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Working Paper

The prospects and challenges for Arctic oil development

OIES Paper: WPM, No. 56

Provided in Cooperation with:

The Oxford Institute for Energy Studies, Oxford

Suggested Citation: Henderson, James; Loe, Julia (2014) : The prospects and challenges for Arctic oil development, OIES Paper: WPM, No. 56, ISBN 978-1-78467-015-3, The Oxford Institute for Energy Studies, Oxford,
<https://doi.org/10.26889/9781784670153>

This Version is available at:

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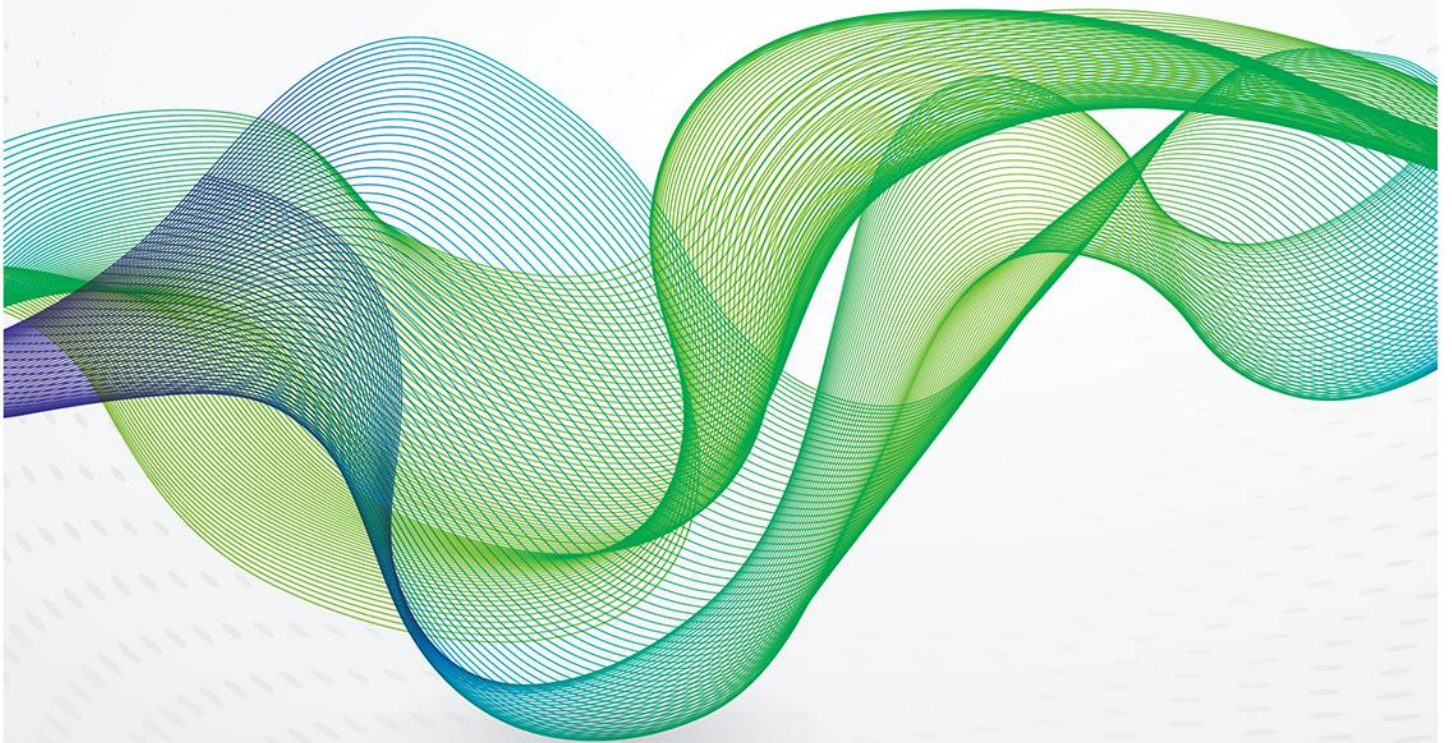
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THE OXFORD
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November 2014

The Prospects and Challenges for Arctic Oil Development





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ISBN 978-1-78467-015-3

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Acknowledgements

We would like to thank our colleagues in Oxford and Oslo for their help with this research. In particular we are very grateful for the support and comments provided by Bassam Fattouh and Arild Moe. We would also like to thank our editor, Jan Cleave, for her detailed corrections and useful comments.

Thanks also to the many industry executives, consultants and analysts with whom we have discussed this topic, but as always the results of the analysis remain entirely our responsibility.



Abbreviations and units of measurement

bbls	Barrels
bcm	Billion cubic metres
bcma	Billion cubic metres per annum
bnbbls	Billion barrels
bnboe	Billion barrels of oil equivalent
boepd	Barrels of oil equivalent per day
bpd	Barrels per day
E&P	Exploration and production
ESPO	East Siberia–Pacific Ocean (pipeline)
FSU	Former Soviet Union
IOC	International oil company
kboepd	Thousand barrels of oil equivalent per day
kbpd	Thousands barrels per day
km	Kilometres
mmbbls	Million barrels
mcm	Thousand cubic metres
mmboepd	Million barrels of oil equivalent per day]
mbpd	Million barrels per day
mbtu	Million British thermal units
mmcm	Million cubic metres
mmt	Million tonnes
mmtpa	Million tonnes per annum
P&P	Proved and probable
tcf	Trillion cubic feet
tcm	Trillion cubic metres

Conversion Factors

<i>Equals</i>			
1	tonne oil	7.3	barrels of oil equivalent
1	tonne condensate	8.0	barrels of oil equivalent
1	bcm gas	6.6	mm barrels of oil equivalent
1	bcm gas	35.3	billion cubic feet of gas
1	bcm gas	0.9	mm tonnes of oil equivalent

Source: BP Statistical Review



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Introduction

The role of the Arctic region in global petroleum supply over the next decades is becoming a subject of increasing interest as the potential of the region's geology is revealed and the shrinking of the ice cap makes drilling an increasingly feasible activity. Nevertheless, significant concerns remain, not least the potential impact of any hydrocarbon E&P activity in an environmentally sensitive region. In addition, the lack of existing infrastructure and the likely high cost of any development in geographically remote and climatically harsh conditions mean that the economics of any new project will depend to a large extent on the size of discoveries and the oil price, which, in turn, will be impacted by the development of other sources of oil supply (for example, US unconventional oil) and alternative energies. As a result, although increased activity in a number of Arctic countries suggests that the region could become a major source of future oil supply, there are a number of challenges – including the impact of sanctions resulting from the Ukraine crisis – to be met before this potential can be realized.

The objective of this paper is to provide an updated overview of offshore oil and gas developments in the Arctic and to discuss the potential for large-scale development of the region as a petroleum province over the next 20-30 years, thereby providing a starting point for future production estimates and for analyzing how relevant such estimates may be for global oil (and gas) markets. The paper argues that the most likely Arctic offshore areas to be developed first are the Barents Sea and the Kara Sea but that various factors – political, commercial, technological and environmental – have the potential to hamper petroleum development, particularly if the conflict between Russia and the international community escalates.

The resource potential is very large

As the era of cheap and easily available oil and gas arguably comes to an end, the Arctic offshore has increasingly been seen over the last decade as the world's next hot spot for hydrocarbon development – largely owing to recent estimates of its huge resource potential. The United States Geological Survey (USGS) in 2008 estimated that up to 22% of the world's undiscovered technically recoverable oil and gas resources are located in the Arctic, including 13% of the world's undiscovered oil.¹ More than three-quarters of these resources are to be found offshore in the territories of the five littoral states of the Arctic Sea – namely, the US, Canada, Russia, Norway and Greenland, of which the first four are already major petroleum-producing countries.² As climate change is reducing both ice thickness and extent,³ these resources are becoming increasingly reachable, opening up new opportunities for industrial development and transport to world markets – for example, through the Northern Sea Route.

However, despite the shift in global temperatures, Arctic offshore production will be far more expensive than production in most other petroleum regions owing to the harsh climatic conditions - including temperatures down to -50 degrees Celsius, extensive ice coverage for significant parts of the year, long distances to land and almost total darkness in winter. This means that multi-billion barrel discoveries will have to be made and oil-price expectations will need to be high if expensive developments are to go ahead. Technological breakthroughs may be needed in several areas, while political support (in particular on the fiscal regime) and extensive cooperation

¹ USGS (2008).

² USGS (2008).

³ BBC, 'Arctic sea ice reaches record low, NASA says', 27 August 2014.



between Arctic states will be prerequisites for success. At the same time, environmental risks and popular opposition to oil and gas activity in the Arctic are factors that could undermine hydrocarbon development, especially as it is clear that the environmental challenges for search-and-rescue and oil-spill preparedness will be significant. In addition, while there is a high probability of finding natural gas in many of the Arctic basins, any gas discovery would, in effect, be worthless under current market conditions, increasing the exploration risk further.

The difficulties involved in Arctic developments can be seen at the only two offshore fields in the region that are currently producing: the Snøhvit LNG scheme in the Norwegian Barents Sea, and the Prirazlomnoye oil field in the Pechora Sea in Russia. Both have experienced significant delays and cost overruns; and although they are now on stream, it is questionable whether the field partners would have proceeded with the developments had they known beforehand about the problems that they have encountered. At the very least, these two fields provide cautionary tales for the partners in future Arctic offshore developments.

Nevertheless, exploration activity is continuing. Most progress is being made in the Norwegian Continental Shelf (NCS): indeed, one-third of offshore investments in the Arctic so far are in the Barents Sea.⁴ However, it is interesting, given the current geo-political climate, that the highest Arctic expectations are linked to the Rosneft-ExxonMobil exploration venture in the Kara Sea, where six wells are due to be drilled in the period 2014–17. It remains to be seen whether this programme will be completed, given the current EU and US sanctions on Russia and the fact that ExxonMobil has been forced to temporarily pull out, but the results of the first well have already been announced and indicate the presence of significant hydrocarbons.

⁴ Økt skipsfart i Polhavet – muligheter og utfordringer for Norge.



1. The Arctic: A region of great variety

The Arctic is often referred to as a single unified region, although it is a large geographical area populated by approximately 4 million people, divided between eight countries that differ significantly in terms of climate, economy and way of life. The Arctic states are Iceland, Sweden, Finland, Norway, Russia, Greenland (Denmark), US (Alaska) and Canada, of which the last five border the Arctic Ocean (littoral states). Of all these countries, Russia has the largest Arctic population – approximately 2 million – followed by the US (Alaska) with approximately 650,000 inhabitants, Norway with 469,000, Canada with 120,000 and Greenland with 58,000.⁵ Approximately 10% of the Arctic population is indigenous, and many Arctic inhabitants sustain a traditional livelihood that combines hunting and fishing or reindeer herding with a nomadic lifestyle. Offshore petroleum activities, which are, of course, carried out mainly at sea, have a limited impact on them, although any industrial development or population increase caused by the oil industry can lead to conflicts of interest related to land use.

There is no single universally accepted definition of the Arctic, although it is commonly referred to as the geographic region above the Arctic circle, at 66° 32" North.⁶ That definition, however, excludes Iceland, which is located just below the Arctic Circle. Alternative definitions include the area north of the tree line – that is, the highest latitude at which trees grow naturally - or areas where the average temperature in the warmest month of the year is below 10 degrees Celsius. In some definitions, certain areas notionally outside the Arctic are included owing to specific climate and ice conditions: Sakhalin, in the Russian Far East, is a prime example, sometimes included in discussions of the Arctic owing to the similarity of its environment with that of the Arctic regions.

