OCS Study
BOEM 2019-xxx

2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Offshore Frontiers Report

U.S. Department of the Interior
Bureau of Ocean Energy Management
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List of Abbreviations and Acronyms

Abbreviation	Description
$/bbl	dollars per barrel
$/MMBTU	dollars per million British thermal unit
bbl	barrel
bcf	billion cubic feet
boe	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management
CAD	Canadian dollar
capex	capital expenditure
CDE	Canadian development expense
CEE	Canadian exploration expense
CFR	Code of Federal Regulations (U.S.)
CO2	carbon dioxide
DOI	U.S. Department of the Interior
DPP	Draft Proposed Program
E&P	exploration and production
EIA	Energy Information Administration
EL	exploration license
EMV	expected monetary value
FID	final investment decision
FPSO	floating production, storage, and offloading vessel
GBS	gravity-based structures
GOM	Gulf of Mexico
GOMESA	Gulf of Mexico Energy Security Act
IRR	internal rate of return
km	kilometer
km2	square kilometer
LNG	liquefied natural gas
LO	licensing option
m	meter
m3	cubic meter
MMbbl	million barrels
MMboe	million barrels of oil equivalent
MMBTU	million British thermal units
MMscf	million standard cubic feet
MPE	Ministry of Petroleum and Energy—Norway
NCS	Norwegian Continental Shelf
NFW	new field wildcat
NPV	net present value
No.	number
NOK	Norwegian Krona

NWT	Northwest Territories
OCS	Outer Continental Shelf
ONHYM	Office of Hydrocarbons and Mines
opex	operating expense
PPT	Petroleum Production Tax—Norway
PRRT	Profit Resource Rent Tax—Norway
RSV	royalty suspension volume
SEC	U.S. Securities Exchange Commission
tCO2e	metric ton of carbon dioxide equivalent
TLP	tension leg platform
TVD	true vertical depth
UK	United Kingdom
U.S.	United States
U.S.C.	U.S. Code
USD	U.S. dollar
USGS	U.S. Geological Survey
WTI	West Texas Intermediate
YTF	yet-to-find

Executive Summary

E.1 Introduction

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

Since the publication of the 2011 Comparative Assessment of the U.S. Federal oil and gas fiscal system[1], significant changes to oil and gas market conditions have globally taken place. With an increase in U.S. onshore supply, world oil and gas prices have fallen. This low price environment has created challenges for governments worldwide to attract oil and gas investments to offshore regions.

Offshore exploration and production (E&P) spending in 2018 suffered a 45 percent decline relative to 2014. Offshore frontier and emerging basins exploration was affected the most, with the share of new field wildcats (NFW) drilled in frontier and emerging basins as a percentage of global conventional NFWs dropping from 20 to 14 percent in the same period.[2] However, such basins play a significant role in regard to new volumes added from conventional exploration, accounting for 60 percent of the discovered volumes.

This is the second of three reports prepared by IHS Markit for the DOI. The first report compares other countries' offshore fiscal systems with the shallow and deepwater of the U.S. Gulf of Mexico (GOM). This second report (Offshore Frontiers Report) provides comparisons of other jurisdictions' fiscal systems with the systems used for Federal offshore frontier areas. The third report provides comparisons of Federal leases onshore Alaska and the Lower 48 with state and private land fiscal systems.

E.2 Objective

The objective of this study is to inform the DOI about the relative competitive position of the Federal oil and gas fiscal systems with oil and gas fiscal systems of other countries competing for investment, to help ensure that oil and gas investment on Federal lands remains competitive with other jurisdictions, and that the public is receiving a fair return for Federal resources. To achieve this objective, the study compares international fiscal systems against current Federal lease terms, as well as alternative fiscal systems requested by the DOI to be included in this study. While current lease terms for Federal lands in offshore frontier regions have not yet been set, the study uses the terms applicable in shallow water GOM as representing the current system. It is not within the scope of this study to make recommendations related to DOI policies on Federal lands, but rather serve as a tool for informing decision-making on the appropriate fiscal terms for Federal oil and gas leases.

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[1] 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.

[2] The term "frontier-phase basin" refers to the stage in the basin's lifecycle where there is no extensive drilling and no commercial discovery has been made yet—exploration is risky, but good geological signs of active hydrocarbon systems lower the risk. The term "emerging-phase basin" refers to the post-commercial discovery stage where most volumes are discovered, and the companies are exploring to the geographical and stratigraphic limits of the basin.

E.3 Scope of Work and Approach

The competitiveness of oil and gas fiscal systems hinges on a number of factors besides fiscal terms. Prospectivity and the scale of the resource base, the cost of exploration and development, prevailing commodity prices, access to resources, and overall regulatory and business environment are among the factors impacting the competitive position of oil and gas investments in a particular jurisdiction. To capture some of these factors, the study mirrors the exploration and development costs in each jurisdiction, taking into consideration the characteristics of the geological formations in the respective jurisdictions, the respective water depths, reservoir pressures, distance from infrastructure, regional costs, and technological challenges associated with each environment and resource type. For this purpose, 60 exploration and development cost models representing 15 offshore Arctic field developments and 45 offshore Non-Arctic frontier developments were created. These development and cost models were analyzed under three different price scenarios, resulting in a total of 180 economic models.

Three oil and gas price scenarios were used for the economic analysis, with global market prices used for crude oil and regional market prices used for natural gas. The regional gas markets have different degrees of maturity. The natural gas prices selected for each region reflect the market structures in the region. For consistency, IHS Markit base case crude oil and natural gas price outlooks are applied for this study, given that the Energy Information Administration (EIA) does not provide outlooks for natural gas prices in Europe. Only the base price scenario reflects the IHS Markit outlook. The outlook for the third quarter of 2018, which corresponds to the time this study was commenced, was applied. The high and low case price scenarios were generated using a variance of minus 40 percent and plus 60 percent from the base case for the low and high case scenarios, respectively. The West Texas Intermediate (WTI) crude oil price scenarios adopted for this study average at about $40, $66, and $105 per barrel (bbl) for the low, base, and high cases, respectively, for the 2019–40 period. The Henry Hub natural gas prices adopted for the economic analysis of U.S. projects average at $2.38, $3.96, and $6.34 per million British thermal units (MMBTU) for the low, base, and high case during the same period. Regional natural gas prices adopted for the international jurisdictions included in this study are about 50 percent higher than Henry Hub prices in the case of Argentina and South Africa and double the Henry Hub prices in the case of Ireland and Morocco. Information on prices used is included in Section 1.3.3 and Appendix C.

Finally, the study assesses the competitiveness of the oil and gas fiscal systems through four key indicators that capture the investor and government perspectives. Economic indicators, such as the internal rate of return (IRR), the net present value per barrel of oil equivalent (NPV/boe), and the expected monetary value (EMV) are among the key metrics used by oil and gas investors when making investment decisions. To compare the NPV of projects of different sizes, this study relies on NPV/boe rather than the NPV, which normalizes results of the NPV across all projects. The study also uses the government take metric as a measure to compare the share of the net revenue accruing to the governments. This metric is often used by resource holders when assessing their competitive position in the regional and global markets.

This Offshore Frontier Report analyzes two peer groups—the Alaska offshore frontier and the Non-Alaska offshore frontier—representing eight fiscal systems. The criteria used to select the different peer groups and field sizes reflect the uniqueness of the current offshore frontier areas.

Alaska Offshore Frontier: The jurisdictions in this peer group were selected for their geological and geographic similarities with the U.S. Beaufort and Chukchi seas areas proposed in the *2019–2024 National Outer Continental Shelf (OCS) Oil and Gas Leasing Draft Proposed Program* (2019–24 DPP). This frontier peer group includes areas in Arctic or sub-Arctic climates where exploration has been sparse, arrested, or is in its early stages with few discoveries made to date.

The Alaska Federal offshore fiscal system is compared against three other offshore Arctic and sub-Arctic environments. Due to the insufficient number of jurisdictions with reported oil and gas discoveries in the Arctic environment, the jurisdictional selection process was extended to sub-Arctic environments to include the Falkland Islands. Table E-1 displays the members of the peer group and the status of discoveries in each jurisdiction. For more information about jurisdictional selection, see Section 1.3.1.

Table E-1. Alaska frontier offshore peer group selection criteria

Number (No.)	Jurisdiction	Location	Production status of discoveries
1.	Canada – NWT	Offshore	Producing and non-producing
2.	Falkland Islands	Offshore	Non-producing (under development)
3.	Norway	Offshore Barents Sea	Producing and non-producing
Key: NWT = Northwest Territories			

Source: IHS Markit © 2019 IHS Markit

IHS Markit reviewed previous oil and gas discoveries in the Beaufort and Chukchi seas and considered the resource endowment for the offshore sections of the North Slope Basin to determine the field sizes for this study. Crude oil volumes from past discoveries in the offshore portion of the North Slope Basin have ranged from 50 million barrels (MMbbl) to 2 billion bbl. That serves as the basis for the selection of the following field sizes for this study: 100 MMbbl, 400 MMbbl, and 1,000 MMbbl.

Non-Alaska offshore frontier: The jurisdictions in this peer group were selected for their geological and bathymetric similarities to the Atlantic, Eastern GOM, and Pacific areas proposed in the 2019–24 DPP. While all frontier areas are different, the selected jurisdictions share common characteristics, such as challenges related to the existence of little or no infrastructure, higher geologic risk, or other challenges associated with ocean currents. The selection process led to the five international jurisdictions shown in Table E-2 for this peer group. For more information about jurisdictional selection, see Section 1.3.1.

Table E-2. Non-Alaska frontier offshore peer group historical discoveries

No.	Jurisdiction	Smallest historical discovery (MMboe)	Largest historical discovery(MMboe)	Number of discoveries
1.	Argentina	4	130	5
2.	Falkland Islands	187	530	9
3.	Ireland	71	79	6
4.	Morocco	13	51	4
5.	South Africa	26	238	9

Source: IHS Markit © 2019 IHS Markit

IHS Markit considered several factors to determine the oil and gas field sizes for this study. These factors included: 1) historical recoverable reserve volumes of fields discovered in each frontier jurisdiction; 2) hydrocarbon resource potential; and 3) economic conditions for development of stand-alone fields in frontier areas. The selection process reconciled the size of historical discoveries in the jurisdictions of the peer group with the investor expectations when entering a frontier basin with no infrastructure. Generally, investors expect field sizes of 500 million barrels of oil equivalent (MMboe) or greater when drilling in a frontier offshore basin with no infrastructure in place. However, given the smaller size of expected discoveries in U.S. Non-Alaska frontier regions, the study considered fields smaller than 500 MMboe. Hence, the resulting field sizes selected for this study are: 100 MMboe, 200 MMboe, and 500 MMboe.

E.4 Evolution of E&P Fiscal Terms

Generally, frontier areas are offered with more attractive fiscal terms to oil and gas investors than established offshore areas. The scarcity of information associated with the exploration and development of hydrocarbons underlying frontier areas and the uncertainty associated with the resource potential often leads to adopting fiscal terms designed to encourage E&P activity in the country. That is the case for both Arctic and Non-Arctic offshore frontier peer groups included in this study. Often, the terms needed to incentivize investment and exploration in a frontier area evolve as more information becomes available and improved knowledge of the resource potential allows the government to design appropriate licensing strategies and fiscal terms that reflect the lower risk profile during later rounds of licensing.[3]

The offshore jurisdictions analyzed in this report are very similar in terms of the level of E&P activity in their offshore frontier areas. Thus, all these jurisdictions present attractive fiscal terms that reflect the uncertainty associated with the resource potential. Some of them are relative newcomers to the offshore E&P industry, while others have opened or are considering opening up areas that were previously placed off-limits or not explored for several decades—mainly the United States and Argentina.

Given the early stages of acreage promotion and E&P activity in the frontier jurisdictions studied, there have been few changes in fiscal terms.[4] This is because most of the jurisdictions in both peer groups have not yet reached the next stage where the uncertainty surrounding the resource potential is reduced.

E.5 Acreage Award Criteria

Jurisdictions in both peer groups rely on competitive bidding, as well as an open-door policy to grant E&P rights. The open-door policy is often adopted in areas where the competitive bidding process is not likely to yield desired results. If properly designed, to ensure transparency and give notice to interested parties, the open-door policy can be an effective means to attract investments in areas where the scarcity of information associated with hydrocarbon exploration and development and the uncertain resource potential may not favor the use of a competitive bidding process. An open-door process still offers other investors the opportunity to compete, such as the European Union Hydrocarbons Directive that gives interested parties notice when an application for an exploration license is received.

Except for Norway, which includes Barents Sea areas in its annual licensing rounds, all jurisdictions in the two frontier offshore peer groups selected for this study offer acreage on an irregular basis. Table E-3 shows the licensing process adopted by each jurisdiction.

[3] Mensah E. Extractive Industries Taxation: CRP.3—Attachment E, Fiscal Take, United Nations, 2016; Tordo S, Johnston D, Johnston D. "Countries' experience with allocation of petroleum exploration and production rights: Strategies and design issues." World Bank. 2009.

[4] Acreage promotion refers to efforts by the governments to attract investments in oil and gas exploration, whether through licensing rounds or open-door policies.

Table E-3. Allocation systems for award of E&P rights

Jurisdiction	Allocation system			Licensing frequency
	Open door	Competitive bidding		
		Discretionary allocation	Auction	
Argentina		●		Irregular
Canada NWT			●	Irregular
Falkland Islands	●			Irregular
Ireland	●	●		Irregular
Morocco	●			Irregular
Norway		●		Annual
South Africa	●	●		Irregular
U.S. OCS Frontier			●	Irregular

Source: IHS Markit

In awarding acreage to oil and gas investors, almost all the countries surveyed rely on work commitment as a bid factor. Cash bonus bids are not frequently used in frontier offshore acreage, given the high risk associated with E&P investments in frontier regions. Table E-4 shows the bid variables applicable in each jurisdiction.

Table E-4. Acreage award criteria

Fiscal system	Cash bonus	Work commitment	Social contribution
Argentina		●	
Canada NWT		●	
Falkland Islands		●	
Ireland		●	
Morocco		●	
Norway		●	
South Africa		●	●
U.S. OCS Frontier	●		

Source: IHS Markit

Minimum work obligations are established as part of the bidding conditions in all jurisdictions except for the United States. The statement for the United States is made based on historical data, since the United States establishes the bid terms on a sale-by-sale basis. The 1953 Outer Continental Shelf Lands Act does provide for work commitment bidding as a potential bid variable under the various systems that the Secretary of the Interior may choose, although current regulations do not. Work commitment bidding, especially one associated with frontier offshore exploration, usually requires the resource holder to offer much larger areas than the ones offered in the U.S. OCS. This method enables the governments to promote exploration and resolve the uncertainty surrounding the resource potential of the frontier acreage. Investors tend to be more incentivized to participate in a licensing process when work commitment is the sole bidding criteria—the cost of entry is lower than in the case of cash bonus bids.

E.6 Comparative Analysis of Fiscal Systems

Alaska Offshore Frontier Results

The jurisdictions in the Alaska offshore frontier peer group are characterized by high per-unit capital and operating costs, with the Chukchi Sea and Falkland Islands presenting relatively higher costs than the Alaskan and Canadian sections of the Beaufort Sea and Norway. The Chukchi Sea and the Falkland Islands are more exposed to weather challenges, more remote, and have deeper waters, necessitating the use of gravity-based structures (GBS) for Chukchi Sea and floating production, storage, and offloading (FPSO) vessels for the Falkland Islands. Oil and gas field developments in the Beaufort Sea, by comparison, are in shallow waters and rely on the use of artificial gravel islands, which are less expensive and easier to access during the winter season.

The jurisdictions in this peer group also vary considerably with regards to resource potential and expected field sizes. The field sizes selected for this peer group are more representative of the discoveries in Alaska than those of the other jurisdictions against which it is compared (i.e., the size of discoveries within the peer group tends to be smaller than in Alaska). When that is taken into account, Alaska's competitive position strengthens. Furthermore, the Mackenzie Delta Basin in the NWT and the Barents Sea Basin in Norway are gas-prone and more challenging to commercialize. The natural gas discoveries in the Canadian portion of the Beaufort Sea are stranded. However, the analysis for this peer group considers oil fields only, given the propensity of the prospects in Alaska and the fact that gas is stranded there, too. Hence, the modeled results of NWT are better than can be expected in reality.

The high cost associated with finding and developing oil and gas resources in the Alaska offshore frontier peer group challenges their economic viability under the base and low price scenarios used for this study. None of the U.S. and international projects considered for this peer group reaches the 15 percent investment return threshold for offshore exploration under the low and base price cases. Investment dollars would more likely go to frontier regions in times of high prices. Even with positive NPVs an investor wouldn't necessarily invest in a frontier region with $60/bbl oil. Therefore, the high price case is the most relevant for this frontier report's analysis. In the high oil price environment, the Alaska Chukchi and Beaufort seas projects are very competitive within the peer group (Figure E-1). The IRR for all three field sizes—the 1,000 MMboe, 400 MMboe, and 100 MMboe—in the Chukchi and Beaufort seas ranges between 15 and 20 percent. However, investors in frontier areas usually expect rates of return well above the 15 percent threshold to account for the significant risk associated with exploring a frontier basin.

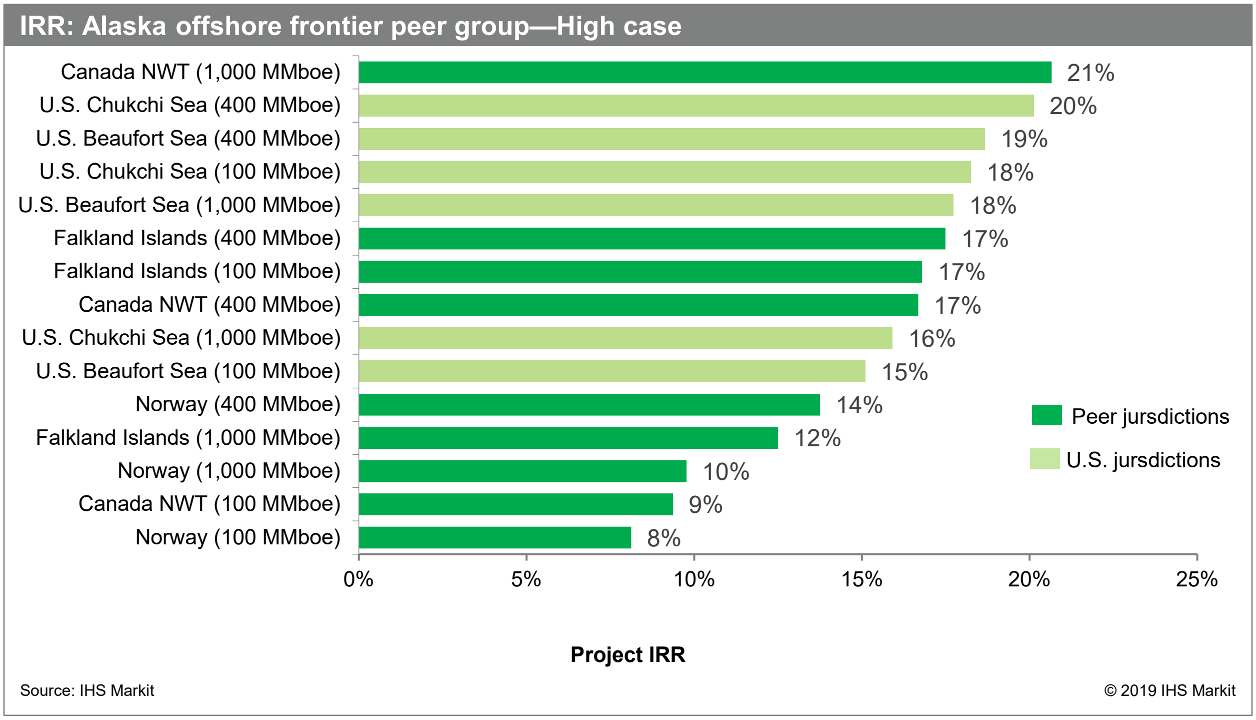

Figure E-1. IRR: Alaska offshore frontier peer group—High case

The Alaska Beaufort Sea and Chukchi Sea projects yield, on a dollar-per-barrel basis, better value to investors than most projects in this peer group in the high oil price environment (Figure E-2). While the Barents Sea is the region with the highest level of exploratory drilling within the peer group (Section 3.1), the NPV/boe values of stand-alone projects in the Beaufort Sea are 4.5 times higher than those for equivalent field sizes in Norway in the high price environment ($9.8/boe versus $2.2/boe). This result is despite the lower per-unit exploration costs in the Barents Sea. The lower NPV/boe for the Norwegian projects can be attributed to the relatively higher government take compared to the U.S. Federal fiscal system.

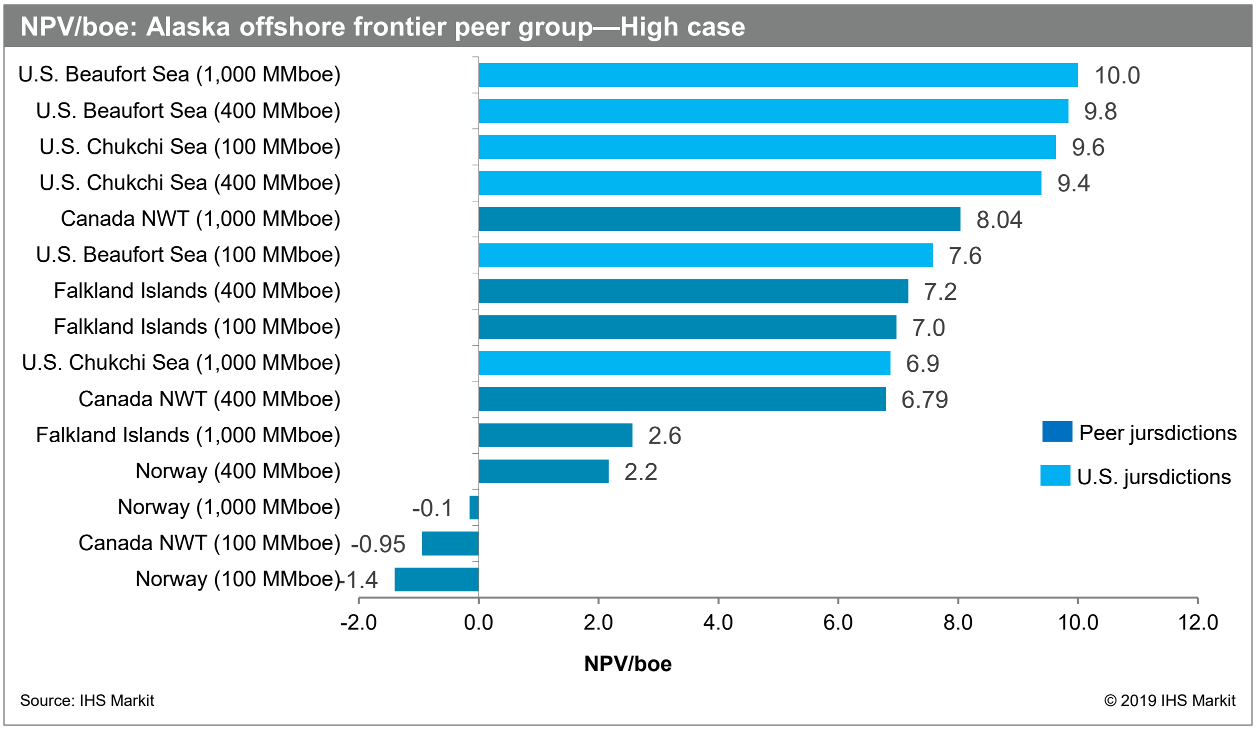

Figure E-2. NPV/boe: Alaska offshore frontier peer group—High case

The larger field sizes in the case of the Alaska Chukchi Sea, Barents Sea, and Falkland Islands yield lower NPV/boe than the medium and small field sizes in this study. The difference in the timing of development impacts whether incremental barrels are more economic in the larger field sizes than the medium or small ones. When the capital spent is more upfront and not done in phases, the larger field often loses the benefit from the economies of scale on a present-value basis. Phased development is quite common for complex projects. The Snøhvit development in the Barents Sea, which includes a cluster of gas fields (Snøhvit, Albatross, and Askeladd), has been developed in multiple phases. The development of clusters such as the Snøhvit field in the Barents Sea has also benefitted from lengthy and flexible lease terms until commerciality was established. It took 18 years from the discovery to the approval of the development plan for Snøhvit in Norway. The Federal oil and gas leases in the United States do not have provisions for retention of discoveries that are not commercial at the time of discovery, but have the potential to be declared commercial within a reasonable time period in the future. Some jurisdictions provide for periods of 5–10 years for retention of discoveries.

The Alaska Beaufort and Chukchi seas projects outperform all the other jurisdictions in this peer group when the EMV is taken into account (Figure E-3). The Beaufort Sea projects offer robust monetary value per exploration well drilled in the high price scenario under all three field sizes, with Chukchi Sea projects coming in second. In the high price scenario, the EMV for Chukchi Sea and Beaufort Sea midsize fields ranges from $900 million to $1 billion, whereas the EMV for the large field ranges from $2.0 billion to $2.5 billion. The value per exploratory well does deteriorate when the low price scenario is taken into account, as it does for all the other jurisdictions in the peer group.

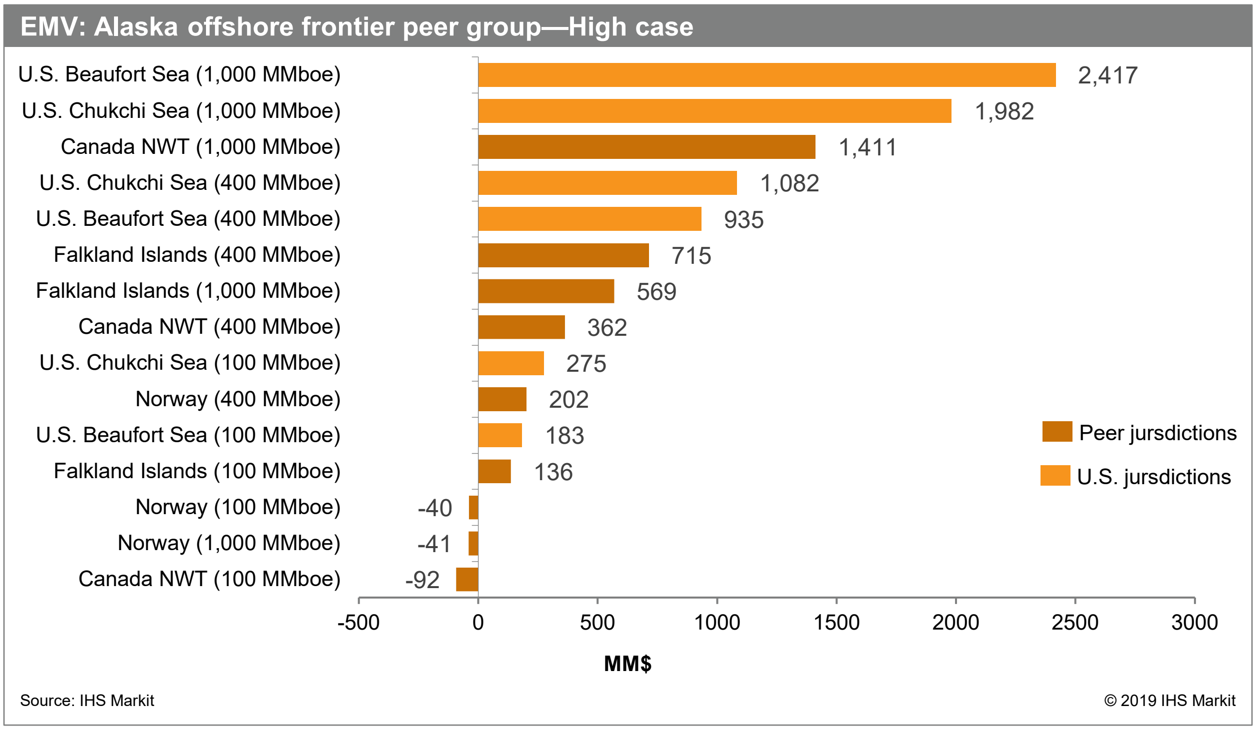

Figure E-3. EMV: Alaska offshore frontier peer group—High case

While the Chukchi Sea and Beaufort Sea projects may not pass all the investment thresholds under the base price scenario as stand-alone developments, cluster and phased development of discoveries in the Alaskan Arctic region could improve project economics.

Fiscal System Alternatives for Alaska

IHS Markit evaluated the competitiveness of the Federal fiscal systems for the Alaska offshore Arctic region by applying a royalty suspension volume (RSV) incentive suggested by the Bureau of Ocean Energy Management (BOEM). The RSV allows royalty relief up to the RSV amount, conditional on price thresholds. When market prices exceed $85/bbl, the RSVs do not apply, and the statutory minimum royalty of 12.5 percent is applied. Thus, the high case results for RSVs remain unchanged from the status quo in this study, since the $85/bbl threshold is below the high case price that averages about $105/bbl.

The RSVs are evaluated for two Federal Alaska offshore areas, the Beaufort Sea and Chukchi Sea, across three different field sizes: 100 MMboe, 400 MMboe, and 1,000 MMboe. All cases are in shallow water and assume a 50 MMboe RSV per lease. The total RSV for each case is based on the number of leases assumed per field size (Table E-5). The RSVs applied for the fields modeled in this study range from 40 to 50 percent of the recoverable reserves.

Table E-5. Alaska offshore cases: Total RSV

Cases	Reservoir depth (ft)	Water depth (ft)	Water depth (m)	No. of leases	RSV per lease (MMboe)	Total RSV (MMboe)	% Royalty free
Beaufort Sea oil 100 MMboe	8,500	24	7	1	50	50	50%
Beaufort Sea oil 400 MMboe	8,500	24	7	4	50	200	50%
Beaufort Sea oil 1,000 MMboe	8,500	24	7	8	50	400	40%
Chukchi Sea oil 100 MMboe	7,160	148	45	1	50	50	50%
Chukchi Sea oil 400 MMboe	7,160	148	45	4	50	200	40%
Chukchi Sea oil 1,000 MMboe	7,160	148	45	8	50	400	40%

Source: IHS Markit

To assess the full impact of royalty on project economics in Alaska, IHS Markit conducted a sensitivity analysis on a range of royalties, including zero percent royalty on Federal lands in offshore Alaska. In Figures E-4 and E-5, the impacts of various royalty rates and RSVs on the IRR and the government take are displayed for the base price scenario. Each trend line represents a different field size. The data points illustrate the impact of royalty rates to the investor IRR and government take as royalty rate changes from 12.5 percent to RSV to zero royalty. The trend lines indicate how sensitive a particular field is to the royalty rate; a more horizontal trend line has higher response to the change in royalty rate, whereas a more vertical line indicates less elasticity. The lines are indicative only and could be inaccurate beyond the data points.

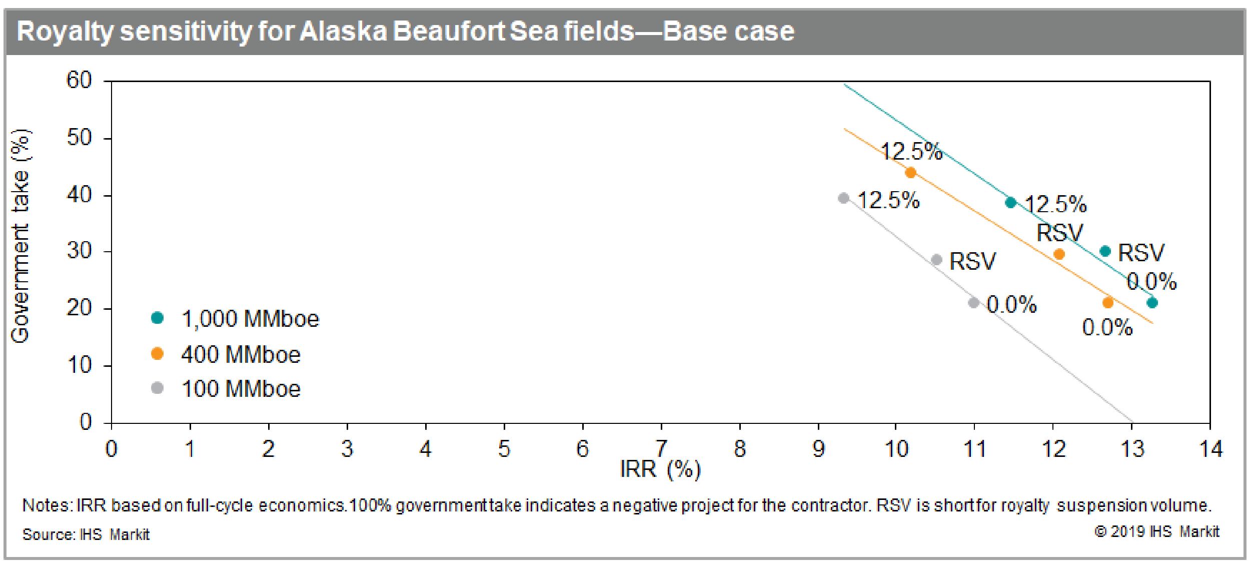

Figure E-4. Royalty sensitivity for Alaska Beaufort Sea fields—Base case

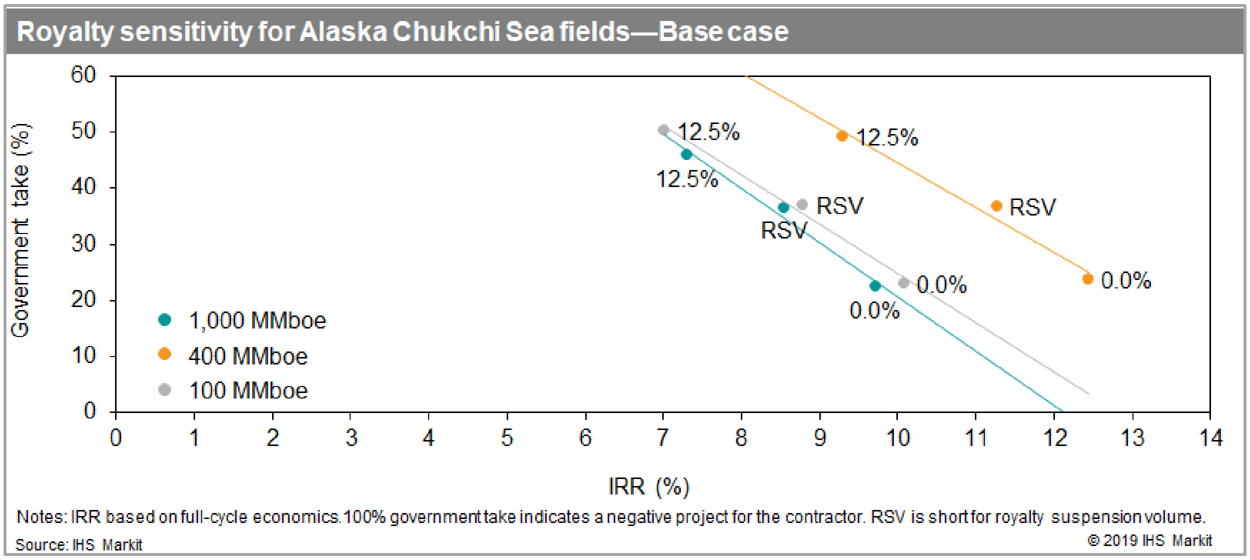

Figure E-5. Royalty sensitivity for Alaska Chukchi Sea fields—Base case

The application of the RSVs for the Alaska Beaufort and Chukchi seas projects improves the IRR; however, the measure is insufficient to enable stand-alone projects to reach the desired 15 percent investment threshold. The development of such fields in the Arctic environment depends more on global market conditions (i.e., commodity price shifts and the industry's ability to lower the exploration and development costs, rather than changes to the Federal fiscal system).

Non-Alaska Offshore Frontier Results

The Non-Alaska offshore frontier peer group is characterized by jurisdictions that have had a few discoveries; however, not all the jurisdictions have discoveries that have been deemed commercial. The size of recent commercial discoveries in the Falkland Islands and South Africa are similar to the volumes modeled for this study. The discoveries in other jurisdictions within this peer group are smaller. Hence, the fields modeled for this study may not be reflective of the current geological prospectivity of the particular jurisdiction. The selected field sizes, however, are likely representative of the minimum an investor would need to invest in a frontier area.

The U.S. Atlantic and Eastern GOM oil field prospects are in water and formation depths two to three times greater than the fields modeled for the frontier peer jurisdictions. The U.S. Pacific region prospects are more similar in water and formation depth to those of the other frontier jurisdictions in this peer group. Table E-6 displays the average water and formation depths for oil fields in the respective region.

Table E-6. Non-Alaska offshore frontier peer group—Average water depth and TVD

Region	Average water depth (m)	Average formation depth (TVD m)
U.S. Atlantic	949	5,693
U.S. Eastern GOM	1,316	5,094
U.S. Pacific	198	2,237
International	366	2,142

Source: IHS Markit

The U.S. frontier offshore oil fields offer high value per exploration well drilled under the high price scenario (Figure E-6). The majority of projects modeled for this study yield negative EMVs under the low price scenario. The costs associated with the water and reservoir depth and lack of infrastructure present challenges for the stand-alone development of fields in the base case scenario. Only half of the fields modeled for the U.S. jurisdictions in this peer group yield positive EMVs under the base price scenario. The Atlantic region, in particular, is the least competitive jurisdiction in the peer group, with negative values per exploration well under all field sizes in the base and low price scenarios.

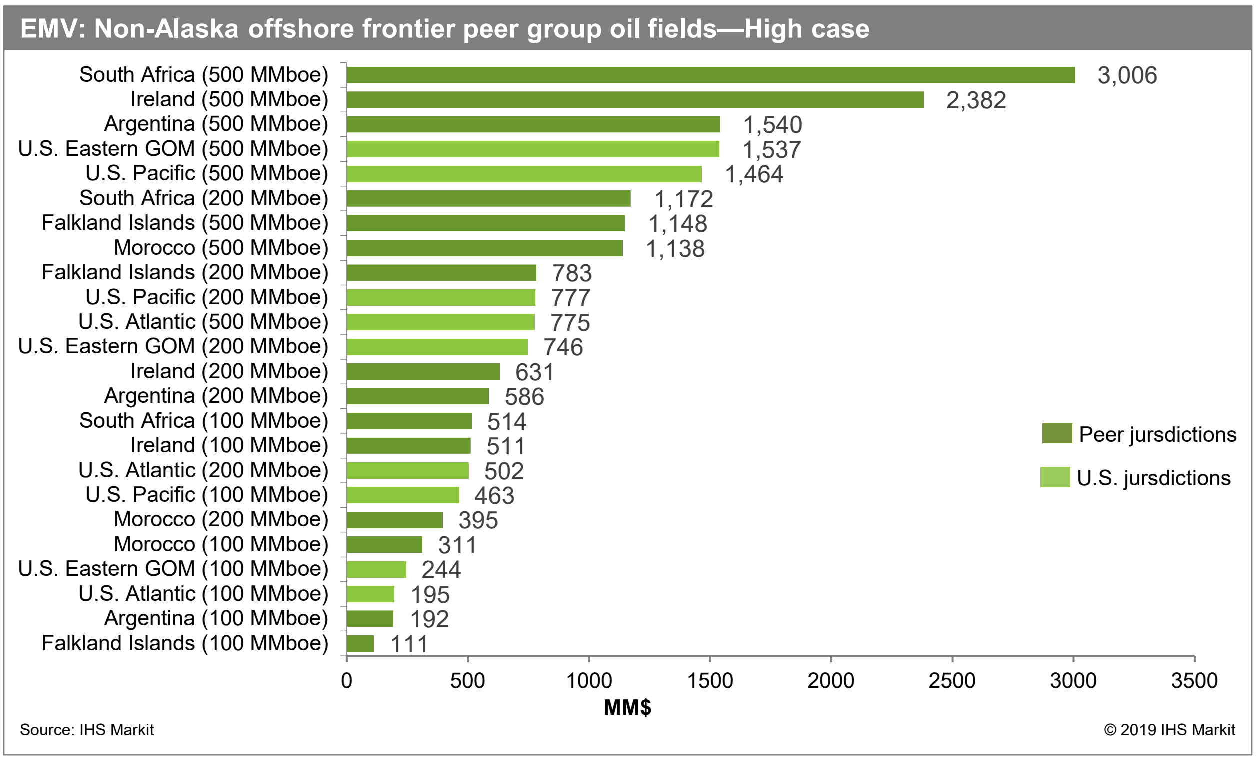

Figure E-6. EMV: Non-Alaska offshore frontier peer group oil fields—High case

The medium and the large oil field sizes in Eastern GOM yield EMVs of $127 million and $301 million, respectively, under the base price scenario. The 100 MMboe oil field presents with negative $40 million EMV in the base case. This is to be expected given the water depth (975 m) and TVD (4,633 m) of the 100 MMboe field (Table 6-8). A field of this size would have marginal economics even in established deepwater regions such as the Central GOM. They can, however, be economically developed as part of a cluster of fields. All three fields modeled for the U.S. Pacific yield positive EMVs of $103–141 million. The shallower water and formation depths give the U.S. Pacific projects a cost advantage over the Atlantic and Eastern GOM.

The IRRs for the U.S. oil field cases are generally very robust under the high price environment, with the majority of the cases yielding 18 percent or greater (Figure E-7). The results of the different field sizes fall within the second and third quartiles in the peer group. However, under the base price scenario, the IRR for the U.S. oil field projects falls in the third and fourth quartiles (Figure 5-8). The higher per-unit costs associated with the development of the Eastern GOM and Pacific projects in the United States contribute to the lower IRR and hence lower ranking under the base price scenario.

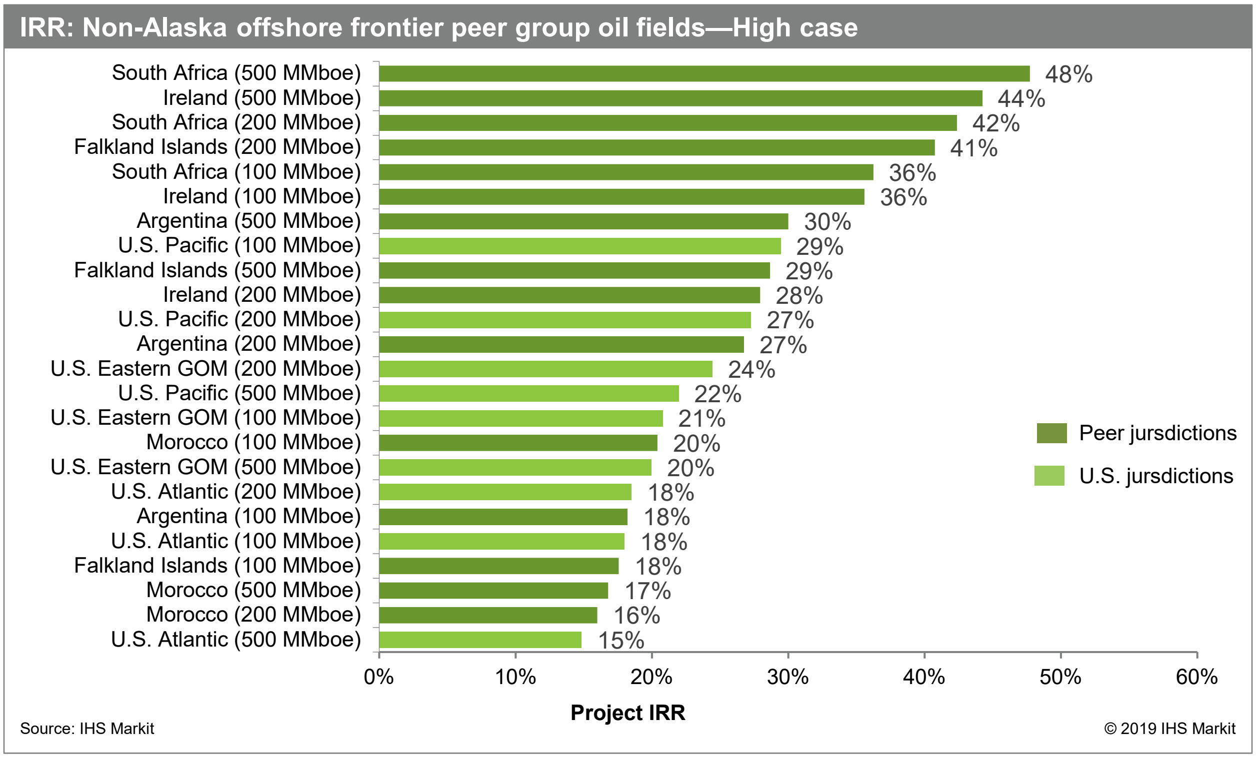

Figure E-7. IRR: Non-Alaska offshore frontier peer group oil fields—High case

Within the peer group, the oil fields in South Africa and Ireland yield the highest return on investment, having the lowest development costs of the peer group. The attractive returns for South African and Irish oil fields are largely attributed to the shallower water depths, 113 m and 122 m, respectively, allowing for the use of jackets as production platforms. The oil formations in South Africa and Ireland have favorable well productivity, requiring fewer wells for the same field size as the other frontier areas modeled. All except one of South Africa’s oil fields yield robust rates of return under all three price scenarios. Most fields in the peer group, however, are sub-economic under the low price case (Table 5-6).

The abundance of low-cost supply from shale gas resources and associated gas produced with tight oil in North America has led to natural gas prices that are lower than those in other regions. As a result, the natural gas prices used for this study are about 50 percent higher than the Henry Hub prices in the case of Argentina and South Africa, and more than double those in the case of Ireland and Morocco (Appendix C.2). This price difference, combined with the greater water and formation depth for the U.S. prospects in the Atlantic and Eastern GOM (Appendix B), results in lower rates of return for natural gas projects in the U.S. offshore frontier areas (Figure E-8).

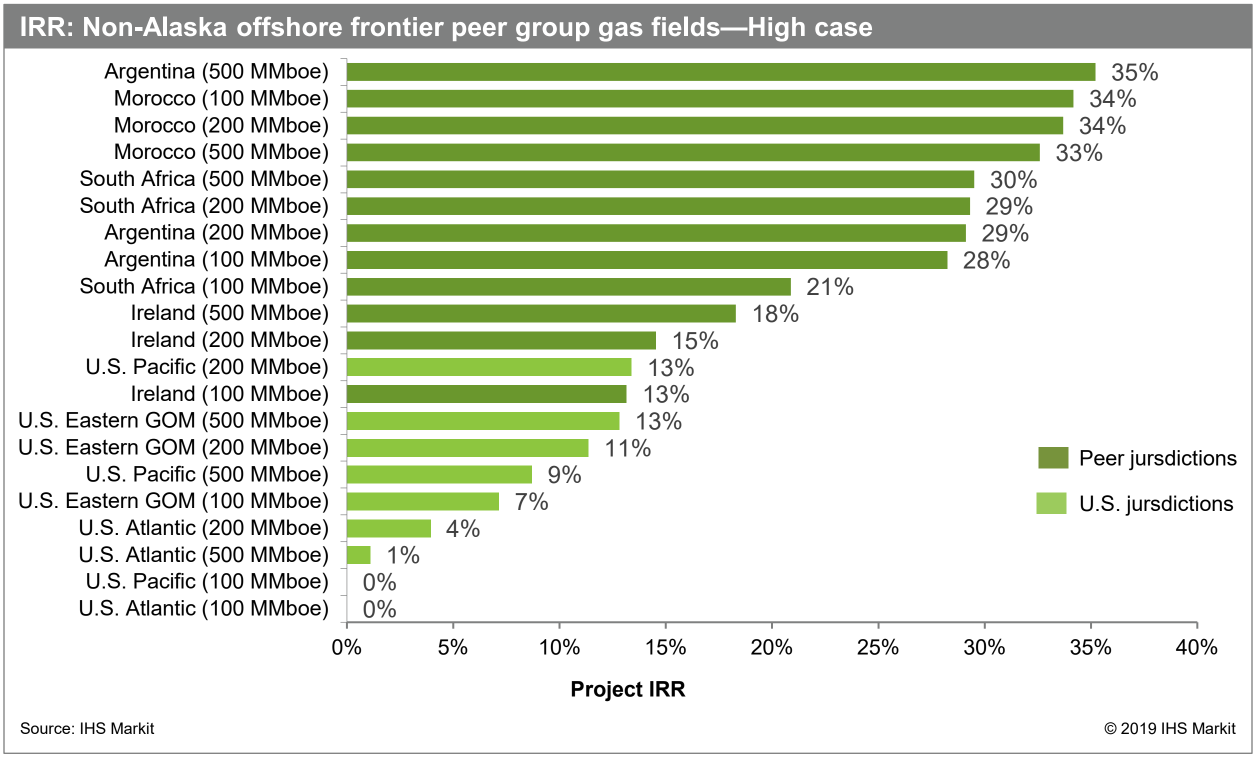

Figure E-8. IRR: Non-Alaska offshore frontier peer group gas fields—High case

Development of natural gas fields in the Non-Alaska offshore frontier regions is not viable under any of the three price scenarios considered for this study. While most U.S. natural gas projects in offshore frontier areas yield positive rates of return under the high price scenario, such returns fall below the 15 percent investment threshold (Table 5-7).

Fiscal System Alternatives for Atlantic, Eastern GOM and Pacific

RSVs suggested by BOEM are evaluated for three Federal Non-Alaska offshore areas, Pacific, Eastern GOM, and Atlantic, across three different field sizes, 100 MMboe, 200 MMboe, and 500 MMboe. The RSV allocated in each case depends on the location of each field (i.e., water depth). Not all fields of the same size are in the same water depth in the three regions. Eastern GOM and Atlantic fields modeled for this study are in deeper waters than the respective field sizes in the Pacific. Table E-7 provides the actual RSVs modeled at the field level for the fields in each offshore region. The royalty-free volumes are 20 percent of the field reserves for all Pacific cases, while they range between 20 percent and 60 percent for the Eastern GOM and Atlantic cases.

Table E-7. Non-Alaska offshore cases and total RSV

Cases	Reservoir depth (ft)	Water depth (ft)	Water depth (m)	Terrain	No. of leases	RSV per lease (MMboe)	Total RSV (MMboe)	% Royalty free
U.S. Atlantic								
Gas 100 MMboe	9,600	72	22	Shallow water	1	20	20	20%
Gas 200 MMboe	8,200	3,220	981	Deepwater	2	60	120	60%
Gas 500 MMboe	4,200	3,220	981	Deepwater	5	60	300	60%
Oil 100 MMboe	5,500	394	120	Shallow water	1	20	20	20%
Oil 200 MMboe	8,100	2,950	899	Deepwater	2	60	120	60%
Oil 500 MMboe	30,000	4,020	1,225	Deepwater	5	60	300	60%
U.S. Eastern GOM								
Gas 100 MMboe	11,600	200	61	Shallow water	1	20	20	20%
Gas 200 MMboe	2,600	400	122	Shallow water	2	20	40	20%
Gas 500 MMboe	21,000	3,240	988	Deepwater	5	60	300	60%
Oil 100 MMboe	15,200	3,200	975	Deepwater	1	60	60	60%
Oil 200 MMboe	10,400	2,540	774	Deepwater	2	40	80	40%
Oil 500 MMboe	24,500	7,220	2,201	Deepwater	5	60	300	60%
U.S. Atlantic								
Gas 100 MMboe	7,970	220	67	Shallow water	1	20	20	20%
Gas 200 MMboe	8,960	660	201	Deepwater	2	20	40	20%
Gas 500 MMboe	11,000	1,030	314	Deepwater	5	20	100	20%
Oil 100 MMboe	6,000	220	67	Shallow water	1	20	20	20%
Oil 200 MMboe	6,990	660	201	Deepwater	2	20	40	20%
Oil 500 MMboe	6,020	1,030	314	Deepwater	5	20	100	20%

Source: IHS Markit

From an EMV perspective, the application of the RSVs yields better results for Eastern GOM projects than for Atlantic and Pacific fields. The EMVs for the three Eastern GOM field sizes under the base price scenario increase by $48 million, $68 million, and $198 million, respectively, for the 100 MMboe, 200 MMboe, and 500 MMboe fields (Table 6-8). The EMV for the 100 MMboe field turns positive under this fiscal system alternative in the base case. While the Pacific projects also benefit from the application of the RSV, the value added per exploratory well drilled is about half of the value addition realized in the Eastern GOM projects—a $157-million combined value addition for the Pacific projects, versus a $314-million combined value addition of for the Eastern GOM projects. The Pacific prospects modeled for this study get about half the volume relief of the Eastern GOM projects due to their location in shallower waters.

The application of the RSVs, however, is unable to yield positive results for any of the Atlantic field sizes under the base case. The EMV under the low oil price scenario continues to be negative for all U.S. cases, as it is for the majority of cases within the peer group. Natural gas fields underperform in the peer group both in terms of value per exploratory well and the number of cases yielding positive EMV. The RSVs applied to natural gas fields do nothing to change the status quo. Development of natural gas fields under the prevailing commodity prices in the United States is challenging even in established areas such as the Central GOM with existing infrastructure in place.

To assess the full impact of royalties on project economics in Non-Alaska offshore frontier regions, IHS Markit conducted a sensitivity analysis on a range of royalties, including zero percent on offshore Federal lands. In Figures E-9 through E-11, the impacts of various royalty rates and RSVs on the IRR and the government take are displayed for each oil field size. Each trend line represents a region. For the 500 MMboe oil fields, the Pacific and Eastern GOM follow a similar trajectory, while the Pacific starts off less economical. At 12.5 percent royalty, the Pacific yields an 11.4 percent IRR, while the Eastern GOM produces a 12.4 percent IRR.

The data points illustrate the impact of royalty rates to the investor's IRR, and government take as royalty rate changes from 12.5 percent to RSV to zero royalty. The trend lines indicate how sensitive a particular field is to the royalty rate; a more horizontal trend line has a higher response to the change in royalty rate, while a more vertical line indicates less elasticity. The lines are indicative only and may be inaccurate beyond the data points.

