in this study should attract investments under the base and high case. Despite the significant cost reduction that has taken place since 2014, not all GOM projects are viable in a low oil price environment (low case).[81] The fields modeled for this study have negative NPV/boe in the low case, which means some of the Lower Tertiary projects may not be sanctioned in a low oil price environment.

Some of the major oil companies are currently making investment decisions at $40/bbl price despite the recovery of the commodity prices over $70/bbl by the end of September 2018. This appears to be a strategy to manage costs and weather any commodity price fluctuations in the future. According to Oil and Gas UK, Shell requires that any investments in upstream oil and gas projects break even at less than $40/boe, while BP is targeting 2021 as the year in which it brings down its break-even costs to $40/boe.[82]

Similar to the shallow water natural gas fields, the value per barrel of oil equivalent associated with deepwater gas fields in U.S. is nearly one-third of the value associated with oil fields in the GOM. The lower prices for gas on an energy-equivalent basis, and the significant disparity among natural gas prices in the U.S., Europe, and Asia (Figure 1-10) contributes to the low ranking of the U.S. and other North American natural gas projects in the peer group.

Table 5-9. NPV/Boe: Deepwater oil and gas fields

Jurisdiction	High Case		Base Case		Low Case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	500	250	500
Crude Oil						
Angola	8.67	8.35	3.65	3.09	-1.84	-3.04
Brazil	13.1	10.8	6.3	3.5	1.6	-1.6
Canada	2.88	4.70	-1.83	0.24	-5.79	-3.22
Guyana	18.28	16.22	8.05	5.97	1.84	-0.15
Mexico	10.1	8.1	4.0	1.1	-0.2	-4.0
Norway	4.1	3.6	1.8	1.2	0.2	-0.5
United Kingdom	9.5	9.7	2.8	2.5	-2.8	-3.9
United States	9.0	10.8	2.5	2.8	-2.1	-2.8
Natural Gas						
Angola	5.44	5.22	2.23	1.87	-0.12	-0.58

[81] Projects with a negative NPV/boe are sub-economic and therefore rejected when investment decisions are made.
[82] Oil & Gas UK – Economic Report 2018.

Jurisdiction	High Case		Base Case		Low Case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	500	250	500
Brazil	8.1	7.5	3.9	3.3	1.0	0.4
Canada	0.66	-1.55	-1.71	-4.23	-3.66	-6.95
Guyana	19.02	17.64	10.07	8.87	4.54	3.41
Mexico	2.6	0.8	-0.9	-2.7	-3.2	-5.8
Norway	2.3	1.9	0.8	0.2	-0.3	-1.1
United Kingdom	9.4	8.3	5.0	3.9	2.0	0.9
United States	3.7	2.3	0.1	-1.2	-2.6	-4.0

Source: IHS Markit

5.2.8 Deepwater Comparative Analysis – Expected Monetary Value (EMV)

The U.S. deepwater oil field projects offer robust monetary value per exploration well drilled (Table 5-10). Unlike the shelf fields where the representative fields of the peer group had larger reserves than the ones expected to be found in the GOM, the deepwater fields of the peer group for this study are more representative of the reserve sizes associated with discoveries in the U.S. GOM.[83]

Similar to the majority of the peers in this group, the GOM deepwater projects analyzed in this study do not have a positive EMV per exploration well drilled under the low case. Brazil, Guyana, and Norway are the only ones with positive EMV for the larger field size under the low oil price environment (i.e., low case in this study). Besides Guyana and Brazil, the U.S. deepwater oil projects face tough competition from Mexico, which has an under-explored deepwater sector. The EMV on the 500MMboe fields in Mexico is double that of the U.S. This is largely attributed to the depth of formations being drilled in the respective jurisdictions. The TVD of wells being drilled on the U.S. side of the GOM is almost double the depth of the wells recently drilled in Mexico, driving up the costs per well. In the future, exploratory drilling in Mexico is likely to move to deeper formations. Up until recently, deepwater drilling in Mexico was limited to the technical capabilities of its national oil company, Pemex. The competition from Mexico, however, will depend on the continuity of the reforms and the pace with which the recently elected and future administrations in Mexico offer acreage for exploration.

From an EMV perspective, the U.S. GOM projects compete reasonably well within the peer group under the high price scenario. As already stated in the analysis of other economic indicators in this study, deepwater natural gas projects in the U.S. GOM are not viable under the base and low case. The long cycle associated with deepwater exploration and development—seven years on average to first oil—and the depressed commodity prices in North America, make exploration for natural gas in the U.S. GOM unappealing compared to natural gas production from unconventional resources in the U.S.

[83] Some of the fields in Guyana and the pre-salt area of Brazil, which ranged between 1-10 billion barrels of oil equivalent were not considered representative of the entire group.

Table 5-10. EMV: Deepwater oil and gas fields

Jurisdiction	High Case Reserve size (MMboe)		Base Case Reserve size (MMboe)		Low Case Reserve size (MMboe)	
	500	250	500	500	250	500
Oil						
Angola	1036.6	472.2	513.0	201.0	-279.1	-202.1
Brazil	1246.9	846.5	622.6	266.1	155.0	-125.5
Canada	123.6	43.7	-330.5	-122.2	-776.6	-308.4
Guyana	3281.3	1502.0	1540.0	596.4	376.8	-20.3
Mexico	2136.0	652.6	899.8	112.1	-31.2	-305.6
Norway	704.6	305.1	295.9	92.0	23.1	-50.7
United Kingdom	1325.6	683.3	380.2	169.0	-383.7	-264.5
United States	1093.2	643.7	293.6	158.6	-247.5	-165.2
Gas						
Angola	615.1	284.0	297.9	122.6	-24.3	-50.5
Brazil	938.0	429.2	450.6	186.9	113.6	19.4
Canada	-59.8	-247.0	-368.2	-417.1	-592.7	-555.5
Guyana	5166.2	2441.9	2890.8	1300.8	1350.4	529.8
Mexico	562.6	101.3	-179.1	-283.2	-724.7	-593.4
Norway	441.0	171.4	141.7	7.9	-62.7	-111.6
United Kingdom	1369.2	604.2	717.5	279.4	279.3	60.1
United States	491.4	151.3	12.6	-77.1	-327.9	-246.6

Source: IHS Markit

5.2.9 Shallow and Deepwater Comparative Analysis – Conclusion

The U.S. GOM fiscal system for shallow water oil fields is very competitive within the peer group from a government take perspective as well as investor IRR and NPV/boe, offering some of the highest values per barrel of oil equivalent under the base and high cases. The shallow water fiscal system has the second lowest government take next to UK for oil fields and competes for second place with Australia for natural gas fields.

However, the fields modeled for this study are not representative of the field size distribution observed from discoveries of the past 15 years in the U.S. The GOM shelf area is more gas prone with 96% of the discoveries since 2003 being under 10MMboe. The 10MMboe oil and gas fields modeled for the GOM in this study failed to meet the hurdle rates for investment decisions with regard to IRR, NPV/boe and EMV. The natural gas projects in particular face significant commercial challenges due to the low natural gas market prices in the U.S. The abundance of lower cost sources of supply from shale gas and tight oil present a significant challenge for natural gas development in the GOM.

The U.S. GOM deepwater fiscal system is very competitive within the peer group, ranking third lowest after UK and Mexico from a government take perspective under the base case for oil fields. However, the government take is not the best measure of competitiveness of oil and gas investments in a particular jurisdiction. The U.S. GOM faces tough competition from Brazil, Guyana, Angola, and Norway that generate higher rates of return for investors, despite the substantially higher government take levied by these jurisdictions. The high cost and technological challenges associated with the development of the Lower Tertiary, which represents a significant portion of the undiscovered technically recoverable resources of the GOM, could disadvantage investments in the U.S. GOM. Some of the Lower Tertiary projects may not be sanctioned in a low oil price environment.

Deepwater natural gas projects in the U.S. GOM are not viable under the base and low case. The long cycle associated with deepwater exploration and development—seven years on average to first oil—and the depressed commodity prices in North America, make exploration for natural gas in the U.S. GOM unappealing compared to natural gas production from unconventional resources in the U.S.

6 Fiscal System Alternatives

6.1 Price Cases

The analysis of alternative fiscal systems uses various price thresholds for two of the fiscal system alternatives considered in this study. For the categorical royalty relief analyzed for both shallow and deepwater projects, a threshold price of $85/bbl has been considered. When market prices exceed $85/bbl the RSVs do not apply, the standard lease royalty applies instead. Thus, the high case results for categorical royalty relief remain unchanged from the status quo in this study—since the $85/bbl threshold is well below the high case price. This threshold was selected to be close to a medium point between the base and the high price.

The sliding scale royalty uses three price thresholds ($50, $80, and $105 per barrel), which have been plotted in Figure 6-1. The prices for the alternative fiscal systems were purposefully selected not to be identical with the low, base, and high case price scenarios selected for this study.

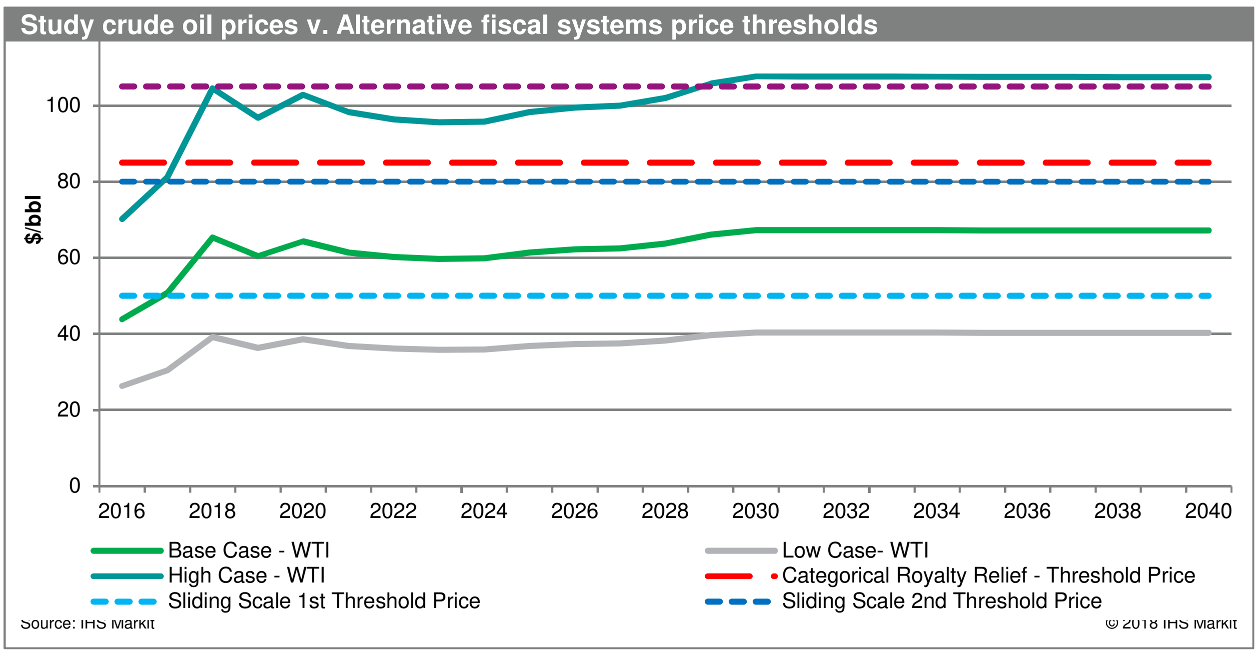


Figure 6-1: Crude oil price cases v. Alternative fiscal systems price thresholds

6.2 Non-discretionary Fiscal System Alternatives

The fiscal system alternatives analyzed in this section are ones that fall within the purview of BOEM. They are usually included in the call for bids and become contractual instruments for leases awarded under that lease sale (i.e., binding on DOI for the duration of the lease). There is no discretionary element related to these alternatives. They apply uniformly on all acreage leased, according to the terms stipulated in the lease sale documents regarding water depth or any other criteria that may be introduced by DOI.

6.2.1 Shallow Water Fiscal System Alternatives

The following fiscal system alternatives were analyzed for the shallow water areas of the U.S. GOM:

Categorical royalty relief: This alternative applies to all leases in water depth less than 200m. A royalty suspension volume (RSV) of 5 MMboe is granted for each qualifying lease when oil prices are less than $85/bbl. For modeling purposes, we assume that the 10 MMboe field contains two leases, that the 30 MMboe field holds three leases, and that the 100 MMboe field holds four leases. The 5 MMboe per-lease RSV is multiplied by the number of leases that make up the field to calculate the total royalty suspension volume for the field. The categorical royalty relief amounts are designed to offer a substantial benefit to help evaluate the maximum potential impact of fiscal terms (Table 6-1).

Table 6-1. Shallow water categorical royalty relief – RSV volumes

Field size (MMboe)	Number of leases	RSV total (Leases x 5 MMboe)	Total % royalty free (low & base case)
100	4	20	20%
30	3	15	50%
10	2	10	100%

Source: IHS Markit

Sliding scale royalty: Lessees pay a variable royalty based on oil and condensate prices. Under this royalty alternative, only gas production is subject to the statutory royalty of 12.5%. This scale is intentionally more onerous than the current statutory minimum of 12.5% in the shallow water GOM. Table 6-2 describes the application of the shallow water sliding scale royalty for oil prices.

Table 6-2. Shallow water sliding scale rates

Oil price ($/bbl)	Royalty rate (%)
< 50	12.5
50 to < 80	16.67
80 to < 105	20
> 105	22.5

Source: IHS Markit

6.2.2 Deepwater Fiscal System Alternatives

The following alternative royalty systems were analyzed for deepwater GOM:

Lower royalty: This alternative lowers the royalty rate to the statutory minimum of 12.5%.

Higher royalty: This alternative increases the royalty rate to 20% and 22.5%, respectively.

Deepwater categorical royalty relief: This fiscal system alternative applies at the lease level for pre-determined volumes for water depths greater than 200m. For modeling purposes, we assume that the 250 MMboe field holds four leases and that the 500 MMboe field holds five leases. An RSV is granted per lease when the oil price is less than $85/bbl. Table 6-3 describes the RSV available by water depth. The per-lease RSV is multiplied by the number of leases a field contains to get the total RSV applied to the hypothetical field. As with the shallow water categorical royalty relief, these royalty suspension amounts are designed to offer a substantial benefit to help evaluate the potential impact of fiscal terms.

Table 6-3. Deepwater royalty relief suspension volumes

Water depth (m)	Royalty suspension volume (MMboe)	Total RSV for 500 MMboe field (leases x RSV)	% Royalty Free 500 MMboe field (non-high case)	Total RSV for 250 MMboe field (leases x RSV)	% Royalty Free 250 MMboe field (non-high case)
200 to < 400	20	100	20%	80	32%

Water depth (m)	Royalty suspension volume (MMboe)	Total RSV for 500 MMboe field (leases x RSV)	% Royalty Free 500 MMboe field (non-high case)	Total RSV for 250 MMboe field (leases x RSV)	% Royalty Free 250 MMboe field (non-high case)
400 to < 800	40	200	40%	160	64%
800 +	60	300	60%	240	96%

Source: IHS Markit

Sliding scale royalty based on commodity price: In this royalty alternative, the gas stream pays the statutory minimum royalty of 12.5%. The oil price that determines the effective royalty rate is the sales price of crude oil or condensate. Table 6-4 describes the application of the sliding scale royalty.

Table 6-4. Deepwater sliding scale rates

Oil price ($/bbl)	Royalty rate (%)
< 50	12.5
50 to < 80	16.67
80 to < 105	20
> 105	22.5

Source: IHS Markit

6.3 Comparative Analysis of Non-Discretionary Alternative Fiscal Systems

6.3.1 Shallow Water Fiscal System Alternatives

6.3.1.1 Categorical Royalty Relief

The categorical royalty relief analyzed in this study results in 50% and 100% effective reduction of the royalty volumes payable to the Federal government for the 30MMboe and 10MMboe fields modeled for this study, transforming the U.S. government take for the shelf projects into the lowest among the peer group (low- to mid-20s in the base case)—perhaps the lowest in the world among jurisdictions that offer acreage for oil and gas investment.[84] Under the status quo, the government take for U.S. GOM shelf projects is already low compared to the majority of the jurisdictions in the peer group—second lowest after the United Kingdom (Figure 6-2, Table 6-5). With rates of return upwards of 20% under existing terms, a categorical relief of this nature may not be necessary for a 30MMboe oil field (Table 6-6). The 100% royalty relief, however is not sufficient to render the 10MMBboe economic under the base and low case. The application of this alternative would however mean no revenue will accrue via royalties to the Federal government under the base and low case for such fields.

The U.S. GOM shallow water oil projects are already competitive from a government take and investor rate of return perspective. A decision whether a categorical royalty relief is necessary should not be pinned on the ranking of the U.S. among the peer group, but rather on what measures are necessary to make a category of investments commercially viable while maintaining an equitable share of project revenues between the government and investors. In this context, the question should be asked whether categorical relief or discretionary relief better serve the government's objectives in the U.S. GOM shelf area.

[84] A government take of 21-25% would rank the United States as the jurisdiction with the lowest government take among 148 fiscal system analyzed in the IHS Markit PEPS database.

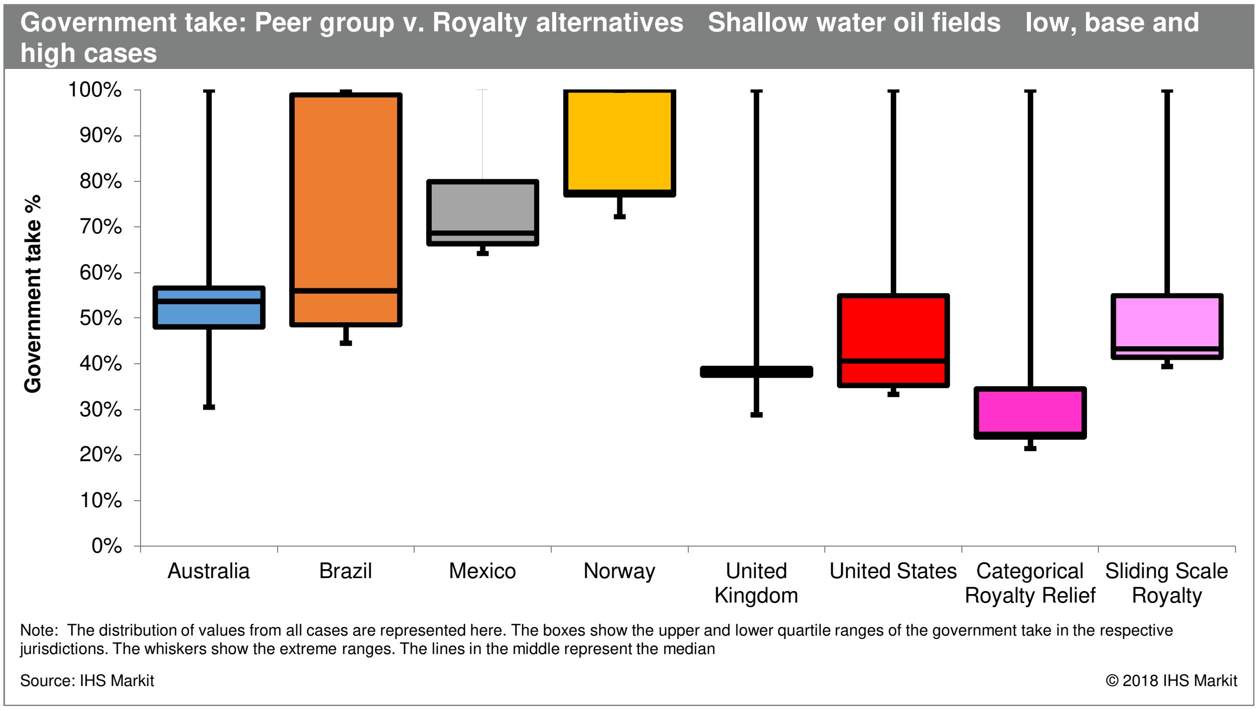


Figure 6-2. Government take: Peer group v. Royalty alternatives - Shallow water oil fields – low, base and high cases

Table 6-5. Government Take: Shallow water oil and gas fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Oil									
Australia	57%	54%	48%	55%	47%	30%	52%	83%	100%
Brazil	45%	49%	62%	47%	56%	100%	52%	99%	100%
Mexico	66%	69%	72%	64%	68%	80%	64%	86%	100%
Norway	78%	77%	72%	78%	76%	100%	77%	100%	100%
United Kingdom	39%	39%	38%	39%	38%	29%	37%	30%	100%
United States	33%	34%	41%	35%	38%	62%	41%	55%	100%
U.S. SW Categorical Relief	33%	34%	41%	23%	21%	25%	24%	24%	100%
U.S. SW Sliding Scale	41%	43%	51%	39%	43%	73%	41%	55%	100%
Gas									
Australia	56%	51%	33%	52%	30%	100%	27%	100%	100%
Brazil	44%	58%	88%	47%	100%	100%	57%	100%	100%
Mexico	66%	93%	84%	67%	100%	100%	83%	100%	100%
Norway	78%	77%	73%	77%	71%	100%	76%	100%	100%
United Kingdom	39%	39%	39%	39%	37%	35%	38%	58%	100%
United States	39%	38%	41%	54%	50%	73%	100%	100%	100%

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
U.S. SW Categorical Relief	39%	38%	41%	32%	26%	25%	100%	100%	100%
U.S. SW Sliding Scale	44%	43%	47%	59%	54%	80%	100%	100%	100%

Source: IHS Markit

Regarding IRR, despite the effective 100% relief for 10MMboe in this study, the categorical royalty relief is not sufficient to push the investor rates of return for the small natural gas field sizes beyond the 15% rate of return threshold (Table 6-6). This shows once again that the challenges associated with natural gas projects in the U.S. GOM are not related to the fiscal system, but rather the market conditions in the U.S.

Table 6-6. IRR: Shallow water oil and gas fields

Jurisdiction	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	100	30	10	100	30	10	100	30	10
Oil									
Australia	39%	25%	19%	31%	16%	11%	22%	1%	0%
Brazil	43%	22%	12%	32%	13%	0%	21%	0%	0%
Mexico	39%	16%	12%	31%	10%	4%	22%	2%	0%
Norway	24%	12%	3%	17%	6%	0%	10%	0%	0%
United Kingdom	44%	29%	16%	33%	19%	5%	22%	8%	0%
United States	45%	38%	19%	34%	26%	6%	20%	10%	0%
U.S. SW Categorical Relief	45%	38%	19%	37%	29%	10%	23%	14%	0%
U.S. SW Sliding Scale	43%	36%	17%	33%	25%	5%	20%	10%	0%
Gas									
Australia	29%	21%	14%	21%	13%	0%	11%	0%	0%
Brazil	32%	9%	2%	22%	0%	0%	11%	0%	0%
Mexico	19%	1%	2%	11%	0%	0%	2%	0%	0%
Norway	20%	8%	4%	13%	3%	0%	7%	0%	0%
United Kingdom	37%	23%	15%	28%	14%	7%	18%	2%	0%
United States	33%	27%	17%	16%	13%	3%	0%	0%	0%
U.S. SW Categorical Relief	33%	27%	17%	20%	17%	7%	0%	0%	0%
U.S. SW Sliding Scale	32%	26%	15%	15%	12%	2%	0%	0%	0%

Source: IHS Markit

6.3.1.2 Sliding Scale Royalty

Sliding scale royalties are usually designed to enable the resource holder to capture the project upside when profitability is high and provide relief when profitability goes down. The triggers for the sliding scale in this instance are crude oil prices—with royalty rates ranging from 12.5% to 22.5%. While this measure results in an increase of the government take for the U.S. GOM shelf projects, it does not change the overall ranking of the U.S. among other jurisdictions in the peer group for oil fields (Figure 6-3), except for the 10MMboe base case. In that case, the U.S. government take shifts from second to third-lowest in the peer group (Table 6-5). Under this measure, the U.S. GOM oil projects on the shelf continue to remain competitive within the peer group. As expected, an increase in government take leads to reduction in investor rates of return. The IRR is reduced by one percentage point in the base case and two percentage points in the high case (Table 6-6).

Overall, the impact of this fiscal system alternative is minimal on natural gas projects on the shelf—since the royalty rate for natural gas is kept constant at 12.5%. Any change in government take or IRR results from the application of the sliding scale to liquids associated with natural gas production.

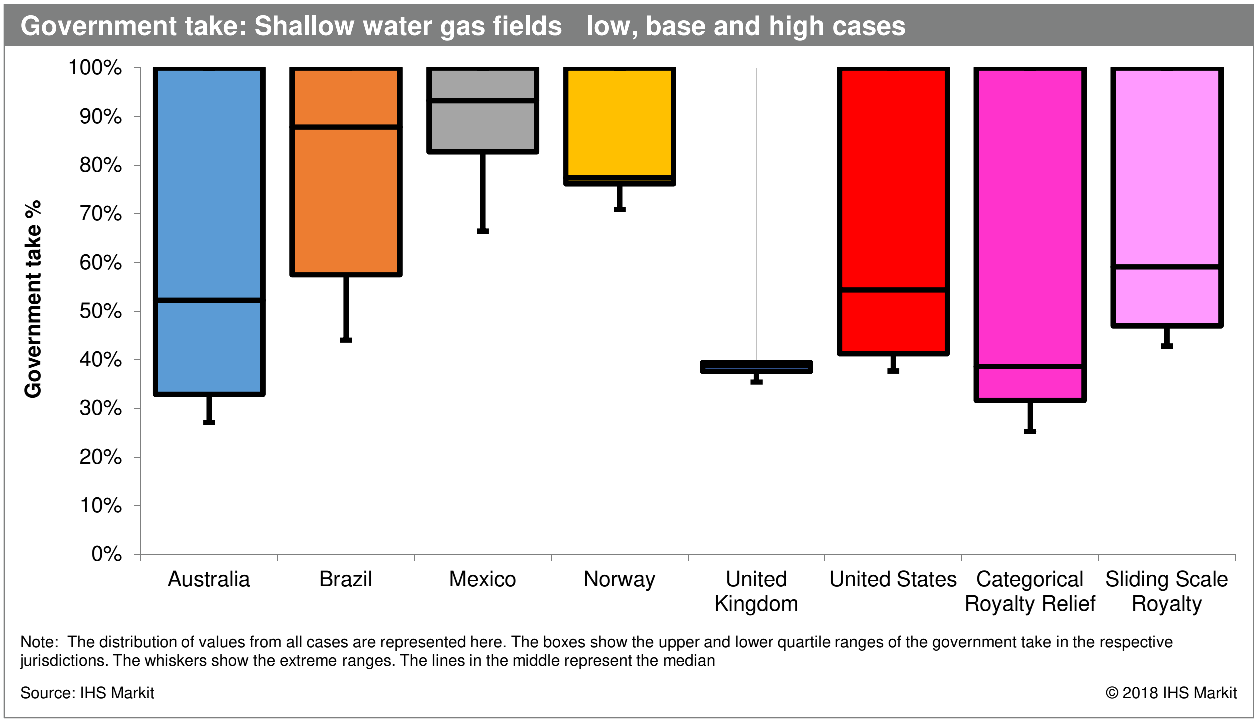


Figure 6-3. Government take: Peer group v. Royalty alternatives - Shallow water gas fields – low, base and high cases

6.3.1.3 Shallow Water Fiscal System Alternatives – Conclusion

The U.S. GOM shallow water fiscal system is already competitive under the status quo for larger field sizes. However, larger fields are not expected to be discovered in shallow water GOM. With expected field sizes of 10MMBoe or lower, the U.S. GOM shallow water could benefit from policies such as those instituted under the MER strategy in the UK. The categorical royalty relief is the closest approximation to the basin wide allowances offered in the UK. While 100% relief was not sufficient to push the 10MMBoe fields in this study across the 15% rate of return threshold required for investment decisions, such a program might work when combined with the use of tie-back technology.

The sliding scale royalty does result in higher government take than the status quo in the GOM shelf projects. Sliding scale royalties usually offer flexibility and are designed to shield investors from the harsh impact of flat royalties when commodity prices drop, and reward the government when commodity prices rise. However, the sliding scale royalty modeled for this study, which keeps the lower rate at the statutory minimum of 12.5%, is designed to provide the government with a larger share of the revenue from oil projects on the shelf without any relief from the status quo when commodity prices are low. Given the maturity of the area and the already challenging economics of the shallow water GOM projects, the introduction of the sliding scale royalty alternative while keeping the statutory minimum rate intact could deter investment. An alternative sliding scale royalty that lowers the royalty rate below the statutory minimum when commodity prices are low could be perceived as more balanced and neutral to investment decisions.

6.3.2 Deepwater Fiscal System Alternatives

Compared to the status quo, the deepwater royalty relief alternatives achieve the following results from a government take perspective for oil fields:

- The 12.5% royalty rate both lowers the government take and narrows the range of government take for projects in the third quartile, thus softening the regressivity of the fiscal system (i.e., the wider the range of government take the higher the progressivity/regressivity of the fiscal system)

- Under the 20% and 22.5% royalty rate alternatives the median government take increases slightly; however, the range widens thus pushing some of the sub-economic cases further into uneconomic territory

- In addition to lowering the government take, the categorical royalty relief eliminates almost entirely the regressivity of the fiscal system (Figure 6-4). This undoubtedly has a significant negative impact on the government's revenue from royalties—the relief constitutes an effective 60% and 96% royalty reduction for the 500MMboe and 250MMboe, respectively.

- The sliding scale royalty offers a more balanced approach by lowering the royalty rate and therefore revenue to the government when commodity prices are below \$80/bbl and \$50/bbl (16.67% and 12.5% royalty, respectively) and increasing the government share when commodity prices cross the \$80/bbl and \$105/bbl thresholds (20% and 22.5%, respectively). The range of the government take narrows significantly compared to the status quo, thus lowering the degree of regressivity of the fiscal system.

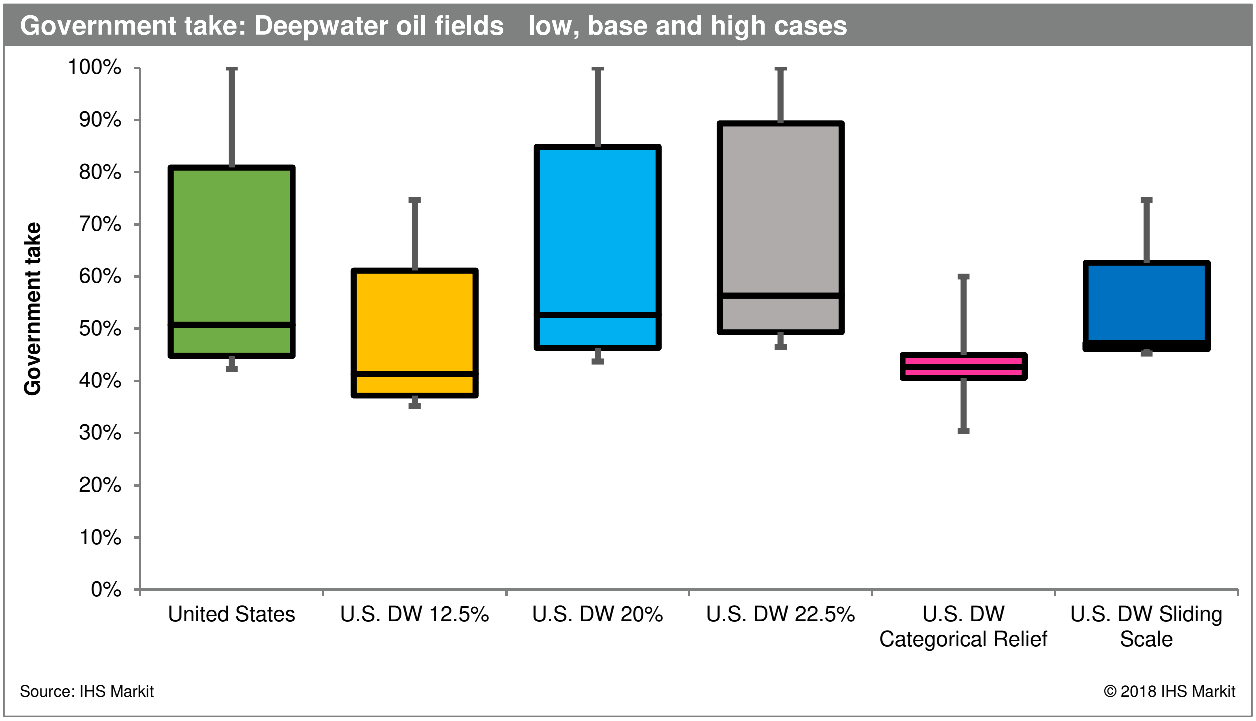


Figure 6-4. Government take: Standard v. Royalty alternatives - Deepwater oil fields (low, base, and high cases)

The impact of royalty alternatives for deepwater gas fields is muted by the marginal economics associated with such fields. The sub-economic results in the base and low case exacerbate the regressivity of the fiscal system—which is evidenced in the wide range of government take under all royalty alternatives when the combined low, base, and high case results are analyzed. The following conclusions are drawn in comparison with the status quo:

- The 12.5% royalty alternative significantly lowers the government take for all fields, with the high case scenario resulting in the lowest government take in the peer group. this is attributed to the regressive nature of the fiscal regime. In the case of profitable fields the relative U.S. government share of the pre-tax revenues declines as profitability goes up. The range of government take remains wide, largely due to uneconomic projects in the base and low case scenario. This royalty alternative may not be sufficient to incentivize deepwater natural gas projects under the base and low price scenarios.