For the purpose of this paper, we consider the DNV definition “The Arctic Ocean and the Arctic Seas (like the Barents and Beaufort Seas), as well as the lands immediately surrounding these areas.” – to be the most appropriate.⁷ With regard to Norway, in line with most studies, we focus on the Barents Sea when discussing Arctic oil and gas, as the Norwegian Sea, of which only parts are located above the Arctic Circle, has operating conditions that are similar to the North Sea and is often left out of the Arctic discourse. As regards Russia, we focus on the northern seas (Barents, South Kara, Chukchi and Laptev) but also discuss Sakhalin as an area of current and future development. Elsewhere, we consider only offshore areas in the Arctic Ocean.

Arctic petroleum resources

Oil and gas exploitation in the Arctic region is by no means a new development. There has been substantial petroleum production in the region since the 1960s, particularly in Russia (Komi Republic and Nenets Autonomous Okrug) and Alaska, where the largest field in the US, Prudhoe Bay, is located, with 25 bnbbls of oil in place.⁸ However, this Arctic activity has so far primarily been onshore, while the current exploration focus is on the potential for large-scale offshore development.

In 2008 the first comprehensive assessment of potential hydrocarbon reserves for the entire area north of the Arctic Circle was published by the USGS.⁹ It concluded that the extensive Arctic continental shelves may constitute the largest unexploited prospective area for petroleum

⁵ <http://int.rgo.ru/arctic/arctic-overview/socio-demographic-situation-in-the-arctic/>.

⁶ National Snow and Ice Data Center, 2013.

⁷ http://www.dnv.com/binaries/arctic_resource_development_tcm4-532195.pdf.

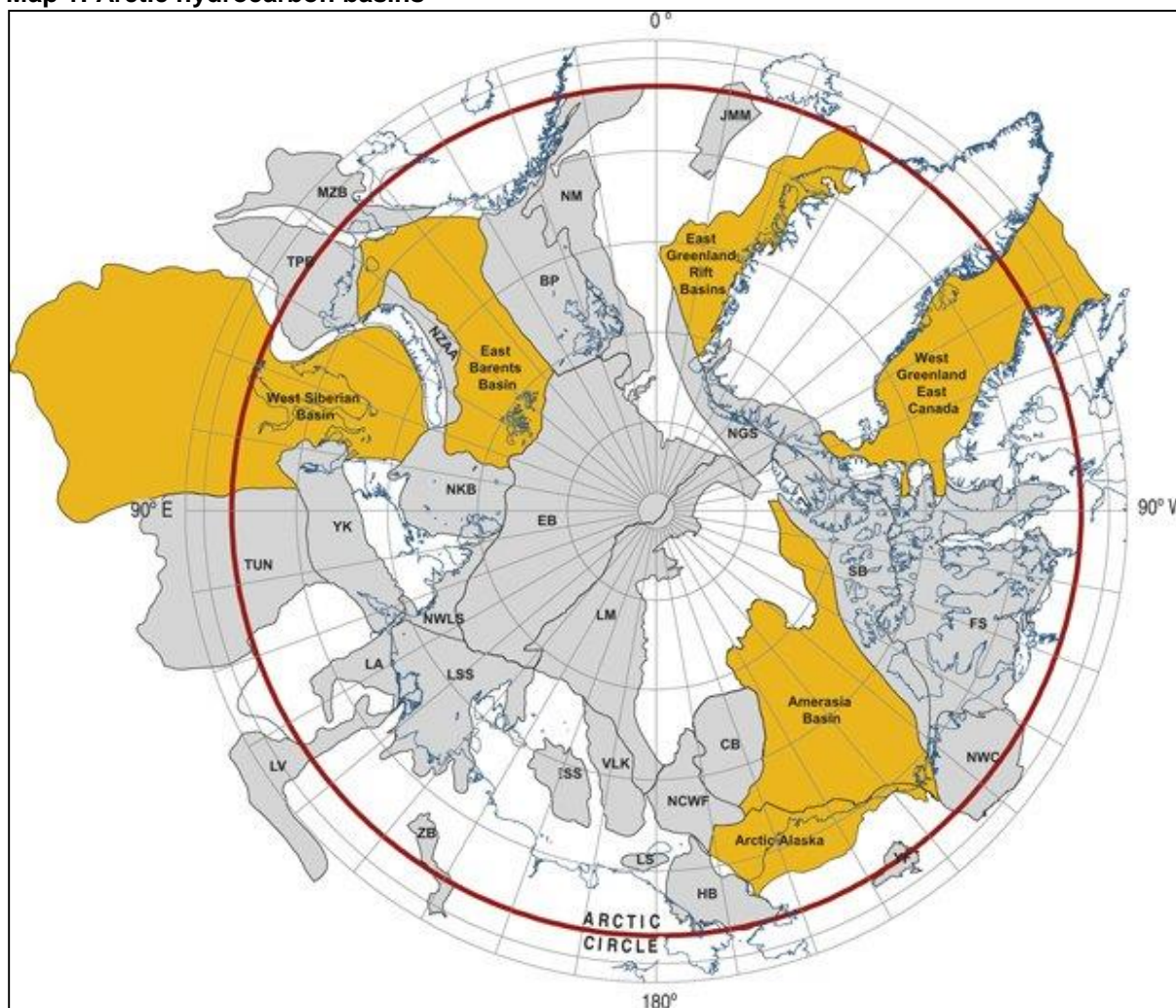
⁸ USGS (2008).

⁹ USGS (2008).



remaining on Earth. According to the assessment, the Arctic resources account for about 22% of the world's undiscovered technically recoverable oil and gas resources, including 13% of undiscovered oil, 30% of undiscovered natural gas and 20% of undiscovered natural gas liquids.¹⁰ This implies an estimated 90 bnbbls of undiscovered technically recoverable oil, 1,670 tcf (47 tcm) of technically recoverable natural gas and 44 bnbbls of technically recoverable natural gas liquids in 25 geologically defined areas north of the Arctic Circle that are thought to have potential for hydrocarbons (see Figure 1 below). Approximately 84% of those resources are expected to occur offshore.¹¹

Map 1: Arctic hydrocarbon basins



Source: USGS.

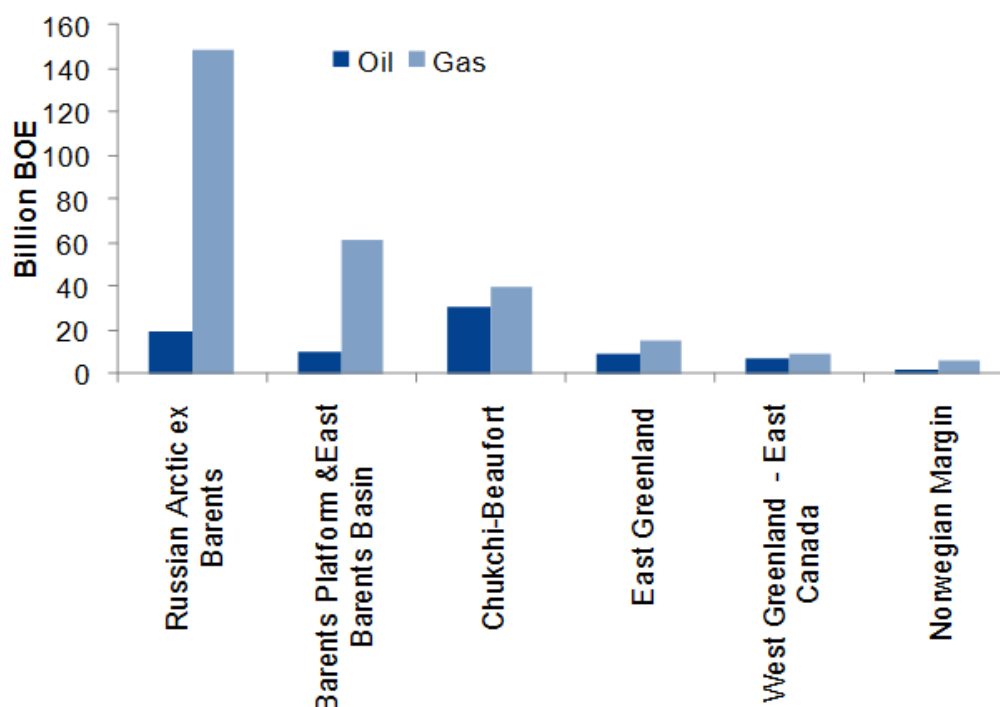
¹⁰USGS (2008).

¹¹ Ernst & Young, *Arctic Oil and Gas*, 2013, at [http://www.ey.com/Publication/vwLUAssets/Arctic_oil_and_gas/\\$File/Arctic_oil_and_gas.pdf](http://www.ey.com/Publication/vwLUAssets/Arctic_oil_and_gas/$File/Arctic_oil_and_gas.pdf).



As can be seen from Figure 1 below, gas accounts for the largest share (approximately 70%) of the estimated recoverable resource base; the majority is located in West Siberia and in the eastern part of the Barents Sea.¹² Most of the oil is located in the Arctic part of Alaska towards the North Pole and in East Greenland.¹³ #

Figure 1: Arctic oil and gas resources



Source: USGS (2008).

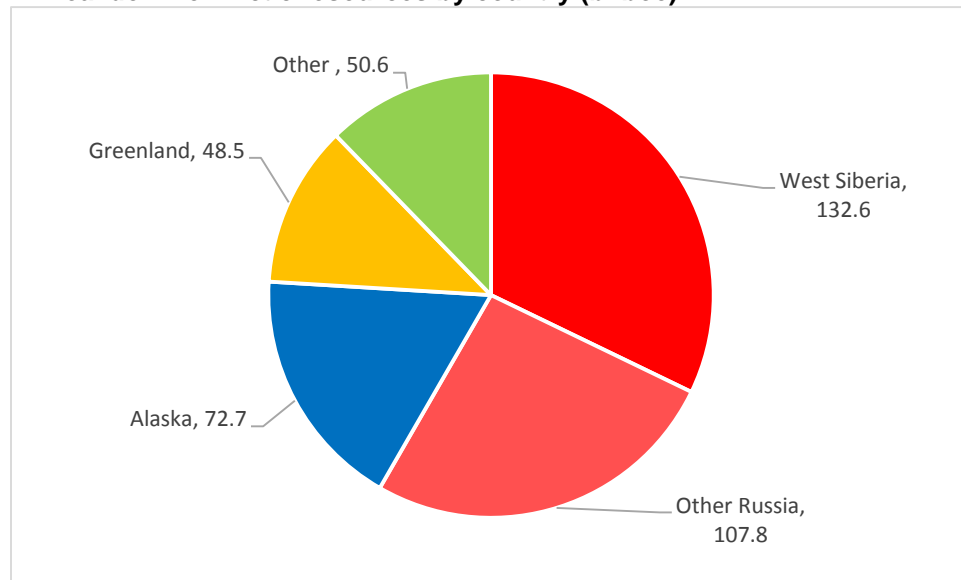
The breakdown by country shows that Russia has by far the largest share of the Arctic resources (see Figure 2 below).¹⁴ The West Siberian shelf alone contains 32% of the total of 412 bnboe of Arctic resources, while other Arctic regions in Russia account for another 26%, meaning the country's overall share is 58%. Of the remaining 42%, Alaska has a share of approximately 18%, Greenland 12% and all other Arctic-region countries, including Norway, 12%. Of course, it must be remembered that the assessment methods are based on geological presumptions, which implies a large degree of uncertainty. Indeed, according to the USGS, the biggest challenge has been the lack of information, as in some areas there are almost no data. For this reason, the assessment is based partly on parallels to analogous geological areas in other parts of the world.¹⁵

¹² Norwegian Petroleum Directorate, <http://www.npd.no/Publikasjoner/Norsk-sokkel/Nr2-2008/Usikkerhet-i-Arktis/>.