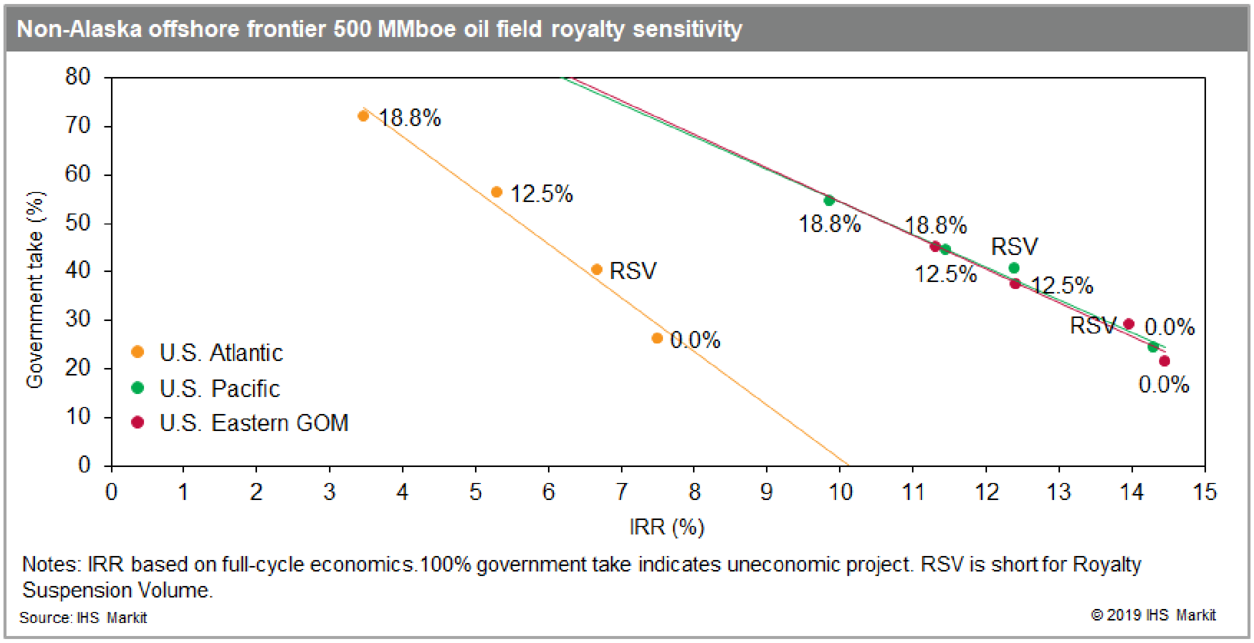

Figure E-9. Non-Alaska offshore frontier 500 MMboe oil field royalty sensitivity

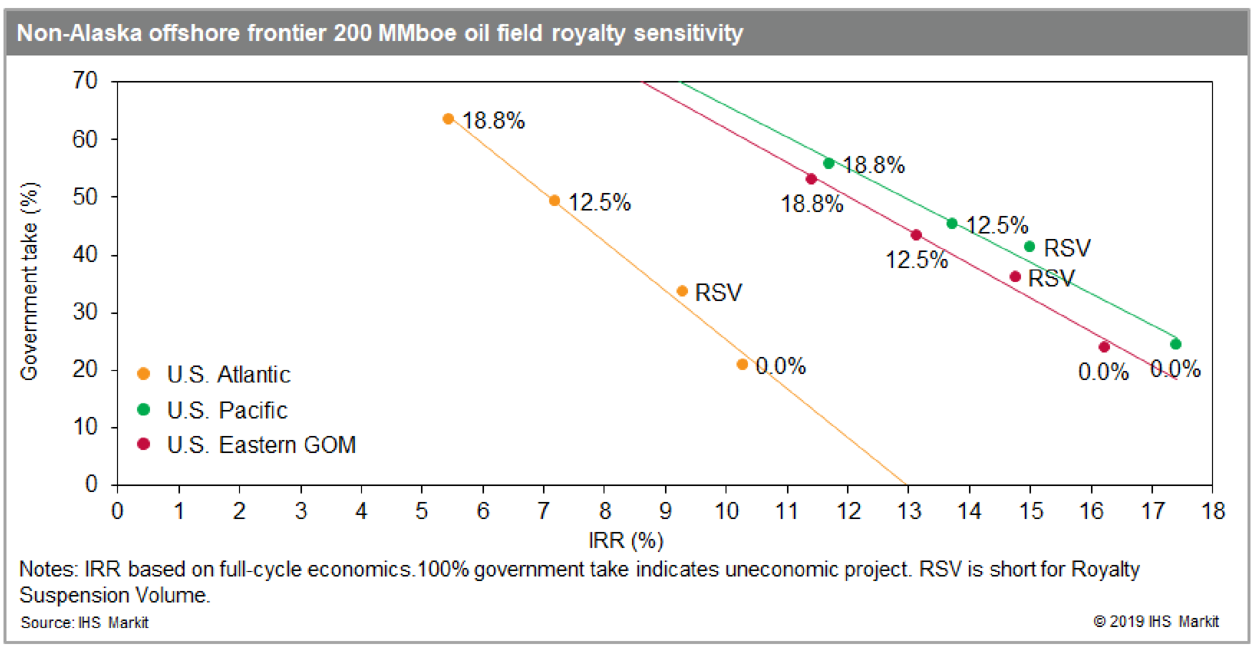

Figure E-10. Non-Alaska offshore frontier 200 MMboe oil field royalty sensitivity

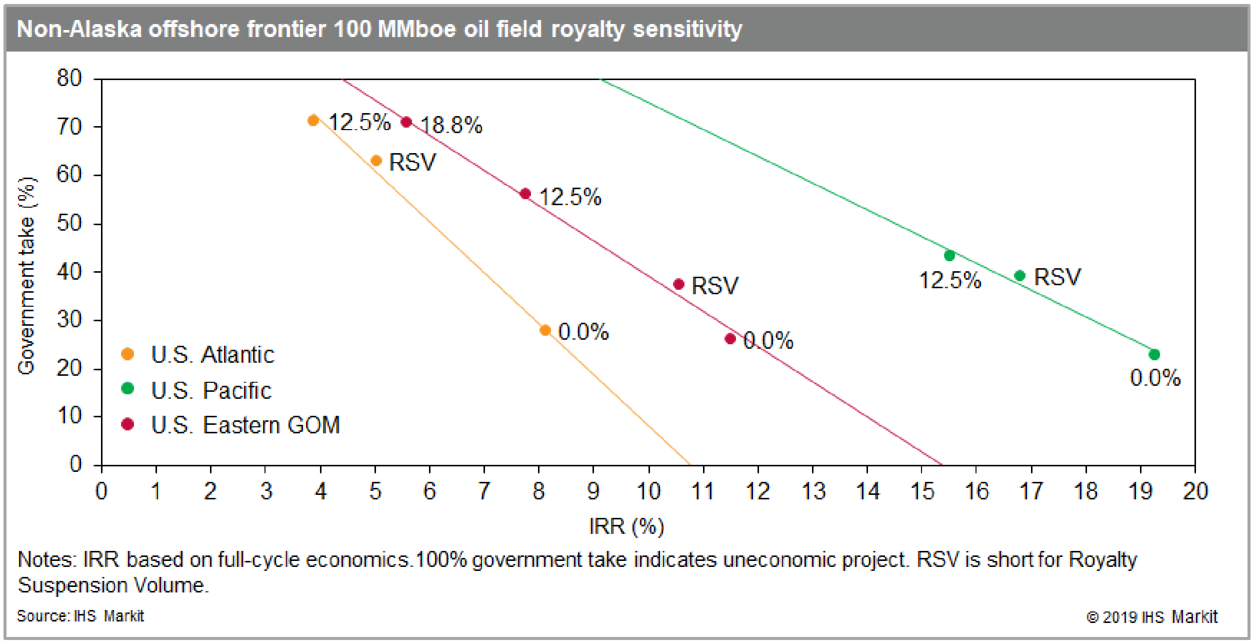

Figure E-11: Non-Alaska offshore frontier 100 MMboe oil field royalty sensitivity

Royalty sensitivity analysis conducted for non-Alaska frontier offshore fields in the United States indicates that fields similar to the 200 MMboe oil fields modeled for this study could cross the 15 percent IRR threshold in Eastern GOM and Pacific regions with substantially larger RSVs or substantially lower royalty rates than the statutory minimum of 12.5 percent. Other fields modeled for this study did not achieve the desired result even under zero percent royalty. One exception is the 100 MMboe oil field in Pacific, which crosses the 15 percent IRR investment threshold under the statutory minimum royalty, prior to the application of RSVs.

E.7 Conclusion

The competitiveness of the U.S. fiscal systems for frontier offshore areas is largely dependent on the prospectivity and scale of the resource base, the exploration and development costs, fiscal terms, and other risk factors. The U.S. offshore frontier areas of Chukchi Sea, Atlantic, and Eastern GOM present higher per-unit costs than the other jurisdictions within the respective peer groups. The resource base and prospect size vary widely among the jurisdictions in each peer group. Within the Arctic peer group, Alaska has a competitive advantage from a resource perspective, since the other members have either smaller-sized prospects or are predominantly gas-prone regions.

The overall level of investment in offshore conventional exploration has declined markedly since 2014. IHS Markit expects a modest but sustained increase in conventional exploration spending and drilling activity through the near term. Given the high risk and long cycle times involved in bringing offshore oil and gas resources to market, frontier exploration has been greatly impacted. The limited level of exploratory drilling in the offshore frontier regions of the United States can be largely attributed to a drilling moratorium that has been in place for decades. This has resulted in a lack of opportunities to reduce the uncertainty and associated risks.

The evolution of other offshore regions from frontier to emerging status has historically shown a long lead time from initial discovery to first commercial development. Companies often rely on the discovery of additional fields to justify the final investment decision (FID). The lead time to FID in a frontier basin can run between 15 and 20 years. A lot of countries provide for a retention period of 5–10 years to establish the commerciality of a discovery. A greater flexibility in U.S. Federal oil and gas leases for offshore frontier acreage, which provides for longer lease terms to establish commerciality of resources discovered, may incentivize investment.

Exploration in the Arctic offshore presents one of the most challenging environments for the oil and gas industry. The technical complexity, the magnitude of investments required, and the environmental sensitivity surrounding the Arctic offshore present challenges even for the large and experienced oil and gas entities having the financial, technical, and managerial capabilities to operate in these environments. Shell's decision to abandon Arctic drilling after investing close to $7 billion over nine years underscores the magnitude of challenges associated with developing U.S. Arctic resources.

In the high oil price environment, the Alaska Chukchi Sea and Beaufort Sea projects are very competitive within the peer group, offering better returns and higher value on a dollar-per-barrel basis than the majority of projects modeled for this study. When the expected field sizes and primary output in the respective jurisdictions are taken into account, the investment opportunities in the Alaska Chukchi and Beaufort seas should be more appealing to investors—Alaska's current discoveries in the Arctic offshore area tend to be oil-prone, versus the gas-prone discoveries of the Mackenzie Delta and Barents Sea. Most companies investing in frontier exploration are looking for oil.

Given the complexity, risks involved, and expected returns at different prices, the current fiscal terms only incentivize investment in a high price scenario on a stand-alone basis, as do those of the other jurisdictions in the peer group. However, cluster and phased developments of the Arctic resources, similar to those undertaken in the Barents Sea in Norway, could enable investment under the base price scenario.

Although RSVs offer an effective 40–50 percent royalty-free volume and higher returns to investors under the base and low price scenarios, the improvement is insufficient to render such projects economic. A zero percent royalty would enhance the attractiveness of the fiscal system, but the expected investor returns would be relatively marginal, given the risks involved.

The U.S. Non-Alaska offshore frontier regions are competing against more dynamic international frontier jurisdictions (i.e., South Africa and the Falkland Islands) that offer very competitive fiscal terms to maximize their share of the already-limited exploration budgets. Both these jurisdictions have had some success in recent years in terms of assessing the resource potential, with a couple of discoveries under development. From a risk perspective, some of the jurisdictions in this peer group have done more to improve industry's knowledge of the geologic potential. Argentina's investment in seismic surveys for its offshore areas resulted in a very successful offshore licensing round. The three U.S. Non-Alaska offshore frontier regions have not been open for leasing for decades, which puts them at a disadvantage to their peers in this group.

The U.S. Non-Alaska offshore frontier regions face greater commercial challenges than the other jurisdictions in the peer group. Prospects in the U.S. Atlantic and Eastern GOM are expected to be in water and formation depths that are two to three times greater than the those in the international jurisdictions. The U.S. frontier offshore oil fields offer high value per exploration well drilled under the high price scenario. However, such values deteriorate quickly when the low price cases are taken into account.

The costs associated with the water and reservoir depth and lack of infrastructure prove challenging for the stand-alone development of projects in the U.S. frontier regions. Deployment of field development concepts that include a cluster of fields could significantly improve the commercial viability of projects in the Eastern GOM and Pacific regions. There is potential for added value in the U.S. Eastern GOM if the development can leverage proximity to the GOM oilfield service centers of Louisiana, Alabama, and Mississippi. A nearby dynamic service market offers greater possibilities to negotiate rates and lower costs.

Development of natural gas fields in the Non-Alaska offshore frontier regions is not viable under current commodity prices in the United States. The abundance of lower-cost natural gas supply, from both shale gas and associated gas produced from tight oil formations, is likely to keep prices at a level inconducive to developing U.S. offshore natural gas resources in the near future.

1 Context and Scope

1.1 Organization of the Report

This report is organized in seven chapters.

Chapter 1 provides context on the study, and describes its scope and approach, including the selection of jurisdictions, field sizes, exploration and development cost models, and price assumptions.

Chapter 2 provides a qualitative assessment of the 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 (YTF) resource potential, and exploration and development costs. Furthermore, this chapter provides an explanation and discussion of the policy decisions made by various jurisdictions, as well as insights on the competitive landscape in the future.

Chapter 4 analyzes trends in fiscal terms since the 2014 drop of commodity prices. The chapter focuses on changes in fiscal terms and the 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 metrics such as government take, IRR, NPV/boe, and EMV. Fiscal systems are ranked on the basis of each individual metric.

Chapter 6 provides a detailed analysis of the fiscal system alternatives for the frontier offshore peer groups. 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.

Appendices A through E provide additional detail related to fiscal systems, price and cost assumptions, and economic outputs. The appendices consist of the following:

- Appendix A provides a summary of fiscal and license/contractual terms for each jurisdiction
- Appendix B provides cost modeling assumptions
- Appendix C summarizes commercial assumptions, such as price cases and cost escalation information
- Appendix D includes all the outputs of the economic analysis
- Appendix E provides a high-level analysis of the E&P activity in the Cook Inlet Basin, another area in the U.S. offshore Alaska that is available for investment. This area, however, is not considered frontier and is not included in the economic analysis of this study.

1.2 Background

The DOI contracted this study with IHS Markit to provide an updated comparative assessment of the Federal oil and gas fiscal systems, with international jurisdictions to help ensure that oil and gas investment on Federal lands remains competitive and that the public is receiving a fair return for Federal resources. [5] As the second in its series, this Offshore Frontiers Report is a continuation of the GOM Report BOEM released in March 2019.[6] The third report focuses on onshore Alaska and Lower-48 onshore resources.

This second report analyzes frontier offshore oil and gas regions in both Alaska and Non-Alaska areas of the OCS. IHS Markit identified three high-level trends that impact the future potential development of frontier areas.

1. Offshore E&P capital expenditure (capex) will continue to play an important role in global upstream spending. IHS Markit expects a modest but sustained increase in conventional exploration spending and drilling activity through the near term. After steadily declining between 2014 and 2018 amid the depressed oil price environment, offshore exploration and appraisal drilling is expected to pick up and increase by 54 percent in 2023 relative to 2018 (Figure 1-1).

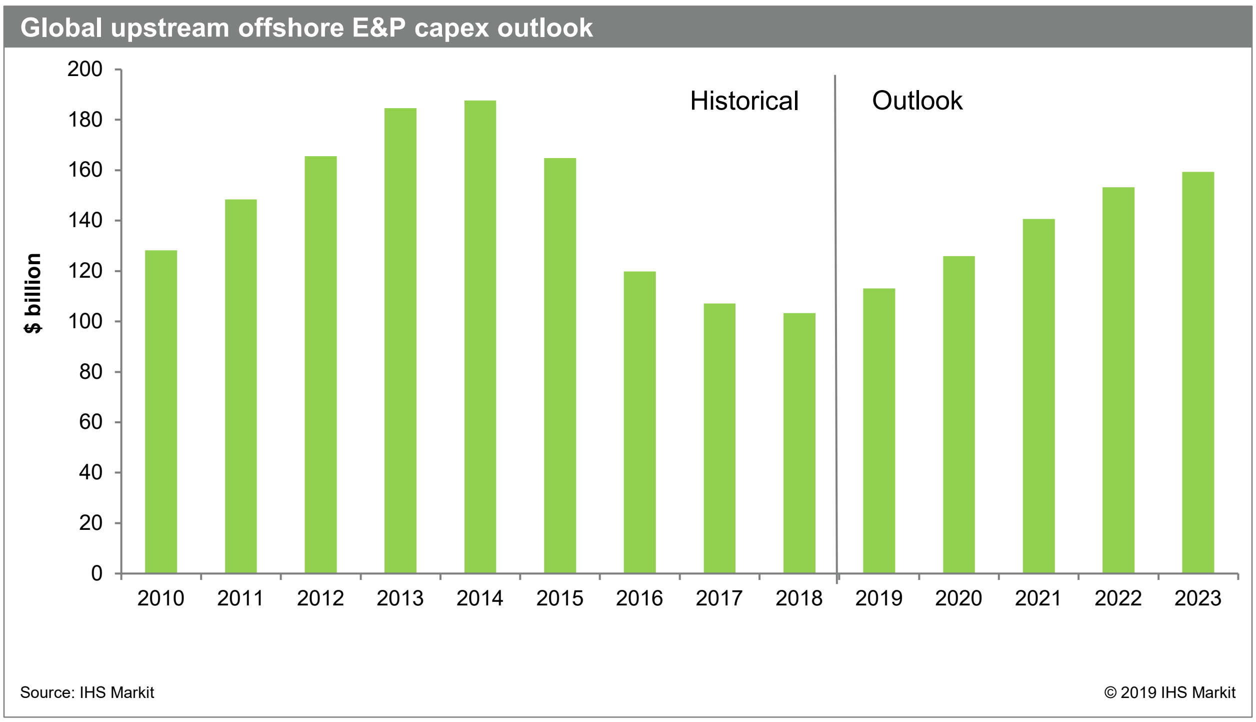

Figure 1-1. Global upstream offshore E&P capex outlook

2. There is a shift away from frontier and emerging phase basin exploration; however, roughly 60 percent of the discovered volumes accrue to frontier and emerging phase basins.[7] While IHS Markit anticipates that maturing and rejuvenated basins will be responsible for an increasing percentage of

[5] See note 1 supra.
[6] Agalliu I, Montero A, Adams S, Gallagher S, 2018. 2018 Comparative Assessment of the Federal Oil and Gas Fiscal Systems. Sterling, VA U.S. Department of the Interior, Bureau of Ocean Energy Management. OCS Study BOEM 2018-xxx. 293 p
[7] Kepes J., King K., Gates D., Hunter C. "Conventional exploration results in 2018 through early 2019: Signs of recovery but no rebound." IHS Markit Upstream Plays & Basins. June 2019.

conventional NFWs given portfolio shifts, cycle compression, and existence of nearby infrastructure, frontier and emerging basins will generate the majority of new conventional volumes.

Basin Classification

- **Frontier Phase:** Prior to initial commercial discovery, not extensively drilled, risky but essential for successful exploration, good geological understanding, signs of active hydrocarbon system lower risk.
- **Emerging Phase:** Post-first commercial discovery, exploring to geographical and stratigraphic limits of basin. Most volumes are discovered.
- **Maturing Phase:** Declining discovery, satellite fields, and incremental recovery improvement.
- **Rejuvenation:** Significant increase in recovery especially due to horizontal drilling and fracking. Unconventional recovery.

The global share of conventional NFWs drilled in frontier areas increased from 8 percent in 2005 to about 20 percent in 2014. However, this trend reversed in 2014, with frontier and emerging basin NFWs accounting for about 14 percent in the 2015–18 period (Figure 1-2). The contribution of NFWs drilled in frontier areas to all global conventional discoveries is, however, much more significant—accounting for 60 percent of the total conventional discovered volumes in the same period (Figure 1-3).

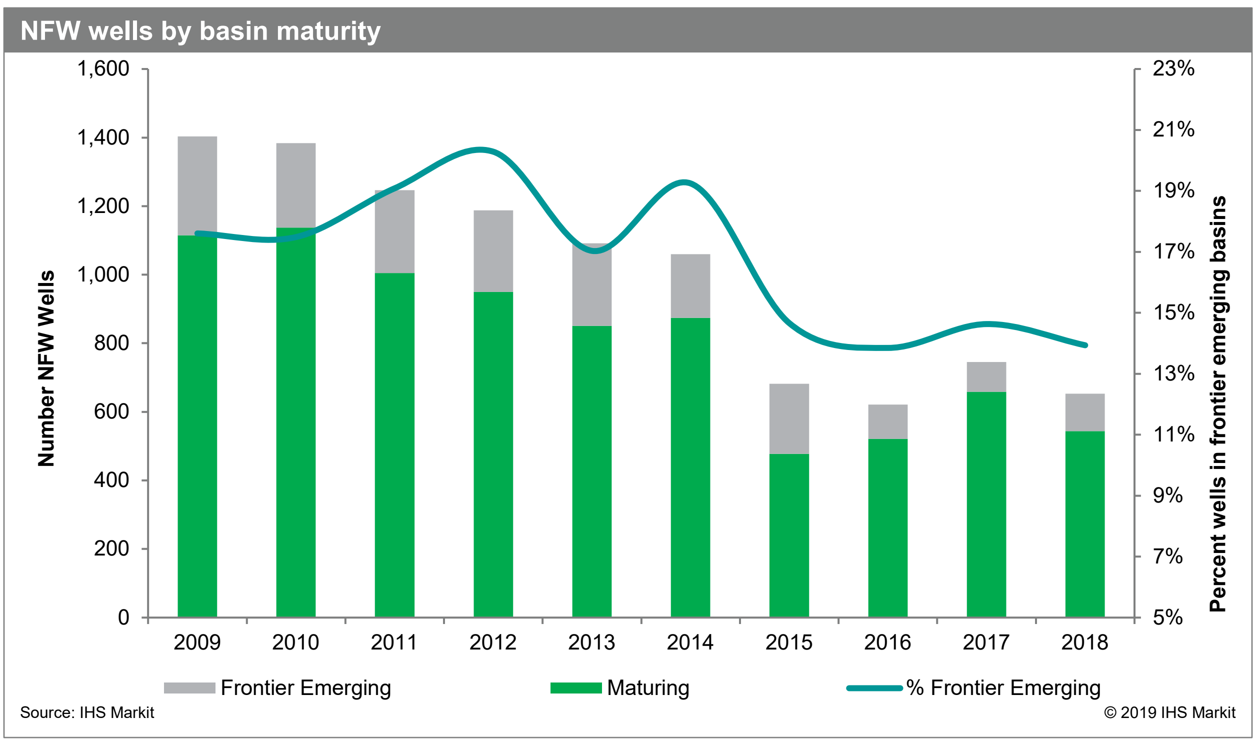

Figure 1-2. Annual NFWs in frontier and emerging basins vs. maturing and rejuvenation basins

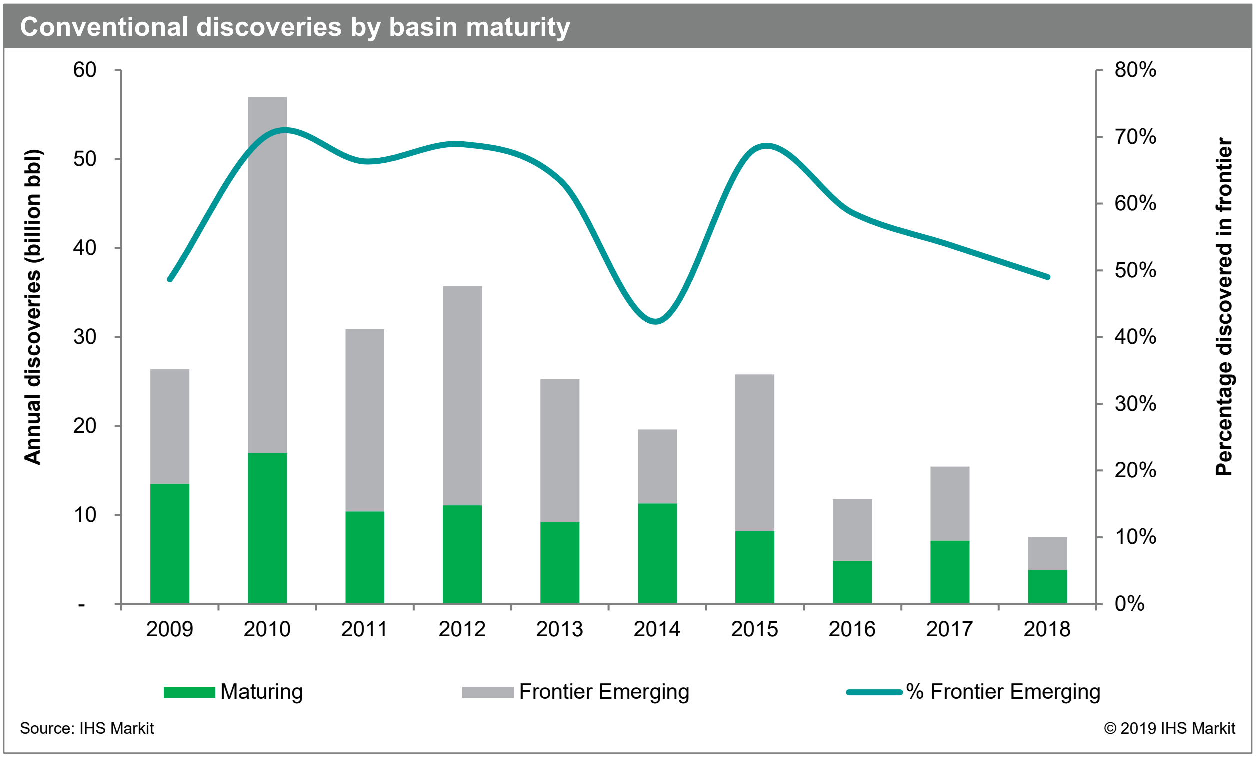

Figure 1-3. Annual conventional discoveries in frontier and emerging basins vs. maturing and rejuvenation basins

3. Going forward, IHS Markit expects increasing efficiencies in the offshore environment, including through digitalization. Technology is broadly expected to continue to yield efficiency and productivity gains in the oil and gas industry, including in the offshore environment.[8] Such advancement can derive from a wide variety of sources, including analytics, artificial intelligence, data science, and machine learning. Organizations increasingly have the capabilities to use data to improve planning and operations.

Frontier offshore oil and gas operations can be extremely expensive and idiosyncratic. Initial finding and development costs may not be greatly impacted by efficiencies and improvements in the industry. However, if any of the frontier areas experience substantial development, they are more likely to benefit from industry improvements.

[8] Jacobs J. et al. "Oil's new strategic asset: leveraging technology, big data, and analytics to create competitive advantage." IHS Markit. January 2019.

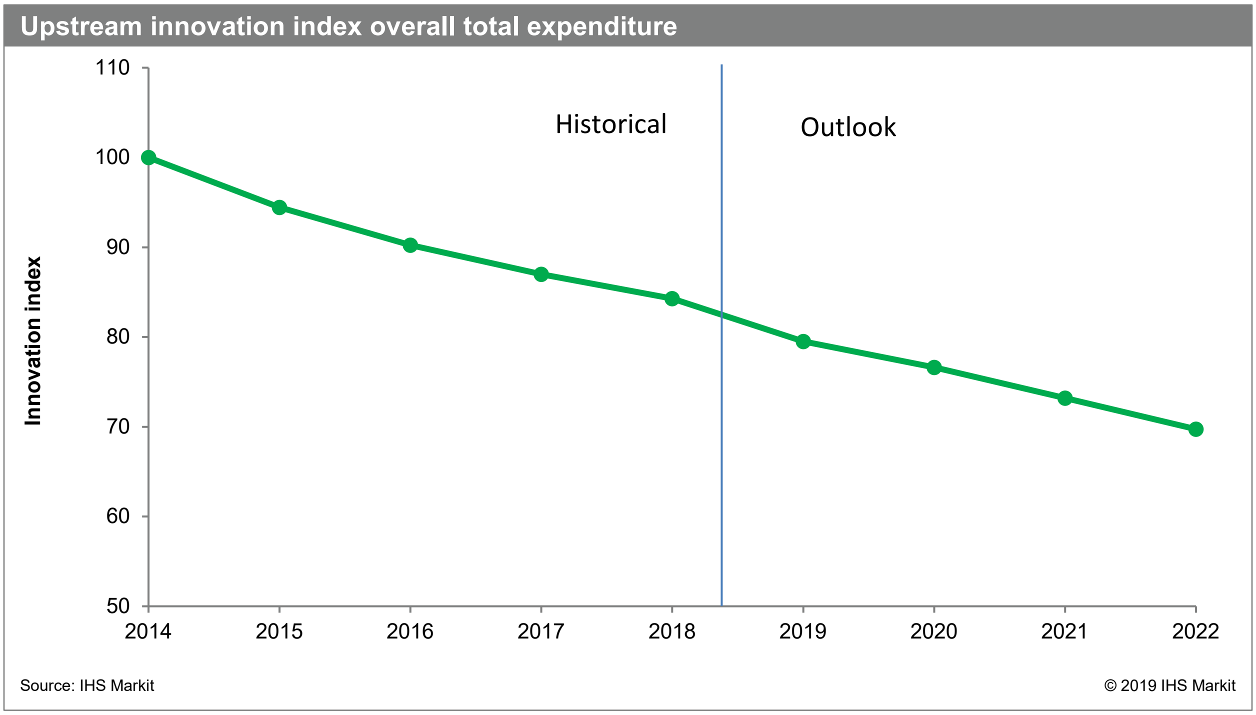

Figure 1-4. Upstream innovation index

The IHS Markit Upstream Innovation Index (Figure 1-3) tracks construction and operations costs for 80 oil and natural gas projects across a variety of terrains and geographies. The index has declined by more than 15 percent from 2014 to 2018 due to innovation and cyclical cost declines.[9] The index is expected to decline by approximately another 15 percent from 2019 to 2022 as a result of additional innovation. Innovations such as digitization and automation are key factors affecting the costs for offshore oil and gas operators, especially those operating in frontier basins. As Equinor officials noted during the 2019 Offshore Technology Conference, in offshore operations, automation and digitization will enable smaller fields to be profitable as technology allows the industry to shift to smaller unmanned structures and the use of advanced robotics.

1.3 Approach and Scope of Work

1.3.1 Jurisdictional Selection and Field Sizes

Following the approach of the GOM international comparison report, this report compares U.S. regions with two separate peer groups—the Alaska offshore frontier and the Non-Alaska offshore frontier. The criteria used to select the different peer groups and field sizes reflect the uniqueness of current offshore frontiers areas.

To mirror each investment environment, this study separately analyzed the offshore Arctic and Non-Arctic regions. IHS Markit relied on its proprietary fields and well data sets to review historical discoveries and generate development cost models for this study. A total of 60 exploration and development cost models representing 15 offshore Arctic field developments and 45 offshore Non-Arctic frontier developments were

[9] Asmar B. "Structural upstream project changes expected to continue to drive costs down by 15 percent until 2022, countering inflationary cyclical costs." IHS Markit Energy & Natural Resources. February 2019.

created for this comparative review—resulting in a total of 180 economic models when the three price scenarios are applied. This report relies on actual exploration and development costs in each jurisdiction, accounting for factors such as reservoir depth, reservoir pressures, water depths, marine weather (e.g., currents, ice) distance to market, local cost factors, local gas prices, and drilling windows in the Arctic environment, as well as many other cost drivers.

Alaska Offshore Frontier Areas: The jurisdictions in this peer group were selected for their geological and geographic similarities with the U.S. Beaufort Sea and Chukchi Sea areas, as proposed in the *2019–2024 National OCS Oil and Gas Leasing Draft Proposed Program* (2019–24 DPP). This frontier peer group includes areas in Arctic or sub-Arctic climates where exploration has been sparse, arrested, or is in its early stages with few discoveries made to date.

Per the study requirements, the Alaska Federal offshore fiscal system is compared against three other offshore Arctic and sub-Arctic environments. Given the insufficient candidates with Arctic exploration activity and presence of commercial discoveries, the peer group selection process was extended to sub-Arctic environments such as the Falkland Islands, and Faroe Islands. By narrowing the peer group, IHS Markit focused on the location of Arctic and sub-Arctic oil and gas discoveries and the production status of such discoveries. Jurisdictions with either producing or developing discoveries were selected. Jurisdictions with no reported discoveries such as Greenland or Iceland were not included for consideration.

Table 1-1. Alaska frontier offshore peer group selection criteria

No.	Fiscal system	Location	Production status of discoveries	Climate	Selected jurisdictions for comparison
1.	Argentina federal	Offshore Malvinas Basin	Non-producing discoveries	Sub-Arctic	
2.	Canada – NWT	Offshore	Producing and non-producing	Arctic	√
3.	Falkland Islands	Offshore	Non-producing (under development)	Sub-Arctic	√
4.	Faroe Islands	Offshore	Non-producing discovery	Sub-Arctic	
5.	Norway	Offshore Barents Sea	Producing and non-producing	Arctic	√
6.	Russia	Offshore (East Barents Sea)	Producing and non-producing	Arctic	

Source: IHS Markit

The filtering process also considered other restrictions on investment in particular jurisdictions. Thus, U.S. sanctions on Russian Arctic oil and gas exploration led to the elimination of Russia as a potential candidate for this analysis.

IHS Markit reviewed previous oil and gas discoveries in the Beaufort and Chukchi seas and considered the resource endowment for the offshore sections of the North Slope Basin to determine the field sizes for this study. Crude oil volumes from past discoveries in the offshore portion of the North Slope Basin have ranged from 50 MMbbl to 2 billion bbl. That served as the basis for the selection of the following field sizes for this study: 100 MMbbl, 400 MMbbl, and 1,000 MMbbl.

Table 1-2. Alaska frontier offshore peer group and hydrocarbon type

Jurisdiction	Basins	Field sizes (MMbbl)	Hydrocarbon type
U.S. Beaufort Sea	U.S. Beaufort & Chukchi Seas	100 MMbbl 400 MMbbl 1,000 MMbbl	Oil
U.S. Chukchi Sea	U.S. Beaufort & Chukchi Seas		
Canada NWT	Canada NWT offshore		
Norway	Norway Barents Sea		
Falkland Islands	North Falkland Basin, Falkland Plateau Basin		

Source: IHS Markit

Non-Alaska offshore frontier: The jurisdictions in this peer group were selected for their geological and bathymetric similarities to the Atlantic, Eastern GOM, and Pacific areas proposed in the 2019–24 DPP. While all frontier areas are different, the selected jurisdictions share common characteristics such as challenges related to existence of little or no infrastructure, higher geologic risk, or other challenges associated with ocean currents. The selection process led to the five international jurisdictions included in Table 1-3 for this peer group. The original selection included French Guyana and New Zealand in this peer group; however, both jurisdictions recently passed regulations preventing the grant of new E&P licenses offshore.

Table 1-3. Non-Alaska frontier offshore peer group historical discoveries

Jurisdiction	Smallest discovery volumes (MMboe)	Largest discovery volumes (MMboe)	Number of discoveries
Falkland Islands	187	530	9
Ireland	71	79	6
Argentina	4	130	5
South Africa	26	238	9
Morocco	13	51	4

Source: IHS Markit

IHS Markit considered several factors to determine the oil and gas field sizes for this study. These factors included: historical recoverable reserve volumes of fields discovered in each frontier jurisdiction, hydrocarbon resource potential, and economic conditions for development of stand-alone fields in frontier areas. The selection process reconciled the size of historical discoveries in the jurisdictions of the peer group with the investor expectations when entering a frontier basin with no infrastructure. Generally, investors expect field sizes of 500 MMboe or greater when drilling in a frontier offshore basin with no infrastructure in place. However, given the smaller size of expected discoveries in U.S. Non-Alaska frontier regions, the study considered fields smaller than 500MMboe. Hence, the resulting field sizes selected for this study are: 100 MMboe, 200 MMboe, and 500 MMboe.

Table 1-4. Non-Alaska offshore frontier peer group and field sizes

U.S. Non-Alaska frontier offshore regions	Peer group	Field sizes (MMboe)
U.S. Federal Atlantic U.S. Federal Eastern GOM U.S. Federal Pacific	Argentina Falkland Islands Ireland Morocco South Africa	100 MMboe 200 MMboe 500 MMboe

Source: IHS Markit

1.3.2 Exploration and Development Costs

To properly represent the investment environment in each jurisdiction, the study relies on development cost models that account for the characteristics of the geological formations in the respective jurisdictions, the respective geological formation and water depths, reservoir pressure, distance from infrastructure, regional costs, etc. The following subsections provide detail to the field development concepts used for each peer group.

1.3.1.1 Alaska Offshore Frontier—Exploration and Development Cost Models

IHS Markit relied on its proprietary regional cost databases and publicly available information to build custom cost models for each jurisdiction in the Alaska offshore frontier peer group.

For the Beaufort Sea development concepts, IHS Markit used gravel islands and ice roads, such as the ones planned for the Liberty project and other Beaufort Sea projects on Federal submerged lands. Gravel islands enable costs saving in terms of rigs and facilities, but the time to complete gravel islands represents a major challenge to project profitability. Arctic pipelines are buried deeper to resist ice flow dredging. Once the pipeline is built, the operator can deliver incremental resources with greater economic efficiency by tie-in to the line. The development concept also accounts for the seasonal drilling restrictions imposed by the Federal government when permitting for oil and gas drilling in the Beaufort Sea.

For the Chukchi Sea (and the Canadian Mackenzie Delta offshore), IHS Markit used a gravity-based structure (GBS) development concept. This is a typical artic development able to survive the harsh environment. Developments using GBS are very capital–intensive, given the sheer amount of steel and cement required.

The Norwegian Barents Sea and the Falkland Island fields are modeled using FPSO development concepts used in these jurisdictions. The Barents Sea—although in the Arctic region—seldom has any ice. This is due to the influence of the warm Gulf Stream current. The Falkland Island concept choice is in line with the Sea Lion development underway in this jurisdiction. FPSOs are flexible solutions for remote offshore areas that involve strong currents and winds, such as the Roaring Forties that affect the Falkland Islands.[10]

The Falkland Islands are in both the Alaska and Non-Alaska offshore frontier peer groups because they have characteristics similar to both environments. The fields modeled for the two peer groups vary with regard to reservoir depth and field development concept. Not only is the field size different, the development schedule and the throughput design differ due to capacity and safety requirements to handle different production volumes.

[10] The Roaring Forties are strong westerly winds found in the Southern Hemisphere, generally between the latitudes of 40 and 50 degrees.

1.3.1.2 Non-Alaska Offshore Frontier—Exploration and Development Cost Models

Unlike the areas covered in the 2018 GOM report, there are very few wells, and fewer discoveries, in the Non-Alaska offshore frontier areas included in this report. To account for the lack of information, analogs were identified. The U.S. Atlantic, Eastern GOM, and Pacific regions were studied particularly for analogs since they have mostly been off-limits for hydrocarbon exploration and development activities for several decades.

In the Atlantic Margin area, IHS Markit relies on the OCS report BOEM 2016-071[11] entitled "Inventory of Technically and Economically Recoverable Hydrocarbon Resources of the Atlantic Outer Continental Shelf" for the identification of the characteristics of the prospects modeled. That report led IHS Markit to conclude that the bulk of resources (both technically and economically recoverable) will most likely be in the Mid-Atlantic. IHS Markit used the top-five assessment units, totaling 88 percent of the total projected resources, to build the analog's characteristics, which yielded the modeling of the fields described in Appendix B.

For the Pacific region, IHS Markit uses analogs in the Santa Maria and Santa Barbara basins in the Southern California Planning Area, as these areas have more historical production. While Southern California is not considered a frontier region, the analogs were used to assess the potential discoveries in Central California and other parts of the Pacific, since additional resources are expected to be found in these regions. Hypothetical fields are situated 50 miles off the coast.

In the Eastern GOM, IHS Markit modeled the large oil and gas fields after the Norphlet play, a major play including large fields such as Appomattox, Destin Dome, and other deep gas discoveries. The Norphlet play gets shallower closer to shore. For the other cases, analogs were derived from the Central GOM, but were adjusted to account for differences in water depth and reservoir depth. Additional research on the Eastern GOM regional bathymetry and geology resulted in significant variances in water depth and reservoir depth (Table 1-5). The oil and gas output per well used in these cases was similar to deepwater GOM averages for similar depths and field types. All models provide for the marketing of both liquids and gas streams in the respective regions.

The analogs for the other jurisdictions rely on public information related to the geology of the region, well test data, and other publicly available information. The field development case inputs for the Atlantic Margin were generated from the parameters determined from the OCS Report BOEM 2016-071. The field development cases for the Pacific margin were generated from oil field analogs in Southern California offshore basins. The field development cases for the Eastern Gulf of Mexico were generated using analogs in the Central Gulf of Mexico.

Table 1-5. Atlantic, Eastern GOM, and Pacific water and reservoir depth assumptions

Field size and primary product	Water depth (m)	Reservoir depth (m)	Development concept
Atlantic Gas 100 MMboe	67.1	4,750	Jacket + subsea tie-back
Atlantic Gas 200 MMboe	980	5,550	Tension Leg Platform (TLP)
Atlantic Gas 500 MMboe	1,590	7,380	TLP + subsea tie-back
Atlantic Oil 100 MMboe	120	4,710	Jacket + subsea tie-back
Atlantic Oil 200 MMboe	898	5,510	TLP + subsea tie-back
Atlantic Oil 500 MMboe	1,830	6,860	TLP + FPSO + subsea tie-back

[11] BOEM 2016-071: "Inventory of Technically and Economically Recoverable Hydrocarbon Resources of the Atlantic Outer Continental Shelf." U.S. Department of the Interior-Bureau of Ocean Energy Management-Gulf of Mexico OCS Region New Orleans-Office of Resource Evaluation. November 2016.

Field size and primary product	Water depth (m)	Reservoir depth (m)	Development concept
Eastern GOM Gas 100 MMboe	616	3,536	Jacket
Eastern GOM Gas 200 MMboe	988	3,840	Jacket
Eastern GOM Gas 500 MMboe	988	6,401	Spar + Subsea tie-back
Eastern GOM Oil 100 MMboe	975	4,633	Semi-submersible + subsea tie-back
Eastern GOM Oil 200 MMboe	774	3,170	TLP+ Subsea tie-back
Eastern GOM Oil 500 MMboe	2,201	7,480	Semi-submersible + subsea tie-back
Pacific Gas 100 MMboe	67	2,430	Jacket
Pacific Gas 200 MMboe	201	2,730	Jacket
Pacific Gas 500 MMboe	313	3,350	TLP + subsea tie-back
Pacific Oil 100 MMboe	78	1,830	Jacket
Pacific Oil 200 MMboe	201	2,130	Jacket
Pacific Oil 500 MMboe	1,030	2,750	Jacket + subsea tie-back

Source: IHS Markit

Exploration and development concepts for the Non-Alaska offshore frontier regions were generated using the regional costs databases of QUE$TOR™ software. This information was supplemented when suitable by publicly available information from projects in the region.

The analysis accounts for differences in water depths, TVD, well productivity, regional capital and operating costs, environmental or other regulatory compliance, and transportation costs in each jurisdiction. Exploration well cost estimates were prepared for each field case for each jurisdiction. These estimates are driven by the water depth and reservoir depth characteristics for each jurisdiction, while also accounting for rig type, local rig rates, and expected drilling times. The profiles modeled consider the exploration success rate in each jurisdiction. The cost of appraisal wells is also included in each model.

IHS Markit applied stand-alone development models for most of the cases in the Non-Alaska offshore frontier areas, except for one case in the Eastern GOM that ties in to the Central GOM existing infrastructure. The reason behind this choice is the expected proximity of the Eastern GOM's large resources to the Central GOM's commercial clusters.

The stand-alone development concepts vary wildly, since they reflect the diversity of the Non-Alaska offshore frontier peer group. This study assessed all types of offshore development, including jackets, tension leg platforms (TLPs), spars, semi-submersibles, FPSOs, and gravel islands. The selection of offshore concepts is driven by water depth, environmental conditions, local hazards, and common practices. All the frontier development concepts consider the level of existing infrastructure, existing and potential market locations, and the density of offtake capacity.

As in the 2018 GOM study, 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 relies on data from the IHS Markit EDIN database to determine the expected development parameters for each field model. EDIN is a global database of international E&P activity, including the frontier areas of the selected peer groups. EDIN also provides data in the form of a geographical information system (GIS) to determine distances and proximities to pipelines, platforms, markets, and other terminals.

The above process results in the following summary of key observation inputs for the Non-Alaska offshore frontier group:

- In Argentina, the target areas are in the shallower end of the Malvinas Basin, with water depths ranging between 43 m and 73 m and reservoir depths between 1,330 m and 1,570 m.
- In Ireland, the target areas are in the Porcupine Basin. Water depths range from 122 m to 146 m, with reservoir depths ranging from 1,330 m to 1,960 m.
- In the Falkland Islands, the target areas are in the North Falkland Basin and the Falkland Plateau Basin, with water depths ranging from 404 m to 450 m and reservoir depths from 2,380 m to 2,430 m.
- In Morocco, the target areas are in the offshore section of the Rhard Prerif Basin, with water depths ranging from 545 m to 1,260 m and reservoir depths from 2,080 m to 2,390 m.
- In South Africa, the target area is in the Outeniqua Basin, with water depths ranging from 113 m to 123 m and reservoir depths from 2,410 m to 3,100 m.

1.3.3 Price Assumptions

The study uses three oil and gas price scenarios; a global market price is used for crude oil, while regional market prices are used for natural gas. The regional gas markets have different degrees of maturity. The natural gas prices selected for each region reflect the market structures in the region. For consistency, the IHS Markit base case crude oil and natural gas price outlooks are applied for this study, given that the EIA does not provide outlooks for natural gas prices in Europe. See Figure 1-5 for IHS Markit and EIA price crude outlooks to 2050. Only the base price scenario reflects the IHS Markit outlook—the outlook for third quarter 2018, which corresponds to the time when this study was commenced. The high and low case price scenarios were generated using a variance of minus 40 percent and plus 60 percent from the base case for the low and high case scenarios, respectively. See Figures 1-6 and 1-7 for the natural gas outlooks. Further explanation of the local gas hubs is included in Appendix C. The selection of crude oil and natural gas 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 witnessed in the past decade.

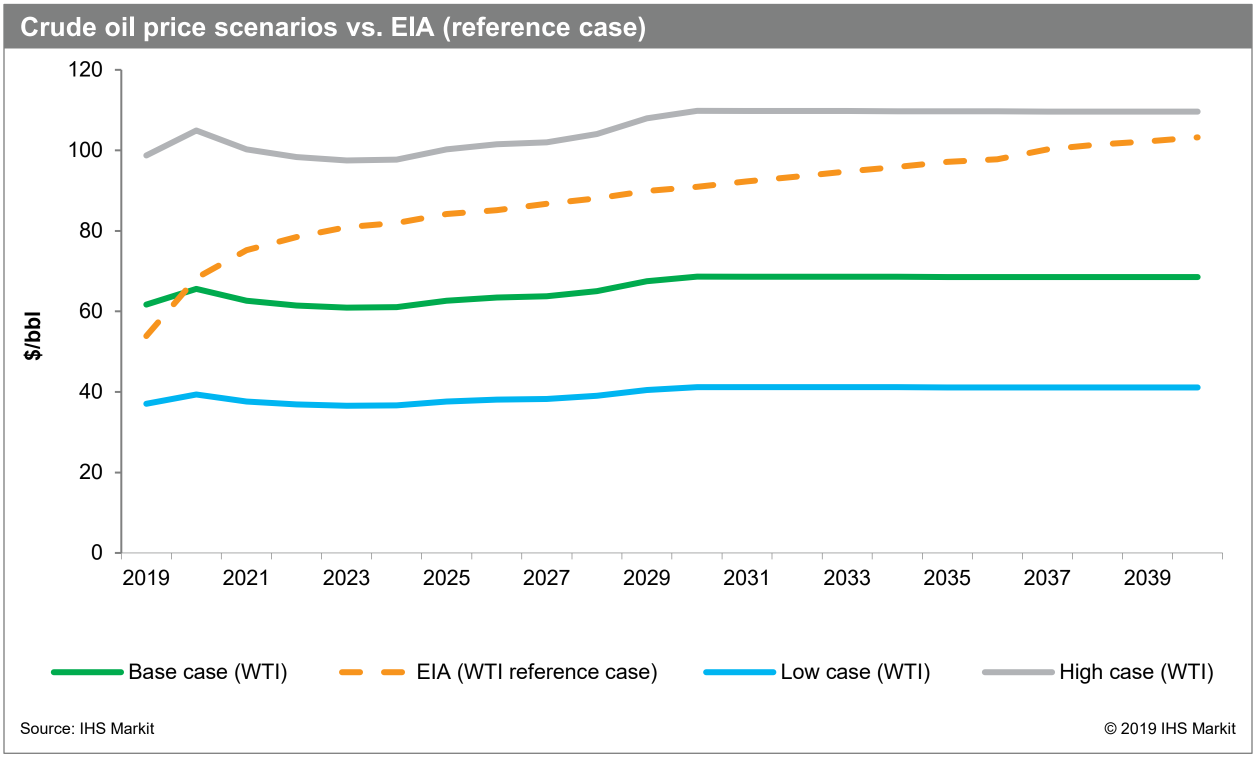

Figure 1-5. Crude oil price scenarios vs. EIA (reference case)

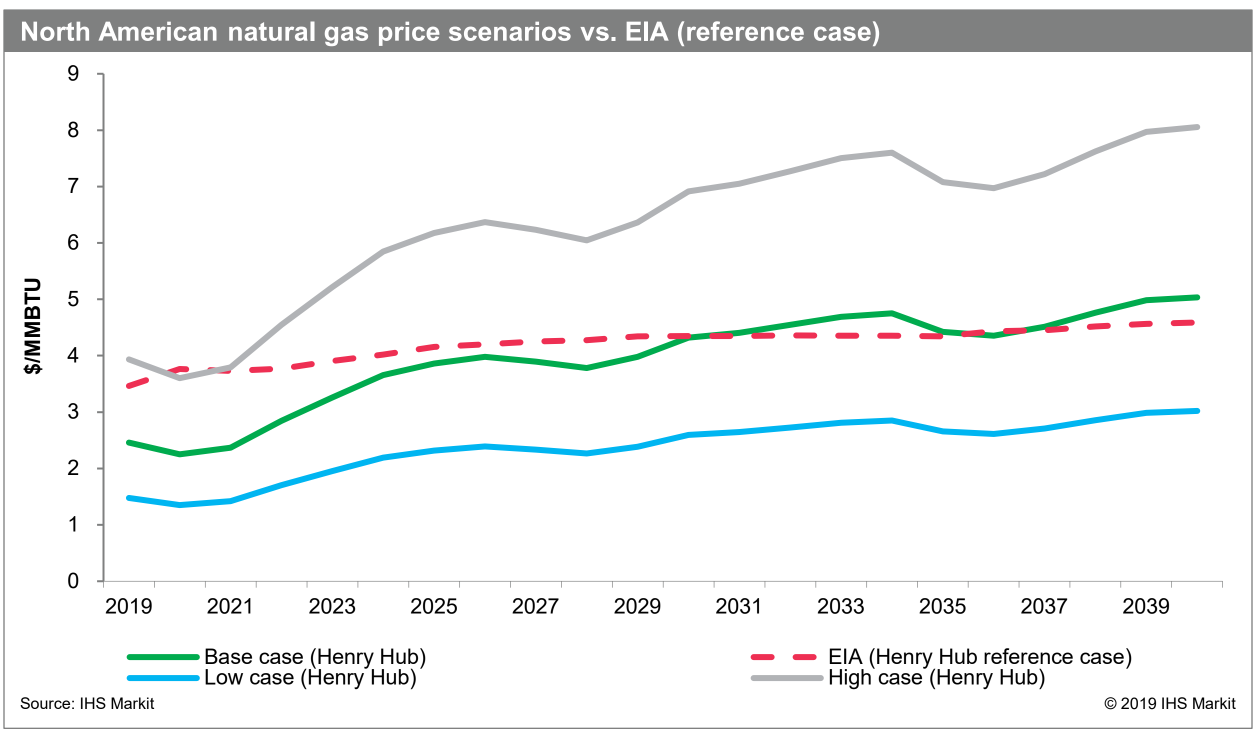

Figure 1-6. North American natural gas price scenarios vs. EIA (reference case)

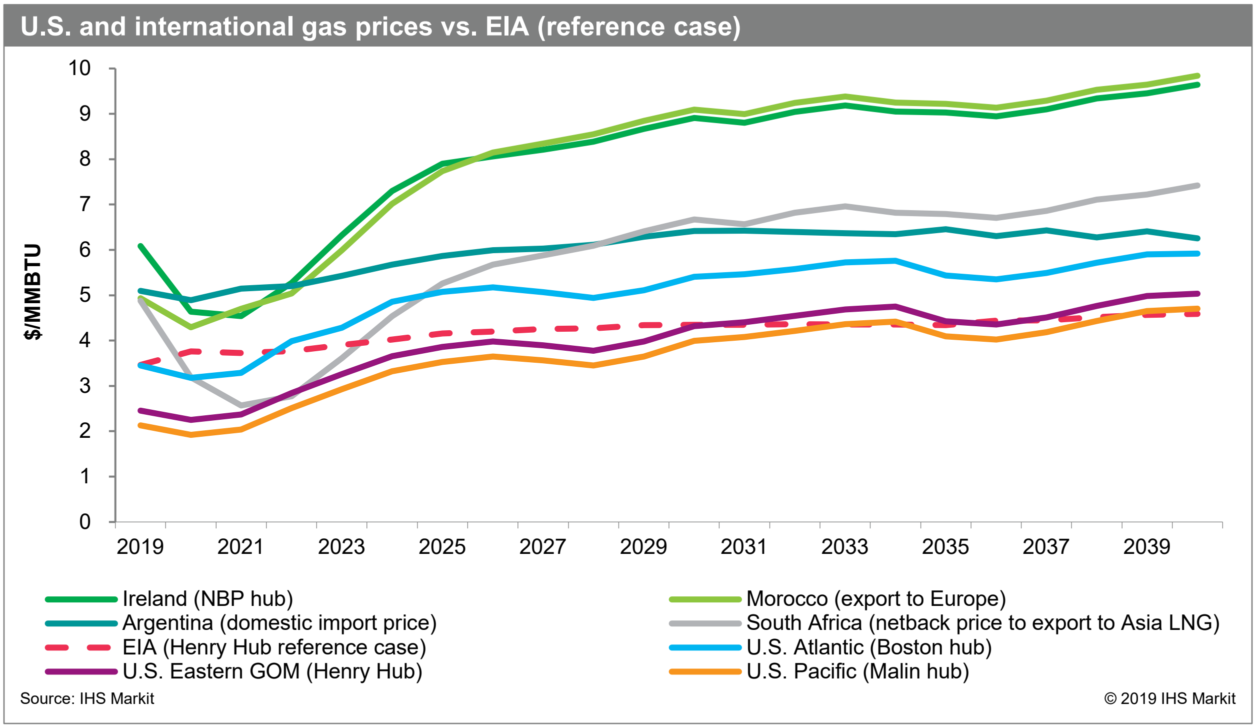

Figure 1-7. U.S. and international gas prices vs. EIA (reference case)

2 Characteristics of Fiscal Systems Reviewed

This chapter provides an overview of the lease/contractual and fiscal terms applicable in the jurisdictions reviewed for this study, as well as the criteria adopted by governments for the grant of E&P rights. Each of the components considered below plays a role in a country's ability to attract investments for oil and gas E&P activities.

2.1 Fiscal and Contractual/Lease Terms

Generally, frontier areas are offered with more attractive fiscal terms to investors than established offshore areas. The favorable fiscal terms are related to the scarcity of information associated with the exploration and development of hydrocarbons underlying frontier areas and the uncertainty associated with the resource potential. That is the case for both Arctic and Non-Arctic offshore frontier peer groups included in this study.

2.1.1 Types of Contractual and Fiscal Systems

The frontier jurisdictions included in this Offshore Frontier Report all adopt the royalty/tax fiscal system. The type of fiscal system adopted is not a predictor of the level of government take or the relative attractiveness of the terms adopted. Governments can achieve the same economic results under any fiscal system. However, the royalty/tax system is usually the preferred contractual system in terms of the degree of control it grants investors over E&P decision-making, as well as title to hydrocarbons.

2.1.2 Key Components of Government Take

This section examines some of the main fiscal instruments for the peer jurisdictions covered in this study; the focus is on the key components of government take. Additional levies and allowances apply in each of the jurisdictions reviewed. High-level summaries of the respective fiscal and contractual terms are shown in Appendix A. Table 2-1 lists the key fiscal instruments adopted by the two frontier offshore peer groups for this study.

Table 2-1. Key fiscal instruments

Fiscal system	Bonus	Royalties	Corporate income tax	Special petroleum tax	State participation
Argentina		●	●		
Canada NWT		●	●		
Falkland Islands			●		
Ireland			●	●	
Morocco	●	●	●		●
Norway			●	●	
South Africa		●	●		●
U.S. OCS	●	●	●		

Source: IHS Markit

2.1.2.1 Production-Based Levies

Royalties are the only production-based levies observed in the peer groups identified in this report. They consist of a combination of flat-based and sliding-scale royalties. For a description of the characteristics and impact of such levies on project economics, see part I of this study, *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison.* Table 2-2 provides the range of royalties applicable in each jurisdiction.

Table 2-2. Royalty rates applicable in peer group jurisdictions

Jurisdiction	Royalty rate
Argentina	5–12%
Falkland Islands	9%
Canada NWT	Maximum (1–5% of gross revenue, 30% net revenue)
Ireland	-
Morocco	0–10%
Norway	–
South Africa	0–5%
U.S. OCS	12.5%

Notes: Canada NWT offshore royalty is levied on either gross or net revenues, as opposed to gross proceeds applicable for other jurisdictions. The gross proceeds royalties do, however, allow for transportation cost deductions for oil and gas and processing costs in the case of 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 (Table 2-3). 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, uplifts, 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 percent of the cost of qualifying capex made during the year the equipment was first purchased. Among the jurisdictions surveyed, the U.S. offers such allowances.
    - **U.S. First-Year Bonus Depreciation:** Introduced under the Tax Cuts and Jobs Act (Public Law 115-97), it provides a 100 percent deduction in the first year that the property was acquired. This applies to 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.
    - **South Africa Uplift:** Capex uplifts of 100 percent for exploration and 50 percent for production are allowed. An uplift is a capex allowance above the 100 percent allowed either through depreciation or as expenses are incurred in the first year. The effect of the South African provisions is to allow investors to expense and deduct immediately 200 percent of the exploration costs and 150 percent of the development costs.
- **The Canadian Oil and Gas Property Expense (COGPE):** This is the cost of acquiring and maintaining an oil and natural gas property or lease and includes expenditure incurred for bonus and rental payment, as well as annual lease and rental payments made to maintain such rights. The

cumulative COGPE is written off at the rate of 10 percent on a declining balance basis for both Federal and provincial income tax purposes.