- As expected, both the 20% and 22.5% royalty alternatives increase the government take for the already uneconomic deepwater natural gas projects.

- While the categorical royalty relief tremendously improves the economics of natural gas projects in the base and high case, in order to do so it requires relief on substantial volumes of natural gas produced, (i.e., 240MMboe and 300MMboe of royalty free production from the 250MMboe and $500MMboe gas fields, or 96% and 60% of production royalty free, respectively.)

- The impact of the sliding scale alternative in deepwater natural gas fields closely mirrors the 12.5% royalty rate alternative (Figure 6-5). The differences in government take are attributed to the share of condensate and other liquids produced in association with natural gas.

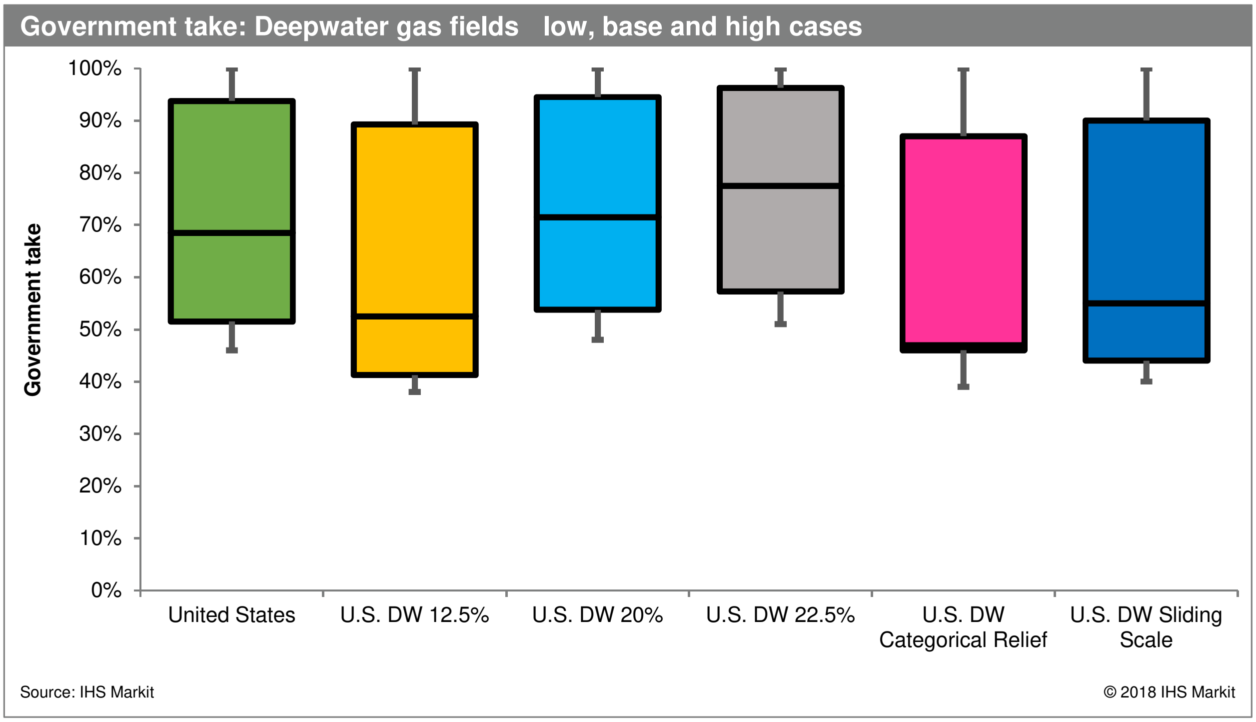


Figure 6-5. Government take: Standard v. Royalty alternatives - Deepwater gas fields (low, base, and high cases)

The following sections provide a more detailed analysis of the impact of each fiscal system alternative on government take and investor rate of return and their relative comparison to the status quo and the peer group.

6.3.2.1 Lower Royalty

This alternative lowers the 18.75% royalty rate to the statutory minimum of 12.5%. This improves the competitiveness of the U.S. deepwater oil projects by lowering and narrowing the range of government take—softening the degree of regressivity of the U.S. fiscal system. With a median government take of 41%, the U.S. fiscal system has the lowest government take under the high case and second lowest next to the United Kingdom under the base case (Figure 6-6). When the overall range of government take is considered under all three cases, the U.S. fiscal system is the most competitive in the peer group. It surpasses the United Kingdom under the low case scenario (Table 6-7).

The investor rates of return increase slightly (one percentage point) under this alternative. This measure, however, is not sufficient to turn oil fields into economic ones under the low case. The 250 MMboe oil field is sub-economic across all jurisdictions in the low case. In the water depths modeled by this study, reserves of 300MMboe or lower are considered marginal under the low oil price scenario. Except for the United Kingdom, all the deepwater oil fields modeled for this study are situated in ultra-deep waters. This is representative of the recent trends in exploratory drilling and discoveries made in the respective jurisdictions.

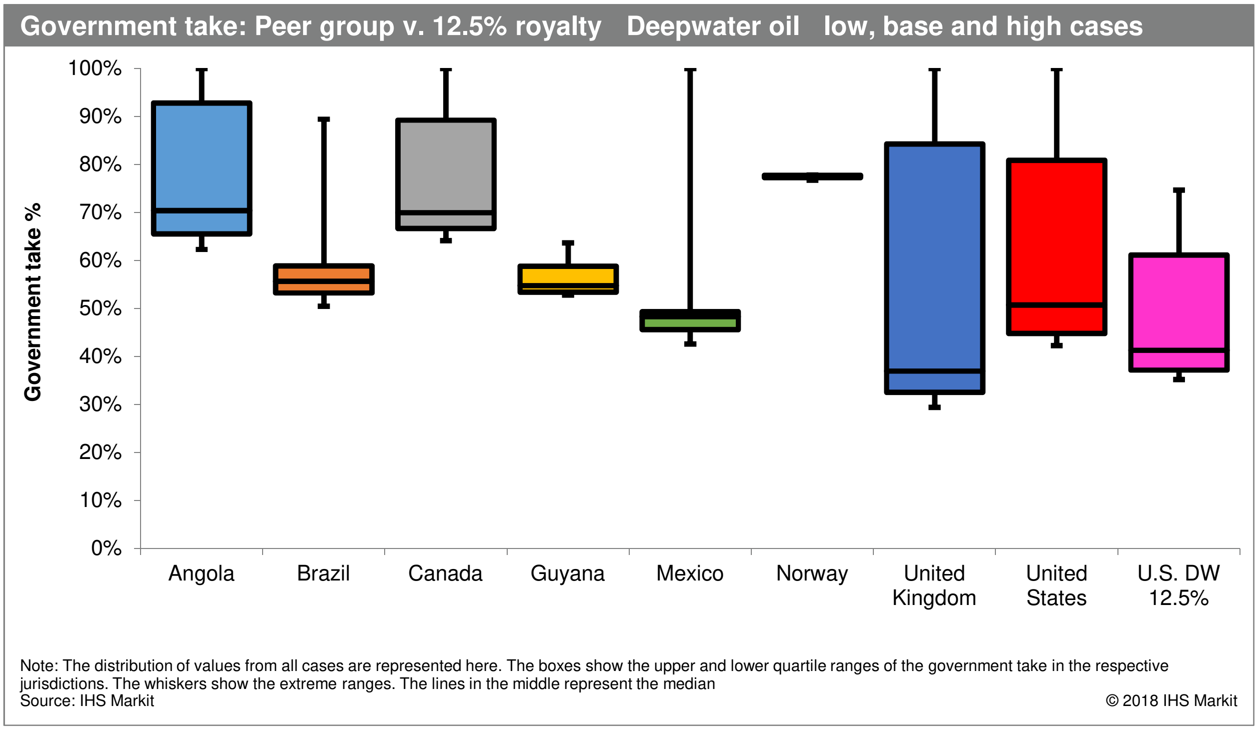


Figure 6-6. Government take: Peer group v. 12.5% royalty - Deepwater oil fields (low, base, and high cases)

Table 6-7. Government take: Deepwater oil and gas fields v. 12.5% royalty alternative

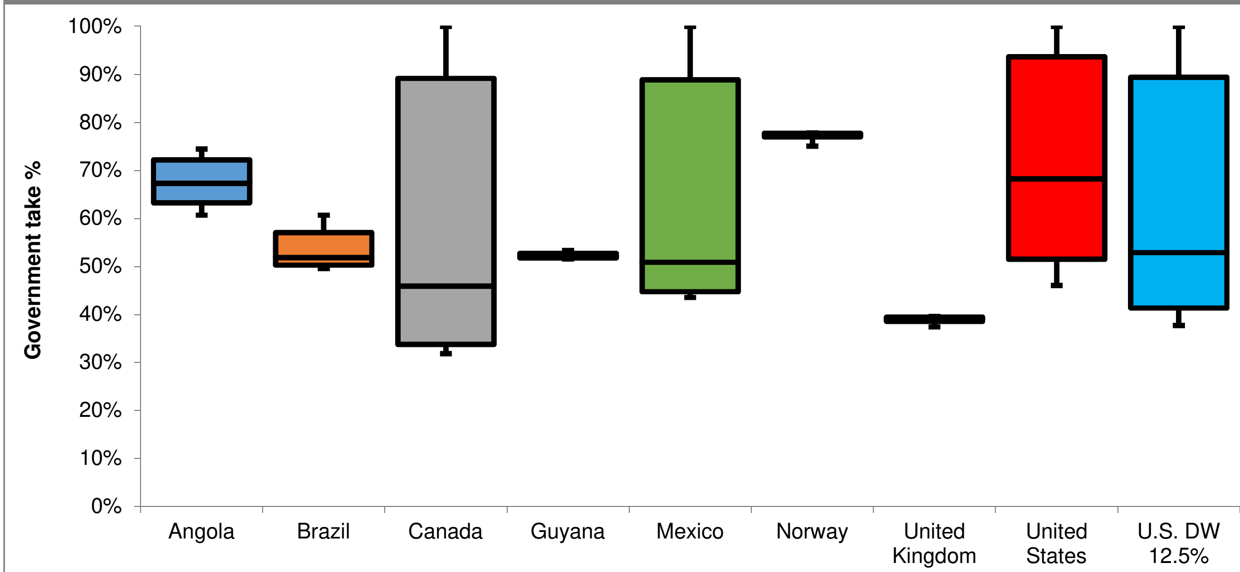
Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Oil						
Angola	71%	70%	64%	62%	100%	100%
Brazil	53%	50%	53%	58%	59%	89%
Canada	64%	72%	68%	66%	100%	95%
Guyana	53%	53%	54%	55%	60%	64%
Mexico	45%	48%	43%	49%	49%	100%
Norway	78%	78%	78%	78%	77%	77%
United Kingdom	37%	37%	31%	29%	100%	100%
United States	43%	42%	52%	50%	91%	100%
U.S. DW 12.5%	36%	35%	42%	40%	67%	75%
Gas						
Angola	74%	74%	67%	68%	61%	62%
Brazil	50%	50%	51%	52%	59%	61%
Canada	32%	33%	35%	57%	100%	100%
Guyana	52%	52%	52%	52%	53%	53%

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Mexico	44%	46%	44%	55%	100%	100%
Norway	78%	78%	78%	77%	77%	75%
United Kingdom	40%	39%	39%	39%	38%	37%
United States	46%	48%	62%	75%	100%	100%
U.S. DW 12.5%	38%	39%	48%	57%	100%	100%

Source: IHS Markit

While the government take for deepwater natural gas projects drops significantly as prices rise, (Figure 6-7) the resulting shift in the investor rate of return is not sufficient to reach the 15% hurdle rate that most investors seek for such projects (Table 6-8) in the base and low cases. This is in no way related to the fiscal system, but rather the challenging economics for natural gas projects in the U.S. GOM and generally in North America. The fact that the deepwater gas projects yield robust rates of return (17%-28%) under the high case for both the standard and the 12.5% royalty alternative indicates that the problems are related to market prices (i.e., low gas prices) rather than the fiscal system.

Government take: Peer group v. 12.5% Royalty   Deepwater gas (low, base and high cases)



Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median

Source: IHS Markit

Figure 6-7. Government take: Peer group v. 12.5% royalty - Deepwater gas fields (low, base, and high cases)

Table 6-8. IRR: Deepwater oil and gas fields v. 12.5% royalty alternative

Jurisdiction	High case	Base case	Low case
	Reserve size (MMboe)	Reserve size (MMboe)	Reserve size (MMboe)

	500	250	500	500	250	500
Oil						
Angola	36%	29%	25%	20%	0%	0%
Brazil	36%	32%	27%	20%	16%	3%
Canada	15%	16%	6%	10%	0%	0%
Guyana	43%	34%	32%	23%	18%	9%
Mexico	36%	23%	25%	12%	9%	0%
Norway	29%	23%	21%	15%	11%	7%
United Kingdom	38%	36%	22%	20%	0%	0%
United States	25%	25%	16%	16%	0%	0%
U.S. DW 12.5%	26%	26%	17%	17%	4%	3%
Gas						
Angola	25%	23%	18%	16%	10%	8%
Brazil	39%	31%	29%	22%	17%	12%
Canada	11%	7%	5%	1%	0%	0%
Guyana	48%	38%	39%	30%	29%	21%
Mexico	16%	12%	7%	3%	0%	0%
Norway	21%	17%	15%	11%	8%	4%
United Kingdom	41%	32%	32%	24%	22%	14%
United States	26%	17%	11%	4%	0%	0%
U.S. DW 12.5%	28%	19%	13%	7%	0%	0%

Source: IHS Markit

6.3.2.2 Higher Royalty

The higher royalty alternatives of 20% and 22.5% have the potential to bring more revenue to the U.S. government without any change in the overall raking in the peer group (Figure 6-8). They also enhance the regressivity of the U.S. fiscal system. The government take for oil fields under the high and base case remains within a reasonable range of 44 to 57% (Table 6-9). However, from an investor perspective, the internal rates of return remain the second lowest in the peer group (Table 6-10). The deepwater oil fields in jurisdictions such as Angola and Norway that have much higher government takes than in the U.S. GOM yield higher rates of return to investors. That is primarily due to their progressive or neutral (in the case of Norway) fiscal systems that rely on measures of profitability for government revenue. The revenue accruing to the governments of Angola, Norway, and the United Kingdom is mostly back-end loaded (i.e., the government is sharing the revenue risk with investors).

As expected, the higher royalty rate alternative pushes further into uneconomic territory the already sub-economic deepwater natural gas projects in the GOM. Form and IRR perspective, the ranking remains unchanged with the U.S. edging Canada and Mexico at the bottom of the peer group.

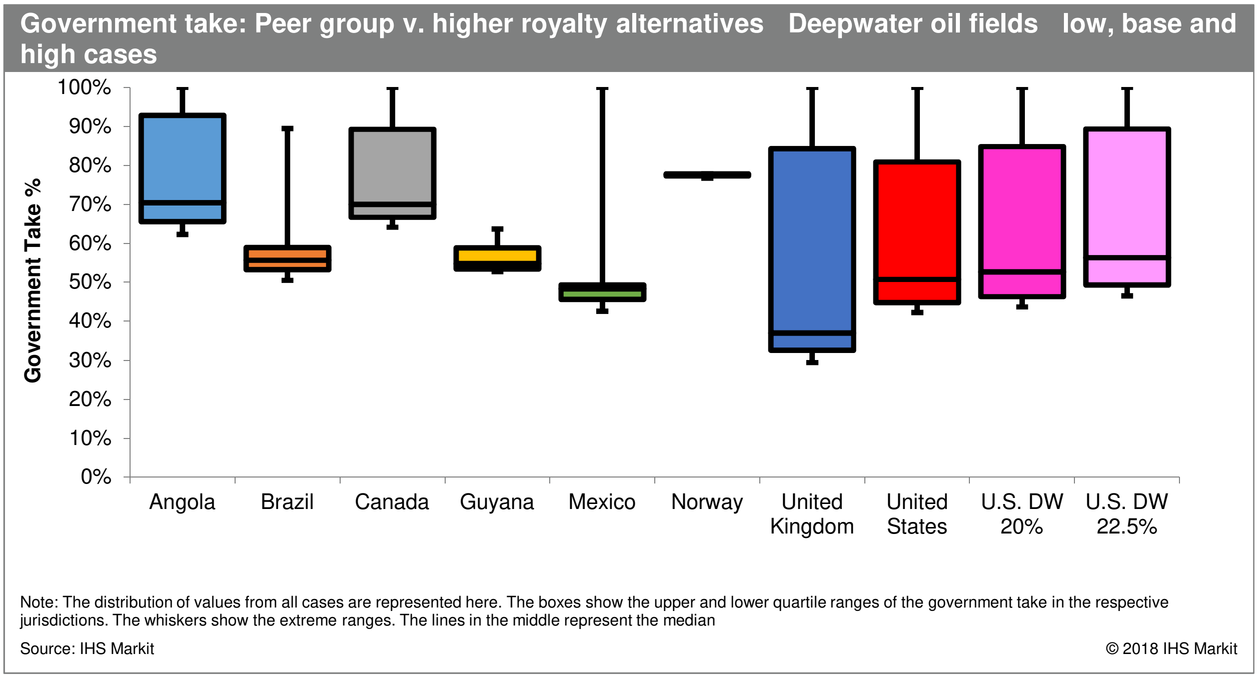


Figure 6-8. Government take: Peer group v. higher royalty alternatives - Deepwater oil fields – low, base, and high cases

Table 6-9. Government take: Deepwater oil and gas fields v. 20% and 22.5% royalty

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Oil						
Angola	71%	70%	64%	62%	100%	100%
Brazil	53%	50%	53%	58%	59%	89%
Canada	64%	72%	68%	66%	100%	95%
Guyana	53%	53%	54%	55%	60%	64%
Mexico	45%	48%	43%	49%	49%	100%
Norway	78%	78%	78%	78%	77%	77%
United Kingdom	37%	37%	31%	29%	100%	100%
United States	43%	42%	52%	50%	91%	100%
U.S. DW 20%	44%	44%	53%	52%	95%	100%
U.S. DW 22.5%	47%	47%	57%	55%	100%	100%
Gas						
Angola	74%	74%	67%	68%	61%	62%
Brazil	50%	50%	51%	52%	59%	61%
Canada	32%	33%	35%	57%	100%	100%
Guyana	52%	52%	52%	52%	53%	53%

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Mexico	44%	46%	44%	55%	100%	100%
Norway	78%	78%	78%	77%	77%	75%
United Kingdom	40%	39%	39%	39%	38%	37%
United States	46%	48%	62%	75%	100%	100%
U.S. DW 20%	48%	50%	65%	78%	100%	100%
U.S. DW 22.5%	51%	53%	70%	85%	100%	100%

Source: IHS Markit

Table 6-10. IRR: Deepwater oil and gas fields v. 20% and 22.5% royalty

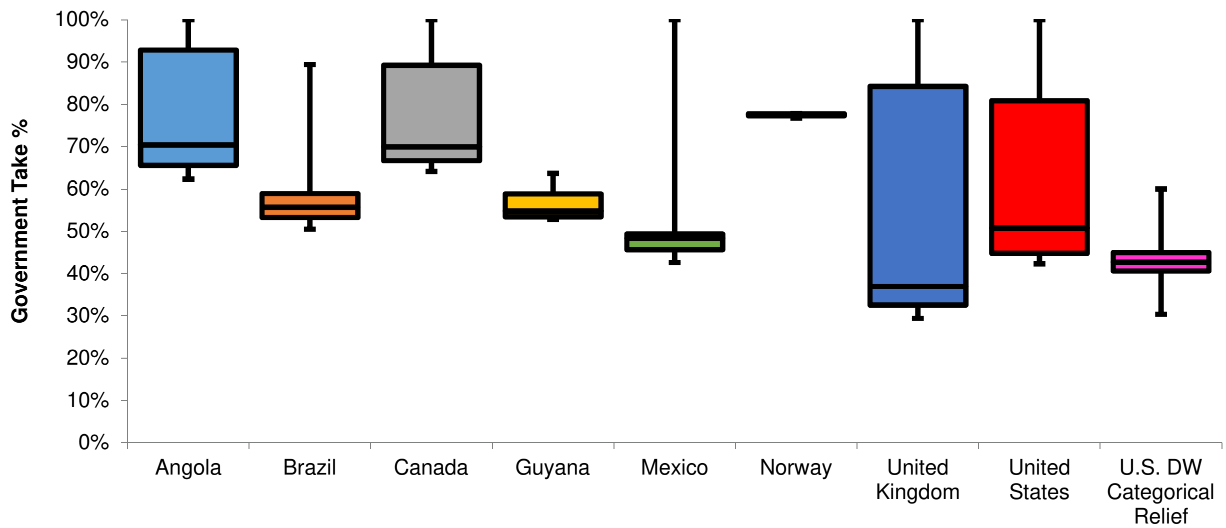
Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	500	250	500
Crude Oil						
Angola	36%	29%	25%	20%	0%	0%
Brazil	36%	32%	27%	20%	16%	3%
Canada	15%	16%	6%	10%	0%	0%
Guyana	43%	34%	32%	23%	18%	9%
Mexico	36%	23%	25%	12%	9%	0%
Norway	29%	23%	21%	15%	11%	7%
United Kingdom	38%	36%	22%	20%	0%	0%
United States	25%	25%	16%	16%	0%	0%
U.S. DW 20%	24%	25%	16%	15%	0%	0%
U.S. DW 22.5%	24%	24%	15%	14%	0%	0%
Natural Gas						
Angola	25%	23%	18%	16%	10%	8%
Brazil	39%	31%	29%	22%	17%	12%
Canada	11%	7%	5%	1%	0%	0%
Guyana	48%	38%	39%	30%	29%	21%
Mexico	16%	12%	7%	3%	0%	0%
Norway	21%	17%	15%	11%	8%	4%
United Kingdom	41%	32%	32%	24%	22%	14%
United States	26%	17%	11%	4%	0%	0%
U.S. DW 20%	26%	17%	10%	4%	0%	0%
U.S. DW 22.5%	25%	16%	9%	3%	0%	0%

Source: IHS Markit

6.3.2.3 Categorical Royalty Relief

The categorical royalty relief is the most impactful fiscal measure with regard to the range of government take in deepwater oil fields (Figure 6-9). While this measure eliminates almost entirely the regressivity of the fiscal system, it comes at the expense of offering 240MMboe and 300MMboe royalty suspension volumes for the 250MMboe and 500MMboe oil fields respectively—representing an effective 96% and 60% reduction in royalty entitlement to the government. From a government take ranking perspective, this measure does not change the already competitive ranking of the U.S. GOM oil projects in the peer group, second lowest government take under the base case (Figure 6-9, Table 6-11). The categorical royalty relief has no impact on the high case as the categorical royalty relief does not apply as the prices are above the $85/bbl threshold.

Government take: Peer group v. categorical royalty relief Deepwater oil fields low, base and high cases



Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median
Source: IHS Markit

Figure 6-9. Government take: Peer group v. categorical royalty relief - Deepwater oil fields – low, base, and high cases

Table 6-11. Government take: Deepwater oil and gas fields v. categorical royalty relief

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Oil						
Angola	71%	70%	64%	62%	100%	100%
Brazil	53%	50%	53%	58%	59%	89%
Canada	64%	72%	68%	66%	100%	95%
Guyana	53%	53%	54%	55%	60%	64%
Mexico	45%	48%	43%	49%	49%	100%
Norway	78%	78%	78%	78%	77%	77%

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
United Kingdom	37%	37%	31%	29%	100%	100%
United States	43%	42%	52%	50%	91%	100%
U.S. DW Categorical Relief	43%	42%	40%	30%	60%	46%
Gas						
Angola	74%	74%	67%	68%	61%	62%
Brazil	50%	50%	51%	52%	59%	61%
Canada	32%	33%	35%	57%	100%	100%
Guyana	52%	52%	52%	52%	53%	53%
Mexico	44%	46%	44%	55%	100%	100%
Norway	78%	78%	78%	77%	77%	75%
United Kingdom	40%	39%	39%	39%	38%	37%
United States	46%	48%	62%	75%	100%	100%
U.S. DW Categorical Relief	46%	48%	46%	39%	100%	100%

Source: IHS Markit

The substantial relief applied to the deepwater oil fields modeled for this study, does not result in significant increase in the IRR. A 96% royalty free volume on the 250MMBoe oil field only pushes the IRR by two percentage points in the base case. The investor rate of return for deepwater oil fields remains sub-economic under the low oil price scenario (low case), despite the substantial giveaway under the categorical royalty relief (Table 6-12).

While the fields modeled for this study are not necessarily representative of the Lower Tertiary, the economics for the Lower Tertiary projects are going to be even more challenging[85]. Despite the large inventory of discovered resources in the Lower Tertiary, a sizeable share of potential volumes are still at the appraisal stage, making the play potential far from proven at the time of this report. This is largely due to development challenges such as tighter reservoirs, poor oil quality and lack of infrastructure compared to Miocene and Miocene Sub salt plays (Figure 6-10). The Perdido Fold Belt and Outboard Lower Tertiary areas have already been reeling with a number of challenges such as:

- Well productivity that is estimated to be as much as 50% lower than in Miocene and Miocene Sub-salt reservoirs (see adjacent chart)
- HPHT reservoirs resulting in more challenging and costly wells
- A lack of existing infrastructure
- The current absence of production technologies to produce at high pressures of up to 20,000 psi.
- Discoveries far from existing production hubs

[85] The total vertical depth of wells modeled for this study is similar to the Lower Tertiary, however, the well productivity and cost are more representative of the wider GOM ultra deepwater area.

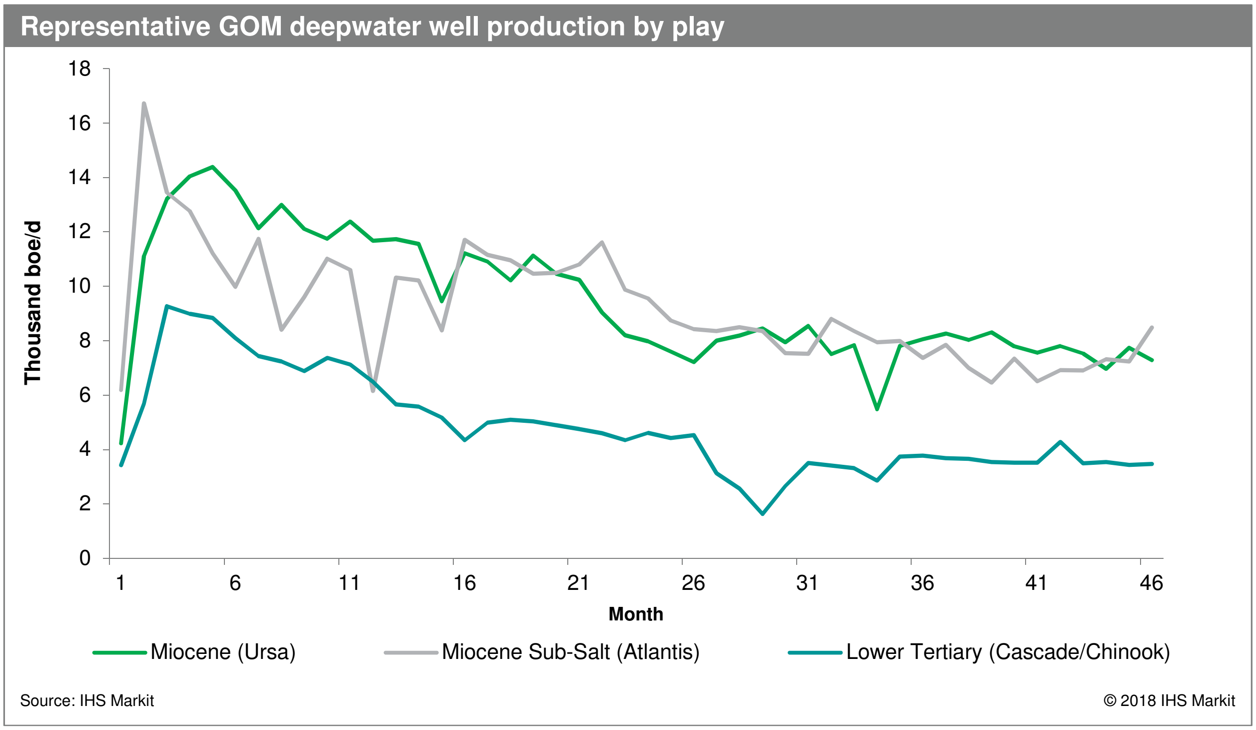


Figure 6-10: Representative GOM deepwater well production by play

From an investor point of view, the IRR improves from 11% to 15% in the base case for the 500MMboe gas field; however it is not able to push the 250MMboe across the 15% IRR threshold (Table 6-12). The deepwater gas fields remain uneconomic in the low case under this royalty alternative. This proves once again that the challenges associated with natural gas projects are market challenges, rather than inherent in the fiscal system—not even a 60% and 96% royalty relief offered for the 500MMboe and 250MMboe gas fields, respectively, could render such fields economic.

Table 6-12. IRR: Deepwater oil and gas fields v. categorical royalty relief

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Crude Oil						
Angola	36%	29%	25%	20%	0%	0%
Brazil	36%	32%	27%	20%	16%	3%
Canada	15%	16%	6%	10%	0%	0%
Guyana	43%	34%	32%	23%	18%	9%
Mexico	36%	23%	25%	12%	9%	0%
Norway	29%	23%	21%	15%	11%	7%
United Kingdom	38%	36%	22%	20%	0%	0%
United States	25%	25%	16%	16%	0%	0%
U.S. DW Categorical Relief	25%	25%	18%	19%	5%	6%
Natural Gas						

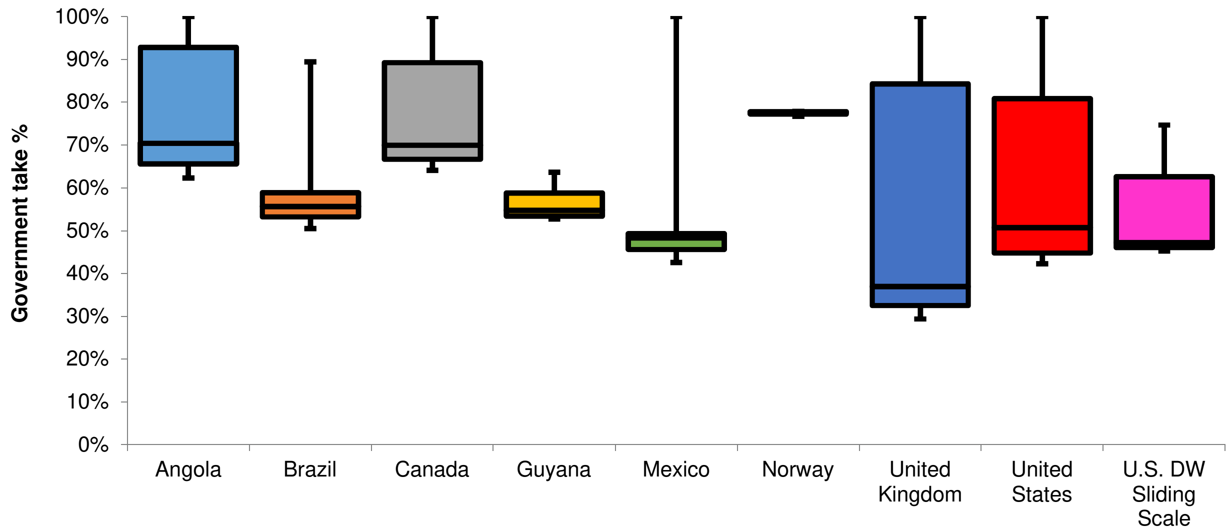
Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Angola	25%	23%	18%	16%	10%	8%
Brazil	39%	31%	29%	22%	17%	12%
Canada	11%	7%	5%	1%	0%	0%
Guyana	48%	38%	39%	30%	29%	21%
Mexico	16%	12%	7%	3%	0%	0%
Norway	21%	17%	15%	11%	8%	4%
United Kingdom	41%	32%	32%	24%	22%	14%
United States	26%	17%	11%	4%	0%	0%
U.S. DW Categorical Relief	26%	17%	15%	9%	0%	0%

Source: IHS Markit

6.3.2.4 Sliding Scale Royalty

The sliding scale royalty offers a more balanced approach by lowering the royalty rate and therefore revenue to the government when commodity prices are below \$80/bbl and \$50/bbl (effective royalty rates of 16.67% and 12.5%, respectively), and increasing the government share when commodity prices cross the \$80/bbl and \$105/bbl thresholds (20% and 22.5%, respectively). The range of the government take narrows compared to the status quo, softening the degree of regressivity of the fiscal system (Figure 6-11). This measure results in increase of the government take by three to four percentage points for oil fields under the high case and a four percentage point rate reduction in the base case (Table 6-13). The government take in the low case for deepwater oil fields drops significantly from 91% to 67% for the 500MMboe and from 100% to 75% for the 250MMboe. Despite the substantial drop in government take, the resulting increase in IRR is not sufficient to make these projects viable under this price scenario (Table 6-14).