¹³ Ibid

¹⁴ Fjærtøft, Lindgren, Loe, Lunden, 2011, Commerciality of Arctic offshore gas: A comparative study of the Snøhvit and burger fields, Geopolitics in the High North Working Paper 2.

Figure 2: Breakdown of Arctic resources by country (bnboe)



Source: Authors' estimate based on USGS data.

Below we discuss the activities in individual countries, beginning with the US, where the first major offshore Arctic activity took place. A common theme is the eagerness of each state to establish itself as an Arctic power and to extend its reach over as broad a swathe as possible in the region – the main argument being that the geological shelves in international waters (defined as more than 200 miles from the established coastline) are connected to their main continental land mass. Thus, although the future of hydrocarbon development in the region will clearly be driven by commercial reality, political dynamics will play a role, too, as countries seek to establish control over transport routes, regional industrial development and potential military sites.



2. Arctic development in the US: Slowed by environmental concerns

Introduction

The story of Arctic development in the US is focused on Alaska, where the main discoveries and production to date have been onshore. The giant Prudhoe Bay field was discovered in 1968; at its peak in the late 1980s, it supplied one quarter of US oil production.¹⁶ However, its output is now just 25% of that level, which could soon have serious consequences for the pipeline infrastructure that transports the oil south as it will be unable to function if the throughput levels drop much lower. This has triggered calls to exploit other areas of Alaska in order to boost overall production, but legislation that protects this wilderness area has restricted activity to date. As a result, the main focus for exploration has been offshore in the Beaufort Sea and Chukchi Sea: numerous leases have been issued since 2003.¹⁷ However, the validity of those leases has been and is still being challenged in the US courts; combined with both the fallout of the Deepwater Horizon disaster in the Gulf of Mexico and Shell's problems with Arctic drilling rigs in 2012, this makes the future of oil exploration in the region very uncertain. While the US appears keen to assert its influence over the Arctic, having announced a 'National Strategy for the Arctic Region' in 2013,¹⁸ it now seems less likely to involve rapid oil and gas development than appeared the case even two to three years ago.

Alaska's role in US oil production

The Prudhoe Bay field on Alaska's North Slope was discovered in 1968 by Humble Oil (a subsidiary of ExxonMobil) and ARCO (now owned by BP). At the time it was believed to contain 9.6 bnbbls of oil, but it has subsequently produced more than 12 bnbbls and remains the largest oil field in the US with an estimated 4 bnbbls of remaining recoverable reserves.¹⁹ Nonetheless, production has been in decline for the past 25 years, having peaked at 2 mmbpd in 1989, and the current rate of output – including production from satellite fields in the Greater Prudhoe Area – is just under 300,000 bpd. That decline has been offset to an extent by Alaska's other smaller oilfields, the majority of which are located on the North Slope, and the combined output of those fields and of Prudhoe Bay means that state's total production in 2013 was 515,000 bpd.²⁰

Figure 3 below puts this figure in the context of overall US oil output and makes clear that the contribution from Alaska has declined not only because of the region's falling output but also because of the recovery of production in the onshore 'Lower 48' states. The main catalyst in this context is the shale revolution, which has led to a dramatic rebound in US onshore production at relatively low risk and cost, compared with the long lead times and high capital expenditure required for Arctic oil E&P. The theme of the overall cost of Arctic oil relative to other new sources of hydrocarbons is one that recurs across all countries in the region; but it is particularly important with regard to the US because of the surge in tight oil (including shale) production over the past

¹⁶ American Petroleum Institute, 'History of Northern Alaskan Petroleum Development', at <http://www.api.org/oil-and-natural-gas-overview/exploration-and-production/alaska/northern-alaska-petroleum-development>.

¹⁷ <http://dog.dnr.alaska.gov/leasing/SaleResults.htm>.

¹⁸ http://www.whitehouse.gov/sites/default/files/docs/nat_arctic_strategy.pdf.

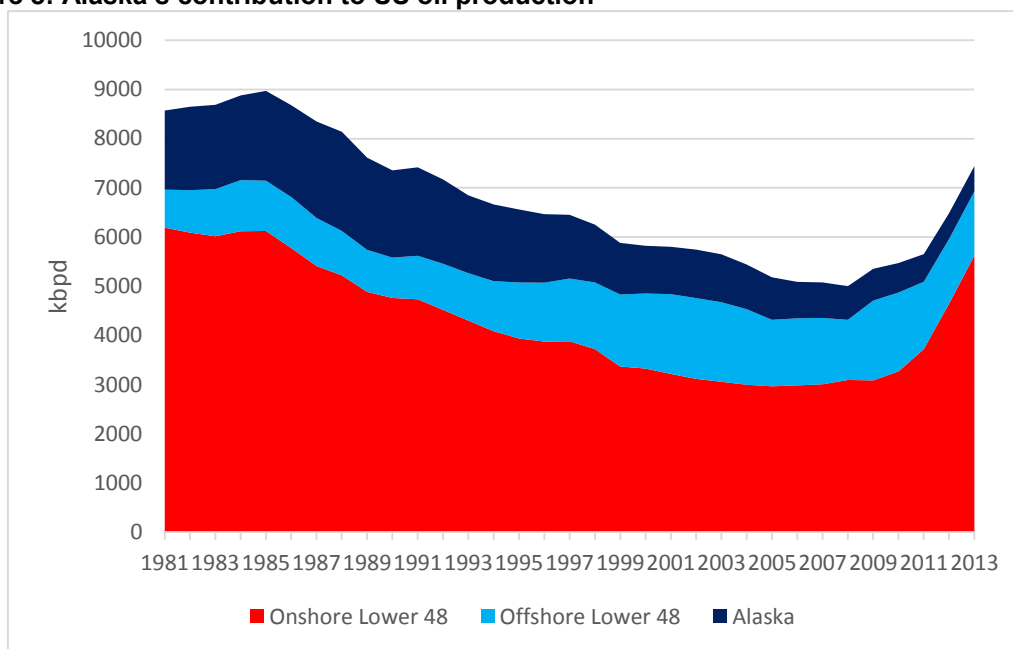
¹⁹ <http://www.bp.com/content/dam/bp/pdf/bp-worldwide/prudhoe-bay-2013.pdf>.

²⁰ <http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPAK2&f=A>.



few years, which saw output jump from around 300,000 bpd in 2005 to 3.25 mmbpd in the fourth quarter of 2013.²¹

Figure 3: Alaska's contribution to US oil production



Source: US Energy Intelligence Agency

The decline in Alaskan oil output has a potentially very significant impact not only on state revenues but also on the future of the entire oil infrastructure in the region. This is owing to the fact that the Trans-Alaska Pipeline System (TAPS), which was built to transport Prudhoe Bay oil south cannot function when throughput falls much below 300,000 bpd because at that level problems such as ice formation and increasing wax settlement become critical.²² As a result, there have been calls to open up new regions in Alaska for oil development in order to sustain overall production. The focus has been on the National Petroleum Reserve – Alaska (NPR) and the Alaska National Wildlife Reserve (ANWR), both of which can be seen in Map 2 below.

Recently, the NPR has been of particular interest because of lease sales in 2008 and 2011 that saw approximately 1.8 million acres (out of a total area of 22.7 million acres) acquired by a various companies for oil exploration. Despite the most recent Energy Intelligence Agency (EIA) estimates of oil resources in the area having been downgraded from the original 10.6 bnbbls to just under 1 bnbbls,²³ ConocoPhillips and Anadarko were especially active purchasers, as they are seeking to tie back any new discoveries to their Alpine field, which is on the nearby North Slope. However, since the lease awards there have been a number of legal cases brought by indigenous tribes and environmental protestors focused on Conoco's plans to drill the CD-5 well on the eastern edge of the reserve.²⁴ Despite the protests, the company plans to move ahead

²¹ Energy Intelligence Agency, 'Tight oil production pushes US crude supply to over 10% of world total',

²² Conley (2013), p. 9.

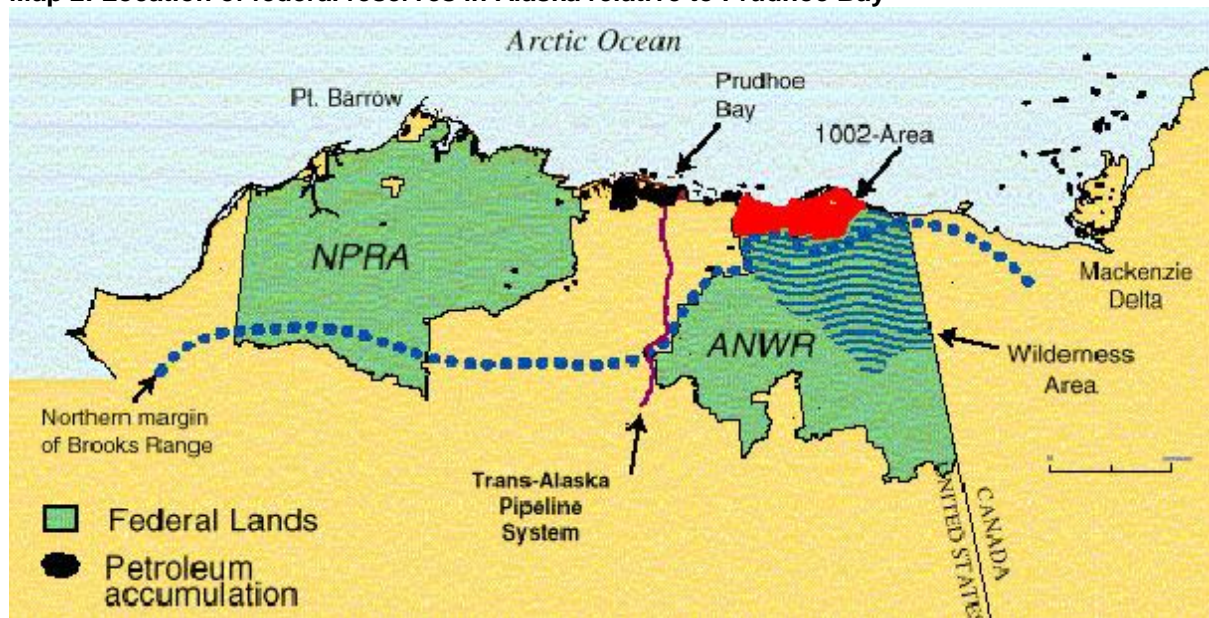
²³ <http://www.blm.gov/ak/st/en/prog/NPR-A.html>.