- **Treatment of Tangible Costs:** Tangible costs are depreciated or expensed in most regimes and can be described as assets 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 United States 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 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 (capitalized cost) 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 midyear spending.
    - **Canada Treatment of Tangible Costs:** In Canada, tangible costs related to the acquisition of assets generally located above ground are capitalized and qualify for the capital cost allowance. The declining balance depreciation rates vary according to classifications provided for in the federal legislation. The legislation provides for rates of 4 percent to 100 percent. However, the applicable rate for property acquired for determining the existence, location, extent, or quality of petroleum or natural gas accumulations for drilling oil or natural gas wells, oil storage tanks, and oil or natural gas well equipment is 30 percent.
- **Treatment of Intangible Costs:** 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 widely vary.
    - **U.S. Treatment of Intangible Costs:** In the United States, 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.
    - In the **Falkland Islands,** intangible development costs (including drilling) are fully deductible in the year they are incurred.
- **Treatment of Development Costs:** The Canadian Development Expense (CDE) includes costs incurred in the drilling, completion, and conversion of any development well and successful exploration well starting in 2019. Such costs are written off at rates of up to 30 percent per annum on a declining-balance basis for both federal and provincial income tax purposes.
- **Treatment of Exploration Costs:** Certain exploration costs could be written off as expenditure. The classification of costs qualifying for such treatment varies in each jurisdiction.
    - The **Canadian** exploration expense (CEE) includes several costs related to drilling oil and gas exploratory wells—the cost of successful exploratory wells is now classified as CDE. CEE can be either fully written off in the year incurred or deducted to the extent that there is sufficient income, after allowing for other income tax deductions, depending on the type of company.
    - In the **United States**, costs incurred in drilling a non-productive well could be deducted by the taxpayer as an ordinary loss.
    - In **Norway**, exploration costs could be expensed and deducted immediately or capitalized and depreciated.
    - **South Africa** provides for expensing of all expenditure of a capital nature incurred for exploration.
    - In **Morocco**, the investors have the option to expense reconnaissance, exploration, appraisal, and development costs, "non-compensated drilling costs," and dry hole costs.

- In **Ireland**, exploration expenditure is capitalized and depreciated. When E&P activities move from exploration license to a petroleum lease, past exploration expenditure can be written off on the day the petroleum lease is granted. Subsequent exploration expenditure is deductible as incurred.
- The **Falkland Islands** provides for deduction of exploration and appraisal costs in the year they are incurred.
- In **Argentina**, the cost of dry exploratory wells is expensed in the year incurred.

Table 2-3. Nominal income tax rates (peer group)

Jurisdiction	Nominal income tax rate
Argentina	30% in 2019, 25% beginning in 2020
Canada NWT	15% (Crown) + 11.5% (Territory)
Falkland Islands	26%
Ireland	25%
Morocco	10–31%, function of taxable income
Norway	23%
South Africa	31%
U.S. OCS	21%

Source: IHS Markit © 2019 IHS Markit

Special Petroleum Taxes: Only two of the jurisdictions reviewed for this study include special/additional petroleum income taxes. Such taxes can be levied on the same basis as income tax with additional credits or allowances, as in Norway, or they can be linked to production volumes and applied at progressive rates on net revenue before income, as is the case in Ireland. Norway applies a flat tax rate of 55 percent. In Ireland, the tax rate ranges between 5 percent and 40 percent of the net revenue.

Notable incentives or allowances for special petroleum taxes include Norway's uplift for development costs—currently applied at 5.3 percent over four years (for a total of 21.2 percent) on development costs, resulting in depreciation rate of 121.2 percent. In the case of Ireland's treatment of deductions, depreciation, overheads, interest, decommissioning and abandonment costs, and interest are the same as they are for the general corporation tax. However, losses may not be carried forward or back for Profit Resource Rent Tax (PRRT).

2.1.2.3 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), as in the case of South Africa, or on a carried interest basis (where the investor carries the national oil company through exploration, and sometimes also through development), as in the case of Morocco. In the latter case, the government pays its share of exploration and/or development costs through proceeds from its profit share. Among the offshore frontier regions covered in this study, Morocco and South Africa are the only ones that use state participation. Norway sometimes uses state participation as an instrument for investment on a working interest basis in offshore licenses. However, this option is not exercised in the Barents Sea areas covered in this analysis.

2.1.2.4 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:

Carbon Tax: Norway, Canada, Argentina, and Ireland 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. Argentina introduced a carbon tax of $1–10/metric ton of CO_2 emitted, starting at $1 in 2019 and reaching $10 in 2028. Canada NWT are also implementing a carbon tax that on July 1, 2019.[12] The price will start at Canadian dollar (CAD) 20 ($15.19) per metric ton of carbon dioxide equivalent (CO_2e) and increase at a rate of CAD10 ($7.59) per year until reaching CAD50 ($37.97) in 2022. In Ireland, a carbon tax has been levied since 2010 at the price of EUR20 ($22.55) per metric ton of CO_2 emitted.

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:** Morocco and the United States are the only frontier jurisdictions where signature bonuses are applicable. More information on bonuses payable is included in Section 2.2, Acreage Award Criteria.
- **Training Fees:** Morocco and South Africa adopted training fees in their respective fiscal terms. Such payments are usually associated with the exploration period, typically a biddable flat amount per hectare in South Africa or a biddable annual flat amount committed by the participants.
- **Rental:** Annual rental payments apply in the majority of the jurisdictions surveyed. They usually apply during the exploration phase.

2.2 Acreage Award Criteria

Jurisdictions in this peer group rely on competitive bidding, as well as open-door policies to grant E&P rights. An open-door policy is often adopted in areas where the competitive bidding process is unlikely to yield desired results. While an open-door policy does not set predetermined timelines, it can still offer investors the opportunity to compete. Thus, in Ireland, a notice inviting competing license applications must be published in the Official Journal of the European Union following a receipt of a license application or prior to granting a license.

Except for Norway, which includes Barents Sea areas in its annual licensing rounds, all jurisdictions in the two frontier offshore peer groups selected for this study offer acreage on an irregular basis. Table 2-4 shows the licensing process adopted by each jurisdiction. For a description of the processes to allocate E&P rights, see part I of this study, *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison.*[13]

Table 2-4. Allocation systems for award of E&P rights

Jurisdiction	Allocation system			Licensing frequency
	Open door	Competitive bidding		
		Discretionary allocation	Auction	
Argentina		●		Irregular
Canada NWT			●	Irregular
Falkland Islands	●			Irregular
Ireland	●	●		Irregular

[12] Government of Northwest Territories. "Implementing carbon pricing in the NWT."
[13] Agalliu I, *supra* note 1.

Jurisdiction	Allocation system			Licensing frequency
	Open door	Competitive bidding		
		Discretionary allocation	Auction	
Morocco	●			Irregular
Norway		●		Annual
South Africa	●	●		Irregular
U.S. OCS Frontier			●	Irregular

Source: IHS Markit

In awarding acreage to oil and gas investors, all peer jurisdictions, except for the United States, rely on work commitment as a bid factor. Cash bonus bids are infrequently used in frontier offshore acreage offerings given the high risk associated with E&P investments in frontier regions. Table 2-5 shows the bid variables applicable in each jurisdiction.

Table 2-5. Acreage award criteria

Fiscal system	Cash bonus	Work commitment	Social contribution
Argentina		●	
Canada NWT		●	
Falkland Islands		●	
Ireland		●	
Morocco		●	
Norway		●	
South Africa		●	●
U.S. OCS Frontier	●		

Source: IHS Markit

2.2.1 Work Commitments

Work program bidding is undertaken by the companies acquiring licenses, either through competitive bidding or an open-door policy, to carry out a specific work program during the initial and subsequent phases of the exploration period. It usually involves the acquisition of 2D and/or 3D seismic surveys in the early stages, followed by drilling one or more exploratory wells in the subsequent phases. Work program bidding is the preferred acreage allocation method for frontier areas. This method enables the governments to promote exploration and resolve the uncertainty surrounding the resource potential of the frontier acreage. Investors tend to be more incentivized to participate in a licensing process when work commitment is the sole bidding criteria—the cost of entry is lower than in the case of cash bonus bids.

Minimum work obligations are established as part of the bidding conditions in all jurisdictions except for the United States. The statement for the United States is made on historical data, since the United States establishes the bid terms on a sale-by-sale basis and no recent lease sales have occurred for the offshore frontier areas. The 1953 Outer Continental Shelf Lands Act does in fact provide for work commitment bidding as a potential bid variable under the various systems that the Secretary of the Interior may choose. Work commitment bidding, especially one associated with frontier offshore exploration, usually requires the resource holder to offer much larger areas than the ones offered in the U.S. OCS. More information on work commitments in each jurisdiction is provided in Appendix A.

2.2.2 Cash Bonus Bidding

Cash bonuses are only applicable in the United States, where traditionally a $25 per acre minimum bid applies for remote areas and a $37.50 per acre minimum bid applies for areas near existing infrastructure offshore Alaska. Lease sale terms are, however, set on a sale-by-sale basis. As of May 2019, the lease sale terms had not been set for the Alaska and Non-Alaska offshore frontier regions. The most recent sales in the U.S. Chukchi and Beaufort seas, which were held in 2008 and 2007, generated an average bonus bids of $965 and $85 per acre, respectively. The Chukchi Sea 2008 lease sale (Sale 193) generated the highest amount in signature bonuses in the history of Alaska OCS lease sales—generating $2.662 billion in revenue.

The most recent lease sale in the Eastern GOM, which was held in 2016, received no bids. Prior to that, the 2014 lease sale also did not receive any bids. The last lease sale to receive bids in the Eastern GOM was Sale 224 held in 2008, when the oil price averaged about $105/bbl—with the average bid at $340 per acre. These sales include only the unrestricted area of the Eastern GOM. Most of the Eastern GOM Planning Area is under moratorium until 2022, under the Gulf of Mexico Energy Security Act (GOMESA) of 2006. GOMESA restricts from oil and gas leasing the portion of the Eastern GOM Planning Area within 125 miles of Florida, all the GOM areas east of 86° 41' West longitude, and the part of Central GOM Planning Area within 100 miles of Florida.

The United States has not held lease sales in the Atlantic and Pacific regions since 1983 and 1984, respectively. The last sale in the Mid-Atlantic Planning Area generated $324.77 per acre, while the last sale in the Pacific—in the Southern California Planning Area—generated $543.17 per acre.

The requirement for upfront cash payments such as signature bonuses could be disadvantageous for U.S. offshore frontier areas. Investors prefer jurisdictions with low entry costs (i.e., low or no upfront payments when going into areas with greater uncertainty and higher costs than those of established offshore oil and gas regions). Cash bonus bidding is less efficient in frontier areas, particularly in a low commodity price environment when capital is limited, and investors are more risk averse.[14]

2.3 E&P Terms

2.3.1 Block Sizes

In frontier areas, the size of the blocks tends to be larger than in established offshore regions. As more information is obtained through seismic surveys and other drilling activity, governments tend to reduce the size of the blocks offered. Governments often correct for large block offerings through intermittent relinquishment obligations that allow relicensing of the relinquished areas and ensure continued investment in exploration of the acreage. The frontier offshore license areas widely vary among the jurisdictions reviewed—with the Falkland Islands and South Africa on one end of the spectrum, offering licenses with average acreage sizes greater than 10,000 square kilometers (km^2) and the United States on the other end of the spectrum with block sizes of 23.3 km^2. The smaller block sizes, combined with the cash bonus bidding, could be disadvantageous for U.S. frontier offshore exploration. Table 2-6 includes information on range of block sizes in each jurisdiction.

[14] Tordo S, *supra* note 3.

Table 2-6. Size of exploration blocks

Fiscal system	Range of block sizes (km^2)	Average block size (km^2)
Falkland Islands	539–29,185	11,034
South Africa	25.5–93,963	10,307
Morocco	1,358–24,054	7,617
Argentina – offshore Malvinas	2,000–8,800	3,020
Ireland	272–3,074	1,126
Canada NWT	659–805	755
Norway	100–3,800	500
U.S. OCS	23.3	23.3

Source: IHS Markit

2.3.2 Contract Duration

The timeframe allowed for exploration activities by the jurisdictions ranges from 8 years, in the case of Morocco, to 13 years, in the case of Argentina and the Falkland Islands. On average, such contracts are awarded for a 10-year period, with an initial period of 3–10 years.[15] The majority of jurisdictions have a cap on the duration of the production period, with the exception of Canada NWT, Ireland, and the United States, where production periods extend for the useful life of the field—or as long as oil and gas is produced in paying quantities. Table 2-7 contains information on E&P periods for the shallow water peer group.

Table 2-7. Offshore frontier contract duration

Jurisdiction	Initial exploration period (years)	1st extension of exploration period (years)	2st extension of exploration period (years)	3rd extension of exploration period (years)	Initial production period (years)	Extension of production period (years)
Argentina shallow water	4	3	4	n/a	30	10
Argentina deepwater	4	4	5	n/a	30	10
Canada NWT	5	4	n/a	n/a	25	Field life
Falkland Islands	8	5	n/a	n/a	35	Possible extension
Ireland	3	3	3	3	Field life	n/a
Morocco	3	5	n/a	n/a	25	10
Norway	10	n/a	n/a	n/a	30	20
South Africa	3	2	2	2	30	30
U.S. OCS Frontier	10	n/a	n/a	n/a	Field life	n/a
Key: n/a = not applicable						

Source: IHS Markit

[15] The initial period under international E&P contracts is not the same as the primary term in the United States. 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.

2.3.3 Relinquishment Obligations

The majority of frontier jurisdictions reviewed in this study impose some relinquishment obligation, except for the United States and Canada. The United States does not impose any relinquishment obligations, largely due to the relatively small size of the blocks being offered. Relinquishment obligations vary among jurisdictions and are often graduated from one phase to the next, with a cumulative of 50 percent of the original area as a common obligation by the end of the exploration period.

The combination of large exploration license areas with gradual investment commitments and relinquishment obligations balances investors' need for flexibility in the work program and governments' objective to ensure that a certain level of exploration will take place.[16] Table 2-8 provides a high-level summary of relinquishment obligations in each jurisdiction.

Table 2-8. Relinquishment obligations

Jurisdiction	Exploration period			
	End of initial period	End of 1st extension	End of 2nd extension	End of exploration period
Argentina	n/a	50%	n/a	n/a
Canada NWT	n/a	n/a	n/a	n/a
Falkland Islands	Can keep 50% of original area + 10% per well drilled	50% of remaining area	n/a	Relinquish all areas except development area
Ireland	25%	50% of remaining area	n/a	n/a
Morocco	20–30%	50% of original area	n/a	n/a
Norway	n/a	n/a	n/a	Relinquish all areas except development area
South Africa	20%	15%	15%	n/a
U.S. OCS	n/a	n/a	n/a	n/a
Key: n/a = not applicable				

Source: IHS Markit © 2019 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 contractors 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 2-9 provides a high-level summary of domestic market obligations.

[16] Flexibility in the work program is ensured by gradual obligations, where the decision to enter into the next work obligation is based on information obtained from the work performed in the preceding phase.

Table 2-9. Domestic market obligations

Jurisdiction	Domestic market obligations	Cap on amount supplied	Market value
Argentina	Yes	n/a	Yes
Canada NWT	None	n/a	n/a
Falkland Islands	None	n/a	n/a
Ireland	None	n/a	n/a
Morocco	Yes	Prorated	Yes
Norway	Yes	n/a	Yes
South Africa	None	n/a	n/a
U.S. OCS	None	20 percent of production to be delivered to small refineries	Yes
Key: n/a = not applicable			
Note: The DOI has not reserved offshore production for small refiners since 2009			

Source: IHS Markit

2.3.5 Decommissioning and Abandonment Requirements

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. While all jurisdictions have provisions for decommissioning and abandonment of offshore installations, not all require the provision of financial security against such obligation. The United States, Norway, and Morocco are among the jurisdictions with requirements for financial security tied to decommissioning and abandonment obligations.

The majority of jurisdictions treat the expenditure incurred for the abandonment of wells and offshore facilities as an operating cost deductible at the time the expenditure is incurred. Table 2-10 provides a summary of decommissioning requirements of the selected offshore jurisdictions.

Table 2-10. Decommissioning requirements

Jurisdiction	Obligation to carry out decommissioning	Financial security	Tax treatment of decommissioning cost
Argentina	Operator/Lessee	There is no provision for financial security.	Deductible
Canada NWT	Operator	There is no provision for financial security.	Abandonment costs may be written off in the year incurred and are classified as operating expenditure.
Falkland Islands	Licensee	There is no provision for financial security.	Deductible at the time of expenditure. Carry-back authorized for three years.
Ireland	Licensee	There is no provision for financial security.	Deductible. Carry back of losses up to three years if no other producing asset exists at the time of decommissioning.
Morocco	Investor	There is an indication that a requirement to contribute to an abandonment fund exists.	There is no specific provision regarding the treatment of decommissioning and abandonment costs.

Jurisdiction	Obligation to carry out decommissioning	Financial security	Tax treatment of decommissioning cost
Norway	Licensee	The Ministry of Petroleum and Energy 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.
South Africa	Right holder	There is no provision for financial security.	No specific mention of tax treatment of decommissioning costs.
U.S. OCS	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-specific abandonment account may be accepted by BOEM to meet decommissioning obligations.	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).

Source: IHS Markit

3 E&P Activity Overview

Assessment of the competitiveness of oil and gas fiscal systems cannot objectively be performed in a vacuum. An understanding of the E&P activity in other jurisdictions is important to understand the investment opportunities available to oil and gas companies globally, as well as the relative attractiveness of potential investments in the U.S. offshore frontier areas vis-a-vis the opportunities existing in the respective peer groups.

This chapter provides an overview of the historical exploration activity and success rates in the frontier basins of Alaska and Non-Alaska offshore frontier peer groups. This analysis is followed by a discussion of the YTF resources in the target regions, as well as a summary of the exploration and development costs in each jurisdiction.

3.1 Alaska Offshore Frontier—Peer Group Exploration and Development Activity

Exploration activity in the Alaska offshore frontier peer group has a long history, extending back to the 1970s. The most intense activity has taken place in the Arctic Norwegian basins relative to the overall peer group. Norway's Barents Sea accounts for 45 percent of the historical exploratory wells drilled within the peer group, followed by Alaska's Beaufort and Chukchi seas, which account for 23 percent of the wells drilled, and Canada's Mackenzie Delta for 20 percent of total wells drilled in the peer group (Figure 3-1). The dominance of exploratory drilling of the Barents Sea region versus other jurisdictions in the peer group is even more pronounced in the past decade, accounting for 63 percent of the wells drilled in the peer group. This is attributed to the fact that the Norwegian Petroleum Directorate offers Barents Sea acreage on an annual basis, while the other jurisdictions in the peer group offer acreage less regularly. The perception of prospectivity may also be a factor.

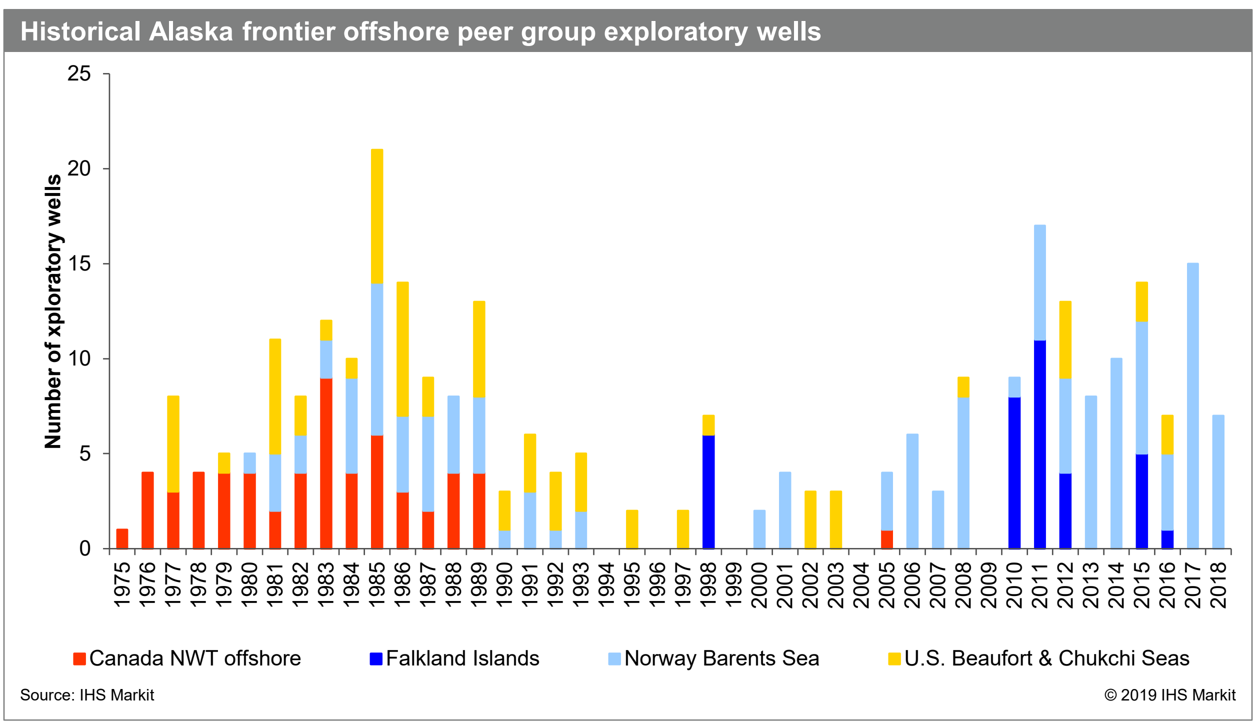

Figure 3-1. Historical Alaska offshore frontier peer group exploratory wells

When the historical success rate is considered, the Barents Sea and the Mackenzie Delta offshore regions have relatively higher success rates, at 35 percent and 33 percent, respectively (Figure 3-2). The U.S. Beaufort and Chukchi seas' historical exploration success rate of 16 percent improves to 25 percent when the focus is on the 2014–18 period (Figure 3-3).

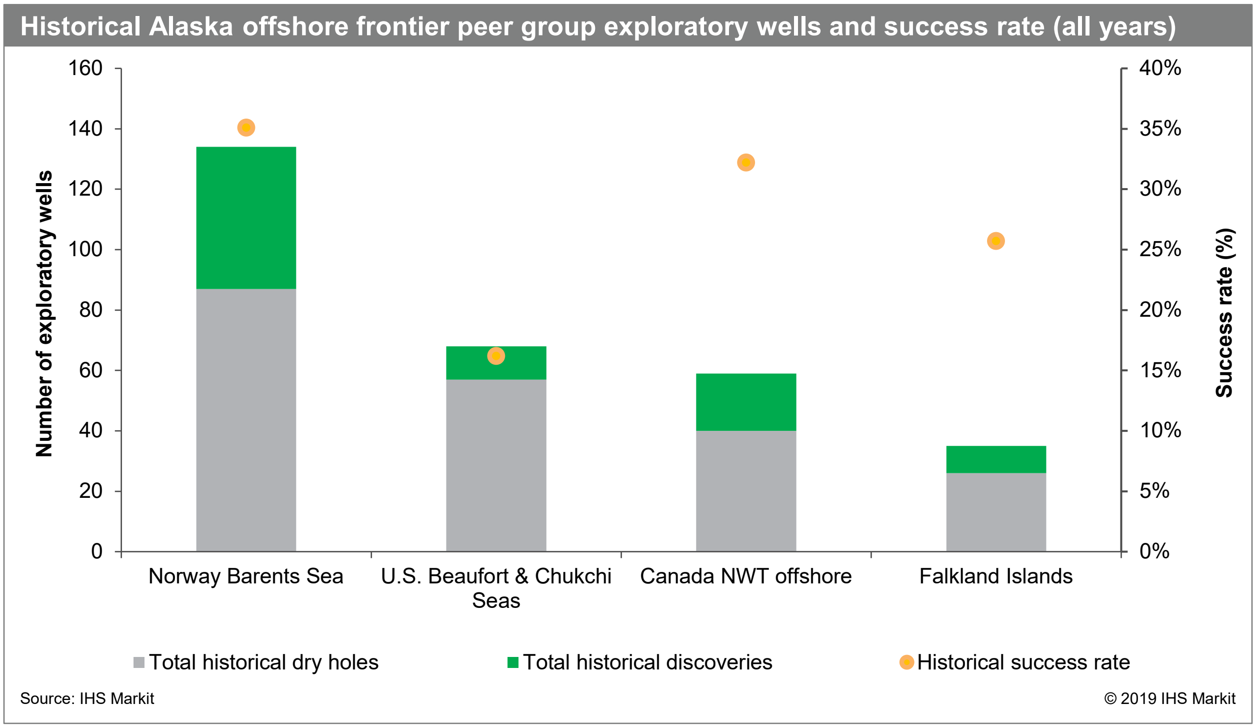

Figure 3-2. Historical Alaska offshore frontier peer group exploratory wells and success rate (all years)

When the focus is on the 2014–18 period, exploratory activity in the Barents Sea surpassed that of all members of the peer group. Indeed, about 76 percent of the peer group's offshore 2D seismic surveys between 2014 and 2018 were acquired in Norway's Barents Sea Basin. The remaining 24 percent was acquired in the U.S. Beaufort and Chukchi seas. Norway's Barents Sea Basin dominates the offshore Arctic peer group in terms of activity, with 43 exploratory wells (out of 53 total for the peer group) drilled in the 2014–18 period. There are several reasons for this.

- The Alaska Arctic offshore has seen little exploration activity due to a combination of factors, including infrequent lease sales, depressed commodity prices, legal challenges, withdrawal of acreage from leasing, and Shell's well-publicized cost overruns and operational challenges offshore Alaska.
- In the Canadian Mackenzie Delta, there has been no exploratory drilling in the same period, largely due to the cancellation of the Mackenzie Valley pipeline project in 2017, which effectively stranded all natural gas discoveries in the gas-prone reservoirs of the NWT section of the Beaufort Sea.
- Ultimately, the low natural gas prices in North America undercut the economics of gas development in NWT.

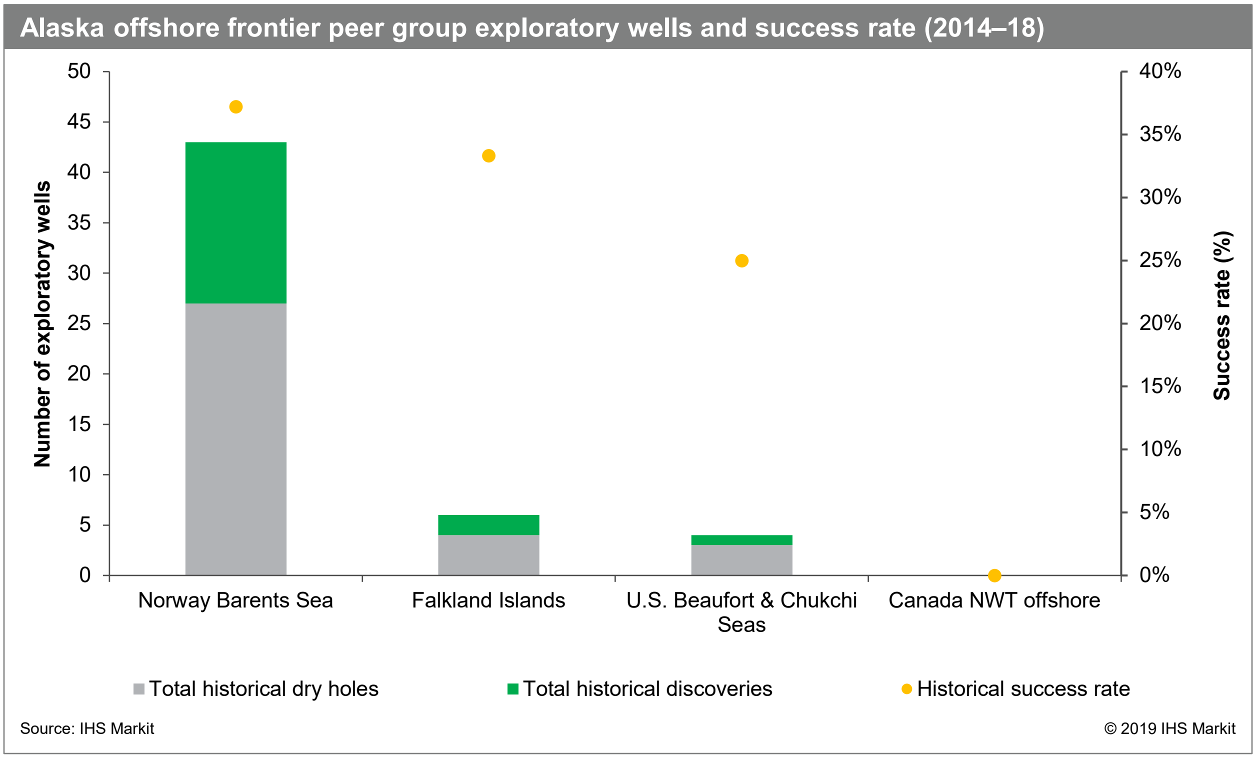

Figure 3-3. Alaska offshore frontier peer group exploratory wells and success rate (2014–18)

Development activity in the 2014–18 period is limited to the Norway Barents Sea in the Alaska offshore frontiers peer group, with 14 oil wells and 2 gas wells. During this time, there were no development wells drilled in Alaska's Beaufort and Chukchi seas, the offshore section of the Mackenzie Delta, or in the North Falklands Basin.

3.2 Non-Alaska Offshore Frontier—Peer Group Exploration and Development Activity (2014–18)

Exploration in this report's offshore frontier peer group peaked from the 1980s through the early 1990s and has since declined. This is due to several factors, including: 1) the opportunity set[17] changed (from exploration to development of discovered resources); 2) the exploration business initiated a more disciplined process of decision-making; and 3) the deepwater plays in the U.S. GOM, Angola, and Nigeria took off, while investment activity in the broader North Sea increased. Figure 3-4 shows the total number of exploratory wells drilled to date within the basins of the peer group. In the past, the shallow water parts of the South African Outeniqua Basin, the Argentina Austral Basin, and the U.S. Pacific basins attracted investment. This translated to various degrees of success (Figure 3-5).

[17] The possible expected return and standard deviation pairs of all portfolios that can be constructed from a given set of assets.

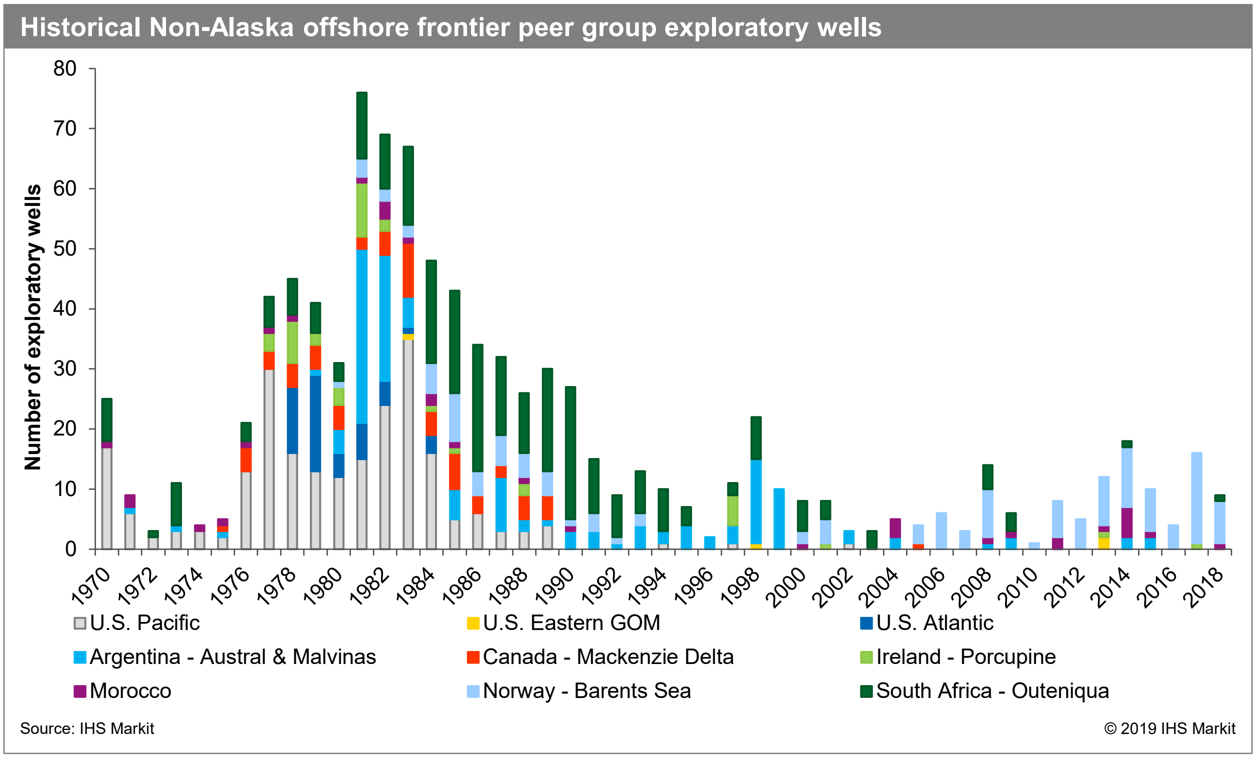

Figure 3-4. Historical Non-Alaska offshore frontier peer group exploratory wells

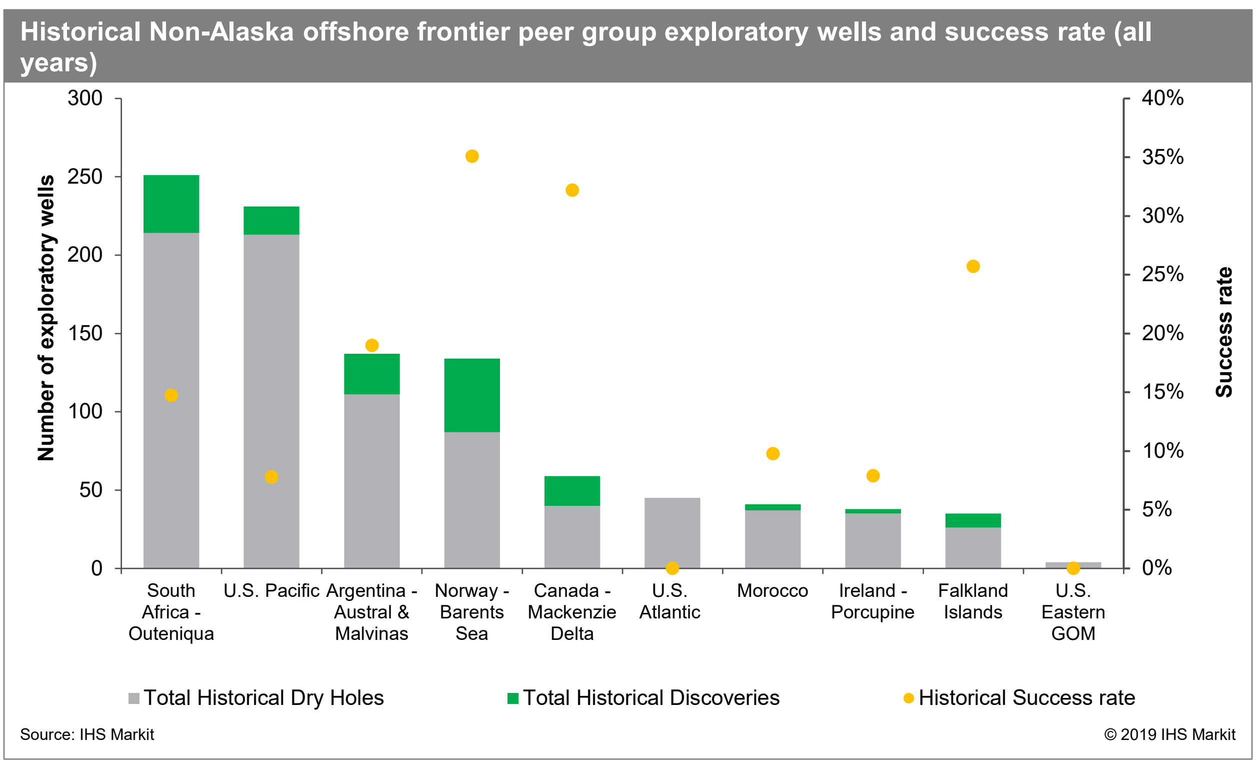

Figure 3-5. Historical Non-Alaska offshore frontier peer group exploratory wells and success rate

This study focuses on the 2014–18 period, which is characterized by a significant drop in global exploratory drilling activity. The underlying drivers include budget cuts in reaction to the fall in crude oil prices at the end of 2014, the breakdown of the consensus that offshore exploration activity represented a positive risk-reward ratio, portfolio choices by many operators (shifting to onshore North America), and the introduction of new play concepts and regions, the Atlantic Margin being one prominent example. Many of the NFWs drilled in the offshore frontier areas prior to the 2000s were shallow water wells, which contrasts with the increasing number of deepwater NFWs drilled post-2000.

The Atlantic Margin play includes offshore Morocco, which hosted the largest number of exploration wells drilled in the 2014–18 period (Figure 3-6). Overall, efforts met with failure, which underscores that in many areas, exploration remains a high-risk endeavor. Exploration and de-risking progress is likely to remain slow on the Moroccan Atlantic Margin. Other areas of the Atlantic Margin (mostly outside the peer group for this study) have been more successful.

Farther north on the Atlantic Margin, Ireland's Porcupine Basin had only two offshore exploratory wells drilled during the 2014–18 period. Technical challenges processing seismic data in the northern part of the Porcupine Basin—due to thick sections of igneous rock (with high velocities), combined with the depressed commodity market of 2015–16—might have contributed to the lack of exploration interest. IHS Markit anticipates a higher level of exploration activity in the southern portion of the basin in the coming years.

In the Southern Atlantic Margin, the Falkland Islands had a relatively high success rate in the peer group—33 percent—with the delineation of the Sea Lion field and potential secondary targets in the area. However, most of the Falkland Islands exploratory wells were drilled between 2010 and 2015.

While South Africa has the highest success rate in the peer group (50 percent success rate) for the 2014–18 period, that is based on a rather limited number of exploratory wells—two wells during the respective period (Figure 3-3). Nevertheless, Total's recent discovery (February 2019), which is reported to hold 500 million to 1 billion boe gas and condensate resource, could lead to the opening of a significant play in the Southern Atlantic Margin. The discovery lies approximately 175 kilometers (km) off the southern coast of South Africa, at water depths of 1,431 meters, in what is considered a very challenging deepwater environment characterized by high seas and strong winds and currents.

Argentina had only four offshore exploratory wells drilled by Total S.A. in the Austral Basin within the 2014–18 period. All wells yielded gas and were suspended. Argentina is expected to see more activity in seismic data acquisition and even a few NFWs as part of the ambitious opening of the offshore frontier areas of the Malvinas and the Austral Basin. The current Argentinean bid round closed on April 16, 2019, with large international operators like ExxonMobil, Total, Shell, and Equinor securing large blocks. This acreage is primarily in deep water (as is the case in the other parts of the Atlantic Margin play).

Exploration drilling is, however, not expected to materialize in the short term in Argentina's remote offshore areas, which are called the Roaring Forties for their punishing storms and sea conditions. The current bid round requirements recognize the difficulties of the enterprise by directing a minimum level of seismic data acquisition. Well commitments do not occur until the second exploration period for Argentina's 1st offshore round licenses.

There was a greater focus on Pacific basins exploration between the mid-1970s and the late 1980s; most of the wells were drilled in the southern Pacific area in the Santa Barbara–Ventura Channel Basin and the Santa Maria Basin. Historical exploration in the Pacific met very modest success, with only 8 percent of the NFWs classified as discoveries.

The Atlantic area also received a moderate exploration focus in the mid-1980s, with 45 exploratory wells drilled. However, exploration in the Atlantic region did not yield any commercial discoveries during this period.

Additionally, there were only four exploratory wells drilled in the Eastern GOM between 1986 and 2013 by Shell, Murphy, and BHP Billiton. All turned out to be non-commercial. There were no exploration wells drilled in the Federal Atlantic, Pacific, or Eastern GOM during the 2014–18 period.

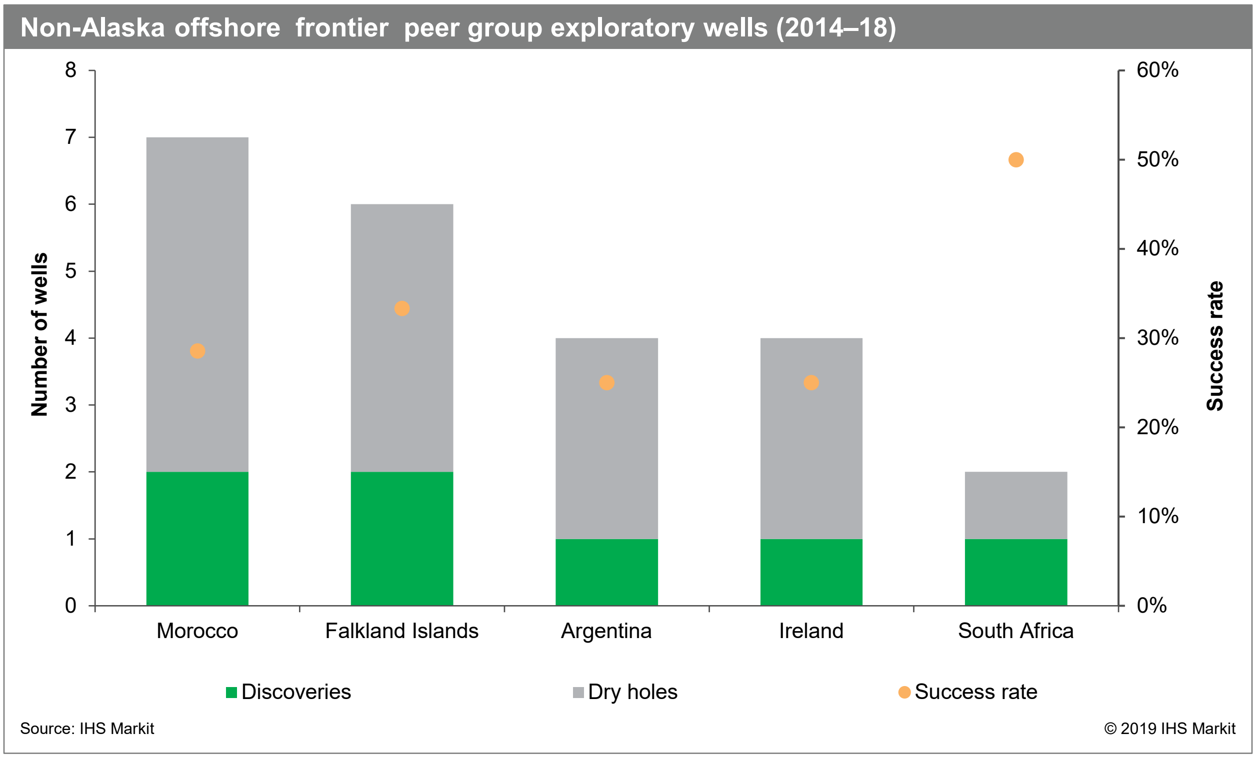

Figure 3-6. Non-Alaska frontier offshore peer group exploratory wells (2014–18)

During the 2014–18 period, development activity was limited to the U.S Santa Barbara (California) Continental Borderland and Santa Maria Basin, Argentina's Austral Basin, and South Africa's Outeniqua Basin (Figure 3-7). All fields developed in Argentina and South Africa are producing gas.

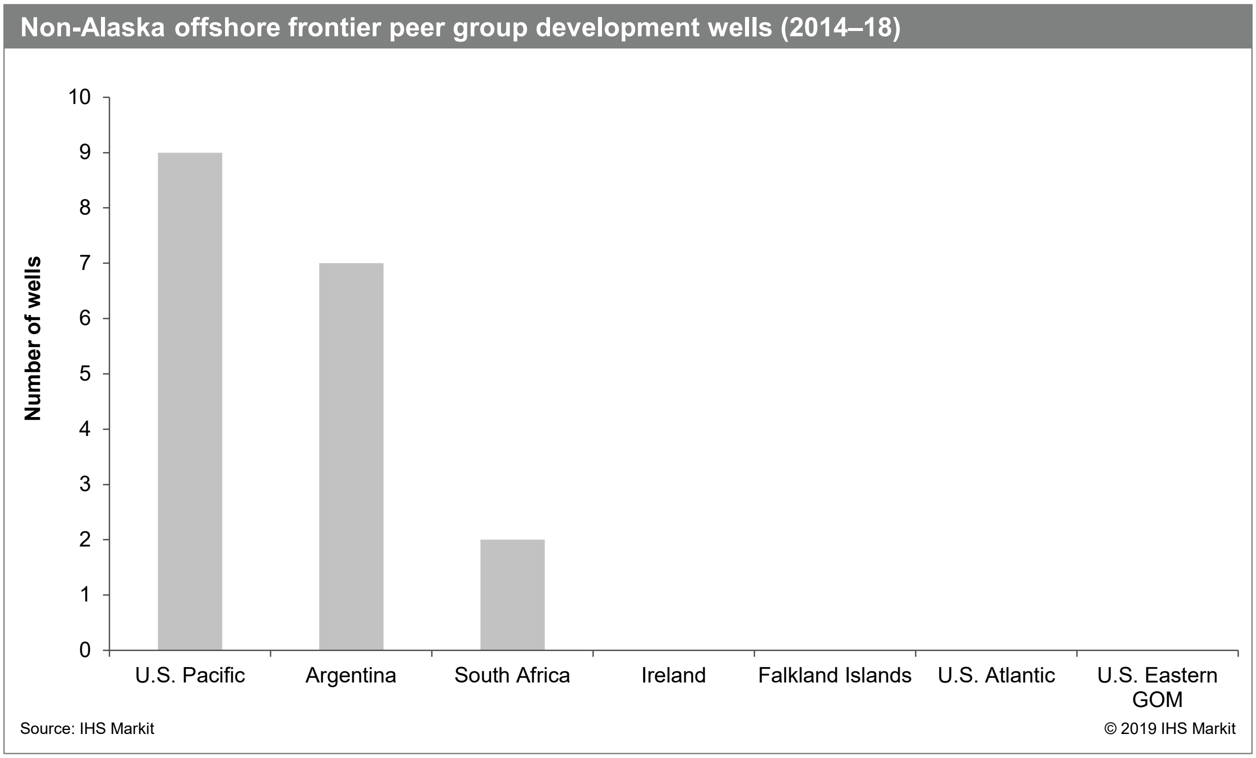

Figure 3-7. Non-Alaska offshore frontier peer group development wells (2014–18)

3.3 Assessment of Offshore Undiscovered and Undeveloped Resource Potential

Evaluating yet-to-find (YTF) resources for frontier areas has challenges inherent to the lack of E&P data, questionable data quality, and risk decisions taken by evaluators. No two evaluation teams generate similar undiscovered resource values, as their methodologies and perceptions of the risk/reward balances for the same areas are often different. IHS Markit's assessment relies on multiple sources to derive at the YTF resource potential for the peer group selection

The first step in the IHS Markit YTF analysis was to assess the public domain view on the yet-to-find potential of the target basins. Publicly available datasets from the BOEM and U.S. Geological Survey (USGS) have been used for this analysis. Published play boundaries or assessment units were available with associated undiscovered resource potential (YTF) numbers. IHS Markit used this data to understand the public domain view of YTF resource potential within the basins earmarked for this study. A public-view richness factor (volume/km^2) was determined by dividing the BOEM/USGS hydrocarbon volumes by the published play boundaries. By intersecting the published play boundaries with IHS Markit demarcated basins in ArcGIS, IHS Markit calculated overlap areas. Then, by multiplying the richness factor by the overlap areas, IHS Markit derived a public domain view of YTF volumes within IHS Markit basins at the play or assessment unit level.

While useful, the results at this stage were based on external entities' valuations of resource potential. Many of the areas involved are frontier, and therefore data coverage was poor and considerable uncertainties are associated with these published volumes. Frontier basin studies rely on the selection of suitable analog basins or plays.

IHS Markit selected analogs based on geological similarity using criteria such as tectonic setting and play-type similarity (similar traps and petroleum system element depositional settings). Then, using the analogs that were identified for all the frontier target basins, IHS Markit generated an analog richness factor, which was then applied to the frontier target basin. To determine this analog richness factor, the EDIN database was used to extract parent plays in each basin, the play extent (km²), and the volumes (MMboe) within the play. The volume was then divided by the play extent to derive a richness factor (volume/km²). This analog-derived richness factor was then applied to the overlap areas between the published play boundaries and the IHS Markit basins to calculate an analog-derived, yet-to-find volume for each of the IHS Markit basins at the play/assessment unit level. This additional step provided a comparison tool to use with the public domain-derived volumes to estimate a more realistic YTF volume for each of the target basins.

The analysis for the U.S. planning areas is limited to a few critical basins. As such, the Atlantic area analysis focuses on the George Bank Basin, the Southeast Georgia Embayment, and the South Georgia Basin. The Pacific area analysis focuses on the Santa Barbara and Santa Maria Basin. The Eastern GOM analysis focuses on the Norphlet play residing to the east of the Central/Eastern GOM basin boundary.

Figure 3-8 shows IHS Markit YTF mean estimates for the Non-Alaska offshore frontier peer group. There is a tremendous range of resource uncertainty in the estimation of the resources trapped in these frontier basins. IHS Markit has estimated the surface of the prospective areas along with their associated richness based on analogies drawing from its geologic understanding of the area. These overlap areas can be smaller than the areas assessed by the BOEM and USGS due to water depth limitations, which lead to lower estimates by IHS Markit. Figure 3-9 shows USGS and BOEM mean estimates for the same basins' undiscovered resources. Differences[18] naturally exist between estimates because the resource assessment areas are different, the rock richness may be different, and the perception of the chance of success may also be different.

Under the IHS Markit approach, the Eastern GOM has the highest estimate, with 2.5 billion boe yet to be found. Most of the Eastern GOM YTF resources are in the Norphlet play in the deepwater GOM Basin. South Africa follows in second position, with 2.06 billion barrels yet to be found, which is underscored by Total's recent success in the Southern Outeniqua Basin. The Falkland Islands holds third place with 1.9 billion boe yet to be found. IHS Markit notes that industry activity, including licensing and further drilling activity, would appear to suggest that the consensus is that the Falkland Island's potential is at the lower end of the range described herein.

IHS Markit estimates the Porcupine Basin holds about 1 billion boe of YTF resources in its southern part. This study considers the northern part of the basin to be much less prospective. The China National Offshore Oil Corporation is drilling one of the first of a series of NFWs by larger operators in the southern portion of the basin. IHS Markit considers the U.S. Federal Pacific basins of Santa Maria and Santa Barbara to be mature, but BOEM analysis indicates 2.6 billion boe undiscovered technically recoverable resources, which IHS Markit has not identified.[19]

[18] IHS Markit estimates the YTF resources in the frontier basins as follows: YTF (frontier) = Area*Richness Factor from analog* Chance of Analog. For unproven U.S. deepwater basins IHS Markit typically saw effective net richness of 1.5 to 4 MMboe/1000 km^2 in the 45-35 percent range of all basins tested. The Chance of Analog is a subjective number based on experience of the geological settings. This factor is less than 1.

[19] OCS Report BOEM 2017-085, 2016a National Assessment of Undiscovered Oil and Gas Resources of the U.S. Outer Continental Shelf

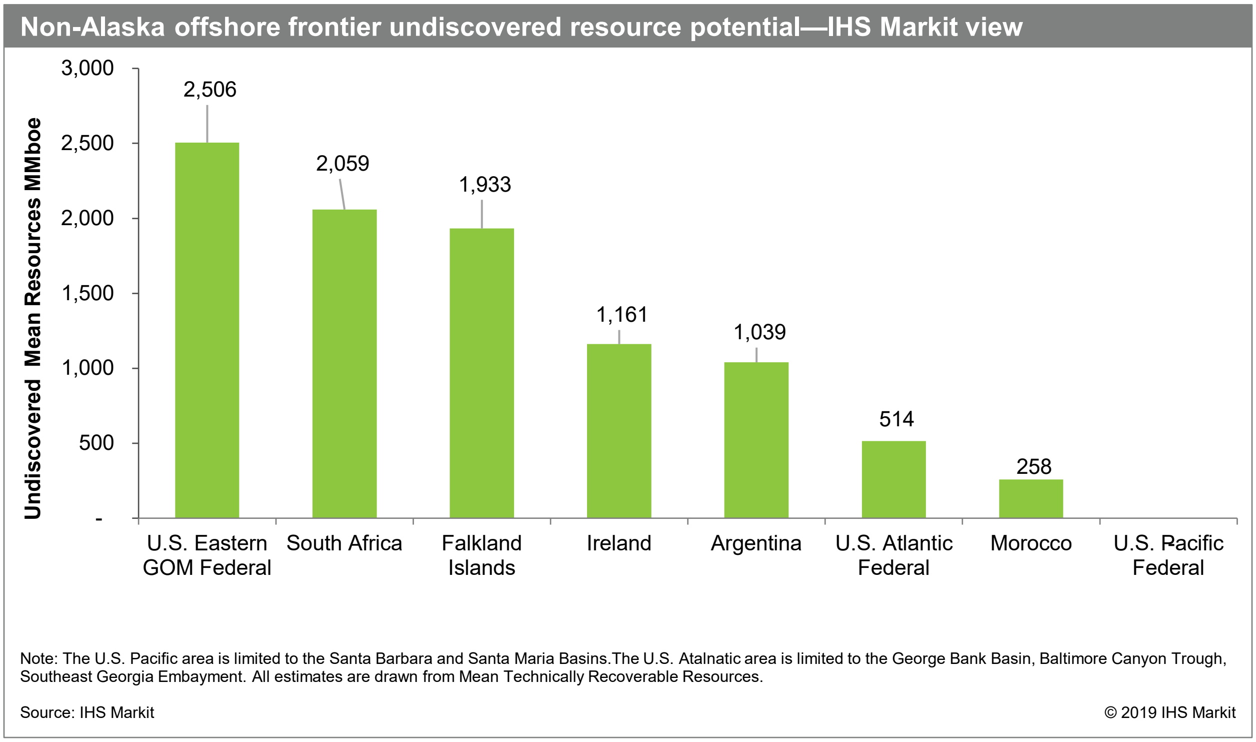

Figure 3-8. Non-Alaska offshore frontier undiscovered resource potential—IHS Markit view

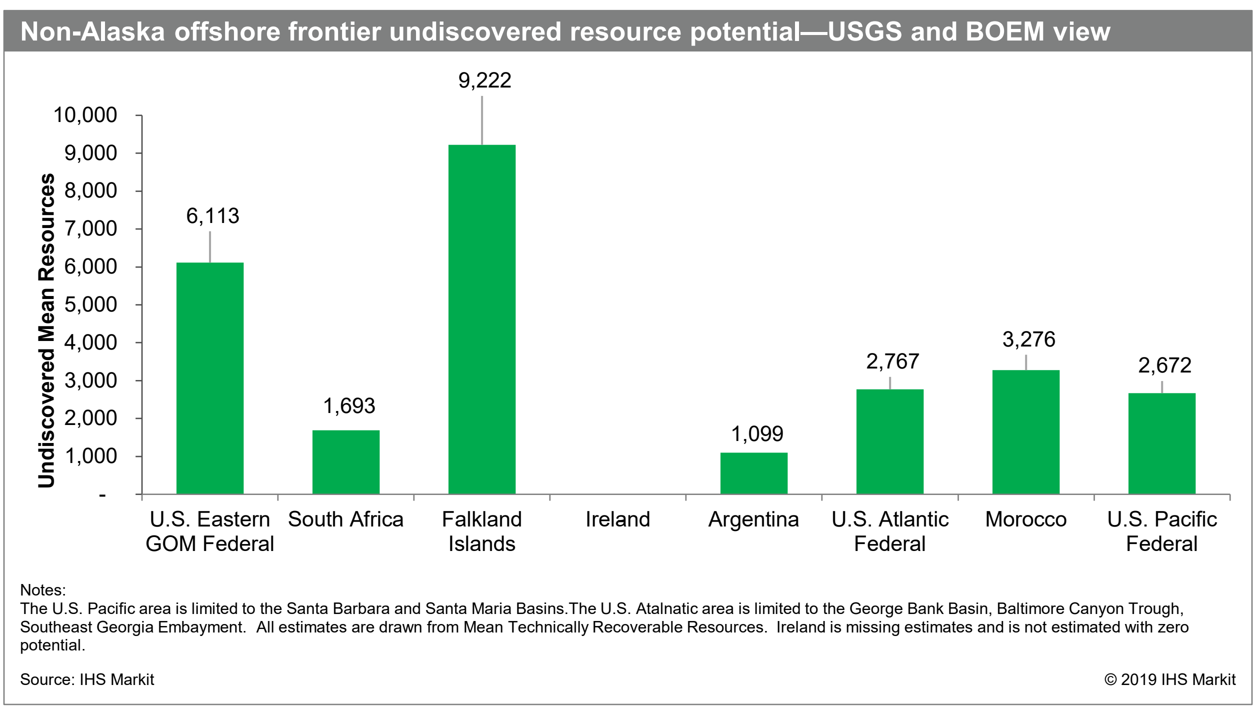

Figure 3-9. Non-Alaska offshore frontier undiscovered resource potential—USGS and BOEM view

Figure 3-9 displays the ultimate technically recoverable resource volumes yet to be found, estimated by BOEM and USGS. Ireland is missing estimates, and not estimated with zero potential. While both organizations follow different methodologies, IHS Markit has placed these estimates on the same graphs to illustrate current views of undiscovered resources that experts in those organizations believe could be residing in these frontier jurisdictions. IHS Markit estimates are systematically lower than the estimates of the USGS and BOEM. IHS Markit estimates frontier basins' potential based a methodology grounded in geology and geography. The lack of data supported by discoveries and production in the frontier areas prevents the use of historical inferences and other statistical calculations. IHS Markit approach starts with the delineation of prospective areas, followed by the estimation of rock richness and our in-house perception of risk. Differences between IHS Markit estimates and BOEM and USGS estimates derive from all of these factors.