Government take: Peer gropup v. Sliding scale royalty Deepwater oil fields   low, base and high cases



Note: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median

Source: IHS Markit

Figure 6-11. Government take: Peer group v. categorical royalty relief - Deepwater oil fields – low, base, and high cases

Table 6-13. Government Take: Deepwater oil and gas fields v. sliding scale royalty

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Oil						
Angola	71%	70%	64%	62%	100%	100%
Brazil	53%	50%	53%	58%	59%	89%
Canada	64%	72%	68%	66%	100%	95%
Guyana	53%	53%	54%	55%	60%	64%
Mexico	45%	48%	43%	49%	49%	100%
Norway	78%	78%	78%	78%	77%	77%
United Kingdom	37%	37%	31%	29%	100%	100%
United States	43%	42%	52%	50%	91%	100%
U.S. DW Sliding Scale	46%	45%	48%	46%	67%	75%
Gas						
Angola	74%	74%	67%	68%	61%	62%
Brazil	50%	50%	51%	52%	59%	61%
Canada	32%	33%	35%	57%	100%	100%
Guyana	52%	52%	52%	52%	53%	53%

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Mexico	44%	46%	44%	55%	100%	100%
Norway	78%	78%	78%	77%	77%	75%
United Kingdom	40%	39%	39%	39%	38%	37%
United States	46%	48%	62%	75%	100%	100%
U.S. DW Sliding Scale	40%	42%	50%	60%	100%	100%

Source: IHS Markit

The sliding scale alternative is not designed to fluctuate with natural gas prices. Royalties for natural gas production remain flat at the statutory minimum of 12.5%. Such projects experience a greater decline in government take in the base case than oil projects, 9-12 percentage point drop due to the application of the statutory minimum royalty rate. What differentiates this alternative from the 12.5% alternative is the royalty applied on liquids. The impact of the sliding scale alternative in deepwater natural gas fields depends on the share of condensate and other liquids produced in associaiton with natural gas. Compared to the 12.5% alternative the sliding scale royalty for natural gas fields yields a slightly higher government take, 2-3 percentage point increase under the high and base case. The sliding scale increases the IRR for high and base case by two percentage points only. Despite the improvements in IRR the deepwater gas projects remain uneconomic in the base and low case (Table 6-14).

Table 6-14. IRR: Deepwater oil and gas fields v. sliding scale royalty

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
Crude Oil						
Angola	36%	29%	25%	20%	0%	0%
Brazil	36%	32%	27%	20%	16%	3%
Canada	15%	16%	6%	10%	0%	0%
Guyana	43%	34%	32%	23%	18%	9%
Mexico	36%	23%	25%	12%	9%	0%
Norway	29%	23%	21%	15%	11%	7%
United Kingdom	38%	36%	22%	20%	0%	0%
United States	25%	25%	16%	16%	0%	0%
U.S. DW Sliding Scale	24%	24%	16%	16%	4%	3%
Natural Gas						
Angola	25%	23%	18%	16%	10%	8%
Brazil	39%	31%	29%	22%	17%	12%
Canada	11%	7%	5%	1%	0%	0%
Guyana	48%	38%	39%	30%	29%	21%
Mexico	16%	12%	7%	3%	0%	0%
Norway	21%	17%	15%	11%	8%	4%

Jurisdiction	High case		Base case		Low case	
	Reserve size (MMboe)		Reserve size (MMboe)		Reserve size (MMboe)	
	500	250	500	250	500	250
United Kingdom	41%	32%	32%	24%	22%	14%
United States	26%	17%	11%	4%	0%	0%
U.S. DW Sliding Scale	28%	19%	13%	6%	0%	0%

Source: IHS Markit

6.4 Discretionary Royalty Relief

To promote increased production or incentivize new projects that are otherwise uneconomic, BSEE may reduce or eliminate royalty under "end-of-life royalty relief" or "special case" relief programs. The purpose of these programs is to allow operators reasonable financial returns to increase ultimate recovery. The discretionary relief programs have had very limited use by lessees since the introduction of the Deepwater Royalty Relief Act of 1995. Only seven leases have benefited from discretionary royalty relief over the three decades this program has been in place, with the most recent approval occurring 17 years prior to the date of this report (Table 6-15).[86] None of the approved discretionary royalty relief applications appears to be associated with the "end-of-life royalty relief" program.

Table: 6-15. Listing of Deepwater Royalty Relief Applications

Field Name	Type	Action	Action Date	Suspension Volume (MMboe)	Withdrawn	Withdrawn Date
EW958	IDWNP	Approved	6/5/1997	52.5	DOI withdrawn	12/1/1999
MC084	IDWNP	Approved	4/30/1998	87.5	DOI withdrawn	5/23/2000
DC133	IDWNP	Approved	7/16/1998	87.5		
MC718	IDWNP	Approved	7/23/1999	87.5		
GB161	IDWSE	Denied	11/4/1999	0		
GC236	IDWNP	Approved	12/4/2000	87.5		
GC472	IDWNP	Approved	6/1/2001	87.5		
GB409	IDWNP	Approved	11/9/2001	52.5		
GB783	IDWNP	Denied	3/30/2005	0		
MC718	IDWNP				Operator withdrawn	3/25/1999

Source: BOEM

The DOI classifies the royalty relief applications into seven categories listed in table 6-16.[87] There does not appear to be any sufficient guidance or notice to lessees as to what these applications cover and what type of information is required to apply for a discretionary royalty relief program, other than the high level provisions contained in the Deepwater Royalty Relief Regulations (30CFR203). While the DOI has issued

[86] BOEM Data Center, Listing of Deepwater Royalty Relief Applications, web site last updated: 12-16-2018 03:00 AM(CST) https://www.data.boem.gov/Other/DataTables/RoyaltyReliefApplications.aspx

[87] BOEM Data Center, Royalty Relief Applications, https://www.data.boem.gov/Other/DataTables/FieldDefinitions.aspx?page=royrelf

guidelines related to end-of-life royalty relief via NTL No. 98-17N, the special case royalty relief is less defined.

Table 6-16. Royalty Relief Application Classifications

Acronym	Description
ADWNP	Abbreviated application to add a lease to a field with an approved volume suspension.
IDWNP	Initial deepwater non-producing field prior to enactment of the act.
IDWSE	Initial deepwater with significant expansion of production (pursuant to an approved supplemental DOCD).
NRSEP	Net revenue share with capital projects to expand production.
NRSML	Net revenue share for marginal leases.
RDWNP	Redetermination of deepwater non-producing field prior to enactment of the act.
RDWSE	Redetermination of deepwater with significant expansion of production.
Note: DOCD = Development Operations Coordination Document	

Source: BOEM

Similar observations were made by the Royalty Policy Committee in its June 6, 2018 meeting. The Royalty Policy Committee acknowledged that there is a process for royalty relief, however "few apply for it and even few receive relief".[88] One of the recommendations of the Royalty Policy Committee was that BSEE should issue a Notice to Lessees and Operators to add specificity regarding factors such as enhanced oil recovery, HPHT, and reservoir depths for royalty relief for late life or challenging assets.[89]

In this section, we discuss the current discretionary royalty relief programs and assess alternative cases to achieve the objectives of the existing discretionary royalty relief programs.

6.4.1 End-of-Life Royalty Relief Program

The end-of-life royalty relief program is applicable to producing leases that are approaching the economic limit (i.e., have earnings that cannot sustain production under existing royalty rates and relief would likely result in additional production). If approved, BSEE grants a reduced royalty rate on the declining production.

The extension of a lease's life is important to increase the ultimate recovery of reserves. End-of-life royalty relief can be granted when royalty payments over a 12-month period exceed 75% of net revenues.[90] The royalty relief regulations issued by the DOI stipulate a reduction of 50% of the royalty payable on the relief volume.

The end-of-life royalty relief program does not appear to have been used by operators in the U.S. GOM. The requirement that royalty payments be in excess of 75% of the net revenue over a 12 month period could be placing a very high bar for qualification. By the time royalty revenue reaches 75% of the net revenue it may be too late in the field life for the operators to undertake any additional investment in relation to the said field. The application of the end-of-life royalty relief as prescribed by 30 Code of Federal Regulations (CFR) 203.50 was not successful in extending the field life for any of the hypothetical fields built for this

[88] Royalty Policy Committee, Summary of Proceedings, June 6, 2018 Meeting.
[89] Ibid.
[90] 30 CFR § 203.52

study. A similar conclusion was reached by the study “Gulf of Mexico Decommissioning Trends & Operating Cost Estimation” commissioned by BOEM. The authors of the study concluded that royalty rate reduction or elimination under the end-of-life royalty relief program “is likely to play a relatively small factor in the economics of operations and decisions of most operators”.[91]

The models used for this study indicate that the current structure of end-of-life relief has no visible or positive impact on the extension of the field life. This result is primarily due to the models’ annual outputs which are not designed to capture the benefit of only a few months of effective relief. This is likely due to field-level economics deteriorating far too rapidly for applicants to meet requirements than for BSEE to analyze and approve the request for RSVs before producing wells are shut-in. Perhaps the program might be improved by lowering the trigger ratio for the relief from 75% to 50% or lower. However, this would require a regulation change.

Tables 6-17 and 6-18 show the effect on uneconomic production[92] and the number of years that a field might be extended when applying the end-of-life relief to oil and gas fields in shallow water and deepwater and under the three price scenarios. In all cases, the relief had no visible impact on the field life. This does not mean there is no impact at all, but that the impact is limited to less than one year.

Tables 6-17 and 6-18 show the commercial production life[93] and the impact on years of production and total production applying the economic relief to the original reserves and declining profile for each of the U.S. GOM fields modeled for this study. For shallow water, three reserves sizes were considered: 10MMboe, 30MMboe and 100MMboe for both oil and gas fields. For deepwater, two reserves sizes were considered: 250MMboe and 500MMboe for both oil and gas. The results show that there is little benefit from relief when it is applied to only the existing production and its decline.

Table 6-17. Shallow Water End-of-life Royalty Relief Effect on Original Production Profile.

Primary Production	Reserve size (MMboe)	Production life (Years)	Stranded reserves (MMboe)	Asset life increase (Years)	Production increase (MMboe)
High Case					
Oil	10	8	0.3	0	0
	30	7	0.1	0	0
	100	9	1.2	0	0
Gas	10	8	0.6	0	0
	30	7	0.1	0	0
	100	12	3.8	0	0
Base Case					
Oil	10	7	0.7	0	0
	30	6	0.3	0	0
	100	8	2.2	0	0
Gas	10	8	0.6	0	0
	30	6	0.3	0	0
	100	11	5.6	0	0
Low Case					

[91] Kaiser M, Narra S, 2018, Gulf of Mexico Decommissioning Trends & Operating Cost Estimation, Herndon, VA US Department of the Interior, Bureau of Ocean Energy Management. OCS Study BOEM 2018-xxx. 546 p.

[92] Uneconomic production is all production that would have occurred after economic limit without royalty relief is reached. This production is intended to indicate all technical production that is not commercial to produce.

[93] All production that is commercial to produce up to the year the field reaches economic limit.

Primary Production	Reserve size (MMboe)	Production life (Years)	Stranded reserves (MMboe)	Asset life increase (Years)	Production increase (MMboe)
Oil	10	6	1.5	0	0
	30	5	0.7	0	0
	100	7	4.2	0	0
Gas	10	7	1.6	0	0
	30	5	0.8	0	0
	100	10	8.2	0	0

Source: IHS Markit © 2018 IHS Markit

Table 6-18. Deepwater End-of-life Royalty Relief Effect on Original Production Profile

Primary Production	Reserve size (MMboe)	Production life (Years)	Stranded reserves (MMboe)	Asset life increase (Years)	Production increase (MMboe)
High case					
Oil	250	13	2.8	0	0
	500	19	0.0	0	0
Gas	250	19	4.5	0	0
	500	19	6.8	0	0
Base case					
Oil	250	12	4.7	0	0
	500	19	2.2	0	0
Gas	250	13	21.5	0	0
	500	13	32.4	0	0
Low case					
Oil	250	10	11.9	0	0
	500	13	31.2	0	0
Gas	250	13	26.9	0	0

Source: IHS Markit © 2018 IHS Markit

6.4.2 Special Case Relief

The special case relief is a discretionary relief granted by BSEE when existing programs do not provide adequate encouragement to increase production or development. Such leases must meet at least two of the following criteria:[94]

a. A royalty relief would allow recovery of significant additional resources
b. There is a substantial risk another lessee would not recover the resources
c. Valuable facilities exist on the lease which a successor would be unlikely to use
d. The lessee made substantial efforts to reduce operating costs, but it is too late to take advantage of other royalty relief programs
e. Circumstances beyond lessee's control preclude reliance on one of the existing royalty relief programs.

[94] 30 CFR 203.80.

This study analyzes the case where the application for royalty relief meets the criteria of item a. and c. of the 30CFR 203.80 i.e. a royalty relief would allow recovery of significant additional resources, and valuable facilities exist on the lease which a successor would be unlikely to use. The study considered the use of royalty relief for marginal fields, however, none of the fields modeled for this study meet the criteria, i.e. having a development forward IRR of less than 15%. The special case royalty relief for marginal fields can find wide application in incentivizing HPHT ultra-deepwater fields in the U.S. GOM.

The study's analysis of 30CFR 203(a) and (c), adds significant additional resources of 10MMboe and 50MMboe to the shallow water and deepwater fields that reached the 15% IRR threshold. The additional resources are added towards the end of the life of the existing fields and tie back to existing facilities. Both the 10MMboe shallow water field and the 50MMboe deepwater field could not reach the 15% IRR on a standalone basis. By using the special case royalty relief program the economics of such fields can be significantly improved by tying-back to existing facilities. Also investments that access significant additional reserves better supplement declining field incomes used to support the baseline field facility operations.

While the regulations offer significant flexibility regarding the royalty rate reduction or elimination, in this analysis we assumed a 50% reduction in royalty rate for the additional reserves, while keeping unchanged the royalty rate for the original field supporting the existing facilities, i.e. the baseline production.

For shallow water analysis, the 10MMboe tie-back to the baseline field production has been added as incremental volumes for each price scenario for the fields that met the original 15% IRR threshold under the base case—the 30MMboe and 100MMboe oil fields and the 100MMboe gas field. Similarly for deepwater the 50MMboe tie-back to the baseline field production has been added as incremental volumes for each price scenario for the fields that met the original 15% IRR threshold under the base case—the 250MMBoe and 500MMboe oil fields. The 10MMboe and 50MMBoe cost levels are calibrated based on the incremental value at the time of development to be set to an NPV10 of 0 when added to the 100MMboe and 250MMboe respectively under the base case. The same incremental profile is added to each shallow and deepwater reserve size respectively for each price scenario to analyze the impact of incremental development for fields nearing end of life.

In the cases portrayed in Tables 6-19 to 6-24, the results show the production volumes and the additional years of commercial production that were added from developing an additional 10MMboe or 50MMboe of marginal reserves, for shallow water and deepwater projects, respectively. The additional production is a combination of the baseline production along with the production from the incremental reserves.

Table 6-19. Shallow water base case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	30	3	0.7	9.3	6.69%
	100	2	1.6	8.6	7.23%
Gas	100	3	4	9.2	8.14%

Source: IHS Markit

Table 6-20. Shallow water high case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)

			increase (MMboe)		
Oil	30	3	0.7	7.7	6.77%
	100	2	0.9	8.5	6.85%
Gas	100	3	2.8	9.3	7.70%

Source: IHS Markit

Table 6-21. Shallow water low case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
OIl	30	N/A	N/A	0	N/A
	100	1	1.9	7.3	7.54%
Gas	100	N/A	N/A	0	N/A

Source: IHS Markit

Table 6-22. Deepwater base case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	250	5	4.7	39.4	10.37%
	500	5	2.2	37.2	9.90%

Source: IHS Markit

Table 6-23. Deepwater high case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	250	6	2.7	40.3	9.96%
	500	6	0	40.4	9.38%

Source: IHS Markit

Table 6-24. Deepwater low case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	250	3	8.7	35.2	11.23%
	500	4	25.7	37.9	13.16%

Source: IHS Markit

The results of the economic analysis show this alternative special case relief could extend on average the asset life for the fields modeled in this study by two years for shallow water and five years for deepwater. Additional baseline production from application of the special case relief averages at 3.7MMboe per field. This special case relief has the capacity to provide considerable expansion of the life of existing assets whilst ensuring that additional reserves would not otherwise be brought on stream are developed in the

GOM. In the current environment when companies are focusing on shorter-cycle projects that can generate first cash within one to two years of development, the special case relief should serve as an incentive to add incremental reserves around existing facilities in the GOM.

7 Conclusion

The competitiveness of oil and gas investments in the U.S. GOM hinges on many factors, including the cost of exploration and development, prospectivity and the scale of the resource base, fiscal terms, and other regulatory and above-ground risk factors.

With respect to the exploration and development costs, the U.S. GOM and other offshore jurisdictions benefitted from the gradual cost cutting that has taken place since 2014. The increase in automation, efficiencies, use of artificial intelligence, and adaptive design changes by oil and gas companies, combined with cyclical cost factors that are sensitive to market conditions and fluctuate with changing oil prices, have resulted in a 38% to 41% decline in project costs for the shallow water and deepwater E&P sectors, respectively. These cost reductions are significant and have led to a recovery in project sanctioning in 2017 and 2018. As a result, most deepwater projects become cost competitive and close the gap with North American tight oil.

From a resource base perspective, the U.S. GOM is a mature province with significant undiscovered resource potential. However, there is steep competition with established oil and gas producers, such as Brazil, Mexico, Norway, and the United Kingdom, as well as frontier/emerging plays such as the Atlantic Margin play in Guyana. A significant portion of the U.S. GOM undiscovered technically recoverable resources lie in the Lower Tertiary formation with total vertical depth greater than 20,000 feet, HPHT reservoirs, lower well productivity, and substantially higher than average exploration and development costs. The comparative ease of producing resources offered by the discoveries in Brazil pre-salt polygon and Guyana deepwater basin gives these two jurisdictions a competitive edge over the U.S. and other countries included in this study. Brazil and Mexico have emerged in the past couple of years as the jurisdictions that have attracted significantly higher investment in their offshore sector via signature bonuses and work commitments.

The passage of the Tax Cuts and Jobs Act in December 2017 has transformed the U.S. Federal oil and gas fiscal system for the U.S. GOM into one of the most competitive fiscal systems in the world from an investor perspective. The U.S. ranks second or third-lowest in terms of government take within the peer groups selected for this study. In this race to compete for investments, the U.S. faces competition from jurisdictions, such as the United Kingdom, that have launched a comprehensive MER strategy that has resulted in adoption of policy solutions that address the maturity of the UKCS. However, the ability of the U.S. GOM sector to compete for investments will depend on measures other than government take. The return on investments, EMV, and resource potential will be key to investment decisions and project prioritization.

Evaluated on its individual merits and assuming the market prices reflect the base case scenario under this study, the current U.S. Deepwater GOM fiscal system offers conditions that should promote investment in oil exploration and development. However, compared with its peers, the U.S. projects for deepwater GOM rank below average based on their return on investment and EMV. The U.S. GOM rates of return are not as attractive as some of the jurisdictions in the peer group, notably, Guyana, Brazil, Angola, the United Kingdom, and Mexico, which offer rates of return above 20% under the base case scenario, compared to only 16% for the U.S. However, this study considers stand-alone projects only and the ability to tie-back to existing infrastructure provides an advantage to the U.S.

The U.S. GOM has a higher capital cost per unit than some of its peers, notably Brazil, Guyana, and Angola. The higher capex per barrel combined with a regressive fiscal system that does not account for profitability makes returns on investment very sensitive to low oil prices. The U.S. GOM fiscal systems for both shallow and deepwater areas yield sub-optimal results under a low oil price environment.

The deepwater oil fields in jurisdictions such as Angola and Norway that have much higher government takes than in the U.S. GOM yield higher rates of return to investors. That is primarily due to their progressive or neutral (in the case of Norway) fiscal systems that rely on measures of profitability for government revenue. The revenue accruing to the governments of Angola, Norway, and the United Kingdom is mostly back-end loaded (i.e., the government is sharing the revenue risk with investors).

Natural gas fields face significant challenges to drive offshore exploration and development on the shelf and deepwater areas of the GOM, even despite its relatively low government take. Potential natural gas projects are met with marginal or negative internal rates of return in the base case scenario, reflecting the value of current gas commodity prices. These projects also face stiff competition from the abundance of onshore natural gas supply from shale and associated gas. None of the fiscal system alternatives presented was sufficient to make most natural gas projects economic in this study, and thus it is unlikely any fiscal system changes can be made to reverse the declining natural gas trend at this time.

Between the two fiscal system alternatives considered for U.S. GOM shallow water, the sliding scale royalty alternative would result in more revenue accruing to the Federal government. Given the maturity of the shallow water areas and the expected field sizes—which are lower than some of the fields modeled for this study—the application of the sliding scale royalty alternative is likely to deter investment in the U.S. GOM shallow water area. While this alternative allows the government to capture the upside, it does not offer any relief for the downside. That is largely due to the floor set by the minimum statutory royalty of 12.5%. The floor for sliding scale royalties in most jurisdictions that adopt them—in this case, Newfoundland and Labrador and Mexico—is set much lower than the U.S. Federal fiscal system.

The categorical royalty relief considered for the U.S. GOM Shelf will make the U.S. fiscal system the most competitive in the world alongside the United Kingdom from a government take perspective. However, it will not significantly improve the ranking with regard to investor rate of return and EMV. Nevertheless, an aggressive royalty relief program can encourage the development of marginal fields and influence investment decisions for undeveloped discoveries. An alternative sliding scale royalty that lowers the royalty rate below the statutory minimum when commodity prices are low could be perceived as more balanced and neutral to investment decisions.

Out of the five fiscal system alternatives considered for the U.S. GOM deepwater areas the 20% and 22.5% royalty alternatives have the potential to generate more revenue for the Federal government, but increase the government take while projects are still sensitive to prices in the low and base price cases for both oil and gas. Given the gradual decline in exploratory and development drilling since 2003 in the GOM deepwater area an increase in royalty rate could further exacerbate the trend.

The 12.5% royalty alternative lowers the government take and increases the IRR in all cases, but not to the degree of categorical royalty relief in the low and base cases for oil and gas. Such measure is most impactful in the high price cases where these changes are the least helpful to project economics.

The sliding scale royalty offers a more balanced approach by lowering the royalty rate, and hence revenue accruing to the government, when commodity prices are less than \$80/bbl and \$50/bbl, and increasing the government share when commodity prices cross the \$80/bbl and \$105/bbl thresholds. The range of the government take among the various cases significantly narrows compared to the status quo, thus softening the degree of regressivity of the fiscal system. Similar to the sliding scale royalty for shallow water, the deepwater sliding scale preserves the statutory minimum rate. As such it is not able to render economic the deepwater projects under the low case.

Among the deepwater alternatives that improve the rate of return to investors, the categorical royalty relief is the most impactful one, but without regard to government take. The threshold price of \$85/bbl for categorical royalty relief gives the government its usual share when commodity prices are high, while marginal projects benefit from the relief in the base case and low-price environment. The deepwater gas fields remain uneconomic in the low case under this royalty alternative, proving once again that the challenges associated with natural gas projects are market challenges, rather than inherent in the fiscal system—not even a 50% and 96% royalty relief offered gas fields in this study could render such fields economic.

The categorical royalty relief, is based on water depth and provides similar relief to deepwater projects within the same water depth, regardless of the reservoir or play characteristics. Under this alternative Lower tertiary projects would be entitled to similar RSVs as Miocene projects. A more effective royalty relief policy could be designed to target the play or plays that need it most. Given the technological and commercial challenges faced by the Lower Tertiary discoveries a categorical royalty relief that targets investments in such a play may prove more beneficial to investors and government alike.

Overall, the U.S. GOM oil projects are competitive within the peer group with the shelf being the most competitive among the two for the fields considered in this study. Such projects offer competitive rates of return under base and high case scenarios. However, the U.S. GOM shelf is limited in terms of resource availability. With the expected field sizes matching the small reserve size under this study, the best hope for such projects on the shelf is reliance on existing facilities and infrastructure. The market conditions do not favor development of the small reserves in the U.S. GOM shelf on a stand-alone basis. With the wave of decommissioning continuing strong in the shelf—more than 100 structures being decommissioned each year—the establishment of efficient policy solutions that encourage such developments could be necessary.

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Appendix A - Fiscal System Information

A.1 Angola—Deepwater

The terms used for this study relate to the latest applicable production sharing terms as of September 2018.

A.1.1 Fiscal and Contractual Terms

BONUSES

A negotiable signature bonus is payable. They can range from USD10 million to 400 million. The bonuses are non-recoverable.

There is no requirement for the payment of discovery or production bonuses.

OTHER PAYMENTS

Rental: *None payable.*[95]

Training fee: The contractor is required to contribute towards the training of Angolan government staff.[96] The training fee is a recoverable cost. The following annual amounts are payable:

- USD300,000 during the exploration and development periods, and
- USD0.15/bbl (USD0.025/Mcf) during the production period. [97]

Social contribution fee: Upon signing the contract, the contractor is required to make a negotiable contribution for social projects. It is a non-recoverable cost. Reported amounts paid in the past are shown in Table A-1.1.[98]

Table A-1.1. Social contribution fees: Angola – deepwater

Block	Social contribution (USD millions)
15	1-50
17	3-200
18	2-200
26	3.25

Source: IHS Markit

STATE PARTICIPATION

[95] The 2004 Petroleum Tax Law provides that development areas under production sharing contracts (and concession areas) are subject to an annual rental fee (referred to as a "surface fee") of USD300 per square kilometre from the date of commercial discovery if the petroleum agreement provides for the same. However, the model contract makes no provisions with regard to rentals.
[96] Law No. 10 on Petroleum Activities of 12 November 2004, Art 57.
[97] Decree No. 17/09 of 26 June 2009.
[98] IHS Markit, Angola Detailed Analysis Report, PEPS, 2017.

The national oil company of Angola, Sonangol, has the option to participate and be carried through to commercial discovery with repayment of the exploration costs from Sonangol's cost recovery petroleum.[99] For this study, 20% carried interest participation has been assumed.

COST RECOVERY

Costs are recovered from 50% of gross revenue (assumed to rise to 65% after five years from the start of production)[100] in the following order: operating costs, development costs, exploration costs.[101] Operating costs and exploration and appraisal costs are expensed and recovered immediately; development costs, including a 20% uplift, [102] are capitalized and recovered over four years on a straight-line basis, starting from the commencement of commercial production.[103] Losses may be carried forward indefinitely, but not beyond the duration of the contract.[104]

PROFIT SHARING

Production remaining after cost recovery is assumed to be shared between Sonangol and the investor on a scale that is linked to the after-tax nominal rate of return (IRR), as shown in Table A-1.2.[105]

Table A-1.2. Assumed contractor profit share: Angola – deepwater

IRR	Contractor's profit share (%)
≤ 10	70
10 – 12.5	55
12.5 – 17.5	45
17.5 – 20	30
≥20	20

Source: IHS Markit

99 The 2007-2008 Bidding Terms of Reference provided for 65% of Sonangol's participating interest with 15% carried through exploration, with repayment of past costs for shallow and deep offshore blocks 9, 20, and 21.
100 2008 Offshore Model Contract Art 11.1, 11.4.
101 Although 2004 Petroleum Tax Law Art 23.2(b) provides that exploration costs are to be recovered last, there is no clear indication of the sequence for the recovery of development and operating costs. However, presentation "Legal and Contractual System for Angolan Petroleum Concessions and Bid Procedures" published on the Sonangol website specifies the following order of cost recovery: operating costs, development costs, exploration costs.
102 2008 Offshore Model Contract Art 11.3. The 2007-2008 Bidding Terms of Reference provide for a 10% uplift of development costs for onshore and shelf/deepwater blocks and a 20% uplift of development costs for ultra-deepwater blocks. Under the terms of the 2005/2006 licensing round, the uplift percentage was 20 to 30%.
103 2004 Petroleum Tax Law Art 23.2(c).
104 2008 Offshore Model Contract Art 11.4; 2004 Petroleum Tax Law Art 23.2(i).
105 For shelf/deep water blocks, the 2007-2008 BTR specify contractor's profit share rates in the range of 70 to 10% with IRR thresholds ranging 15 to 40%.

INCOME TAX

The petroleum income tax is levied on the contractor's profit share at a rate of 50%.[106] Companies are exempt from the general corporate income tax, currently applicable at the rate of 35%.

A.1.2 Acreage Award Criteria

SIGNATURE BONUSES

Signature bonuses are a biddable or negotiable item, in the case of acreage awarded under ad-hoc negotiation. They can range from USD10 million to 400 million.

WORK AND EXPENDITURE COMMITMENT

Minimum expenditure and work obligations are biddable/negotiable. Minimum expenditures are specified in U.S. dollars and work obligations are specified in terms of line-kilometers of 2D seismic or square kilometers of 3D seismic, and numbers of wells for each exploration phase. Table A-1.3 contains data from various contracts signed during 2011-12 period.

Table A-1.3. Work commitments from recent deepwater contracts: Angola – deepwater

Operator Contract block (Award date)	Area (km^2)	Work commitment
ConocoPhillips Block 37 (Dec 2012)	5,378	Yrs 1 – 4: 3000 sq km 3D seismic + 2 wells Yrs 5 – 7: 1000 sq km 3D seismic + 1 well
Eni Angola BV Block 35 (Dec 2012)	4,931	Yrs 1 – 4: 2500 sq km 3D seismic + 2 wells Yrs 5 – 7: 1000 sq km 3D seismic + 1 well
Repsol SA Block 22 (Dec 2012)	5,180	Yrs 1 – 4: 2500 sq km 3D seismic + 2 wells Yrs 5 – 7: 1000 sq km 3D seismic + 1 well
BP Block 20 (Dec 2011)	4,856	Yrs 1-5: 1500 sq km 3D seismic + 4 wells
ENI Block 35 (Dec 2011)	4,931	Yrs 1-5: 2500 sq km 3D seismic + 2 wells

Source: IHS Markit

A minimum expenditure obligation is applicable in case the contractor fails to fulfill the work obligations during the exploration period. Such expenditure obligations can be in the order of tens of millions of dollars for seismic and hundreds of millions of dollars for wells. In the case of BP Block 20 PSA, the contractor was required to pay Sonangol USD30 million minus USD20 thousand for each square kilometer of the seismic program concluded before relinquishment of the area. The expenditure commitment for failure to

106 2004 Petroleum Tax Law Art 19, 41(b).

drill exploratory wells under the same contract was USD120 million for each pre-salt exploration well not drilled, and USD70 million for any other well not drilled.[107]

OTHER FACTORS

Profit oil share: In recent licensing activity, profit oil share has been included as a bid variable. In the past, the profit sharing thresholds were fixed by Sonangol per each block.

Social regional development: The social contribution has been a bid variable since the 2006 licensing round. The weighting associated to this bid factor has ranged between 10% and 20%. Table A-1.4 provides the social contribution amounts committed under the BP contract for Block 20 awarded in 2011.[108]

Table A-1.4. Example of social contribution payments: Angola – deepwater

Type of contribution	Timing of payment	Contribution amount (USD)
Contribution for social projects	Contract effective date	200 million
Contribution for the Sonangol Research and Technology Center	Contract effective date	25 million
	First anniversary of effective date	75 million
	Second anniversary of effective date	75 million
	Third anniversary of effective date	75 million
	Fourth anniversary of effective date	100 million

Source: IHS Markit © 2018 IHS Markit

A.1.3 Exploration and Production Terms

BLOCK SIZES

Concession areas are defined by the Minister of Petroleum by executive decree. Production sharing contracts have typically been awarded for areas of between 3,500 square kilometers and 7,500 square kilometers.

CONTRACT DURATION

Exploration period: Seven to eight years. Initial period of four years and an optional period of two to three years.

Production period: 25 years.

RELINQUISHMENT OBLIGATIONS

There are no interim relinquishment requirements during the exploration period. At the end of the exploration period, all areas, other than development areas or areas in which appraisal work is in progress, must be relinquished.

[107] The BP contract for Block 20 was last accessed on SEC web site on October 2, 2018. https://www.sec.gov/Archives/edgar/data/1471261/000104746912001183/a2207234zex-10_20.htm
[108] Ibid.

DOMESTIC MARKET OBLIGATIONS

The government has the right, upon 90 days' notice, to require the national oil company, Sonangol, and the contractor to supply the domestic market at market prices pro rata to their share of total Angolan production, subject to a ceiling of 40% of the total production from the contract area.[109]

ABANDONMENT REQUIREMENTS

The 2004 Petroleum Tax Law provides that production expenditures may include costs of abandonment, with applicable limits to be established in the contract. Provisions for recovery of abandonment costs under the 2008 offshore model contract, which classifies them as operating (production) costs to be recovered, are as follows:

- A minimum of 90 days before the beginning of the calendar year for which the operator forecasts that the cumulative production of each of the development areas will lead to a situation in which the recoverable reserves of each of the development areas at the end of the year in question represent less than
    - 50% of the declared recoverable reserves under 50 MMbbl,
    - 30% of declared recoverable reserves above 50 MMbbl but not more than 100 MMbbl, or
    - 25% of declared recoverable reserves above 100 MMbbl.

  the operator should provide the national oil company, Sonangol, with a technical study for the alternative possibilities of abandonment and its best calculations on the costs of abandonment with respect to each development area for approval purposes.
- This calculation should be up-to-date and inflated by reference to estimated data for the effective removal of the production infrastructure in each of the development areas.
- After the approval of Sonangol and at the beginning of the calendar year referred to above, the operator must calculate, on a three-month basis, the recoverable costs of relinquishment using the unit-of-production method, in accordance with the following formula:

Quarterly production (MMbbl)				
Declared recoverable reserves (MMbbl) minus the cumulative production up to the beginning of the quarter (MMbbl)	x	Total approved abandonment costs minus the amounts paid pursuant to the final bullet point below	=	Abandonment costs quarterly recoverable

- The amount calculated under the terms of the previous bullet, will be imputed to the production expenditures of the relevant development area and paid to Sonangol within 30 days of the end of each quarter.

[109] *2004 Petroleum Law Art 78; 2008 Offshore Model Contract Art 26.5*

A.2 Australia—Offshore

The terms used for this study relate to the latest applicable terms as of September 2018.