²⁴ 'Conoco sees construction of CD-5 project in 2014, production in 2015', *Alaska Journal of Commerce*, 25 December 2011.

with drilling in 2014 and to produce first oil in 2015, although peak expected output is a relatively modest 16,000 bpd.²⁵ Further exploration activity in the NPRA is anticipated following the Conoco drilling but is likely to be met by increased opposition and may yield only small discoveries, which will slow, but not halt, the decline in overall Alaskan production.

The ANWR is believed to offer a much greater onshore prize, but this environmentally sensitive wildlife preserve has been under federal protection since 1960. Periodic requests have been made by the oil industry to begin exploration of the 11 bnbbls of oil resources that may lie within the 19 million acres of the ANWR, and Alaskan politicians are generally in favour of development to provide a new boost to the local economy.²⁶ However, such requests have been consistently turned down by the US Senate on environmental grounds (most recently in 2012);²⁷ and it seems unlikely that this view will change in the short to medium term.

Map 2: Location of federal reserves in Alaska relative to Prudhoe Bay



Source: <http://naturalresources.house.gov/anwr/>.

Given that the outlook for Alaska's onshore oil is one either of declining production or of boosting output by awarding leases in environmentally sensitive areas, it would appear that the greatest hope for a recovery in US Arctic oil output lies offshore in the Beaufort Sea and Chukchi Sea. The 2008 USGS survey estimated that Arctic Alaska has a total of 36 bnbbls of oil and natural gas liquid resources and 221 tcf of gas,²⁸ of which the US Bureau of Ocean Energy Management believes that 26 bnbbls of liquids and 131 tcf of gas lie offshore in the two US Arctic seas.²⁹ This would mean not only that the US has the largest Arctic oil resource base but also that more than two-thirds of the liquids are offshore.

²⁵ http://www.conocophillips.com/zmag/SMID_392_FactSheet-Alaska.html.

²⁶ <http://www.cbsnews.com/news/alaska-gov-sean-pannell-seeks-to-reopen-arctic-national-wildlife-refuge-drilling-debate/>.

²⁷ <http://www.adn.com/2012/03/13/2368427/senate-rejects-drilling-in-arctic.html>.

²⁸ USGS (2008).

²⁹ BOEM (2011).



In pursuit of these liquids, a number of leases have been sold over the past decade. Between 2003 and 2007 some 1.3 million acres in the Beaufort Sea were offered in 241 leases and in 2008 a further 2.7 million acres were offered in the Chukchi Sea in 487 leases.³⁰ The Chukchi Sea is estimated to hold more than 15 bnbbbls of the 26 bnbbbls in Alaska's offshore oil resources, which probably explains why \$2.7 billion was spent on leases for acreage in that sea, compared with \$97 million in the Beaufort Sea. Shell was by far the most active player, taking 133 Beaufort Sea leases and 275 Chukchi Sea leases (that is, more than half the leases in the two regions combined) and spending \$2.2 billion in the process. ConocoPhillips was another active player, taking 98 Chukchi Sea leases for \$506 million, while BP, Total and ENI are participants in the Beaufort Sea and ENI, Repsol, Statoil and Iona in the Chukchi Sea.

However, the awarding of those leases has been the catalyst not only for oil exploration activity in Alaska but also for a wave of protests that began as early as 2010, when the Chukchi lease sales were challenged in the US District Court because of concerns related to the National Environmental Policy Act (NEPA).³¹ Initially, the courts agreed that the lease sales did not comply with the NEPA rules, but that decision was overturned in 2011 by the Department of the Interior, which confirmed the lease awards.³² This opened the way for Shell, in particular, to proceed with exploration plans in both the Beaufort Sea and the Chukchi Sea. However, as discussed below, its activities since then, combined with reaction to the Deepwater Horizon oil spill in the Gulf of Mexico, have set back US Arctic oil exploration significantly. Indeed, in January 2014 another court ruling called into question the 2008 lease sales,³³ forcing Shell to postpone indefinitely its Arctic offshore activities in the US.³⁴

Shell's problems in the US Arctic

However, this legal setback was not the only reason for Shell's decision to delay its Arctic exploration in US waters; rather, the decision came on the heels of several operational and legal incidents since 2012. Shell first drilled in the Chukchi and Beaufort seas in the 1970s and 1980s but relinquished its licences after the fall in the oil price in the mid-1980s. The company's massive investment in new licences followed its estimates that new discoveries could produce as much as 1.2 mmbpd in the Chukchi Sea and 600,000 bpd in the Beaufort Sea,³⁵ which would make a significant contribution to its overall oil output (currently 3.2 mmboepd).³⁶

First drilling activity was initially planned for 2010. However, although Shell passed numerous regulatory hurdles, all drilling activity in the region was suspended following the Deepwater Horizon accident in the Gulf of Mexico as the US authorities assessed the implications for offshore drilling around its shores – especially in environmentally sensitive areas such as the Arctic. The suspension was lifted in 2011, but Shell had to pass even more stringent regulatory hurdles to gain approval of its drilling plan for 2012. Among many requirements, the company had to submit details on how to prevent oil spills, how to avoid disturbing native mammals and how to deploy well-capping and spill-containment equipment. At the same time, it had to apply for air

³⁰ <http://dog.dnr.alaska.gov/Leasing/LeaseSales.htm>.

³¹ <http://birds.audubon.org/newsroom/press-releases/2010/federal-court-halts-oil-and-gas-activities-under-chukchi-sea-lease-sale>.

³² <http://www.naturalgasintel.com/articles/87868-interior-affirms-alaska-lease-sale>.

³³ <http://www.nationaljournal.com/energy/court-decision-may-cloud-arctic-drilling-plans-20140122>.

³⁴ *Financial Times*, 'US court delays Shell Arctic drill plans', 23 January 2014.

³⁵ <http://www.ogj.com/articles/print/volume-111/issue-11/exploration-development/alaska-s-oil-crossroads-lucrative-ocs-prize-and-taps.html>.

³⁶ <http://s07.static-shell.com/content/dam/shell-new/local/corporate/corporate/downloads/pdf/investor/investor-highlights/shell-investor-highlights-may-2014.pdf>.



permits for its drilling rig and all the support vessels as well as draw up a plan to monitor and evaluate the movement of all mammals within the vicinity of the leased areas. This lengthy process is one that all companies will now have to undertake before each year's drilling programme, which will escalate the costs of any exploration programme.³⁷

However, after Shell had received all the necessary permits and gained approval for its 2012 drilling programme, which focused on the Burger A prospect in the Chukchi Sea,³⁸ its operational problems began. In July 2012, while being floated out to the well site, the Noble Discoverer drilling rig drifted too close to the shore, nearly running aground and prompting an inspection by the coast guard.³⁹ Following this incident Shell failed to gain approval to start drilling because its oil spill containment equipment did not meet required standards. Then it was told that although drilling could begin, it could go down only to a depth of 1,500 metres, which is well above the oil-bearing zones.⁴⁰ Even this proved too difficult, though: after all the regulatory delays, the company was forced to halt drilling after just one day owing to encroaching ice floes. Finally, one of the oil spill response vessels was damaged, as a result of which the entire drilling programme had to be suspended for the rest of the year.⁴¹

To add to Shell's problems, a second drilling rig, the Kulluk, which had been operating in the Beaufort Sea, ran aground near Alaska's Kodiak Island as it was being towed to Seattle, allegedly for maintenance.⁴² Although no oil was spilled and the rig was successfully re-floated after a two-week operation, the US Environment Protection Agency later issued citations to Shell for multiple permit violations; and the company's cause was further harmed when it was discovered that the rig was being moved to Seattle to avoid Alaskan taxes. Furthermore, although a Department of Interior review of the two 2012 rig incidents concluded that Shell had generally performed in line with safety standards throughout the period in question, a subsequent US Coast Guard enquiry found that the company was guilty of a 'chain of errors' leading up to the Kulluk accident.⁴³ Needless to say, that criticism sparked further approbation from US politicians and led to Shell announcing a halt to its programme for 2013, which has been extended into 2014 because of the possibility of another lawsuit against the company.⁴⁴

Outlook for Alaskan offshore exploration and development

In the wake of Shell's problems and because of the environmental regulatory hurdles that have to be overcome for operations in the Beaufort and Chukchi seas to begin, two other operators have postponed their drilling plans. ConocoPhillips announced in April 2013 that it will not start drilling until 2015 at the earliest, and in September of the same year Statoil announced a one-year delay in its drilling programme, originally due to start in 2014. Both delays could be extended if investigations into Shell's activities are prolonged. In such a case, further activity in the region would not be imminent. Indeed, given the huge costs that would be involved in field development in the region (it is estimated that Shell might have to spend as much as \$180 billion to meet its

³⁷ Conley (2013), pp. 15–16.

³⁸ <http://www.shell.com/global/aboutshell/media/news-and-media-releases/2012/alaska-drilling-update-17092012.html>.

³⁹ *Financial Times*, 'Fresh doubts about Shell's Alaska plans', 12 February 2013.

⁴⁰ *Ibid.*

⁴¹ *Financial Times*, 'Shell's Arctic ambition dented by mishaps', 17 September 2012.

⁴² http://www.washingtonpost.com/national/health-science/shell-abandons-arctic-drilling-in-2013/2013/02/27/32a1c032-8115-11e2-b99e-6baf4e42df_story.html.

⁴³ <http://www.ogj.com/articles/print/volume-112/issue-4a/general-interest/uscg-chain-of-errors-led-to-shell-drilling-unit-running-aground.html>.

⁴⁴ <http://www.reuters.com/article/2013/03/28/us-shell-alaska-idUSBRE92R03120130328>.

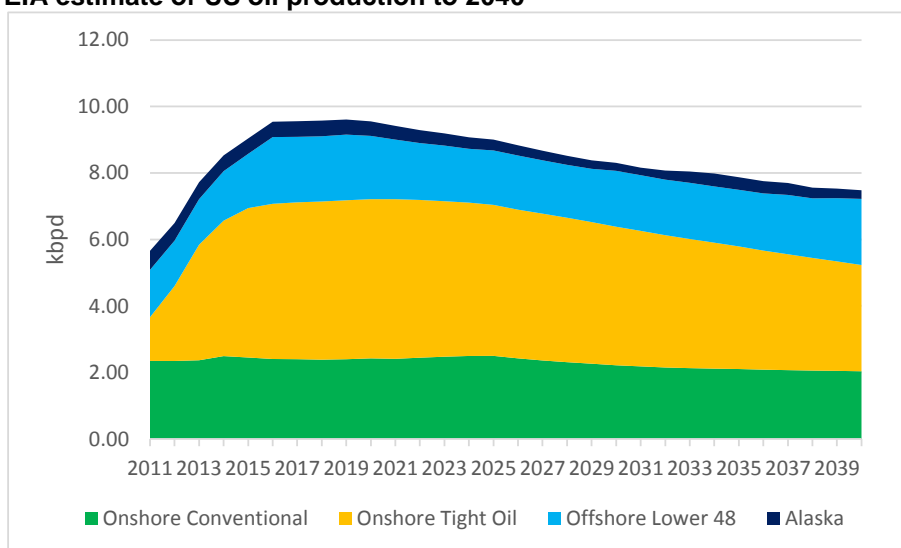


1.8 mmbpd production target), the future of all Alaskan offshore development is being called into question.⁴⁵

While the short-term outlook is somewhat negative, there are a number of positive signs for the longer term. The resource potential, as mentioned above, is very large; moreover, it is mainly oil, which is easier to transport and currently more valuable than gas. In addition, although the climatic conditions are tough, the water depth is relatively shallow (140 feet) and the reservoir pressure is reportedly quite low (3,000 psi) compared with that of some wells in the Gulf of Mexico (which can be 10,000psi or more).⁴⁶ Another important consideration is that the local tax regime is relatively benign, not least following reforms introduced in 2013, which reduced the rate on oil profits in Alaska to a flat 35%, implying an overall government take (including federal income taxes) of 60–62%. This is low by international standards and has already encouraged BP and ConocoPhillips to announce renewed activity under their North Slope licences.