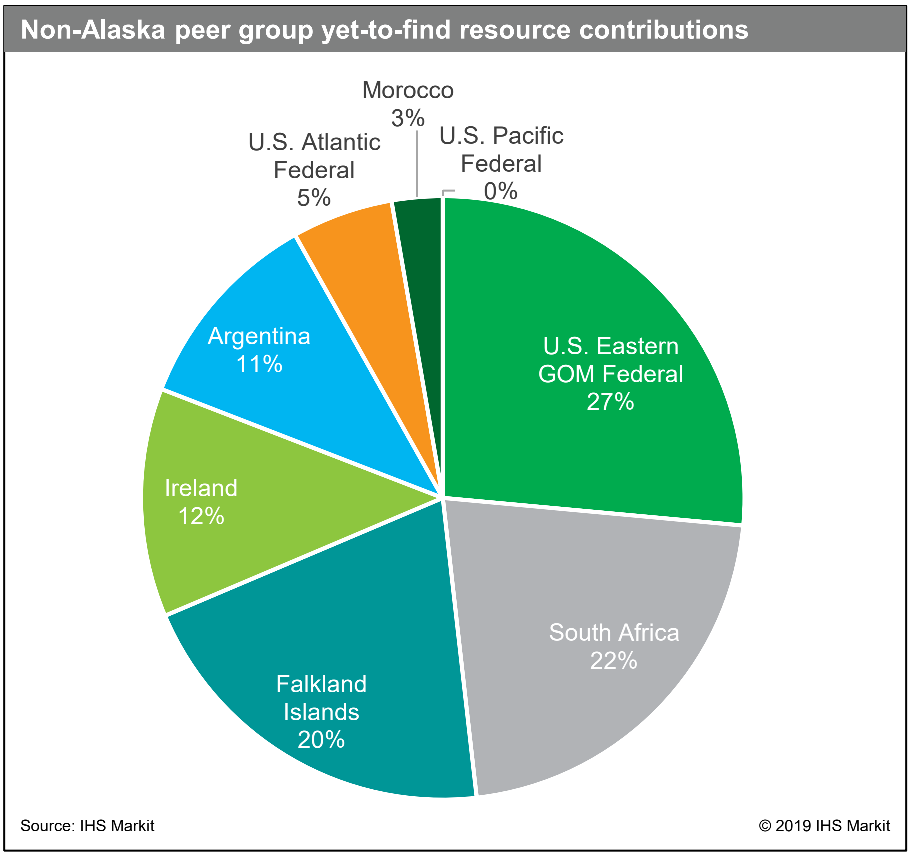

Figure 3-10. Non-Alaska offshore frontier distribution of the undiscovered resource potential—IHS Markit view

Figure 3-10 shows each peer group's contribution to the total peer group YTF volumes. Total Non-Alaska frontier peer group YTF is around 9 billion boe. Based on IHS Markit estimates, the U.S. Eastern GOM represents 27 percent of the peer group total volume. The U.S. Non-Alaska offshore frontier regions all together represent almost one-third of the peer group's total undiscovered resources.

Figure 3-11 shows the estimated undiscovered resources for the Alaska offshore frontier peer group. The analysis follows the same logic as that used for the Non-Alaska offshore frontier peer group. The offshore section of the North Slope Basin was selected for the Beaufort and the Chukchi seas, while the offshore section of the Mackenzie Delta Basin was selected for Canada NWT. IHS Markit considered the Barents Sea Platform Basin for Norway and the North Falkland and the Falkland Plateau basins for the Falkland Islands.

The Alaska Beaufort and Chukchi seas and the Norway Barents Sea estimates are close (minimum 1.0 billion boe; maximum 23.5 billion boe), with the former being oil-prone, and the latter gas-prone. Canada's offshore Mackenzie Delta is a different system than the Alaska Beaufort and Chukchi seas area, with most discoveries being natural gas.

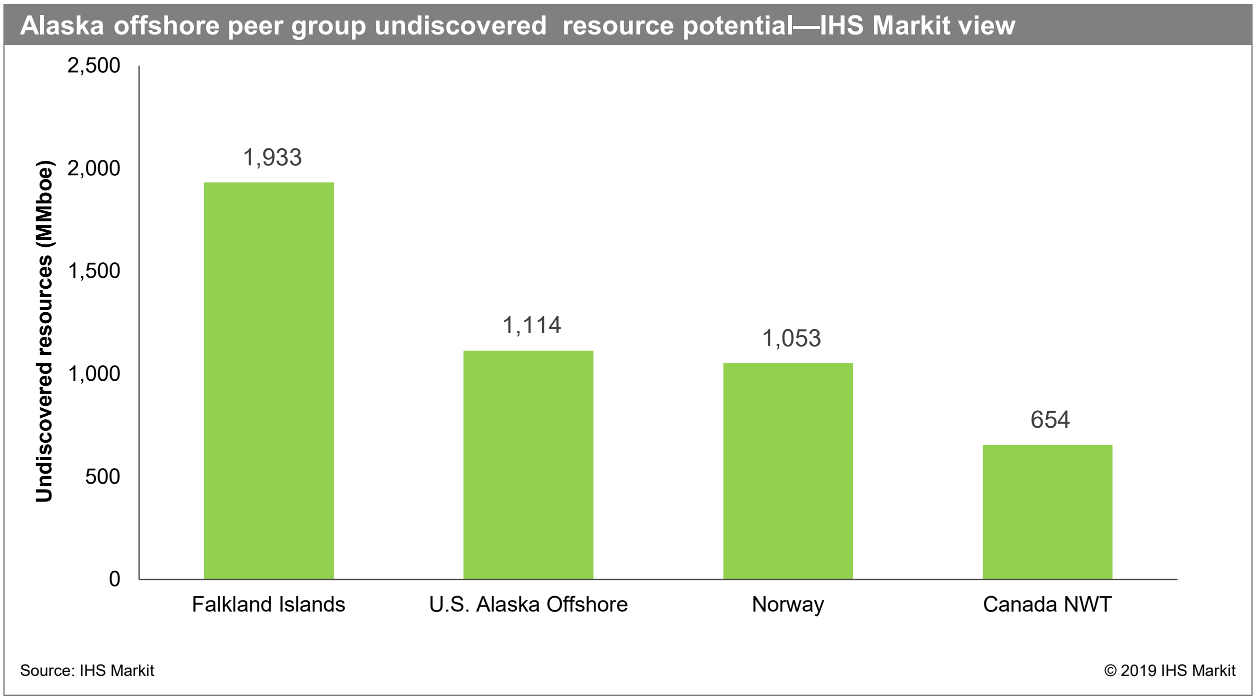

Figure 3-11. Alaska offshore frontier undiscovered resource potential—IHS Markit view

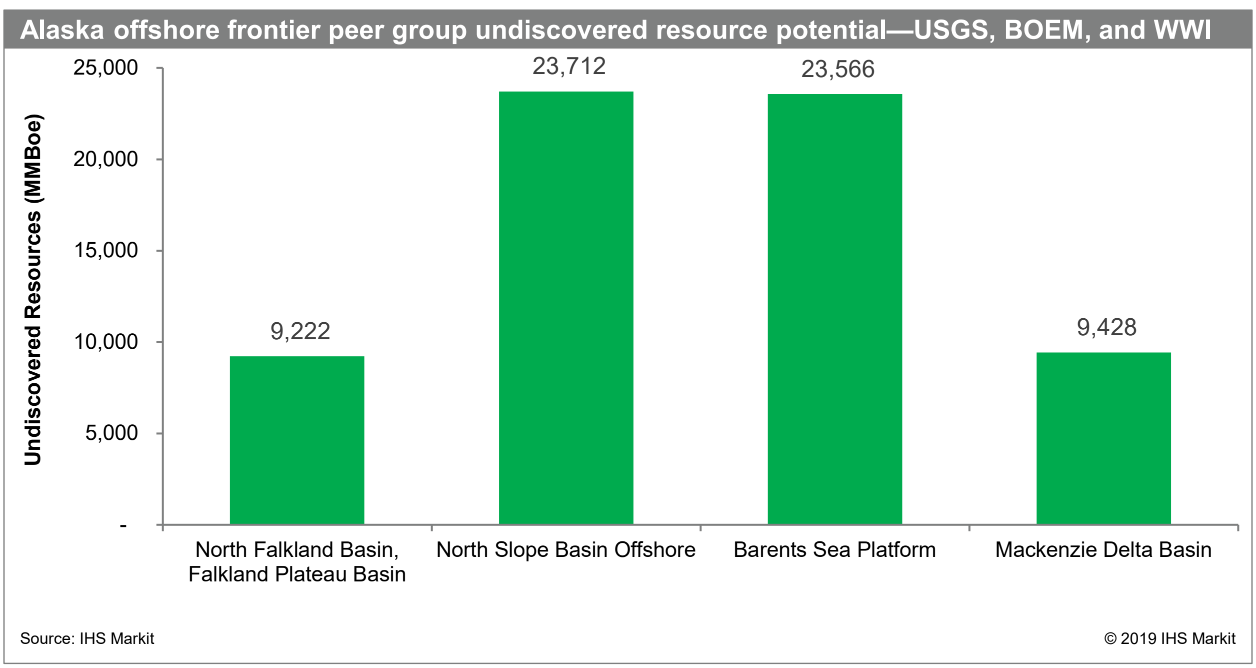

Figure 3-12. Alaska offshore frontier undiscovered resource potential—USGS, BOEM, and Woodrow Wilson Institute (WWI) view

IHS Markit estimates of YTF volumes in the Arctic are considerably lower than other publicly available estimates because the delineation of the prospective areas is different, and the concept of risk is different.

3.4 Exploration and Development Costs

There has been little exploration in the world's offshore frontier basins since the oil-price collapse of 2014. Frontier-basin exploration and development costs require high resource estimates, with wide ranges of variation. There are high uncertainty levels inherent to frontier areas, but a few factors are common among these areas, including remoteness and difficult geological and geographic settings, which create additional pressure on both exploration and development costs. Despite the current context of capital discipline, continuous learning, innovation, and recurring negotiations with contractors of the offshore world, developing frontier areas still require large resource finds to balance the degree of risk taken by investors. Figures 3-13 and 3-14 exhibit the range of exploration well costs for the Alaska and Non-Alaska offshore frontier peer groups. The wide range of exploration well costs ($20–118 million for the Non-Alaska offshore frontier peer group) reflects the influence of the geographic and geological settings for the frontier jurisdictions. Water depth and reservoir depth associated with location remoteness and icy conditions drive cost differences at multiple points of the value chain. There is a wider cost range in the Alaska offshore frontier peer group, because the Norway Barents Sea is much less of a frontier environment than the Chukchi Sea area. Marine weather and ice flows pose threats to offshore oil and gas installations such as pipelines or subsea wells in the Alaska Arctic. This study does not model subsea clusters in North American Arctic regions, but instead considers caissons and auxiliary platforms. Pipeline costs are higher in the Alaskan Artic because they need to be buried deeper to resist possible ice scour. In both peer groups, the median exploration well cost estimated for this study is around $80 million.

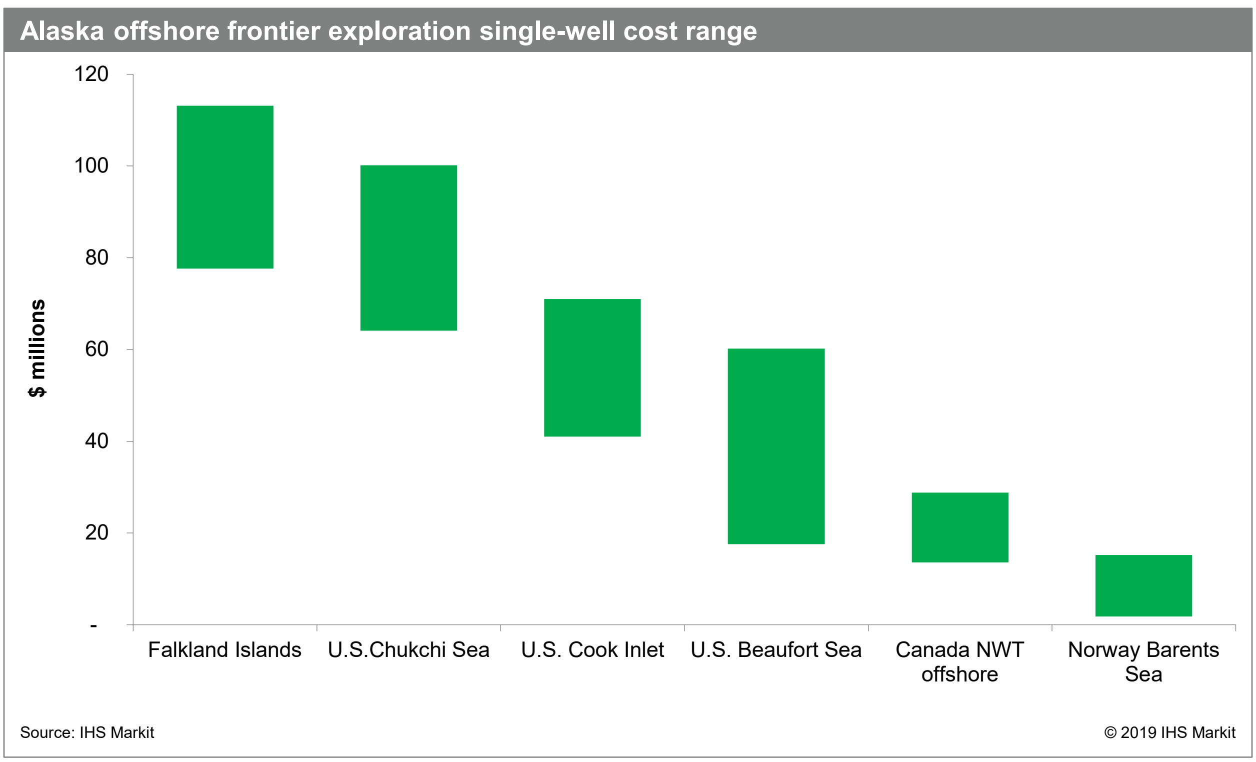

Figure 3-13. Alaska offshore frontier exploration single-well cost range

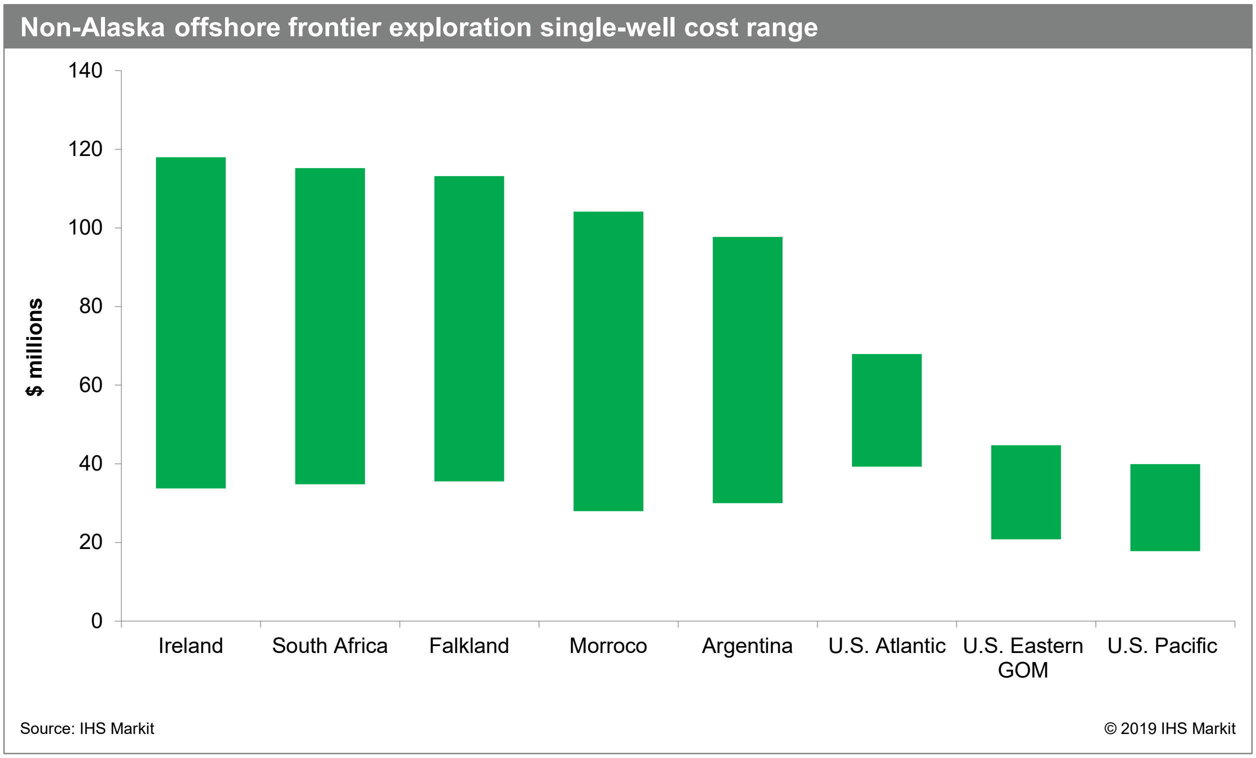

Figure 3-14. Non-Alaska frontier offshore exploration single-well cost range

4 Trends in Fiscal Terms since 2014

Oil and gas fiscal systems often respond to market signals and changes in the prospectivity of the area. In particular, governments tend to respond to commodity price changes to ensure that a fair share of the revenue is obtained for the nation. This section explores the changes in fiscal terms since the 2014 drop in commodity prices, and the oil and gas industry's reaction to such changes.

4.1 Changes in Fiscal Terms

When frontier acreage is first offered for investment, contractual and fiscal terms tend to be more favorable for investors. That is, fiscal terms reflect the resource uncertainty surrounding an area, as well as the cost associated with reducing that uncertainty. Usually the terms needed to incentivize investment in the early stages of exploration of a frontier area evolve as more information becomes available and improved knowledge of resource potential allows the government to design appropriate licensing strategies and fiscal terms that reflect the lower risk profile of future licensing rounds.[20]

The offshore jurisdictions analyzed in this report are very similar in terms of the level of E&P activity in their offshore frontier areas. Thus, all peer jurisdictions studied present attractive fiscal terms that reflect the uncertainty associated with the resource potential. Some of the jurisdictions are relative newcomers to the offshore E&P industry, while others are planning a comeback to areas that were placed off-limits or not explored for several decades—mainly the United States and Argentina.

Given the early stages of acreage promotion and E&P activity in the frontier jurisdictions in this peer group, not much has happened with regard to changes in fiscal terms. Most of them have not yet reached the next stage where the uncertainty surrounding the resource potential is reduced. Hence, any measures that could affect the fiscal terms in the respective jurisdiction, except for Ireland, were not necessarily designed or introduced specifically for the frontier areas; however, given their broad application in the oil and gas sector, such measures ultimately affect investments in frontier basins. This section examines the key measures likely to affect fiscal terms in the offshore frontiers peer group.

4.1.1 Argentina—Recession Throws a Wrench in Fiscal Policy

The Argentine economy is in recession, with the gross domestic product contracting by 2.6 percent in 2018. Argentina's GDP is expected to contract by 2.1 percent in 2019, while inflation reached 56 percent by April 2019. President Mauricio Macri is implementing deep austerity measures to comply with a $57-billion stand-by arrangement with the International Monetary Fund, aimed at reaching a primary fiscal balance in 2019.[21]

Income Tax: The Macri government that came into power in 2015 intended to reduce the tax burden to facilitate investment. A 2017 reform reduced corporate tax rates, but efforts to reduce the fiscal deficit have delayed its implementation. Tax reform was expected to gradually reduce the corporate tax rate from 35

[20] Mensah E. "Extractive Industries Taxation: CRP.3 – Attachment E, Fiscal Take, United Nations." 2016; Tordo S, Johnston D. "Countries' experience with allocation of petroleum exploration and production rights: Strategies and design issues." World Bank. 2009.
[21] IHS Markit. Argentina Country Report. May 2019. The IMF stand-by agreement offers financial aid to member states in need of assistance. This is usually conditioned with reforms in the recipient country to bring them back on the path of financial stability.

percent to 25 percent by 2021 for companies that reinvest profits in the country. However, this measure is unlikely to be implemented as planned in 2019, since the government is seeking to increase revenue from tax collection.

Export Duties: President Macri also eliminated export duties for hydrocarbon resources upon taking office, but these were reinstated in September 2018 to meet fiscal-deficit targets. Now, exports will be taxed at 12 percent, effective January 1, 2019, with a cap of the Argentinean peso (ARS) at ARS3 ($0.078)[22] or ARS4 ($0.105) for each U.S. dollar (USD) exported.[23] The government also is maintaining the prerogative to introduce further changes up to 2020 to reflect its fiscal needs.

4.1.2 Canada—New Government Keeps Election Promise

The changes to the CEE that were introduced in the 2017 budget make good on a promise made by the current administration during the 2015 election. Prior to the 2017 Federal budget, expenses related to the drilling and completion of a discovery well were classified as CEE and were written off (100 percent deduction) in the year incurred. The 2017 Federal budget reclassifies such expenditures as CDE, which are capitalized and deducted at 30 percent per year on a declining-balance basis. Only expenses related to the drilling of dry holes can be classified as CEE, and thus eligible for the 100 percent deduction.

4.1.3 Falkland Islands—Public Consultation on Taxation Regime

There is no indication of any fiscal changes since 2014. However, in February 2018, the Falkland Islands government initiated a public consultation concerning the existing fiscal system for oil projects.[24] The oil taxation regime, called "Open for investment: A public consultation into Falkland Islands," focused on the corporate income tax treatment of finance and interest expenses, leasing and hire purchases, and decommissioning.[25] Results were to be reviewed at the end of 2018. To date, there is no known legislation proposed from this consultation.

4.1.4 Ireland—Balancing Revenue Risk

Ireland's offshore fiscal regime has become less generous to operators since 2014. To increase the overall take by the state and ensure an earlier share of revenue, in 2015, the Irish government unveiled laws to increase the maximum tax on producing oil and gas fields in Ireland from 40 percent to 55 percent.[26] The new Petroleum Production Tax (PPT) increased the financial return to the state earlier in a field's production lifetime than the previous tax regime. The measures introduced include the following:

- Replacement of PRRT that had an effective rate of 40 percent with a PPT with an effective rate of 55 percent.
- Introduction of a minimum payment of 5 percent on gross revenues less transportation expenditure is due annually once a field starts producing, with the ultimate rate of tax determined on a variable basis depending upon the profitability of an individual field. The minimum PPT, which functions like a royalty, applied for the first time to licenses awarded as part of the 2015 Atlantic Margin licensing round.

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[22] Exchange rate of 0.02615 applied for conversion of ARS to USD.
[23] Mancinelli A. "Argentina: new export duties in force; peso devaluation may impact inflation." DLA Piper. September 13, 2018.
[24] Falkland Islands Government. "FIG issues public consultation into taxation for the oil industry." February 2018.
[25] Falkland Islands Government Taxation Office. "Open for investment: A public consultation into the Falkland Islands' oil taxation regime." February 2018.
[26] IHS Markit. "Irish government draft laws affecting oil and gas exploration budget 2016." GEPS, 2015. 1997 Taxes Consolidation Act s. 696G-696M and summarized in Tax Duty Manual Petroleum Production Tax Part 24-04-01.

4.1.5 United States—Access Restrictions Affect the Development of Offshore Frontier Resources

While the lease terms for the offshore frontier areas in the United States (both Alaska and Non-Alaska frontier) have not been yet been determined, the major challenge these regions face compared to the other jurisdictions reviewed in this study is access to acreage. The majority of acreage has been off-limits for decades. These access restrictions have originated within and outside of the National OCS Program development process, which establishes the schedule of oil and gas lease sales proposed for the U.S. OCS planning areas. Under this program, the secretary of the Interior determines the size, timing, and location of proposed leasing activity that is deemed to best meet national energy needs.

OCS Access Restrictions

Outside of the National OCS Program development process, restrictions on offshore areas on the OCS can be imposed by presidential withdrawals under the Outer Continental Shelf Lands Act or the Antiquities Act, or by Congress through statutes such as GOMESA. Table 4-1 summarizes the historical access restrictions imposed on the Alaska and Non-Alaska offshore frontier in the United States.

Table 4-1. Access restrictions on U.S. OCS frontier regions

Planning area	Congressional restrictions	Presidential withdrawals	Current status
Alaska Region			
Beaufort Sea	-	December 20, 2016—President Obama withdrew the majority of the Beaufort Sea Planning Area from future oil and gas leasing consideration for a time period without specific expiration. April 28, 2017 — E.O. 13795 rescinded this withdrawal	Under litigation.
Chukchi Sea	-	**December 20, 2016**—President Obama withdrew the entire Chukchi Sea Planning Area from future oil and gas leasing consideration for a time period without specific expiration. April 28, 2017 — E.O. 13795 rescinded this withdrawal	Under litigation.
North Aleutian Basin	-	December 16, 2014—President Obama withdrew the entire North Aleutian Planning Area from oil and gas leasing consideration for a time period without specific expiration.	Unavailable for OCS oil and gas leasing, pursuant to Section 12 of the OCS Lands Act.
Atlantic Region			
North Atlantic	Annual congressional restrictions Fiscal year 1984 – 2008	Presidential withdrawal 1990 – July 2008	Available for leasing consideration.
Mid Atlantic	Annual congressional restrictions Fiscal year 1999 – 2008	Presidential withdrawal 1998 – July 2008	Available for leasing consideration.
South Atlantic	Annual congressional restrictions Fiscal year 1999 – 2008	Presidential withdrawal 1998 – July 2008	Available for leasing consideration.
Northeast Canyons and Seamounts	Presidential withdrawal September 15, 2016	-	Unavailable for OCS oil and gas leasing, pursuant to the

Planning area	Congressional restrictions	Presidential withdrawals	Current status
Marine National Monument			Antiquities Act (54 U.S.C. 320301).
GOM Region			
Eastern GOM	Congressional restriction GOMESA 2006 – June 2022	-	Most of Eastern GOM is under restriction until 2022.
Pacific Region			
Washington/Oregon	Annual congressional restrictions Fiscal year 1991 – 2008	Presidential withdrawal 1990 – July 2008	Available for leasing consideration.
Northern California	Annual congressional restrictions Fiscal year 1982 – 2008	Presidential withdrawal 1990 – July 2008	Available for leasing consideration.
Central California	Annual congressional restrictions Fiscal year 1991 – 2008	Presidential withdrawal 1990 – July 2008	Available for leasing consideration.
Southern California	Annual congressional restrictions Fiscal year 1985 – 2008	Presidential withdrawal 1990 – July 2008	Available for leasing consideration.
All Regions			
National Marine Sanctuaries designated as of July 14, 2008		Presidential withdrawal April 27, 2017	Unavailable for OCS oil and gas leasing, pursuant to the OCS Lands Act, 43 U.S.C. 1341(a).

Sources: BOEM and IHS Markit

Access restrictions, however, often originate from within the National OCS Program development process. In the process of balancing environmental, national security needs, and other regional development goals, the DOI makes a decision whether to include or exclude specific planning areas from the National OCS Program. Table 4-2 contains information about the last lease sale held in the offshore frontier regions of the U.S.

Table 4-2. Last lease sale in each U.S. OCS frontier region

Planning area	Last lease sale
Alaska Region	
Beaufort Sea	2018
Chukchi Sea	2008
Atlantic Region	
North Atlantic	1979
Mid Atlantic	1983
South Atlantic	1983
Straits of Florida	1959
GOM Region	
Eastern GOM (Sale 224 area only)	2018
Pacific Region	
Washington/Oregon	1964
Northern California	1963
Central California	1963

Planning area	Last lease sale
Southern California	1984

Sources: BOEM and IHS Markit

Although most of the Chukchi Sea and Beaufort Sea OCS were withdrawn from leasing consideration by President Obama in 2015 and 2016, President Trump issued E.O. 13795 rescinding these withdrawals, which is pending litigation. Rights under existing leases in the withdrawn areas were not affected.

Subsequent to Executive Order 13795 of April 28, 2017, BOEM started the planning process for the development of the new 2019–2024 National OCS Oil and Gas Leasing Program. A request for information was published in the *Federal Register* on July 3, 2017, and the DPP was released on January 4, 2018. The DPP provided a lease sale schedule that included all planning areas of the U.S. OCS—subject to the restrictions in force under GOMESA, the withdrawals under the Antiquities Act, and marine sanctuaries restrictions under the OCS Lands Act.

Fiscal Terms

As far as fiscal terms are concerned, 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 oil and gas 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 mission to collect and account for royalties and would "impose a costly and unnecessary burden on the Federal and Indian lessees."[27]
- 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."[28]

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 percent for new shallow water leases in the GOM. Sales held in previous years in the GOM included an 18.75 percent royalty rate for such leases. This lower shallow water royalty rate was also offered in Lease Sale 250, held in March 2018, Lease Sale 251, held in August 2018, and Lease Sale 252, held in March 2019.

Reduction of the Corporate Income Tax: The most significant recent change affecting 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 United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation: The Tax Cuts and Jobs Act increased the bonus depreciation percentage from 50 percent to 100 percent 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 percent.

[27] 30 CFR Parts 1202 and 1206, *Federal Register*, Vol. 82, No. 150, August 7, 2017.
[28] Ibid.

The Tax Cuts and Jobs Act provides for a five-year phase down of the 100 percent 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 percent 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 percent of taxable income computed without regard to the deduction allowable under 26 U.S.C. Section 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

4.2 Industry Response

Among the four jurisdictions that have introduced measures impacting E&P fiscal terms since 2014, two of them—the United States and Canada—have limited or no activity currently in the frontier areas being analyzed. Activity in the Beaufort Sea off the coast of Canada NWT has been at an all-time low since 2013. This is due to issues involving the remoteness of the area and the lack of infrastructure in the far north of Canada. In the United States, most of the area under review has been off-limits for investment either through GOMESA, Presidential Withdrawal, or the DOI's withdrawal of acreage from leasing.

With respect to Argentina and Ireland, the only measure that could be used to gauge investor reaction to changes in fiscal terms is licensing activity. Unlike onshore areas, where it takes only a few months from the time a well is drilled to first production, it takes several years from license awards to the drilling of the first exploratory well in offshore frontier regions. The majority of fiscal term changes have occurred in the past couple of years, and there has been insufficient time to observe changes in industry behavior through drilling activity.

4.2.1 Argentina

Despite the austerity measures introduced by the government in Argentina, the industry showed confidence in the country's first offshore license round in the Austral, Malvinas, and Argentina basins. On April 16, 2019, the government announced the winning bids for the round—with 18 out of 38 blocks offered receiving bids, with a total investment commitment of $724 million out of $995 million that was offered. Table 4-3 provides information on the blocks and companies that won the bids.

Table 4-3. Offshore round one results

Block name	Area (km^2)	Winning bid participants
AUS-105	2,117.56	Equinor
AUS-106	2,279.00	Equinor
CAN-102	8,950.54	YPF, Equinor
CAN-107	8,346.53	Shell, Qatar Petroleum
CAN-108	2,882.32	Equinor
CAN-109	7,880.24	Shell, Qatar Petroleum
CAN-111	6,325.53	Total, BP
CAN-113	6,578.37	Total, BP
CAN-114	7,084.94	Equinor, YPF
MLO-113	5,826.21	ExxonMobil, Qatar Petroleum
MLO-114	5,946.59	Tullow, Pluspetrol, Wintershall
MLO-117	4,903,05	ExxonMobil, Qatar Petroleum
MLO-118	4,202.61	ExxonMobil, Qatar Petroleum

Block name	Area (km^2)	Winning bid participants
MLO-119	4,549.98	Tullow, Pluspetrol, Wintershall
MLO-121	4,292.82	Equinor
MLO-122	4,421.25	Tullow Oil
MLO-123	3,788.57	Total, YPF, Equinor
MLO-124	4,421.25	Eni, Mitsui, Tecpetrol

Source: IHS Markit

4.2.2 Ireland

Prior to the 2015 change in fiscal terms, Ireland's government take was among the lowest in the world. The increase of the government take does not appear to have affected the oil and gas company interest in the Atlantic Margin licensing round that was held subsequent to the implementation of the PPT. The licensing round resulted in the award of 28 licensing options. The 2015 Atlantic Margin licensing round exceeded the number of licensing options awarded in a licensing round in Ireland. The previous Atlantic Margin licensing round was held in 2010, and resulted in 13 licensing options—at the time, the largest amount ever in a licensing round in Ireland. Table 4-4 provides the list of companies that were awarded licensing options in 2015.

Table 4-4. Atlantic Margin 2015 licensing round results

Companies	Licensing option
Eni, BP	16/01
Europa	16/02
ExxonMobil, Statoil	16/03, 16/04
Nexen	16/05, 16/06, 16/07, 16/08
Scotia	16/09
Statoil, ExxonMobil	16/10, 16/11, 16/12, 16/13
Woodside	16/14
AzEire	16/16, 16/17
Capricorn	16/18
Europa	16/19, 16/20, 16/21, 16/22
Faroe Petroleum	16/23
Petrel	16/24, 16/25
Predator, Theseus	16/26

Source: IHS Markit

5 Comparison and Ranking of U.S. Fiscal System

The study compares the oil and gas fiscal systems for offshore frontier areas relying on measures used by investors to assess global investment opportunities and make investment decisions such as IRR, NPV/boe, and EMV. The study also uses the government take as a measure often relied upon by governments to assess their relative take with that of other jurisdictions. To assess the competitiveness of prospective investments in the respective jurisdictions under a wide range of commodity prices, the study examines the results of the above metrics under three different oil and gas price scenarios: base case, high case, and low case. For more information on price assumptions, see Section 1.3.2. All metrics, prices, and costs are modeled in real terms using 2018 U.S. dollars.

5.1 Economic Metrics

Internal Rate of Return (IRR): 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. 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 tend to be greater for higher risk exploration versus lower risk development projects.

The IRR, however, has some limitations, and therefore is never referenced or used as the sole evaluation criterion.[29] One of the main limitations of the IRR is its inability to help evaluate incremental 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 in this section) 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 boe of entitlement production[30] 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 hundred million 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 midyear basis,[31] which is 2019 in the IHS Markit models. The NPV is also referred to as present worth,

[29] Mian, M. "Projects Economics and Decision Analysis, Volume 1: Deterministic Models." 2002.
[30] Entitlement production is all equity production to the operator net of royalty volumes for concession contracts. In production sharing contracts, entitlement production is the sum of cost oil, cost gas, profit oil, and profit gas net to the operator.
[31] All cash inflows and outflows are allocated to the middle of the year to approximate even spending and discounting throughout a year.

as it looks at the present value of the project's economic streams. The calculation below is used to determine NPV:

$$\boldsymbol{NPV = \sum_{t=1}^{n} \frac{net\ cash\ flow\ at\ t}{(1 + discount\ rate)^\wedge t}}$$

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 on 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 boe 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.

$$\boldsymbol{NPV\ per\ boe = \frac{1}{P} \sum_{t=1}^{n} \frac{net\ cash\ flow\ at\ t}{(1 + discount\ rate)^\wedge t}}$$

Where *P* is the total hydrocarbon production over the same period expressed in boe.

This study uses a real 10 percent 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 aboveground risks. The cost of capital varies among companies—smaller companies tend to have a greater than 10 percent cost of capital, due to their financial capability and the riskier nature of projects they tend to pursue.[32] Comparative analysis studies of this nature use the same discount rate across all jurisdictions and all projects for the sake of consistency.[33] This approach is also consistent with the U.S. Securities and Exchange Commission (SEC). The SEC requires public companies to use a 10 percent discount for their filings, no matter where their investments are located.[34]

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:

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

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 decisionmakers. The EMV analysis is important for this study because it incorporates

[32] Alberta Government. "Alberta at a Crossroads, Royalty Review Advisory Panel Report." 2016.

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

[34] Campbell R., "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 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.

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. 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, which includes federal, state, and private take:

$$\boldsymbol{Government\ take = 1 - \left(\frac{Contractor\ Cash\ Flow}{Contractor\ Gross\ Revenue - Contratctor\ OPEX - Contractor\ CAPEX}\right) \times 100}$$

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.

5.2 Alaska Offshore Frontier

5.2.1 Alaska Offshore Frontier—IRR

The high cost associated with the exploration and development of oil and gas resources in the Alaska offshore frontier peer group challenges their economic viability under the base and low price scenarios used for this study (Table 5-1). In the high oil price environment, the Alaska Beaufort and Chukchi Sea projects are very competitive within the peer group (Figure 5-1). The IRR for all three field sizes—the 1,000 MMboe, 400 MMboe, and 100 MMboe—in the Beaufort and Chukchi seas ranges between 15 percent and 20 percent. However, investors in frontier areas usually expect rates of return well above the 15 percent threshold to account for the significant risk associated with exploring a frontier basin.

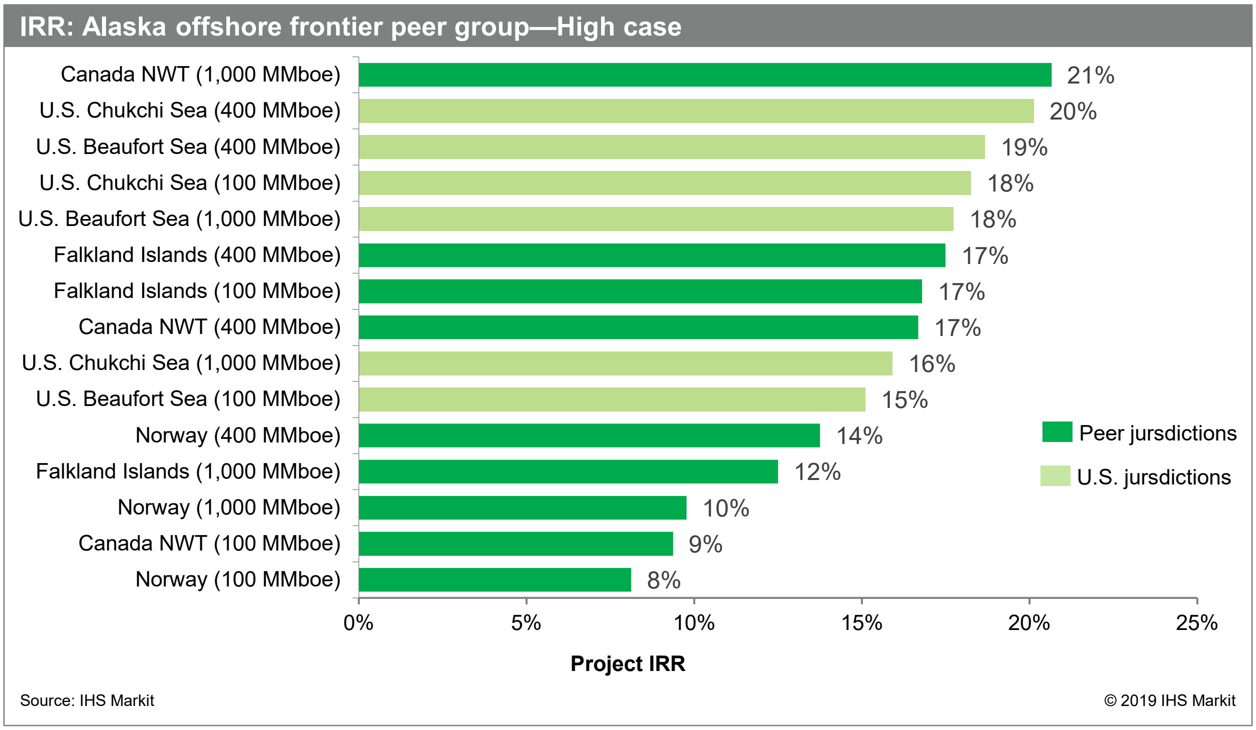

Figure 5-1. IRR: Alaska offshore frontier peer group—High case

The field sizes selected for this peer group are more representative of the discoveries in Alaska than those of the other jurisdictions it is compared against—the size of discoveries within the peer group tends to be smaller than in Alaska. Furthermore, the Mackenzie Delta Basin in the NWT and the Barents Sea Basin in Norway are gas-prone and more challenging to commercialize. The natural gas discoveries in the NWT portion of the Beaufort Sea are stranded. The environmental challenges and the low natural gas prices in North America played a role in the cancellation of plans to construct a pipeline to bring the natural gas to Alberta.

Table 5-1. IRR: Alaska offshore peer group—Low, base, and high cases

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	1,000	400	100	1,000	400	100	1,000	400	100
Canada NWT	21	17	9	14	10	3	7	1	0
Falkland Islands	12	17	17	8	10	6	3	2	0
Norway	10	14	8	6	7	2	3	2	0
U.S. Beaufort Sea	18	19	15	11	10	9	3	0	2
U.S. Chukchi Sea	16	20	18	7	9	7	0	0	0

Source: IHS Markit

Within the peer group, projects in the Chukchi Sea and Falkland Islands have higher per-unit exploration and development costs than other regions (Figure 3-10). They are more exposed to weather challenges, more remote, and in deeper waters, requiring the use of GBS in the case of Chukchi Sea and FPSO in the case of the Falkland Islands. Oil and gas field developments in the Beaufort Sea, by comparison, are in shallow waters and rely on the use artificial gravel islands, which are less expensive and easier to access during the winter season. That accounts for better rates of return in Beaufort Sea compared to Chukchi Sea under the base price scenario—the IRR, however, is not high enough to justify investment decisions.

The results of investor IRR for this study mirror the reality on the ground with regard to the Chukchi Sea Planning Area. The cancellation of the lease sale planned for the Chukchi Sea in 2015 due to lack of industry interest and then-existing market conditions reaffirms the results of the IRR analysis for the low price environment in this study. The exploration challenges faced in the Chukchi Sea go beyond the market conditions of the 2014–18 period. In 2008, the DOI held a lease sale in Chukchi Sea that was the most successful lease sale ever in the history of Alaska OCS in terms of revenue generated. However, all 487 leases issued in 2008 have been relinquished.[35] The sale was held in an environment where oil prices were on the rise (above $100/bbl) and investors were bullish about the oil markets. Since then, the oil price has crashed twice—in 2008 and 2014. While the markets rebounded reasonably quickly after the 2008 crash, the 2014 drop in commodity prices has resulted in persistently lower commodity prices, lower investment budgets, and stronger spending discipline by the oil and gas operators. This certainly affects companies' appetite for frontier acreage and exploration in high-risk and high-cost environments such as Alaska's Chukchi Sea.

5.2.2 Alaska Offshore Frontier—NPV/boe

The Alaska Beaufort Sea and Chukchi Sea projects yield better value to investors on a dollar-per-barrel basis than most projects within this peer group in the high oil price environment (Figure 5-2). As in the case of IRR, the majority of projects yield negative NPV/boe under the base and low cases—except for two fields in Alaska Beaufort Sea and one in NWT (Table 5-2). The positive NPV/boe in the base case for the three field sizes in Alaska and Canada does not indicate such fields pass investment thresholds. Companies could use higher discount rates for frontier areas to account for the high geological and commercial risk involved.[36]

While the Barents Sea is the region with the highest level of exploratory drilling within the peer group (Section 3.1), the NPV/boe values of stand-alone projects in the Beaufort Sea are 4.5 times higher than those for equivalent field sizes in Norway in the high price environment ($9.8/boe versus $2.2/boe). This result is despite the lower per-unit exploration costs in the Barents Sea. The lower NPV/boe for the Norwegian projects is attributable to the relatively higher government take compared to the U.S. fiscal system.

[35] BOEM. "2019–2024 Outer Continental Shelf Oil and Gas Leasing Draft Proposed Program." BOEM. 2018.
[36] This study uses a 10 percent discount rate, while investors are likely to use a discount rate of 18 percent or higher for frontier areas.

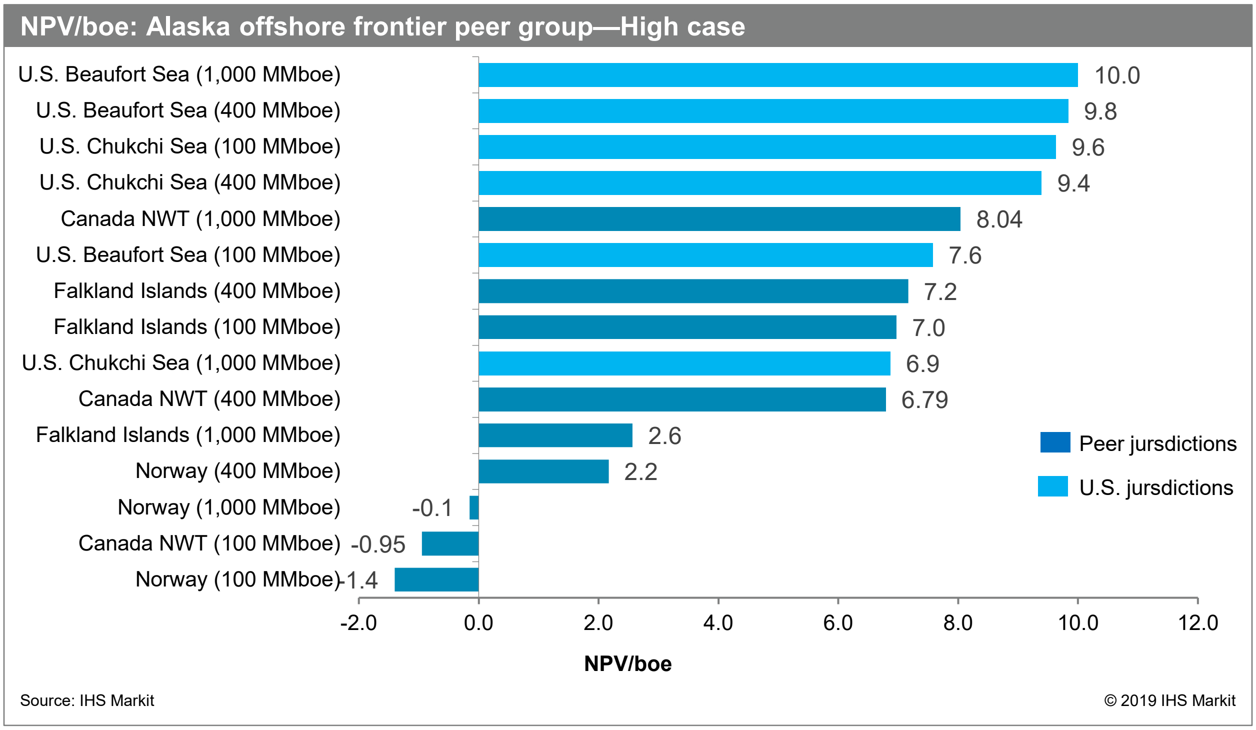

Figure 5-2. NPV/boe: Alaska offshore frontier peer group—High case

The larger field sizes in the case of the Alaska Chukchi Sea, Barents Sea, and the Falkland Islands yield a lower NPV/boe than the medium and small field sizes (Table 5-2). The difference in the timing of development impacts whether incremental barrels are more economic in the larger field sizes than the medium or small ones. When the capital spent is more upfront and not phased, the larger field often loses the benefit from the economies of scale on a present-value basis. Phased development is quite common for complex projects. The Snøhvit development in the Barents Sea, which includes a cluster of gas fields (Snøhvit, Albatross, and Askeladd), has been developed in multiple phases. The development of clusters such as Snøhvit in the Barents Sea has also benefitted from lengthy and flexible lease terms until commerciality was established. It took 18 years from the discovery to the approval of the development plan for Snøhvit in Norway. The Federal oil and gas leases in the United States do not have provisions for retention of discoveries that are not commercial at the time the discovery is made, but have the potential to be declared commercial within a reasonable time period in the future.

Table 5-2. NPV/boe: Alaska offshore peer group—Low, base, and high cases

Jurisdiction	NPV/boe ($)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	1,000	400	100	1,000	400	100	1,000	400	100
Canada NWT	8.0	6.8	-0.9	2.2	0.0	-8.1	-1.2	-4.1	-15.6
Falkland Islands	2.6	7.2	7.0	-2.1	0.0	-3.3	-5.8	-6.0	-13.0
Norway	-0.1	2.2	-1.4	-2.6	-1.3	-5.7	-4.6	-4.1	-13.9
U.S. Beaufort Sea	10.0	9.8	7.6	1.5	0.2	-0.8	-4.7	-7.1	-6.5
U.S. Chukchi Sea	6.9	9.4	9.6	-2.5	-0.5	-2.8	-9.1	-7.5	-11.9

Source: IHS Markit
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5.2.3 Alaska Offshore Frontier—EMV

The Alaska Beaufort Sea and Chukchi Sea projects outperform all the other jurisdictions in this peer group when the EMV is taken into account (Figure 5-3). The Beaufort Sea projects offer robust monetary value per exploration well drilled in the high price case under all three field sizes and in the base case under the 1,000 MMboe and 400 MMboe oil fields (Table 5-3). The Chukchi Sea projects rank second after the Beaufort Sea in the high price scenario in terms of value per exploration well drilled. In the high price scenario, the EMV for Chukchi Sea and Beaufort Sea midsize fields ranges from $900 million to $1 billion, whereas the EMV for large fields ranges from $2.0 billion to 2.5 billion.

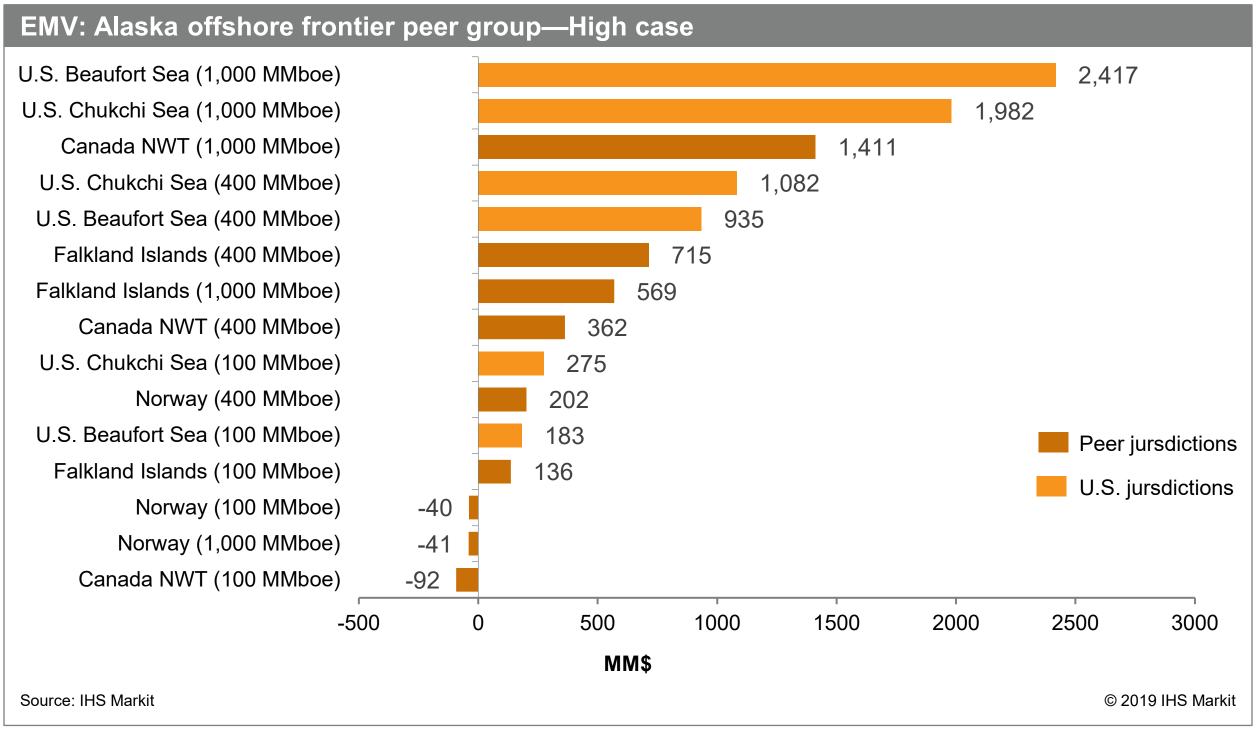


Figure 5-3. EMV: Alaska offshore frontier peer group—High case

Table 5-3. EMV: Alaska offshore peer group—Low, base, and high cases

Jurisdiction	EMV ($ millions)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	1,000	400	100	1,000	400	100	1,000	400	100
Canada NWT	1,411	362	-92	339	-71	-278	-352	-368	-468
Falkland Islands	569	715	136	-666	-58	-138	-1,531	-593	-350
Norway	-41	202	-40	-611	-130	-141	-1,074	-396	-318
U.S. Beaufort Sea	2,417	935	183	339	11	-21	-1,060	-612	-157
U.S. Chukchi Sea	1,982	1,082	275	-722	-58	-84	-2,636	-866	-343

Source: IHS Markit

While the Chukchi Sea and Beaufort Sea projects may not pass all the investment thresholds under the base-price scenario as stand-alone developments, cluster and phased development of discoveries in the Alaskan Arctic region could improve project economics.

5.2.4 Alaska Offshore Frontier—Government Take

The median government take of Alaska offshore projects is among the lowest in the peer group, ranging between 39 percent and 49 percent for the Beaufort and Chukchi seas. The highest government take among all fields under the high and base case scenarios for the Alaska Chukchi and Beaufort seas is 50 percent (Table 5-4).

Among the jurisdictions in the peer group, the Falkland Islands fiscal terms appear to offer the lowest government take, when both the median and the range of the take are considered. Norway presents with the highest level of government take across all fields and price scenarios.

Table 5-4. Government take: Alaska offshore fields—Low, base, and high cases

Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	1,000	400	100	1,000	400	100	1,000	400	100
Canada NWT	50	49	50	52	52	53	53	77	100
Falkland Islands	35	35	38	38	40	49	49	54	100
Norway	77	78	77	76	77	72	70	68	100
U.S. Beaufort Sea	35	37	35	39	44	39	61	100	64
U.S. Chukchi Sea	37	38	38	46	49	50	100	100	100

Source: IHS Markit

Discounted share of the barrel

Each column displays for a barrel of revenue what percentage goes to different components of cash flow: capex, operating expense (opex), Federal (taxes and royalties), and company (the investor's after-tax net cash flow). The total in each column adds up to 100 percent. In the case of negative NPV projects, the company share will appear negative and other components, such as costs, will add up to greater than 100 percent.

When the discounted share of the barrel is taken into consideration for all three field sizes in the base case, the Alaska Beaufort Sea yields better results for investors. The results for Canada NWT are not necessarily reflective of the actual investment environment. The Mackenzie Delta is a gas-prone region with stranded gas discoveries.

In the majority of cases, investors fail to get a positive NPV under the base case. The high costs associated with oil and gas development in the harsh Arctic environment present challenges for the development of such projects at $60–70/barrel crude oil price on a stand-alone basis. The sub-economic results are driven by the rather high per-unit capital costs. In the 1,000 MMboe case, capital costs make up 46– 87 percent of the discounted share of the barrel within the peer group, with the Chukchi Sea having the highest per-unit cost (Figures 5-4 to 5-6).