A.2.1 Fiscal and Contractual Terms

BONUSES

Cash bonuses are payable for permits granted under cash bidding (but not under work program bidding). Bonus payments are deductible for income tax purposes if exploration is successful. In the case of unsuccessful exploration, bonus payments may be treated as a capital loss for capital gains tax purposes. Bonuses are not deductible for resource rent tax purposes. A small percentage of blocks on offer are awarded under cash bonus bids. This practice that had been suspended since 1992 was reinstated in 2014. One contract awarded under this system generated a bonus of AU3 million.

OTHER PAYMENTS

Rental: Rentals in Australia are generally applied for per license or application. Table A-2.1 contains information on amount of rental payments for each type of license or permit.

Table A-2.1. Rental payments: Australia – Offshore

Type of rental	AUD (USD)/year[110]
Exploration permit	10,000 (7,189) per block
Retention lease	20,000 (14,379) per block
Production license	20,000 (14,379) per block
Infrastructure license	25,000 (17,974) per title
Pipeline license	100 (72) per kilometer
Greenhouse gas lease	20,000 (14,379) per block
Greenhouse gas injection license	20,000 (14,379) per block
Late payment penalty – 0.3333 percent per day	

Source: IHS Markit

ROYALTY

None payable under offshore areas under Federal jurisdiction.

INCOME TAX

Income tax is imposed at rates set by the 1986 Income Tax Rates Act including amendments up to Act No. 41, 2017. Since 2001/2002, the income tax rate has been 30%.

PETROLEUM RESOURCE RENT TAX

Under the 2012 Petroleum Resource Rent Tax (PRRT) Act sec 5, companies can recover their costs plus uplift at varying rates before PRRT becomes payable at a rate of 40%.

[110] Exchange rate of 0.719015 applicable on October 2, 2018 was applied for conversion of AUD to USD.

Exploration expenditures are uplifted at the long-term bond rate (LTBR) plus 15%, while general project expenditure is uplifted at LTBR plus 5%. For all classes of deductible expenditure (excluding closing-down expenditure), the total expenditure for a year includes the expenditure incurred in the year plus the uplifted, un-deducted expenditure from any previous years.

Closing-down expenditure in excess of assessable receipts is creditable. The credit is limited to the lesser or the excess multiplied by the PRRT rate of 40% and the actual PRRT paid.

For 2018, the LTBR for PRRT was 2.70%.

DIVERTED PROFITS TAX

A Diverted Profits Tax (that came into force in April 2017) applies to profits of multi-national corporations that transfer profits generated in Australia and send them to offshore jurisdictions. The levy will apply at a fixed rate of 40% to Australian companies that are part of a multi-national group with gross global income of over AUD1 billion.

CARBON TAX

As of July 2014, there is no carbon tax payable. On July 17, 2014, Royal Assent was given to a suite of legislation to repeal the carbon tax. The primary act passed was the 2014 Clean Energy Legislation (Carbon Tax Repeal) Act. The laws took effect in July 1, 2014.

The carbon tax was introduced by the 2011 Clean Energy Act and the carbon pricing mechanism came into force on July 1, 2012. The starting carbon price was fixed at AUD25 per ton of greenhouse gases generated and was scheduled to rise by up to 4% per year in real terms. It increased to AUD26 in 2013/14 and was supposed to increase to AUD30 in 2014/15.

A.2.2 Acreage Award Criteria

Applicants are invited to bid on a competitive basis under either work program bidding or cash bidding arrangements.

CASH BIDDING

The cash bidding system has been used in areas considered to be highly prospective. Cash bidding was introduced in 1985 by an amendment to the Petroleum (Submerged Lands) Act 1967 by the Petroleum (Submerged Lands) (Cash Bidding) Amendment Act of November 22, 1985 and now referred to in the 2006 Petroleum Act. Under this system, an applicant nominates a sum that they he would be prepared to pay for the award of the exploration permit. An exploration permit is awarded to the highest cash bidder. Although a work program is not a requirement of the bid, applicants must still demonstrate their financial and technical competence to undertake petroleum exploration work, as part of their application.

Cash bidding had not been used since the early 1990s. However, the Cash Bidding Act 2013 that amended the Offshore Petroleum and Greenhouse Gas Storage Act of 2006 reintroduced cash bidding to allocate offshore petroleum acreage in mature areas and in areas containing known petroleum accumulation. It has been applicable since January 2014.

For the 2017 acreage release, one out of a total of 21 blocks was proposed for cash bidding. Cash bids can only be submitted by invitation, and applicants must be pre-qualified by the Joint Authority. For the 2014 acreage release, four out of a total of 30 blocks were proposed for cash bidding.

WORK AND EXPENDITURE COMMITMENT

The work program bidding system is the more traditionally used method of awarding offshore exploration permits in Australia. The applicant must propose a six-year exploration program which is split between:

- The primary term – exploration work (not appraisal), all of which must be completed over the three-year period to ensure the permit is not cancelled, and
- The secondary term – work programs must be divided into yearly periods and the minimum work program must be completed within the specified year to retain the permit and continue to the next year.

Work program commitments have greater focus on acquiring and processing 2D and 3D seismic, particularly in the three-year primary term, and more emphasis on drilling in the three-year secondary term.

In determining the most suitable application, the Joint Authority will use the following criteria:

- The relevance of the proposed work program to the technical evaluation and exploration strategy,
- The amount, type, and timing of seismic acquisition and processing to be carried out,
- The amount, type, and timing of seismic data to be purchased or licensed and seismic data reprocessing to be carried out,
- The type, scope, and objectives of the geophysical and geological studies,
- The number and timing of exploration wells proposed,
- The past performance of the applicant, and
- Significant appraisal work over previous petroleum discoveries.

If an application cannot be chosen based on the primary work program using the criteria above, the secondary work program will be assessed and ranked. If it is still not possible to select the best bid, the Joint Authority may seek proposals for additional work and expenditures from each applicant. Table A-2.2 contains information on the work and expenditure commitments on some of the winning bids in recent years.

Table A.2.2. Exploration work and expenditure commitments: Australia—offshore

Operator Block (Award date)	Area (km²)	Work commitments	Expenditure commitment (USD)
Exxon Mobil WA-527-P (Mar 2017)	6,558	Yr 1: Seismic and studies Yr 2: 3D Seismic and studies Yr 3: 3D Seismic Yr 4: Studies Yr 5: 1 well Yr 6: Studies	316,800 316,800 2,423,000 237,500 23,760,000 395,800
Carnarvon WA-521-P (Mar 2016)	5,050.77	Yr 1: Seismic and studies Yr 2: Seismic and studies Yr 3: Seismic and studies Yr 4: 3D Seismic Yr 5: Survey Yr 6: Studies	440,000 440,000 440,000 120,000 3,300,000 150,000

Operator Block (Award date)	Area (km^2)	Work commitments	Expenditure commitment (USD)
Apache WA-51–P (Jan 2015)	461.9	Yr 1: seismic and studies Yr 2: seismic and studies Yr 3: seismic and studies Yr 4: studies Yr 5: 1 well Yr 6: studies	404,820 6,881,840 607,230 323,856 16,192,800 161,928
Murphy AC/P57 (Apr 2014)	335.5	Yr 1: seismic and studies Yr 2: seismic and studies Yr 3: seismic Yr 4: studies Yr 5: 1 well Yr 6: studies	121,446 485,784 323,856 161,928 48,578,400 80,964

Source: IHS Markit

A.2.3 Exploration and Production Terms

BLOCK SIZES

Each permit area contains one or more blocks. These are defined as graticular blocks of five minutes of latitude by five minutes of longitude. The average block size is approximately 67 square kilometers in southern parts of the country and approximately 83 square kilometers in northern parts of the country.

An exploration permit granted under work program bidding may not exceed 400 blocks. The minimum number of blocks that may be granted under work program bidding must not be less than 16 (if the number of blocks on offer is less than 16, then the number of blocks specified will be the same as the number of blocks on offer).

Typically, permit areas cover some 6,400 to 10,000 square kilometers. No limit is specified for permits granted under cash bidding; however, in most cases only a few blocks are offered at a time.

CONTRACT DURATION

Exploration period: Exploration permits are granted for an initial period of six years divided into two phases of three years each. The first phase is the "primary term", while the second phase is the "secondary term".

A work program exploration permit may be renewed for a further two terms of five years, while a cash bid permit may be renewed for one term of five years.

Production period: Life-of-field production licenses.

RELINQUISHMENT OBLIGATIONS

At the end of the secondary phase (i.e. the end of year six), 50% of the permit area must be relinquished. A further 50% of the remaining permit area must be relinquished at the end of each renewal until the area reaches a minimum of 16 blocks.

On expiry of the exploration permit (including renewals), the permit holder may only retain areas that have been nominated as discovery blocks or converted to either a production license or retention lease.

For permits of less than 16 blocks:

- A permit comprising one block cannot be renewed;
- A permit comprising five or six blocks can be renewed in respect of only four blocks; and
- A permit comprising two, three, or four blocks can be renewed in respect of all blocks.

DOMESTIC MARKET OBLIGATIONS

There is no fixed permanent legislative domestic supply obligation for petroleum in Australia. Detailed below is a recently introduced domestic supply mechanism for LNG in Australia.

On July 1, 2017, the Australian Domestic Gas Security Mechanism (ADGSM) entered into force, in the form of an amendment to the 1958 Customs (Prohibited Exports) Regulations. The amendment, formally referred to as The Customs (Prohibited Exports) Amendment (Liquefied Natural Gas) Regulations 2017, was inserted into the 1958 Customs Regulations as "Division 6". The division creates a framework that will enable the Minister for Resources to determine that there may be a shortage of LNG to the domestic market, and subsequently impose export controls to resupply the domestic market, with the aim of easing upward pressure on wholesale gas prices for domestic consumers. The mechanism has national jurisdiction, but can be imposed on individual projects in the region that the Minister determines there is a supply shortage, and can be ended at any time. The ADGSM is a short-term measure that is part of a wider package in which the government aims to reconfigure LNG gas supply in Australia. The ADGSM aspect will be repealed on January 1, 2023.

ABANDONMENT REQUIREMENTS

The rightholder must remove from the title area all structures and equipment that are not used in connection with petroleum operations. A former rightholder (i.e. a titleholder which has had revoked, cancelled, or terminated a title or where the title has expired) may also be asked to remove all property and abandon wells to the satisfaction of the National Offshore Petroleum Titles Administrator.

Under the APPEA Code of Environmental Practice 2008, no equipment should be left on an abandoned site without the express approval of the relevant regulatory authorities. In practice, what constitutes removal is defined on a case-by-case basis in consultation between relevant governmental agencies. The Federal government acknowledges, but has not adopted as law, the resolutions of the International Maritime Organisation on removal of structures.

Expenditure associated with abandonment is deductible as incurred.

A.3 Brazil—Concessionary System

The terms used for this study relate to the latest applicable concessionary terms as of September 2018. These terms apply to standard areas, i.e. all offshore areas excluding pre-salt.

A.3.1 Fiscal and Contractual Terms

BONUSES

A signature bonus must be included as a condition for the award of a concession agreement. The minimum value is established in the bidding procedures. Prior to 2017, bonuses for standard areas under concessionary system averaged between 1.5 and 20 million BRL per block (USD1-5 million). The 14th and 15th licensing round that concluded in 2017 garnered significantly higher per block amounts, BRL104 million and 364 million per block, respectively (USD25-90 million).

OTHER PAYMENTS

Rental:

Annual rentals are specified in the bidding procedures. Rates may vary depending on geological characteristics, the location of the sedimentary basin and other relevant factors. Different amounts of rental payments are determined by the basin and sector location of the block. Rental amounts in the past ranged between USD11.39 to USD427.28 USD.

Rentals are doubled in the case of an extension to the exploration phase and the development period. For the production period, the rental payments are nine times those of the first exploration phase. Further, the amounts are readjusted from the date of execution of the contract by the accumulated Brazilian general price index, IGP-DI, for the prior 12 months.[111]

Research and development fee: If the special participation fee is payable with respect to a field in any given calendar quarter, the concessionaire will be required to spend on research and development activities an amount equal to 1% of production gross revenues for the field subject to the special participation fee for such quarter. Up to 50% of such research and development payments may be spent in universities and research and development institutes and in the ‘priority areas” both previously authorized and approved by the ANP. At least 10% must be spent in the hiring of activities of research, development, and innovation in companies supplying the oil industry. The rest of the resources may be spent in research and innovation activities in line with the concessionaire projects.

ROYALTY

The royalty rate is 10%. However, at the time of an invitation to bid, this rate may be reduced by the ANP to no lower than 5% for a particular block to reflect geological, economic factors, and other relevant factors such as production in remote areas, non-associated gas, and heavy oil.

INCOME TAX

[111] IGP-DI (Índice Geral de Preços-Disponibilidade Interna) is a General Prices Index established in 1944 with the goal of measuring the general prices behavior in the Brazilian Economy. The IGP-DI is calculated using an arithmetic formula and certain indices.

Corporate income tax is governed by Decreto 3.000 of March 26, 1999, and levied at the rate of 34%. It consists of a basic rate of 15%, increased by a surtax of 10% on annual taxable profits exceeding BRL240,000 or BRL20,000 per month, plus a 9% social contribution tax or CSLL under its Portuguese acronym.

SPECIAL PARTICIPATION FEE

The concessionaire is subject to payment of a "special participation fee" (SPF). SPF is calculated quarterly and applied at progressive rates on net revenue before income tax from each field under the concession agreement. Net revenue for SPF is gross revenue from the field less signature bonuses, royalty, operating costs, exploration and appraisal costs, a quarterly allowance, and depreciation of development costs over 10 years straight line. The SPF rates are shown together with the quarterly allowances in the Table A-3.1.

Table A-3.1. Brazil special participation fee: Brazil—concessionary system

Quarterly production volume (thousand meters)	Average daily production during the quarter (mbd)[112]	Deduction from quarterly net field revenue (BRL)[113]	SPF rate (%)
FIRST YEAR OF PRODUCTION			
< 1,350	*0–93*	-	Exempt
1,350–1,800	*93–124*	1,350 * RLP / VPF	10
1,800–2,250	*124–155*	1,575 * RLP / VPF	20
2,250–2,700	*155–186*	1,800 * RLP / VPF	30
2,700–3,150	*186–217*	675 / 0.35 * RLP / VPF	35
> 3,150	*> 217*	2,081.25 * RLP / VPF	40
SECOND YEAR OF PRODUCTION			
< 1,050	*0–72*	-	Exempt
1,050–1,500	*72–103*	1,050 * RLP / VPF	10
1,500–1,950	*103–134*	1,275 * RLP / VPF	20
1,950–2,400	*134–165*	1,500 * RLP / VPF	30
2,400–2,850	*165–196*	570 / 0.35 * RLP / VPF	35
> 2,850	*> 196*	1,781.25 * RLP / VPF	40
THIRD YEAR OF PRODUCTION			
< 750	*0–52*	-	Exempt
750–1,200	*52–83*	750 * RLP/VPF	10
1,200–1,650	*83–114*	975 * RLP/VPF	20
1,650–2,100	*114–145*	1,200 * RLP/VPF	30
2,100–2,550	*145–176*	465 / 0.35 * RLP/VPF	35
> 2,550	*> 176*	1,481.25 * RLP/VPF	40
FOURTH AND SUBSEQUENT YEARS OF PRODUCTION			
< 450	*0–31*	-	Exempt
450–900	*31–62*	450 * RLP/VPF	10

112 Approximate conversion of quarterly volumes to mbd using 1 quarter = 91.5 days and 1 cubic meter = 6.29 barrels.

113 RLP = the quarterly net field revenue, in Reais; and VPF = the volume of the inspected quarterly production for each field, measured in thousands of cubic meters of oil equivalent. Although described as a "fee," SPF is actually a profits-based "tax."

Quarterly production volume (thousand meters)	Average daily production during the quarter (mbd)[112]	Deduction from quarterly net field revenue (BRL)[113]	SPF rate (%)
900–1,350	*62–93*	675 * RLP/VPF	20
1,350–1,800	*93–124*	900 * RLP/VPF	30
1,800–2,250	*124–155*	360 / 0.35 * RLP/VPF	35
> 2,250	*> 155*	1,181.25 * RLP/VPF	40

Source: IHS Markit

<u>OTHER TAXES</u>

The concessionaire is subject to payment of all Federal, state, and municipal taxes; charges; and levies. Local taxes include the following:

- **Municipal service tax (ISS)** is levied on gross billings for services and varies between municipalities. The rate ranges between 2% and 5%, with 5% being the most common.
- **Excise tax (IPI)** is paid on imported goods and those manufactured in Brazil. The tax is paid on an *ad valorem* basis ranging between 0% and 365%. For items utilized in E&P operations, the tax ranges between 0% and 8%.
- **Municipal sales tax (ICMS)** is levied on all purchases of goods at a rate between 7% and 25%. ICMS is also levied on intermunicipal transport services, communications, and electricity.
- **Social contribution for welfare programs (COFINS)** is levied at 7.6% of gross revenue. The tax is also levied on imports of goods and services at a rate of 7.6%.
- **Social integration program contribution (PIS)** is levied on gross revenues at a rate of 1.65% and used to fund unemployment and insurance programs. The tax is also levied on imports of goods and services at a rate of 1.65%.

A temporary admission system (REPETRO) waives IPI, PIS, and COFINS for certain types of equipment used for oil and gas E&P activities. REPETRO's term of validity is set to expire on December 31, 2040. A new REPETRO Law was introduced on December 29, 2017, extending the validity of the temporary importation regime from 2020 to 2040 and applying the regime to the definitive importation of goods.

A.3.2 Acreage Award Criteria

Since 2017, the award of acreage is based on cash bonus and minimum exploratory program (PEM). Bid evaluation is based 80% on signature bonus and 20% on PEM. Local content used to be a bid factor. However, since the 14th bidding round in 2017, local content is no longer a biddable factor. Local content is fixed by ANO in each licensing round.

<u>SIGNATURE BONUS</u>

Signature bonuses in the order of BRL104 million and 364 million (USD25-90 million) per block have been paid since 2017.

<u>MINIMUM EXPLORATORY PROGRAM</u>

Work commitments for the first, second, third, and fourth bidding rounds were fixed and predefined by the ANP and differed depending on the acreage. All subsequent bidding rounds work commitments have been a biddable item. Companies offered work units, the value of which was determined by the ANP based on the location of the block.

A.3.3 Exploration and Production Terms

BLOCK SIZES

The exploration area is defined in the concession agreement in relation to the block(s) awarded. From the fifth through to the thirteenth round, the basins were divided into sectors and each sector was divided into blocks of a predefined size. Blocks awarded range on average between 700 – 850 square kilometers.

CONTRACT DURATION

Exploration period: Five to seven years.

Production period: In concession agreements, the production period commences with the declaration of a commercial discovery and lasts for 27 years.

RELINQUISHMENT OBLIGATIONS

A 100% relinquishment, excluding areas retained for evaluation or development, is required at the end of the final exploration period.

DOMESTIC MARKET OBLIGATIONS

Under concession agreements, the concessionaire may be required to supply the domestic market only under an "emergency situation" upon 30 days' written notice given by the ANP. The way the requirement is determined and how the obligation is discharged, are not defined.

ABANDONMENT REQUIREMENTS

On expiry or revocation of a concession, the concessionaire must remove equipment and facilities which are not transferred to the state and carry out any restoration of the environment ordered by regulatory agencies.

The model concession agreement requires the concessionaire to provide an abandonment guarantee, secured by a letter of credit, sinking fund, or other guarantees acceptable to the ANP. The value of the abandonment guarantee is subject to revision if amendments made to the development plan and approved by the ANP result in alteration of the abandonment costs or of the total volume of oil and gas production originally envisaged. If the guarantee is constituted by a sinking fund, any remaining balance after the completion of the abandonment operations will revert exclusively to the concessionaire. The provision of an abandonment guarantee does not relieve the concessionaire of the obligation to complete, at its cost and risk, all the operations necessary to decommission and abandon the field.

Although not specifically addressed in the Petroleum Law or model concession agreement, it is assumed that decommissioning and abandonment costs are deductible for income tax purposes.

A.4 Brazil—Production Sharing System

The terms used for this study relate to the latest applicable production sharing terms as of September 2018. These terms apply to pre-salt offshore areas.

A.4.1 Fiscal and Contractual Terms

BONUSES

A signature bonus must be included as a condition for the award of a production sharing agreement. The minimum value must be established in the bidding procedures. In all PSAs carried out at the time of writing, signature bonuses have been fixed. This area is dominated by very high signature bonuses ranging from BRL100 million to a maximum of BRL15 billion per block. The average per block for areas awarded in 2017 has varied between BRL990 million and 1.1 billion.

OTHER PAYMENTS

Rental: None specified in the current agreements.

Research and development fee: Contractors are required to allocate resources for research and development "in areas of interest and topics relevant to the sector of petroleum, natural gas, and biofuels" equivalent to at least 1% of the gross oil and gas annual production.

STATE PARTICIPATION

On November 30, 2016, a law amending the Pre-Salt Law (Lei 12,351 of 2010) was published in the Official Gazette. This law abolishes Petrobras' mandatory participation and operatorship in all pre-salt projects. Instead, the law establishes something "akin to a preferential right" in favor of Petrobras in which the National Council for Energy Policy (CNPE) will first offer Petrobras the option to participate and be the operator with at least 30% of the shares in any pre-salt block that is put up for offer. Petrobras' participation, however, is on a working interest basis.

Before the 2016 Pre-Salt Law amendment, Petrobras had a mandatory minimum of 30% equity participation in all production sharing agreements entered into in connection with the pre-salt and those areas deemed as strategic by the CNPE. Petrobras also had the right to participate in a bidding round in case it wanted to increase its 30% mandatory equity participation. The 2013 Libra Field PSA was the only contract signed under these conditions in which Petrobras has 40% participation.

ROYALTY

The royalty rate is 15%.

COST RECOVERY CEILING

The cost recovery rate is 50% of gross production for the first two years of production and 30% thereafter.

PROFIT SHARING

Contractors and the Federal government share the profit oil on a monthly basis. The sharing of profit oil will vary depending on the Brent benchmark average price and the average daily production per producing well per field. Table A-4.1 shows the minimum state profit share (SPS) established for the 2nd and 3rd pre-salt licensing rounds held in 2017.

Table A-4.1. Brazil state profit share: Brazil—production sharing system

Pre-salt licensing round	Area	Minimum state profit share (SPS)
2nd pre-salt bidding round	Carcará North	22.08%
	Tartaruga Verde	12.98%
	Gato do Mato	11.53%
	Sapinhoá	10.34%
3rd pre-salt bidding round	Alto de Cabo Frio Central	21.38%
	Alto de Cabo Frio West	22.87%
	Peroba	13.89%
	Pau Brasil	14.40%
4th pre-salt bidding round	Três Marias	8.33%
	Uirapuru	22.18%
	Dois Irmãos	16.43%
	Itaimbezin ho	7.07%

Source: IHS Markit

INCOME TAX

Corporate income tax is governed by Decreto 3.000 of March 26, 1999, and levied at the rate of 34%. It consists of a basic rate of 15%, increased by a surtax of 10% on annual taxable profits exceeding BRL240,000 or BRL20,000 per month, plus a 9% social contribution tax or CSLL under its Portuguese acronym.

SPECIAL PARTICIPATION FEE

The Pre-Salt Law explicitly establishes that the "special participation fee" is not applicable to production sharing agreements.

OTHER TAXES

The concessionaire is subject to payment of all Federal, state, and municipal taxes; charges; and levies. Local taxes include the following:

- **Municipal service tax (ISS)** is levied on gross billings for services and varies between municipalities. The rate ranges between 2% and 5%, with 5% being the most common.
- **Excise tax (IPI)** is paid on imported goods and those goods manufactured in Brazil. The tax is paid on an *ad valorem* basis and ranges between 0% and 365%. For items utilized in E&P operations, the tax ranges between 0% and 8%.
- **Municipal sales tax (ICMS)** is levied on all purchases of goods at a rate between 7% and 25%. ICMS is also levied on intermunicipal transport services, communications, and electricity.
- **Social contribution for welfare programs (COFINS)** is levied at 7.6% of gross revenue. The tax is also levied on imports of goods and services at a rate of 7.6%.
- **Social integration program contribution (PIS)** is levied on gross revenues at a rate of 1.65% and is used to fund unemployment and insurance programs. The tax is also levied on imports of goods and services at a rate of 1.65%.

A temporary admission system (REPETRO) waives IPI, PIS, and COFINS for certain types of equipment used for oil and gas E&P activities. REPETRO's term of validity is set to expire on December 31, 2040. A new REPETRO Law was introduced on December 29, 2017, extending the validity of the temporary importation regime from 2020 to 2040 and applying the regime to the definitive importation of goods.

A.4.2 Acreage Award Criteria

STATE PROFIT SHARE

A production sharing agreement must be awarded to the company offering the best terms as established in the bidding procedures, the main bid parameter being the highest share of "profit oil" offered to the state. Table A-4.2 shows the minimum bid criteria and the winning bids for pre-salt rounds 2-4.

Table A-4.2. Brazil state profit share in rounds 2-4: Brazil—production sharing system

Pre-salt licensing pound	Area	Minimum state profit share (SPS)	Winning bid
2nd pre-salt bidding round	Carcará North	22.08%	67.12%
	Tartaruga Verde	12.98%	No bid
	Gato do Mato	11.53%	11.53%
	Sapinhoá	10.34%	80.00%
3rd pre-salt bidding round	Alto de Cabo Frio Central	21.38%	75.80%
	Alto de Cabo Frio West	22.87%	22.87%
	Peroba	13.89%	76.96%
	Pau Brasil	14.40%	No bids
4th pre-salt bidding round	Três Marias	8.33%	49.95%
	Uirapuru	22.18%	75.49%
	Dois Irmãos	16.43%	16.43%
	Itaimbezin ho	7.07%	No bids

Source: IHS Markit

A.4.3 Exploration and Production Terms

BLOCK SIZES

Blocks for the pre-salt areas are of similar size as the offshore blocks for standard areas. They range between 700 square kilometers and 880 square kilometers.

CONTRACT DURATION

Exploration period: Under the production sharing agreement regime, the exploration duration is negotiable. According to the 2013 Production Sharing Agreement Model, the exploration phase consists of a single four-year period. The exploration phase may be extended at the contractor’s discretion prior to the ANP opinion.

Production period: In production sharing agreements, the duration of the production period is negotiable. However, the maximum duration for this type of contract is 35 years, divided into an exploration phase and a production phase.

RELINQUISHMENT OBLIGATIONS

The contractor must relinquish the areas of the fields which are not included in the “Final Discovery Evaluation Plan” approved by the ANP.

DOMESTIC MARKET OBLIGATIONS

No provision to address domestic supply obligation for pre-salt areas has been identified.

ABANDONMENT REQUIREMENTS

On expiry or revocation of a production sharing agreement, the contractor must remove equipment and facilities which are not transferred to the state and carry out any restoration of the environment ordered by regulatory agencies.

An environmental audit of all decommissioning operations must be carried out under the production sharing agreement regime. Costs relating to decommissioning and abandonment activities are recoverable and recognized as “cost oil” in each month.

A.5 Canada—Newfoundland & Labrador Offshore

The terms used for this study relate to the latest applicable terms as of September 2018.

A.5.1 Fiscal and Contractual Terms

BONUSES

None payable.

OTHER PAYMENTS

Rental: Rental is payable during the second period of the exploration license and any extension thereof.

Area rentals are specified in each call for bids and are payable during the second period of the exploration license. Rental rates in recent years have been CAD5, 10 and 15 per hectare in years 1, 2, and 3, respectively.

If an exploration license continues in force beyond the second exploration period, rental is payable at the rates applicable during the final year of the second exploration period.

Rentals under a significant discovery license issued during the first or second period of an exploration license are payable at the rates applicable to the exploration license of origin until the expiration of such exploration license. After that, the rentals are payable until the significant discovery license is relinquished or converted to a production license.

Environmental studies research fund: Under the Canada Petroleum Resources Act section 81, right holders must pay an environmental studies research fund (ESRF) levy, applicable for the two previous calendar years, within 15 days of notification of being a successful bidder. Recent calls for bids also include the obligation on interest owners and holders of exploration licenses to pay ESRF fees. The ESRF fees are established annually and vary by region. These fees are shown in Table A-5.1 below.

Table A-5.1. ESRF fees per hectare: Newfoundland and Labrador offshore

Region	2016-17 levy #28 rate (CAD/ha)	2017-18 levy #29 rate (CAD/ha)	2018-19 levy #30 rate (CAD/ha)
Labrador North	0	0	0.1194
Labrador Central	0.2537	0	0
Labrador South	0.2537	0	0.1803
Northeast Newfoundland	0.6240	0.7037	0.2991
Newfoundland Slope	0.6181	0.4645	0.2596
Grand Banks North	0.6781	0.4467	0.1067
Grand Banks South	0.6154	0	0.1776

Source: IHS Markit

ROYALTY

The Generic Offshore Royalty Regime Regulations were promulgated on November 1, 2017. Royalties levied under this regime are based on project cost recovery and profitability with progressive royalty rates linked to the ratio of cumulative revenue over cumulative project costs, referred to as the R-factor. The new generic regime is summarized as follows:

- The new regime comprises a basic and net royalty with both linked to cost recovery and profitability as measured by one R-factor calculation.
- Basic royalty rates range from 1% to 7.5% with step increases linked to the R-factor.
- Net royalty is set to one tier with sliding scale flexible rates ranging from 10% to 50%. Rates are linked to the same R-factor as defined for basic royalty.
- Basic royalty is credited against net royalty.
- The new regime does not include return allowances, uplifts, and consumer price index adjustments on project costs.

Tables A-5.2 and A-5.3 provide a high-level description of the basic and net royalty components of the generic royalty regime for offshore areas.

Table A-5.2. Basic royalty: Newfoundland offshore

R-factor (R)	Basic royalty rate (BRR)
First oil to $R < 0.25$	1%
$0.25 \leq R < 1$	2.5%
$1 \leq R < 1.25$	5%
$R \geq 1.25$	7.5%
where R = (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: IHS Markit © 2018 IHS Markit

Table A-5.3. Net royalty: Newfoundland offshore

R-factor (R)	Net royalty rate (NRR)
$R < 1$ (R_{min})	0%
$1 \leq R \leq 3$	10% (NRR_{min}) - 50% (NRR_{max})
$R > 3$ (R_{max})	50%
R has the same definition and calculation as for the basic royalty in the above table $NRR = NRR_{min} + \{[(R - R_{min}) \div (R_{max} - R_{min})] \times (NRR_{max} - NRR_{min})\}$ Net royalty = (gross sales revenue + incidental revenue – transportation costs – project capital & operating costs) x NRR	

Source: IHS Markit © 2018 IHS Markit

STATE PARTICIPATION

Current energy policy requires 10% equity participation through Nalcor.

INCOME TAX

The general corporate tax rate effective January 1, 2013 is 38%. With the Federal abatement of 10% (applicable where a company is subject to provincial income tax), this is reduced to 25%. In addition, a manufacturing and processing (M & P) deduction (applicable where a corporation derives at least 10% of gross revenues from manufacturing and processing goods in Canada for sale or lease) or a rate reduction (available on certain qualifying income), both 13%, bring the rate to 15%.

The provincial income tax rate in Newfoundland and Labrador for business income and investment income is 15% from January 1, 2016 onwards. The rate prior to January 1, 2016 was 14%.

If the provincial income tax rate in a taxation year exceeds the national average rate, corporations operating in the offshore area are entitled to a refund of the amount by which the Newfoundland and Labrador provincial income tax rate exceeds the national average rate for the said year.

A.5.2 Acreage Award Criteria

WORK AND EXPENDITURE COMMITMENT

The sole selection criteria is the total amount of money which the bidder commits to spend on exploration of the parcel (and on research and development and education and training), if they choose to include this, within the first period of the exploration phase. This amount is known as the "work expenditure bid" and calls for bids to specify the minimum work expenditure required for the relevant parcels. Bid documents from 2013 through 2017 specify minimum work expenditure bids of CAD10 million. The successful bidder is committed to spending a minimum of 95% of the work expenditure bid on exploration in the initial exploration period.

A.5.3 Exploration and Production Terms

BLOCK SIZES

The Newfoundland and Labrador offshore territory is divided into three main areas: Area A located in the Northeast Grand Banks, Area B located in the Western Newfoundland Offshore Region, and Area C covering the remaining offshore area. The size of a license area may vary depending on the location. The call for nominations of acreage specifies the maximum and minimum parcel size for nominating blocks. The minimum parcel size is 25 sections (approximately 80 square kilometers). The maximum parcel size is 400 sections (approximately 1,280 square kilometers) in Area A and 800 sections (approximately 2,560 square kilometers) in Areas B and C. One license is issued for each parcel.

CONTRACT DURATION

Exploration period: The Atlantic Accord Implementation Act provides for a maximum term of nine years consisting of an initial six-year period and a subsequent three-year period. The nine-year term cannot be renewed. However, if the drilling of a well has commenced prior to the license expiry date and is diligently being pursued, the license may continue in force after its expiry for as long as may be necessary to determine the existence of a significant discovery.

The initial six-year period may be extended by up to three one-year extensions based upon provisions of the following escalating drilling deposits (each one a separate “drilling deposit”). The 2017 call for bids included the following amounts as a pre-requisite for each extension:

- Period I A: 1-year extension – CAD5 million
- Period I B: 1-year extension – CAD10 million
- Period I C: 1-year extension – CAD15 million

Production period: A production license is issued for a 25-year term. The license may be extended if petroleum continues to be produced in commercial quantities, for as long as commercial production continues.