Another long-term positive is that the Alaskan state is clearly very keen for tax revenues from the oil industry to continue and for its pipeline infrastructure to be utilized. If TAPS throughput falls below 300,000 bpd, the pipeline will almost certainly have to close, cutting off the remaining fields in the North Slope area; and offshore production tied back to the North Slope is one potential solution to that problem. Thus there is a large incentive for the regional and federal authorities to maintain oil-company interest in the region. It is, however, a fine balance that could be tipped by another operational incident, a fall in the oil price or the continued rise in tight oil production in the Lower 48 states. Even the most optimistic observers now concede that offshore production in Alaska is unlikely before 2025 and may be delayed to 2030, meaning that output even close to Shell's 1.8 mmbpd aspiration is very unlikely any time before 2040. And in its most recent forecast, the EIA is even more conservative, as can be seen in Figure 4 below: it sees total Alaskan oil production plummeting to 260,000 bpd by 2040, implying the possibility of complete failure in the US sector of the Arctic offshore.

Figure 4: EIA estimate of US oil production to 2040



Source: EIA

⁴⁵ EnergyWire, 'Is Arctic oil exploration dead in the US?' 18 July 2013.

⁴⁶ <http://www.ogj.com/articles/print/volume-111/issue-11/exploration-development/alaska-s-oil-crossroads-lucrative-ocs-prize-and-taps.html>.



3. Greenland: Huge resource potential but no success to date

The history of exploration for oil and gas offshore Greenland stretches back to the 1970s, but despite the huge identified potential for discoveries, the industry to date has been undermined by the difficult environmental conditions and the lack of drilling success. As can be seen from Map 3 below, the island has five main exploration areas: three on the west coast, one on the south coast, and one on the northeast coast; those in the west and south have long periods of ice-free sea conditions but the continuous risk of icebergs, while there are a number of areas in the northeast that have zero days of ice-free conditions and very difficult operating conditions owing to multi-year ice. Average temperatures for the region as a whole range from minus 10 degrees Celsius in the winter to plus 10 degrees Celsius in the summer. Meanwhile, high winds and fog can exacerbate the already difficult working environment.⁴⁷

Such harsh conditions, especially in the east of the country, explain why the focus of the oil and gas industry has traditionally been in the west and the south. During the period 1975–77, 17 initial exploration licences were awarded for drilling offshore West Greenland and five wells were completed, but no discoveries made.⁴⁸ There was little further activity until a decade or so later when a consortium of oil companies called the Kanumas Group, which comprised ExxonMobil, Shell, Statoil, BP, JNOC and Texaco as well as the newly formed Greenland state oil company Nunaoil, was asked to conduct extensive seismic surveys around the island; further licensing was to be based on the results of those surveys.⁴⁹ During the next seven years, companies belonging to the consortium surveyed a total area of 7,000 square km, in return for which they were given preferential rights in future licensing rounds.

The next significant activity was the drilling of the Qulleg-1 well by Shell in 2000,⁵⁰ which was followed by a series of 'open door' licensing periods in which various companies were able to bid for acreage without any time constraints. There was little interest, however, until the process was formalized in 2006/07 with the first official licensing round for the Disko West area; seven licences were awarded, and Cairn Energy was the main winner. In 2010 Cairn subsequently three wells, one of which offered oil and gas shows, whereupon another licensing round took place for acreage in the Baffin Bay area. Cairn drilled another five wells in 2011 but failed to discover any commercial amounts of oil or gas, having spent in total \$1.2 billion on its entire eight-well programme.⁵¹ The company claims to remain confident in the future of the Greenland play, having established 'reservoir-quality sands' in a number of the wells.⁵² Indeed interest in its Greenland acreage was confirmed when Statoil purchased a 30.6% stake in the Pitu block in Baffin Bay in 2012.⁵³

⁴⁷ Greenland Bureau of Minerals and Petroleum, *Weather, Sea and Ice Conditions Offshore Western Greenland*, Copenhagen, 2004.

⁴⁸ Nunaoil Annual Report 2013, p. 4.

⁴⁹ Casey, K., 'Greenland's New Frontier: Oil and Gas Licenses Issued Though Development Likely Years Off' (published on the website of the Arctic Institute), 20 January 2014.

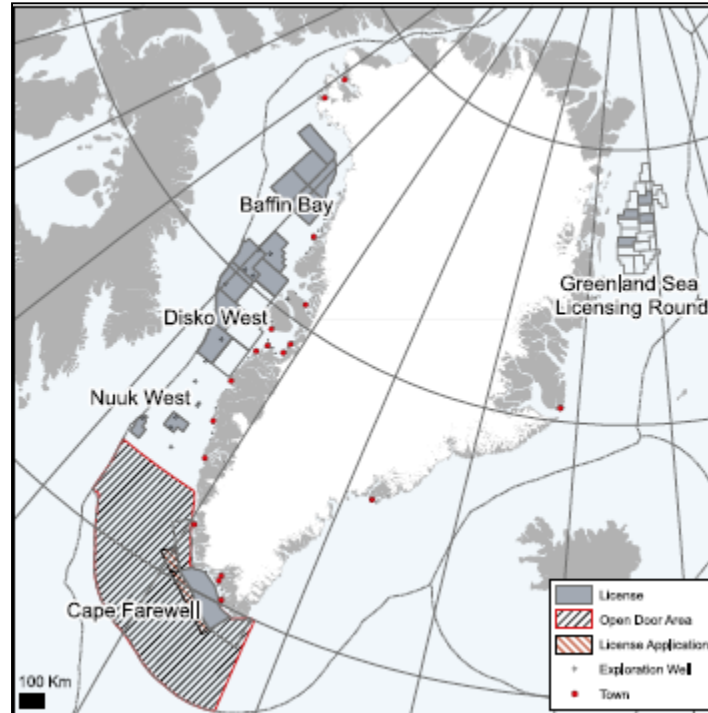
⁵⁰ Nunaoil Annual Report 2013, p. 6.

⁵¹ 'Greenland in transition', *Oil and Gas Journal*, 14 April 2014.

⁵² 'Pushing upstream boundaries in the Arctic', *Petroleum Economist*, 22 February 2012.

⁵³ 'Cairn to partner with Statoil in Greenland oil hunt', Reuters, 23 January 2012.

Map 3: Licence areas offshore Greenland



Source: Nunaoil.

Confidence in the long-term prospectivity of the region was further underlined by the participation of a number of major IOCs in the most recent licensing round, which was completed at the end of 2013.⁵⁴ Four new licences were awarded, and most of the successful companies were original members of the Kanumas Group that had finally exercised their option to bid following the seismic surveys conducted by them in the 1990s. Today, a significant number of IOCs are involved in the region, as can be seen in Table 1 below. According to the Greenland government, a total of 23 offshore licences for petroleum exploration have been awarded:⁵⁵ Cairn Energy holds 11 of those licences, and the other licence-holders are Shell, ConocoPhillips, Statoil, Chevron and DONG. Nunaoil is a partner in each licence and usually has a 12.5% interest.

⁵⁴ 'DONG Energy awarded license in north-east Greenland', *Scandinavian Oil and Gas Magazine*, 23 December 2013.

⁵⁵ <http://www.govmin.gl/index.php/petroleum/current-licences>.

Table 1: Licence ownership in Greenland

Operator	Partners	Licences		
		West Greenland	Northwest Greenland	Northeast Greenland
Cairn	Nunaoil	8	2	
Husky Oil	Nunaoil	2		
PA Resources	Nunaoil	1		
ConocoPhillips	DONG, Nunaoil		1	
Shell	Statoil, GDF Suez, Nunaoil		2	
Cairn	Statoil, Nunaoil		1	
Maersk Oil	Tullow, Nunaoil		1	
ENI	BP, DONG, Nunaoil			2
Statoil	ConocoPhillips, Nunaoil			1
Chevron	Greenland Petroleum, Statoil, Nunaoil			2

Source: Mineral Licence and Safety Authority, Government of Greenland, July 2014.

Many of the IOCs involved in Greenland have expressed their hope of making major oil discoveries in the long term. Statoil, for example, has said that it 'recognizes that this is a challenging area, but it is also potentially prospective',⁵⁶ while Cairn has described the region as having the potential to create 'transformational growth'.⁵⁷ The Arctic resources survey carried out by the USGS in 2008 would appear to support that view: it identified a total of 52 bnboe of potential oil and gas resources in three major basins around the island. Table 2 below, which details the results of that survey, suggests the most prospective area is the recently licensed Greenland Sea, offshore from the northeast coast.

Table 2: Estimates of Greenland's resources

	Oil <i>mmbo</i>	Gas <i>bcf</i>	NGLs <i>mmbo</i>	Total <i>mmboe</i>
Northeast Greenland (Greenland Sea)	8902	86180	8121	31387
West Greenland/Eastern Canada	7274	51818	1153	17063
North Greenland Shared	1350	10207	273	3324
Total	17526	148205	9547	51774

Source: USGS.

However, despite this optimistic outlook, the companies themselves – including Greenland's state oil company Nunaoil – are pragmatic about the likely timescale for any significant production of oil. Recently, after receiving a licence in the northeast of the country, Shell stated that 'even if oil should be found in commercial quantities it will still be 15–20 years before any production can take place'.⁵⁸ Statoil noted that it would 'only move as fast as the technology would allow, following a step-wise process in a long-term project'.⁵⁹ Indeed, the Norwegian state company has even suggested that it may dispose of its licences on the west coast because of their high cost

⁵⁶ 'Pushing upstream boundaries in the Arctic', *Petroleum Economist*, 22 February 2012.

⁵⁷ Cairn Energy, *Analyst Presentation in Greenland*, May 2011, p. 5.

⁵⁸ 'Harsh realities temper explorers' Arctic enthusiasm', *International Oil Daily*, 10 March 2014.