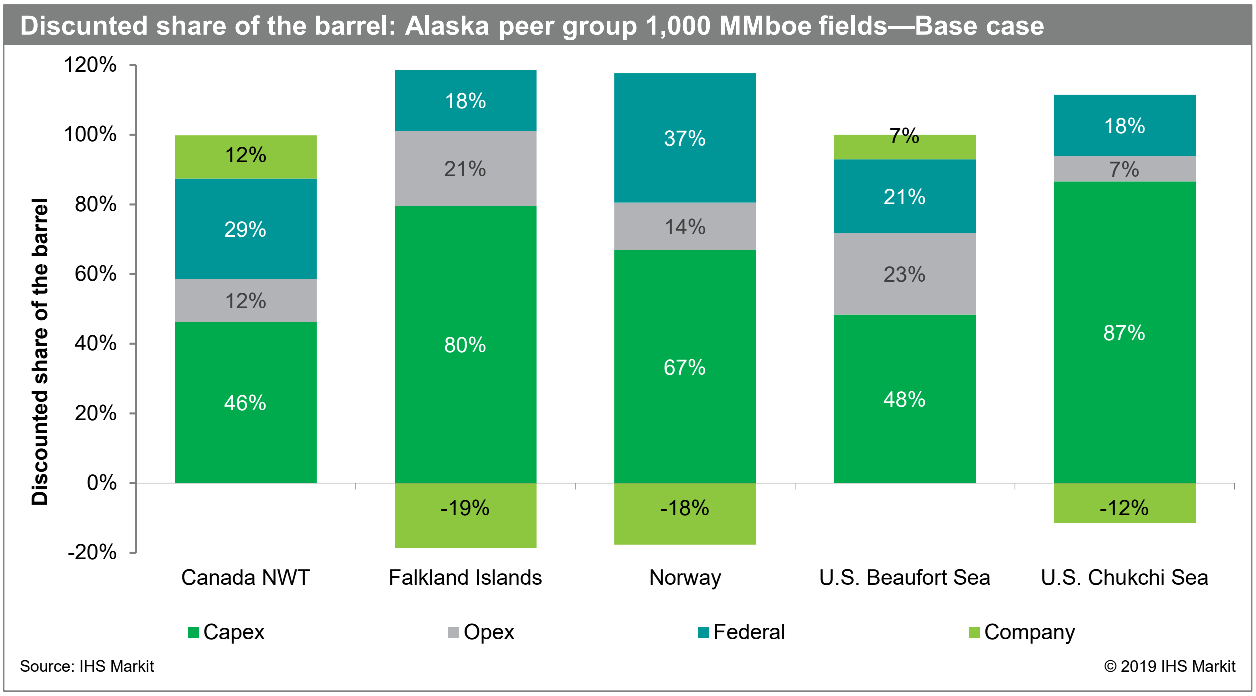


Figure 5-4. Discounted share of the barrel: Alaska peer group 1,000 MMboe fields—Base case

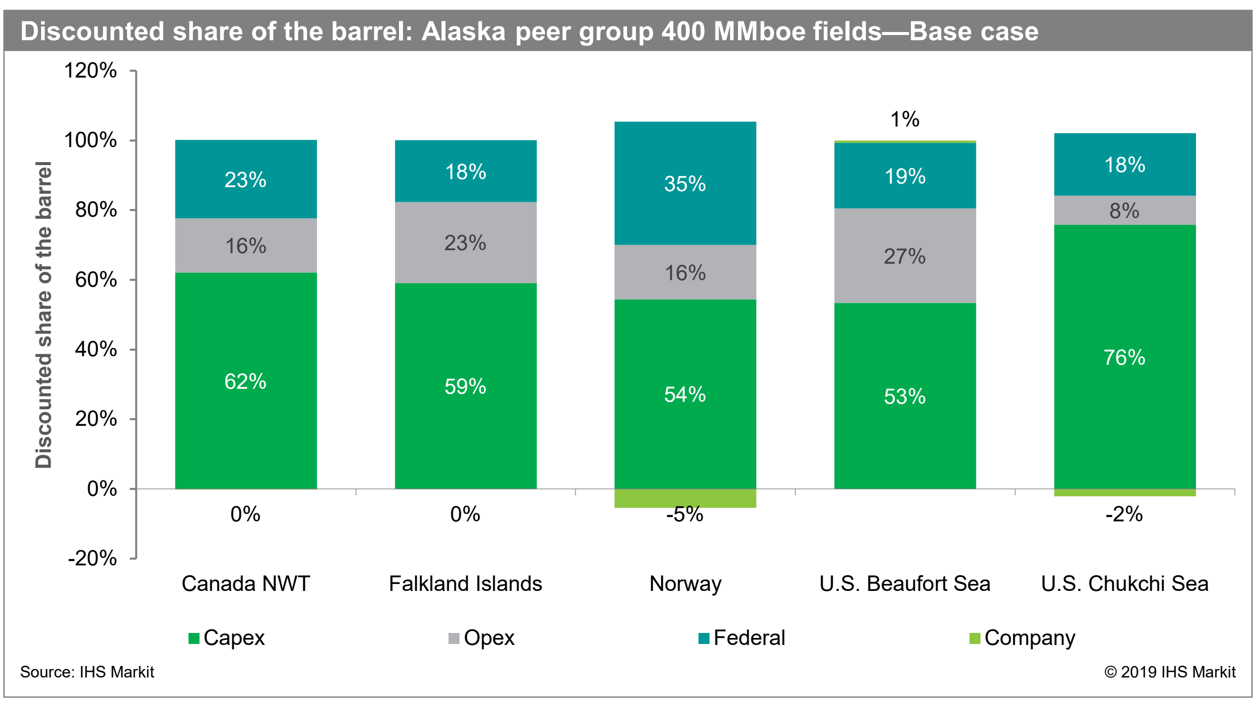


Figure 5-5. Discounted share of the barrel: Alaska peer group 400 MMboe fields—Base case

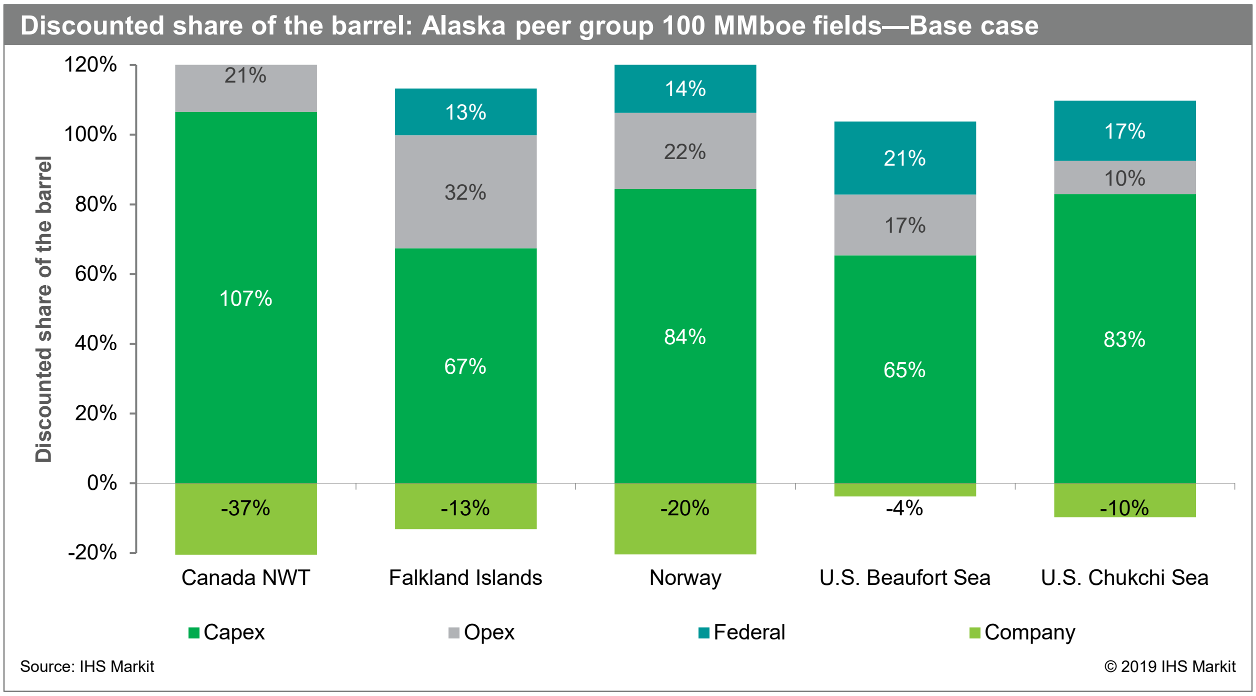


Figure 5-6. Discounted share of the barrel: Alaska peer group 100 MMboe fields—Base case

The capital cost differences between the Chukchi Sea and Beaufort Sea stem from the different environments in the two planning areas. Water is deeper at 45 meters in the Chukchi Sea when compared to 9 meters in the Beaufort Sea, currents are stronger, and the Federal leases in the Chukchi Sea are more exposed to inclement weather events than in the Beaufort Sea. The capex associated with GBS in the Chukchi Sea is much higher than the investment required to build artificial gravel islands in the Beaufort Sea.

In addition to capex, project lifecycle operations are more expensive in the Chukchi Sea than the Beaufort Sea fields. In the Beaufort Sea, once the gravel island is built, everything from drilling to workovers are much less expensive than any Arctic offshore environment. In the Chukchi Sea, the ice thickness, water depth, and currents necessitate the use of the typical Arctic GBS, which is more expensive to maintain, especially when particular safety requirements require creating room for a large volume of production storage.

5.3 Non-Alaska Offshore Frontier

5.3.1 Non-Alaska Offshore Frontier—IRR

The Non-Alaska offshore frontier peer group is characterized by jurisdictions that have had a few discoveries, although not all discoveries have been declared commercial. The exceptions are the Falkland Islands and South Africa, where the size of recent discoveries approximates the volumes modeled for this study. The discoveries in other regions within this peer group are smaller and not necessarily reflective of the current geological prospectivity of the region. The decision to consider larger field sizes than those currently discovered in the majority of regions for this peer group was based on what investors would expect as a minimum investment in a frontier region.

The investor rates of return for the U.S. oil field cases are generally very robust under the high price environment, with the majority of the cases yielding an 18 percent or greater IRR (Figure 5-7). The results of the different field sizes fall within the second and third quartiles of the peer group.

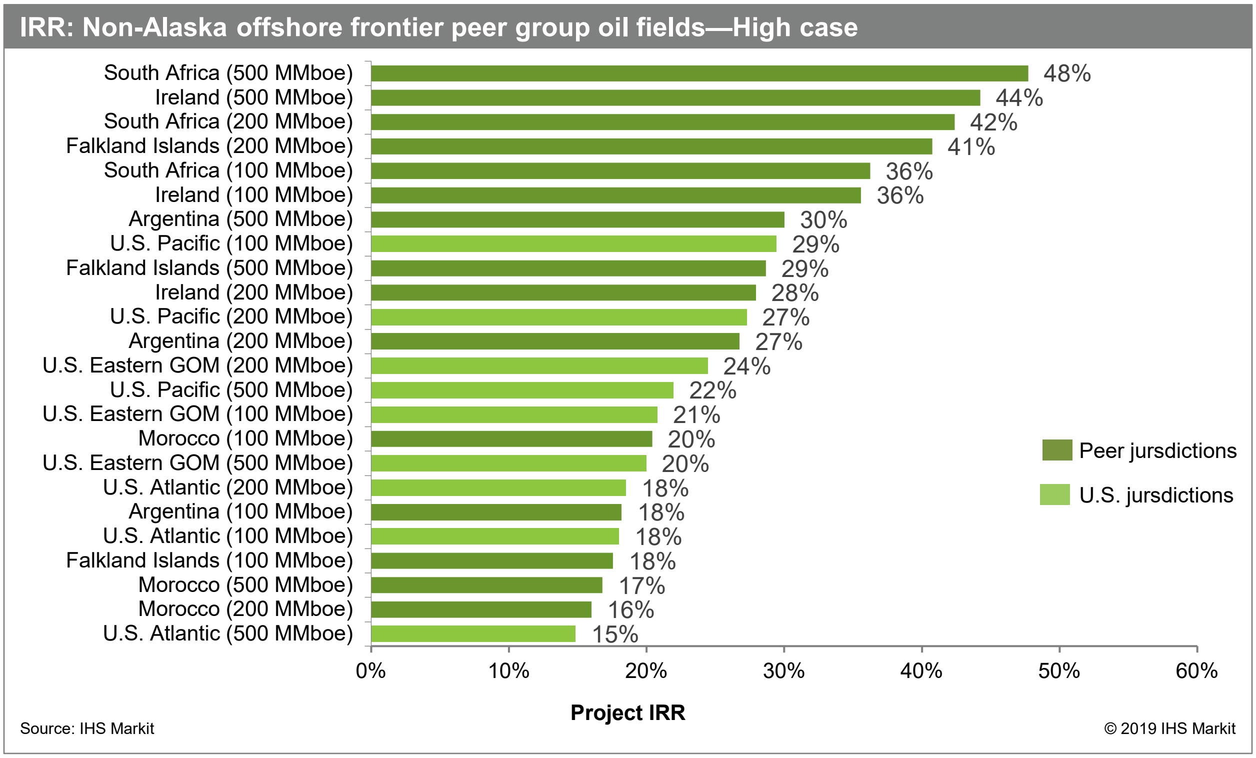


Figure 5-7. IRR: Non-Alaska offshore frontier peer group oil fields—High case

From a ranking perspective within the peer group, the IRR for the U.S. oil field projects falls in the third and fourth quartiles under the base price scenario (Figure 5-8). The higher per-unit costs associated with the development of the Eastern GOM and Pacific projects in the United States contribute to the lower IRR, and hence lower ranking under the base price scenario.

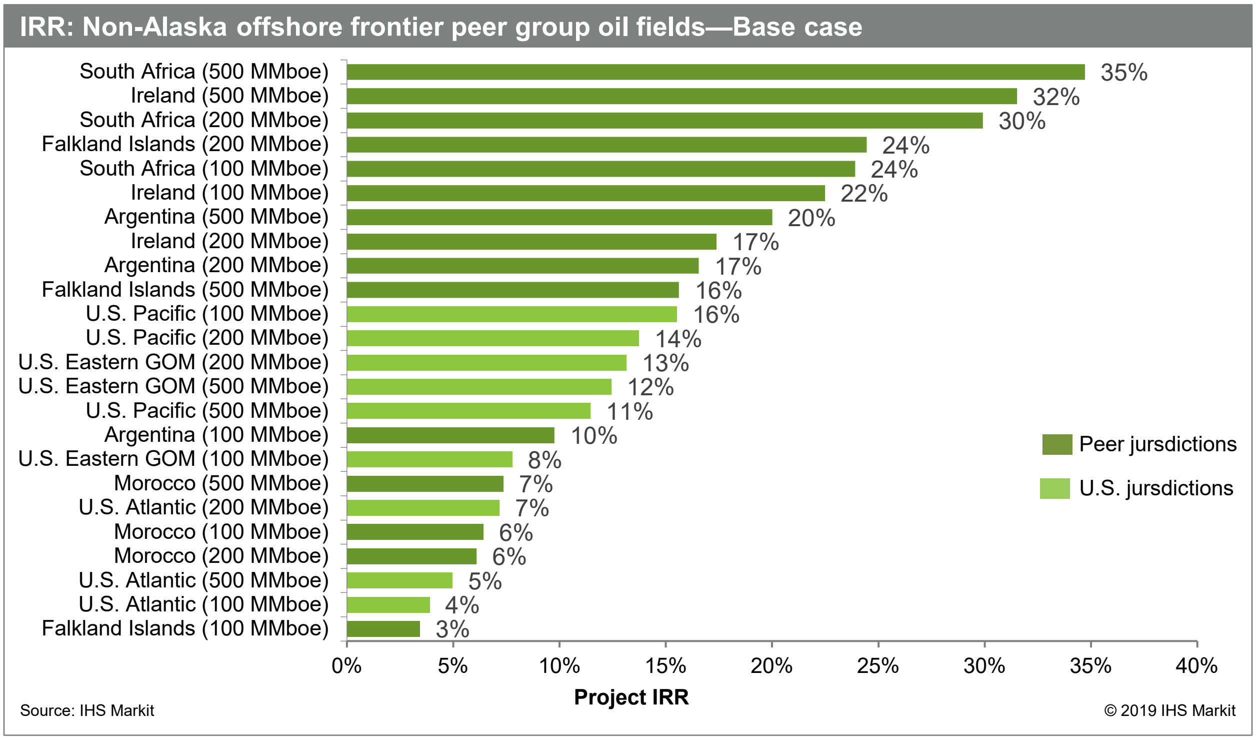


Figure 5-8. IRR: Non-Alaska offshore frontier peer group oil fields—Base case

The reason why U.S. prospects yield lower IRR than the majorly of the jurisdictions in the Non-Alaska offshore frontier peer group has more to do with the formation and water depth than the fiscal system. The U.S. Atlantic and Eastern GOM oil field prospects are in water and formation depths that are two to three times greater than those in the international jurisdictions. The U.S. Pacific region prospects are the exception, appearing closer to the water and formation depths of the other frontier jurisdictions in this peer group. The average water depth for oil field prospects in the international jurisdictions of this peer group is 366 meters, versus 949 meters for the U.S. Atlantic prospects and 1,316 meters for the Eastern GOM prospects. Similarly, the TVD for the U.S. Atlantic and Eastern GOM oil field prospects is more than twice the TVD of the prospects of international jurisdictions—averaging at 5,693 meters and 5,094 meters for the U.S. Atlantic and Eastern GOM, respectively, and 2,142 meters for the international jurisdictions. Table 5-5 displays the average water and formation depths for oil fields in the respective region.

Table 5-5. Non-Alaska offshore frontier peer group—Average water depth and TVD

Region	Average water depth (m)	Average formation depth (TVD m)
U.S. Atlantic	949	5,693
U.S. Eastern GOM	1,316	5,094
U.S. Pacific	198	2,237
International	366	2,142

Source: IHS Markit

Within the peer group, South African and Irish oil fields yield the highest returns on investment, having the lowest development costs. The returns for South African and Irish oil fields are largely attributed to the shallower water depths of 113 meters and 122 meters, respectively, allowing for the use of jackets as production platforms. The oil formations in South Africa and Ireland have favorable well productivity, requiring fewer wells for the same field size than the other frontier areas. All except one of South Africa's oil fields yields robust rates of return under all three price scenarios. Most fields in the peer group, however, are sub-economic under the low price case (Table 5-6).

Table 5-6. IRR: Non-Alaska frontier oil fields—Low, base, and high cases

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	30	27	18	20	17	10	11	8	1
Falkland Islands	29	41	18	16	24	3	2	8	0
Ireland	44	28	36	32	17	22	19	7	8
Morocco	17	16	20	7	6	6	0	0	0
South Africa	48	42	36	35	30	24	23	18	12
U.S. Atlantic	15	18	18	5	7	4	0	0	0
U.S. Eastern GOM	20	24	21	12	13	8	5	0	0
U.S. Pacific	22	27	29	11	14	16	0	0	0

Source: IHS Markit

Since crude oil is more fungible, the economic analysis is based on global price assumptions—in that regard, the commodity price scenarios apply uniformly among all jurisdictions. There is no global market price for natural gas—prices are more regional. While there are developed spot markets for natural gas in North America, other regions rely on a combination of spot and oil-indexed, long-term contract pricing, particularly for liquefied natural gas (LNG). Regional market fundamentals and natural gas prices are other important factors in the differing project economics for U.S. and international jurisdictions within this peer group. The natural gas sales delivery points for this study are set at the nearest local hub (Appendix C.2).

The abundance of low-cost supply from North American shale gas resources and associated gas produced with tight oil has led to lower natural gas prices there than in other regions. As a result, the natural gas prices used for this study are about 50 percent higher than the Henry Hub prices in the cases of Argentina and South Africa, and more than double in the cases of Ireland and Morocco (Appendix C.2). These price differences, combined with the greater water and formation depths for the U.S. prospects in the Atlantic and Eastern GOM (Appendix B), result in lower rates of return for natural gas projects in the U.S. offshore frontier areas (Table 5-7). Despite the substantially higher commodity prices in international offshore frontier regions, all but one of the fields modeled for this study meets the 15 percent investor IRR under the low price scenario. In the base case, natural gas projects in Argentina, Morocco, and to some extent South Africa, yield reasonable returns to investors.

Table 5-7. IRR: Non-Alaska frontier gas fields—Low, base, and high cases

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	35	29	28	25	19	16	15	9	3
Ireland	18	15	13	11	7	4	2	0	0
Morocco	33	34	34	21	21	21	11	10	6
South Africa	30	29	21	20	19	12	11	9	2
U.S. Atlantic	1	4	0	0	0	0	0	0	0
U.S. Eastern GOM	13	11	7	4	0	0	0	0	0
U.S. Pacific	9	13	0	0	0	0	0	0	0

Source: IHS Markit

While most U.S. natural gas projects in offshore frontier areas yield positive rates of return under the high price scenario, such returns fall below the 15 percent investment threshold (Figure 5-9). The natural gas fields in Argentina, Morocco, and South Africa yield very robust rates of return in the high price scenario.

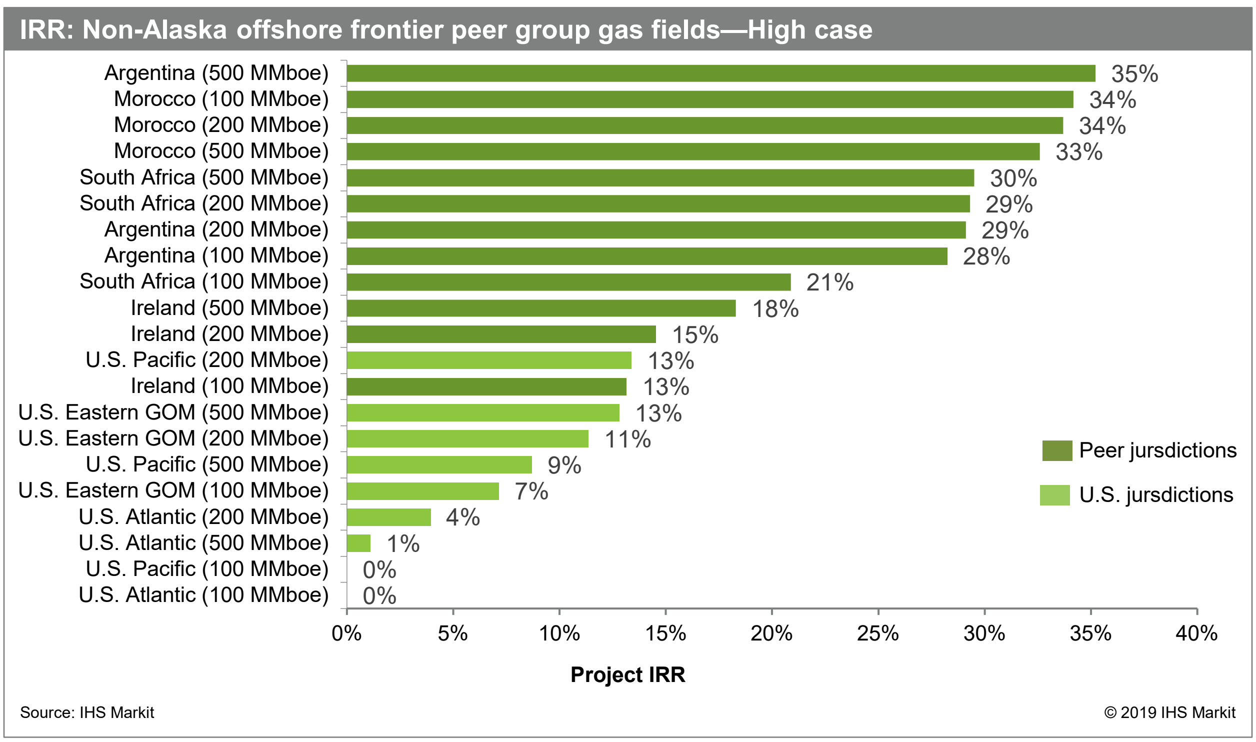


Figure 5-9. IRR: Non-Alaska offshore frontier peer group gas fields—High case

Except for Morocco’s natural gas fields, which lie in water depths of 1,260 meters, the natural gas fields of other international jurisdictions are in even shallower depths than their respective oil fields. This has contributed to the more favorable economics for gas fields in some international jurisdictions. In the case of Argentina, the shallow water depth and the reservoir characteristics—high daily production rate per well of 50 million standard cubic feet per day (MMscf per day)—have contributed to its top ranking for 500 MMboe gas fields. The performance of Morocco's natural gas fields is attributable to a number of factors, such a natural gas prices at 220 percent of Henry Hub prices, attractive fiscal system terms, and favorable reservoir characteristics—i.e., higher total volumes per well than other jurisdictions in this study. The Falkland Islands have not been included in the analysis of gas fields because discoveries of natural gas fields there would be stranded.

5.3.2 Non-Alaska Offshore Frontier—NPV/boe

When commodity prices are high, the U.S. oil fields in the Pacific offer relatively high values per boe compared to their peers (Figure 5-10). All three U.S. frontier offshore areas perform well under the high price scenario. For the most part, however, they rank in the bottom half of the peer group under the base and low price scenarios (Table 5-8). The high capital costs associated with the development of U.S. frontier offshore fields, in particular the Atlantic fields, contribute to the lower competitive position of U.S. Federal fiscal systems within the peer group. Jurisdictions with a lower cost base and progressive fiscal systems, such as South Africa and Ireland, offer higher values per boe under the base and low cases of this study.

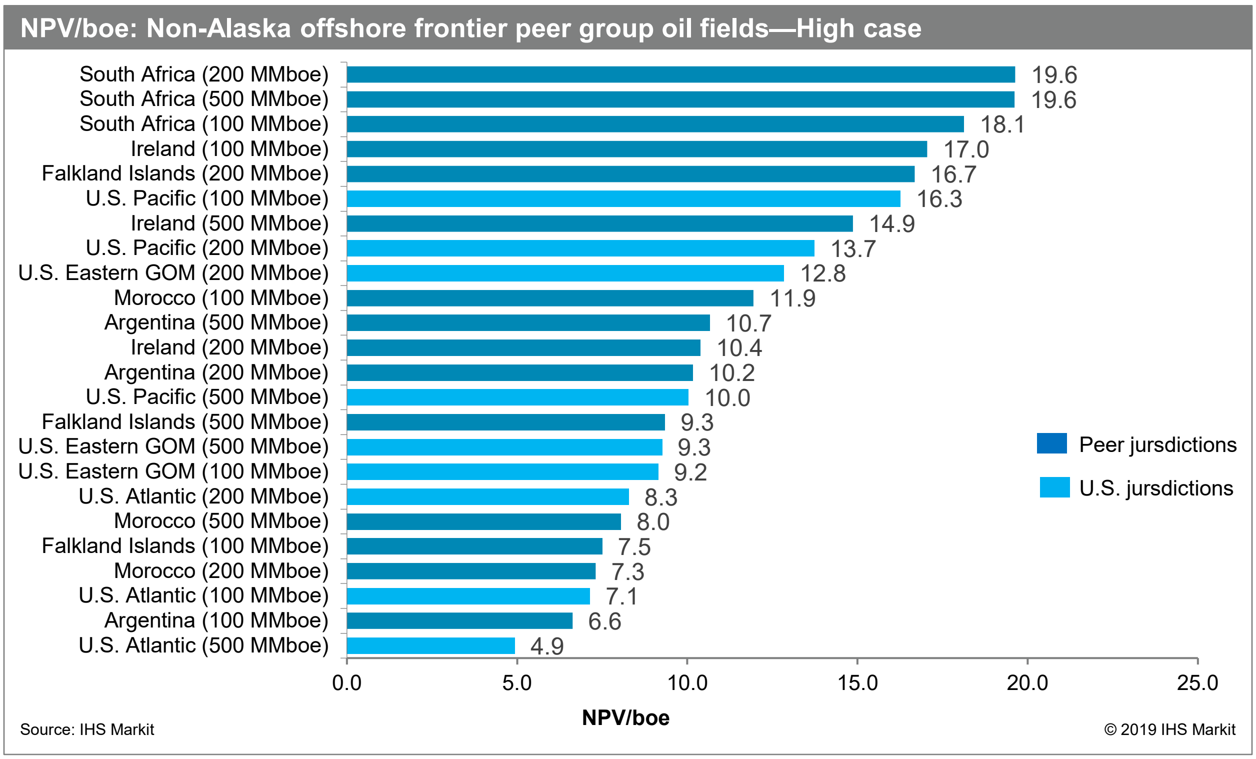


Figure 5-10. NPV/boe: Non-Alaska offshore frontier peer group oil fields—High case

In terms of natural gas fields, the U.S. frontier areas are the least competitive within the peer group, with only 3 out of 27 cases run yielding a positive NPV/boe (Table 5-8). This is largely the result of two factors: the higher costs of exploration and development, and depressed U.S. natural gas prices due to the abundance of onshore unconventional production.

Table 5-8. NPV/boe: Non-Alaska offshore frontier oil and gas fields—Low, base, and high cases

Jurisdiction	NPV/boe ($)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Oil									
Argentina	10.7	10.2	6.6	4.5	3.4	-0.2	0.5	-1.0	-5.4
Falkland Islands	9.3	16.7	7.5	2.5	6.6	-4.7	-2.8	-0.7	-18.6
Ireland	14.9	10.4	17.0	8.4	3.8	7.0	2.9	-1.2	-0.8
Morocco	8.0	7.3	11.9	-2.5	-4.0	-3.7	-10.3	-11.5	-14.1
South Africa	19.6	19.6	18.1	10.5	9.8	7.8	4.3	3.2	0.7
U.S. Atlantic	6.0	8.3	7.1	-5.0	-2.2	-4.0	-12.3	-10.7	-14.3
U.S. Eastern GOM	9.3	12.8	9.2	1.8	2.4	-1.4	-3.3	-4.6	-9.0
U.S. Pacific	10.0	13.7	16.3	1.0	2.4	3.7	-5.2	-5.5	-5.0
Gas									
Argentina	9.7	9.7	10.2	4.6	3.5	2.6	1.3	-0.5	-2.3
Ireland	6.0	3.8	2.8	0.3	-2.3	-4.2	-3.8	-6.7	-10.9
Morocco	11.9	14.3	18.5	4.9	5.5	6.2	0.2	-0.3	-2.3
South Africa	12.9	14.1	8.8	5.4	5.3	1.1	0.3	-0.7	-4.9
U.S. Atlantic	-8.0	-5.0	-6.7	-14.4	-14.0	-16.0	-19.4	-20.8	-25.1
U.S. Eastern GOM	2.0	0.9	-2.0	-3.1	-4.2	-8.1	-6.8	-8.2	-13.4
U.S. Pacific	-1.1	2.2	-9.9	-7.5	-5.9	-15.6	-12.9	-12.7	-19.4

Source: IHS Markit

For fields modeled in this study, each case represents a different part of the basin, so there is no correlation in project economics or economies of scale reflected when the field size increases. In some instances, the smaller field size is situated in shallow water, as is the case of the U.S. Atlantic and Pacific oil fields, which account for relatively better economics for the smaller field size in these regions.

Reservoir depths and pressures are tremendous cost factors. In the Norphlet play in the Eastern GOM, reservoir depths are close to 25,000 feet for the oil case, and close to 21,000 feet for the gas case. Despite the sheer depth in the oil case, pressure drops quickly and water injection wells are needed to maintain production, which leads to an increase in cost. These development concepts are in line with Shell's Appomattox field development in the GOM.

The U.S. Eastern GOM has multiple prospective areas, but only the 500 MMboe case is close enough to tie-in to the producing clusters in the commercial GOM, using a 90-mile dual phase pipeline with oil and gas processing tariffs. The rest of the frontier peer group cases assume stand-alone development.

5.3.3 Non-Alaska Offshore Frontier—EMV

The U.S. frontier offshore oil fields offer high value per exploration well drilled under the high price scenario (Figure 5-11). However, such values deteriorate when the base and low price cases are taken into account. The majority of the projects modeled for this study yield negative EMVs under the low price scenario. The costs associated with the water and reservoir depth and lack of infrastructure present challenges for the stand-alone development of field in the base case scenario. Only half of the fields modeled for the U.S. jurisdictions in this peer group yield positive EMVs under the base price scenario.

The Atlantic region in particular is the least competitive jurisdiction in the peer group, with negative values per exploration well under all field sizes in the base and low price scenario.

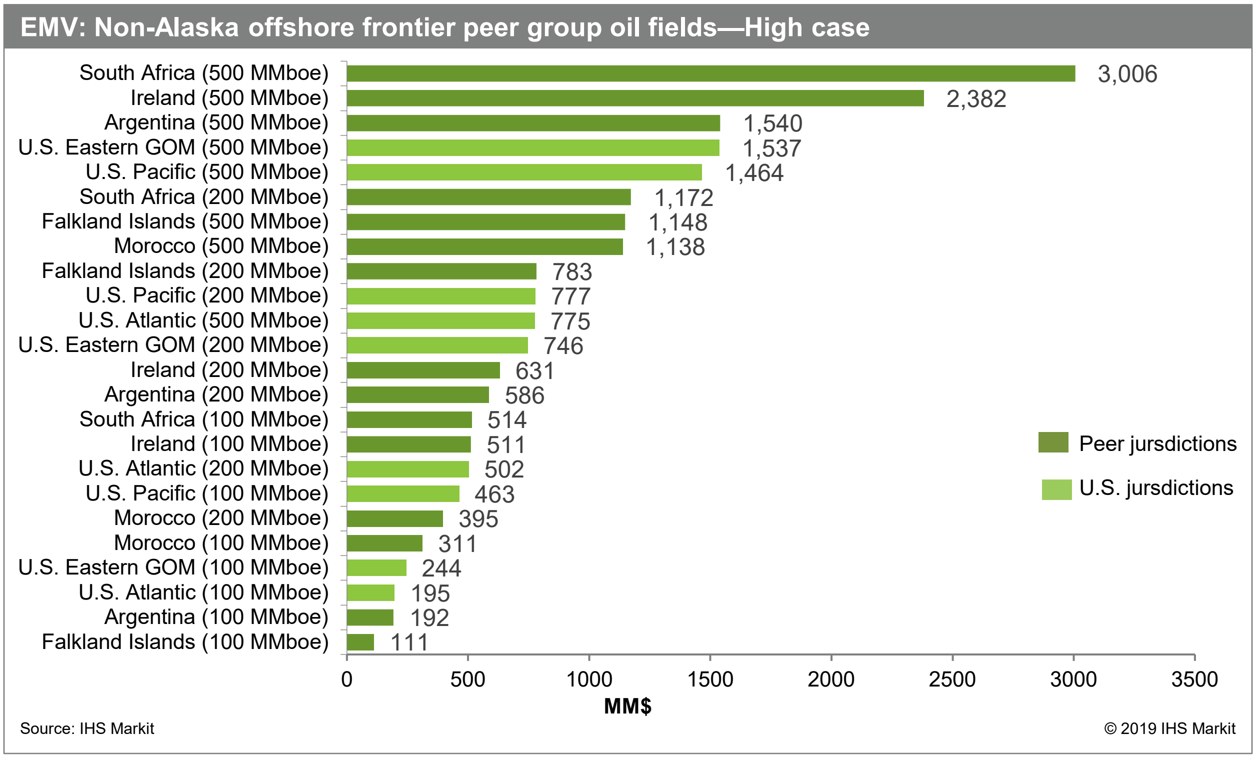


Figure 5-11. EMV: Non-Alaska offshore frontier peer group oil fields—High case

The medium and large oil field sizes in the Eastern GOM yield EMVs of $127 million and $301 million, respectively, under the base price scenario. The 100 MMboe oil field presents with negative $40-million EMV in the base case. This is to be expected given the water depth (975 meters) and TVD (4,633 meters) of the 100 MMboe field. A field of this size would present with marginal economics even in established deepwater regions such as the Central GOM. Fields of this size can, however, be economically developed as part of a cluster of fields (Table 5-9). All three fields modeled for the U.S. Pacific yield positive EMVs between $103 million and –141 million. The shallower water and formation depths give the U.S. Pacific projects a cost advantage over the Atlantic and Eastern GOM.

Development of natural gas fields in offshore frontier areas is highly unlikely under the current U.S. commodity prices. Only 3 out of the 27 cases reviewed for the three U.S. regions in this study result in positive expected values per exploration well drilled. The abundance of cheaper sources of natural gas from onshore shale gas and tight oil development does not favor the development of offshore gas resources in the short-to-medium term.

Table 5-9. EMV: Non-Alaska frontier oil and gas fields—Low, base, and high cases

Jurisdiction	EMV ($ millions)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Oil									
Argentina	1,540	586	192	663	199	-4	77	-61	-137
Falkland Islands	1,148	783	111	253	262	-202	-379	-87	-454
Ireland	2,382	631	511	1,334	205	183	422	-123	-69
Morocco	1,138	395	311	-409	-275	-144	-1,463	-722	-444
South Africa	3,006	1,172	514	1,586	562	194	627	150	-26
U.S. Atlantic	944	502	195	-799	-138	-113	-1,938	-609	-355
U.S. Eastern GOM	1,537	746	244	301	127	-40	-543	-293	-242
U.S. Pacific	1,464	777	463	141	133	103	-767	-310	-139
Gas									
Argentina	1,403	565	296	675	209	77	189	-28	-70
Ireland	942	215	57	20	-181	-172	-654	-474	-356
Morocco	1,819	859	544	725	310	158	-4	-55	-103
South Africa	1,962	820	218	790	273	-25	-17	-106	-206
U.S. Atlantic	-1,345	-283	-185	-2,425	-785	-422	-3,220	-1,161	-586
U.S. Eastern GOM	271	44	-60	-472	-266	-233	-1,011	-504	-373
U.S. Pacific	-155	127	-286	-1,073	-338	-447	-1,805	-712	-554

Source: IHS Markit

5.3.4 Non-Alaska Offshore Frontier—Government Take

The median government take for the U.S. Non-Alaska offshore frontier regions ranges from 43 percent and 45 percent for the Eastern GOM and Pacific, respectively, to 57 percent for the Atlantic region (Table 5-10). The government take under the U.S. fiscal system that utilizes front-end loaded levies, such as signing bonuses and royalties, has an inverse relationship with project profitability. As project costs go up, the share of net revenues accruing to the government increases. The higher costs associated with the development of oil fields in the Atlantic region account for the higher percentage of government take compared to the U.S. Pacific and Eastern GOM. The reservoir and water depths for the U.S. Atlantic fields modeled for this study are often more than double that of the fields modeled for the U.S. Pacific and international jurisdictions.

Table 5-10. Government take: Non-Alaska frontier oil fields—Low, base, and high cases

Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	36	37	38	37	38	41	38	42	67
Falkland Islands	37	36	41	42	40	73	82	61	100
Ireland	47	40	38	39	34	34	35	38	38
Morocco	35	34	28	54	58	58	100	100	100
South Africa	31	31	31	31	31	30	31	30	26
U.S. Atlantic	40	39	42	57	49	71	100	100	100
U.S. Eastern GOM	34	37	40	37	43	56	50	96	100
U.S. Pacific	37	37	37	45	45	43	100	100	95

Source: IHS Markit © 2019 IHS Markit

The government take for natural gas projects for all three U.S. frontier offshore regions is the highest among the jurisdictions in this peer group—with the Atlantic and Pacific offshore presenting with the highest government take (Table 5-11). Compared to oil fields, the government take for natural gas fields modeled in this study is significantly higher. The average government take for all three offshore areas of the U.S. combined moved from 58 percent in the case of oil fields to 86 percent in the case of gas fields (Tables 5-11 and 5-12). Given the inverse government take relationship with project profitability in a regressive fiscal system, such as is the U.S. system. The higher government take for natural gas projects is attributed to the low U.S. natural gas market prices.

Table 5-11. Government take: Non-Alaska frontier gas fields—Low, base, and high cases

Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	37	39	42	39	43	48	43	53	74
Ireland	37	34	35	36	39	50	58	100	100
Morocco	28	24	13	32	28	19	42	43	46
South Africa	31	31	31	31	30	29	29	27	100
U.S. Atlantic	85	69	94	100	100	100	100	100	100
U.S. Eastern GOM	41	45	52	61	100	100	100	100	100
U.S. Pacific	48	48	100	100	100	100	100	100	100

Source: IHS Markit © 2019 IHS Markit

The discounted share of the barrel indicates that the U.S. jurisdictions have much higher per-unit capital costs than the majority of jurisdictions in the peer group for all three oil field sizes in the base case. This contributes to a significantly lower investor share of the barrel (Figures 5-12 to 5-14). The capex in the U.S. offshore frontier areas averages at 64 percent of the discounted barrel in the case of the 100 MMboe oil field, 62 percent for the 200 MMboe oil field, and 66 percent for the 500 MMboe oil field. By comparison, the share of capital costs for the top four jurisdictions in the peer group—Falkland Islands, Ireland, South Africa, and Argentina—averages at 49 percent for the 100 MMboe oil field, 33 percent for the 200 MMboe oil field, and 30 percent for the 500 MMboe oil field. From a revenue-sharing perspective, South Africa offers investors the highest share of the barrel, which is attributed to the fact that it has the lowest cost per unit for oil fields among all the jurisdictions in the peer group.

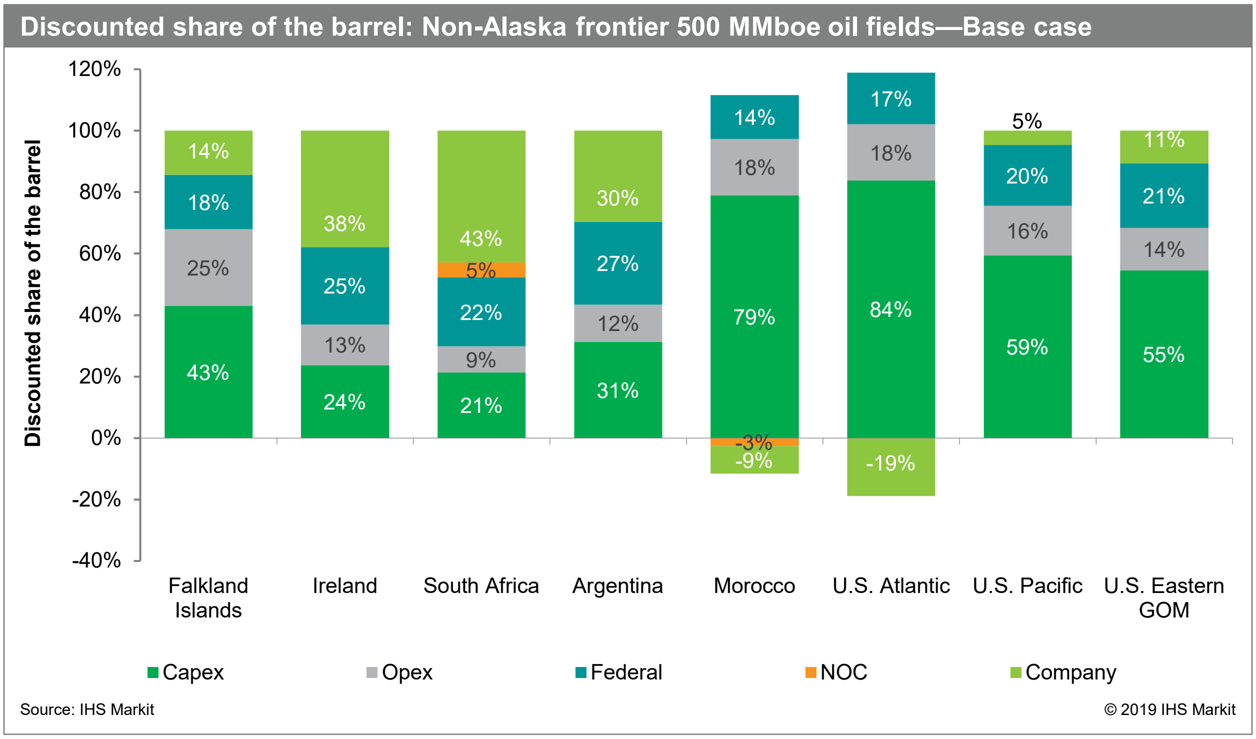


Figure 5-12. Discounted share of the barrel: Non-Alaska frontier 500 MMboe oil fields—Base case

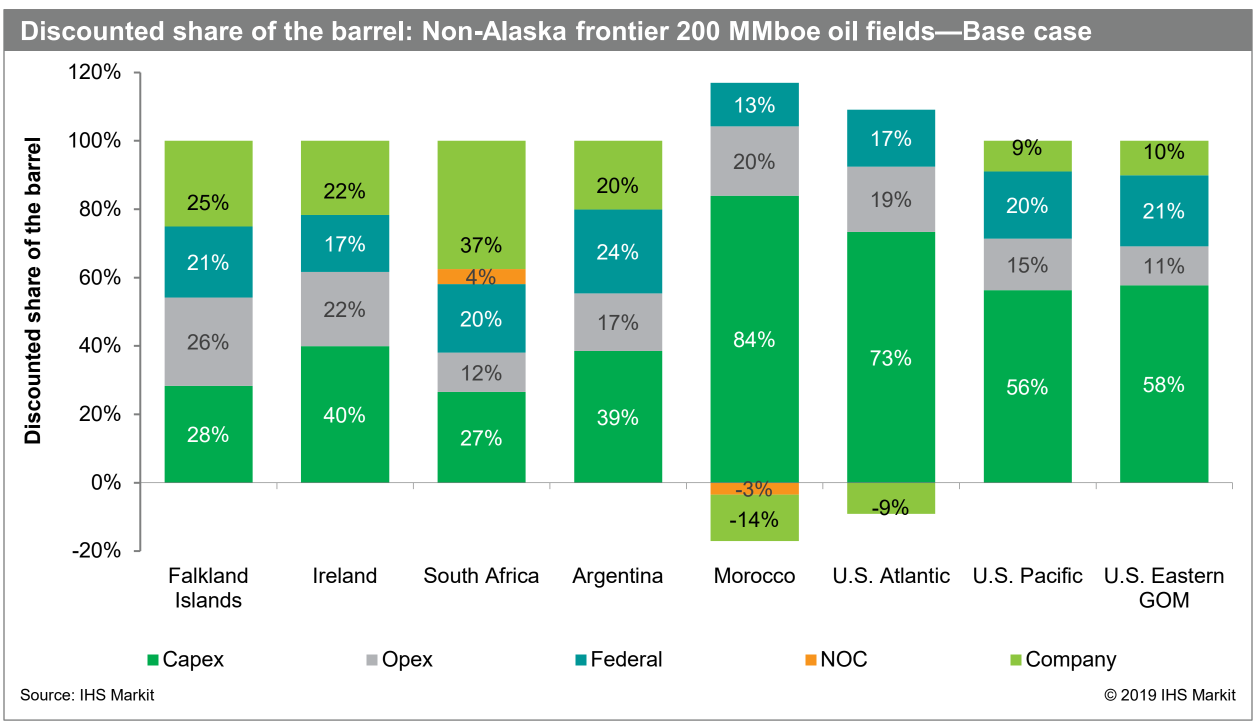


Figure 5-13. Discounted share of the barrel: Non-Alaska frontier 200 MMboe oil fields—Base case

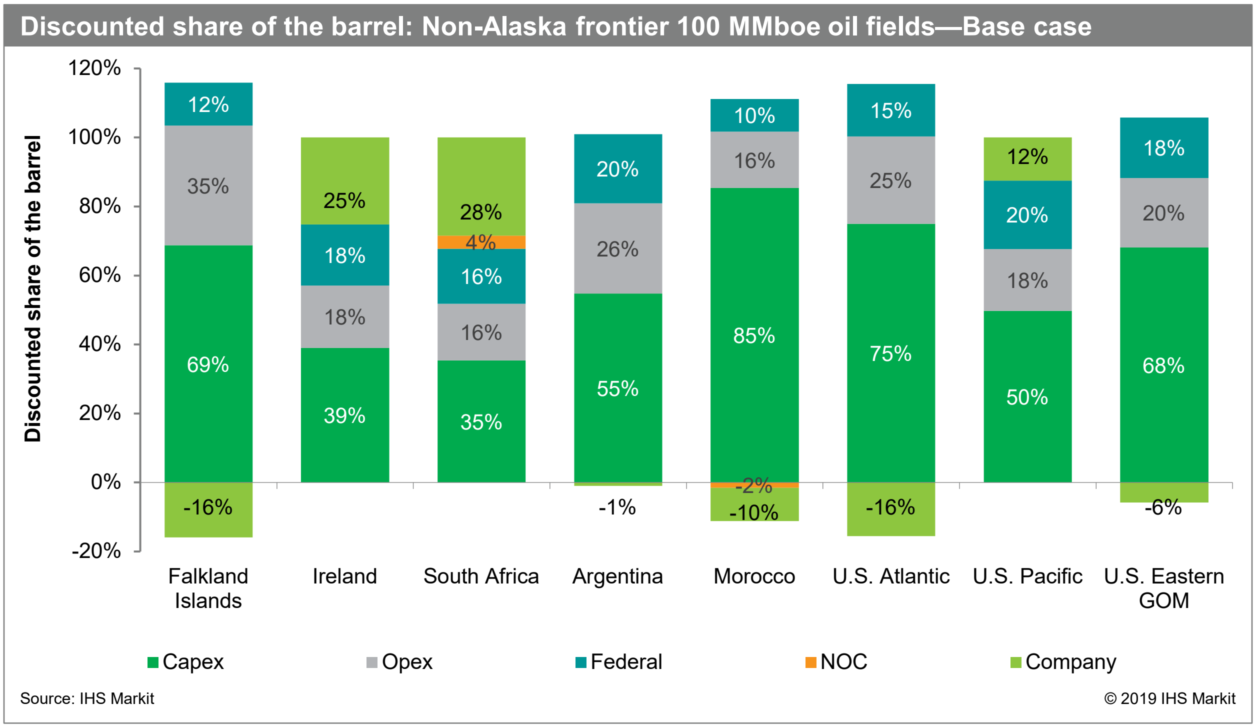


Figure 5-14. Discounted share of the barrel: Non-Alaska frontier 100 MMboe oil fields—Base case

The discounted investor share of the barrel for natural gas fields in all three U.S. offshore frontier regions is negative for all field sizes under the base case (Figures 5-15 to 17). The capital cost share of the discounted barrel ranges from 87 percent to 177 percent, rendering all U.S. projects uneconomic. Morocco, Argentina, and South Africa lead the peer group by offering investors 26–36 percent of the discounted barrel in the 500 MMboe gas field, 23–25 percent in the 200 MMboe gas field, and 621 percent in the 100 MMboe field.

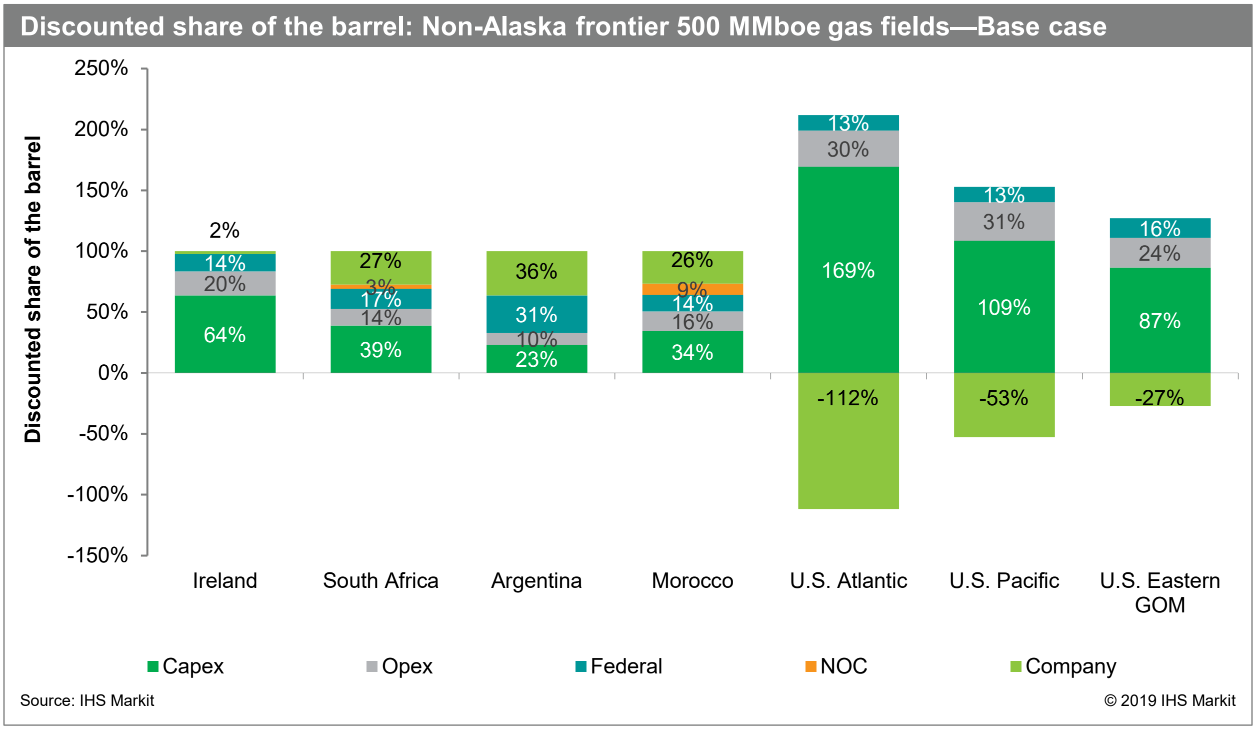


Figure 5-15. Discounted share of the barrel: Non-Alaska frontier 500 MMboe gas fields—Base case

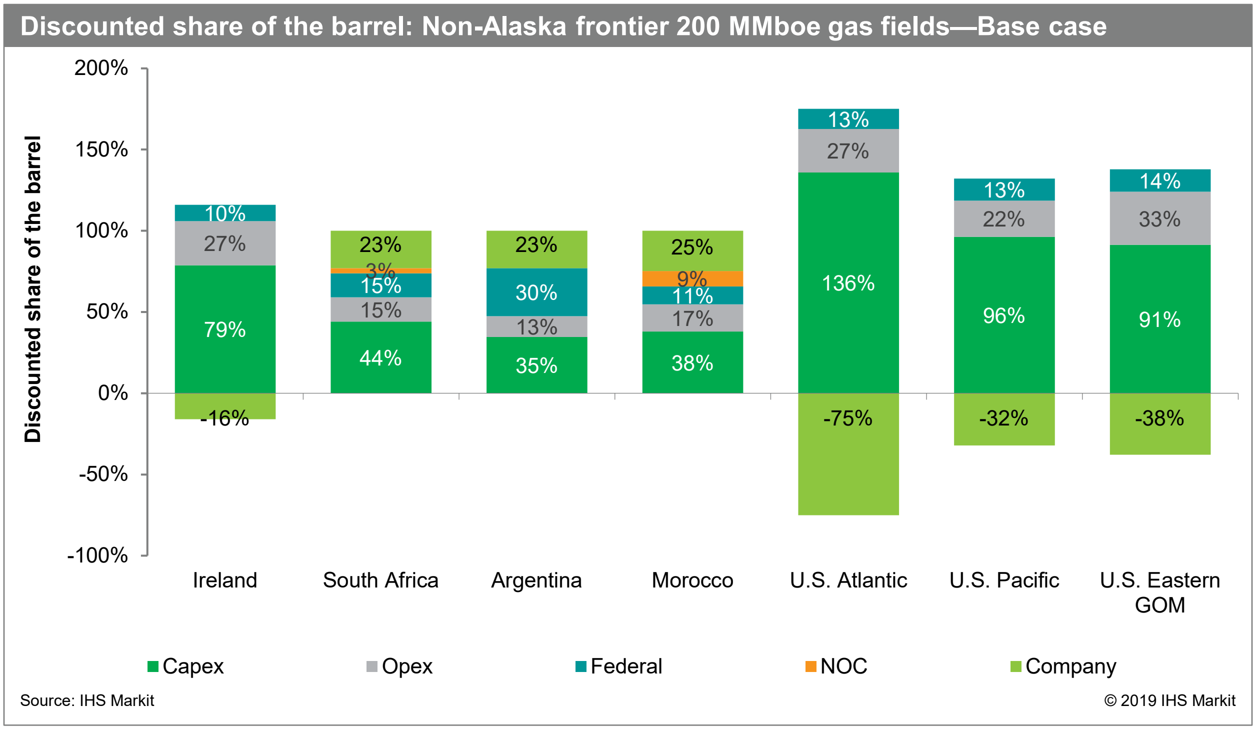


Figure 5-16. Discounted share of the barrel: Non-Alaska frontier 200 MMboe gas fields—Base case

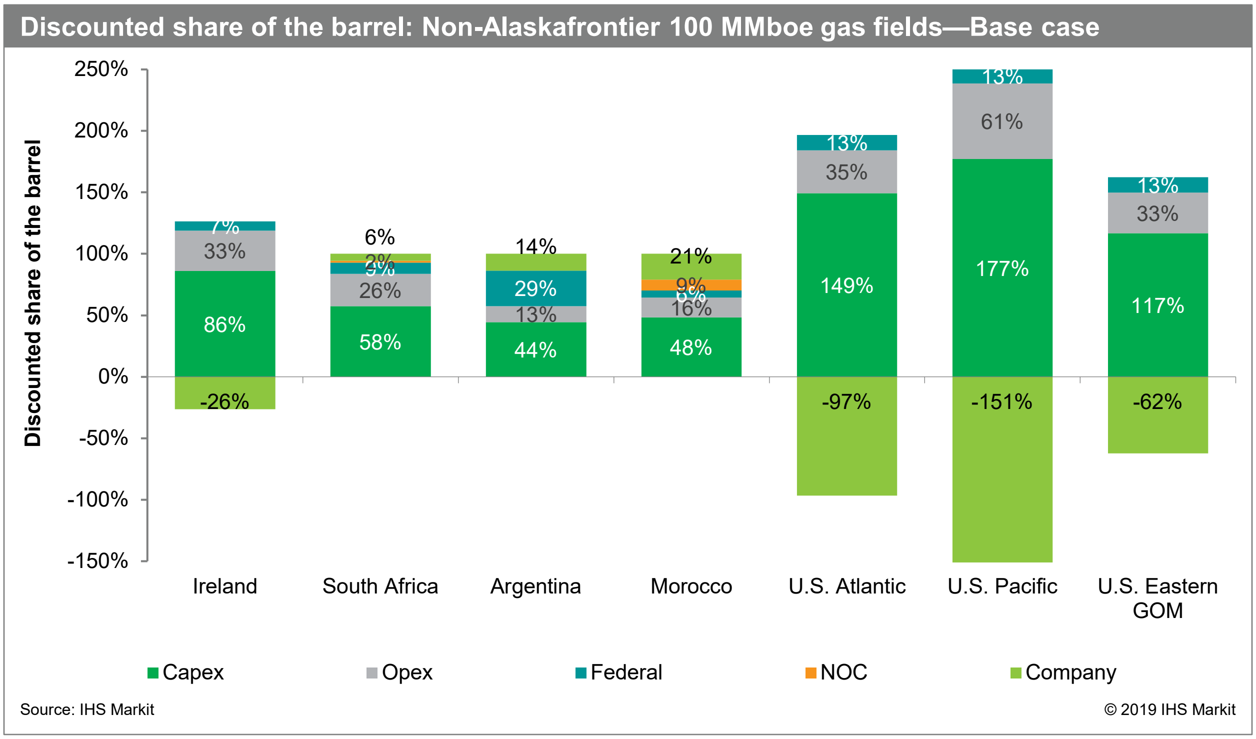


Figure 5-17. Discounted share of the barrel: Non-Alaska frontier 100 MMboe gas fields—Base case

5.4 Conclusion

In the high oil price environment, the Alaska Beaufort Sea and Chukchi Sea projects are very competitive within the peer group, offering better returns and higher value on a dollar-per-barrel basis than the majority of projects modeled for this study. When considering the expected field sizes and primary product output in the respective jurisdictions, the investment opportunities in Alaska Beaufort and Chukchi seas should be more appealing to investors—Alaska's current discoveries in the Arctic offshore area tend to be oil-prone versus the gas-prone discoveries of the Mackenzie Delta and Barents Sea. The majority of companies investing in frontier exploration are looking for oil.