RELINQUISHMENT OBLIGATIONS

There is no requirement for mandatory relinquishment of any part of the exploration license during its term.

DOMESTIC MARKET OBLIGATIONS

Where there is a shortfall of petroleum deliveries in the province, the provincial minister may, after consulting with the Federal minister, give notice to the holders of production licenses to give the first option to acquire, on commercial terms, the petroleum produced in the offshore area at the facilities specified in the notice, unless a sales contract has been entered into prior to the serving of notice. The notice will be in effect for as long as the shortfall of petroleum deliveries in the province exists.

The domestic supply obligation is subject to the determination of self-sufficiency and security of supply reached by agreement of the Federal and provincial governments and the determination of a shortfall of petroleum deliveries in the province made by the provincial government.

ABANDONMENT REQUIREMENTS

An application for authorization to carry out activities/undertake works must include a description of the decommissioning and abandonment of the site, including methods for the restoration of the site after its abandonment.

The operator must also ensure that every well that is abandoned (or suspended) can be readily located and left in a condition that (a) provides for isolation of all hydrocarbon bearing zones and discrete pressure zones; and (b) prevents any formation fluid from flowing through or escaping from the well bore. There is also an obligation upon the operator to ensure that any suspended well is monitored and inspected to maintain its integrity and that, where a well is abandoned, the seafloor is cleared of any material or equipment that might interfere with other commercial uses of the sea.

In addition, in accordance with Section 42 of the *1997* Offshore Petroleum Installation Newfoundland and Labrador Regulations, where the removal of a fixed production installation is a condition for the approval of a development plan, the operator must incorporate in the design of the installation those measures that are necessary to facilitate its removal from the site without causing significant effects to navigation or the marine environment.

Abandonment costs may be written off in the year incurred and are classified as operating expenditure. This is relevant in the case of the abandonment of individual wells during the life of the field, or final abandonment of the field when the rightholder has revenues from other fields.

A.6 Guyana—Deepwater

The terms used for this study relate to the latest applicable production sharing terms as of September 2018.

A.6.1 Fiscal and Contractual Terms

BONUSES

Negotiable bonuses are payable. USD18 million is indicative.[114]

OTHER PAYMENTS

Rental: Rental is payable at a fixed annual fee per year throughout the duration of the exploration period. USD1 million per year is indicative.[115]

Training fee: The contractor is required to contribute towards the training of Guyana government staff. The training fee is set at USD300,000 per year throughout the duration of the prospecting license.

Financial support for environmental and social projects: The contractor is required to contribute USD300,000 annually towards environmental and social projects to be agreed upon with the Minister.

STATE PARTICIPATION

There is no state participation provision in the current agreements.

ROYALTY

Royalty is payable at the rate of 2% of all petroleum produced and sold minus the amounts of petroleum used for fuel and the cost of transport.

COST RECOVERY

Costs are recovered from 75% of gross revenue.

PROFIT SHARING

Production remaining after cost recovery is shared between the government and the investor on a 50:50 basis.

INCOME TAX

Income tax is payable on the investor's behalf by the Government of Guyana out of the government's share of profit under the respective petroleum agreement. The amount equivalent to the contractor's tax obligation that is payable by the government is considered the income of the contractor.

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[114] The bonus amount represents the signature bonus under the Petroleum Agreement between the Government of Guyana and ExxonMobil, dated June 27, 2016, which was made publicly available by the government of Guyana.
[115] Ibid.

A.6.2 Acreage Award Criteria

The contracts currently in effect in Guyana have been awarded under ad-hoc negotiation. The outdated 1986 Petroleum Act does not provide any acreage award criteria. For this analysis, we have focused on the Exxon Mobil contract terms that have been made public by the Government of Guyana to determine terms that could be negotiable and therefore serve as award criteria.

SIGNATURE BONUSES

In the case of acreage awarded under ad-hoc negotiation, signature bonuses are a negotiable item.

WORK AND EXPENDITURE COMMITMENT

Minimum work obligations are negotiable. The current contracts do not provide for specific expenditure obligations in the event of failure to perform the minimum work commitment. Indicative work commitments during exploration period are defined in Table A-6.1.

Table A-6.1. Work commitments from a recent deepwater contract: Guyana—deepwater

Contract period	Duration	Minimum work commitment
Initial period	4 years	3D seismic + 1 well
First renewal period	3 years	1 well
Second renewable period	3 years	1 well

Source: IHS Markit © 2018 IHS Markit

OTHER FACTORS

Profit oil share: In PSAs, the share of profit between investor and the government is usually negotiable. In recent contracts, it has been set at 50%.

Cost recovery ceiling: In PSAs, the share of revenue available for cost recovery is usually negotiable. In recent contracts, it has been set at 75%.

A.6.3 Exploration and Production Terms

BLOCK SIZES

Contracts awarded in recent years range between 1,800 and 17,000 square kilometers, averaging at around 7,000 square kilometers per block.

CONTRACT DURATION

Exploration period: Seven to ten years.

Production period: A petroleum production license is granted for a period of 20 years. It may be renewed once for up to ten years.

RELINQUISHMENT OBLIGATIONS

The 1986 Petroleum (Exploration and Production) Act provides for relinquishment to take place on each renewal on terms specified in the petroleum agreement. In practice, relinquishment requirements occur after the expiration of the first renewal period equal to at least 20% of the contract area.

DOMESTIC MARKET OBLIGATIONS

The contractor may be required to supply a share of its crude oil production to the domestic market if there is a domestic shortfall. Domestic requirements must first be satisfied by the state's share of profit oil. The Minister must give three months' notice of any domestic supply requirement. The amount will be prorated among all contractors in Guyana and may not exceed the contractor's share of profit oil.

ABANDONMENT REQUIREMENTS

The PSC awarded to ExxonMobil in 2016 Art 20.1(d)(iii)(gg) stipulates that all approved costs in the abandonment program will be eligible for cost recovery. Abandonment costs will be treated as operating costs and recovered on a unit-of-production basis from the period when the abandonment program and budget is approved. The abandonment program and budget is submitted as part of the development plan, which means that the contractor can annually deduct an amount calculated by dividing the approved abandonment budgets by the estimated ultimate recoverable reserves and multiplying the results by the units produced in the period. Both the abandonment budget and the estimated ultimate recoverable reserves may be revised from time to time.

A.7 Mexico—Shallow Water

The terms used for this study relate to the latest applicable production sharing terms as of September 2018.

A.7.1 Fiscal and Contractual Terms

BONUSES

None payable.

OTHER PAYMENTS

Rental: The contractor must pay an exploration phase rental of MXN1,294.71 per square kilometer per month for the first 60 months (five years) for the areas which are part of the contractual area not in production. If the exploration phase is extended beyond 61 months, the payment will be MXN3,096.04 per square kilometer per month. These values are to be adjusted in January of every year, taking into account the Consumer Price National Index. This rental is payable from the contract signature until the declaration of commerciality.

Hydrocarbons Exploration and Production Activity Tax: Contractors are liable for the payment of a monthly per square kilometer Hydrocarbons Exploration and Production Activity Tax during both the exploration and the production phase over the contractual area. Table A.7.1 provides the applicable rates for the exploration and production periods.

Table A.7.1. Hydrocarbons Exploration and Production Activity Tax: Mexico—shallow water

Phase	Amount in Mexican pesos (MXN)/km^2
Exploration	MXN 1,500
Production	MXN 6,000
MXN 1 = USD**0.0525 in October 2018**	

Source: IHS Markit © 2018 IHS Markit

STATE PARTICIPATION

There is no state participation.

ROYALTY

All contractors are liable to pay royalties. Different royalty rates apply on different hydrocarbon types and are based on sliding scales.

Crude oil: A 7.5% royalty applies when the crude oil or condensate 'contract price' is below USD47.95 per barrel.

When the crude oil 'contract price' is equal to or above USD47.95 per barrel, the following sliding scale formula applies:

Royalty Rate = [(0.125 x crude oil contractual price) + 1.5] %

Table A-7.2. Crude oil royalty rates: Mexico—shallow water

'Contractual price' (USD/barrel)	Royalty rate (%)
<48	7.50
≥48	7.51
50	7.75
60	9.00
70	10.25
80	11.50
100	14.00
110	15.25
120	16.50

Source: IHS Markit

Condensates: A 5% royalty applies when the condensate 'contract price' is below USD59.94 per barrel. When the crude oil 'contract price' is equal to or above USD59.94 per barrel, the following sliding scale formula applies:

Royalty= [(0.125 x condensate contractual price) - 2.5] %

Table A.7.3. Condensate royalty rates: Mexico—shallow water

'Contractual price' (USD/barrel)	Royalty rate (%)
<60	5.00
≥60	5.01
70	6.25
80	7.50
90	10.00
100	11.25
110	11.25
120	12.50

Source: IHS Markit

Associated natural gas: The associated natural gas royalty rate is calculated according to the following formula:

$$\text{Royalty rate} = \frac{\text{contractual price for natural gas}}{90.90}$$

Non-associated natural gas: A 0% royalty applies when the natural gas 'contract price' is equal to or below USD5 per MMBTU.

When the natural gas 'contract price' is above USD5 per MMBTU, but below USD5.49 per MMBTU, the following sliding scale formula applies:

$$\text{Royalty rate} = \left[\frac{(\text{contractual price for natural gas} - 5) \times 60.5\%}{\text{contractual price for natural gas}}\right]\%$$

When the natural gas 'contract price' is equal to or above USD5.49 per MMBTU, the following sliding scale formula applies:

$$\text{Royalty rate} = \frac{\text{contractual price for natural gas}}{90.90}$$

In all cases, royalties must be calculated using the 'contractual price' of hydrocarbons actually produced.

COST RECOVERY

The cost recovery (CR) limit is the result obtained by multiplying the cost recovery percentage by the hydrocarbons contractual value. The percentage is set at 60% unless the discovery is a non-associated gas discovery, in which case the percentage is set at 80%.

Under the **PSA – Exploration** eligible costs contemplated in the minimum and additional work programs are recognized with an uplift of 25% of the original amount listed on both the minimum work program and in the additional work program.

PROFIT SHARING

Production remaining after the CR is shared between the government and the investor on a sliding scale based on the scale shown in Table A-7.3.

Table A-7.3. Profit sharing formula: Mexico—shallow water

Internal rate of return (IRR)	Contractor's production sharing
<25	X
25-40	X - (X-Y) * (MRO-25/40-25)
>40	Y (=0.25*Y)
The first hurdle rate (X) of profit share scale is biddable.	

Source: IHS Markit © 2018 IHS Markit

The profit share rates offered in the recent licensing round (round 3.1) for shallow water acreage held in 2018 ranged between 24.23% and 65%.

INCOME TAX

The general income tax rate for corporations in Mexico is 30%.

A.7.2 Acreage Award Criteria

The acreage award criteria vary with each licensing round. Under the latest round's terms of reference (round 3.1), the following criteria were considered:

- State's participation on the operating profit, and
- Additional investment factor.

$$\text{VPO} = \text{state profit share} + \left(5.72 \times \frac{\text{state profit share}}{100} + 2.26\right) \times \text{investment factor}$$

Where:

VPO is the weighted value of the economic offer, and

Investment factor is a variable related to additional work commitments offered by the bidder that are above the minimum stipulated in the tender documents.

The results of the latest bidding round showed the companies offering the following variables:

- State's participation on the operating profit,
- Additional state participation share,
- Additional investment factor,
- Second additional investment factor,
- Tie-break bonus, and
- Second tie-break bonus.

TIE-BREAK BONUSES

Tie-break bonuses may be offered when the economic offers are tied. These are not very common. Out of 16 blocks that received offers in round 3.1 that was held in 2018 in Mexico, only three blocks had tie-break bonuses, two of which had a second tie-break bonus. Such bonuses have ranged between USD13 and 60 million.

WORK AND EXPENDITURE COMMITMENT

Minimum work obligations expressed in work units are established in the terms of reference for the licensing rounds. The companies can decide whether they want to offer investment factors for additional work. A factor of one means one additional well, a factor of 1.5 means two wells. In the latest round, the estimated values of work units per block ranged from USD1 to 90 million.

STATE PROFIT SHARE

Production remaining after the CR is shared between the government and the investor on a sliding scale, with the contractor share gradually declining when the IRR is equal to or greater than 25%.

The state determines the minimum and maximum profit shares for the government in the tender documents. In the latest round, the minimum rates ranged between 8.5% and 22.5%, with the maximum rate being set at 65%. The profit share rates offered in the recent licensing round (round 3.1) for shallow water acreage held in 2018 ranged between 24.23% and 65%.

A.7.3 Exploration and Production Terms

BLOCK SIZES

Contracts awarded in recent years range between 300 to 1,000 square kilometers, averaging at around 700 square kilometers per block.

CONTRACT DURATION

Exploration period: Four to six years.

Production period: 20 years from the contract signature with two possible extensions of 5 years each.

RELINQUISHMENT OBLIGATIONS

The contractor is required to relinquish 50 percent of the contract area upon expiration of the initial 4-year period and the remainder of the contract area that is not included in the development plan at the end of the exploration period.

DOMESTIC MARKET OBLIGATIONS

There are no domestic supply obligations in both the exploration and extraction PSAs.

ABANDONMENT REQUIREMENTS

The contractor is responsible for carrying out all operations related to the abandonment of the contract area. The development plan, and each work program and budget submitted for the CNH approval, must contain a specific abandonment section, covering activities necessary for the plugging of wells, cleaning, return to its natural condition, decommissioning of facilities, removal of machinery and equipment, and delivery in an orderly fashion and free of debris and waste in the contract area. The contractor is responsible for all abandonment costs, with the understanding that said costs are considered not recoverable costs.

The contractor must establish an 'abandonment trust' ('trust') when declaring commerciality. The trust will be jointly controlled by CNH and the contractor at a bank designated by a financial Mexican institution authorized by CNH. The contractor must deposit one-fourth of the 'annual contribution' at the end of each quarter in the trust. The 'annual contribution' is determined on a unit-of-production basis.

A.8 Mexico—Deepwater

The terms used for this study relate to the latest applicable license terms as of September 2018.

A.8.1 Fiscal and Contractual Terms

BONUSES

None payable.

OTHER PAYMENTS

Rental: The contractor must pay an exploration phase rental of MXN 1,294.71 per square kilometer per month for the first 60 months (five years) for the areas which are part of the contractual area not in production. If the exploration phase is extended beyond 61 months, the payment will be MXN 3,096.04 per square kilometer per month. These values are to be adjusted in January of every year taking into account the Consumer Price National Index. This rental is payable from the contract signature until the declaration of commerciality.

Hydrocarbons exploration and production activity tax: Contractors are liable for the payment of a monthly hydrocarbons exploration and production activity tax during both the exploration and the production phase, per square kilometer, over the contractual area. Table A-8.1 provides the applicable rates for exploration and production periods.

Table A-8.1. Hydrocarbons exploration and production activity tax: Mexico—deepwater

Phase	Amount in Mexican pesos (MXN) / km^2
Exploration	MXN 1,500
Production	MXN 6,000
MXN 1 = USD**0.0525 in October 2018**	

Source: IHS Markit

STATE PARTICIPATION

There is no state participation.

ROYALTY

All contractors are liable to pay royalties. Different royalty rates apply on different hydrocarbons types and are based on sliding scales. An additional royalty is often established as a bid variable.

Crude oil: A 7.5% royalty when the crude oil or condensate ‘contract price’ is below USD47.95 per barrel.

When the crude oil ‘contract price’ is equal to or above USD47.95 per barrel, the following sliding scale formula applies:

$$\text{Royalty Rate} = [(0.125 \times \text{crude oil contractual price}) + 1.5]\ \%$$

Table A-8.2. Crude oil royalty rates: Mexico deepwater

'Contractual price' (USD/barrel)	Royalty rate (%)
<48	7.50
≥48	7.51
50	7.75
60	9.00
70	10.25
80	11.50
100	14.00
110	15.25
120	16.50

Source: IHS Markit

Condensates

A 5% royalty applies when the condensate 'contract price' is below USD59.94 per barrel. When the crude oil 'contract price' is equal to or above USD59.94 per barrel, the following sliding scale formula applies:

Royalty = [(0.125 x condensate contractual price) - 2.5] %

Table A-8.3. Condensate royalty rates: Mexico deepwater

'Contractual price' (USD/barrel)	Royalty rate (%)
<60	5.00
≥60	5.01
70	6.25
80	7.50
90	10.00
100	11.25
110	11.25
120	12.50

Source: IHS Markit

Associated Natural Gas

The associated natural gas royalty rate is calculated according to the following formula:

$$\text{Royalty rate} = \frac{\text{contractual price for natural gas}}{90.90}$$

Non-associated Natural Gas

A 0% royalty applies when the natural gas 'contract price' is equal to or below USD5 per MMBTU.

When the natural gas 'contract price' is above USD5 per MMBTU but below USD5.49 per MMBTU the following sliding scale formula applies:

$$\text{Royalty rate} = \left[\frac{(\text{contractual price for natural gas} - 5) \times 60.5\%}{\text{contractual price for natural gas}}\right]\%$$

When the natural gas ‘contract price’ is equal to or above USD5.49 per MMBTU the following sliding scale formula applies:

$$\text{Royalty rate} = \frac{\text{contractual price for natural gas}}{90.90}$$

In all cases, royalties must be calculated using the ‘contractual price’ of hydrocarbons actually produced.

INCOME TAX

The general income tax rate for corporations in Mexico is 30%.

A.8.2 Acreage Award Criteria

According to the bidding terms, there are two bidding parameters. Namely:

- Additional royalty factor (AR)
- Additional investment factor (AIF)

The following formula is used to calculate the weighted score of the economic bid:

VPO = 4 * [AR + (11.5 * (AR/100) + 3.45) * AIF]

Where:

- ‘VPO’ is the weighted score of the economic bid,
- ‘AR’ is a percentage of the contractual value of hydrocarbons offered to the state,
- ‘AIF’ is a discrete variable that may take three values, as follows:
    - AIF = 1.5 if the bidder commits to an additional investment for working units equivalent to the drilling of two exploratory wells,
    - AIF = 1 if the bidder commits to an additional investment for working units equivalent to the drilling of one exploratory well, or
    - AIF = 0 if the bidder does not commit to an additional investment.

TIE-BREAK BONUSES

If there is a tie between offers, the main criteria to determine the winning bidder will be an additional payment in cash. The bidder offering the highest payment will be the winning bidder.

WORK AND EXPENDITURE COMMITMENT

The minimum work program, the minimum program increase, and, in such case, the additional commitments acquired during the first additional exploration period or second additional exploration period shall be expressed in work units.

A.8.3 Exploration and Production Terms

BLOCK SIZES

Blocks offered for deepwater areas in recent years range between 300 to 3,200 square kilometers, averaging at around 2000 square kilometers per block.

CONTRACT DURATION

Exploration period: Four to six years.

Production period: 22 years from contract signature with two possible extensions of 10 and 5 years, respectively.

RELINQUISHMENT OBLIGATIONS

The contractor is required to relinquish 50% of the contract area upon expiration of the initial 4-year period, and the remainder of the contract area that is not included in the development plan at the end of the exploration period.

DOMESTIC MARKET OBLIGATIONS

There are no domestic supply obligations.

ABANDONMENT REQUIREMENTS

The contractor is responsible for carrying out all operations related to the abandonment of the contract area. The development plan, and each work program and budget submitted for the CNH approval, must contain a specific abandonment section, covering activities necessary for the plugging of wells, cleaning, return to its natural condition, decommissioning of facilities, removal of machinery and equipment, and delivery in orderly fashion and free of debris and waste in the contract area.

The contractor must establish an 'abandonment trust' ('trust') when declaring commerciality. The trust will be jointly controlled by CNH and the contractor at a bank designated by a financial Mexican institution authorized by CNH. The contractor must deposit one-fourth of the 'annual contribution' in the trust at the end of each quarter. The 'annual contribution' is determined on a unit-of-production basis.

A.9 Norway—Offshore

The terms used for this study relate to the latest applicable terms as of September 2018.

A.9.1 Fiscal and Contractual Terms

BONUSES

The 1996 Petroleum Act contains a provision that establishes the possibility of a signature bonus being imposed as a condition for the grant of a license. However, in practice no bonuses are payable.

OTHER PAYMENTS

Rental: During the initial period of a production license, there is no requirement for an annual rental payment. If the license is extended beyond the initial period, the following annual rental payments are payable in advance:[116]

Table A-9.1. Annual rental payments: Norway—offshore

Year following initial license period	'Area fee' per km²
1st year	NOK34,000
2nd year	NOK68,000
3rd year, onwards	NOK137,000
Note: NOK 1 = USD0.121549 in July 2018	

Source: IHS Markit

The Ministry of Petroleum and Energy (MPE) may decide to exempt (wholly or partially) or postpone area fees. The MPE may adjust the area fee at least at five-year intervals to bring it into line with changes in the value of NOK.

STATE PARTICIPATION

State direct financial interest (SDFI) has ranged between 20% 33.6% in recent years. It does not apply to all production licenses. Table A-9.2 provides information on state participation in recent years.

Table A-9.2. State participation in production licenses: Norway—offshore

Licensing round	Number of licenses with participation/total	(Number of licenses @) SDFI working interest
APA round 2014	*11/54*	(11) 20%

[116] Regulation No. 1213 of 9 October 2013.

Licensing round	Number of licenses with participation/total	(Number of licenses @) SDFI working interest
APA round 2015	*13/56*	(12) 20% (1) 24.5%
23rd licensing round 2014/2015	*0/10*	none
APA round 2016	*13/56*	(10) 20% (1) 24.5% (1) 30% (1) 33.6%
APA round 2017	*17/75*	(13) 20% (11) 30%
24th licensing round 2018	*4/12*	(1) 25% (3) 20%

Source: IHS Markit

ROYALTY

None payable.

INCOME TAX

The standard rate of corporate income tax – applicable to petroleum E&P operations – is 23%, effective January 1, 2018.[117] Since 2013, Norway has been gradually reducing the corporate income tax. Table A-9.2 provides the rate reductions since 2013.

Table A-9.3. Corporate income tax rate: Norway—offshore

Tax year	Corporate income tax rate (%)
2013	28
2014	27
2015	27
2016	25
2017	24
2018	23

Source: IHS Markit

The income tax rate is determined annually by Parliament with the rate for any year usually announced in a resolution from the Minister of Finance in November of the preceding year.

SPECIAL PETROLEUM TAX

A special petroleum tax is paid in respect of income from all upstream interests held by the taxpayer, after deductions allowed by the 1975 Petroleum Taxation Act including the investment uplift. The uplift includes

[117] Tax Resolution No. 2183 of December 12, 2017, § 4-1

development costs and capitalized interest, but not exploration costs. That is, the base for additional profits tax is the same as for income tax plus the uplift.

From January 1, 2018, the Special Petroleum Tax (SPT) rate is 55%.[118] The SPT has been increasing gradually each year to offset the rate reductions of the corporate income tax and to preserve the level of taxation for the oil industry at the same rate. Table A-9.3 provides the rate increases since 2013.

Table A-9.4. Special petroleum tax rate: Norway—offshore

Tax year	Special petroleum tax (SPT) rate (%)
2013	50
2014	51
2015	51
2016	53
2017	54
2018	55

Source: IHS Markit © 2018 IHS Markit

The uplift is currently applied at 5.3% over four years (i.e. 21.2%, with the effect that development costs are depreciated at a rate of 121.2% for SPT). The uplift was originally equal to 5% of the capital investment (i.e. development costs and capitalized interest, but not exploration costs) for six years starting from the year the investment was made (i.e. 130% of development costs and capitalized interest are depreciated over six years straight-line). From January 1, 2005, the uplift was accelerated to 7.5% per annum over a four-year period from the year the investment was made.

On May 7, 2013, the Norwegian government announced a revised budget for 2013, resulting in the adoption of several amendments to the legal framework for E&P fiscal terms. This includes, from May 5, 2013, the reduction of the SPT uplift for new investments, from 7.5% per annum of the original cost price of depreciable operating assets, to 5.5% (i.e. over the four years from the date of expenditure, a reduction from 30% to 22%). This has since been adjusted downwards, to account for tax rate adjustments.

These measures were intended to be revenue neutral, with adjustments made to SPT uplift, as an increase in the tax rate would otherwise increase the value of an investment allowance. However, while the adjustments would appear to have left the marginal rate of taxation unchanged at 78%, the accompanying budget papers account for a small reduction in government revenues due to a difference in the taxable bases for corporate income tax as compared to SPT.

CARBON TAX

CO_2 emissions on the Norwegian continental shelf are taxed at NOK1.06 per liter. The tax is assessed on volumes of petroleum burned as fuel, natural gas burned or vented, and CO_2 separates from petroleum and vented on platforms and other installations used for production or transportation of petroleum. However, if CO_2 is injected, it is not taxable.

The rates of CO_2 tax have steadily increased since its introduction. The rates are defined on the basis of the equivalent amounts of fuel consumed (i.e. expressed in NOK per liter of petroleum liquid/scm of gas). Table A-9.4 provides the rates of the CO_2 tax.

[118] Tax Resolution No. 2183 of 12 December 2017, § 4-2

Table A-9.5. CO_2 tax: Norway—offshore

Effective date	NOK per liter or Sm3
January 1, 2018	1.06 *(7.30 for natural gas emitted to air)*
January 1, 2017	1.04
January 1, 2016	1.02
January 1, 2015	1.00
January 1, 2014	0.98
January 1, 2013	0.96
January 1, 2012	0.49
January 1, 2011	0.48

Source: IHS Markit

A.9.2 Acreage Award Criteria

Licenses are not awarded based on commercial bid factors, but rather on evaluation of technical and financial capability. More specifically, the evaluation of offers includes:

- Technical expertise,
- Financial capacity,
- Geological understanding,
- Methods proposed to conduct exploration efficiently and previous conduct (where applicable, e.g. past inefficiency),
- Relevant expertise, such as on the Norwegian Continental Shelf (NCS) or equivalent thereof, with some minimum drilling experience in NCS required for operators,
- Competence and composition of a group and operator, and
- Experience in drilling wells in certain environments – for example, including an operator and an additional party with such experience, in deepwater or high-pressure and/or high-temperature (HPHT) areas.

The MPE reserves the right to negotiate terms with the applicant regarding:

- Extent, content, and timing of the work obligation;
- Duration of the initial period and the license period thereafter; and
- Area.

WORK AND EXPENDITURE COMMITMENT

The award of a production license may impose a specific work obligation on the licensee. Such a work program is to be completed within the initial exploration period (or a shorter period if stipulated). This may include seismic work and the drilling of an agreed number of wells to specified depths and geological formations. Work programs are regarded as confidential and the details are not released. These obligatory work commitments are listed in the production license. Applicants are not required to propose exploration expenditure and it is assumed that obligations of a financial nature are not imposed.

If a license is extended at the end of 10 years, the MPE may impose conditions for the extension period, including additional work obligations. In recent awards, work programs typically included reprocessing seismic, acquiring 2D and/or 3D seismic, and the drilling of a well.

A.9.3 Exploration and Production Terms

BLOCK SIZES

The area awarded in a production license may cover one block (15 latitudinal minutes by 20 longitudinal minutes, i.e. around 500 square kilometers) or several blocks or part blocks. Areas offered from 2016 to 2018 have averaged around 500 square kilometers per license.

CONTRACT DURATION

Exploration period: Production licenses are awarded for an initial period of ten years.

Production period: 30 to 50 years.

RELINQUISHMENT OBLIGATIONS

The licensee must relinquish all area that is not part of a development area at the end of the initial 10-year period.

DOMESTIC MARKET OBLIGATIONS

The government may demand that the licensee deliver petroleum from its production to satisfy national demand and provide transportation to the Norwegian mainland.

In such cases, the government decides upon the recipient. The licensee must be paid a price determined in the same way as the price that forms the basis for the calculation of the royalty payment, plus transportation costs. If agreement on further terms of delivery is not reached between the licensee and the designated buyer, such delivery terms are determined by the MPE.

ABANDONMENT REQUIREMENTS

The 1996 Petroleum Act specifies that the abandonment of production installations (including pipelines) must be authorized by the MPE and then approved by the Norwegian parliament (*Storting*). The Act specifies that disposal options include further use in petroleum activities, other uses, complete or partial removal or abandonment. As the OSPAR Convention 1992 does not cover the disposal of pipelines and cables, in those matters, the guidelines in *Storting White Paper No. 47* (1999-2000) are applied.

The 1996 Petroleum Act also addresses liability for decommissioned facilities. The Act was amended in 2009 to create the legal provision that an assignor of an interest in a license can remain alternatively liable for the financial obligations of the decommissioning decision.

Any person who is under an obligation to implement an approved decommissioning plan is liable for any willful or inadvertent damage caused in connection with the facility. The 1996 Petroleum Act makes provision for the licensee, the facility owner, and the state to agree that future maintenance, responsibility, and liability for decommissioned facilities is to be taken over by the state on the basis of agreed financial compensation.

Expenses for the abandonment of wells and the removal of installations and pipelines are deductible at the time such expenses are incurred, but no deduction is permitted for future abandonment expenses. Act No. 104 of June 19, 2009 amended section 5(3) of the 1996 Petroleum Act to make the licensees completely liable for abandonment costs.

A.10 United Kingdom—Offshore

The terms used for this study relate to the latest applicable terms as of September 2018.

A.10.1 Fiscal and Contractual Terms

BONUSES

Signature bonuses may be called for as the basis for a cash auction bid round. However, in practice this option has only been used for selected blocks in the 1970s and early 1980s (in the 4th, 8th, and 9th rounds). At various times since then, the government has reviewed the option of employing this method for allocating acreage. A review conducted in the mid-1990s decided against adopting cash auctions.

OTHER PAYMENTS

Rental: The licensee must pay annual rental yearly in advance while holding a seaward production license. The amounts payable are announced for each licensing round and form part of the formal notice published in the *Official Journal of the European Union*. Rental rates are subject to biennial review (i.e. every other year) in line with movements in the Index of the Price of Crude Oil acquired by refineries. An adjustment may only be made if the movement in such index exceeds 5% lower or higher in the relevant period (though not less than the original schedule of periodic payments). Table A-10.1 provides current rental rates for seaward production licenses.

Table A-10.1. Annual rental payments: United Kingdom—offshore

Phase/year	Rental payment
RENTAL DUE DURING THE INITIAL TERM	
Phase A	GBP 15 × AF
Phase B	GBP 30 × AF
Phase C	GBP 150 × AF
RENTAL DUE ON ANNIVERSARY OF START DATES AFTER THE INITIAL TERM	
Start Date +1, +2 and +3 years	GBP 150 × AF
+4 years	GBP 300 × AF
+5 years	GBP 1200 × AF
+6 years	GBP 2100 × AF
+7 years	GBP 3000 × AF
+8 years	GBP 3900 × AF
+9 years	GBP 4800 × AF
+10 years	GBP 5700 × AF
+11 years	GBP 6600 × AF
+12 and subsequent years	GBP 7500 × AF
Area Factor (AF) = the number of square kilometers of the licensed area on the date that the periodic payment is due	

Source: IHS Markit

ROYALTY

With effect from January 1, 2003, the last remaining royalties levied on oil and gas production in the UK Continental Shelf were abolished.

INCOME TAX

Taxation relating to the petroleum industry is subject to frequent legislative modification. New measures and legislative amendments are regularly incorporated within the annual Finance Act (which is adopted following a parliamentary budget announcement, now timed for the autumn, for adoption by the beginning of the subsequent tax year).Thus, Part 8 of Corporate Tax Act 2010, entitled, 'Oil Activities', which consolidates provisions for ring fence corporation tax (RFCT) and the supplementary charge (SC), has since been amended by a Finance Act in each and every year between 2011 and 2017.

RFCT is levied at a rate of 30% on total petroleum 'ring fence' profits made by a company.

Allowances for Income Tax

The **ring fence expenditure supplement (RFES)** mechanism allows E&P investors who are not in a position to generate taxable income – and therefore deduct qualifying exploration costs – to carry forward those costs, accruing at a rate of 10% (compensating for the loss in real terms value). The number of accounting periods (i.e. years – not necessarily consecutive) for which this may occur has been increased from six to ten. RFES is set out in Part 8, Chapter 5 of Corporation Tax Act (CTA) 2010 – the additional four-year extension for qualifying expenditure incurred on or after December 5, 2013 and was implemented by Section 47 of Finance Act 2015 and its Schedule 11.

First-year allowances (FYAs) for oil and gas activities subject to the SC were introduced under the Finance Act 2002 at the rate of 100% for 'first-year qualifying expenditure'. FYAs stand in the place of depreciation in company accounts. FYAs include:

- Plant and machinery, and
- Mineral exploration and access

SUPPLEMENTARY CHARGE

The supplementary charge (SC) is levied at a rate of 10% on the same basis as income tax (less financing costs). The rate was reduced from 20 to 10 percent for accounting periods starting after January 1, 2016.

Allowances for Supplementary Charge

Basin-Wide Investment Allowance: Shields an amount equal to 62.5% of capital expenditure of corresponding taxable income from the supplementary charge. This allowance is granted in recognition of the significant capital costs of North Sea projects. The Basin-Wide Investment Allowance has the following notable features:

- Designed to shield an amount ('allowance') of taxable income from the SC proportionate to 'qualifying expenditure' incurred in relation to a given field,
- Non-transferrable between fields (although it may be used 'against all' of the investor's 'adjusted ring fence profits'), and
- Any basin allowance not used in one accounting period may be carried forward to a subsequent accounting period.