⁵⁹ Ibid.



and risk profile.⁶⁰ Meanwhile, Nunaoil has added its own note of caution, stating that the first wells in northeast Greenland are unlikely to be drilled for another 10 years.⁶¹

The rather uncertain views about the future of the oil sector in Greenland reflects the early stage of its development and the changing nature of the global oil industry. Only 14 offshore wells have been drilled in total around the shores of the island over the past 40 years, none of which has yet found commercial reserves. Meanwhile, the development of tight oil and other unconventional oil and liquids in the US and the opening up of other less environmentally sensitive offshore areas – such as the deep-water Gulf of Mexico, offshore Brazil and offshore West Africa – have created new areas of interest for IOCs. As a result, Greenland, which claimed home rule from Denmark in 1979 and then authority over its oil, gas and mineral resources in 2009, has sought to provide a competitive tax environment: oil revenues are subject only to a 30% corporate profit tax and exploration costs are an expense that can be carried forward indefinitely.⁶²

Nevertheless, despite the eagerness of the authorities to encourage investment in a sector that could provide the revenues to lay the foundation for increased budgetary autonomy from Denmark, there is still opposition from a number of sources. Greenland has a population of only 56,000, many of whom are involved in the fishing and hunting industries; and the local Organization of Fishermen and Hunters has consistently expressed its concerns about the potential impact of the oil industry on the lives of its members.⁶³ On a broader scale, the environmental group Greenpeace has been actively involved in protesting about drilling in Greenland's offshore waters; in 2011 some of its members scaled a Cairn drilling rig,⁶⁴ while it has made a stream of complaints about the possibility of oil spills and other environmental impacts.⁶⁵ Indeed, domestic and international lobby groups have been so persistent that the Greenland government that came to power in March 2013 initially deferred the licensing round in the Greenland Sea. Finally, when that round took place later the same year, the terms for licence-holders were significantly more stringent.⁶⁶

Conclusions on Greenland

In conclusion it seems that, despite the potential for large discoveries offshore Greenland, the likelihood of any significant production within the next 20 years is remote. Very little exploration has been conducted so far, and no well has found commercial reserves. Companies are concerned about high costs and have alternative ventures to pursue in less environmentally sensitive areas. Those that have received licences are realistic about the prospects for short-term development and are likely to face increasing protests from domestic and international lobby groups. Although the Greenland government is offering very competitive tax terms and has ended its short-lived moratorium on licensing, there appears to be little it can do to further encourage the oil industry – other than hope that a major discovery is made soon.

Meanwhile, concerns about the possible impact of industrial activity on Greenland's pristine natural environment have led some companies to ignore the area altogether. Former Total CEO Christophe de Margerie, for example, stated that 'oil on Greenland would be a disaster ... A leak

⁶⁰ 'Statoil considers leaving West Greenland to keep lid on spending', Bloomberg, 21 January 2014.

⁶¹ *International Oil Daily* article of 10 March 2014.

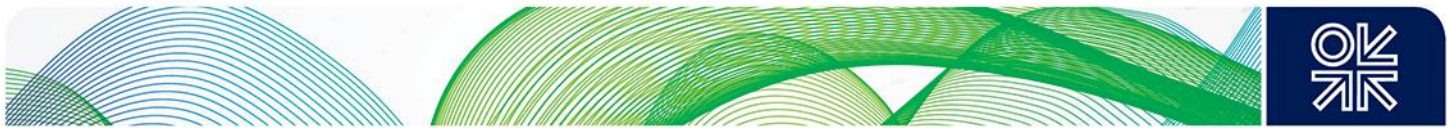
⁶² Ernst & Young, 'Oil and Gas Alert: Greenland – The New Frontier', March 2011.

⁶³ 'The struggle for Greenland's oil', *Financial Times*, 26 August 2011.

⁶⁴ 'Greenland condemns Greenpeace Arctic oil protest', Reuters, 30 May 2011.

⁶⁵ <http://www.greenpeace.org.uk/search/node/greenland>.

⁶⁶ <http://energiaadebate.com/gambling-on-greenland/>.



would do too much damage to the image of the company.’⁶⁷ If many other companies start to take a similar view, it may be many decades before Greenland can generate the oil revenues that could give it financial independence from Denmark.

⁶⁷ ‘Total warns against oil drilling in Arctic’, *Financial Times*, 25 September 2012.



4. Canada: Return to exploration of Arctic waters unlikely before 2020

Canada's first Arctic exploration well was drilled off Melville Island in the North West Territories in the late 1960s in response to the discovery of the supergiant Prudhoe Bay field in Alaska.⁶⁸ Since then many licences have been issued and a number of wells drilled, primarily in the Mackenzie Delta/Beaufort Sea region to the east of the Alaskan North Slope producing area. Although some discoveries have been made, Canadian oil production in the Arctic region has been minimal owing to the changing conditions in the global oil market and the high capital, as well as potential environmental, costs of developing Arctic fields. However, the Canadian government's increased focus on the country's rights to claim sovereignty over larger parts of the Arctic geography, which has led to territorial disputes with all Canada's Arctic neighbours, suggests a new long-term initiative may be in the offing.

Canada's Arctic waters cover three main areas – in the west, north and east of its High North regions (see Map 4 below). In the west, the Beaufort Sea and the Mackenzie Delta form part of the Amerasia Basin, which was identified by the USGS as containing potential resources of 10.2 bnbbls of liquids and 57 tcf (1.6tcm) of gas resources. The Amerasia Basin covers part of the Alaskan offshore, and a continuing border dispute between the US and Canada underlines the potential future importance of the region as an oil and gas province. As regards Canada's oil and gas resources in the area, recent government estimates have suggested a total recoverable oil resource of 10.6 bnbbls and a total gas resource of 56.9 tcf.⁶⁹ For this reason, it is perhaps unsurprising that Canada suggests it has the bigger claim over the region.

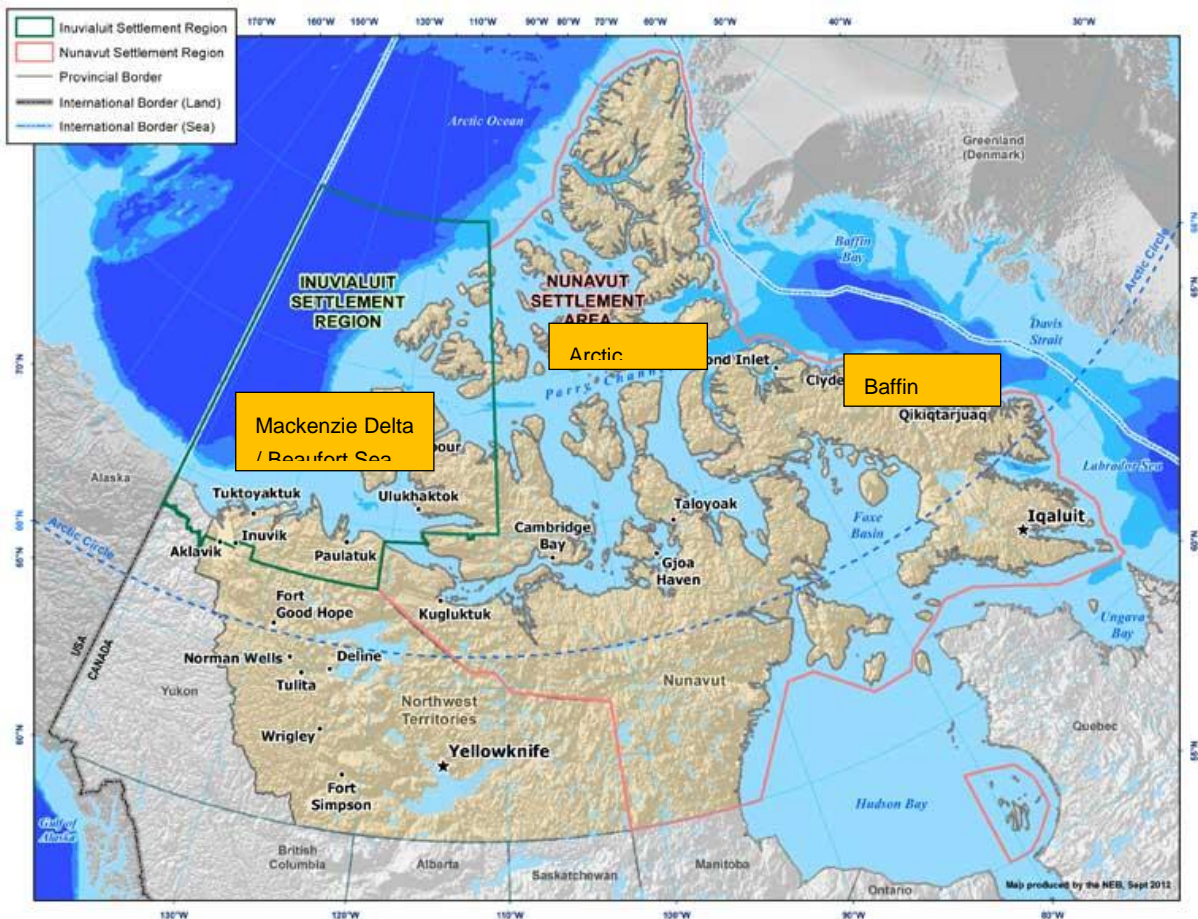
In the east of Canada, the waters of the West Greenland–Eastern Canada offshore area between Greenland and Baffin Island are disputed too – in this case, by Canada and Denmark. The disagreement focuses on Baffin Island itself; but given the USGS estimate that this region contains 9.5 bnbbls of liquid resources and 52 tcf of gas, there is also an offshore element to the debate. A part-resolution reached in 2012 in effect leaves the majority of the resources with Greenland; however, the border has not been finalized in the very far north around Hans Island, leaving room for further negotiation if significant oil and gas is discovered.⁷⁰ Far less controversial is Canada's Arctic archipelago of islands, off its north shore, some of which are included in the USGS's assessment of the Sverdrup Basin. This area contains a much smaller resource base of 1.1 bnbbls of oil and 8.5 tcf of gas.

⁶⁸ 'North America's Arctic drive idles', *Petroleum Economist*, 20 February 2014.

⁶⁹ Aboriginal Affairs and Northern Development Canada, *Oil and Gas Exploration and Development Activity Forecast: Canadian Beaufort Sea 2013–2028*, March 2013, p. 40.

⁷⁰ 'Canada-Denmark border deal leaves island at sea', *Wall Street Journal*, 29 November 2012.

Map 4: Canada's Arctic Offshore



Source: Canadian National Energy Board.

In all, some 125 wells have been drilled in Canada's offshore waters to date, of which 92 have been located in the Beaufort Sea, just over 30 in the Arctic Islands and three in the eastern waters.⁷¹ The bulk of the drilling activity was carried out in the 1970s and 1980s, initially by Panarctic Oil, a partnership between the Canadian government and domestic oil companies, and a number of oil discoveries were made. One of those discoveries, Bent Horn, became the source of Canada's first offshore oil production; but the minimal quantities sent to market (two shipments a year for 11 years [to 1996], during which a total of 2.8 mm bbls were sold) underlines the fact that development in the region faces significant commercial and operational issues.⁷²

Records maintained by the Canadian National Energy Board show that the last well was drilled in the Beaufort Sea in 2005,⁷³ when Devon Energy discovered a 240 mm barrel field at Pakto C-60, which was subsequently deemed uncommercial. Since then, licensing activity has continued and

⁷¹ Ernst & Young (2013), p. 8.

⁷² Petroleum Economist article of 20 February 2014., "North America's Arctic drive idles"

⁷³ Aboriginal Affairs and Northern Development Canada (2013), p. 5.



companies have once again started to regard the area as a prospective opportunity, albeit in the longer term. Nevertheless, of the 152 exploration licences recorded as active in Arctic Canada, only 16 are classified as active exploration licences in the Beaufort Sea⁷⁴ – the main operators being Imperial Oil, BP, Chevron, ConocoPhillips and Franklin Petroleum. Since 2006 seismic activity has been increasing: a number of 2D and 3D surveys have been conducted, and as of 2013 applications for drilling have been stepped up significantly. In particular, an Imperial Oil-led consortium, which includes BP and ExxonMobil and was formed in 2010 after the three companies decided to join forces in the Beaufort Sea, has proposed a plan to explore the Ajurak and Pokak blocks.⁷⁵ Wells drilled in those blocks would be the farthest north in Canadian oil-exploration history and would involve operating in water depths of up to 1,500 metres, compared with less than 100 metres in the case of most of the Beaufort Sea wells to date.