Given the current complexity, risks involved, and expected returns at different prices, the current fiscal terms only foster investment in a high price scenario on a stand-alone basis, as do those of the other jurisdictions in the peer group. However, cluster and phased development of the Arctic resources similar to the ones undertaken in the Barents Sea in Norway could enable investment under the base price scenario.

The U.S. Non-Alaska offshore frontier regions face greater commercial challenges than the other jurisdictions in the peer group. Prospects in the U.S. Atlantic and Eastern GOM are expected to be in water and formation depths that are two to three times greater than the respective ones in the international jurisdictions. The U.S. frontier offshore oil fields offer high value per exploration well drilled under the high price scenario. However, such values deteriorate fast when the low price cases are taken into account.

The costs associated with the water and reservoir depth and lack of infrastructure prove challenging for the stand-alone development of projects in the U.S. frontier regions. Deployment of field development concepts that include a cluster of fields could significantly improve the commercial viability of projects in Eastern GOM and Pacific region. There is potential for added value for the U.S. Eastern GOM if the development can leverage proximity to the GOM oilfield service centers of Louisiana, Alabama, and Mississippi. A nearby dynamic service market offers greater possibilities to negotiate rates and lower costs.

Development of natural gas fields in the Non-Alaska offshore frontier regions is not viable under the current commodity prices in the United States. The abundance of lower cost natural gas supply from shale gas and associated gas produced from tight oil formations is likely to keep prices at a level that is not conducive to develop offshore natural gas resources in the United States in the near future.

The evolution of other frontier offshore regions from frontier to emerging status has historically shown a long lead time from the initial discoveries to first commercial development. Companies often rely on the discovery of additional fields to justify the final investment decision (FID). The lead time to FID in a frontier basin can be anywhere between 15 and 20 years. A lot of countries provide for a retention period of 5–10 years to establish the commerciality of a discovery. A greater degree of flexibility in the U.S. Federal oil and gas leases for offshore frontier acreage, which provides for longer lease terms to establish commerciality of resources discovered, may incentivize investment.

6 Fiscal System Alternatives

BOEM requested that this study analyze fiscal system alternatives presented here. The cases in this section do not represent plans or policy decisions at the time of the study. The cases are prepared to understand to what extent, if any, such alternatives could impact investment decisions and the competitiveness of the Federal offshore frontier areas.

6.1 Alternative Royalties

IHS Markit analyzed fiscal sensitivities for each Alaska offshore and Non-Alaska offshore frontier peer group by applying an RSV incentive suggested by BOEM. The RSV allows royalty relief up to the RSV amount, conditional on price thresholds. The operator draws from an RSV bank, determined by water depth for deepwater and by reservoir depth for shallow water areas.

The fiscal alternative relies on a threshold price of $85/bbl. When market prices exceed $85/bbl, the RSVs do not apply, and the standard lease royalty of 12.5 percent is applied. Thus, the high case results for RSV remain unchanged from the status quo in this study since the $85/bbl threshold is below the high case price. This threshold price is the midpoint between the base and the high price (Figure 6-1).

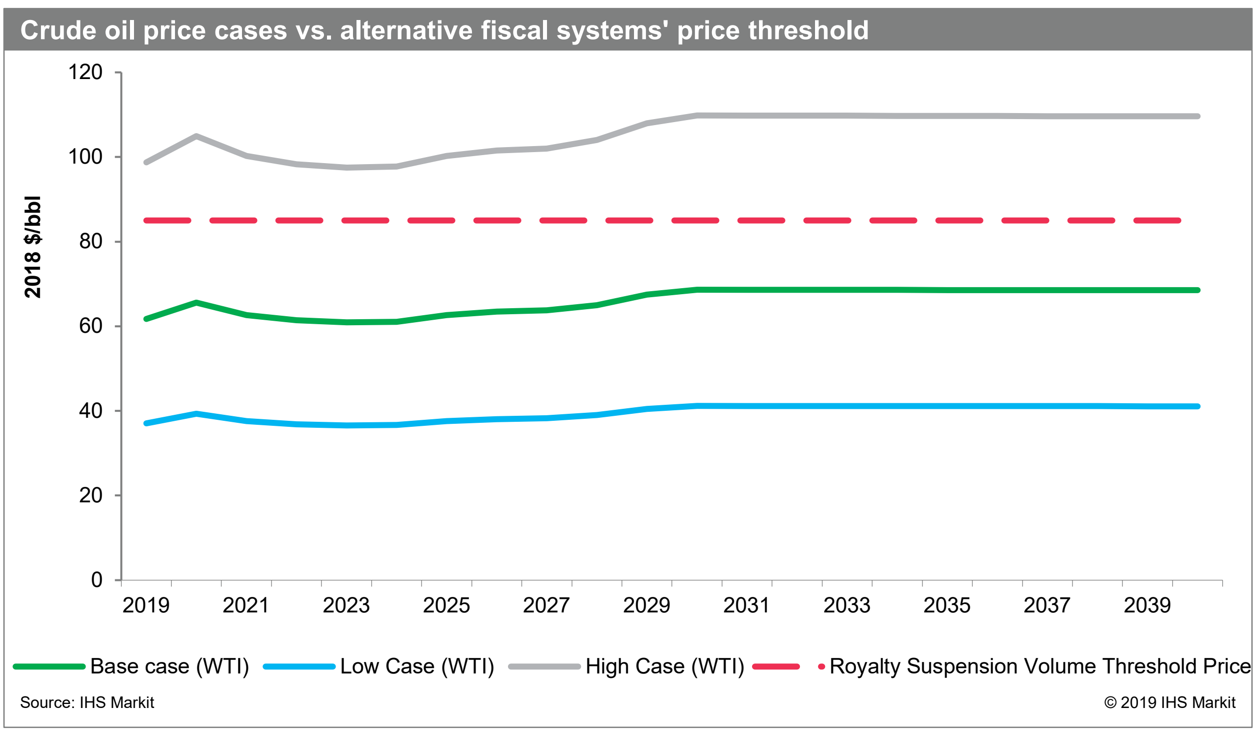


Figure 6-1. Crude oil price cases vs. alternative fiscal systems' price thresholds

All RSVs are applied at the lease level. The per-lease RSV is multiplied by the number of leases that make up the field to calculate the total RSV for the field. Tables 6-1 and 6-2 provide information on the RSVs and the number of leases assumed for each field size.

Table 6-1. Royalty relief—RSVs for offshore frontier

Non-Alaska frontier		Alaska offshore	
Water depth (m)	Relief volumes (MMboe)	Water depth (m)	Relief volumes (MMboe)
0 to < 400	20	0–200	50
400 to < 800	40		
800 +	60		

Source: IHS Markit © 2019 IHS Markit

Table 6-2. Number of leases by field size to determine total RSV

Field size (≥ MMboe)	Number of leases per field
100	1
200	2
400	4
500	5
1,000	8

Source: IHS Markit © 2019 IHS Markit

6.1.1 Alaska Offshore Frontier Fiscal System Alternatives

The RSV is evaluated for both Federal Alaska offshore areas, the Beaufort Sea and Chukchi Sea, across three different field sizes: 100 MMboe, 400 MMboe, and 1,000 MMboe. All cases assume a 50 MMboe RSV per lease. The total RSV for each field case is based on the number of leases assumed per field size (Table 6-3). The RSVs applied for the fields modeled in this study range from 40 percent to 50 percent of the recoverable reserves.

Table 6-3. Alaska offshore cases: Total RSV

Cases	Reservoir depth (ft)	Water depth (ft)	Water depth (m)	No. of leases	RSV per lease (MMboe)	Total RSV (MMboe)	% Royalty free
Beaufort Sea oil 100 MMboe	8,500	24	7	1	50	50	50%
Beaufort Sea oil 400 MMboe	8,500	24	7	4	50	200	50%
Beaufort Sea oil 1,000 MMboe	8,500	24	7	8	50	400	40%
Chukchi Sea oil 100 MMboe	7,160	148	45	1	50	50	50%
Chukchi Sea oil 400 MMboe	7,160	148	45	4	50	200	40%
Chukchi Sea oil 1,000 MMboe	7,160	148	45	8	50	400	40%

Source: IHS Markit © 2019 IHS Markit

6.1.2 Non-Alaska Offshore Frontier Fiscal System Alternatives

The statutory minimum royalty rate of 12.50 percent is assumed for all U.S. offshore frontier areas. Since deepwater GOM currently uses an 18.75 percent royalty rate, the Non-Alaska frontier sensitivity cases display 16.67 percent and 18.75 percent royalty rates in addition to the RSV alternative.

RSV is evaluated for three Federal Non-Alaska offshore areas, Pacific, Eastern GOM, and Atlantic, across three different field sizes: 100 MMboe, 200 MMboe, and 500 MMboe. The RSVs allocated in each case will depend on the location of each field (i.e., water depth). Not all fields of the same size are in the same water depth in the three regions. The Eastern GOM and Atlantic fields modeled for this study are in deeper waters than the respective field sizes in the Pacific. Table 6-4 provides the actual RSVs modeled at the field level for the fields in each offshore region. The royalty-free volumes are 20 percent of the field reserves for all Pacific cases, while they range between 20 percent and 60 percent for the Eastern GOM and Atlantic cases.

Table 6-4. Non-Alaska offshore cases and total RSV

Cases	Reservoir depth (ft)	Water depth (ft)	Water depth (m)	Terrain	No. of leases	RSV per lease (MMboe)	Total RSV (MMboe)	% Royalty free
U.S. Atlantic								
Gas 100 MMboe	9,600	72	22	Shallow water	1	20	20	20%
Gas 200 MMboe	8,200	3,220	981	Deepwater	2	60	120	60%
Gas 500 MMboe	4,200	3,220	981	Deepwater	5	60	300	60%
Oil 100 MMboe	5,500	394	120	Shallow water	1	20	20	20%
Oil 200 MMboe	8,100	2,950	899	Deepwater	2	60	120	60%
Oil 500 MMboe	30,000	4,020	1,225	Deepwater	5	60	300	60%
U.S. Eastern GOM								
Gas 100 MMboe	11,600	200	61	Shallow water	1	20	20	20%
Gas 200 MMboe	2,600	400	122	Shallow water	2	20	40	20%
Gas 500 MMboe	21,000	3,240	988	Deepwater	5	60	300	60%
Oil 100 MMboe	15,200	3,200	975	Deepwater	1	60	60	60%
Oil 200 MMboe	10,400	2,540	774	Deepwater	2	40	80	40%
Oil 500 MMboe	24,500	7,220	2,201	Deepwater	5	60	300	60%
U.S. Atlantic								
Gas 100 MMboe	7,970	220	67	Shallow water	1	20	20	20%
Gas 200 MMboe	8,960	660	201	Deepwater	2	20	40	20%
Gas 500 MMboe	11,000	1,030	314	Deepwater	5	20	100	20%
Oil 100 MMboe	6,000	220	67	Shallow water	1	20	20	20%
Oil 200 MMboe	6,990	660	201	Deepwater	2	20	40	20%
Oil 500 MMboe	6,020	1,030	314	Deepwater	5	20	100	20%

Source: IHS Markit

6.2 Comparative Analysis of Alternative Fiscal Systems

6.2.1 Alaska Offshore Frontier Fiscal System Alternatives

The RSVs applied in the Beaufort Sea and Chukchi Sea fields turn a couple of projects from negative to positive NPV/boe in the base case—the 100 MMboe field in Beaufort Sea and the 400 MMboe field in Chukchi Sea. Under this metric and the EMV per exploration well drilled, the Beaufort Sea oil fields yield positive results for the high and base price scenarios. Only one of the Chukchi Sea fields, however, yields a positive NPV/boe and EMV in the base case (Figure 6-3 and Table 6-5). That is reflective of the higher cost associated with exploration and development of oil and gas fields in the Chukchi Sea. Not even a 40–50 percent relief from royalty payable to the Federal government is sufficient to render such projects economically viable on a stand-alone basis in the base case.

Figures 6-2 to 6-5 display the NPV/boe for the low, base, and high case. The sum of the three cases yields an aggregate value that is used to determine rank order from the largest value to the smallest.

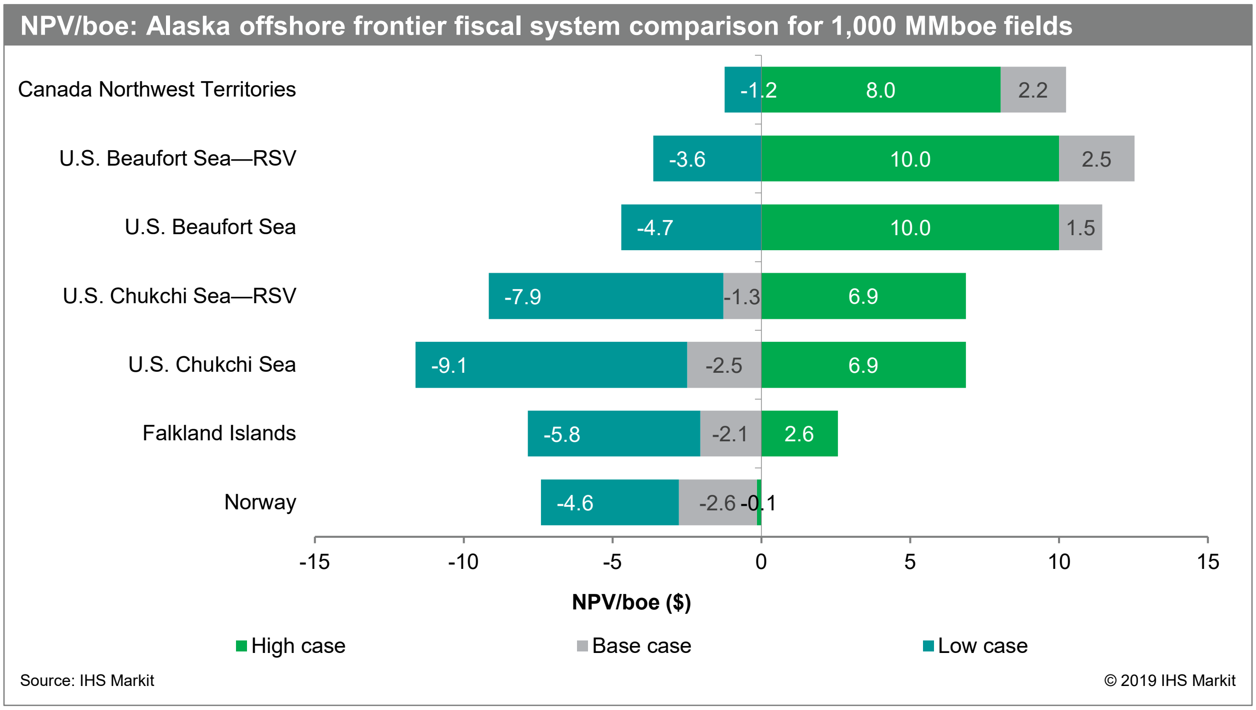


Figure 6-2. NPV/boe: Alaska offshore frontier fiscal system comparison for 1,000 MMboe fields

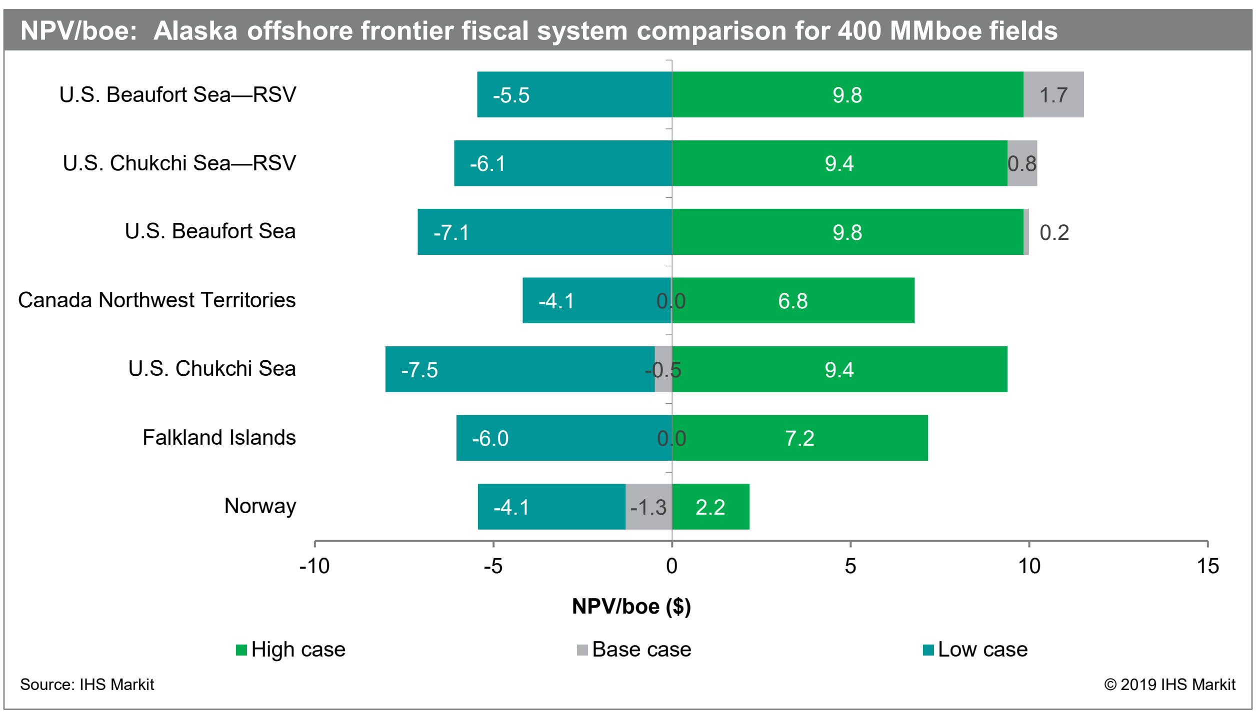


Figure 6-3. NPV/boe: Alaska offshore frontier fiscal system comparison for 400 MMboe fields

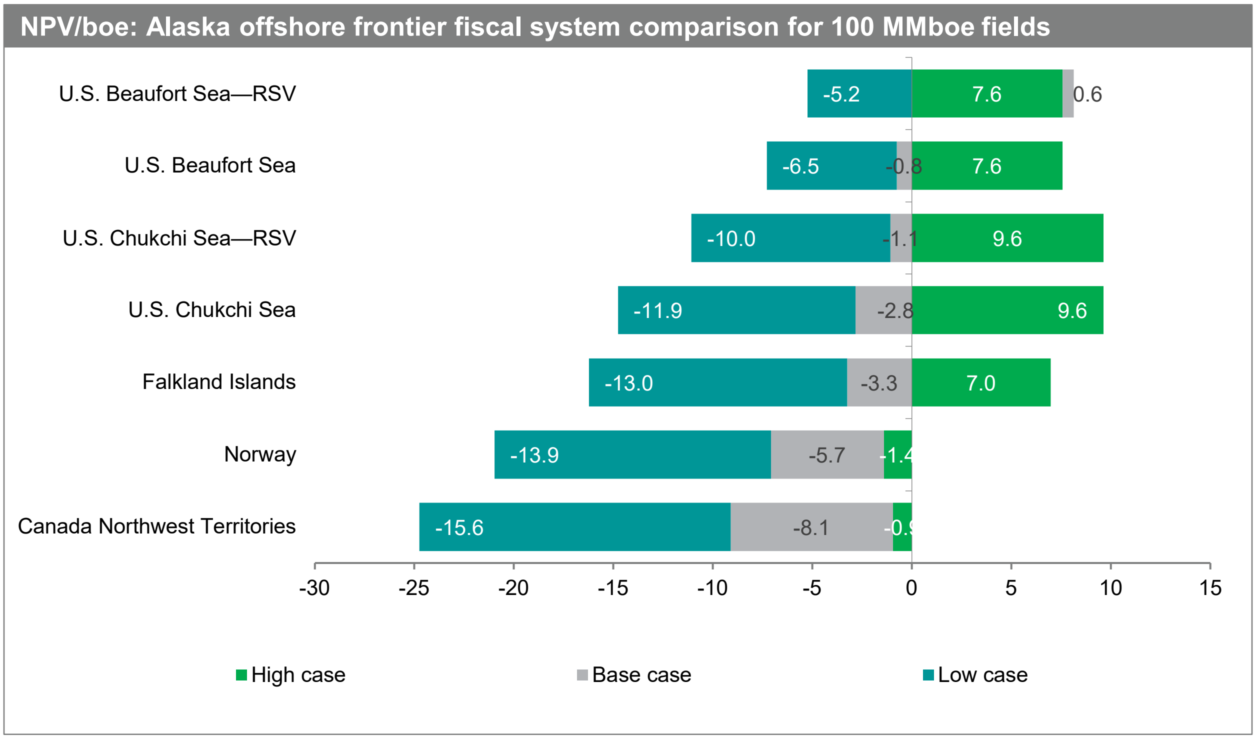


Figure 6-4. NPV/boe: Alaska fiscal system comparison for 100 MMboe fields

Table 6-5. EMV: Alaska Federal fiscal system alternatives

Jurisdiction	EMV ($ million)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	1,000	400	100	1,000	400	100	1,000	400	100
Canada NWT	1,411	362	-92	339	-71	-278	-352	-368	-468
Falkland Islands	569	715	136	-666	-58	-138	-1,531	-593	-350
Norway	-41	202	-40	-611	-130	-141	-1,074	-396	-318
U.S. Beaufort Sea	2,417	935	183	339	11	-21	-1,060	-612	-157
U.S. Beaufort Sea—RSV	2,417	935	183	637	166	12	-878	-515	-137
U.S. Chukchi Sea	1,982	1,082	275	-722	-58	-84	-2,636	-866	-343
U.S. Chukchi Sea—RSV	1,982	1,082	275	-393	100	-36	-2,405	-751	-308

Note: RSV not eligible in the high case.

Source: IHS Markit

The application of the RSV improves the IRR for the Alaska Beaufort and Chukchi seas projects; however, the measure is insufficient to enable stand-alone projects to reach the desired 15 percent investment threshold (Figure 6-5).

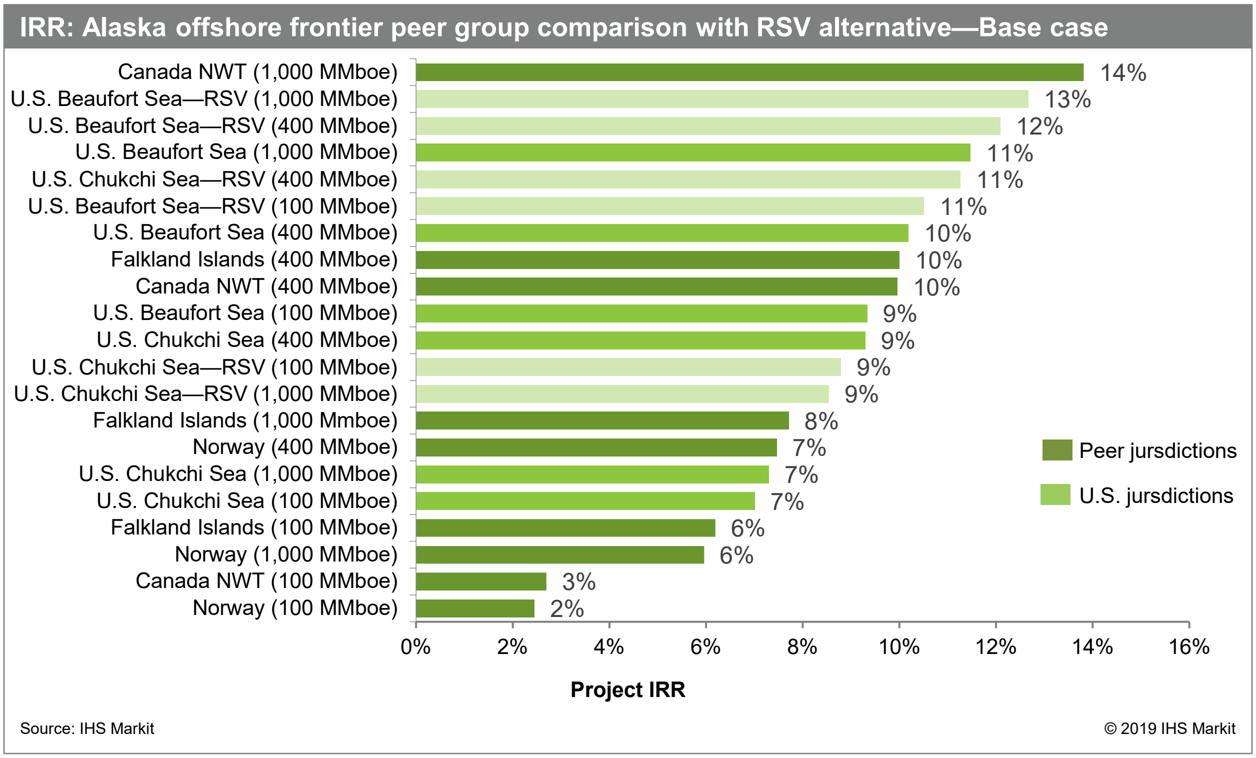


Figure 6-5. IRR: Alaska offshore frontier peer group comparison with RSV alternative—Base case

The only cases that continue to be viable under the royalty suspension alternative are those in the high price scenario, which is not subject to the application of RSVs. The two intended targets of the RSV—the base and low price cases—fail to reach the 15 percent hurdle rate of return for both the Beaufort Sea and Chukchi Sea fields, as do all the other jurisdictions in this peer group (Table 6-6). The lackluster economics of the Alaska offshore frontier peer group are not related to the fiscal system, but rather the challenges associated with the high cost of development in the Arctic environment.

Table 6-6. IRR: Alaska Federal fiscal system alternatives

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	1,000	400	100	1,000	400	100	1,000	400	100
Canada NWT	21	17	9	14	10	3	7	1	0
Falkland Islands	12	17	17	8	10	6	3	2	0
Norway	10	14	8	6	7	2	3	2	0
U.S. Beaufort Sea	18	19	15	11	10	9	3	0	2
U.S. Beaufort Sea—RSV	18	19	15	13	12	11	5	0	3
U.S. Chukchi Sea	16	20	18	7	9	7	0	0	0
U.S. Chukchi Sea—RSV	16	20	18	9	11	9	0	0	0
Note: RSV not eligible in the high case.									

Source: IHS Markit © 2019 IHS Markit

The impact of the categorical royalty relief is not uniform among the Beaufort Sea and Chukchi Sea areas of Federal lands in Alaska when the government take percentage is taken into account. The RSVs significantly lower the government take for the Beaufort Sea, transforming it into the lowest government take in the peer group. The overall impact on Chukchi Sea government take is not as significant. This is attributed to the higher per-unit cost structure of the Chukchi Sea projects. The government take for all three field sizes in the low price scenario in the Chukchi Sea remains at 100 percent under this alternative fiscal system (Table 6-7).

Table 6-7. Government take: Alaska Federal fiscal system alternatives

Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	1,000	400	100	1,000	400	100	1,000	400	100
Canada NWT	50	49	50	52	52	53	53	77	100
Falkland Islands	35	35	38	38	40	49	49	54	100
Norway	77	78	77	76	77	72	70	68	100
U.S. Beaufort Sea	35	37	35	39	44	39	61	100	64
U.S. Beaufort Sea—RSV	35	37	35	30	30	28	43	100	38
U.S. Chukchi Sea	37	38	38	46	49	50	100	100	100
U.S. Chukchi Sea—RSV	37	38	38	37	37	37	100	100	100
Note: RSV not eligible in the high case.									

Source: IHS Markit

To assess the full impact of royalty on project economics in Alaska, IHS Markit conducted sensitivity analysis on a range of royalties including zero percent royalty on Federal lands offshore Alaska. Figures 6-6 and 6-7 show the impact of various royalty rates, the RSVs on the IRR, and the government take. Each trend line represents a field size. The data points illustrate the impact of royalty rates to the investor IRR and government take as the royalty rate changes from 12.5 percent to RSV to zero royalty. The trend lines indicate how sensitive a particular field is to the royalty rate; a more horizontal trend line has higher response to the change in royalty rate, while a more vertical line indicates less elasticity. The lines are indicative only and could be inaccurate beyond the data points.

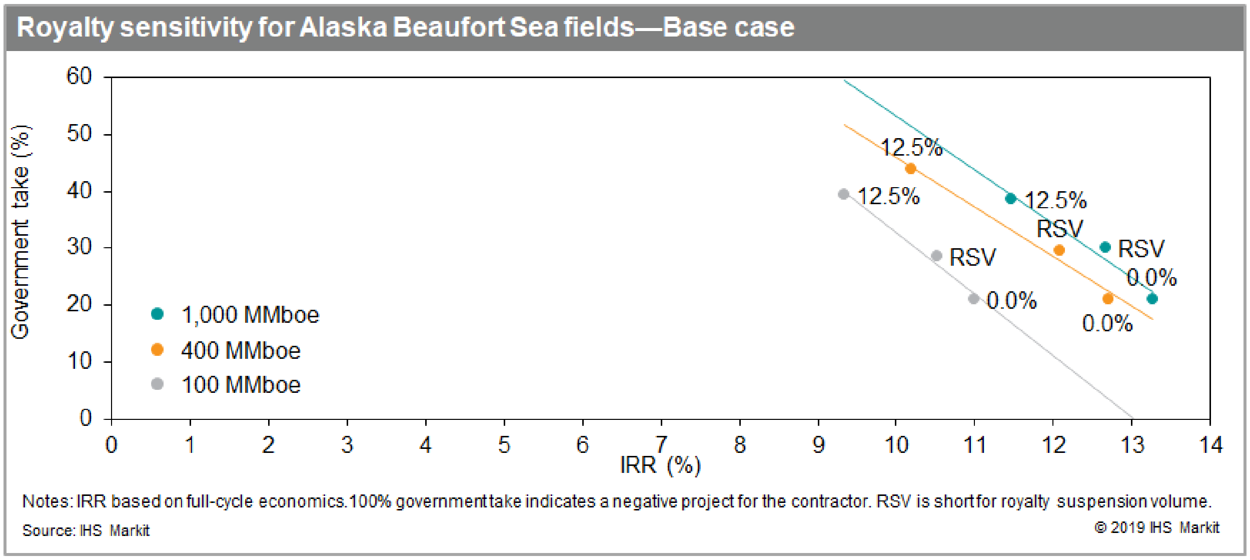


Figure 6-6. Royalty sensitivity for Alaska Beaufort Sea fields—Base case

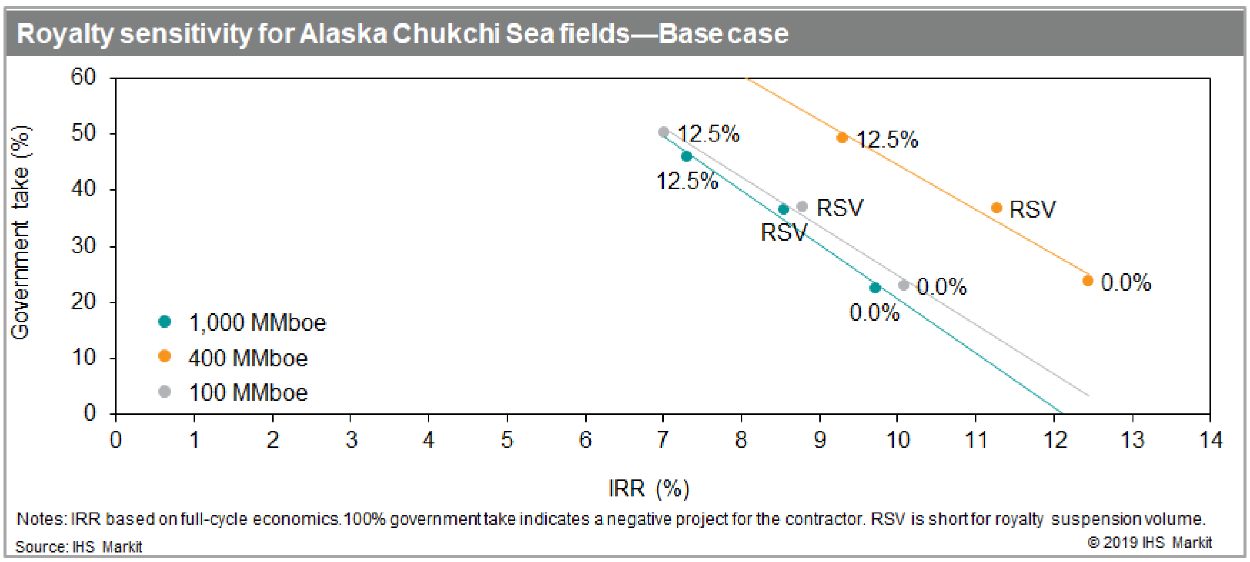


Figure 6-7. Royalty sensitivity for Alaska Chukchi Sea fields—Base case

The results displayed in Figures 6-6 and 6-7 indicate that even a zero percent royalty would not push the Alaska offshore frontier fields above the 15 percent IRR investment threshold under the base price scenario as stand-alone developments. The development of such fields in the Arctic environment depends more on global market conditions (i.e., commodity price shifts and industry's ability to lower the exploration and development costs, rather than changes to the Federal fiscal system).

6.2.2 Non-Alaska Offshore Frontier Fiscal System Alternatives

The application of the RSVs onto the U.S. Federal fiscal systems for the Atlantic, Eastern GOM, and Pacific regions from an EMV perspective yields better results for the Eastern GOM projects. The EMV for the three Eastern GOM field sizes under the base price scenario increases by $48 million, $68 million, and $198 million for the 100 MMboe, 200 MMboe, and 500 MMboe fields, respectively. The EMV for the

100 MMboe field turns positive under this fiscal system alternative in the base case. While the Pacific projects also benefit from the application of the RSV, the value added per exploratory well drilled is about half of the value addition realized in the Eastern GOM projects—a $157-million combined-value addition for the Pacific projects, versus a $314-million combined-value addition for the Eastern GOM projects (Table 6-8). The Pacific prospects modeled for this study get about half the volume relief as the Eastern GOM projects due to their location in shallower waters.

The application of the RSVs, however, does not yield positive results for any of the Atlantic field sizes under the base case. The EMV under the low price scenario continues to be negative for all U.S. cases, as it is for the majority of cases within the peer group. Natural gas fields underperform in the peer group, both in terms of value per exploratory well as well as the number of cases yielding positive EMV. The RSVs applied to natural gas fields do nothing to change the status quo. Development of natural gas fields is challenging even in mature areas such as the Central GOM with existing infrastructure in place.

Table 6-8. EMV: Non-Alaska offshore frontier Federal fiscal system alternatives

Jurisdiction	EMV ($ million)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Oil									
Argentina	1,540	586	192	663	199	-4	77	-61	-137
Falkland Islands	1,148	783	111	253	262	-202	-379	-87	-454
Ireland	2,382	631	511	1,334	205	183	422	-123	-69
Morocco	1,138	395	311	-409	-275	-144	-1,463	-722	-444
South Africa	3,006	1,172	514	1,586	562	194	627	150	-26
U.S. Atlantic	944	502	195	-799	-138	-113	-1,938	-609	-355
U.S. Atlantic—RSV	944	502	195	-539	-38	-93	-1,751	-537	-340
U.S. Eastern GOM	1,537	746	244	301	127	-40	-543	-293	-242
U.S. Eastern GOM—RSV	1,537	746	244	500	195	8	-419	-251	-207
U.S. Pacific	1,464	777	463	141	133	103	-767	-310	-139
U.S. Pacific—RSV	1,464	777	463	232	176	126	-710	-283	-125
Gas									
Argentina	1,403	565	296	675	209	77	189	-28	-70
Ireland	942	215	57	20	-181	-172	-654	-474	-356
Morocco	1,819	859	544	725	310	158	-4	-55	-103
South Africa	1,962	820	218	790	273	-25	-17	-106	-206
U.S. Atlantic—Existing	-1,345	-283	-185	-2,425	-785	-422	-3,220	-1,161	-586
U.S. Atlantic—RSV	-1,345	-283	-185	-2,251	-693	-408	-3,118	-1,108	-578
U.S. Eastern GOM	271	44	-60	-472	-266	-233	-1,011	-504	-373
U.S. Eastern GOM—RSV	271	44	-60	-343	-244	-221	-923	-490	-365
U.S. Pacific	-155	127	-286	-1,073	-338	-447	-1,805	-712	-554
U.S. Pacific—RSV	-155	127	-286	-1,008	-308	-437	-1,763	-693	-548
Note: RSV not eligible in the high case.									

Jurisdiction	EMV ($ million)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100

Source: IHS Markit

Figures 6-8 through 6-10 display the results of the impact of the application of the RSV on the NPV/boe in the Non-Alaska offshore frontier region of the United States. Under this metric, and similar to the impact on EMV, the Eastern GOM gets a greater benefit from the application of the RSVs than does the Pacific region. In the base case, the NPV/boe for the 500 MMboe and 200 MMboe increases by $1.0, whereas the 100 MMboe has a $1.8 increase in NPV/boe. The added value to the Pacific projects is lower by comparison. The application of RSVs adds $0.6/boe in the 500 MMboe and $0.7/boe for each of the other two fields.

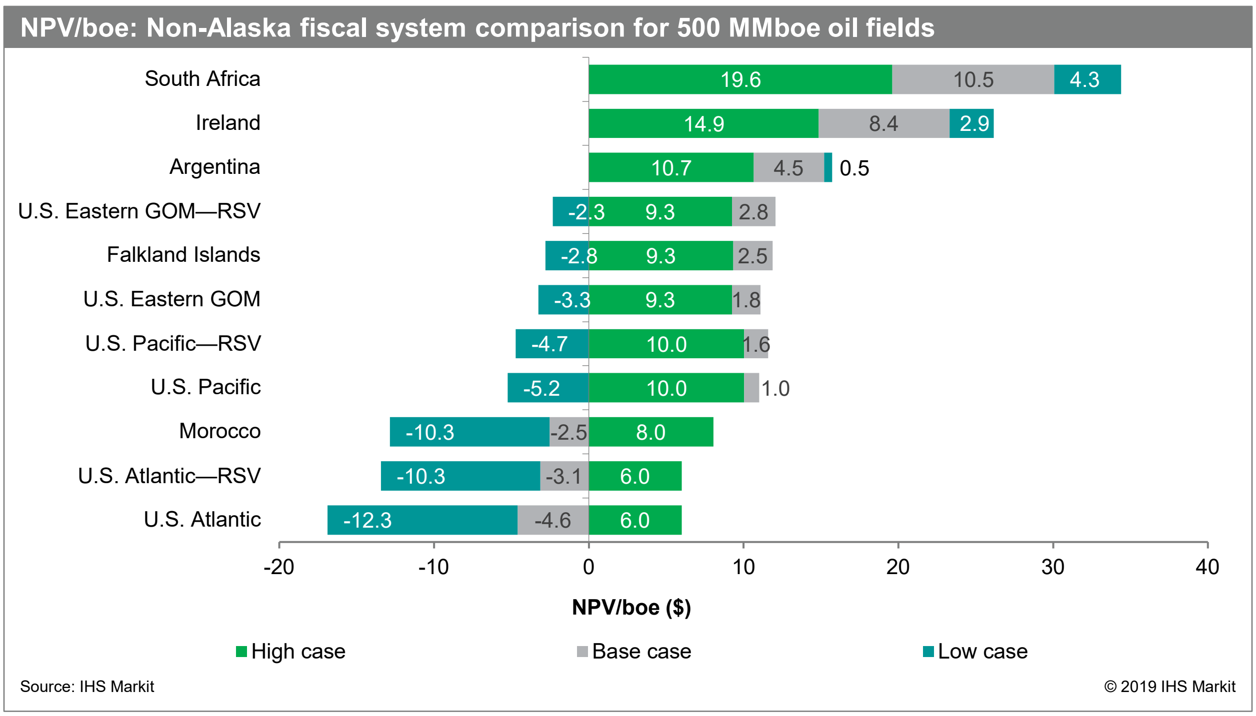


Figure 6-8. NPV/boe: Non-Alaska fiscal system comparison for 500 MMboe oil fields

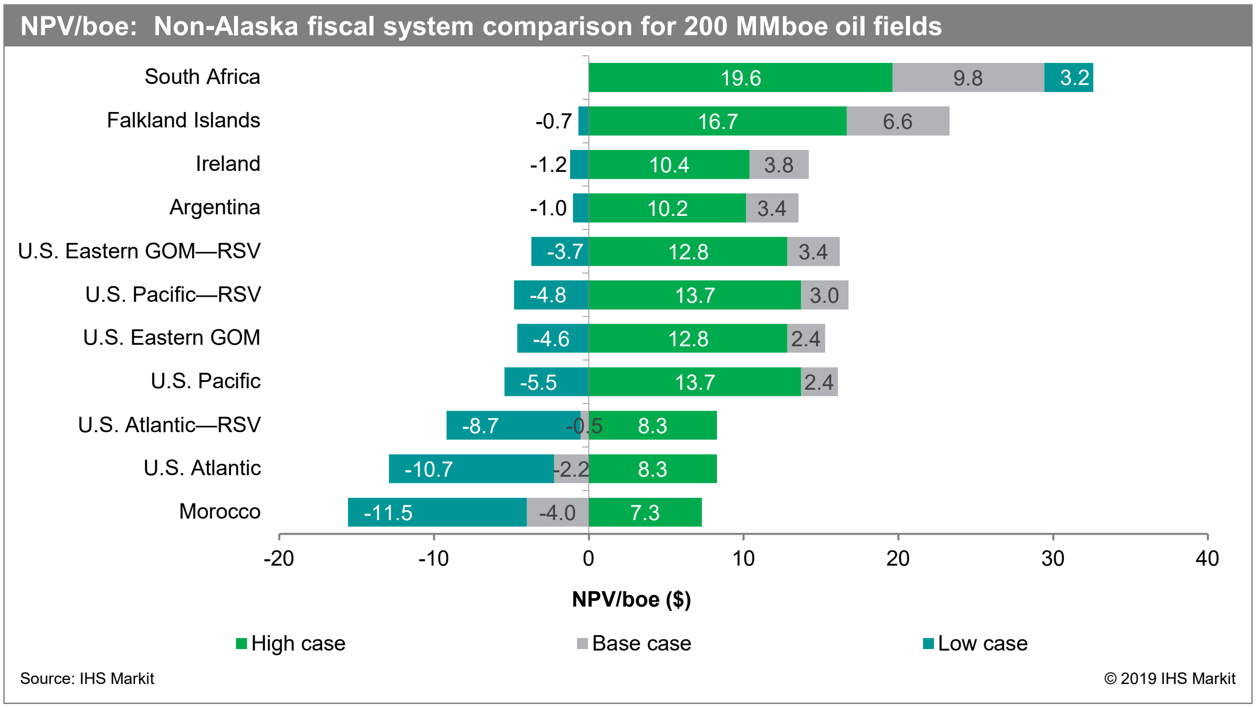


Figure 6-9. NPV/boe: Non-Alaska fiscal system comparison for 200 MMboe oil fields

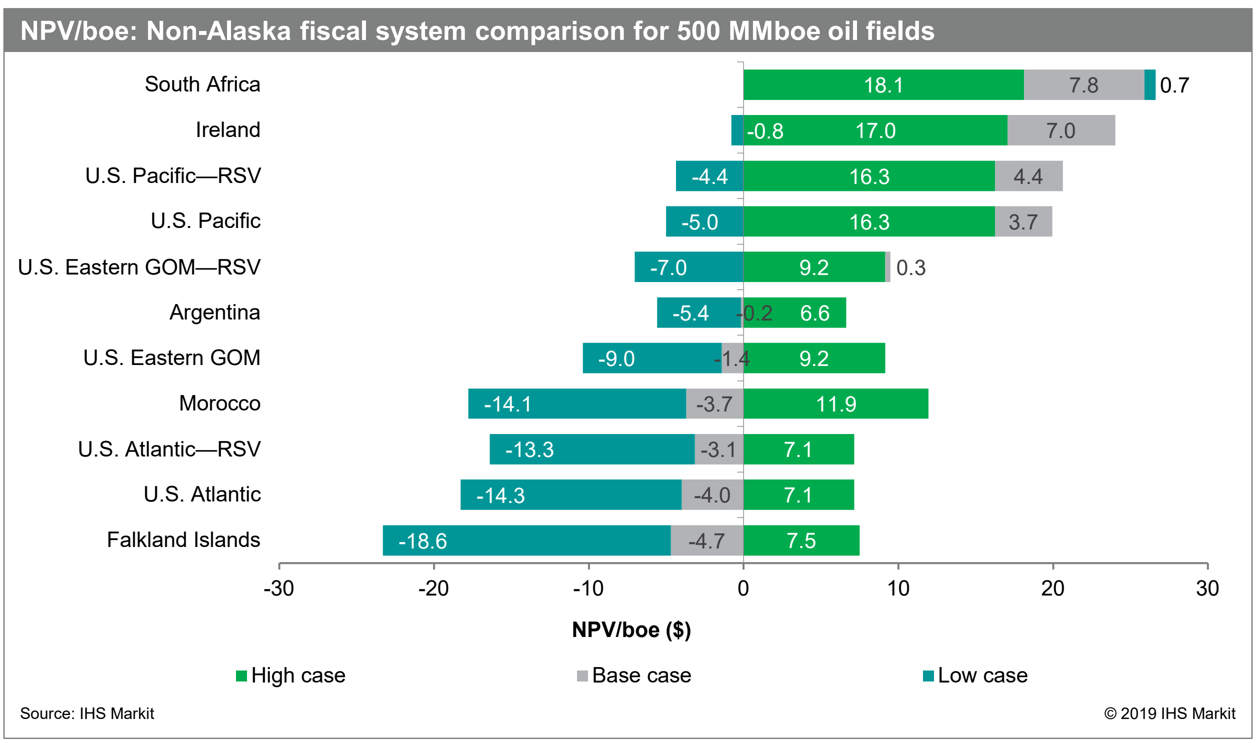


Figure 6-10. NPV/boe: Non-Alaska fiscal system comparison for 100 MMboe oil fields

As already indicated under the EMV analysis, the RSV fiscal system alternative is unable to meet or exceed the investment threshold for natural gas projects in all three U.S. Non-Alaska offshore frontier regions. All the projects present with negative NPV/boe under the base price scenario (Table 6-9).

Table 6-9. NPV/boe: Non-Alaska frontier oil and gas fields—Low, base, and high cases

Jurisdiction	NPV/boe ($)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Gas									
Argentina	9.7	9.7	10.2	4.6	3.5	2.6	1.3	-0.5	-2.3
Ireland	6.0	3.8	2.8	0.3	-2.3	-4.2	-3.8	-6.7	-10.9
Morocco	11.9	14.3	18.5	4.9	5.5	6.2	0.2	-0.3	-2.3
South Africa	12.9	14.1	8.8	5.4	5.3	1.1	0.3	-0.7	-4.9
U.S. Atlantic	-8.0	-5.0	-6.7	-14.4	-14.0	-16.0	-19.4	-20.8	-25.1
U.S. Atlantic—RSV	-8.0	-5.0	-6.7	-12.5	-11.4	-15.0	-17.5	-18.2	-23.9
U.S. Eastern GOM	2.0	0.9	-2.0	-3.1	-4.2	-8.1	-6.8	-8.2	-13.4
U.S. Eastern GOM—RSV	2.0	0.9	-2.0	-2.0	-3.8	-7.5	-5.7	-7.7	-12.8
U.S. Pacific	-1.1	2.2	-9.9	-7.5	-5.9	-15.6	-12.9	-12.7	-19.4
U.S. Pacific—RSV	-1.1	2.2	-9.9	-6.9	-5.2	-14.8	-12.2	-12.0	-18.7

Source: IHS Markit

The IRR increases on average by two percentage points when the RSVs are applied. The 200 MMboe oil fields in the Eastern GOM and Pacific reach the 15 percent IRR threshold when the RSVs are applied. The 500 MMboe field in Eastern GOM also becomes more attractive to investors when the RSV volumes are applied. The IRR improves from 12 percent to 14 percent (Table 6-10). The U.S. Atlantic oil fields are the most economically challenging within the peer group under the status quo—not even a 60 percent royalty relief can change the status quo for these fields. They are viable only in the high price environment.

Table 6-10. IRR: Non-Alaska frontier oil fields—Low, base, and high cases

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	30	27	18	20	17	10	11	8	1
Falkland Islands	29	41	18	16	24	3	2	8	0
Ireland	44	28	36	32	17	22	19	7	8
Morocco	17	16	20	7	6	6	0	0	0
South Africa	48	42	36	35	30	24	23	18	12
U.S. Atlantic	15	18	18	5	7	4	0	0	0
U.S. Atlantic—RSV	15	18	18	7	9	5	0	0	0
U.S. Eastern GOM	20	24	21	12	13	8	5	0	0
U.S. Eastern GOM—RSV	20	24	21	14	15	11	6	2	0
U.S. Pacific	22	27	29	11	14	16	0	0	0
U.S. Pacific—RSV	22	27	29	12	15	17	0	0	1
Note: RSV is not eligible in the high case									

Source: IHS Markit

As already indicated, under the EMV and NPV/boe analysis, the application of RSVs to gas fields in the Atlantic, Eastern GOM, and Pacific regions does not change the status quo from an investor IRR perspective. Natural gas fields in all three U.S. Non-Alaska offshore frontier regions remain uneconomic under all three price scenarios (Table 6-11).

Table 6-11. IRR: Non-Alaska frontier gas fields—Low, base, and high cases

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	35	29	28	25	19	16	15	9	3
Ireland	18	15	13	11	7	4	2	0	0
Morocco	33	34	34	21	21	21	11	10	6
South Africa	30	29	21	20	19	12	11	9	2
U.S. Atlantic	1	4	0	0	0	0	0	0	0
U.S. Atlantic—RSV	1	4	0	0	0	0	0	0	0
U.S. Eastern GOM	13	11	7	4	0	0	0	0	0
U.S. Eastern GOM—RSV	13	11	7	6	0	0	0	0	0
U.S. Pacific	9	13	0	0	0	0	0	0	0
U.S. Pacific—RSV	9	13	0	0	0	0	0	0	0

Note: RSV is not eligible in the high case.

Source: IHS Markit

The greatest impact, from a government take perspective, is observed in the Eastern GOM oil fields where the range of government take significantly narrows, almost on a par with Ireland and Argentina. The measures are less impactful in the Pacific fields, which are in relatively shallower water depths and receive an effective 20 percent relief on the amount of royalty payable to the Federal government. The median government take is reduced from 48 percent to 43 percent largely due to the impact on the base case economics (Table 6-12).

Table 6-12. Government take: Non-Alaska frontier oil fields—Low, base, and high cases

Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	36	37	38	37	38	41	38	42	67
Falkland Islands	37	36	41	42	40	73	82	61	100
Ireland	47	40	38	39	34	34	35	38	38
Morocco	35	34	28	54	58	58	100	100	100
South Africa	31	31	31	31	31	30	31	30	26
U.S. Atlantic	40	39	42	57	49	71	100	100	100
U.S. Atlantic—RSV	40	39	42	41	34	63	100	100	100
U.S. Eastern GOM	34	37	40	37	43	56	50	96	100
U.S. Eastern GOM—RSV	34	37	40	29	36	37	36	74	100
U.S. Pacific	37	37	37	45	45	43	100	100	95

Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
U.S. Pacific—RSV	37	37	37	41	41	39	100	100	81
Note: RSV is not eligible in the high case									

Source: IHS Markit

Across the board, the U.S. alternative royalty policies for frontier offshore areas do little to nothing to change the status quo for natural gas fields. The high cost associated with development of infrastructure and the depressed natural gas commodity prices in the United States pose significant challenges for the economic viability of frontier offshore gas projects in the United States. Additionally, the U.S. government take for the gas fields remains the highest in the peer group. Except for the 500 MMboe gas field in the Eastern GOM, where the government take drops from 61 percent to 42 percent in the base case, the results of the other cases remain largely unchanged (Table 6-13).

Table 6-13. Government take: Non-Alaska frontier gas fields—Low, base, and high cases

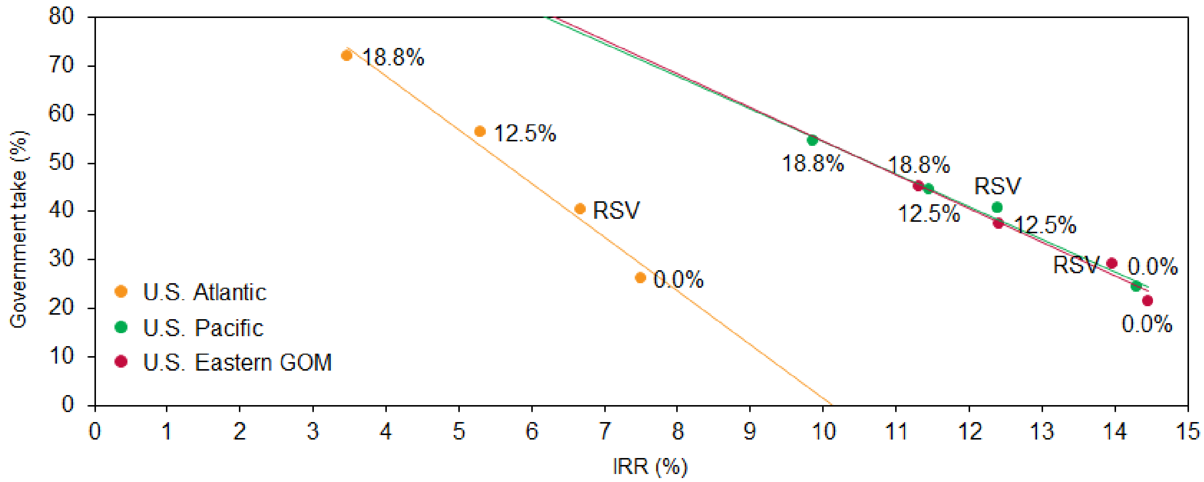
Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	500	200	100	500	200	100	500	200	100
Argentina	37	39	42	39	43	48	43	53	74
Ireland	37	34	35	36	39	50	58	100	100
Morocco	28	24	13	32	28	19	42	43	46
South Africa	31	31	31	31	30	29	29	27	100
U.S. Atlantic	85	69	94	100	100	100	100	100	100
U.S. Atlantic—RSV	85	69	94	100	100	100	100	100	100
U.S. Eastern GOM	41	45	52	61	100	100	100	100	100
U.S. Eastern GOM—RSV	41	45	52	42	96	100	100	100	100
U.S. Pacific	48	48	100	100	100	100	100	100	100
U.S. Pacific—RSV	48	48	100	100	100	100	100	100	100
Note: RSV is not eligible in the high case.									

Source: IHS Markit

To assess the full impact of royalty on project economics in Non-Alaska offshore frontier regions, IHS Markit conducted a sensitivity analysis on a range of royalties, including zero percent royalty on offshore Federal lands. In Figures 6-11 through 6-13, the impact of various royalty rates, the RSVs on the IRR, and the government take is displayed for each oil field size. Each trend line represents a region. For the 500 MMboe oil fields, the Pacific and Eastern GOM follow a similar trajectory, but the Pacific starts off less economic. At 12.5 percent royalty, the Pacific yields 11.4 percent IRR, while the Eastern GOM produces 12.4 percent IRR.