The allowance addresses new investments in both new and existing fields (e.g. brown fields and near-field developments).

Cluster Area Allowance (CAA): Operates alongside the basin investment allowance (IA). CAA is equal to 62.5% of the qualifying expenditure in relation to a cluster (a high-pressure, high-temperature (ultra-HPHT) discovery, which may contain more than one discrete field). Expenditure that already qualifies for CAA does not qualify for IA.

A.10.2 Acreage Award Criteria

The Oil and Gas Authority (OGA) uses a 'Seaward Marks Scheme' for assessing the technical requirements of applications for all offshore licenses. Marks are awarded in the following eight categories:

- Geotechnical database;
- Geotechnical evaluation;
- Specific prospectivity identified;
- New plays;
- Geotechnical work program;
- Drilling work program, of which there are three levels:
    - Firm well drilling commitments (50 marks + up to 20 additional marks),
    - Contingent well drilling commitments (20 marks + up to 10 additional marks), and
    - 'Drill-or-Drop' commitments (20 marks if committed by the end of year one, 10 marks by the end of year two; for traditional applications only);
- 'Promote' applications; and
- Evaluation and plans for existing discoveries or re-developments.

In certain circumstances, the OGA may take into consideration additional factors that fall outside the marks scheme, such as:

- An applicant's track record on completing work programs,
- An applicant's performance record such as activity on suspended wells or fallow blocks and discoveries, and
- Where direct comparison between different applications is difficult due to, for example, incommensurable geographical coverage or geological focus, or contrasting investigative approaches (prospect specific versus wider-area).

WORK COMMITMENT

The innovate multiple-phase licenses (MPL) will end at each phase of the initial term (or specified deadline for a given commitment where applicable) unless the licensee has met its obligations – each phase is designed to accommodate different types of (escalating) commitment.

Phases A and B are optional and depend on the applicant’s plans. Every work program must have at least a Phase C (just as a drilling commitment was the minimum work program before the innovate concept).

Table A-10.2. Exploration work commitments: United Kingdom—offshore

Phase	Type of obligations
Phase A	Geotechnical studies and geophysical data purchase and /or reprocessing
Phase B	Shooting new seismic and acquiring other geophysical data
Phase C	Drilling

Source: IHS Markit

A.10.3 Exploration and Production Terms

BLOCK SIZES

A license may include one or more designated blocks or tranches of blocks. Recent multi-block awards are also required to be contiguous. Areas released by previous licensees may be re-granted.

Offshore blocks are composed of sections measured by one minute of latitude by one minute of longitude and on average a block is 250 square kilometers.

CONTRACT DURATION

The holder of any type of production license may produce petroleum from any discovery in relation to which it has received development consent. There have been various types of 'seaward production license' on offer in recent years:

- Multiple-phase license (MPL, often referred to as an 'Innovate' License, from 2016/7 – replacing all others, below),
- Traditional license,
- Promote license (MPLs take over features of promote licenses),
- Six-year frontier license, and
- Nine-year frontier license (introduced for the West of Scotland).

Table A-10.3. Exploration and production terms: United Kingdom—offshore

License name	Initial term	Second term	Third term	Comments
Traditional seaward production licence	4 years	4 years	18 years	
Promote licence	4 years	4 years	18 years	*Ceased to exist as innovate; MPL was introduced*

License name	Initial term	Second term	Third term	Comments
Six-year frontier licence	6 years	6 years	18 years	*Ceased to exist as innovate; MPL was introduced*
Nine-year frontier license (West of Scotland)	9 years	6 years	18 years	*Ceased to exist as innovate MPL was introduced*
Innovate "multiple phase license" (MPL)	Flexible duration			*Replaced "promote", "six-year frontier" and "nine-year frontier" licenses*
Exploration license	3 years	3 years	N/A	

Source: IHS Markit

RELINQUISHMENT OBLIGATIONS

There is no compulsory relinquishment at the end of Phase A and up to 25% negotiable relinquishment (with three months' notice) at the end of Phase B. At the end of Phase C/the initial term, the license is relinquished down to the 'prospective area' – with 50% of the initial acreage surrendered.

Traditional production licenses and promote licenses require that 50% of their original area be relinquished at the end of the initial term.

DOMESTIC MARKET OBLIGATIONS

There has never been any formal domestic supply obligation.

ABANDONMENT REQUIREMENTS

Liability for Abandonment

UK law on decommissioning and abandonment is based on the requirements of the 1992 OSPAR Convention and, in particular, OSPAR Decision 98/3 on the disposal of disused offshore installations, which came into force on February 9, 1999. The latter sets out three principal disposal options:

- Steel installations weighing 10,000 tons or less in air must be completely removed,
- For steel installations weighing over 10,000 tons placed in the maritime area before February 9, 1999, all or part of the footings may be left in place, and
- Gravity-based concrete installations, floating concrete installations and concrete anchor-bases may be left wholly or partly in place.

The Petroleum Act 1998 contains provisions relevant to disused offshore installations and pipelines concerning the submission and approval of relevant programs. The Minister (i.e. OGA/BEIS) has the power at any time to request that a licensee draw up and present a detailed decommissioning program by serving a statutory notice to that effect. Section 30 of the Petroleum Act 1998 and amendments made thereto by the

Energy Act 2008 details the persons who may be required to submit a program. Such persons include (but are not limited to):

- The person having the management of the installation,
- The person who has the right to (a) exploit or explore mineral resources in any area; (b) to unload, store or recover gas in any area or to convert any natural feature in any area for the purpose of storing gas; (c) to explore any area with the purpose of doing any of the foregoing,
- A person carrying on, or intending to carry on, any of the following activities from, by means of, or on the installation: (a) the exploitation or exploration of mineral resources; (b) the unloading, storage or recovery of gas in the exercise of that right; (c) the conversion of a natural feature for the purposes of storing gas (d) the exploration in exercise of the right listed in (c); (e) the conveyance by a system of pipes in the area of minerals obtained or gas stored or recovered; (f) the provision of accommodation for persons who work on or from an installation which is or has been maintained for the carrying on of an activity falling within paragraphs (i) (ii) or (iii). We understand that where a person holding such rights transfers them to another person but fails to obtain the appropriate consent for such transfer, then they remain liable., and
- A person subject to a joint operating agreement by virtue of which they have the rights/undertake the activities set out in (ii) and (iii) above.

The Minister may withdraw a statutory decommissioning notice where the licensee assigns its interest to another party before the cessation of production operations. Alternatively, the Minister may require the assignor to enter into a financial security agreement with the assignee if there is reason to believe that the assignee on its own would be unable to honor the decommissioning and abandonment obligations of the assignor.

Additionally, the Petroleum Act 1998 provides an avenue for any former petroleum licensee, who has been subject to the Section 29 notice/program procedure to be brought back to share in the decommissioning costs of a petroleum installation, even after they have validly assigned all their interest in the petroleum license to another party. This is because a power exists for the Minister or the parties that initially submitted the abandonment program to impose a duty on a person, who may no longer be a party to the license, that the terms of an agreed program must still be complied with. This power is limited in some regards by virtue of subsection 3 of Section 34 of the1998 Petroleum Act which was amended in 2008 by the Energy Act 2008.

Following amendments made by the Energy Act 2016, there is an obligation for licensees to work with the OGA to ensure costs are minimized, notwithstanding the OGA's powers to seek alternatives to abandoning or decommissioning the installation or pipeline, such as reusing or preserving it (Maximizing Economic Recovery policy).

Tax Treatment of Decommissioning Costs

A 100% corporation tax allowance is available for expenditure incurred in abandoning offshore oil and gas fields under approved decommissioning programs.

<u>Decommissioning Relief Deeds</u>

Further measures on decommissioning relief were introduced in the Finance Act 2013[119] giving the government statutory authority to sign contracts with companies operating in the UK Continental Shelf to

[119] Finance Act 2013, ss.80-85.

'provide assurance on the relief they will receive when decommissioning assets'. On September 3, 2013, the UK government announced that it would enter into 'legally-binding contracts' termed 'decommissioning relief deeds' (DRDs) that purport to guarantee future tax relief on decommissioning costs.

DRDs are essentially bilateral agreements made with the UK government amounting to 'contracts for difference on the future tax code'. It is understood that DRDs establish a reference amount – to 'crystalize' the regime of tax relief available for decommissioning, as at the time of the enactment of Finance Act 2013 – that qualifies for tax relief 'in perpetuity'. This is to allow the DRD holder to claim any shortfall from the government if this amount is not achieved through the taxation system.

DRDs provide for two potential scenarios:

- Where a DRD holder is meeting another's decommissioning costs, the DRD guarantees relief at a rate of 30% regarding income tax and 20% regarding surcharge – the level of relief regarding PRT will be the same as that which the defaulting party would have received (or 'greater, from their own tax history'), or
- Where a DRD holder is meeting its own liabilities for decommissioning, the DRD guarantees relief 'aligned to the rate of tax paid' (as well as access to relief regarding PRT if PRT is abolished)

The stated aim of the government's introduction of DRDs is so that they act as a disincentive to government-led changes and create certainty. They are thus an instrument of 'last-resort' and so there is a stated expectation that they will not need to be relied upon.

<u>Transferable Tax History for Decommissioning</u>

In late 2017, the UK government announced a mechanism unique to income tax and the petroleum industry: 'transferable tax history' (TTH). This is designed to allow purchasers of UKCS assets to deduct decommissioning costs paid by previous licensees where the purchaser has not generated enough tax history to such costs as determined in a costed decommissioning plan.

For 'deals that complete on or after November 1, 2018', the government intends that some of the historical tax paid for given oil and gas fields be made available to successive licensees when assets are sold. This will allow purchasers to claim greater decommissioning relief by offsetting costs against a potentially larger pool of previously paid tax. It is also the government's intention that the complexity of deals for acquiring UKCS late-life assets be reduced, facilitating continuing activity, consistent with the Maximizing Economic Recovery (MER) policy.

A.11 United States—Gulf of Mexico

The terms used for this study relate to the latest applicable terms as of September 2018.

A.11.1 Fiscal and Contractual Terms

BONUSES

A minimum U.S. dollar amount per acre or hectare is specified in the notice of sale. The minimum amounts stated in recent lease sale notices were USD25 per acre for blocks in water depths of less than 400 meters and USD100 per acre for blocks in water depths of 400 meters or more. While the minimum bonus amount for shallow water acreage has remained unchanged, the minimum bonus amount for deepwater acreage has increased from USD37.50 to USD100 per acre in 2011and USD100 has been used since. The bonus bid amount must be started in whole dollars. In recent year, high bids have ranged from USD144 thousand to 25 million.

OTHER PAYMENTS

Rental: Rentals are announced in advance in each notice of lease sale. Annual rentals are due and payable in advance on the first day of each lease year prior to the discovery of oil or gas on the lease. Table A-11.1 includes the applicable rental rates in the Gulf of Mexico.

Table A-11.1. Rental rates: United States—Gulf of Mexico

Water depth (Meters)	Years 1-5 (USD/acre)	Year 6 (USD/acre)	Year 7 (USD/acre)	Year 8+ (USD/acre)
0 to < 200	7	14	21	28
200 to < 400	11	22	33	44
400+	11	16	16	16

Source: IHS Markit

In the case of leases with an eight-year primary term in less than 400 meters water depth, the rental rates after the fifth year will be fixed and no longer escalate if another well is spudded targeting hydrocarbons below 25,000 feet TVDSS after the fifth year of the lease. In this case, the rental rate will become fixed at the rental rate in effect during the lease year in which the additional well was spudded.

ROYALTY

The royalty rate may be a fixed bidding term stipulated in each notice of sale or a bidding variable. The applicable rates, at the time this report was written, are:

- 12.5% for leases situated in water depths less than 200 meters, and
- 18.75% for leases situated in water depths of 200 meters and deeper.

Royalty Reliefs

The Department of the Interior offers two types of royalty relief: categorical and discretionary. Categorical royalty relief is specified in the lease agreement when the lease is issued by BOEM, and includes deepwater and deep gas royalty relief. Discretionary royalty relief is granted upon application by the companies under certain scenarios, and include end-of-life and special case royalty relief.

Categorical Royalty Relief

Deepwater royalty relief: Deepwater royalty relief consists of two types of leases:

- "Eligible" leases offered in sales held from 1996 through 2000 in water depths 200 meters or deeper that lie wholly west of 87 degrees, 30 minutes West longitude, and
- "Royalty suspension" leases offered post-2000 and issued with a royalty suspension volume at the lease sale. The lease sale notice specified the water depth categories and the royalty suspension volumes.

Royalty suspension volumes are subject to price thresholds that are established by lease vintage. Beginning in the second quarter of each year, BOEM estimates the average New York Mercantile Exchange market price at which oil or gas would have to sell during the remainder of the calendar year for the estimated price threshold to be exceeded for that year. In recent years, the deepwater royalty suspension volumes have not been available for crude oil, as the market prices have exceeded the threshold prices. Table A-11.2. describes the deepwater royalty relief for past leases sold in the Gulf of Mexico.

Table A-11.2. Gulf of Mexico deepwater royalty relief: United States—Gulf of Mexico

Type of lease	Water depth (meters)	Royalty suspension volume (MMboe)	Time leases were sold
Eligible leases	200 to < 400	17.5	1996 - 2000
	400 to < 800	52.5	
	800 +	87.5	
Royalty Suspension leases	400 to < 800	5	Mar 2002 – Aug 2010
	800 to < 1,600	9	Mar 2001 – Aug 2010
	1,600 +	12	Mar 2001 – Aug 2005
	1,600 to < 2,000	12	Mar 2001 – Aug 2010
	2000 +	16	Aug 2005 – Aug 2010

Source: IHS Markit

Deep Gas Royalty Relief: The royalty relief currently offered for shallow water deep gas wells stands at 35 billion cubic feet on the production of natural gas. Such a royalty suspension volume is offered for leases in water depths of less than 400 meters that complete the drilling of a well to 20,000 feet TVDSS or deeper. Table A-11.3 provides information on historical shallow water deep gas royalty relief programs.

Table A-11.3. Gulf of Mexico Shallow Water Deep Gas Relief: United States—Gulf of Mexico

Water depth (meters)	Well depth (feet TVDSS)	Royalty suspension volume (Bcf)	Time leases were sold
< 400	15,000 to < 20,000	20	Mar 2001 – Mar 2003
	15,000 to < 18,000	15	Mar 2003 – May 2013
	18,000 to < 20,000	25	Mar 2003 – May 2013
	20,000 +	12	May 2007 to present

Source: IHS Markit

Discretionary Reliefs

BSEE may reduce or eliminate the royalty for producing leases to promote increased production or incentivize new projects that are otherwise uneconomic. The purpose of royalty relief is to allow operators reasonable financial returns to increase ultimate resource recovery.

End-of-life royalty relief: This relief is applicable to producing leases that have reached the economic limit, i.e. have earnings that cannot sustain production under existing royalty rates and relief would likely result in increased production. If approved, the Department of the Interior grants a reduced royalty rate on existing production and a higher rate, not to exceed the lease stipulated rate, on additional production.

Special case relief: This is another type of discretionary relief that can be requested when the existing royalty relief programs do not provide adequate encouragement to increase production or development. Such leases must meet at least two of the following criteria:

i. Royalty relief would allow recovery of significant additional resources,
ii. Substantial risk another lessee would not recover the resources,
iii. Valuable facilities exist on the lease which a successor would be unlikely to use, and
iv. The lessee made substantial efforts to reduce operating costs, but it is too late to take advantage of other royalty relief programs

INCOME TAX

In December 2017, the President signed the Tax Cuts and Jobs Act into law. This Act (Section 13001) changes the corporate income tax rate in the USA from a maximum of 35% to a flat rate of 21%, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50% to 100% for qualified property acquired and placed in service after September 27, 2017, and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017, and placed in service before January 1, 2018, remains at 50%. The Tax Cuts and Jobs Act provides for a five-year phase down of the 100% depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100% of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80% of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry back option.

A.11.2 Acreage Award Criteria

The allocation of rights is performed through lease sales. Bids are invited by a notice published in the Federal Register. The notice identifies the bidding system to be utilized for the lease sale and the reasons for the utilization of such system, and designates tracts selected for offer under each bidding system.[120]

Various bidding systems are applicable which differ as to the bidding terms or bidding variables. A common condition of all the various bidding systems is that none of them should have more than one bidding

[120] 1953 OCSLA Sec 1337.a.8

variable. The following is a list of the applicable bidding systems under the 1953 Outer Continental Shelf Lands Act:

- Cash bonus bid with a fixed royalty of no less than 12.5% of the amount or value of production saved, removed, or sold;
- Variable royalty bid with either a fixed work commitment or a fixed cash bonus as determined by the Secretary, or both;
- Cash bonus bid or work commitment bid based on a U.S. dollar amount for exploration with a fixed cash bonus, and a diminishing or sliding royalty based on such formula as the Secretary determines as equitable to encourage continued production from the lease area as resources diminish but not less than 12.5% at the beginning of the lease period;
- Cash bonus bid with a fixed net profit share of no less than 30%;
- Fixed cash bonus with the net profit share being a bid variable;
- Cash bonus bid with a fixed royalty of no less than 12.5% and a fixed net profit share of no less than 30%;
- Work commitment[121] bid based on a U.S. dollar amount for exploration with a fixed cash bonus and fixed royalty; and
- Cash bonus bid with fixed royalty of no less than 12.5% and with a suspension of royalties for a defined period, volume, or value of production, which suspension may vary based on the price of production from the lease.

In practice, however, cash bonus bids with fixed royalty that is announced in the lease notice have been used by the Department of the Interior since 1982. When Congress amended the OCS Lands Act in 1978, it instructed the DOI to experiment with alternative biddings systems for OCS leasing, primarily to encourage participation of small companies by reducing upfront costs associated with the traditional cash bonus bid system. The government used four alternative bidding systems from 1978 through 1982, but these systems were not found to enhance OCS program performance compared to the fixed royalty rate system. Among other things, they did not increase participation by small companies; were significantly more complex to administer; distorted bids, which made it more difficult to identify the high bid; and often were not beneficial to the taxpayer.[122]

A.11.3 Exploration and Production Terms

BLOCK SIZES

Unless specifically authorized, an oil and gas lease must consist of a compact area, not exceeding 5,760 acres (23.3 square kilometers). The lease size is specified in each notice of sale.

CONTRACT DURATION

Exploration period: The duration of the primary term of the lease depends on water depth and other conditions imposed to ensure expedited exploration of the leased blocks. Table A-11.4 shows the primary term for each water depth category in the Gulf of Mexico.

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[121] Currently not required under applicable BOEM regulations.

[122] James L. Smith, Daniel R. Siegel, and C. S. Agnes Cheng, 1988. "Failure of the Net Profit Share Leasing Experiment for Offshore Petroleum Resources," *The Review of Economics and Statistics* 70, no.2 (MIT Press: May 1988), 199-206.

Table A-11.4. Gulf of Mexico primary lease term: United States—Gulf of Mexico

Water depth (meters)	Primary term	Condition for extension
0 to < 400	5 + 3	If a well is spudded targeting hydrocarbons below 25,000 feet true vertical depth subsea (TVDSS) during the first five years of the lease
400 to < 800	5 + 3	If a well is spudded during the first five years of the lease
800 to < 1,600	7 + 3	If a well is spudded during the first seven years of the lease
1,600 +	10	

Source: IHS Markit

Production period: The lease remains in force for as long as oil or gas is produced in paying quantities and as long as any break in operations is no longer than 180 days.

RELINQUISHMENT OBLIGATIONS

There is no interim relinquishment requirement.

DOMESTIC MARKET OBLIGATIONS

There are no domestic supply obligations. However, the lease does provide for the allocation of 20% of the crude oil, condensate, and natural gas liquids produced under the lease to be delivered to small or independent refiners at market value, at the applicable delivery point as defined in the Emergency Petroleum Allocation Act 1973.

ABANDONMENT REQUIREMENTS

The abandonment of wells and platforms requires the prior approval of an abandonment plan by the regional supervisor. The platforms including casing, well head equipment, templates, and piling must be removed by the lessee to a depth of at least 15 feet below the ocean floor or to another depth approved by the regional supervisor.

30 CFR Part 556.56-57 provides that, to ensure compliance with abandonment obligations, the Regional Director may authorize the establishment of lease-specific abandonment accounts in a federally insured institution as an alternative to payment of supplemental bonds. A possible way of funding the lease-specific abandonment account is the creation of overriding royalties or production payment obligations when so required by the Regional Director. Third-party guarantees may also be accepted by the Regional Director for meeting abandonment obligations. [123]

Costs incurred by the lessee for the demolition of structures and losses sustained on account of such demolition are not allowed as a deduction for income tax purposes. Instead, they are chargeable to the capital account with respect to the land on which the demolished structure was located.

[123] 2018. https://www.boem.gov/Third-Party-Guarantees/. Bureau of Ocean Energy Management.

The 1984 amendment to the Internal Revenue Code enforces the rule that deductions for abandonment costs may only occur when the expenditure has been made, i.e. there can be no tax deductions for abandonment provisions during the producing life of the asset.

Appendix B Cost Modeling Assumptions

B.1 Shallow Water Development Assumptions

B.1.1 Australia Shallow Water

Table B-1. Australia shallow water gas

Country	Reserve Size (MMboe)	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Australia	100	103	3,073	1,140	Fixed platform	Nearby offtake	Ship to shore
	30	99	3,330	1,140	Fixed platform	Nearby offtake	Ship to shore
	10	78	2,484	1,140	Wellhead tie-back	Nearby platform	Nearby platform

Table B-2. Australia shallow water oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Australia	100	114	4,510	877	Fixed platform	Nearby offtake	Ship to shore
	30	97	2,511	877	Fixed platform	Nearby offtake	Ship to shore
	10	73	1,933	877	Wellhead tie-back	Nearby platform	Nearby platform

B.1.2 Brazil Shallow Water

Table B-3. Brazil shallow water gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Brazil	100	126	3,311	5.88	Fixed platform	Nearby offtake	Ship to shore
	30	111	3,735	5.88	Fixed platform	Nearby offtake	Ship to shore
	10	111	3,125	5.88	Fixed platform	Nearby offtake	Ship to shore

Table B-4. Brazil shallow water oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Brazil	100	128	2,801	858	Fixed platform	Nearby offtake	Ship to shore
	30	130	2,927	858	Fixed platform	Nearby offtake	Ship to shore
	10	94	3,167	858	Fixed platform	Flared	Nearby platform

B.1.3 Mexico Shallow Water

Table B-5. Mexico shallow water gas

Country	Reserve size	Water depth (m)	True Vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Mexico	100	23	4,453	0.08	Fixed platform	Nearby offtake	Ship to shore
	30	21	6,315	0.08	Fixed platform	Nearby offtake	Ship to shore
	10	24	2,591	0.08	Wellhead tie-back	Nearby platform	Nearby platform

Table B-6. Mexico shallow water oil

Country	Reserve size	Water depth (m)	True Vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Mexico	100	54	4,422	818	Fixed platform	Nearby offtake	Ship to shore
	30	53	4,311	818	Fixed platform	Flare	Nearby offtake
	10	27	3,195	818	Fixed platform	Flare	Nearby offtake

B.1.4 Norway Shallow Water

Table B-7. Norway shallow water gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Norway	100	102	3,999	7.25	Fixed platform	Nearby offtake	Ship to shore
	30	108	3,959	7.25	Fixed platform	Nearby offtake	Ship to shore
	10	110	2,811	7.25	Wellhead tie-back	Nearby platform	Nearby platform

Table B-8. Norway shallow water oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Norway	100	113	2,166	1,557	Fixed platform	Nearby offtake	Ship to shore
	30	106	2,429	1,557	Fixed platform	Nearby offtake	Ship to shore
	10	107	2,877	1,557	Wellhead tie-back	Nearby Platform	Nearby platform

B.1.5 United Kingdom Shallow Water

Table B-9. United Kingdom shallow water gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
United Kingdom	100	67	3,197	7	Fixed platform	Nearby offtake	Ship to shore
	30	110	3,595	7	Fixed platform	Nearby offtake	Ship to shore
	10	63	3,160	7	Wellhead tie-back	Nearby platform	Nearby platform

Table B-10. United Kingdom shallow water oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
United Kingdom	100	156	1,647	1,001	Fixed platform	Reinjection	Nearby offtake
	30	111	2,178	1,001	Fixed platform	Reinjection	Nearby offtake
	10	106	2,319	1,001	Wellhead tie-back	Nearby offtake	Nearby offtake

B.1.6 United States Shallow Water

Table B-11. United States shallow water gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
United States	100	75	4,593	18	Fixed platform	Nearby offtake	Ship to shore
	30	50	2,516	18	Fixed platform	Nearby offtake	Ship to shore
	10	15	3,159	18	Wellhead tie-back	Nearby platform	Nearby platform

Table B-12. United States shallow water oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
United States	100	97	1,503	1,194	Fixed platform	Reinjection	Nearby offtake
	30	22	1,827	1,194	Fixed platform	Reinjection	Nearby offtake
	10	148	1,827	1,194	Wellhead tie-back	Nearby platform	Nearby platform

B.2 Deepwater Development Assumptions

B.2.1 Angola Deepwater

Table B-13. Angola deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Angola	500	1,529	4,630	0	FPSO	Nearby offtake	Dry Gas
	250	1,378	4,840	0	FPSO	Nearby offtake	Dry Gas

Table B-14. Angola deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Angola	500	1,176	2,642	1,281	FPSO	Nearby offtake	Ship to shore
	250	1,247	3,074	1,281	FPSO	Reinjected	Ship to shore

B.2.2 Brazil Deepwater

Table B-15. Brazil deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Brazil	500	1,253	2,439	24	FPSO	Nearby offtake	Ship to shore
	250	1,253	2,439	24	FPSO	Nearby offtake	Ship to shore

Table B-16. Brazil deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Brazil	500	2,113	5,311	755	Cylindrically hulled FPSO	Nearby offtake	Ship to shore
	250	1,621	3,947	755	FPSO	Reinjected	Ship to shore

B.2.3 Canada Deepwater

Table B-19. Canada deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Canada	500	221	4,538	0	GBS platform with subsea tie-backs	Pipe to shore	Dry Gas
	250	221	4,538	0	GBS platform with subsea tie-backs	Pipe to shore	Dry Gas

Table B-20. Canada deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Canada	500	1,172	3,429	621	GBS platform with subsea tie-backs	Reinjection	Ship to shore
	250	1,128	3,227	621	GBS platform with subsea tie-backs	Reinjection	Ship to shore

B.2.4 Guyana Deepwater

Table B-17. Guyana deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Guyana	500	2,172	4,116	0	FPSO	Near-shore offtake	Dry Gas
	250	1,843	3,906	0	FPSO	Near-shore offtake	Dry Gas

Table B-18. Guyana deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Guyana	500	2,172	4,116	1,639	FPSO	Nearby offtake	Ship to shore
	250	1,843	3,906	1,639	FPSO	Nearby offtake	Ship to shore

B.2.5 Mexico Deepwater

Table B-21. Mexico deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Mexico	500	2,159	4,303	0	Spar buoy	Pipe to near-shore offtake	Dry Gas
	250	2,385	4,146	0	Spar buoy	Pipe to near-shore offtake	Dry Gas

Table B-22. Mexico deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Mexico	500	2,267	4,770	2,265	Spar buoy	Pipe to near-shore offtake	Ship to shore
	250	2,406	4,906	2,265	Spar buoy	Reinjection	Ship to shore

B.2.6 Norway Deepwater

Table B-23. Norway deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
Norway	500	552	3,960	27	Semi-submersible platform	Nearby offtake	Ship to shore
	250	552	3,960	27	Semi-submersible platform	Nearby offtake	Ship to shore

Table B-24. Norway deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
Norway	500	352	3,107	1,275	Semi-submersible platform	Nearby offtake	Ship to shore
	250	341	3,285	1,275	Semi-submersible platform	Nearby offtake	Ship to shore

B.2.7 United Kingdom Deepwater

Table B-25. United Kingdom deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	Productivity (Bcf/well)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
United Kingdom	500	741	3,030	120	5	Semi-submersible platform	Nearby offtake	Ship to shore
	250	1,408	2,539	120	5	Semi-submersible platform	Nearby offtake	Ship to shore

Table B-26. United Kingdom deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	Productivity (MMbbl/well)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
United Kingdom	500	602	2,695	3.1	993	Semi-submersible platform	Nearby offtake	Ship to shore
	250	856	2,311	3.1	993	Semi-submersible platform	Nearby offtake	Ship to shore

B.2.8 United States Deepwater

Table B-27. United States deepwater gas

Country	Reserve size	Water depth (m)	True vertical depth (m)	CGR (MMscf/bbl)	Development concept	Gas export method	Oil export method
United States	500	1,311	3,910	18	Spar buoy	Nearby offtake	Ship to shore
	250	898	5,146	18	Spar buoy	Nearby offtake	Ship to shore

Table B-28. United States deepwater oil

Country	Reserve size	Water depth (m)	True vertical depth (m)	GOR (bbl/scf)	Development concept	Gas export method	Oil export method
United States	500	1,806	8,656	1,194	Spar buoy	Nearby offtake	Nearby offtake
	250	1,621	8,031	1,194	Spar buoy	Nearby offtake	Nearby offtake

Appendix C - Commercial Assumptions

C.1 Oil Price Forecast

Table C-1. Annual global base oil price assumptions, $/bbl in 2018 real terms

Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
$/bbl	61.71	65.58	62.65	61.45	60.93	61.08	62.64	63.44	63.73	65.01	67.46	68.63	68.61	68.60	68.59	68.58	68.55	68.54	68.54	68.53	68.51	68.50

Table C-2. Annual global high oil price assumptions, $/bbl in 2018 real terms

Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
$/bbl	98.73	104.92	100.23	98.31	97.49	97.73	100.22	101.50	101.97	104.02	107.93	109.82	109.78	109.76	109.74	109.73	109.69	109.67	109.66	109.65	109.61	109.60

Table C-3. Annual global low oil price assumptions, $/bbl in 2018 real terms

Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
$/bbl	37.02	39.35	37.59	36.87	36.56	36.65	37.58	38.06	38.24	39.01	40.48	41.18	41.17	41.16	41.15	41.15	41.13	41.13	41.12	41.12	41.10	41.10

C.2 Gas Sales Price

Table C-4. Gas hub assignments

Country	Hub	Sales point
Angola	Europe market price	Export to Spain, Europe market LNG price
Australia	Asia spot price	Export to Asia market LNG price
Brazil	Southern Cone	Bolivia import to Brazil
Canada	U.S. East Coast	Transport to nearest sales point
Guyana	Fixed contract price, GoM fuel oil equivalent	Fixed contract pricing to sell domestically
Mexico	East Reynosa	Transport to nearest sales point
Norway	Europe market price	Export to Germany, Europe market LNG price
United Kingdom	NBP	Transport to nearest sales point
United States	Henry Hub	Transport to nearest sales point

Table C-5. Annual base gas net sales price assumptions, \$/Mcf in 2018 real terms

Country	Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Angola	$Mcf	4.43	3.79	4.2	4.54	5.49	6.52	7.24	7.65	7.84	8.05	8.35	8.6	8.49	8.74	8.88	8.75	8.72	8.64	8.79	9.03	9.15	9.34
Australia	$Mcf	4.34	2.65	2.03	2.23	3.07	4	4.72	5.14	5.34	5.56	5.87	6.13	6.03	6.28	6.42	6.28	6.26	6.17	6.32	6.48	6.48	6.48
Brazil	$Mcf	6.69	5.87	5.92	6.07	6.43	6.82	7.04	7.16	7.2	7.27	7.41	7.54	7.57	7.55	7.53	7.52	7.5	7.49	7.48	7.48	7.47	7.47
Canada	$Mcf	3.45	3.18	3.29	3.99	4.29	4.86	5.07	5.17	5.07	4.94	5.11	5.4	5.46	5.58	5.72	5.76	5.44	5.35	5.49	5.72	5.9	5.92
Guyana	$Mcf	11.86	12.04	12.02	11.99	12.12	12.01	11.75	11.49	11.39	11.3	11.5	11.64	11.65	11.65	11.63	11.64	11.64	11.64	11.66	11.68	11.7	11.72
Mexico	$Mcf	3.9	3.81	3.79	4.02	4.23	4.48	4.87	4.92	4.94	5.09	5.36	5.78	6.2	6.14	6.55	6.85	6.77	6.92	6.92	7.3	7.81	8.15
Norway	$Mcf	1.47	0.83	1.24	1.58	2.53	3.55	4.27	4.68	4.88	5.09	5.39	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
United Kingdom	$Mcf	6.12	4.66	4.56	5.3	6.36	7.34	7.94	8.1	8.25	8.43	8.71	8.95	8.84	9.09	9.23	9.09	9.07	8.99	9.14	9.38	9.5	9.69
United States	$Mcf	2.46	2.25	2.37	2.84	3.26	3.66	3.86	3.98	3.89	3.78	3.98	4.32	4.41	4.55	4.69	4.75	4.43	4.36	4.51	4.76	4.98	5.03

Table C-6. Annual high gas net sales price assumptions, $/Mcf in 2018 real terms

Country	Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Angola	$Mcf	2.66	2.27	2.52	2.72	3.29	3.91	4.34	4.59	4.7	4.83	5.01	5.16	5.09	5.24	5.33	5.25	5.23	5.18	5.27	5.42	5.49	5.6
Australia	$Mcf	2.6	1.59	1.22	1.34	1.84	2.4	2.83	3.08	3.2	3.34	3.52	3.68	3.62	3.77	3.85	3.77	3.76	3.7	3.79	3.89	3.89	3.89
Brazil	$Mcf	4.01	3.52	3.55	3.64	3.86	4.09	4.22	4.3	4.32	4.36	4.45	4.52	4.54	4.53	4.52	4.51	4.5	4.49	4.49	4.49	4.48	4.48
Canada	$Mcf	2.07	1.91	1.97	2.39	2.57	2.92	3.04	3.1	3.04	2.96	3.07	3.24	3.28	3.35	3.43	3.46	3.26	3.21	3.29	3.43	3.54	3.55
Guyana	$Mcf	7.12	7.22	7.21	7.19	7.27	7.21	7.05	6.89	6.83	6.78	6.9	6.98	6.99	6.99	6.98	6.98	6.98	6.98	7	7.01	7.02	7.03
Mexico	$Mcf	2.34	2.29	2.27	2.41	2.54	2.69	2.92	2.95	2.96	3.05	3.22	3.47	3.72	3.68	3.93	4.11	4.06	4.15	4.15	4.38	4.69	4.89
Norway	$Mcf	0.88	0.5	0.74	0.95	1.52	2.13	2.56	2.81	2.93	3.05	3.23	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24
United Kingdom	$Mcf	3.67	2.8	2.74	3.18	3.82	4.4	4.76	4.86	4.95	5.06	5.23	5.37	5.3	5.45	5.54	5.45	5.44	5.39	5.48	5.63	5.7	5.81
United States	$Mcf	1.48	1.35	1.42	1.7	1.96	2.2	2.32	2.39	2.33	2.27	2.39	2.59	2.65	2.73	2.81	2.85	2.66	2.62	2.71	2.86	2.99	3.02

Table C-7. Annual low gas net sales price assumptions, $/Mcf in 2018 real terms

Country	Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Angola	$Mcf	7.09	6.06	6.72	7.26	8.78	10.43	11.58	12.24	12.54	12.88	13.36	13.76	13.58	13.98	14.21	14	13.95	13.82	14.06	14.45	14.64	14.94
Australia	$Mcf	6.94	4.24	3.25	3.57	4.91	6.4	7.55	8.22	8.54	8.9	9.39	9.81	9.65	10.05	10.27	10.05	10.02	9.87	10.11	10.37	10.37	10.37
Brazil	$Mcf	10.7	9.39	9.47	9.71	10.29	10.91	11.26	11.46	11.52	11.63	11.86	12.06	12.11	12.08	12.05	12.03	12	11.98	11.97	11.97	11.95	11.95
Canada	$Mcf	5.52	5.09	5.26	6.38	6.86	7.78	8.11	8.27	8.11	7.9	8.18	8.64	8.74	8.93	9.15	9.22	8.7	8.56	8.78	9.15	9.44	9.47
Guyana	$Mcf	18.98	19.26	19.23	19.18	19.39	19.22	18.8	18.38	18.22	18.08	18.4	18.62	18.64	18.64	18.61	18.62	18.62	18.62	18.66	18.69	18.72	18.75
Mexico	$Mcf	6.24	6.1	6.06	6.43	6.77	7.17	7.79	7.87	7.9	8.14	8.58	9.25	9.92	9.82	10.48	10.96	10.83	11.07	11.07	11.68	12.5	13.04
Norway	$Mcf	2.35	1.33	1.98	2.53	4.05	5.68	6.83	7.49	7.81	8.14	8.62	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64	8.64
United Kingdom	$Mcf	9.79	7.46	7.3	8.48	10.18	11.74	12.7	12.96	13.2	13.49	13.94	14.32	14.14	14.54	14.77	14.54	14.51	14.38	14.62	15.01	15.2	15.5
United States	$Mcf	3.94	3.6	3.79	4.54	5.22	5.86	6.18	6.37	6.22	6.05	6.37	6.91	7.06	7.28	7.5	7.6	7.09	6.98	7.22	7.62	7.97	8.05

C.3 Cost Escalation

The table below shows the real annual fluctuations in cost levels applied to the IHSM models. These are representative of the IHSM Upstream Capital Cost Index and Operating Cost Index for the IHSM macroeconomic scenario called Rivalry.