Such extreme water depth, combined with very harsh climatic conditions that result in air temperatures as low as -40 degrees Fahrenheit in winter and just a three-four month window of ice-free conditions in the summer, is a root cause of one of the two main factors that will continue to slow Arctic development in Canada – namely, high costs (the other main factor is regulation owing to the Arctic being an environmentally sensitive region of ecological significance).⁷⁶ The most recently constructed drill-ship suitable for use in the Beaufort Sea, the Stena Drill-Max Ice, cost more than \$1 billion to complete and, as a result, will undoubtedly command some of the highest day-rates in the world. Given estimates that the drilling of one well will take up to three summer seasons, it is perhaps not surprising that some advisers to Imperial, Exxon and BP believe that the proposed well may end up being the most expensive well ever drilled, with a possible cost in the range of \$500 million and \$1 billion. Thus a significant discovery (between 500 mm bbls and 1 bn bbls) is thought to be necessary if any find is to be proved commercial.⁷⁷

Tight safety regulations are in place to protect environment

One of the reasons for the drilling period lasting several years, apart from the small ice-free window, is the fact that one of the major planks of Canadian regulation is its 'same-season relief well' policy.⁷⁸ That policy states that any operator must leave enough time in a drilling season for the drilling of a relief well in the event that an exploration well has a major incident that cannot be contained using existing facilities. Essentially, this implies that if a well has a duration of 90 days it must be completed with enough time for another 90-day well to be drilled before the end of the weather window. In the case of wells in the Beaufort Sea, especially in the more northern areas, this is almost impossible to achieve, given that the entire drilling window is only four months.

In 2009, when Imperial Oil first began to discuss resuming exploration in the region, the issue related to the 'same-season relief well' was raised with the National Energy Board of Canada, the main industry regulator. However, having initially agreed that alternative solutions might be considered if appropriate, the country's entire Arctic offshore regulation was reviewed in the light of the Macondo disaster in the Gulf of Mexico in 2010. Canada's 'Arctic Offshore Drilling Review'⁷⁹ established a series of new requirements for oil and gas companies, including the provision of a range of safety and emergency response plans, proof of sufficient financial resources to cover any compensation claims resulting from an accident and provision of the

⁷⁴ Aboriginal Affairs and Northern Development Canada (2013), p. 31.

⁷⁵ Ebinger et al. (2014), p. 10.

⁷⁶ http://www.wwf.ca/conservation/arctic/oil_exploration/.

⁷⁷ Callow, L. (2013), pp. 32–34.

⁷⁸ <http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/rctcfshdrllngrvw/fnlrprt2011/bckgrndr-eng.html>.

⁷⁹ <http://www.neb-one.gc.ca/clf-nsi/rthnb/pplctnsbfrthnb/rctcfshdrllngrvw/rctcfshdrllngrvw-eng.html>.



'same season relief well'. This last condition is now being challenged by Imperial Oil and other operators that are planning new wells: they claim that it is excessively onerous in the light of new well-capping technology. However, the debate continues and is likely to delay drilling timetables further, especially as environmental lobby groups and local indigenous tribes are arguing for enhanced safety measures.⁸⁰ Indeed, the first well in the area may not be drilled until 2020 at the earliest (despite the fact that some of the exploration licences require activity by 2015). Meanwhile, Imperial has suggested that it may reconsider its entire exploration plan if the relief well condition is not removed.

This potential for a significant delay in further drilling activity in the Canadian Arctic is somewhat at odds with the country's overall regional strategy, which has become more assertive since 2013. In addition to its border disputes with the US and Denmark, which are likely to be resolved in a relatively uncontentious fashion, the Canadian government is now laying claim to sovereignty over the Lomonosov Ridge, which runs all the way to the North Pole and is also being claimed by Russia.⁸¹ While it is widely acknowledged that the exploitation of any resources in the area is unlikely for many decades, Canadian politicians have nevertheless been adamant that the country should claim its long-term rights: Foreign Affairs Minister John Baird stated late last year that, 'We are determined to ensure that all Canadians benefit from the tremendous resources that are to be found in Canada's Far North.'⁸² Thus the Canadian authorities do have at least a long-term ambition to create an option for the development of Arctic hydrocarbon resources, even though in the short to medium term this ambition is likely to be constrained by environmental and other (mainly regulatory) concerns.

Conclusions on the Canadian Arctic

Canada's Arctic waters have significant hydrocarbon potential and have been subject to sporadic exploration activity since the early 1970s. However, environmental concerns, combined with high costs and, to a lesser extent, border disputes, are constraining such activity at present, although there have been recent applications for deep-water drilling by Imperial Oil and others. As a result, it would appear that any new drilling activity is some years away, possibly not until 2020 at the earliest; and even then, the possible \$1billion cost of each well may prove prohibitive. At the same time, the current regulation requiring sufficient time to be left in each drilling season to drill a relief well may likewise prove too much of a disincentive for any company to begin serious exploration. Given all these concerns and given the opportunities for non-conventional activity in the more southern regions of the country, it seems likely that, though laying claim to ever larger portions of the Arctic region, Canada will not begin exploiting its Arctic resources in the near or medium term.

⁸⁰ 'Imperial Oil presses for alternatives to relief well measure in Arctic undersea drilling rules', *Financial Post*, 5 May 2014.

⁸¹ 'Arctic resources claim deadline today for Canada', CBC News, 10 December 2013.

⁸² 'Race to claim High Arctic's oil resources may be a fool's mission', CBC News, 12 December 2013.



5. The Russian Arctic: Increasing offshore activity and international cooperation – unless sanctions persist

Introduction

The geography of Russia's Arctic regions is extensive, covering just over one half of the total coastline of the Arctic Ocean⁸³ and including six seas – the Barents, Pechora, South Kara, Kara, Laptev and Chukchi (the Sea of Okhotsk, in the Russian Far East, is also often referred to as Arctic waters because of the local climatic conditions, although it is, in fact, below the Arctic Circle). Given this geographical spread, it is little surprise that the Russian government regards the Arctic as an area of huge domestic and geopolitical importance. In February 2013 President Vladimir Putin approved a Strategic Programme for Arctic Development to 2020, which outlines the country's vision for the region.⁸⁴ Though relatively general in nature, the programme includes the development of transport and communications infrastructure, the establishment of a scientific and technological sector, the creation of centres for search and rescue, environmental monitoring and the strengthening of the coast guard service. At the same time, it guarantees that the state will support the development of industrial, scientific and energy projects in order to encourage economic growth and social development in the region.

Map 5: The Russian Arctic Seas



Source: EIA.

In reality, the Russian state is likely to focus on the hydrocarbons industry in the short term owing to vast potential resources that have been identified in the Russian Arctic. The USGS estimates that there are some 240 bnboe located in Russian waters out of a total of 412 bnboe in the Arctic

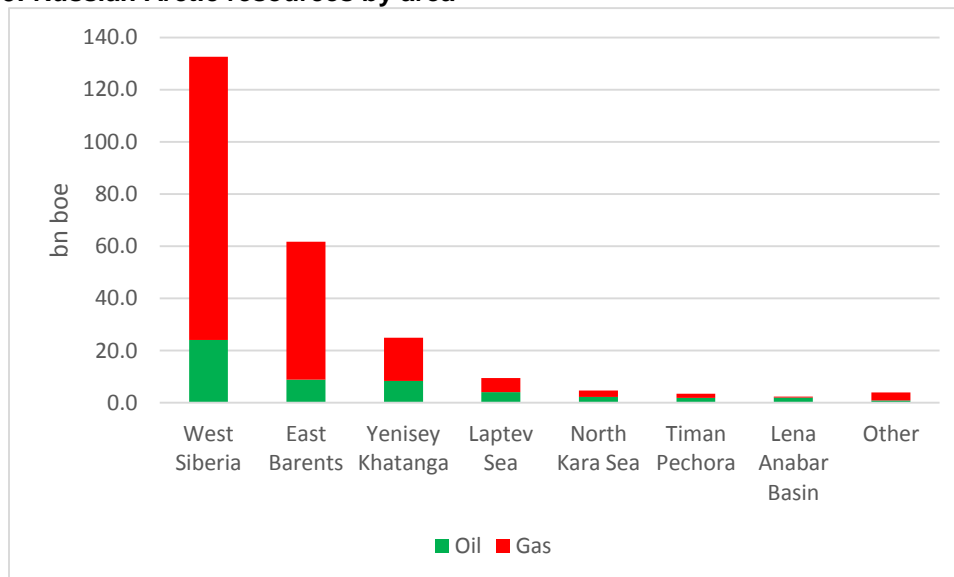
⁸³ According to the *CIA World Factbook*, the coastline of the Arctic Ocean stretches for 45,389 km, while Russia's Arctic coastline is 24,140 km long (see <http://diplomatonline.com/mag/2012/10/the-arctic-country-by-country/>).

⁸⁴ <http://barentsobserver.com/en/arctic/2013/02/russia-launches-program-arctic-development-2020-20-02>.



region as a whole;⁸⁵ according to that estimate, Russia is by far the largest resource holder with 58% of the total (see Figure 1 above). Of the potential Russian Arctic resources, more than half is to be found in the West Siberian basin and, equally important, almost 80% is gas. That leaves just 50 bnbbbls of potential oil resources, highlighting the higher probability of finding gas – which, as discussed below, is a much less desirable outcome, given the current state of the global energy economy.

Figure 5: Russian Arctic resources by area



Source: Author estimates based on data derived from USGS (2008).

It is interesting and perhaps not unexpected that Russian estimates of resources in the Russian Arctic are somewhat higher, although the bias towards gas remains. As can be seen in Figure 6 below, the Russian government estimates a total of 66.6 billion tonnes of oil equivalent (toe), which is equivalent to 471 bnboe; of that total 9 billion toe (64 bnboe) is oil.⁸⁶ The Russian Gas Society is even more optimistic: it estimates total resources at 106 bntoe or 757 bnboe, of which a significantly larger share is oil (just under 300 bnboe) – according to that estimate, gas resources total 69.5 tcm (or 463 bnboe).⁸⁷

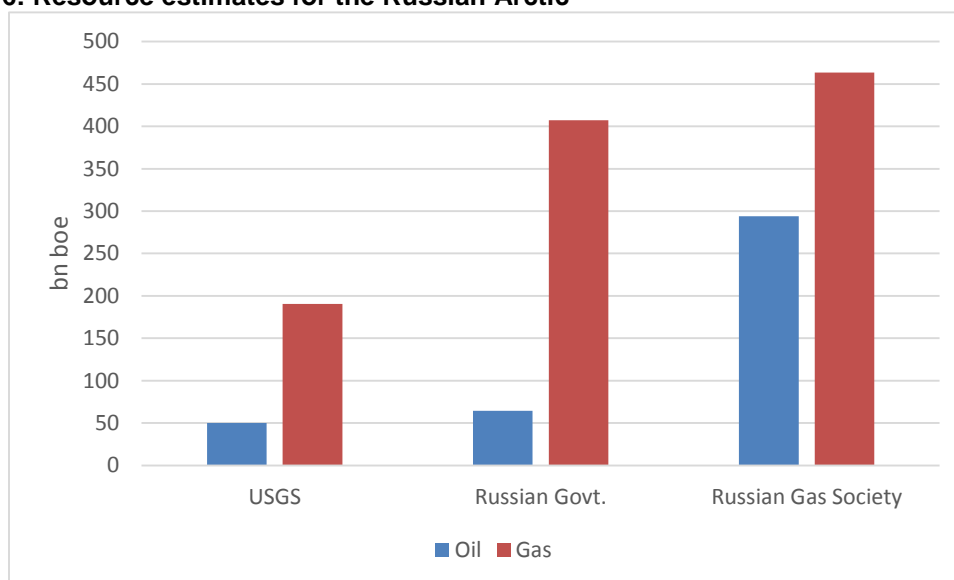
⁸⁵ USGS (2008), p. 4.