The data points illustrate the impact of royalty rates to the investor IRR and government take as the royalty rate changes from 12.5 percent to zero percent. The trend lines indicate how sensitive a particular field is to the royalty rate; a more horizontal trend line has higher response to the change in royalty rate, while a more vertical line indicates less elasticity. The lines are indicative only and could be inaccurate beyond the data points.

Non-Alaska offshore frontier 500 MMboe oil field royalty sensitivity

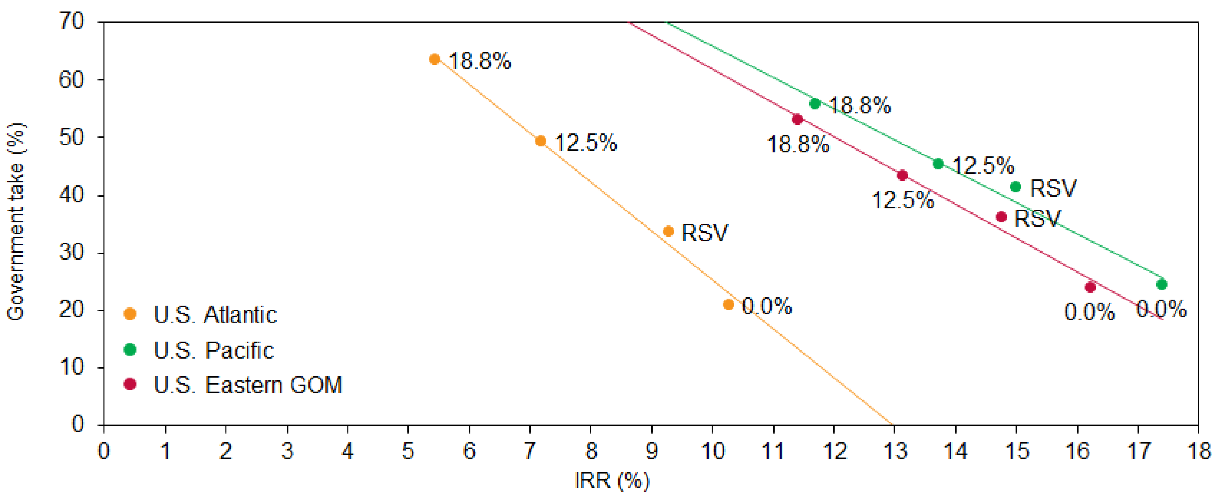


Notes: IRR based on full-cycle economics.100% government take indicates uneconomic project. RSV is short for Royalty Suspension Volume.

Source: IHS Markit

Figure 6-11. Non-Alaska offshore frontier 500 MMboe oil field royalty sensitivity

Non-Alaska offshore frontier 200 MMboe oil field royalty sensitivity



Notes: IRR based on full-cycle economics.100% government take indicates uneconomic project. RSV is short for Royalty Suspension Volume.

Source: IHS Markit

Figure 6-12. Non-Alaska offshore frontier 200 MMboe oil field royalty sensitivity

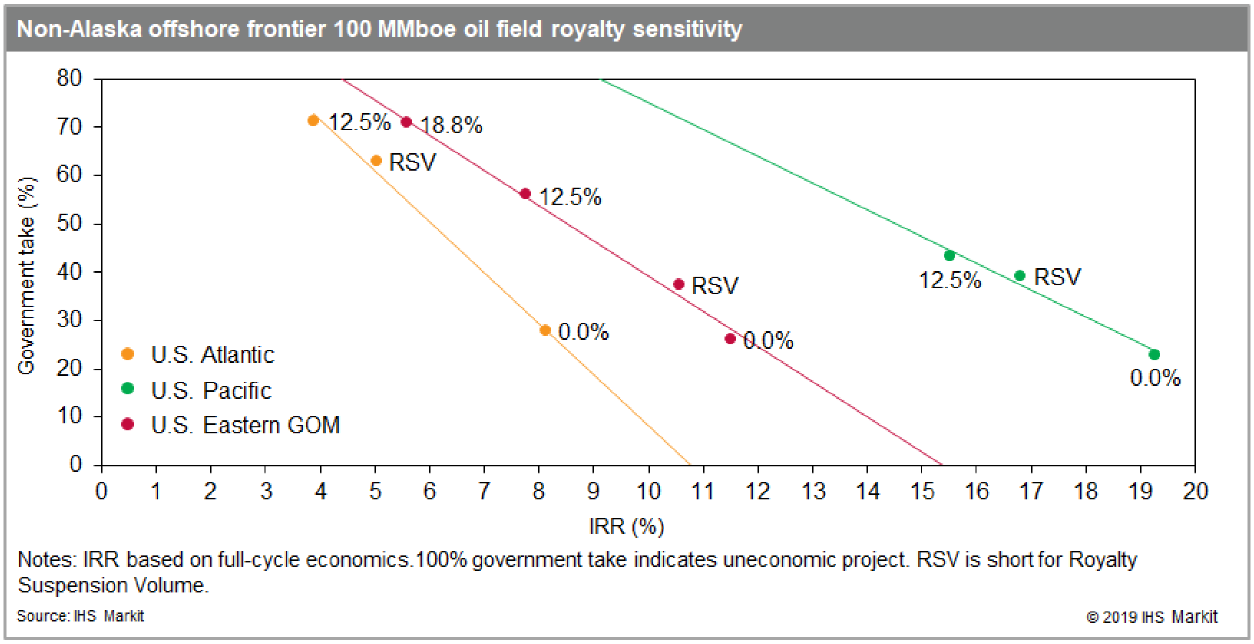


Figure 6-13. Non-Alaska offshore frontier 100 MMboe oil field royalty sensitivity

Royalty sensitivity analysis conducted for Non-Alaska frontier offshore fields in the United States indicates that fields similar to the 200 MMboe oil fields modeled for this study could cross the 15 percent IRR threshold in the Eastern GOM and Pacific regions, with substantially larger RSVs or substantially lower royalty rates than the statutory minimum of 12.5 percent. Other fields modeled for this study did not achieve the desired result even under zero percent royalty. One exception is the 100 MMboe oil field in Pacific that crosses the 15 percent IRR investment threshold under the statutory minimum royalty, prior to the application of RSVs.

7 Conclusion

The competitiveness of the U.S. fiscal systems for frontier offshore areas is largely dependent on the prospectivity and scale of the resource base, the exploration and development costs, fiscal terms, and other risk factors. The U.S. offshore frontier areas of Chukchi Sea, Atlantic, and Eastern GOM present with higher per-unit costs than the other jurisdictions within the respective peer groups. The resource base and prospect size vary widely among the jurisdictions in each peer group. Within the Arctic peer group, Alaska has a competitive advantage over its peers from a resource perspective, since the other members of the group have either smaller-sized prospects or are predominantly gas-prone regions.

The overall level of investment in offshore conventional exploration has declined markedly since 2014. IHS Markit expects a modest but sustained increase in conventional exploration spending and drilling activity through the near term. Given the high risk and long cycle times involved in bringing offshore oil and gas resources to market, frontier exploration has been greatly impacted. The limited level of exploratory drilling in the respective offshore frontier regions in the United States can be largely attributed to a drilling moratorium, which has been in place for decades. This has resulted in a lack of opportunities to reduce the uncertainty and associated risks.

The evolution of other frontier offshore regions from frontier to emerging status has historically shown a long lead time from initial discovery to first commercial development. Companies often rely on the discovery of additional fields to justify the final investment decision (FID). The lead time to FID in a frontier basin can be anywhere between 15 years and 20 years. A lot of countries provide for a retention period of 5–10 years to establish the commerciality of a discovery. A greater degree of flexibility in the U.S. Federal oil and gas leases for offshore frontier acreage, which provides for longer lease terms to establish commerciality of resources discovered, may incentivize investment.

Exploration in the Arctic offshore presents one of the most challenging environments for the oil and gas industry. The technical complexity, the magnitude of investments required, and the environmental sensitivity surrounding the Arctic offshore present challenges even for the large and experienced oil and gas entities having the financial, technical, and managerial capability to operate in these environments. Shell's decision to abandon Arctic drilling after investing close to $7 billion over nine years is an example of the magnitude and challenges associated with developing U.S. Arctic resources.

In the high oil price environment, the Alaska Chukchi Sea and Beaufort Sea projects are very competitive within the peer group, offering better returns and higher value on a dollar-per-barrel basis than the majority of projects modeled for this study. When the expected field sizes and primary output in the respective jurisdictions are taken into account, the investment opportunities in the Alaska Chukchi and Beaufort seas should be more appealing to investors—Alaska's current discoveries in the Arctic offshore area tend to be oil-prone, versus the gas-prone discoveries of the Mackenzie Delta and Barents Sea. The majority of companies investing in frontier exploration are looking for oil.

Given the current complexity, risks involved, and expected returns at different prices, the current fiscal terms only foster investment in a high price scenario on a stand-alone basis, as do those of the other jurisdictions in the peer group. However, cluster and phased development of the Arctic resources similar to those undertaken in the Barents Sea in Norway could enable investment under the base price scenario.

Although the RSVs offer effective 40–50 percent royalty-free volumes and improve returns to investors under the base and low price scenarios, the improvement is insufficient to render such projects economic. A zero percent royalty would improve the attractiveness of the fiscal system, but the expected investor returns would be relatively marginal given the risks involved.

The U.S. Non-Alaska offshore frontier regions are competing against more dynamic international frontier jurisdictions (i.e., South Africa and the Falkland Islands) that offer very competitive fiscal terms to maximize their share of the already-limited exploration budgets. Both these jurisdictions have had some success in recent years in terms of the assessment of the resource potential, with a couple of discoveries under development. From a risk perspective, some of the jurisdictions in this peer group have done more to improve industry's knowledge of the geologic potential. Argentina's investment in seismic surveys for the offshore areas resulted in a very successful offshore licensing round. The three U.S. Non-Alaska offshore frontier regions have not been open for leasing for decades, which puts them at a disadvantage to their peers in this group.

The U.S. Non-Alaska offshore frontier regions face greater commercial challenges than the other jurisdictions in the peer group. Prospects in the U.S. Atlantic and Eastern GOM are expected to be in water and formation depths that are two to three times greater than the respective ones in the international jurisdictions. The U.S. frontier offshore oil fields offer high value per exploration well drilled under the high price scenario. However, such values deteriorate quickly when the low price cases are taken into account.

The costs associated with the water and reservoir depth and lack of infrastructure prove challenging for the stand-alone development of projects in the U.S. frontier regions. Deployment of field development concepts that include a cluster of fields could significantly improve the commercial viability of projects in Eastern GOM and Pacific regions. There is potential for added value for the U.S. Eastern GOM if the development can leverage proximity to the GOM oilfield service centers of Louisiana, Alabama, and Mississippi. A nearby dynamic service market offers greater possibilities to negotiate rates and lower costs.

Development of natural gas fields in the Non-Alaska offshore frontier regions is not viable under the current commodity prices in the United States. The abundance of lower cost natural gas supply from shale gas and associated gas produced from tight oil formations is likely to keep prices at a level that is not conducive to develop offshore natural gas resources in the United States in the near future.

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Appendix A—Fiscal System Information

A.1 Argentina Offshore

The terms used for this study relate to the latest applicable terms as of February 2019.

A.1.1 Fiscal and Contractual Terms

Bonuses

There is no provision for bonuses.

Other Payments

Rental: Rentals in Argentina are payable according to the rates in Table A-1.1.

Table A-1.1. Rental payments: Argentina offshore

Type of rental	ARS ($)/year
Exploration—first period	250 (7) per km^2
Exploration—second period	1,000 (26) per km^2
Exploration—extension first year	17,500 (458) per km^2
Exploration—after first year	25% cumulative increment per year
Production	4,500 (118) per km^2
Note: Exchange rate of 0.02615 applicable on February 11, 2019, was applied for conversion of ARS to USD.	

Source: IHS Markit

Royalty

The standard royalty rate is 12 percent for both oil and gas. Royalties start at 5 percent offshore, but increase to 12 percent depending on performance. The lower value accounts for a provision that the royalty rate may be reduced on a case-by-case basis to as low as five percent, taking into account productivity (marginal fields), condition, and location of the producing wells.[37]

Deductions are allowed for transportation, treatment, and commercialization costs between the wellhead and the commercialization point. With regard to natural gas, deductions are specifically allowed on the following:

- Volumes used for internal operations
- Losses due to force majeure (proven)
- Reinjection
- Compression costs
    - Low pressure gas receives a 30 percent discount on sales price of gas, and medium pressure receives a 15 percent discount.
    - It is possible to add up to three percent to the cost of compression of the gas under the heading of internal expenses, including treatment and conditioning expenses. Gas

[37] 1967 Hydrocarbons Law (HL), 2014 Hydrocarbons Investment Promotion Regime Amendment and Transitional Provisions (IPRHL), 1993 Resolution 188.

processing costs are allowed up to Argentine pesos 0.32 [$0.0084] per 1,000 cubic meters (m^3).

- A freight tariff of $0.012 is allowed for every 1,000 m^3 per km, but this may be increased with proof of higher costs.

With respect to oil and condensate, a deduction for internal operating costs of up to three percent of the wellhead price is allowable. A deductible allowance of up to 0.25 percent of the wellhead price is allowable for transport.

Income Tax

Oil companies pay either income tax or minimum tax on presumed income (asset tax), whichever is greater.[38] An income tax rate of 30 percent applies in 2019, but will decline to 25 percent beginning in 2020.

The rate had been 35 percent since 1999. The minimum tax is levied on cumulative capital less accumulated depreciation plus an inflation adjustment at a rate of 1.0 percent.

Allowances for Income Tax

The following costs are deductible:

- Operating costs
- Surface rental
- Rights-of-way
- Royalty
- Administration fees
- Exploration dry hole costs
- Bonuses paid to obtain exploration rights (if applicable) provided they are supported by documentation
- Interest paid, including inflation adjustment
- Parent company technical assistance
- Export tax
- Value-added tax
- Head office technical assistance, subject to the requirement to prove that such assistance was unavailable in Argentina and that a technology transfer agreement had been entered into
- Interest paid by local subsidiaries of nonresident companies to parent companies, provided the loan has been approved by the Central Bank.

The income tax regulations provide for all successful exploration and field development costs (including intangible costs) to be depreciated on a unit-of-production basis.

Tangible goods other than wells, machinery, equipment, and productive assets, are depreciated in a straight line (considering the useful lives of the assets). Depreciation rates are 20 percent for automobiles, 10 percent for machinery and equipment and furniture, and 2 percent for buildings and other construction.

The income tax law provides two alternatives for the treatment of losses resulting from abandonment activity. The right holder may either continue depreciating the assets on an annual basis until the original value is recovered or cease depreciation in the year of termination. If the asset is sold, the difference between

[38] Decree No. 649 on Income Tax of 1997 (the Income Tax Law—ITL), Decree No. 1344/98 on Regulations on Income Tax of 1998.

the remaining value and the purchase price is deductible. If the asset value is zero or negative, the remaining value must be deducted in the year in which the asset is abandoned.

Losses can be carried forward for up to five years. Losses carried forward are adjusted for inflation. No loss carry-back is allowed.

In terms of the price of gas used for income tax purposes, compression costs (up to 30 percent for low pressure gas and up to 15 percent for medium pressure gas) are deductible; additionally, 3 percent of compression costs are allowable to reflect internal gas field expenditure.

Carbon Tax

A carbon tax began on January 1, 2019 for most liquid fuels at a rate of $10 per metric ton of CO_2e.[39] However, for mineral coal, petroleum, and fuel oil, the rate starts at only 10 percent of that level, increasing annually to reach 100 percent of the level in 2028. Tax rates will be updated each quarter to account for inflation. Only about 20 percent of CO_2e emissions are covered by this tax.

A.1.2 Acreage Award Criteria

Allocation of rights is carried out through a competitive bidding process. Work commitment is the only criteria for the grant of rights.

Work and Expenditure Commitment

Minimum work obligations are generally established as part of the bidding conditions. They generally depend on number of work units achieved, depending on the activity completed. Table A-1.2 is an example of a work unit schedule. For determining the value of the performance guarantee, each work unit corresponds to $5,000. A maximum of $750,000 is set for offshore blocks. Expenditure commitments are common.

Table A-1.2. Work unit measurements: Argentina offshore

Exploration operation	Work units
Seismic reprocessed	0.03 per km^2
Magnetic survey	0.006 per km^2
Gravimetry	0.05 per km^2
2D seismic shot	0.16 per km^2
3D seismic shot	3 per km^2
Wells drilled <1,000 m	600
Wells drilled (1,000–2,000 m)	1,000
Wells drilled (2,000–3,000 m)	2,100
Wells drilled (3,000–4,000 m)	4,000
Wells drilled (4,000–5,000 m)	6,100
Wells drilled (5,000–6,000 m)	8,300

Source: IHS Markit

[39] World Bank. Carbon pricing dashboard.

A.1.3 E&P Terms

Block Sizes

Block sizes in the Argentina Basin range from 2,882 km^2 to 8,951 km^2. Block sizes in the Malvinas Basin range from 3,667 km^2 to 6,260 km^2. Block sizes in the Austral Basin are more consistent in size, ranging from 2,014 km^2 to 2,696 km^2.

Contract Duration

Exploration Period: The contracts for the blocks in Round 1 will reportedly consist of 13 years of exploration period (4 years each in the first and second phases, and 5 years in the third phase). However, shallow water blocks will include 11 years of exploration period (4 years in the first phase, 3 years in the second phase, and 4 years in the third phase). In addition, blocks in the Malvinas Basin will also include an evaluation phase.

Production Period: The production period is for 30 years, with a possible 10-year extension.

Relinquishment Obligations

Upon the expiration of the basic phase (first and second phases), the right holder must relinquish 50 percent of the acreage.

Domestic Market Obligations

The government may require, in the event of national emergency (including when domestic production does not meet domestic needs), hydrocarbons to be supplied domestically by giving at least one year's prior notice. The price which the producer is entitled to receive for such domestic deliveries is as follows:

> **Crude oil:** The international cost insurance and freight price
> **Natural gas:** Not less than 35 percent of the equivalent price of Arabian Light (34° API) based on 1,000 m^3 = 1 m^3 of crude oil.

Abandonment Requirements

The legislative framework regarding the abandonment of E&P operations is provided by the Hydrocarbon Law and Resolution No 105/92. In addition, Resolution No 341/93, Resolution No 5/95, and Resolution No 201 of 8 March 1996 set out requirements for the abandonment of E&P operations and the clean-up of land pools. Provisions on the abandonment and decommissioning of pipelines are provided by Resolution No 186/1995 (on gas pipelines) and Disposition No 56/97 (on oil pipelines). Collectively, these instruments provide, in detail, the requirements regarding the abandonment of hydrocarbons wells and pipeline installations. The competent authority regarding abandonment of E&P activities and oil pipelines is, at the Federal level, the Ministry of Energy and Mines (previously the Energy Secretariat).

A.2 Canada Northwest Territories Offshore

The terms used for this study relate to the latest applicable terms as of February 2019.

A.2.1 Fiscal and Contractual Terms

Bonuses

Bonuses are not used in the Canadian Arctic.

Other Payments

Rental: No rentals are payable during the first period of the exploration license, i.e., the first five years. In the second period the following rentals are payable:

Table A-2.1. Rental rates

2nd period rentals—CAD/ha ($/ha)	
1st year	3.00 ($2.28)
2nd year	5.50 ($4.18)
3rd and 4th year	8.00 ($6.10)

Royalty

Before "project payout," royalties start at 1 percent of gross revenues for the first 18 months.[40] They then increase by 1 percent of gross revenues every 18 months, until reaching a maximum of 5 percent. After project payout, the royalty is the greater of 5 percent of gross revenues or 30 percent of net revenues. Gas processing and transportation allowances are subtracted from gross revenues when making the calculation.

Project payout is the first month when the interest holder's cumulative gross revenues are equal to or greater than the cumulative costs for the project. Cumulative costs include the following, and the first four are subtracted to calculate net revenues:

- Allowed capital costs
- Allowed operating costs
- One percent capital cost adjustment
- Ten percent operating cost adjustment
- Royalty paid
- A return allowance.

Income Tax

Federal: The general corporate tax rate is 38 percent. With the Federal abatement of 10 percent,[41] the rate is reduced to 28 percent. In addition, a manufacturing and processing deduction (applicable where a corporation derives at least 10 percent of gross revenues from manufacturing and processing goods in Canada for sale or lease) or a rate reduction (available on certain qualifying income), both of which are 13 percent, can bring the Federal income tax rate to 15 percent.

Territorial: The provincial income tax rate in the Northwest Territories for business income and investment income is 11.5 percent.

[40] Indigenous and Northern Affairs Canada. Calculating Royalty. 15 September 2010.
[41] Where a company is subject to provincial income tax, the Federal income tax rate is reduced by 10 percent.

Allowances for Income Tax

The same income tax allowances and deductions apply for Federal and territorial income tax. Deductions include the following:

- Exploration costs (The Canadian Exploration Expense—CEE):
    - Any expense incurred by the taxpayer (other than an expense incurred for drilling or completing an oil or gas well or in building a temporary access road to, or preparing, a site in respect of, any such well) for the purpose of determining the existence, location, extent, or quality of an accumulation of petroleum or natural gas in Canada, including such an expense that is a geological, geophysical, and geochemical expense, or an expense for environmental studies or community consultations (including studies or consultations that are undertaken to obtain a right, license, or privilege to search for oil or gas)
    - Any expense incurred for bringing a natural accumulation of oil or gas in Canada into production, and any expense incurred prior to such production on stream, including (i) clearing, removing overburden, and stripping, and (ii) sinking a shaft or constructing an underground entry.
- Operating and lifting costs, including the following:
    - Overhead administrative costs
    - Abandonment costs, but the money deposited in the abandonment fund levy for the final abandonment of the field is classified for accounting purposes as money for future work and is not deductible.
- A capital cost allowance (in the case of acquisitions)
- Oil and gas property expenses, up to a certain percentage of the depreciated costs
- Interest expenses
- General and administrative expenses
- Royalties.

The following costs are capitalized and depreciated:

- Development costs:
    - The Canadian Development Expense (CDE) includes costs incurred in the drilling, completion, and conversion of any development well. IHS Markit understands these costs are written off at rates of up to 30 percent per annum on a declining balance basis. [42]
- Oil and gas property expense:
    - This is the cost of acquiring and maintaining an oil and natural gas property or lease (including oil sands rights acquired after March 21, 2011). It is written off at the rate of 10 percent on a declining-balance basis.
- Tangible costs related to the acquisition of assets generally located above ground:

[42] It is worth noting that the definition of CEE was amended pursuant to the 2017 Federal Budget, often expanding the scope of CDE, thus reducing the cost items that can be expensed under CEE. These include drilling and completing a (new discovery) oil or gas well and preparing the well site and building temporary access roads thereto. However, the change occurs in 2021 if the expense is incurred in connection with an obligation that was committed to in writing by the taxpayer before March 22, 2017, or 2019 otherwise.

- These are capitalized and qualify for the capital cost allowance. The declining balance depreciation rates vary according to classifications provided for in Federal legislation. The legislation provides for rates of 4–100 percent.
- The rate for oil storage tanks and oil or natural gas well equipment is 30 percent. In the case of oil and natural gas pipelines with a life expectancy of less than 15 years, the depreciation rate is four percent per annum. Tangible development drilling and tangible facilities have rates of 25 percent.[43]

Losses (non-capital losses) may be carried back for 3 years and forward for 20 years. Net capital losses may be carried back for three years, and carried forward indefinitely.

Carbon Tax

The Northwest Territories is implementing a carbon tax that will begin to apply on July 1, 2019.[44] The price will start at CAD20 ($15.19) per metric ton of CO_2e. It will increase at a rate of CAD10 ($7.59) per year until reaching a level of CAD50 ($37.97) per metric ton of CO_2e in 2022.

A.2.2 Acreage Award Criteria

There is a single criterion used to select the winning bid: generally, a "work bid" for the highest exploration dollars a bidder will commit to during the term of the exploration license.

Work and Expenditure Commitment

Work proposal bids of less than CAD1 million for each parcel will not be considered. Winning work proposal bids in the Federal Arctic have ranged from CAD1 million ($795,300) to CAD1.1801 billion ($896,050,000).[45] Successful bidders must deposit 25 percent of the work commitment when submitting their bids.[46]

A.2.3 E&P Terms

BLOCK SIZES

Winning bids since 2012 in the Federal Canadian Arctic have ranged in size from 47,945 hectares to 205,321 hectares.[47]

Contract Duration

Exploration License: There is a maximum nine-year exploration term for an exploration license. For licenses in Beaufort Sea and Mackenzie Delta, the exploration license comprises of two consecutive periods of 5 + 4 years or 7 + 2 years.

Significant Discovery License: When oil and/or gas is discovered, a significant discovery license may be applied for when the market conditions may not warrant immediate development of the discovery. This type of right is intended to encourage exploration in remote areas where there are no prospects of immediate commercial development. Such licenses are granted for an indefinite duration until the discovery becomes commercially viable and a production license is issued to that effect.

[43] IHS Markit, Koakoak, Vantage, 2018.
[44] Government of Northwest Territories. "Implementing carbon pricing in the NWT."
[45] Indigenous and Northern Affairs Canada. Northern Oil and Gas Annual Report 2016. 2017 May 10.
[46] Ibid.
[47] Ibid.

Production period: 25 years, extendable 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.[48]

Domestic Market Obligations

There is no domestic supply obligation.[49]

Abandonment Requirements

The operator must leave wells in a condition that provides for isolation of all oil- or gas-bearing zones and prevents formation fluid from flowing through or leaving the wellbore.[50] The well must be monitored. The seafloor must be cleared of any material or equipment that could interfere with other commercial uses.

[48] IHS Markit, Northwest Territories, IHS Markit Petroleum Economics and Policy Solutions service, 2018.
[49] Ibid.
[50] Government of Canada. Canada oil and gas drilling and production regulations. Equipment and operations.

A.3 Falkland Islands Offshore

The terms used for this study relate to the latest applicable terms as of February 2019. According to the Falkland Islands' Department of Mineral Resources, "As a self-governing British Overseas Territory, law in the Falkland Islands largely resembles the United Kingdom (UK) controlling legislation in many areas. For offshore oil and gas regulation, this means the Falkland Islands implements its own legislation mirroring much of the equivalent in the UK North Sea."[51] Therefore, there are large areas of legal overlap between the Falkland Islands and the UK, although many of the details below show large differences between the UK and Falkland Islands terms.

A.3.1 Fiscal and Contractual Terms

Bonuses

There are no bonuses.

Other Payments

Rental: The licensee must pay annual rental yearly in advance while holding a seaward production license. Table A-3.1 provides rates for production licenses awarded either in 1996 under competitive bidding, or since 2001 under open-door access.[52]

Table A-3.1 Annual rental payments: Falkland Islands offshore

Phase/year	Rental payment (US$)
FOR PRODUCTION LICENSES UNDER OPEN-DOOR ACCESS SINCE 2001	
Phase 1	30,000 for first license and 10,000 for each additional license
Phase 2	30,000 for first license and 10,000 for each additional license
Discovery area	375,000 per discovery area
Field production	375,000 per field only until first royalties from production

Source: IHS Markit © 2019 IHS Markit

Royalty

There is a nine percent royalty on the value of production.[53] However, the governor may decide to reduce the royalties in the following cases:

- It would encourage development from smaller fields that would otherwise not be economic
- It is needed to extend life of a producing field
- It is needed in an extended period of extraordinarily low petroleum prices to prevent a field from being abandoned.

51 Falkland Islands Government, Department of Mineral Resources.
52 Ibid.
53 1995 Offshore Petroleum Regulations (OPR) Sched 2 Sec 11; 2000 OPR Sched 2 Sec 11; Guidance Document 2008 Part 9.

Technically, the value of production is the tax disposal value, which accounts for variations related to disposal of certain production.

Income Tax

There is a 26 percent corporation tax on chargeable profits.[54]

Royalty payments, intangible development costs (including drilling), and exploration and appraisal costs are fully deductible in the year they are incurred, as are abandonment costs.

Tangible capital assets are depreciated using the declining balance basis at a rate of 25 percent per annum. Upon cessation of a ring fence trade, any undepreciated capital balances may be carried back and written off against the revenue of the past three years of operations. Any operating losses may be carried forward indefinitely as long as the ring fence trade continues. Losses may not be carried back, with two exceptions: undepreciated capital balances and abandonment costs.

Interest expenses are deductible but are subject to a number of tests, including commercial interest rates and debt/equity ratios. Interest paid at an arm's length is fully deductible. Home office overhead costs are not deductible for income tax purposes.

A.3.2 Acreage Award Criteria

In 1995, the Falkland Islands' government opened the first offshore licensing round. It closed in July 1996, with seven awards made. In 2000, the government launched an open-door licensing policy, with licenses being awarded on a "first-come, first-served" basis, and licenses began covering significantly larger acreage. In September 2005, the government decided to indefinitely suspend the open-door licensing policy and wait for the result of existing licenses. No new contracts have been awarded in the Falkland Islands since 2008.[55]

Work Commitment

A work program is also required for the areas applied for, as is a full technical assessment of the area to justify the proposed work program. For the work program, seismic surveys, seabed sampling, and drilling activities are considered appropriate, while desk studies and the acquisition of presently available data sets are not.

When presenting the work program, the applicants are required to do the following:

- For wells:
  - Include the number of firm or contingent wells, and, if possible, include for each one an indication of the target depth (minimum depth), stratigraphic formation or seismic target reflector qualification, and the seismic horizon to be penetrated
  - For a contingent drilling commitment, indicate what it is contingent upon.
- For seismic data:
  - Give the amount of 2D (in line-km) or 3D seismic (area of full migration, in km^2) to be acquired over the block (must distinguish between shooting new data and obtaining existing data)
  - Indicate whether the new data will be proprietary or speculative
  - Include an outline of any reprocessing program
  - Indicate the timing of the proposed activity after award of license.

[54] 1997 Tax Ordinance (TO); 2003 TO Sec 5; Guidance Document 2008 Part 9.
[55] IHS Markit, 2016 license activity, GEPS, 2017.

- For other work:
    - Include a brief summary of any other work not already described, such as surveys, research, technological development, or studies relevant to the evaluation of the block (e.g., geotechnical studies, gravity or magnetic studies, electromagnetic seabed logging).

It is highly improbable that acreage will be awarded unless there is a firm drilling commitment with regard to the initial term of the license.

The second term requires a firm commitment to drill one or more exploration wells irrespective of whether any were drilled in the first term.

A.3.3 E&P Terms

Block Sizes

A license application could be for any number of whole blocks (12 minutes longitude by 10 minutes latitude) up to a total of 30 contiguous blocks per each license.

Contract Duration

Exploration: The Phase 1 initial exploration term duration depends on what is being conducted:

- 2D seismic (3 years)
- 2D + 3D seismic (5 years)
- 2D seismic + well (6 years)
- 2D + 3D seismic + well (8 years)

The Phase 2 exploration period is five years.

Production: The production period is 35 years after the end of the total exploration period. If the production right was granted before the end of the exploration period, the license may be extended beyond 35 years.

Relinquishment Obligations

If the licensee has drilled four or more approved wells during the first exploration period, it will not be required to relinquish part of the licensed area.[56] Otherwise, the licensee may retain only an area that is determined as follows:

Retained area = (Original contract area/2) + ((Original contract area/10) * Number of wells drilled)

At the end of the second exploration period, the retained area must equal half the area retained during the first extension period. However, if the licensee submits a development program and a continuing exploration work program, no relinquishment is required at the end of the second exploration period. Additionally, if the licensee submits a development program without a continuing exploration work program, then it may only retain the area to which the development program relates.

Domestic Market Obligations

There are no domestic supply obligations.

[56] Ibid.

Abandonment Requirements

The governor may require the licensee to submit an abandonment program. If the licensee proposes to leave an installation or pipeline in position or not wholly remove it, it must include provisions as to any continuing maintenance that could be necessary. Upon abandonment of the license area, the governor may direct the licensee to plug and seal wells in accordance with the governor's direction.

A.4 Ireland Offshore

The terms used for this study relate to the latest applicable terms as of February 2019.

A.4.1 Fiscal and Contractual Terms

Bonuses

There have been no bonuses since the 1992 Licensing Terms were issued. Before that time, investors had the option to propose a signature bonus in its application for a license.

Other Payments

Rental: Licensees/lessees must pay rentals as prescribed by the minister. In January 2009, the rates shown in Table A-4.1 were set, which remain current.[57]

Table A-4.1. Rental payments: Ireland offshore

Type of rental	EUR ($)/year
Petroleum prospecting license	7,601 (8,701) per block
Licensing option	29 (33) per km^2
Standard exploration license	Phase 1 period rental: 182 (208) per km^2; Phase 2 period rental: 365 (417) per km^2
Deepwater exploration license	Phase 1 period rental: 91 (104) per km^2; Phase 2 period rental: 182 (208) per km^2; Phase 3 period rental: 365 (417) per km^2
Frontier exploration license	Initial period rental: 29 (33) per km^2; Phase 2 period rental: 60 (69) per km^2; Phase 3 period rental: 121 (139) per km^2
Lease undertaking	Year 1: 1,216 (1,392) per km^2; Each additional year: 152 (174) more per km^2
Petroleum lease	Pre-production: 2,643 (3,025) per km^2; Post-production: 4,133 (4,731) per km^2
Note: Exchange rate of 1.1447 applicable on February 4, 2019 was applied for conversion of EUR to USD.	

Source: IHS Markit

Annual Contributions to Petroleum Research Programs: Under the terms of the 2009 Rockall Licensing Round, holders of frontier exploration licenses are required to pay annual contributions to petroleum research programs, as directed by the minister, to support the funding of research and applied research projects aimed at developing knowledge of the Irish offshore and promoting exploration and development activity. The contributions are as follows:

- An annual payment of EUR87,361 ($100,002) per license (for the Irish Shelf Petroleum Study Group)
- An annual payment of EUR17,422 ($19,943) per company (for the Expanded Offshore Support Group).

Royalty

There have been no royalties since the 1987 Ministerial Statement abolished royalties.

[57] Department of Communications, Climate Action, and Environment, 2007 Licensing Terms Appendix 1.

Income Tax

The income tax is known as the corporation tax, and it is imposed at rates set by the 1997 Taxes Consolidation Act.[58] The applicable rate is 25 percent.

Allowances for Income Tax

There is a ring fence around all mining and upstream petroleum activities. This means that petroleum and mining activities are segregated from other activities for tax purposes, so that losses arising from activities outside the ring fence may not be offset directly, or by way of group relief, against profits within the ring fence. The ring fence includes all profits and losses, including capital gains and losses.

There is 100 percent depreciation of allowable exploration and development capex. Allowable expenditure includes the following:

- Explorations expenditure:
    - Capex on petroleum exploration activities, subject to a 25-year time limit, in the case of abortive expenditure
    - Payments made to the Department of Communications, Climate Action, and Environment (DCENR) on the application for, or the granting of, a license or other payments made in respect of holding the license.
- Development expenditure:
    - Capex on machinery, plants, works, buildings or structures that will have little or no value when the relevant field ceases to be worked
    - Expenditure on leased assets or expenditure on works, buildings, and structures for the initial treatment and storage of produced petroleum
    - Payments made to the Minister on the application for, or the granting of, a Petroleum Lease.

Such expenditure (apart from interest payments, which are expensed) is depreciated in accordance with the normal rules applying in Ireland as follows:

- 12.5 percent straight-line for plant and machinery
- 12.5 percent straight-line for vehicles
- four percent for industrial buildings.

In general, there is a prohibition on the deduction of certain interest payments. Allowable development expenditure also does not include road vehicles; buildings, or structures for use as houses, shops, or offices; expenditure on the acquisition of the site of a relevant field; or expenditure on the acquisition of, or of rights in or over, deposits of petroleum.

Abandonment losses may be offset against income and profits in the chargeable period in which they are incurred. Exploration expenditure may be carried forward to offset against taxable profit from any subsequent petroleum trade for up to 25 years. Transfers are not chargeable to income tax provided that the minister is satisfied that the sole purpose of the disposal of an interest in a licensed area is the proper exploration and development of the area.

Additional Profits Tax

Section 45 of the 2008 Finance Act introduced a new chapter into Part 24 of the 1997 Taxes Consolidation Act.[59] This new chapter gives effect to the Irish government's decision on July 30, 2007 to implement PRRT applicable to petroleum leases granted after January 1, 2007.

[58] 1997 Taxes Consolidation Act ss. 684-690, 692-693, 695-697.
[59] 1997 Taxes Consolidation Act s. 696B, and 2008 Finance Act s. 45.

PRRT is levied on the taxable profit from a field at a rate that depends on the profit ratio (R) of said field. The profit ratio calculated for any year is defined as the ratio at the end of the preceding year of the cumulative post-tax profits to the cumulative value of capital invested. More specifically, the R-factor is the cumulative gross revenues divided by the cumulative field costs.

The rates are shown in Table A-4.2.

Table A-4.2. PRRT: Ireland offshore

Profit ratio	PRRT rate
R < 1.5	0%
1.5 ≤ R < 3.0	5%
3.0 ≤ R < 4.5	10%
R > 4.5	15%

Source: IHS Markit © 2019 IHS Markit

Treatment of deductions, depreciation, overheads, interest, decommissioning and abandonment costs, and interest are the same as they are for the general corporation tax. However, losses may not be carried forward or back for PRRT.

Petroleum Production Tax

In late 2015, the Irish government unveiled laws that increased the maximum tax on producing oil and gas fields in Ireland to 55 percent, from 40 percent.[60] The new PPT increased the financial return to the state earlier in a field's production lifetime than the current tax regime. A minimum payment of five percent less transportation expenditure of annual gross revenues is due annually once a field starts producing, with the ultimate rate of tax determined on a variable basis, depending upon the profitability of an individual field. The same profit ratio (R) used for the PRRT is used here. The increased tax rate applies to licenses awarded as part of the 2015 Atlantic Margin licensing round.

Table A-4.3. PPT: Ireland offshore

Profit ratio	PPT rate
R < 1.5	Minimum of 5% of field gross revenue less transportation expenditure
1.5	10%
1.5 < R ≤ 4.5	Linearly increases as R increases
R > 4.5	40%

Source: IHS Markit © 2019 IHS Markit

A.4.2 Acreage Award Criteria

Applicants are invited to bid on a competitive basis either via a licensing round or an open-door policy, but the latter can only be used within the Celtic Sea area.

[60] IHS Markit, Irish government draft laws affecting oil and gas exploration budget 2016, GEPS, 2015. 1997 Taxes Consolidation Act s. 696G-696M and summarized in Tax Duty Manual Petroleum Production Tax Part 24-04-01.

Work Program Commitments

After the 2015 Atlantic Margin licensing round, most winning companies received licensing options (LO), providing a two-year period to undertake the required work commitments prior to converting to an exploration license where they would be able to drill a well.

Following the LO, companies can decide to convert the LO into exploration licenses (EL), of which there are three types. Many of the LOs from the 2015 Atlantic Margin licensing round were converted into one of the following three frontier ELs:

- Standard EL—In areas with water depths up to 200 meters. The work program must include at least one exploration well in the first phase.
- Deepwater EL—In areas with water depths greater than 200 meters. The work program must include at least one exploration well during the first phase.
- Frontier EL—In areas of special difficulty related to the physical environment, geology, or technology, as defined by the DCENR. The period of the license consists of four phases. A work program must be agreed upon for in the first phase and, before the second phase may start, a further work program, including the drilling of an exploration well, must be agreed upon.

The minimum work commitments are shown in Table A-4.4.

Table A-4.4. Minimum work commitments: Ireland offshore

Type of license	Minimum period work commitments
Standard exploration license	1 well in phase 1
Deepwater exploration license	1 well in phase 1 1 well in phase 2
Frontier exploration license	1 well in phase 2 1 well in phase 3

Source: IHS Markit

A.4.3 E&P Terms

Contract Duration

Exploration Period: The contract duration depends on the type of exploration license, as shown below:

- Standard EL—The exploration duration is six years, divided into two phases of three years each.
- Deepwater EL—The exploration duration is nine years, divided into three phases of three years each.
- Frontier EL—The exploration duration is at least 12 years, divided into at least four phases of three years each.

Production Period: A petroleum lease may be maintained as long as production can commercially continue. The term of the petroleum lease is decided by the minister based on the expected production profile. An extension is possible. However, an application for extension must be submitted to the minister at least one year prior to the expiration date of the license.

Relinquishment

The minister may revoke petroleum rights if any terms and conditions of the license/lease have been breached by the licensee/lessee or if it goes bankrupt or a receiver or any liquidator is appointed for the company. Additionally, provided that all obligations and liabilities have been discharged, the licensee may surrender its interest in any specified part of an area subject to a license.

Domestic Market Obligations

There are no domestic market obligations. The 1975 Licensing Terms had provided an option for the government to require delivery of oil to the domestic market.

Abandonment Requirements

It Is the responsibility of the licensee/lessee to make provision for, and to carry out abandonment of, fixed facilities as approved by the minister. The lessee must submit to the minister for approval a written plan setting out proposals for the abandonment. The minister may attach conditions to the approval of abandonment proposals. If the licensee/lessee fails to implement an abandonment plan approved by the minister or fails to submit an abandonment plan, the minister may carry out an abandonment program and the licensee/lessee will be liable for all costs incurred by the minister.

A.5 Morocco Offshore

The terms used for this study relate to the latest applicable terms as of February 2019.

A.5.1 Fiscal and Contractual Terms

Bonuses

There are no signature bonuses. The 2014 Model Petroleum Agreement requires the investor to pay to the state a negotiated U.S. dollar bonus for a commercial discovery of oil or gas. The bonus is payable within 30 days of the award of an exploitation concession.

Additionally, the 2014 Model Petroleum Agreement requires the investor to pay to the state a negotiated U.S. dollar production bonus once production from the contract area has attained specified levels. The model agreement provides for three thresholds, with corresponding bonuses based on barrels of oil—or oil equivalent—produced per day, maintained over a period of 30 days.

Bonuses are deductible for tax purposes.

Other Payments

Rental: Annual rental is payable to the state in respect of each exploitation concession at a rate of MAD1,000 (approximately $105 in February 2019) per square kilometer. This is payable by each party in proportion to the interest held in the exploitation concession.

Training: The 2014 Model Petroleum Agreement requires the investor to agree to an annual level of funding, denominated in U.S. dollars, for the training of National Office of Hydrocarbons and Mines (ONHYM) personnel. The amount of funding increases by an agreed amount each time an exploitation concession is granted following a commercial discovery. Training expenditures are deductible for tax purposes.

State Participation

The state holds an interest in every exploration permit granted, which entitles it to back in to any commercial discovery. The state's interest, which is specified in the petroleum agreement, may not exceed 25 percent.

Royalty

Annual royalty is payable on production of oil and gas, excluding any petroleum used in operations. This is payable by each party to the government in proportion to the interest held in the exploitation concession. Rates vary by hydrocarbon type, as well as water depth. Royalty rates are shown in Table A-5.1.

Table A-5.1. Royalty rates: Morocco offshore

Hydrocarbon type	Water depth (m)	Production	Royalty rate
Crude oil and other liquids	≤ 200	First 300,000 tons (2.25 MMbbl)	0%
		Additional production beyond first 300,000 tons (2.25 MMbbl)	10%
	> 200	First 500,000 tons (3.75 MMbbl)	0%
		Additional production beyond first 500,000 tons (3.75 MMbbl)	7%
Natural gas	≤ 200	First 300 million m^3 (10.59 billion cubic feet (bcf))	0%
		Additional production beyond first 300 million m^3 (10.59 bcf)	5%
	> 200	First 500 million m^3 (17.66 bcf)	0%

Hydrocarbon type	Water depth (m)	Production	Royalty rate
		Additional production beyond first 500 million m^3 (17.66 bcf)	2.5%

Source: IHS Markit © 2019 IHS Markit

In determining royalty payable, the fixed market price will be adjusted by the deduction of all expenses relating to processing, transportation, and sales costs incurred for delivery to the purchaser (i.e., between the point of production and the point of sale).

Income Tax

Corporate income tax is payable on profits from petroleum operations. Rates are shown in Table A-5.2 for companies operating in Morocco on Moroccan-sourced income.

Table A-5.2. Income tax rates: Morocco offshore

Taxable income in MAD ($)	Rate (%)
≤ 300,000 (31,535)	10
300,001–1,000,000 (31,536–105,118)	20
1,000,001–5,000,000 (105,119–525,590)	30
5,000,000 (> 525,591)	31

Source: IHS Markit © 2019 IHS Markit

The amount of income tax payable is subject to a minimum amount defined as "minimum tax," which is due even if a taxpayer makes a loss. Minimum tax is the greater of MAD1,500 ($158 in June 2018) or 0.5 percent of annual turnover. Liability for minimum tax arises after the taxpayer has been trading for three consecutive years. When minimum tax is payable, the amount that exceeds the corporate income tax calculated at the 31 percent rate can be credited against corporate income tax payable in the subsequent three years. However, this credit cannot reduce the net corporate income tax liability below the amount of minimum tax in these subsequent years.

However, the taxpayer benefits from a 10-year tax holiday from the commencement of commercial production from an exploitation concession. This applies for each exploitation concession and would enable the taxpayer to benefit from consecutive tax holidays in the event of consecutive field developments. The minimum tax is subject to the same 10-year tax holiday applicable to income tax at the full rate.

Allowances for Income Tax

Tax liability is determined by consolidating revenues and costs of all exploration permits and exploitation concessions in which the taxpayer has an interest. Thus, there is a ring fence around the taxpayer's upstream petroleum assets in Morocco.

Taxable profits are defined as gross proceeds from the sale of petroleum less deductions and depreciation and losses carried forward. Deductible costs are as follows:

- Costs of establishing petroleum operations in Morocco
- Reconnaissance, exploration, appraisal and development costs, "non-compensated drilling costs," and dry hole costs (Includes bonuses and expenditure on training)
- Production costs
- Rentals
- Royalty.

Costs included in the first two categories of deductible costs listed above may be, at the election of the taxpayer, either deducted in the year of expenditure or capitalized and depreciated over a period of up to 10 subsequent years. The depreciation rate is to be set in the petroleum agreement, although the 2014 Model Petroleum Agreement contains no specific provision for this.

Installations, plants, and equipment with a useful life of more than one year (i.e., tangible assets) are depreciated on a straight-line basis over the period of their useful lives. Accelerated depreciation may be applicable to heavily used equipment (e.g., equipment in use 24 hours a day). Standard depreciation rates are 4–5 percent for commercial and industrial buildings, 10 percent for office equipment, 10 percent for plants and machinery, and 20 percent for motor vehicles. Direct services relating to joint operations can be charged on a monthly basis (this includes operating/personnel costs of administrative, legal, accounting, sales, and financial and tax services). Other services can be charged at three percent for the first $1 million, two percent for the next $1 million, and one percent for additional expenditures. Moroccan-registered companies can deduct bank interest charges, but the position of a foreign company is not clear.

Tax losses may be carried forward for up to four years. No carry-back is allowed. Capital gains are taxed at standard corporate income tax rates.

Additional Taxes

Payroll Tax: Levied on gross monthly remuneration at a rate of 1.6 percent.

Withholding on Subcontractor Services: Where services are acquired from foreign subcontractors, the investor must withhold 10 percent of the contract value in lieu of income tax due under the General Tax Code (2014 MPA Art 14.3; GTC Art. 19-IV-B).

Capital Duty: Under the Hydrocarbons Code, there is a 0.50 percent levy on all capital contributions made at the time of incorporation (2000 HL s. 53).

Registration Fees: Fees range between 0.25 percent and 6.0 percent depending on the nature of the transaction.

A.5.2 Acreage Award Criteria

Past practice has been to accept applications on an ad hoc basis for areas defined by the applicant. However, in October 2000, Morocco launched its only competitive bidding round for selected blocks demarcated in Atlantic Margin waters following completion of a non-exclusive seismic survey. At the end of 2018, there were 15 offshore blocks available for direct negotiations.

Work and Expenditure Commitment

The applicant must make a commitment to fulfill a minimum work program backed by a corresponding financial commitment.

Prior to the signature of the petroleum agreement, the investor must supply ONHYM with an irrevocable bank guarantee in U.S. dollars to guarantee performance of the minimum work program in the initial exploration period. A further bank guarantee must be supplied on each extension of the exploration period. The bank guarantee is released at the end of the relevant period provided that the work obligations have been fulfilled or that the investor has made payment of any shortfall. A shortfall is the difference between sums spent and the amount that it is estimated to be spent to complete the minimum work program.

Exploration obligations are set out in the petroleum agreement for the initial period and the two extension periods. These are accompanied by expenditure estimates corresponding to each period, which are used to determine the penalty payable if there is a shortfall in work. However, it is the performance of the minimum work program, and not the expenditures associated with the program, that determine the contractor's compliance with the contract terms.

Table A-5.3. Work commitments under exploration permits and reconnaissance licenses: Morocco offshore

Block (operator) [award date]	Area (km^2)	Work commitment
Ras Juby (Genting) [May 2006]	1,840	250 km^2 3D seismic + 1 well
Boujdour Offshore (Kosmos) [March 2006]	7,142	Initial period (18 months): 15,230 km 2D seismic + 1 well + geological and geophysical works Subsequent extension periods: 1 exploration well
Mediterranee Est (Afrex Ltd) [July 2004]	6,355	500 km 2D seismic
Safi Offshore Nord Ouest (Norsk Hydro) [May 2004]	6,542	Geological studies + seismic reprocessing + collation of 2D seismic
Tarfaya Shallow (Maersk) [April 2004]	14,709	Initial 3.5 years: Acquisition of 2D and 3D seismic + evaluation study
Rabat Sale Haute Mer (Petronas) [January 2004]	13,541	Initial 3 years: Acquisition and processing of 2,000 km 2D seismic + 1 well

Note: Note that this particular agreement for the Boujdour offshore block requires a performance guarantee equivalent to 50 percent of the minimum expenditure obligation (in this case, equivalent to $1 million), to be reduced to $500,000 upon fulfillment of the work obligations for the then current period.

Source: IHS Markit

A.5.3 E&P Terms

Block Sizes

Block sizes awarded have ranged in size from 1,840 km^2 to 14,709 km^2.

The offshore blocks available for direct negotiation range in size from 1,873 km^2 for the Loukos Offshore block in the Rharb-Prerif Basin to 103,891 km^2 for the Dakhla Atlantique block in the Aaiun-Tarfaya Basin.[61]

An exploration permit may not exceed 2,000 km^2 and may not be smaller than 200 km^2. The area covered by a petroleum agreement may include more than one exploration permit. However, there is an upper limit to the amount of acreage a single investor may hold directly or indirectly, of 20,000 km^2 offshore, unless special exemption is approved.

Contract Duration

Exploration Period: A Reconnaissance License (*Contrat de Reconnaissance*) is granted for a period of up to one year with the option to extend for additional periods of a maximum of one year for either part or the whole license area, provided that obligations have been fulfilled and a commitment to a further work program has occurred.

An exploration permit (*Permis de Recherche*), issued after the conclusion of a petroleum agreement, is for a maximum of eight years. This is subdivided into an initial period and one or two extension periods as defined in the petroleum agreement.

[61] IHS Markit, Open acreage in Morocco, GEPS, 2018.

The exploration period may be extended by a further two years if, in the course of the eighth year, a discovery is made. The extension is to allow appraisal to take place; it applies to the entire exploration area, not just the discovery area.

In the 2000/2001 Rabat-Safi Atlantic Offshore Round, the eight-year exploration period was divided 2 + 3 + 3 years for shallow-water blocks (less than 200 m) and 3 + 2 + 3 years for deepwater blocks (greater than 200 m).

Production Period: An exploitation concession (*Concession de l'exploitation*) allows the holder to develop and produce oil and gas fields and carry out exploration in the concession area on terms set out in the petroleum agreement. The production period is a maximum of 25 years, but may be extended once for up to 10 years, provided the extension is justified by the rationale and economic exploitation of the deposit.

Relinquishment Obligations

Relinquishment of a portion of the exploration area is mandatory at the end of the initial period and the first extension period. The first relinquishment is 10 percent times the number of years in the initial period (e.g., normally 20 percent or 30 percent) and the second relinquishment is the balance such that the area is reduced to 50 percent of the original area. The relinquished area is returned and available again for exploration.

However, there is no relinquishment provision in the 2014 Model Petroleum Agreement.

Domestic Market Obligations

The needs of the domestic market must be contemplated before export of a contractor's share. ONHYM may require the investor to supply crude oil to the domestic market. The amount to be supplied will be the lesser of:

- A negotiated share of the investor's share of production (net of oil used in operations)
- The investor's share of the domestic market deficit as measured by the ratio of its own production entitlement (net of oil used in operations) to total production under all petroleum agreements then in force.

The price payable for domestic deliveries is the market price determined for valuation purposes. There are no specific provisions relating to emergency supply. Fields brought on stream before April 14, 2002 are exempt from any domestic supply obligation.

Abandonment Requirements

When any area is relinquished, surrendered, or forfeited, it must be cleaned and restored. It is understood that the investor must pay the ONHYM the amount accrued to a fund for abandonment on a pro rata basis and not yet paid at the date of abandonment.

A.6 Norway Offshore

The terms used for this study relate to the latest applicable terms as of February 2019.

A.6.1 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. In practice, however, 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.[62] See Table A-6.1 for annual rental payments.

Table A-6.1. 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: Norwegian Krona (NOK) 1 = $0.121549 in July 2018	

Source: IHS Markit © 2019 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 the national currency.

State Participation

State direct financial participation does not apply to licenses in the Barents Sea.

Royalty

None payable.

Income Tax

The standard rate of corporate income tax—applicable to petroleum E&P operations—is 23 percent, effective January 1, 2018.[63] Since 2013, Norway has been gradually reducing the corporate income tax. Table A-6.3 provides the rate reductions since 2013.

Table A-6.3. Corporate income tax rate: Norway offshore

Tax year	Corporate income tax rate (%)
2013	28
2014	27
2015	27
2016	25
2017	24

[62] Regulation No. 1213 of 9 October 2013.
[63] Tax Resolution No. 2183 of December 12, 2017, § 4-1

Tax year	Corporate income tax rate (%)
2018	23

Source: IHS Markit © 2019 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 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 percent.[64] 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-6.4 provides the rate increases since 2013.

Table A-6.4. 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 © 2019 IHS Markit

The uplift is currently applied at 5.3 percent over four years (i.e., 21.2 percent, with the effect that development costs are depreciated at a rate of 121.2 percent for SPT). The uplift was originally equal to 5 percent 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 percent of development costs and capitalized interest are depreciated over six years straight-line). From January 1, 2005, the uplift was accelerated to 7.5 percent 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 percent per annum of the original cost price of depreciable operating assets, to 5.5 percent (i.e., over the four years from the date of expenditure, a reduction from 30 percent to 22 percent). 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 percent, 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.

[64] Tax Resolution No. 2183 of 12 December 2017, § 4-2

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 equivalent amounts of fuel consumed (i.e., expressed in NOK per liter of petroleum liquid or m^3 of gas). Table A-6.5 provides the rates of the CO_2 tax.

Table A-6.5. CO_2 tax: Norway offshore

Effective date	NOK per liter of liquid or m^3 of gas
January 1, 2011	0.48
January 1, 2012	0.49
January 1, 2013	0.96
January 1, 2014	0.98
January 1, 2015	1.00
January 1, 2016	1.02
January 1, 2017	1.04
January 1, 2018	1.06 *(7.30 for natural gas emitted to air)*

Source: IHS Markit

A.6.2 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 the following:

- Technical expertise
- Financial capacity
- Geological understanding
- Methods proposed to conduct exploration efficiently and previous conduct (where applicable, such as 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
- 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 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
- 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.6.3 E&P Terms

Block Sizes

The area awarded in a production license may cover one block (15 latitudinal minutes by 20 longitudinal minutes, which is approximately 500 km^2) or several blocks or partial blocks. Areas offered from 2016 to 2018 have averaged around 500 km^2 per license.

Contract Duration

Exploration Period: Production licenses are awarded for an initial period of 10 years.

Production Period: 30–50 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 Convention for the Protection of the Marine Environment of the North-East Atlantic of 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.7 South Africa Offshore

The terms used for this study relate to the latest applicable terms as of February 2019.

A.7.1 Fiscal and Contractual Terms

Bonuses

There are no signature, discovery, or production bonuses.

Other Payments

Training Fee: Both the 2007 exploration right agreement and the 2007 production right agreement require right holders to contribute to an Upstream Training Trust to be used for the training and education of South Africans.[65]

Rental: A rental in South Africa is known as an exploration fee. A degree square is about 10,000 km^2.

Table A-7.1. Rental payments: South Africa offshore

Type of rental	ZAR ($)/year[66]
Exploration rights	200,000 (14,930) per degree square, subject to a minimum of 50,000 (3,732) per degree square
1st Renewal of exploration right	225,000 (16,796) per degree square, subject to a minimum of 56,250 (4,199) per degree square
2nd Renewal of exploration right	250,000 (18,662) per degree square, subject to a minimum of 62,500 (4,666) per degree square
3rd Renewal of exploration right	275,000 (20,529) per degree square, subject to a minimum of 68,750 (5,132) per degree square

Source: IHS Markit

State Participation

The state has the right to a minimum 10 percent participating interest in any production right granted over any part of the exploration area. If the state does not wish to participate in any such production right it must renounce its right by written notice to the holder of mineral right within 90 days of the grant of the production right.