The Rivalry scenario assumes intense competition among energy sources and evolutionary social change. Gas loosens oil's grip on transport demand and renewables become increasingly competitive with gas, coal and nuclear power. The world transitions from concentrated political and economic power to a broader distribution of wealth and influence. Expansion of international trade and investment continues, but is hobbled at times by domestic politics and misaligned interest among large global players. Inter-fuel competition is driven by four factors: price differentials, environmental concerns, technology improvements and efforts to enhance national competitiveness. Social and political opposition to local pollution grows in many countries, leading to incremental environmental improvements and moderation in greenhouse gas emissions growth. Technological progress and cultural change regarding public opinion on climate, pollution and emissions continue to advance at an evolutionary pace, resulting in steady change over time but with no fundamental or revolutionary shocks to energy demand supply.

Table C-8. Annual real cost escalation

Country	Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Angola	Annual change	0%	1%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	1%	1%	0%	0%	0%	1%	1%	0%
Australia	Annual change	0%	3%	0%	-1%	0%	-1%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Brazil	Annual change	0%	2%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%
Canada	Annual change	0%	3%	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	0%	1%	1%	0%	0%	1%	1%	1%	1%
Guyana	Annual change	0%	2%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%
Mexico	Annual change	0%	3%	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	0%	1%	1%	0%	0%	1%	1%	1%	1%
Norway	Annual change	0%	-5%	-2%	-1%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	1%	0%	0%	0%	1%	1%	0%
United Kingdom	Annual change	0%	-5%	-2%	-1%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	0%	1%	0%	0%	0%	1%	1%	0%
United States	Annual change	0%	3%	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	0%	1%	1%	0%	0%	1%	1%	1%	1%

Table C-9. Annual real operating cost escalation

Country	Units	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Angola	Annual change	0%	-6%	6%	-1%	0%	1%	0%	1%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Australia	Annual change	0%	-2%	2%	-1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
Brazil	Annual change	0%	-3%	4%	-3%	0%	1%	0%	1%	-1%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Canada	Annual change	0%	-1%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Guyana	Annual change	0%	-3%	4%	-3%	0%	1%	0%	1%	-1%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Mexico	Annual change	0%	-3%	4%	-3%	0%	1%	0%	1%	-1%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Norway	Annual change	0%	-1%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
United Kingdom	Annual change	0%	-1%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
United States	Annual change	0%	-2%	4%	-2%	1%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

C.4 Shallow Water Commercial Assumptions

C.4.1 Australia Shallow Water

Table C-10. Australia shallow water commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Australia	Gas	100	N/A	N/A	2.00	2.25	LNG liquefaction and shipping	Asia LNG spot price
		30	N/A	N/A	2.00	2.25	LNG liquefaction and shipping	Asia LNG spot price
		10	0.20	1.25	2.00	2.25	LNG liquefaction and shipping	Asia LNG spot price
	Oil	100	N/A	N/A	2.00	2.25	LNG liquefaction and shipping	Asia LNG spot price
		30	N/A	N/A	2.00	2.25	LNG liquefaction and shipping	Asia LNG spot price
		10	0.20	1.25	2.00	2.25	LNG liquefaction and shipping	Asia LNG spot price

C.4.2 Brazil Shallow Water

Table C-11. Brazil shallow water commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Brazil	Gas	100	N/A	N/A	0.15	1.00	N/A	Southern Cone
		30	N/A	N/A	0.15	1.00	N/A	Southern Cone
		10	N/A	N/A	0.15	1.80	N/A	Southern Cone
	Oil	100	N/A	N/A	0.15	1.80	N/A	Southern Cone
		30	N/A	N/A	0.15	1.80	N/A	Southern Cone
		10	N/A	N/A	N/A	1.80	N/A	N/A

C.4.3 Mexico Shallow Water

Table C-12. Mexico shallow water commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Mexico	Gas	100	N/A	N/A	0.25	1.25	N/A	East Reynosa
		30	N/A	N/A	0.25	0.50	N/A	East Reynosa
		10	0.10	0.85	0.25	0.50	N/A	East Reynosa
	Oil	100	N/A	N/A	0.25	1.25	N/A	East Reynosa
		30	N/A	N/A	N/A	1.25	N/A	N/A
		10	N/A	N/A	N/A	1.25	N/A	N/A

C.4.4 Norway Shallow Water

Table C-13. Norway shallow water commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Norway	Gas	100	N/A	N/A	0.28	1.00	LNG liquefaction and shipping	Europe market price
		30	N/A	N/A	0.28	1.00	LNG liquefaction and shipping	Europe market price
		10	0.20	1.25	0.28	1.00	LNG liquefaction and shipping	Europe market price
	Oil	100	N/A	N/A	0.28	1.00	LNG liquefaction and shipping	Europe market price
		30	N/A	N/A	0.28	1.00	LNG liquefaction and shipping	Europe market price
		10	0.20	1.25	0.28	1.00	LNG liquefaction and shipping	Europe market price

C.4.5 United Kingdom Shallow Water

Table C-14. United Kingdom shallow water commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
United Kingdom	Gas	100	N/A	N/A	0.23	1.25	N/A	NBP
		30	N/A	N/A	0.23	1.25	N/A	NBP
		10	0.20	1.25	0.23	1.25	N/A	NBP
	Oil	100	N/A	N/A	0.23	1.25	N/A	NBP
		30	N/A	N/A	0.23	1.25	N/A	NBP
		10	0.20	1.25	0.23	1.25	N/A	NBP

C.4.6 United States Shallow Water

Table C-15. United States shallow water commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
United States	Gas	100	N/A	N/A	0.31	1.50	N/A	Henry Hub
		30	N/A	N/A	0.31	1.50	N/A	Henry Hub
		10	0.15	1.00	0.31	1.50	N/A	Henry Hub
	Oil	100	N/A	N/A	0.31	1.50	N/A	Henry Hub
		30	N/A	N/A	0.31	1.50	N/A	Henry Hub
		10	0.15	1.00	0.31	1.50	N/A	Henry Hub

C.5 Deepwater Commercial Assumptions

C.5.1 Angola Deepwater

Table C-16. Angola deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Angola	Gas	500	N/A	N/A	0.30	2.50	LNG liquefaction and shipping	Asia LNG spot price
		250	N/A	N/A	0.30	2.50	LNG liquefaction and shipping	Asia LNG spot price
	Oil	500	N/A	N/A	0.30	0.00	LNG liquefaction and shipping	Asia LNG spot price
		250	N/A	N/A	N/A	2.50	N/A	N/A

C.5.2 Brazil Deepwater

Table C-17. Brazil deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Brazil	Gas	500	N/A	N/A	0.20	2.50	N/A	Southern Cone
		250	N/A	N/A	0.20	2.50	N/A	Southern Cone
	Oil	500	N/A	N/A	0.20	2.80	N/A	Southern Cone
		250	N/A	N/A	0.20	2.50	N/A	Southern Cone

C.5.3 Canada Deepwater

Table C-18. Canada deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Canada	Gas	500	N/A	N/A	0.00	6.00	N/A	U.S. East Coast
		250	N/A	N/A	0.00	6.00	N/A	U.S. East Coast
	Oil	500	N/A	N/A	N/A	6.00	N/A	N/A
		250	N/A	N/A	N/A	6.00	N/A	N/A

C.5.4 Guyana Deepwater

Table C-19. Brazil deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Guyana	Gas	500	N/A	N/A	0.20	3.20	N/A	Contract price
		250	N/A	N/A	0.20	3.20	N/A	Contract price
	Oil	500	N/A	N/A	0.20	3.20	N/A	Contract price
		250	N/A	N/A	0.20	3.20	N/A	Contract price

C.5.5 Norway Deepwater

Table C-20. Canada deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Norway	Gas	500	N/A	N/A	0.33	2.00	LNG liquefaction and shipping	European market
		250	N/A	N/A	0.33	2.00	LNG liquefaction and shipping	European market
	Oil	500	N/A	N/A	0.33	2.00	LNG liquefaction and shipping	European market
		250	N/A	N/A	0.33	2.00	LNG liquefaction and shipping	European market

C.5.6 Mexico Deepwater

Table C-21. Mexico deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
Mexico	Gas	500	N/A	N/A	0.10	3.00	LNG liquefaction and shipping	European market
		250	N/A	N/A	0.10	3.00	LNG liquefaction and shipping	European market
	Oil	500	N/A	N/A	0.10	3.00	LNG liquefaction and shipping	European market
		250	N/A	N/A	0.10	3.00	LNG liquefaction and shipping	European market

C.5.7 United Kingdom Deepwater

Table C-22. United Kingdom deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
United Kingdom	Gas	500	N/A	N/A	0.38	2.00	N/A	NBP
		250	N/A	N/A	0.38	2.00	N/A	NBP
	Oil	500	N/A	N/A	0.33	2.00	N/A	NBP
		250	N/A	N/A	0.33	2.00	N/A	NBP

C.5.8 United States Deepwater

Table C-23. United States deepwater commercial assumptions

Country	Type	Reserve size	Gas processing ($/Mcf)	Oil processing ($/bbl)	Gas transportation ($/Mcf)	Oil transportation ($/bbl)	Net-back applied to gas price	Gas market
United States	Gas	500	N/A	N/A	0.38	2.80	N/A	Henry Hub
		250	N/A	N/A	0.38	2.80	N/A	Henry Hub
	Oil	500	N/A	N/A	0.38	1.50	N/A	Henry Hub
		250	N/A	N/A	0.38	1.50	N/A	Henry Hub

Appendix D - Results of Economic Analysis

In the sections below Government Takes for projects with no project profit, where the government take calculation was negative and where the government take calculation was over 100%, these figures have been represented as 100% Government Take. For models that produced no return their IRR figures have been represented as 0%. Also, depth assumptions between reserve size cases in a country may not correlate positively with the reserve size making results for a smaller case possibly better than one with greater reserves.

D.1 Government Take Results

D.1.1 Shallow Water Peer Group

Table D-1. Government take–shallow water

Jurisdiction	High case			Base case			Low case		
	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe
Crude Oil									
Australia	57%	54%	48%	55%	47%	30%	52%	83%	100%
Brazil	45%	49%	62%	47%	56%	100%	52%	99%	100%
Mexico	66%	69%	72%	64%	68%	80%	64%	86%	100%
Norway	78%	77%	72%	78%	76%	100%	77%	100%	100%
United Kingdom	39%	39%	38%	39%	38%	29%	37%	30%	100%
United States	33%	34%	41%	35%	38%	62%	41%	55%	100%
Natural Gas									
Australia	56%	51%	33%	52%	30%	100%	27%	100%	100%
Brazil	44%	58%	88%	47%	100%	100%	57%	100%	100%
Mexico	66%	93%	84%	67%	100%	100%	83%	100%	100%
Norway	78%	77%	73%	77%	71%	100%	76%	100%	100%
United Kingdom	39%	39%	39%	39%	37%	35%	38%	58%	100%
United States	39%	38%	41%	54%	50%	73%	100%	100%	100%

Source: IHS Markit

D.1.2 Deepwater Peer Group

Table D-2. Government take–deepwater

Jurisdiction	High case		Base case		Low case	
	500 MMboe	250 MMboe	500 MMboe	250 MMboe	500 MMboe	250 MMboe
Crude Oil						
Angola	71%	70%	64%	62%	100%	100%
Brazil	53%	50%	53%	58%	59%	89%
Canada	64%	72%	68%	66%	100%	95%
Guyana	53%	53%	54%	55%	60%	64%
Mexico	45%	48%	43%	49%	49%	100%
Norway	78%	78%	78%	78%	77%	77%
United Kingdom	37%	37%	31%	29%	100%	100%
United States	43%	42%	52%	50%	91%	100%
Natural Gas						
Angola	74%	74%	67%	68%	61%	62%
Brazil	50%	50%	51%	52%	59%	61%
Canada	32%	33%	35%	57%	100%	100%
Guyana	52%	52%	52%	52%	53%	53%
Mexico	44%	46%	44%	55%	100%	100%
Norway	78%	78%	78%	77%	77%	75%
United Kingdom	40%	39%	39%	39%	38%	37%
United States	46%	48%	62%	75%	100%	100%

Source: IHS Markit

D.2 Internal Rate of Return Results

D.2.1 Shallow Water Peer Group

Table D-3. Internal rate of return–shallow water

Jurisdiction	High case			Base case			Low case		
	100MMboe	30MMboe	10MMboe	100MMboe	30MMboe	10MMboe	100MMboe	30MMboe	10MMboe
Crude Oil									
Australia	39%	25%	19%	31%	16%	11%	22%	1%	0%
Brazil	43%	22%	12%	32%	13%	0%	21%	0%	0%
Mexico	39%	16%	12%	31%	10%	4%	22%	2%	0%
Norway	24%	12%	3%	17%	6%	0%	10%	0%	0%
United Kingdom	44%	29%	16%	33%	19%	5%	22%	8%	0%
United States	45%	38%	19%	34%	26%	6%	20%	10%	0%
Natural Gas									
Australia	29%	21%	14%	21%	13%	0%	11%	0%	0%
Brazil	32%	9%	2%	22%	0%	0%	11%	0%	0%
Mexico	19%	1%	2%	11%	0%	0%	2%	0%	0%
Norway	20%	8%	4%	13%	3%	0%	7%	0%	0%
United Kingdom	37%	23%	15%	28%	14%	7%	18%	2%	0%
United States	33%	27%	17%	16%	13%	3%	0%	0%	0%

Source: IHS Markit

D.2.2 Deepwater Peer Group

Table D-4. Internal rate of return–deepwater

Jurisdiction	High Case		Base Case		Low Case	
	500 MMboe	250 MMboe	500 MMboe	250 MMboe	500 MMboe	250 MMboe
Crude Oil						
Angola	36%	29%	25%	20%	0%	0%
Brazil	36%	32%	27%	20%	16%	3%
Canada	15%	16%	6%	10%	0%	0%
Guyana	43%	34%	32%	23%	18%	9%
Mexico	36%	23%	25%	12%	9%	0%
Norway	29%	23%	21%	15%	11%	7%
United Kingdom	38%	36%	22%	20%	0%	0%
United States	25%	25%	16%	16%	0%	0%
Natural Gas						
Angola	25%	23%	18%	16%	10%	8%
Brazil	39%	31%	29%	22%	17%	12%
Canada	11%	7%	5%	1%	0%	0%
Guyana	48%	38%	39%	30%	29%	21%
Mexico	16%	12%	7%	3%	0%	0%
Norway	21%	17%	15%	11%	8%	4%
United Kingdom	41%	32%	32%	24%	22%	14%
United States	26%	17%	11%	4%	0%	0%

Source: IHS Markit

*Note: The 500MMboe oil field in the U.S. has similar internal rate of return to the 250 MMboe oil field in the U.S. since the 500MMboe case is at 6,000 feet greater reservoir depth and has higher costs as a result.

D.3 Net Present Value per Barrel of Oil Equivalent Results

D.3.1 Shallow Water Peer Group

Table D-5. NPV/boe–shallow water

Jurisdiction	High case			Base case			Low case		
	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe
Crude Oil									
Australia	12.7	9.3	7.9	6.9	3.1	0.7	3.0	-2.8	-8.2
Brazil	17.7	11.7	2.2	9.0	2.0	-9.3	3.1	-4.9	-17.5
Mexico	18.4	7.7	3.1	9.6	-0.4	-5.0	3.8	-6.2	-14.7
Norway	4.8	1.4	-8.4	1.9	-1.9	-17.8	-0.1	-5.4	-31.6
United Kingdom	17.2	14.4	5.9	8.9	5.3	-4.0	3.3	-1.0	-14.0
United States	18.6	17.5	8.5	9.0	7.0	-2.3	2.6	-0.1	-10.6
Natural Gas									
Australia	7.5	6.3	3.3	3.2	1.5	-6.6	0.2	-4.6	-15.8
Brazil	9.8	-1.3	-6.8	4.1	-7.8	-14.8	0.3	-13.6	-21.9
Mexico	3.9	-8.0	-5.6	0.2	-13.4	-11.3	-2.0	-19.0	-15.6
Norway	3.1	-1.1	-5.9	0.9	-3.9	-12.2	-0.7	-9.3	-22.6
United Kingdom	12.3	8.7	5.1	6.2	2.1	-2.6	2.2	-2.8	-9.0
United States	5.9	6.9	3.6	1.0	1.1	-2.6	-2.8	-3.0	-7.9

Source: IHS Markit

D.3.2 Deepwater Peer Group

Table D-6. NPV/boe–deepwater

Jurisdiction	High Case		Base Case		Low Case	
	500 Mmboe	250 Mmboe	500 Mmboe	250 Mmboe	500 Mmboe	250 Mmboe
Crude Oil						
Angola	8.67	8.35	3.65	3.09	-1.84	-3.04
Brazil	13.1	10.8	6.3	3.5	1.6	-1.6
Canada	2.88	4.70	-1.83	0.24	-5.79	-3.22
Guyana	18.28	16.22	8.05	5.97	1.84	-0.15
Mexico	10.1	8.1	4.0	1.1	-0.2	-4.0
Norway	4.1	3.6	1.8	1.2	0.2	-0.5
United Kingdom	9.5	9.7	2.8	2.5	-2.8	-3.9
United States	9.0	10.8	2.5	2.8	-2.1	-2.8
Natural Gas						
Angola	5.44	5.22	2.23	1.87	-0.12	-0.58
Brazil	8.1	7.5	3.9	3.3	1.0	0.4
Canada	0.66	-1.55	-1.71	-4.23	-3.66	-6.95
Guyana	19.02	17.64	10.07	8.87	4.54	3.41
Mexico	2.6	0.8	-0.9	-2.7	-3.2	-5.8
Norway	2.3	1.9	0.8	0.2	-0.3	-1.1
United Kingdom	9.4	8.3	5.0	3.9	2.0	0.9
United States	3.7	2.3	0.1	-1.2	-2.6	-4.0

Source: IHS Markit

*Note, the 500MMboe oil field in the U.S. has lower NPP/boe than the 250 MMboe oil field in the U.S. since the 500MMboe case is at 6,000 feet greater reservoir depth and has higher costs as a result.

D.4 Expected Monetary Value Results

D.4.1 Shallow Water Peer Group

Table D-7. Expected monetary value–shallow water

Jurisdiction	High case			Base case			Low case		
	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe	100 MMboe	30 MMboe	10 MMboe
Crude Oil									
Australia	386.0	77.0	16.7	202.4	17.7	-4.9	80.5	-27.0	-25.9
Brazil	578.2	112.9	4.5	290.8	16.8	-27.1	98.2	-48.1	-49.5
Mexico	326.4	64.3	14.0	211.0	19.5	-1.8	97.0	-16.3	-18.9
Norway	166.3	6.3	-30.4	59.3	-29.4	-51.1	-11.7	-62.1	-76.3
United Kingdom	623.5	135.5	15.5	318.7	46.6	-15.2	115.5	-12.5	-42.0
United States	503.5	141.2	22.1	239.2	54.8	-7.8	65.4	-2.5	-28.9
Natural Gas									
Australia	217.2	46.5	1.3	83.5	2.8	-21.1	-4.3	-37.7	-42.9
Brazil	326.7	-15.7	-23.3	134.6	-77.5	-48.6	6.2	-126.7	-65.3
Mexico	95.6	-34.1	-6.3	18.1	-75.3	-18.8	-41.5	-109.2	-31.5
Norway	105.7	-20.8	-28.1	23.0	-47.7	-44.1	-33.8	-88.6	-70.5
United Kingdom	465.7	96.1	16.1	231.5	21.0	-12.2	74.2	-33.0	-33.9
United States	188.5	64.2	10.8	25.6	6.4	-9.9	-92.3	-33.8	-25.3

Source: IHS Markit

D.4.2 Deepwater Peer Group

Table D-8. Expected monetary value–deepwater

Jurisdiction	High Case		Base Case		Low Case	
	500 Mmboe	250 Mmboe	500 Mmboe	250 Mmboe	500 Mmboe	250 Mmboe
Crude Oil						
Angola	1036.6	472.2	513.0	201.0	-279.1	-202.1
Brazil	1246.9	846.5	622.6	266.1	155.0	-125.5
Canada	123.6	43.7	-330.5	-122.2	-776.6	-308.4
Guyana	3281.3	1502.0	1540.0	596.4	376.8	-20.3
Mexico	2136.0	652.6	899.8	112.1	-31.2	-305.6
Norway	704.6	305.1	295.9	92.0	23.1	-50.7
United Kingdom	1325.6	683.3	380.2	169.0	-383.7	-264.5
United States	1093.2	643.7	293.6	158.6	-247.5	-165.2
Natural Gas						
Angola	615.1	284.0	297.9	122.6	-24.3	-50.5
Brazil	938.0	429.2	450.6	186.9	113.6	19.4
Canada	-59.8	-247.0	-368.2	-417.1	-592.7	-555.5
Guyana	5166.2	2441.9	2890.8	1300.8	1350.4	529.8
Mexico	562.6	101.3	-179.1	-283.2	-724.7	-593.4
Norway	441.0	171.4	141.7	7.9	-62.7	-111.6
United Kingdom	1369.2	604.2	717.5	279.4	279.3	60.1
United States	491.4	151.3	12.6	-77.1	-327.9	-246.6

Source: IHS Markit

D.5 Discounted Share of the Barrel Metrics

D.5.1 Shallow Water Peer Group

Table D-9. Discounted share of barrel–shallow water, low case, oil

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Australia	Oil	10	-53%	4%	48%	101%
		30	-19%	8%	39%	72%
		100	23%	34%	15%	28%
Brazil	Oil	10	-96%	39%	26%	131%
		30	-29%	34%	20%	75%
		100	21%	37%	12%	30%
Mexico	Oil	10	-66%	26%	20%	121%
		30	-30%	27%	12%	91%
		100	18%	45%	6%	30%
Norway	Oil	10	-191%	1%	55%	235%
		30	-36%	9%	27%	100%
		100	-1%	40%	20%	41%
United Kingdom	Oil	10	-86%	1%	35%	150%
		30	-7%	7%	21%	78%
		100	24%	20%	15%	41%
United States	Oil	10	-70%	14%	27%	130%
		30	-1%	18%	17%	65%
		100	20%	21%	15%	44%

Source: IHS Markit

Table D-10. Discounted share of barrel–shallow water, base case, oil

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Australia	Oil	10	3%	11%	30%	56%
		30	12%	23%	23%	42%
		100	31%	44%	9%	16%
Brazil	Oil	10	-31%	37%	15%	79%
		30	7%	36%	13%	44%
		100	36%	39%	8%	18%
Mexico	Oil	10	-13%	31%	14%	68%
		30	-1%	39%	8%	54%
		100	25%	53%	4%	18%
Norway	Oil	10	-66%	1%	36%	129%
		30	-8%	32%	19%	56%
		100	9%	55%	13%	24%
United Kingdom	Oil	10	-15%	6%	23%	86%
		30	21%	19%	14%	46%
		100	39%	28%	9%	24%
United States	Oil	10	-9%	18%	18%	73%
		30	28%	23%	11%	38%
		100	40%	25%	10%	26%

Source: IHS Markit

Table D-11 Discounted share of barrel–shallow water, high case, oil

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Australia	Oil	10	19%	28%	20%	33%
		30	24%	36%	16%	25%
		100	35%	49%	6%	10%
Brazil	Oil	10	4%	37%	11%	47%
		30	27%	37%	9%	27%
		100	44%	40%	5%	11%
Mexico	Oil	10	4%	44%	10%	41%
		30	11%	50%	5%	33%
		100	27%	59%	3%	11%
Norway	Oil	10	-19%	18%	24%	77%
		30	4%	49%	13%	35%
		100	14%	63%	8%	15%
United Kingdom	Oil	10	14%	18%	16%	53%
		30	36%	27%	10%	28%
		100	47%	32%	6%	15%
United States	Oil	10	21%	23%	12%	44%
		30	44%	26%	8%	23%
		100	51%	27%	7%	16%

Source: IHS Markit

Table D-12. Discounted share of the barrel–shallow water, low case, gas

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Australia	Gas	10	-175%	2%	88%	185%
		30	-57%	1%	61%	96%
		100	3%	10%	39%	48%
Brazil	Gas	10	-183%	40%	44%	200%
		30	-130%	35%	38%	158%
		100	3%	32%	19%	45%
Mexico	Gas	10	-180%	15%	49%	216%
		30	-230%	14%	39%	277%
		100	-26%	16%	24%	86%
Norway	Gas	10	-180%	1%	66%	213%
		30	-86%	0%	59%	126%
		100	-7%	29%	28%	49%
United Kingdom	Gas	10	-73%	1%	36%	136%
		30	-25%	6%	31%	89%
		100	21%	20%	17%	42%
United States	Gas	10	-96%	14%	33%	148%
		30	-39%	13%	29%	97%
		100	-41%	13%	34%	94%

Source: IHS Markit

Table D-13. Discounted share of the barrel–shallow water, base case, gas

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Australia	Gas	10	-37%	6%	46%	85%
		30	10%	13%	33%	44%
		100	23%	33%	21%	23%
Brazil	Gas	10	-75%	35%	29%	112%
		30	-45%	30%	24%	91%
		100	26%	35%	12%	27%
Mexico	Gas	10	-76%	17%	29%	130%
		30	-96%	17%	27%	152%
		100	1%	32%	15%	51%
Norway	Gas	10	-59%	1%	41%	118%
		30	-22%	14%	37%	71%
		100	5%	48%	18%	29%
United Kingdom	Gas	10	-13%	9%	22%	81%
		30	12%	17%	19%	52%
		100	37%	27%	11%	25%
United States	Gas	10	-18%	16%	21%	81%
		30	8%	19%	18%	55%
		100	8%	18%	21%	53%

Source: IHS Markit

Table D-14. Discounted share of the barrel–shallow water, high case, gas

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Australia	Oil	10	11%	15%	28%	47%
		30	23%	33%	19%	25%
		100	31%	43%	13%	13%
Brazil	Oil	10	-22%	34%	18%	70%
		30	-5%	33%	16%	56%
		100	38%	37%	8%	17%
Mexico	Oil	10	-22%	25%	20%	77%
		30	-34%	24%	17%	93%
		100	14%	44%	9%	32%
Norway	Oil	10	-18%	21%	27%	70%
		30	-4%	37%	25%	43%
		100	12%	59%	11%	18%
United Kingdom	Oil	10	16%	20%	15%	49%
		30	30%	25%	13%	32%
		100	46%	32%	7%	16%
United States	Oil	10	16%	21%	14%	48%
		30	32%	23%	11%	33%
		100	32%	23%	13%	32%

Source: IHS Markit

D.5.2 Deepwater Peer Group

Table D-15. Discounted share of barrel–deepwater, low case, oil

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Angola	Oil	250	-16%	28%	19%	69%
		500	-10%	29%	20%	62%
Brazil	Oil	250	-12%	35%	16%	61%
		500	8%	42%	12%	38%
Canada	Oil	250	-28%	15%	18%	95%
		500	-60%	4%	24%	133%
Guyana	Oil	250	-1%	20%	19%	62%
		500	12%	24%	17%	47%
Mexico	Oil	250	-33%	8%	20%	106%
		500	-2%	13%	16%	73%
Norway	Oil	250	-4%	28%	28%	48%
		500	2%	38%	22%	38%
United Kingdom	Oil	250	-33%	0%	27%	106%
		500	-25%	0%	24%	101%
United States	Oil	250	-23%	20%	15%	88%
		500	-21%	20%	13%	88%

Source: IHS Markit

Table D-16. Discounted share of barrel–deepwater, base case, oil

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Angola	Oil	250	10%	37%	13%	40%
		500	12%	39%	13%	37%
Brazil	Oil	250	16%	38%	10%	36%
		500	19%	51%	8%	22%
Canada	Oil	250	1%	31%	11%	56%
		500	-11%	19%	16%	76%
Guyana	Oil	250	20%	31%	12%	37%
		500	27%	34%	10%	28%
Mexico	Oil	250	5%	19%	13%	62%
		500	23%	24%	10%	44%
Norway	Oil	250	6%	48%	18%	28%
		500	10%	54%	14%	22%
United Kingdom	Oil	250	13%	9%	17%	62%
		500	15%	10%	15%	60%
United States	Oil	250	13%	26%	10%	51%
		500	15%	27%	9%	49%

Source: IHS Markit

Table D-17. Discounted share of barrel–deepwater, high case, oil

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Angola	Oil	250	14%	53%	9%	25%
		500	14%	55%	8%	23%
Brazil	Oil	250	31%	40%	7%	22%
		500	24%	57%	5%	14%
Canada	Oil	250	10%	48%	7%	35%
		500	9%	34%	10%	48%
Guyana	Oil	250	31%	38%	8%	23%
		500	35%	40%	7%	17%
Mexico	Oil	250	23%	30%	8%	39%
		500	34%	32%	7%	27%
Norway	Oil	250	12%	59%	11%	17%
		500	14%	62%	9%	14%
United Kingdom	Oil	250	31%	20%	11%	38%
		500	32%	21%	10%	37%
United States	Oil	250	33%	30%	6%	31%
		500	34%	30%	6%	31%

Source: IHS Markit

Table D-18. Discounted share of barrel–deepwater, low case, gas

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Angola	Gas	250	-5%	28%	27%	50%
		500	-1%	30%	23%	48%
Brazil	Gas	250	3%	37%	21%	38%
		500	9%	39%	23%	29%
Canada	Gas	250	-186%	0%	39%	246%
		500	-106%	1%	30%	175%
Guyana	Gas	250	23%	33%	15%	29%
		500	29%	36%	11%	23%
Mexico	Gas	250	-104%	0%	39%	165%
		500	-60%	0%	30%	130%
Norway	Gas	250	-14%	19%	38%	57%
		500	-4%	29%	30%	45%
United Kingdom	Gas	250	12%	15%	28%	45%
		500	26%	21%	20%	33%
United States	Gas	250	-82%	19%	35%	129%
		500	-53%	19%	27%	107%

Source: IHS Markit

Table D-19. Discounted share of barrel–deepwater, base case, gas

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Angola	Gas	250	9%	45%	17%	30%
		500	11%	46%	14%	29%
Brazil	Gas	250	17%	47%	13%	23%
		500	21%	48%	14%	17%
Canada	Gas	250	-71%	4%	25%	141%
		500	-31%	10%	20%	101%
Guyana	Gas	250	34%	40%	9%	17%
		500	38%	42%	7%	13%
Mexico	Gas	250	-29%	10%	26%	93%
		500	-10%	14%	18%	78%
Norway	Gas	250	2%	41%	24%	34%
		500	7%	48%	19%	26%
United Kingdom	Gas	250	32%	24%	18%	27%
		500	40%	28%	13%	19%
United States	Gas	250	-14%	21%	20%	73%
		500	1%	22%	16%	61%

Source: IHS Markit

Table D-20. Discounted share of barrel–deepwater, high case, gas

Country	Primary product	Reserve size (MMboe)	Company cash flow	Government cash flow	Opex	Capex
Angola	Gas	250	13%	58%	10%	19%
		500	14%	59%	9%	18%
Brazil	Gas	250	25%	53%	8%	14%
		500	27%	54%	9%	11%
Canada	Gas	250	-16%	13%	16%	88%
		500	8%	17%	12%	63%
Guyana	Gas	250	40%	44%	6%	11%
		500	42%	45%	5%	8%
Mexico	Gas	250	5%	21%	17%	58%
		500	16%	24%	12%	48%
Norway	Gas	250	9%	54%	15%	21%
		500	13%	59%	12%	16%
United Kingdom	Gas	250	43%	30%	11%	17%
		500	48%	32%	8%	12%
United States	Gas	250	18%	26%	14%	42%
		500	26%	28%	12%	34%

Source: IHS Markit

D.6 Fiscal System Alternatives

D.6.1 Shallow Water

Table D-21. Alternative fiscal systems–shallow water, base case, oil, 100 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	100	202	6.9	31%	55%
Brazil	Oil	100	291	9.0	32%	47%
Mexico	Oil	100	211	9.6	31%	64%
Norway	Oil	100	59	1.9	17%	78%
United Kingdom	Oil	100	319	8.9	33%	39%
United States	Oil	100	239	9.0	34%	35%
U.S. SW Sliding Scale	Oil	100	220	8.8	33%	39%
U.S. SW Categorical Relief	Oil	100	292	9.8	37%	23%

Source: IHS Markit

Table D-22. Alternative fiscal systems–shallow water, base case, oil, 30 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	30	18	3.1	16%	47%
Brazil	Oil	30	17	2.0	13%	56%
Mexico	Oil	30	20	-0.4	10%	68%
Norway	Oil	30	-29	-1.9	6%	76%
United Kingdom	Oil	30	47	5.3	19%	38%
United States	Oil	30	55	7.0	26%	38%
U.S. SW Sliding Scale	Oil	30	49	6.5	25%	43%
U.S. SW Categorical Relief	Oil	30	75	8.3	29%	21%

Source: IHS Markit

Table D-23. Alternative fiscal systems–shallow water, base case, oil, 10 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	10	-5	0.7	11%	30%
Brazil	Oil	10	-27	-9.3	0%	100%
Mexico	Oil	10	-2	-5.0	4%	80%
Norway	Oil	10	-51	-17.8	0%	100%
United Kingdom	Oil	10	-15	-4.0	5%	29%
United States	Oil	10	-8	-2.3	6%	62%
U.S. SW Sliding Scale	Oil	10	-10	-3.1	5%	73%
U.S. SW Categorical Relief	Oil	10	-1	0.2	10%	25%

Source: IHS Markit

Table D-24. Alternative fiscal systems–shallow water, low case, oil, 100 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	100	80	3.0	22%	52%
Brazil	Oil	100	98	3.1	21%	52%
Mexico	Oil	100	97	3.8	22%	64%
Norway	Oil	100	-12	-0.1	10%	77%
United Kingdom	Oil	100	116	3.3	22%	37%
United States	Oil	100	65	2.6	20%	41%
U.S. SW Sliding Scale	Oil	100	65	2.6	20%	41%
U.S. SW Categorical Relief	Oil	100	97	3.4	23%	24%

Source: IHS Markit

Table D-25. Alternative fiscal systems–shallow water, low case, oil, 30 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	30	-27	-2.8	1%	83%
Brazil	Oil	30	-48	-4.9	0%	99%
Mexico	Oil	30	-16	-6.2	2%	86%
Norway	Oil	30	-62	-5.4	0%	100%
United Kingdom	Oil	30	-13	-1.0	8%	30%
United States	Oil	30	-3	-0.1	10%	55%
U.S. SW Sliding Scale	Oil	30	-3	-0.1	10%	55%
U.S. SW Categorical Relief	Oil	30	9	1.2	14%	24%

Source: IHS Markit

Table D-26. Alternative fiscal systems–shallow water, low case, oil, 10 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	10	-26	-8.2	0%	100%
Brazil	Oil	10	-50	-17.5	0%	100%
Mexico	Oil	10	-19	-14.7	0%	100%
Norway	Oil	10	-76	-31.6	0%	100%
United Kingdom	Oil	10	-42	-14.0	0%	100%
United States	Oil	10	-29	-10.6	0%	100%
U.S. SW Sliding Scale	Oil	10	-29	-10.6	0%	100%
U.S. SW Categorical Relief	Oil	10	-25	-7.8	0%	100%

Source: IHS Markit

Table D-27. Alternative fiscal systems–shallow water, high case, oil, 100 MMboe reserve size

Royalty case	Primary product	Reserve size MMboe	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	100	386	12.7	39%	57%
Brazil	Oil	100	578	17.7	43%	45%
Mexico	Oil	100	326	18.4	39%	66%
Norway	Oil	100	166	4.8	24%	78%
United Kingdom	Oil	100	624	17.2	44%	39%
United States	Oil	100	503	18.6	45%	33%
U.S. SW Sliding Scale	Oil	100	439	17.6	43%	41%
U.S. SW Categorical Relief	Oil	100	503	18.6	45%	33%

Source: IHS Markit

Table D-28. Alternative fiscal systems–shallow water, high case, oil, 30 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	30	77	9.3	25%	54%
Brazil	Oil	30	113	11.7	22%	49%
Mexico	Oil	30	64	7.7	16%	69%
Norway	Oil	30	6	1.4	12%	77%
United Kingdom	Oil	30	135	14.4	29%	39%
United States	Oil	30	141	17.5	38%	34%
U.S. SW Sliding Scale	Oil	30	122	16.3	36%	43%
U.S. SW Categorical Relief	Oil	30	141	17.5	38%	34%

Source: IHS Markit

Table D-29. Alternative fiscal systems–shallow water, high case, oil, 10 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Oil	10	17	7.9	19%	48%
Brazil	Oil	10	4	2.2	12%	62%
Mexico	Oil	10	14	3.1	12%	72%
Norway	Oil	10	-30	-8.4	3%	72%
United Kingdom	Oil	10	16	5.9	16%	38%
United States	Oil	10	22	8.5	19%	41%
U.S. SW Sliding Scale	Oil	10	15	6.7	17%	51%
U.S. SW Categorical Relief	Oil	10	22	8.5	19%	41%

Source: IHS Markit

Table D -30. Alternative fiscal systems–shallow water, base case, gas, 100 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	100	84	3.2	21%	52%
Brazil	Gas	100	135	4.1	22%	47%
Mexico	Gas	100	18	0.2	11%	67%
Norway	Gas	100	23	0.9	13%	77%
United Kingdom	Gas	100	232	6.2	28%	39%
United States	Gas	100	26	1.0	16%	54%
U.S. SW Sliding Scale	Gas	100	20	0.8	15%	59%
U.S. SW Categorical Relief	Gas	100	54	1.7	20%	32%

Source: IHS Markit

Table D -31. Alternative fiscal systems–shallow water, base case, gas 30 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	30	3	1.5	13%	30%
Brazil	Gas	30	-77	-7.8	0%	100%
Mexico	Gas	30	-75	-13.4	0%	100%
Norway	Gas	30	-48	-3.9	3%	71%
United Kingdom	Gas	30	21	2.1	14%	37%
United States	Gas	30	6	1.1	13%	50%
U.S. SW Sliding Scale	Gas	30	5	0.9	12%	54%
U.S. SW Categorical Relief	Gas	30	18	2.0	17%	26%

Source: IHS Markit

Table D-32. Alternative fiscal systems–shallow water, base case, gas, 10 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	10	-21	-6.6	0%	100%
Brazil	Gas	10	-49	-14.8	0%	100%
Mexico	Gas	10	-19	-11.3	0%	100%
Norway	Gas	10	-44	-12.2	0%	100%
United Kingdom	Gas	10	-12	-2.6	7%	35%
United States	Gas	10	-10	-2.6	3%	73%
U.S. SW Sliding Scale	Gas	10	-11	-2.8	2%	80%
U.S. SW Categorical Relief	Gas	10	-5	-1.0	7%	25%

Source: IHS Markit

Table D-33. Alternative fiscal systems–shallow water, low case, gas, 100 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	100	-4	0.2	11%	27%
Brazil	Gas	100	6	0.3	11%	57%
Mexico	Gas	100	-41	-2.0	2%	83%
Norway	Gas	100	-34	-0.7	7%	76%
United Kingdom	Gas	100	74	2.2	18%	38%
United States	Gas	100	-92	-2.8	0%	100%
U.S. SW Sliding Scale	Gas	100	-92	-2.8	0%	100%
U.S. SW Categorical Relief	Gas	100	-72	-1.9	0%	100%

Source: IHS Markit

Table D-34. Alternative fiscal systems–shallow water, low case, gas, 30 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	30	-38	-4.6	0%	100%
Brazil	Gas	30	-127	-13.6	0%	100%
Mexico	Gas	30	-109	-19.0	0%	100%
Norway	Gas	30	-89	-9.3	0%	100%
United Kingdom	Gas	30	-33	-2.8	2%	58%
United States	Gas	30	-34	-3.0	0%	100%
U.S. SW Sliding Scale	Gas	30	-34	-3.0	0%	100%
U.S. SW Categorical Relief	Gas	30	-26	-2.0	0%	100%

Source: IHS Markit

Table D-35. Alternative fiscal systems–shallow water, low case, gas, 10 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	10	-43	-15.8	0%	100%
Brazil	Gas	10	-65	-21.9	0%	100%
Mexico	Gas	10	-32	-15.6	0%	100%
Norway	Gas	10	-70	-22.6	0%	100%
United Kingdom	Gas	10	-34	-9.0	0%	100%
United States	Gas	10	-25	-7.9	0%	100%
U.S. SW Sliding Scale	Gas	10	-25	-7.9	0%	100%
U.S. SW Categorical Relief	Gas	10	-22	-6.0	0%	100%

Source: IHS Markit

Table D-36. Alternative fiscal systems–shallow water, high case, gas, 100 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	100	217	7.5	29%	56%
Brazil	Gas	100	327	9.8	32%	44%
Mexico	Gas	100	96	3.9	19%	66%
Norway	Gas	100	106	3.1	20%	78%
United Kingdom	Gas	100	466	12.3	37%	39%
United States	Gas	100	189	5.9	33%	39%
U.S. SW Sliding Scale	Gas	100	169	5.5	32%	44%
U.S. SW Categorical Relief	Gas	100	189	5.9	33%	39%

Source: IHS Markit

Table D-37. Alternative fiscal systems–shallow water, high case, gas, 30 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	30	47	6.3	21%	51%
Brazil	Gas	30	-16	-1.3	9%	58%
Mexico	Gas	30	-34	-8.0	1%	93%
Norway	Gas	30	-21	-1.1	8%	77%
United Kingdom	Gas	30	96	8.7	23%	39%
United States	Gas	30	64	6.9	27%	38%
U.S. SW Sliding Scale	Gas	30	58	6.4	26%	43%
U.S. SW Categorical Relief	Gas	30	64	6.9	27%	38%

Source: IHS Markit

Table D-38. Alternative fiscal systems–shallow water, high case, gas, 10 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Australia	Gas	10	1	3.3	14%	33%
Brazil	Gas	10	-23	-6.8	2%	88%
Mexico	Gas	10	-6	-5.6	2%	84%
Norway	Gas	10	-28	-5.9	4%	73%
United Kingdom	Gas	10	16	5.1	15%	39%
United States	Gas	10	11	3.6	17%	41%
U.S. SW Sliding Scale	Gas	10	8	3.0	15%	47%
U.S. SW Categorical Relief	Gas	10	11	3.6	17%	41%

Source: IHS Markit

D.6.2 Deepwater

Table D-39. Alternative fiscal systems–deepwater, base case, oil, 500 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Oil	500	513	3.6	25%	64%
Brazil	Oil	500	623	6.3	27%	53%
Canada	Oil	500	-331	-1.8	6%	68%
Guyana	Oil	500	1540	8.1	32%	54%
Mexico	Oil	500	900	4.0	25%	43%
Norway	Oil	500	296	1.8	21%	78%
United Kingdom	Oil	500	380	2.8	22%	31%
United States	Oil	500	294	2.5	16%	52%
U.S. DW 12.5%	Oil	500	394	3.0	17%	42%
U.S. DW 20%	Oil	500	274	2.3	16%	53%
U.S. DW 22.5%	Oil	500	234	2.1	15%	57%
U.S. DW Sliding Scale	Oil	500	331	2.7	16%	48%
U.S. DW Categorical Relief	Oil	500	455	3.4	18%	40%

Source: IHS Markit

*Note, the 500MMboe oil field in the U.S. has similar internal rate of return to the 250 MMboe oil field in the U.S. since the 500MMboe case is at 6,000 feet greater reservoir depth and has higher costs as a result.

Table D-40. Alternative fiscal systems–deepwater, base case, oil, 250 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Oil	250	201	3.1	20%	62%
Brazil	Oil	250	266	3.5	20%	58%
Canada	Oil	250	-122	0.2	10%	66%
Guyana	Oil	250	596	6.0	23%	55%
Mexico	Oil	250	112	1.1	12%	49%
Norway	Oil	250	92	1.2	15%	78%
United Kingdom	Oil	250	169	2.5	20%	29%
United States	Oil	250	159	2.8	16%	50%
U.S. DW 12.5%	Oil	250	221	3.5	17%	40%
U.S. DW 20%	Oil	250	147	2.6	15%	52%
U.S. DW 22.5%	Oil	250	120	2.2	14%	55%
U.S. DW Sliding Scale	Oil	250	181	3.0	16%	46%
U.S. DW Categorical Relief	Oil	250	296	4.4	19%	30%

Source: IHS Markit

Table D-41. Alternative fiscal systems–deepwater, low case, oil, 500 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Oil	500	-279	-1.8	0%	100%
Brazil	Oil	500	155	1.6	16%	59%
Canada	Oil	500	-777	-5.8	0%	100%
Guyana	Oil	500	377	1.8	18%	60%
Mexico	Oil	500	-31	-0.2	9%	49%
Norway	Oil	500	23	0.2	11%	77%
United Kingdom	Oil	500	-384	-2.8	0%	100%
United States	Oil	500	-248	-2.1	0%	91%
U.S. DW 12.5%	Oil	500	-189	-1.5	4%	67%
U.S. DW 20%	Oil	500	-259	-2.3	0%	95%
U.S. DW 22.5%	Oil	500	-283	-2.6	0%	100%
U.S. DW Sliding Scale	Oil	500	-190	-1.5	4%	67%
U.S. DW Categorical Relief	Oil	500	-151	-1.2	5%	60%

Source: IHS Markit

Table D-42. Alternative fiscal systems–deepwater, low case, oil, 250 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Oil	250	-202	-3.0	0%	100%
Brazil	Oil	250	-125	-1.6	3%	89%
Canada	Oil	250	-308	-3.2	0%	95%
Guyana	Oil	250	-20	-0.1	9%	64%
Mexico	Oil	250	-306	-4.0	0%	100%
Norway	Oil	250	-51	-0.5	7%	77%
United Kingdom	Oil	250	-264	-3.9	0%	100%
United States	Oil	250	-165	-2.8	0%	100%
U.S. DW 12.5%	Oil	250	-130	-2.0	3%	75%
U.S. DW 20%	Oil	250	-172	-2.9	0%	100%
U.S. DW 22.5%	Oil	250	-186	-3.3	0%	100%
U.S. DW Sliding Scale	Oil	250	-130	-2.1	3%	75%
U.S. DW Categorical Relief	Oil	250	-84	-1.2	6%	46%

Source: IHS Markit

Table D-43. Alternative fiscal systems–deepwater, high case, oil, 500 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Governmen t take
Angola	Oil	500	1,037	8.7	36%	71%
Brazil	Oil	500	1,247	13.1	36%	53%
Canada	Oil	500	124	2.9	15%	64%
Guyana	Oil	500	3,281	18.3	43%	53%
Mexico	Oil	500	2,136	10.1	36%	45%
Norway	Oil	500	705	4.1	29%	78%
United Kingdom	Oil	500	1,326	9.5	38%	37%
United States	Oil	500	1,093	9.0	25%	43%
U.S. DW 12.5%	Oil	500	1,254	9.6	26%	36%
U.S. DW 20%	Oil	500	1,061	8.9	24%	44%
U.S. DW 22.5%	Oil	500	996	8.6	24%	47%
U.S. DW Sliding Scale	Oil	500	1,027	8.7	24%	46%
U.S. DW Categorical Relief	Oil	500	1,093	9.0	25%	43%

Source: IHS Markit

*Note, the high price case has prices above the price threshold for royalty relief making this identical to the United States results for the standard terms.

Table D-44. Alternative fiscal systems–deepwater, high case, oil, 250 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Oil	250	472	8.4	29%	70%
Brazil	Oil	250	847	10.8	32%	50%
Canada	Oil	250	44	4.7	16%	72%
Guyana	Oil	250	1502	16.2	34%	53%
Mexico	Oil	250	653	8.1	23%	48%
Norway	Oil	250	305	3.6	23%	78%
United Kingdom	Oil	250	683	9.7	36%	37%
United States	Oil	250	644	10.8	25%	42%
U.S. DW 12.5%	Oil	250	741	11.6	26%	35%
U.S. DW 20%	Oil	250	624	10.7	25%	44%
U.S. DW 22.5%	Oil	250	585	10.3	24%	47%
U.S. DW Sliding Scale	Oil	250	603	10.4	24%	45%
U.S. DW Categorical Relief	Oil	250	644	10.8	25%	42%

Source: IHS Markit

Table D-45. Alternative fiscal systems–deepwater, base case, gas, 500 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Gas	500	298	2.2	18%	67%
Brazil	Gas	500	451	3.9	29%	51%
Canada	Gas	500	-368	-1.7	5%	35%
Guyana	Gas	500	2891	10.1	39%	52%
Mexico	Gas	500	-179	-0.9	7%	44%
Norway	Gas	500	142	0.8	15%	78%
United Kingdom	Gas	500	718	5.0	32%	39%
United States	Gas	500	13	0.1	11%	62%
U.S. DW 12.5%	Gas	500	67	0.5	13%	48%
U.S. DW 20%	Gas	500	2	0.0	10%	65%
U.S. DW 22.5%	Gas	500	-20	-0.2	9%	70%
U.S. DW Sliding Scale	Gas	500	58	0.4	13%	50%
U.S. DW Categorical Relief	Gas	500	96	0.7	15%	46%

Source: IHS Markit

Table D-46. Alternative fiscal systems–deepwater, base case, gas, 250 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Gas	250	123	1.9	16%	68%
Brazil	Gas	250	187	3.3	22%	52%
Canada	Gas	250	-417	-4.2	1%	57%
Guyana	Gas	250	1301	8.9	30%	52%
Mexico	Gas	250	-283	-2.7	3%	55%
Norway	Gas	250	8	0.2	11%	77%
United Kingdom	Gas	250	279	3.9	24%	39%
United States	Gas	250	-77	-1.2	4%	75%
U.S. DW 12.5%	Gas	250	-48	-0.6	7%	57%
U.S. DW 20%	Gas	250	-82	-1.3	4%	78%
U.S. DW 22.5%	Gas	250	-93	-1.5	3%	85%
U.S. DW Sliding Scale	Gas	250	-52	-0.7	6%	60%
U.S. DW Categorical Relief	Gas	250	-17	-0.2	9%	39%

Source: IHS Markit

Table D-47. Alternative fiscal systems–deepwater, low case, gas, 500 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Governmen t take
Angola	Gas	500	-24	-0.1	10%	61%
Brazil	Gas	500	114	1.0	17%	59%
Canada	Gas	500	-593	-3.7	0%	100%
Guyana	Gas	500	1350	4.5	29%	53%
Mexico	Gas	500	-725	-3.2	0%	100%
Norway	Gas	500	-63	-0.3	8%	77%
United Kingdom	Gas	500	279	2.0	22%	38%
United States	Gas	500	-328	-2.6	0%	100%
U.S. DW 12.5%	Gas	500	-289	-2.2	0%	100%
U.S. DW 20%	Gas	500	-336	-2.8	0%	100%
U.S. DW 22.5%	Gas	500	-351	-3.0	0%	100%
U.S. DW Sliding Scale	Gas	500	-290	-2.2	0%	100%
U.S. DW Categorical Relief	Gas	500	-269	-2.0	0%	100%

Source: IHS Markit

Table D-48. Alternative fiscal systems–deepwater, low case, gas, 250 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Gas	250	-50	-0.6	8%	62%
Brazil	Gas	250	19	0.4	12%	61%
Canada	Gas	250	-556	-6.9	0%	100%
Guyana	Gas	250	530	3.4	21%	53%
Mexico	Gas	250	-593	-5.8	0%	100%
Norway	Gas	250	-112	-1.1	4%	75%
United Kingdom	Gas	250	60	0.9	14%	37%
United States	Gas	250	-247	-4.0	0%	100%
U.S. DW 12.5%	Gas	250	-228	-3.4	0%	100%
U.S. DW 20%	Gas	250	-250	-4.1	0%	100%
U.S. DW 22.5%	Gas	250	-259	-4.5	0%	100%
U.S. DW Sliding Scale	Gas	250	-228	-3.4	0%	100%
U.S. DW Categorical Relief	Gas	250	-204	-2.8	0%	100%

Source: IHS Markit

Table D-49. Alternative fiscal systems–deepwater, high case, gas, 500 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Gas	500	615	5.4	25%	74%
Brazil	Gas	500	938	8.1	39%	50%
Canada	Gas	500	-60	0.7	11%	32%
Guyana	Gas	500	5,166	19.0	48%	52%
Mexico	Gas	500	563	2.6	16%	44%
Norway	Gas	500	441	2.3	21%	78%
United Kingdom	Gas	500	1,369	9.4	41%	40%
United States	Gas	500	491	3.7	26%	46%
U.S. DW 12.5%	Gas	500	583	4.0	28%	38%
U.S. DW 20%	Gas	500	473	3.6	26%	48%
U.S. DW 22.5%	Gas	500	436	3.4	25%	51%
U.S. DW Sliding Scale	Gas	500	552	3.9	28%	40%
U.S. DW Categorical Relief	Gas	500	491	3.7	26%	46%

Source: IHS Markit

Table D-50. Alternative fiscal systems–deepwater, high case, gas, 250 MMboe reserve size

Royalty case	Primary product	Reserve size (MMboe)	Expected monetary value (EMV)	NPV/boe ($/boe)	IRR	Government take
Angola	Gas	250	284	5.2	23%	74%
Brazil	Gas	250	429	7.5	31%	50%
Canada	Gas	250	-247	-1.6	7%	33%
Guyana	Gas	250	2442	17.6	38%	52%
Mexico	Gas	250	101	0.8	12%	46%
Norway	Gas	250	171	1.9	17%	78%
United Kingdom	Gas	250	604	8.3	32%	39%
United States	Gas	250	151	2.3	17%	48%
U.S. DW 12.5%	Gas	250	195	2.8	19%	39%
U.S. DW 20%	Gas	250	143	2.2	17%	50%
U.S. DW 22.5%	Gas	250	125	2.0	16%	53%
U.S. DW Sliding Scale	Gas	250	180	2.6	19%	42%
U.S. DW Categorical Relief	Gas	250	151	2.3	17%	48%

Source: IHS Markit

D.6.3 Discounted Share of the Barrel–Shallow water

Table D-51. Fiscal System Alternatives: Discounted Share of a Barrel–Shallow Water Oil Field – base case

Country	Reserve Size (MMboe)	Field Type	Fiscal Case	Company Cashflow	Government Cashflow	Opex	Capex
United States	10	Oil	U.S. SW Standard Terms	-9%	18%	18%	73%
			U.S. SW Categorical Relief	1%	8%	18%	73%
			U.S. SW Sliding Scale	-12%	21%	18%	73%
United States	30	Oil	U.S. SW Standard Terms	28%	23%	11%	38%
			U.S. SW Categorical Relief	38%	13%	11%	38%
			U.S. SW Sliding Scale	25%	26%	11%	38%

Source: IHS Markit

Table D-52. Fiscal System Alternatives: Discounted Share of a Barrel–Shallow Water Gas Field – base case

Country	Reserve Size (MMboe)	*Field Type*	*Fiscal Case*	Company cashflow	Government cashflow	Opex	Capex
United States	10	Gas	U.S. SW Standard Terms	-18%	16%	21%	81%
			U.S. SW Categorical Relief	-8%	6%	21%	81%
			U.S. SW Sliding Scale	-20%	17%	21%	81%
United States	30	*Gas*	U.S. SW Standard Terms	8%	19%	18%	55%
			U.S. SW Categorical Relief	17%	10%	18%	55%
			U.S. SW Sliding Scale	7%	20%	18%	55%

Source: IHS Markit

D.6.4 Discounted Share of the Barrel–deepwater

Table D-53. Fiscal Sensitivities Discounted Share of a Barrel–Deepwater Oil Field – base case

Country	Reserve Size (MMboe)	Field Type	Fiscal Case	Company cashflow	Government cashflow	Opex	Capex
United States	250	Oil	U.S. DW Standard Terms	13%	26%	10%	51%
			U.S. DW 12.5%	19%	21%	10%	50%
			U.S. DW 20%	12%	27%	10%	51%
			U.S. DW 22.5%	10%	29%	9%	51%
			U.S. DW Categorical Relief	25%	15%	10%	51%
			U.S. DW Sliding Scale	15%	25%	10%	51%
United States	500	Oil	U.S. DW Standard Terms	15%	27%	9%	49%
			U.S. DW 12.5%	20%	22%	9%	49%
			U.S. DW 20%	14%	28%	9%	49%
			U.S. DW 22.5%	12%	30%	9%	49%
			U.S. DW Categorical Relief	23%	19%	9%	49%
			U.S. DW Sliding Scale	17%	25%	9%	49%

Source: IHS Markit

Table D-54. Fiscal Sensitivities Discounted Share of a Barrel–Deepwater Gas Field – base case

Country	Reserve Size (MMboe)	Field Type	Fiscal Case	Company cashflow	Government cashflow	Opex	Capex
United States	250	Gas	U.S. DW Standard Terms	-14%	21%	20%	73%
			U.S. DW 12.5%	-8%	16%	21%	71%
			U.S. DW 20%	-15%	22%	20%	73%
			U.S. DW 22.5%	-17%	24%	20%	73%
			U.S. DW Categorical Relief	-2%	9%	20%	73%
			U.S. DW Sliding Scale	-9%	17%	21%	71%
United States	500	Gas	U.S. DW Standard Terms	1%	22%	16%	61%
			U.S. DW 12.5%	6%	17%	16%	61%
			U.S. DW 20%	0%	23%	16%	61%
			U.S. DW 22.5%	-2%	25%	16%	61%
			U.S. DW Categorical Relief	9%	15%	16%	61%
			U.S. DW Sliding Scale	5%	18%	16%	61%

Source: IHS Markit

D.6.5 Discretionary Reliefs: End-of-Life and Special Case

End of Life Royalty Relief

Table D-55. Shallow Water End-of-life Royalty Relief Effect on Original Production Profile.

Primary Production	Reserve size (MMboe)	Production life (Years)	Stranded reserves (MMboe)	Asset life increase (Years)	Production increase (MMboe)
High Case					
Oil	10	8	0.3	0	0
	30	7	0.1	0	0
	100	9	1.2	0	0
Gas	10	8	0.6	0	0
	30	7	0.1	0	0
	100	12	3.8	0	0
Base Case					
Oil	10	7	0.7	0	0
	30	6	0.3	0	0
	100	8	2.2	0	0
Gas	10	8	0.6	0	0
	30	6	0.3	0	0
	100	11	5.6	0	0
Low Case					
Oil	10	6	1.5	0	0
	30	5	0.7	0	0
	100	7	4.2	0	0
Gas	10	7	1.6	0	0
	30	5	0.8	0	0
	100	10	8.2	0	0

Source: IHS Markit

Table D-56. Deepwater End-of-life Royalty Relief Effect on Original Production Profile

Primary Production	Reserve size (MMboe)	Production life (Years)	Stranded reserves (MMboe)	Asset life increase (Years)	Production increase (MMboe)
High case					
Oil	250	13	2.8	0	0
	500	19	0.0	0	0
Gas	250	19	4.5	0	0
	500	19	6.8	0	0
Base case					
Oil	250	12	4.7	0	0
	500	19	2.2	0	0
Gas	250	13	21.5	0	0
	500	13	32.4	0	0
Low case					
Oil	250	10	11.9	0	0
	500	13	31.2	0	0
Gas	250	13	26.9	0	0

Source: IHS Markit

Special Case Royalty Relief

Table D-57. Shallow water base case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	30	3	0.7	9.3	6.69%
	100	2	1.6	8.6	7.23%
Gas	100	3	4	9.2	8.14%

Source: IHS Markit © 2018 IHS Markit

Table D-58. Shallow water high case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	30	3	0.7	7.7	6.77%
	100	2	0.9	8.5	6.85%
Gas	100	3	2.8	9.3	7.70%

Source: IHS Markit © 2018 IHS Markit

Table D-59. Shallow water low case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
OIl	30	N/A	N/A	0	N/A
	100	1	1.9	7.3	7.54%
Gas	100	N/A	N/A	0	N/A

Source: IHS Markit © 2018 IHS Markit

Table D-60. Deepwater base case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	250	5	4.7	39.4	10.37%
	500	5	2.2	37.2	9.90%

Source: IHS Markit © 2018 IHS Markit

Table D-61. Deepwater high case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	250	6	2.7	40.3	9.96%
	500	6	0	40.4	9.38%

Source: IHS Markit

Table D-62. Deepwater low case: Additional reserves special case

Primary production	Baseline reserve size (MMboe)	Asset life increase (Years)	Baseline production increase (MMboe)	Incremental production (MMboe)	Combined royalty rate (baseline and additional reserves)
Oil	250	3	8.7	35.2	11.23%
	500	4	25.7	37.9	13.16%

Source: IHS Markit

Appendix E - Yet-to-Find Methodology

For this study, IHS Markit calculated yet-to-find volumes of oil and gas in the Study core jurisdictions. Such volumes yet to be found are usually calculated for main basins or well-known plays but the objective of this analysis is to give an approximation of the undiscovered and undeveloped resource potential at the country level. In this context, when we provide estimated yet-to-find at country level these would represent the summation of the main basins included in the analysis.

The IHS Markit yet-to-find (YTF) methodology starts with its data from IHS Markit's core E&P database where fields and new field wildcats (NFW) are identified and where YTF locations are defined. Once a YTF location is defined, IHS Markit assesses the historical data for this location. Key historical data markers are the number of NFW, the chances of success, the average discovery size, the P90/P10 ratio, the discovered volumes and other statistic around vintage production start dates. In general, IHS Markit combines:

- Forecasts of new field wildcat exploration drilling activity in the area over a time (typically 40 years) with
- What a potential area could provide in terms of oil and gas volumes (typically through extrapolation of creaming curves linking cumulative discovered volumes with exploration well activity) and
- And the likely chance of success (typically based on historical ratios) to estimate both the volumes and the number of discoveries that could yet be found in a particular area over the forecast period.

It should be noted that in many cases we consider that the 40-year well estimate is capped by the likely field sizes that will be discovered becoming sub-economic and hence the YTF volume can essentially be regarded as an ultimate recoverable. IHS Markit estimates are under continuous review. Table E.1 contains the main basins included in the YTF analysis.

Table E.1. Main basins for YTF analysis

Country	Deepwater Main Parent Basin	Shallow Water Main Parent Basin
Angola	Congo Fan	
Angola	Kwanza Basin	
Australia		North Carnavon
Australia		Bonaparte Basin
Brazil		Potiguar Basin
Brazil	Santos Basin	
Brazil	Campos Basin	
Canada	Flemish Pass Basin	
Guyana	Guyana Basin	
Mexico		Sureste Basin
Mexico	Deepwater Gulf of Mexico basin	
Norway		Horda Platform
Norway		Viking Graben Province
Norway		Central Graben Province
Norway	Barents Sea platform	
Norway	Voring Basin	

Country	Deepwater Main Parent Basin	Shallow Water Main Parent Basin
United Kingdom		Central Graben Province
United Kingdom		Viking Graben Province
United Kingdom		West Shetland Basin
United Kingdom		Moray Firth Province
United Kingdom		Anglo-Dutch Basin
United Kingdom		East Shetland Platform
United Kingdom	Faroe Shetland Trough	
United States	Deepwater Gulf of Mexico	
United States		Gulf Coast Basin

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