Where the state does not renounce its right to participate, as a member of the right holder group the state will pay its participating interest share of all costs and expenses related to the development plan and approved production work programs but will not be liable for any exploration costs or expenses.

A further 10 percent interest must be made available on commercial terms for participation by black South African companies under the Black Economic Empowerment program.

Royalty

The royalty rate for refined mineral resources (which includes both oil and gas) is based on the following formula:

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[65] 2007 Exploration Right Agreement Sec 20; 2007 Production Right Agreement Sec 20.

[66] Exchange rate of 0.07465 applicable on February 5, 2019 was applied for conversion of ZAR to USD.

$$\text{Royalty rate (\%)} = 0.5 + [\text{EBIT} / (\text{gross sales x } 12.5)] \text{ x } 100$$

The royalty rate must not exceed five percent.

EBIT = Earnings before deduction of interest and taxes (but never below zero) and is calculated as follows: gross sales less operating costs, including capital depreciation/amortization related to extraction and development of minerals as per the 1962 Income Tax Act - Schedule 10 (to refinery inlet), but excluding the additional oil and gas tax deductions in Section 5.2 of Schedule 10.

Income Tax

The standard corporate income tax rate is 28 percent.

However, in many cases where the oil and gas company is not resident and carries on its trade through a branch or agency, the rate will be 31 percent. In these cases, the lower rate of 28 percent is used only if income is derived by virtue of an OP26 right previously held by the company. Prospecting lease OP26 was part of the first international licensing round in 1994.

Allowances for Income Tax

An oil and gas company may deduct from its oil and gas income all expenditure and losses incurred in that year in respect of exploration or production. Deductions allowed are as follows:

- 100 percent of all expenditure of a capital nature incurred for exploration
- 50 percent of all expenditure of a capital nature incurred for production.

The effect of the provisions above is to allow investors to expense and deduct immediately 200 percent of the exploration costs and 150 percent of the development costs. Losses in respect of E&P may only be set-off against oil and gas income (and income derived from the refining of gas) to the extent that those losses do not exceed that income. Where losses remain after set-off, as aforesaid, an amount of 10 percent of the losses remaining may be set off against any other income derived by the oil and gas company.

There is no provision for the carry back of losses. There are no specific provisions with regard to the treatment of decommissioning and abandonment costs.

Carbon Tax

As of February 2019, there is no carbon tax payable.

On October 24, 2018, South African Finance Minister Tito Mboweni postponed implementation of the carbon tax for six months.[67] If it comes into effect, the current plan is for the rate to start at ZAR120 ($8.96) per metric ton of carbon dioxide equivalent (tCO_2e). It would then increase annually by the consumer price inflation rate plus two percentage points through 2022. After 2022, increases would match the inflation rate.

At least 60 percent of emissions in all covered sectors would be exempt, with additional tax-free emissions allocations for trade-exposed sectors or those that had invested in efficiency, and offsets would be able to be used. A maximum of 90 percent of emissions from any firm would be exempt. A simple calculation of effective tax rates would suggest rates of between ZAR12-48/tCO_2e ($0.90-3.58), but a more complex analysis suggests a lower range between ZAR 642/tCO_2e ($0.45-3.14).

[67] Curran P. London School of Economics Grantham Research Institute. "As South Africa's carbon tax is delayed again what is the story so far?" 24 October 2018.

A.7.2 Acreage Award Criteria

If sufficient requirements are met, applicants must be granted an exploration right or a production right, and if no other person holds a technical cooperation permit, exploration right, or production right for petroleum over any part of the area for which an application is submitted.

Applicants must be granted an exploration right if they meet the following criteria:

- The applicant has access to financial resources and has the technical ability to conduct the proposed exploration operations optimally in accordance with the exploration work program
- The estimated expenditure is compatible with the intended exploration operations and duration of the exploration work program
- The minister has issued an environmental authorization (see Environmental Permitting)
- The applicant has the ability to comply with the relevant provisions of the 1996 Mine Health and Safety Act
- The applicant is not in contravention of any relevant provisions of the 2002 Mineral and Petroleum Resources Development Act
- The applicant has complied with the terms and conditions of the technical cooperation permit, if applicable
- The granting of such right will substantially and meaningfully expand opportunities for historically disadvantaged persons, promote employment, and advance the social and economic welfare of all South Africans.

The weighting scheme in Table A-7.2 was used for the 2009 International Licensing Round, which was the last one that occurred.

Table A-7.2. Weighting scheme for applications for 2009 International Licensing Round: South Africa offshore

Subject	Weighting
Corporate / financial information	5%
Experience and exploration success	10%
Work commitments / program (exploration right only)	35%
Data utilization / geological understanding / prospect evaluation	20%
Training and technology transfer ($ million / annum over first period)	15%
Environmental and safety (omission will disqualify bid)	15%

Source: IHS Markit

<u>Work and Expenditure Commitment</u>

Minimum work obligations are negotiable and are specified in the exploration right agreement in terms of work to be carried out (i.e., geological, geochemical, geophysical, exploration drilling, and other work to be performed) and financial commitments (i.e., exploration costs and costs pertaining to the rehabilitation and management of environmental impact) for the initial exploration period and the three possible extension periods.

A.7.3 E&P Terms

Block Sizes

The sizes of exploration blocks awarded since 1999 have ranged from 8.7 km^2 (Anglo Operations 04ER in 2009) to 185,000 km^2 (Shell Exploration Co BV South Karoo TCP in 2009). The areas formally designed as "blocks" are shown in the Table A-7.3.

Table A-7.3. Exploration blocks formally labeled "blocks" awarded since 1999: South Africa offshore

Block (Operator)	Area (km^2)
Block 1 (Cairn India Ltd)	19,922
Block 5/6 (Anadarko Operations Ltd)	9,964
Block 3B/4B (BHP Billiton Ltd)	18,218
Block 2A (Forest Exploration International)	4,974
Block 01 (New Age [African Global Energy] Ltd)	19,922

Source: IHS Markit

Contract Duration

Exploration Period: There are various types of exploration rights.

A Reconnaissance Permit (Maximum One Year, Nonrenewable): This grants a non-exclusive right to undertake geological, geophysical, and photogeological surveys and remote sensing techniques. No exploration operations are permitted.

A Technical Cooperation Permit (Maximum One Year, Nonrenewable): This grants an exclusive right to study and evaluate the potential of an area through the integrated interpretation of all the geological and geophysical data provided by the Petroleum Agency relating to the area and provides the basis upon which an oil company will have the exclusive right to negotiate with the Petroleum Agency for an exploration right. The permit has a maximum duration of one year, which is nonrenewable.

An Exploration Right (Initial Period Not Exceeding Three Years, and May Be Renewed for a Maximum of Three Further Periods Not Exceeding Two Years Each [i.e., a Maximum of Nine Years]): This grants an exclusive right, subject to the provisions of the exploration right agreement, to reprocess existing seismic data, acquire and process new seismic data, and conduct any other related activity to define a trap to be tested by drilling, logging, and testing, including extended well testing, of a well with the intention of locating a discovery within the exploration area.

Production Period: A production right is valid for a period not exceeding 30 years and may be renewed for further periods, not exceeding 30 years each.

Relinquishment Obligations

The right holder must make the following relinquishments:

- At the end of the initial period: No less than 20 percent of the original exploration area
- At the end of the first renewal period: No less than 15 percent of the original exploration area
- At the end of the second renewal period: No less than 15 percent of the original exploration area.

Within six months of relinquishment, the right holder must deliver to the state all data relating to the areas(s) relinquished.

Domestic Market Obligations

There are no domestic supply obligations.

Abandonment Requirements

The right holder must, on the abandonment, expiration, or termination of the exploration or production right, or relinquishment of part of the contract area, remove all equipment and installations from the contract area, perform all necessary site rehabilitation, and take all other actions necessary to minimize hazards to human or other life, to the contract area or to the environment in general.

Specifically, upon completion or abandonment of a well, the right holder must remove from the drill site all guide bases and other substantial equipment to leave the environment free of significant obstruction, except where the relevant well is intended to be used as a production well. The right holder must inform the relevant government agencies that the location is free of obstruction, or, if it is not, inform the relevant government agency of the location, nature, and extent of any obstruction.

The holder or previous holder of an old order right or previous owner of works that have ceased to exist remains responsible for any environmental liability, pollution, ecological degradation, pumping and treatment of extraneous water, compliance with the conditions of the environmental authorization, and the management and sustainable closure until the minister of the Energy and Mineral Department has issued a closure certificate.

A.8 United States Alaska Frontier

The terms used for this study relate to the latest applicable terms as of February 2019.

A.8.1 Fiscal and Contractual Terms

Bonuses

A minimum U.S. dollar amount per acre or hectare is specified in the notice of sale. A minimum of $25 per acre applies generally, and $37.50 per acre is applied for areas nearest to infrastructure.

Other Payments

Rental: Rentals are announced in advance in each notice of lease sale. The most recent sale in 2017 provided for an annual rental rate of $13 per hectare, or fraction thereof, until the start of year eight of the primary term or a discovery of oil and gas, whichever occurs first; then at an annual rate of $20 per hectare or fraction thereof.

Royalty

The royalty rate may be a fixed bidding term stipulated in each notice of sale or a bidding variable. The statutory minimum of 12.5 percent applies in Alaska.

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 United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent 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 percent. The Tax Cuts and Jobs Act provides for a five-year phase down of the 100 percent 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 U.S. Code [U.S.C.]) provided that 100 percent 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 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 percent of taxable income computed without regard to the deduction allowable under 26 U.S.C. §172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

A.8.2 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 used for the lease sale and the reasons for using such a system, and designates tracts selected for offer under each bidding system.[68]

Various bidding systems, which differ as to the bidding terms or bidding variables, are applicable. A common condition of all the various bidding systems is that none of them should have more than one bidding 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 percent 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 percent at the beginning of the lease period
- Cash bonus bid with a fixed net profit share of no less than 30 percent
- 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 percent and a fixed net profit share of no less than 30 percent
- Work commitment[69] bid based on a U.S. dollar amount for exploration with a fixed cash bonus and fixed royalty
- Cash bonus bid with fixed royalty of no less than 12.5 percent and with a suspension of royalties for a defined period, volume, or value of production, where 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 DOI 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.[70]

A.8.3 E&P Terms

<u>Block Sizes</u>

Unless specifically authorized, an oil and gas lease must consist of a compact area, not exceeding 5,760 acres (23.3 km^2).

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[68] 1953 OCSLA Sec 1337.a.8

[69] Currently not required under applicable BOEM regulations.

[70] 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.

Contract Duration

Exploration Period: Leases are offered for a primary term of 10 years.

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 percent 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 of 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 that 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.

As provided in 30 Code of Federal Regulation (CFR) Part 556.56-57, 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. [71]

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. 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).

[71] BOEM. "Third-Party Guarantees." 2018.

A.9 United States Non-Alaska Frontier

The terms used for this study relate to the latest applicable terms as of February 2019.

A.9.1 Fiscal and Contractual Terms

Bonuses

A minimum U.S. dollar amount per acre or hectare is specified in the notice of sale. This analysis assumes $25 per acre, similar to the ones applicable on Alaska frontier offshore.

Other Payments

Rental: Rentals are announced in advance in each notice of lease sale. This analysis assumes a rental rate of $13 per hectare or fraction thereof, until the start of year eight of the primary term or a discovery of oil and gas, whichever occurs first, then at an annual rate of $20 per hectare or fraction thereof.

Royalty

The royalty rate may be a fixed bidding term stipulated in each notice of sale or a bidding variable. The statutory minimum of 12.5 percent has been assumed.

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 United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent 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 percent. The Tax Cuts and Jobs Act provides for a five-year phase down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 U.S.C.) provided that 100 percent 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 percent of taxable income computed without regard to the deduction allowable under 26 U.S.C. §172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

A.9.2 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 used for the lease sale and the reasons for using such a system, and designates tracts selected for offer under each bidding system.[72]

Various bidding systems which differ as to the bidding terms or bidding variables are applicable. A common condition of all the various bidding systems is that none of them should have more than one bidding 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 percent 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 percent at the beginning of the lease period
- Cash bonus bid with a fixed net profit share of no less than 30 percent
- 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 percent and a fixed net profit share of no less than 30 percent
- Work commitment[73] bid based on a U.S. dollar amount for exploration with a fixed cash bonus and fixed royalty
- Cash bonus bid with fixed royalty of no less than 12.5 percent and with a suspension of royalties for a defined period, volume, or value of production, where 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 DOI 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.[74]

A.9.3 E&P Terms

Block Sizes

Unless specifically authorized, an oil and gas lease must consist of a compact area, not exceeding 5,760 acres (23.3 km^2).

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[72] 1953 OCSLA Sec 1337.a.8

[73] Currently not required under applicable BOEM regulations.

[74] 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.

Contract Duration

Exploration Period: This analysis assumes the same duration as those applicable to Alaska frontier areas (i.e., 10-year period).

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 percent 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 of 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 that 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.

As provided in 30 CFR Part 556.56-57, 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. [75]

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.

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).

[75] BOEM. "Third-Party Guarantees." 2018.

Appendix B—Cost Modeling Assumptions

B.1 Alaska Offshore Frontier

B.1.1 Domestic

Table B-1. Alaska offshore

Area	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
Beaufort Sea	1,000	Artificial gravel island	Gas either used as fuel gas or reinjected in reservoir	Tie-in to Badami Sales Oil Pipeline	0, Artificial Island	2,591	1,180
	400	Artificial gravel island	Gas either used as fuel gas or reinjected in reservoir	Tie-in to Badami Sales Oil Pipeline	0, Artificial Island	2,591	1,180
	100	Artificial gravel island	Gas either used as fuel gas or reinjected in reservoir	Tie-in to Badami Sales Oil Pipeline	0, Artificial Island	2,591	1,180
Chukchi Sea	1,000	Gravity-Based Platform	Gas either used as fuel gas or reinjected in reservoir	New pipeline to shore	45	2,182	1,570
	400	Gravity-Based Platform	Gas either used as fuel gas or reinjected in reservoir	New pipeline to shore	45	2,182	1,570
	100	Gravity-Based Platform	Gas either used as fuel gas or reinjected in reservoir	New pipeline to shore	45	2,182	1,570
Key: GOR = gas oil ratio							
Note: Once the pipeline is constructed, incremental projects that tie in will benefit from improved economics.							

Source: IHS Markit

International

Table B-2. Falkland Islands offshore oil

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
Falkland Islands	1,000	FPSO and subsea tie-back	Flared	Offshore loading / ship to ship	404	2,430	680
	400	FPSO and subsea tie-back	Flared	Offshore loading / ship to ship	404	2,430	680
	100	FPSO and subsea tie-back	Flared	Offshore loading / ship to ship	404	2,430	680
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-3. Canada NWT offshore oil

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
Canada NWT	1,000	GBS	Injection at the field	Offshore loading / ship to ship	47	3,475	2,600
	400	GBS with 1 satellite platform	Injection at the field	Offshore loading / ship to ship	38	2,371	4,380
	100	Central GBS	Injection at the field	Offshore loading / ship to ship	47.2	3,470	1,520
Key: GOR = gas oil ratio							

Source: IHS Markit

B.2 Non-Alaska Offshore Frontier

B.2.1 Domestic

Table B-4. U.S. Atlantic offshore oil

Region	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
U.S. Atlantic	500	Tension-leg platform and FPSO and subsea tie-back	Pipeline to shore	Offshore loading	1,830	6,860	1,620
	200	Tension-leg platform and subsea tie-back	Pipeline to shore	Offshore loading	898	5,510	5,000
	100	Production platform and subsea tie-back	Pipeline to shore	Offshore loading	120	4,710	4,280
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-5. U.S. Atlantic offshore gas

Region	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	CGR (bbl/MMscf)
U.S. Atlantic	500	Tension-leg platform and subsea tie-back	LNG processing via pipeline	Offshore loading	1,590	7,380	103
	200	Tension-leg platform and subsea tie-back	LNG processing via pipeline	Offshore loading	980	5,550	103
	100	Production platform	LNG processing via pipeline	Offshore loading	67	4,750	14
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-6. U.S. Eastern Gulf offshore oil

Region	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
U.S. Eastern Gulf	500	Semi-submersible + subsea	Pipeline to shore	Pipeline to shore	2,200	7,480	1,200
	200	TLP +subsea	Pipeline to shore	Pipeline to shore	774	3,170	1,940
	100	Semi-submersible + subsea	Pipeline to shore	Pipeline to shore	975	4,633	1,940
Note: The U.S. Eastern GOM prospectivity is mostly linked to the Norphlet play, which has a yet-to-find potential around 2 billion barrels of oil equivalent.							
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-7. U.S. Eastern Gulf offshore gas

Region	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	CGR (bbl/MMscf)
U.S. Eastern Gulf	500	Spar buoy + subsea	Pipeline to shore	Pipeline to shore	988	6,401	72
	200	Jacket	Pipeline to shore	Pipeline to shore	122	3,840	35
	100	Jacket	Pipeline to shore	Pipeline to shore	61	3,536	35
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-8. U.S. Pacific offshore oil

Region	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
U.S. Pacific	500	Production platform and subsea tie-back	Pipeline to shore	Offshore loading	314	2,750	2,180
	200	Production platform	Pipeline to shore	Offshore loading	201	2,130	970
	100	Production platform	Pipeline to shore	Offshore loading	78	1,830	426
Note: U.S. Pacific fields are assumed to be in the Southern Pacific area (Santa Barbara-Ventura Channel and Santa Maria basin							
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-9. U.S. Pacific offshore gas

Region	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	CGR (bbl/MMscf)
U.S. Pacific	500	Tension-leg platform and subsea tie-back	LNG processing via pipeline	Offshore loading	313	3,350	103
	200	Production platform	LNG processing via pipeline	Offshore loading	201	2,730	103
	100	Production platform	LNG processing via pipeline	Offshore loading	67	2,430	7
Key: GOR = gas oil ratio							

Source: IHS Markit

B.2.2 International

Table B-10. Argentina offshore frontier oil

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
Argentina	500	Tension-leg platform and subsea tie-back	Pipeline to LNG	Offshore loading	600	1,570	3,650
	200	Tension-leg platform and subsea tie-back	Pipeline to LNG	Offshore loading	600	1,570	3,650
	100	Tension-leg platform and subsea tie-back	Pipeline to LNG	Offshore loading	600	1,570	3,650
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-11. Argentina offshore frontier gas

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	CGR (bbl/MMscf)
Argentina	500	Production platform	Pipeline	Pipeline	73	1,330	12.5
	200	Production platform	Pipeline	Pipeline	73	1,330	12.5
	100	Production platform	Pipeline	Pipeline	73	1,330	12.5
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-12. Falkland Islands offshore oil

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
Falkland Islands	500	Leased FPSO	Fuel and injection at the field	Offshore loading / ship to ship	450	2,380	1,160
	200	Leased FPSO	Fuel and injection at the field	Offshore loading / ship to ship	450	2,380	1,160
	100	Leased FPSO	Fuel and injection at the field	Offshore loading / ship to ship	450	2,380	1,160
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-13. Ireland offshore oil

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
Ireland	500	Production platform	Pipeline	Pipeline	122	1,960	550
Ireland	200	Production platform	Pipeline	Pipeline	122	1,960	550
Ireland	100	Production platform	Pipeline	Pipeline	122	1,960	550
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-14. Ireland offshore gas

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	CGR (bbl/MMscf)
Ireland	500	Production platform	Pipeline	Inject into gas line	146	1,330	0.22
Ireland	200	Production platform	Pipeline	Inject into gas line	146	1,330	0.22
Ireland	100	Production platform	Pipeline	Inject into gas line	146	1,330	0.22
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-15. Morocco offshore oil

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
Morocco	500	Tension-leg platform and subsea tie-back	Pipeline	Pipeline	545	2,390	1,300
Morocco	200	Tension-leg platform and subsea tie-back	Pipeline	Pipeline	545	2,390	1,300
Morocco	100	Tension-leg platform and subsea tie-back	Pipeline	Pipeline	545	2,390	1,300
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-16. Morocco offshore gas

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	CGR (bbl/MMscf)
Morocco	500	Tension-leg platform and subsea tie-back	Flared	Pipeline	1,260	2,080	5
Morocco	200	Tension-leg platform and subsea tie-back	Flared	Pipeline	1,260	2,080	5
Morocco	100	Tension-leg platform and subsea tie-back	Flared	Pipeline	1,260	2,080	5
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-17. South Africa offshore oil

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	GOR (scf/bbl)
South Africa	500	Production platform	Pipeline	Inject into gas line	113	2,410	2,270
South Africa	200	Production platform	Pipeline	Inject into gas line	113	2,410	2,270
South Africa	100	Production platform	Pipeline	Inject into gas line	113	2,410	2,270
Key: GOR = gas oil ratio							

Source: IHS Markit

Table B-18. South Africa offshore gas

Jurisdiction	Reserves size (MMboe)	Development plan			Parameters		
		Development concept	Gas export method	Oil export method	Water depth (m)	True vertical depth (m)	CGR (bbl/MMscf)
South Africa	500	Production platform	Pipeline	Inject into gas line	128	3,100	14
South Africa	200	Production platform	Pipeline	Inject into gas line	128	3,100	14
South Africa	100	Production platform	Pipeline	Inject into gas line	128	3,100	14
Key: GOR = gas oil ratio							

Source: IHS Markit

Appendix C—Commercial Assumptions

C.1 Oil Price Forecast

Table C-1. Annual global WTI oil price assumptions, $/bbl in 2018 real terms

Case	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
High	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
Base	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
Low	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

Source: IHS Markit

C.2 Gas Sales Price

For Alaska offshore, all gas is assumed to be flared or reinjected. For the Non-Alaska peer group, gas in the Falkland Islands is assumed to be stranded with no gas sales.

Gas and associated gas sales are assigned to the nearest delivery point for the Non-Alaska peer group countries (Table C-2).

Table C-2. Gas sales delivery points

Jurisdiction	Gas sales delivery point
Argentina	Domestic price
Ireland	National Balancing Point
Morocco	Export to Spain
South Africa	Netback LNG price to Asia
U.S. Atlantic	Boston (Algonquin Gas Transmission Citygates)
U.S. Eastern GOM	Henry Hub
U.S. Pacific	Southern California Border

Source: IHS Markit

Table C-3. Annual gas sales price assumptions, $/MMBTU in 2018 real terms—Base case

Jurisdiction	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Argentina	5.10	4.89	5.15	5.20	5.43	5.68	5.86	5.99	6.03	6.11	6.29	6.41	6.42	6.40	6.37	6.35	6.46	6.30	6.43	6.28	6.41	6.26
Ireland	6.09	4.64	4.54	5.27	6.33	7.30	7.90	8.07	8.21	8.39	8.67	8.91	8.80	9.05	9.18	9.05	9.03	8.95	9.10	9.34	9.45	9.64
Morocco	4.93	4.29	4.70	5.04	5.99	7.02	7.74	8.15	8.34	8.55	8.85	9.10	8.99	9.24	9.38	9.25	9.22	9.14	9.29	9.53	9.65	9.84
South Africa	4.88	3.19	2.57	2.78	3.62	4.54	5.26	5.68	5.88	6.10	6.42	6.68	6.57	6.82	6.96	6.82	6.80	6.71	6.87	7.11	7.23	7.43
U.S. Atlantic	3.45	3.18	3.29	3.99	4.29	4.86	5.07	5.17	5.07	4.94	5.11	5.40	5.46	5.58	5.72	5.76	5.44	5.35	5.49	5.72	5.90	5.92
U.S. Eastern GOM	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
U.S. Pacific	2.39	2.18	2.30	2.77	3.19	3.59	3.79	3.91	3.82	3.71	3.91	4.25	4.34	4.48	4.62	4.68	4.35	4.29	4.44	4.69	4.91	4.96

Source: IHS Markit

Table C-4. Annual gas sales price assumptions, $/MMBTU in 2018 real terms—High case

Jurisdiction	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Argentina	8.16	7.83	8.23	8.32	8.69	9.08	9.38	9.58	9.65	9.78	10.06	10.26	10.28	10.24	10.19	10.15	10.33	10.08	10.28	10.04	10.25	10.01
Ireland	9.74	7.42	7.26	8.44	10.12	11.68	12.64	12.90	13.14	13.42	13.87	14.25	14.08	14.47	14.69	14.48	14.44	14.31	14.56	14.94	15.12	15.43
Morocco	7.89	6.87	7.52	8.06	9.59	11.23	12.38	13.03	13.35	13.68	14.16	14.55	14.39	14.79	15.01	14.79	14.76	14.62	14.87	15.25	15.43	15.74
South Africa	9.78	7.08	6.09	6.42	7.76	9.24	10.39	11.06	11.39	11.73	12.24	12.66	12.48	12.89	13.12	12.89	12.85	12.71	12.96	13.35	13.54	13.85
U.S. Atlantic	5.53	5.09	5.26	6.38	6.86	7.77	8.12	8.28	8.11	7.91	8.18	8.65	8.74	8.92	9.16	9.22	8.70	8.57	8.78	9.15	9.44	9.47
U.S. Eastern GOM	3.93	3.60	3.79	4.55	5.22	5.85	6.18	6.37	6.23	6.05	6.37	6.92	7.05	7.27	7.50	7.60	7.08	6.97	7.22	7.62	7.97	8.06
U.S. Pacific	3.82	3.49	3.68	4.43	5.10	5.74	6.06	6.26	6.12	5.93	6.25	6.80	6.94	7.16	7.39	7.49	6.97	6.86	7.11	7.51	7.86	7.94

Source: IHS Markit

Table C-5. Annual gas sales price assumptions, $/MMBTU in 2018 real terms—Low case

Jurisdiction	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Argentina	3.06	2.93	3.09	3.12	3.26	3.41	3.52	3.59	3.62	3.67	3.77	3.85	3.85	3.84	3.82	3.81	3.87	3.78	3.86	3.77	3.84	3.75
Ireland	3.65	2.78	2.72	3.16	3.80	4.38	4.74	4.84	4.93	5.03	5.20	5.34	5.28	5.43	5.51	5.43	5.42	5.37	5.46	5.60	5.67	5.79
Morocco	2.96	2.58	2.82	3.02	3.60	4.21	4.64	4.89	5.01	5.13	5.31	5.46	5.39	5.55	5.63	5.55	5.53	5.48	5.57	5.72	5.79	5.90
South Africa	1.61	0.60	0.23	0.35	0.85	1.41	1.84	2.09	2.21	2.34	2.53	2.69	2.63	2.78	2.86	2.78	2.76	2.71	2.80	2.95	3.02	3.14
U.S. Atlantic	2.07	1.91	1.97	2.39	2.57	2.91	3.04	3.10	3.04	2.97	3.07	3.24	3.28	3.35	3.43	3.46	3.26	3.21	3.29	3.43	3.54	3.55
U.S. Eastern GOM	1.48	1.35	1.42	1.71	1.96	2.19	2.32	2.39	2.34	2.27	2.39	2.59	2.64	2.73	2.81	2.85	2.66	2.61	2.71	2.86	2.99	3.02
U.S. Pacific	1.43	1.31	1.38	1.66	1.91	2.15	2.27	2.35	2.29	2.22	2.34	2.55	2.60	2.69	2.77	2.81	2.61	2.57	2.67	2.82	2.95	2.98

Source: IHS Markit

C.3 Cost Escalation

The following tables show the real annual fluctuations in cost levels. These are representative of the IHS Markit Upstream Capital Cost Index and Operating Cost Index for the IHS Markit 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 renewable energy becomes 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-6. Jurisdictions and regional cost escalation

Jurisdiction	Regional cost escalation
Argentina	South America
Ireland	Europe
Morocco	Africa
South Africa	Africa
U.S. Atlantic	North America
U.S. Eastern GOM	North America
U.S. Pacific	North America

Source: IHS Markit

Table C-7. Annual real cost escalation for offshore capex by region, year-on-year percentage change

Region	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Africa	0.0	1.5	0.4	1.0	1.4	1.3	1.0	0.8	0.8	1.1	1.1	0.9	0.5	0.4	0.6	0.7	0.4	0.4	0.4	0.6	0.6	0.4
Europe	0.0	-4.8	-2.4	-0.9	0.0	0.3	0.5	0.4	0.5	0.9	0.8	0.6	0.3	0.2	0.4	0.5	0.3	0.4	0.4	0.6	0.6	0.5
North America	0.0	3.2	1.5	2.0	2.0	1.6	1.1	0.9	0.8	1.1	1.1	0.9	0.5	0.4	0.5	0.7	0.4	0.5	0.5	0.7	0.7	0.6
South America	0.0	1.8	-0.4	-0.2	0.5	0.4	-0.2	-0.1	0.0	0.5	0.7	0.6	0.4	0.4	0.7	1.0	0.7	1.2	1.0	1.2	1.3	1.1

Source: IHS Markit

Table C-8. Annual real operating cost escalation by region, year-on-year percentage change

Region	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Africa	0.0	-6.2	6.3	-1.4	0.4	0.8	0.3	0.5	-0.4	0.3	-0.2	0.5	-0.4	-0.2	-0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.1
Europe	0.0	-1.3	2.1	-0.2	-0.2	0.0	0.2	0.1	-0.1	0.1	0.0	0.5	-0.4	-0.3	-0.1	0.2	-0.2	-0.3	0.3	0.0	0.1	0.1
North America	0.0	-2.2	4.0	-2.1	0.7	0.4	0.2	0.5	-0.3	-0.1	0.3	0.1	-0.4	-0.3	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0
South America	0.0	-3.0	4.4	-2.8	0.2	0.7	0.0	0.7	-0.6	0.0	0.6	0.0	-0.3	-0.2	-0.2	0.0	0.4	-0.1	-0.2	0.1	0.2	0.2

Source: IHS Markit

Appendix D—Results of Economic Analysis

D.1 Alaska Offshore Frontier

D.1.1 Discounted Share of the Barrel

Table D-1. Discounted share of the barrel: Alaska peer group 1,000 MMboe fields by case

Jurisdiction	Discounted share of the barrel (%)											
	High case				Base case				Low case			
	Company	Federal	Opex	Capex	Company	Federal	Opex	Capex	Company	Federal	Opex	Capex
Canada NWT	27%	36%	8%	29%	12%	29%	12%	46%	-13%	15%	21%	77%
Falkland Islands	15%	22%	13%	50%	-19%	18%	21%	80%	-81%	12%	35%	134%
Norway	-1%	50%	9%	41%	-18%	37%	14%	67%	-52%	18%	23%	111%
U.S. Beaufort Sea	31%	25%	15%	30%	7%	21%	23%	48%	-38%	16%	38%	84%
U.S. Chukchi Sea	20%	22%	4%	54%	-12%	18%	7%	87%	-71%	13%	12%	147%

Source: IHS Markit

Table D-2. Discounted share of the barrel: Alaska peer group 400 MMboe fields by case

Jurisdiction	Discounted share of the barrel (%)											
	High case				Base case				Low case			
	Company	Federal	Opex	Capex	Company	Federal	Opex	Capex	Company	Federal	Opex	Capex
Canada NWT	21%	31%	10%	38%	0%	23%	16%	62%	-38%	8%	25%	105%
Falkland Islands	26%	22%	15%	37%	0%	18%	23%	59%	-50%	11%	36%	103%
Norway	6%	51%	10%	34%	-5%	35%	16%	54%	-29%	12%	25%	91%
U.S. Beaufort Sea	27%	23%	18%	32%	1%	19%	27%	53%	-50%	13%	43%	94%
U.S. Chukchi Sea	25%	23%	5%	47%	-2%	18%	8%	76%	-55%	13%	14%	129%

Source: IHS Markit

Table D-3. Discounted share of the barrel: Alaska peer group 100 MMboe fields by case

Jurisdiction	Discounted share of the barrel (%)											
	High case				Base case				Low case			
	Company	Federal	Opex	Capex	Company	Federal	Opex	Capex	Company	Federal	Opex	Capex
Canada NWT	-2%	22%	13%	67%	-37%	9%	21%	107%	-118%	4%	35%	180%
Falkland Islands	18%	20%	20%	42%	-13%	13%	32%	67%	-80%	10%	51%	119%
Norway	-3%	37%	14%	53%	-20%	14%	22%	84%	-82%	0%	33%	149%
U.S. Beaufort Sea	24%	25%	11%	40%	-4%	21%	17%	65%	-56%	15%	28%	112%
U.S. Chukchi Sea	21%	22%	6%	51%	-10%	17%	10%	83%	-70%	13%	16%	141%

Source: IHS Markit

D.1.2 Royalty Sensitivity

Table D-4. Alaska offshore Beaufort royalty sensitivity: government take vs. IRR and NPV/boe

Field size (MMboe)	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
1,000	12.5%	11%	39%	1.45
	0%	13%	21%	3.02
	RSV	13%	30%	2.54
400	12.5%	10%	44%	0.16
	0%	13%	21%	2.14
	RSV	12%	30%	1.69
100	12.5%	9%	39%	-0.75
	0%	11%	21%	1.06
	RSV	11%	28%	0.56
Key: RSV = royalty suspension volume				

Source: IHS Markit

Table D-5. Alaska offshore Chukchi royalty sensitivity: government take vs. IRR and NPV/boe

Field size (MMboe)	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
1,000	12.5%	7%	46%	-2.49
	0%	10%	22%	-0.25
	RSV	9%	37%	-1.28
400	12.5%	9%	49%	-0.48
	0%	12%	24%	1.60
	RSV	11%	37%	0.83
100	12.5%	7%	50%	-2.83
	0%	10%	23%	0.08
	RSV	9%	37%	-1.07
Key: RSV = royalty suspension volume				

Source: IHS Markit

D.2 Non-Alaska Offshore Frontier

D.2.1 Discounted Share of the Barrel

Table D-6. Discounted share of the barrel: Non-Alaska frontier 500 MMboe oil fields by case

Jurisdiction	Discounted share of the barrel (%)														
	High case					Base case					Low case				
	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex
Falkland Islands	34%	23%	0%	16%	27%	14%	18%	0%	25%	43%	-24%	11%	0%	41%	73%
Ireland	42%	35%	0%	8%	15%	38%	25%	0%	13%	24%	21%	17%	0%	22%	39%
South Africa	50%	26%	6%	5%	13%	43%	22%	5%	9%	21%	30%	17%	4%	14%	36%
Argentina	43%	30%	0%	8%	20%	30%	27%	0%	12%	31%	6%	22%	0%	20%	52%
Morocco	18%	15%	6%	11%	49%	-9%	14%	-3%	18%	79%	-59%	14%	-19%	28%	137%
U.S. Atlantic	13%	21%	0%	12%	53%	-22%	17%	0%	20%	86%	-91%	13%	0%	34%	145%
U.S. Pacific	30%	24%	0%	10%	37%	5%	20%	0%	16%	59%	-43%	14%	0%	27%	101%
U.S. Eastern GOM	33%	24%	0%	9%	34%	11%	21%	0%	14%	55%	-32%	16%	0%	23%	92%
Key: Comp = company share; NOC = national oil company															

Source: IHS Markit

Table D-7. Discounted share of the barrel: Non-Alaska frontier 200 MMboe oil fields by case

Jurisdiction	Discounted share of the barrel (%)														
	High case					Base case					Low case				
	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex
Falkland Islands	41%	25%	0%	17%	17%	25%	21%	0%	26%	28%	-4%	14%	0%	41%	49%
Ireland	37%	25%	0%	14%	25%	22%	17%	0%	22%	40%	-12%	9%	0%	36%	67%
South Africa	47%	24%	5%	7%	17%	37%	20%	4%	12%	27%	20%	14%	3%	19%	44%
Argentina	37%	28%	0%	11%	24%	20%	24%	0%	17%	39%	-10%	18%	0%	28%	64%
Morocco	16%	13%	6%	13%	52%	-14%	13%	-3%	20%	84%	-65%	12%	-20%	34%	140%
U.S. Atlantic	21%	22%	0%	12%	45%	-9%	17%	0%	19%	73%	-72%	13%	0%	30%	130%
U.S. Pacific	32%	24%	0%	9%	35%	9%	20%	0%	15%	56%	-35%	14%	0%	26%	95%
U.S. Eastern GOM	33%	24%	0%	7%	36%	10%	21%	0%	11%	58%	-32%	15%	0%	20%	98%

Key: Comp = company share; NOC = national oil company

Source: IHS Markit

Table D-8. Discounted share of the barrel: Non-Alaska frontier 100 MMboe oil fields by case

Jurisdiction	Discounted share of the barrel (%)														
	High case					Base case					Low case				
	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex
Falkland Islands	16%	19%	0%	22%	43%	-16%	12%	0%	35%	69%	-91%	9%	0%	51%	131%
Ireland	39%	26%	0%	11%	24%	25%	18%	0%	18%	39%	-5%	9%	0%	29%	66%
South Africa	41%	21%	5%	10%	22%	28%	16%	4%	16%	35%	4%	8%	1%	27%	59%
Argentina	24%	25%	0%	16%	34%	-1%	20%	0%	26%	55%	-48%	12%	0%	41%	96%
Morocco	20%	10%	8%	11%	53%	-10%	10%	-2%	16%	85%	-61%	10%	-18%	27%	142%
U.S. Atlantic	17%	21%	0%	16%	46%	-16%	15%	0%	25%	75%	-90%	13%	0%	39%	138%
U.S. Pacific	34%	24%	0%	11%	30%	12%	20%	0%	18%	50%	-28%	13%	0%	29%	86%
U.S. Eastern GOM	23%	22%	0%	12%	42%	-6%	18%	0%	20%	68%	-62%	13%	0%	34%	116%
Key: Comp = company share; NOC = national oil company															

Source: IHS Markit

Table D-9. Discounted share of the barrel: Non-Alaska frontier 500 MMboe gas fields by case

Jurisdiction	Discounted share of the barrel (%)														
	High case					Base case					Low case				
	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex
Ireland	27%	21%	0%	12%	40%	2%	14%	0%	20%	64%	-46%	7%	0%	33%	106%
South Africa	41%	22%	5%	9%	24%	27%	17%	3%	14%	39%	2%	9%	1%	23%	65%
Argentina	47%	32%	0%	6%	14%	36%	31%	0%	10%	23%	17%	28%	0%	16%	39%
Morocco	40%	14%	14%	10%	21%	26%	14%	9%	16%	34%	2%	13%	2%	27%	57%
U.S. Atlantic	-38%	15%	0%	18%	105%	-112%	13%	0%	30%	169%	-254%	13%	0%	50%	291%
U.S. Pacific	-5%	19%	0%	19%	67%	-53%	13%	0%	31%	109%	-153%	13%	0%	53%	188%
U.S. Eastern GOM	11%	21%	0%	15%	53%	-27%	16%	0%	24%	87%	-102%	13%	0%	42%	148%

Key: Comp = company share; NOC = national oil company

Source: IHS Markit

Table D-10. Discounted share of the barrel: Non-Alaska frontier 200 MMboe gas fields by case

Jurisdiction	Discounted share of the barrel (%)														
	High case					Base case					Low case				
	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex
Ireland	17%	17%	0%	17%	49%	-16%	10%	0%	27%	79%	-80%	3%	0%	45%	131%
South Africa	38%	20%	5%	9%	28%	23%	15%	3%	15%	44%	-5%	7%	0%	25%	73%
Argentina	39%	31%	0%	8%	22%	23%	30%	0%	13%	35%	-5%	26%	0%	22%	58%
Morocco	40%	12%	14%	10%	24%	25%	11%	9%	17%	38%	-2%	10%	1%	28%	63%
U.S. Atlantic	-17%	16%	0%	16%	84%	-75%	13%	0%	27%	136%	-189%	13%	0%	45%	231%
U.S. Pacific	8%	20%	0%	14%	59%	-32%	13%	0%	22%	96%	-117%	13%	0%	37%	168%
U.S. Eastern GOM	5%	19%	0%	20%	56%	-38%	14%	0%	33%	91%	-125%	13%	0%	56%	156%

Key: Comp = company share; NOC = national oil company

Source: IHS Markit

Table D-11. Discounted share of the barrel: Non-Alaska frontier 100 MMboe gas fields by case

Jurisdiction	Discounted share of the barrel (%)														
	High case					Base case					Low case				
	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex	Comp	Federal	NOC	Opex	Capex
Ireland	11%	15%	0%	21%	54%	-26%	7%	0%	33%	86%	-105%	3%	0%	52%	149%
South Africa	28%	16%	4%	16%	36%	6%	9%	2%	26%	58%	-40%	2%	-3%	43%	98%
Argentina	33%	31%	0%	8%	28%	14%	29%	0%	13%	44%	-21%	26%	0%	21%	75%
Morocco	39%	6%	14%	10%	30%	21%	6%	9%	16%	48%	-13%	6%	-1%	25%	84%
U.S. Atlantic	-25%	13%	0%	22%	90%	-97%	13%	0%	35%	149%	-252%	13%	0%	56%	284%
U.S. Pacific	-59%	13%	0%	38%	109%	-151%	13%	0%	61%	177%	-325%	13%	0%	106%	306%
U.S. Eastern GOM	-10%	17%	0%	20%	72%	-62%	13%	0%	33%	117%	-174%	13%	0%	55%	206%
Key: Comp = company share; NOC = national oil company															

Source: IHS Markit

D.2.2 Royalty Sensitivity

Table D-12. Non-Alaska offshore oil 500 MMboe royalty sensitivity: government take vs. IRR and NPV/boe

Region	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
U.S. Atlantic	12.5%	5%	57%	-5.04
	18.8%	3%	72%	-6.70
	0%	8%	26%	-2.35
	RSV	7%	41%	-3.14
U.S. Pacific	12.5%	11%	45%	0.97
	18.8%	10%	55%	-0.10
	0%	14%	24%	2.70
	RSV	12%	41%	1.55
U.S. Eastern GOM	12.5%	12%	37%	1.83
	18.8%	11%	45%	1.03
	0%	14%	22%	3.12
	RSV	14%	29%	2.81

Key: RSV = royalty suspension volume

Source: IHS Markit

Table D-13. Non-Alaska offshore oil 200 MMboe royalty sensitivity: government take vs. IRR and NPV/boe

Region	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
U.S. Atlantic	12.5%	7%	49%	-2.24
	18.8%	5%	64%	-3.76
	0%	10%	21%	0.21
	RSV	9%	34%	-0.53
U.S. Pacific	12.5%	14%	45%	2.37
	18.8%	12%	56%	1.11
	0%	17%	24%	4.40
	RSV	15%	41%	3.04
U.S. Eastern GOM	12.5%	13%	43%	2.44
	18.8%	11%	53%	1.32
	0%	16%	24%	4.25
	RSV	15%	36%	3.39

Key: RSV = royalty suspension volume

Source: IHS Markit

Table D-14. Non-Alaska offshore oil 100 MMboe royalty sensitivity: government take vs. IRR and NPV/boe

Region	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
U.S. Atlantic	12.5%	4%	71%	-3.99
	0%	8%	28%	-1.21
	RSV	5%	63%	-3.14
U.S. Pacific	12.5%	16%	43%	3.69
	0%	19%	23%	5.81
	RSV	17%	39%	4.37
U.S. Eastern GOM	12.5%	8%	56%	-1.42
	18.8%	6%	71%	-2.86
	0%	12%	26%	0.92
	RSV	11%	37%	0.34
Key: RSV = royalty suspension volume				

Source: IHS Markit

Table D-15. Non-Alaska offshore gas 500 MMboe royalty sensitivity: government take vs. IRR and NPV/boe

Region	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
U.S. Atlantic	12.5%	0%	-41%	-14.42
	18.8%	0%	-61%	-16.70
	0%	0%	0%	-11.20
	RSV	0%	-20%	-12.47
U.S. Pacific	12.5%	-2%	175%	-7.54
	18.8%	-3%	228%	-9.06
	0%	1%	40%	-5.27
	RSV	-1%	149%	-6.89
U.S. Eastern GOM	12.5%	4%	61%	-3.08
	18.8%	2%	77%	-3.96
	0%	6%	28%	-1.65
	RSV	6%	42%	-2.02

Key: RSV = royalty suspension volume

Source: IHS Markit

Table D-16. Non-Alaska offshore gas 200 MMboe royalty sensitivity: government take vs. IRR and NPV/boe

Region	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
U.S. Atlantic	12.5%	0%	-59%	-14.03
	18.8%	0%	-89%	-16.37
	0%	0%	0%	-10.24
	RSV	0%	-24%	-11.39
U.S. Pacific	12.5%	-2%	145%	-5.89
	18.8%	-6%	199%	-7.38
	0%	2%	53%	-3.49
	RSV	-1%	125%	-5.23
U.S. Eastern GOM	12.5%	0%	108%	-4.23
	RSV	0%	96%	-3.77
	0%	3%	36%	-2.65

Key: RSV = royalty suspension volume

Source: IHS Markit

Table D-17. Non-Alaska offshore gas 100 MMboe royalty sensitivity: government take vs. IRR and NPV/boe

Region	Royalty rate	Royalty sensitivity		
		Base case		
		IRR	Government take	NPV/boe
U.S. Atlantic	12.5%	0%	-30%	-16.00
	RSV	0%	-24%	-14.98
	0%	0%	0%	-12.19
U.S. Pacific	12.5%	0%	-19%	-15.60
	RSV	0%	-15%	-14.82
	0%	0%	0%	-12.52
U.S. Eastern GOM	12.5%	-7%	-425%	-8.13
	RSV	-6%	-347%	-7.47
	0%	-2%	-66%	-5.83

Key: RSV = royalty suspension volume

Source: IHS Markit

Appendix E—Cook Inlet Basin

The Cook Inlet Basin in the U.S. offshore Alaska experienced a great deal of exploratory activity in the 1960s. Production peaked in the 1970s; approximately 165,000 bbls/day of oil were produced in 1975. Since then, activity has diminished greatly, and total offshore production in 2018 was 25,482 boe/day, split 54 percent for oil (13,770 bbls/day) and 46 percent for gas (11,712 boe/day). Hilcorp is the major producer in the region, and has plans for some activity in the future.

Offshore exploratory wells peaked in the mid-1960s, with 23 exploratory wells in 1966. The last exploratory well was drilled in 2014. Only 8 of 110 exploratory wells (7 percent) have been discoveries (see Figure E-1). The last discovery from an exploratory well was in 2012. All the discoveries were made in the Upper Cook Inlet. There are only exploratory wells in the Lower Cook Inlet.

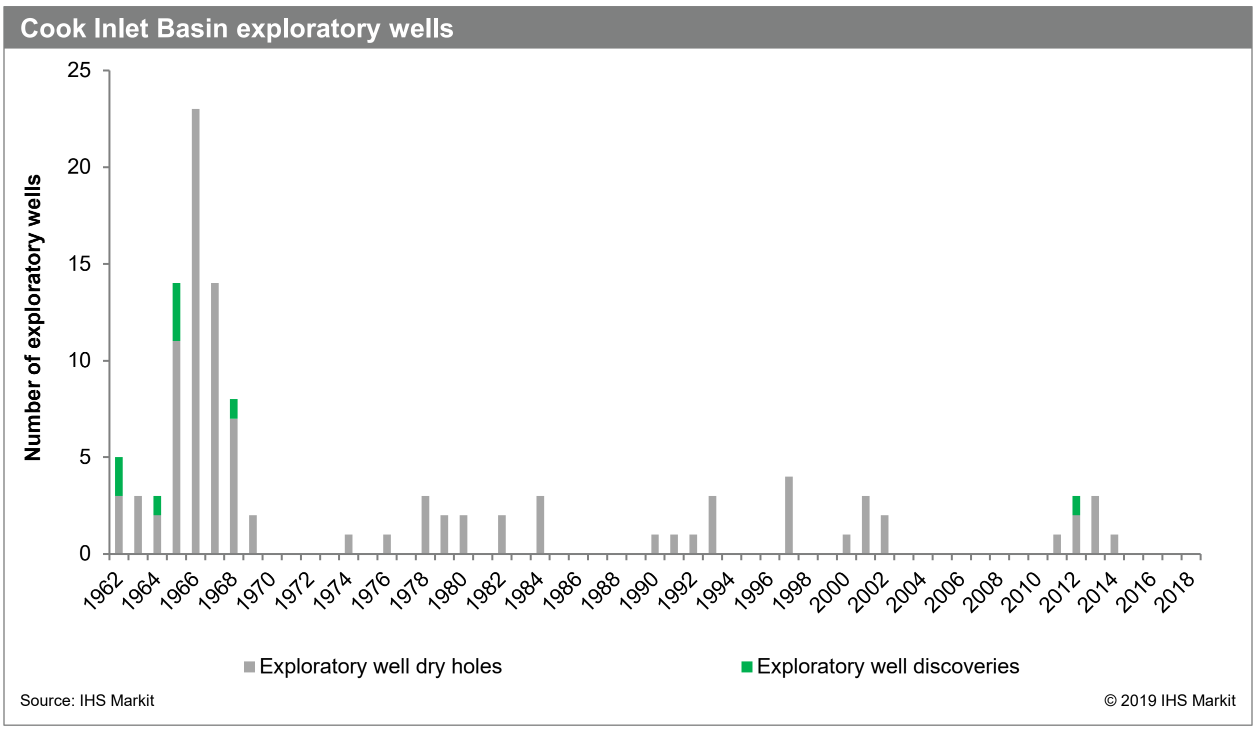

Figure E-1. Cook Inlet Basin offshore exploratory wells and discoveries

As shown in Figure E-2, most reserves were added in the 1960s. In 2018, cumulative reserves are split 54.8 percent for gas, 44.9 percent for oil, and 0.3 percent condensate. The last increase for oil recoverable reserves was in 2002, and for natural gas and condensate was in 2012. To date, offshore Cook Inlet seems as mature as the onshore sections, or it could be arrested.[76]

[76] An arrested basin is a basin where development has been halted by economic conditions or regulations.

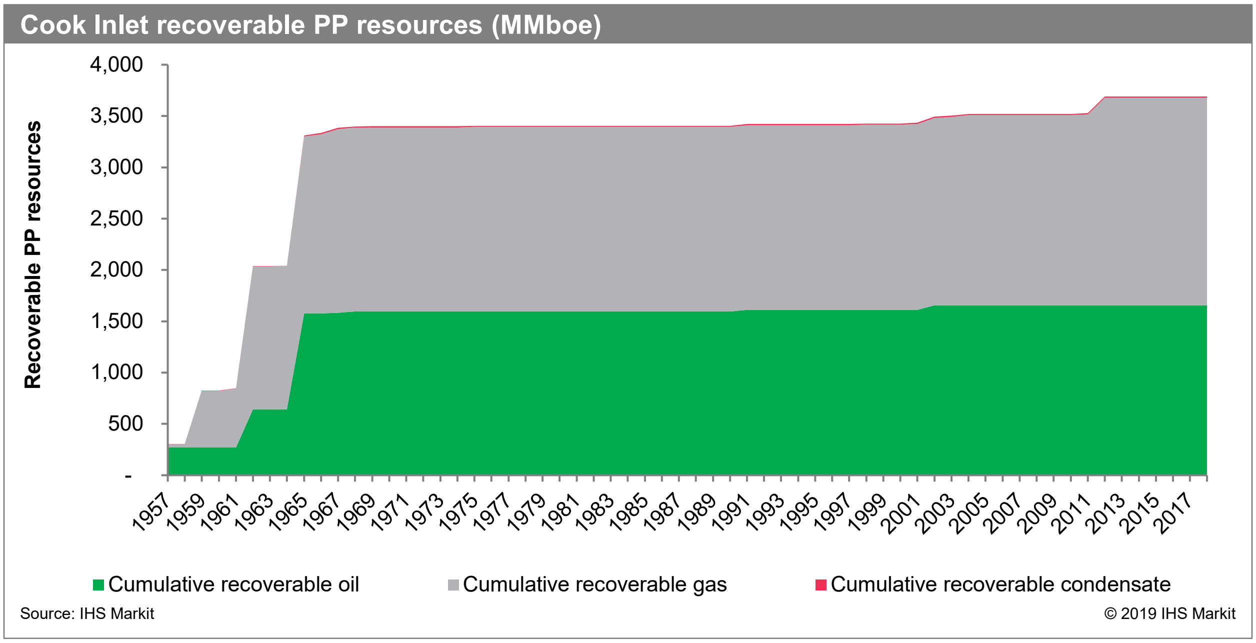

Figure E-2. Cook Inlet Basin offshore recoverable proven and probable reserves

In the past five years, there has been some seismic activity, with 12 formation evaluations offshore, 10 of which were 3D seismic surveys (see Figure E-3).

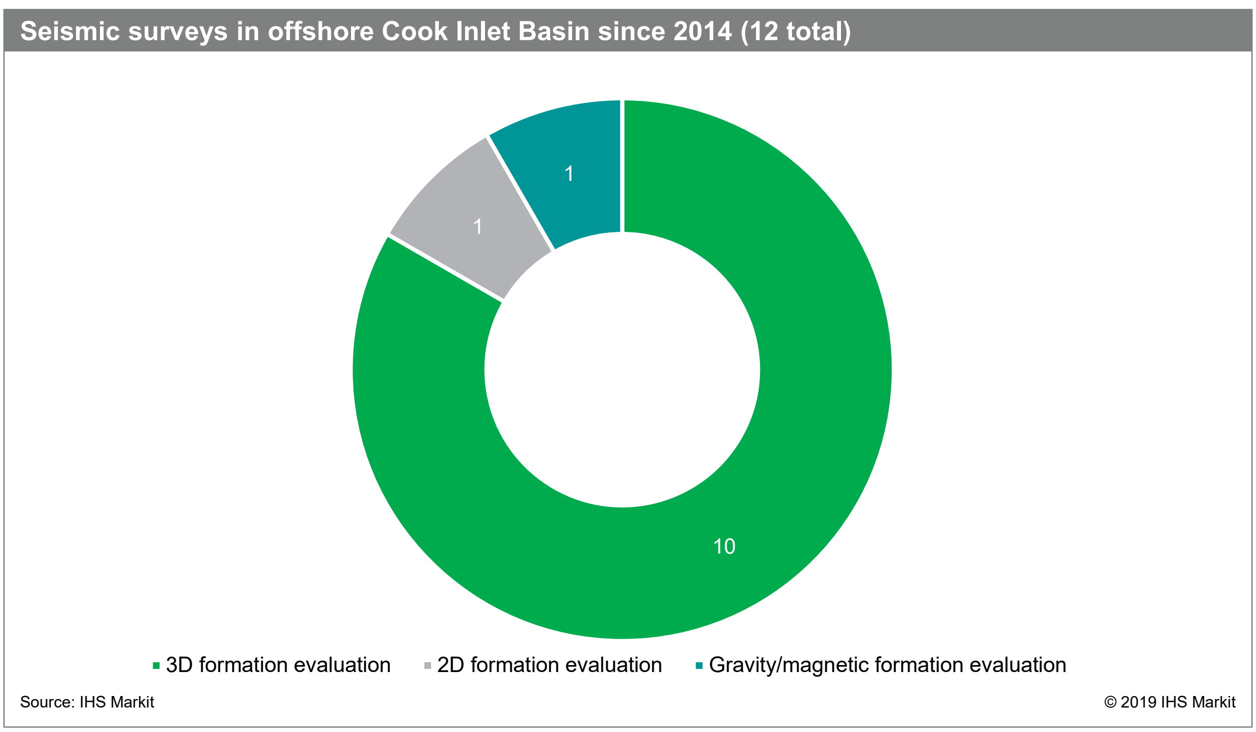

Figure E-3. Cook Inlet Basin offshore seismic surveys since 2014

Hilcorp is the independent oil and gas operator driving most of the Cook Inlet Basin activity at present. After entering the area in 2011, it now owns 16 of 18 platforms in the Cook Inlet state waters.[77] It was the only company to bid for offshore Cook Inlet Basin acreage in the Cook Inlet Area-wide 2017W Competitive Oil and Gas Lease Sales, held on June 21, 2017, and the 2018 Cook Inlet Area-wide 2018W Competitive Oil and Gas Lease Sale.[78] Hilcorp completed a $90-million pipeline project in 2018 that will displace tankers that previously had transported crude oil to a nearby refinery; Hilcorp expects transportation costs for crude oil to fall by one-third, and it claims that the life of the field could be extended by about 20 years.[79]

Hilcorp filed an application in late 2018 with its plans for the upcoming five years.[80] These plans include 2D, 3D, and geohazard surveys, as well as drilling at least two new exploratory wells.

[77] Cochran S. "Hilcorp lays out five-year Cook Inlet plan." KDLL: Public Radio for the Central Kenai Peninsula, 2018 November 6.
[78] Alaska Department of Natural Resources Division of Oil & Gas. "Current Lease Sales."
[79] Boettger B. "Hilcorp replaces oil tankers with pipeline for Cook Inlet crude," *Alaska Journal of Commerce,* October 25, 2018.
[80] Cochran S. "Hilcorp lays out five-year Cook Inlet plan." KDLL: Public Radio for the Central Kenai Peninsula, 2018 November 6.

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