⁸⁶ Skolkovo Energy Centre (2012), p. 25.

⁸⁷ 'Russia to play leading role in development of Arctic oil and gas resources', Voice of Russia, 20 April 2014.



Figure 6: Resource estimates for the Russian Arctic



Sources: USGS (2008), Skolkovo Energy Centre (2012) and Voice of Russia.

The exploration for and development of these huge resources could be of vital importance for the Russian economy in the long term not just because of the economic benefits it could bring to the northern regions of the country but also because the generation of oil revenues remains extremely important for the Russian budget.⁸⁸ Furthermore, as output in the core onshore regions of West Siberia and European Russia continues to gradually decline, the exploitation of new green-field areas such as the Arctic and other offshore areas (the Black Sea and the Caspian Sea) as well as of East Siberia and hard-to-recover oil in more unconventional reservoirs will be crucial if Russian oil production is to be maintained at 10 mmbpd or above.

Figure 7 below shows three forecasts of Russian oil production, two of which have been produced by the Russian Government's Energy Commission in the 'General Scheme of Oil Industry Development to 2030'⁸⁹ and the other by the EIA. Both Russian government forecasts show a clear decline in output, while the EIA forecast assumes a number of new areas such as the Arctic offshore will be developed over the next two decades. Thus the pressure on the Russian state companies Rosneft and Gazprom – which under Russian law are the only entities permitted to control the country's offshore licences⁹⁰ – to accelerate the development of the Arctic is intense. Indeed, President Putin himself has emphasized that Russia intends to increase its influence in the Arctic and that one important way to do this is through the exploitation of its hydrocarbon resource base in that region.⁹¹

⁸⁸ Henderson and Pirani (2014), p. 15.

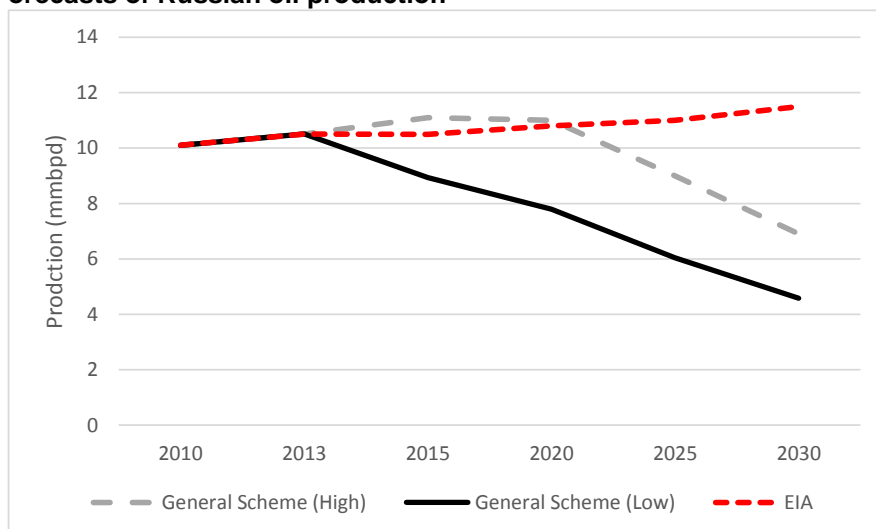
⁸⁹ Henderson (2013), p. 2.

⁹⁰ 'Russia's Energy Strategies in the Arctic', Valdai Discussion Club, 7 January 2013, at <http://valdaiclub.com/economy/59747.html>.

⁹¹ 'Russia's Putin wants beefed up presence in Arctic', Reuters, 21 April 2014.



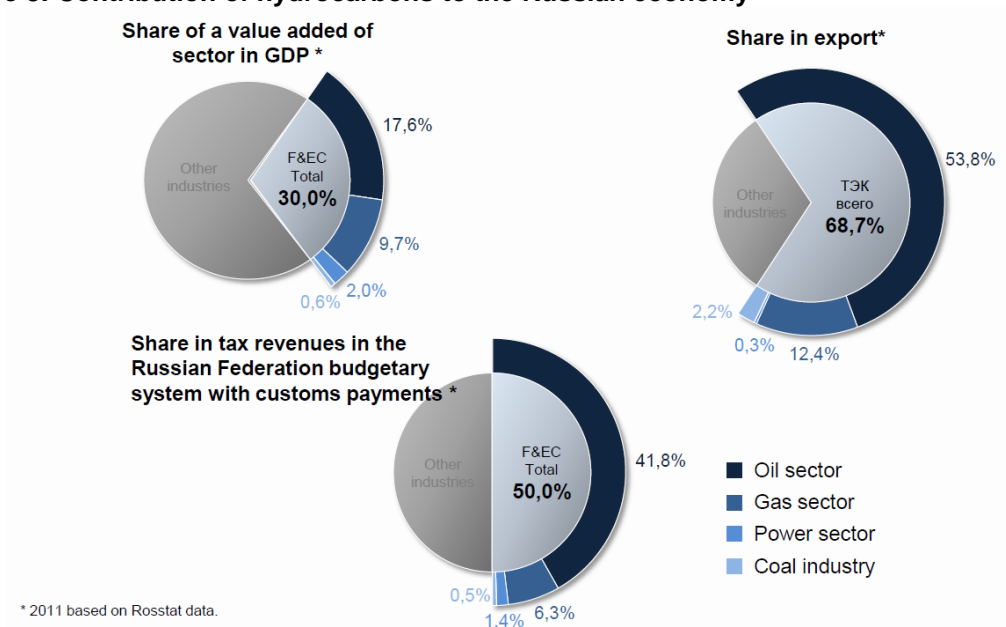
Figure 7: Forecasts of Russian oil production



Sources: Russian government's Energy Commission and EIA.

The overall importance of maintaining Russia's oil production is highlighted by Figure 89, which underlines the contribution that the sector makes to the Russian budget and economy. In 2012 the oil industry alone accounted for almost 18% of GDP, more than 50% of export revenues and 42% of budget revenues. Thus any decline in output (or prices) could have a significant effect on the Russian economy. And this means that the incentive to encourage the development of regions such as the Arctic offshore is very strong.

Figure 8: Contribution of hydrocarbons to the Russian economy



Source: 2012 Rosstat data



History of oil and gas development in the Russian Arctic

Despite the positive estimates of resources on Russia's continental shelf in the Arctic and the strong rationale for active oil and gas exploration and development in the region, the history of such activity does not suggest rapid development. Indeed, the first two major projects undertaken in the region have faced significant delays and cost overruns, while the long-term postponement of another project has highlighted not only the potential for domestic operational problems but also the risk that changes in global market conditions pose for projects in a relatively high-cost region. Of course, the first projects in any new province will always be the most difficult, not least owing to the need to establish new infrastructure. However, the examples described below indicate that development of the Russian Arctic is likely to be a very lengthy and expensive process.

Shtokman– a high-cost gas giant with no market

Shtokman is a giant gas field located in the Russian part of the Barents Sea. It was discovered towards the end of the Soviet era, in 1988, and became one of Russia's key strategic projects as it developed its energy strategy in the 1990s and 2000s. The field has 3.8 tcm of reserves, making it twice as big as the Troll field in Norway, which used to be considered the world's largest offshore gas-producing field,⁹² but its location, 650 km offshore Murmansk in north-western Russia, means it is a very difficult project to progress commercially.

Seven exploration wells were drilled in the 1990s to establish the full extent of reserves at the Shtokman field; but it was not until 2003, when plans were drawn up for a major LNG scheme targeting the Atlantic Basin market, that real progress towards a development plan was made.⁹³ At that time, Gazprom was starting to devise its overall LNG plan for Russia, at the core of which was Shtokman as the main source of gas exports to the US – then a growing market where gas production was in decline and imports were set to increase rapidly. Against this background, the Russian gas monopoly held a tender process for foreign companies to take part in the development of the field; Chevron, ConocoPhillips, Total, Statoil and Norsk Hydro were all short-listed for participation. However, in 2006 Gazprom had decided that it would pursue the project alone, perhaps dissatisfied with the offers made by the IOCs, only to change its mind in 2007 and form a joint operating company, Shtokman Development AG, with Total and Statoil. Gazprom took a 51% stake in that company, while Total and Statoil held 25% and 24%, respectively.⁹⁴

The unique feature of this company was that Gazprom retained full control over the field licence and reserves while the IOCs had access to the cash flows generated from future gas sales. However, despite this innovative arrangement, which satisfied all the parties' need for some control over the assets, disagreement over how to develop a technically challenging field continued and was exacerbated by the 2008/09 financial crisis and the transformation of the US gas market through the emergence of shale gas as a new source of domestic supply. The initial plan for the field envisaged a three-stage development combining LNG and pipeline exports: each stage foresaw the production of 24 bcma of gas to be expanded to a total output of 72 bcma, while further expansion to 95 bcma was seen as possible if market conditions permitted.⁹⁵

Debates between the partners centred on use of subsea technology (favoured by Statoil) or a traditional platform development (Gazprom's preferred option); but even after a compromise had

⁹² Moe (2010), p. 233.

⁹³ Moe (2010), p.234

⁹⁴ <http://www.gazprom.com/about/production/projects/deposits/shp/>.

⁹⁵ Gazprom (2007), p. 129.



been reached on that issue (namely, a subsea development tied back to a floating platform), the high cost of operating in such a remote area, where the risk of icebergs, high waves and strong winds prevailed posing a huge logistical challenge for the construction and support of any new infrastructure, led to regular delays in the project schedule. Initially, the deadline for Final Investment Decision (FID) was 2009, but this was pushed back to 2010 when financing became problematic in the wake of the 2008 economic crisis. Subsequently, it was moved back to 2011 as the opportunity in the US market started to fade and the potential to sell the gas into Europe via the Nord Stream pipeline was undermined by declining European gas demand. By June 2012 a decision had still not been reached and the initial, five-year shareholder agreement at Shtokman Development AG had expired. Statoil decided not to renew its holding in the company, writing off \$336 million in the process.⁹⁶

Gazprom, having become a 75% shareholder in the project, continued to investigate development options with Total, including a new business model focused entirely on LNG exports.⁹⁷ Although a FEED⁹⁸ study was completed, the project was put indefinitely on hold: Gazprom Finance Director Andrei Kruglov suggested that the field 'may be developed by a future generation'.⁹⁹ The rising cost of the project, which had doubled from an initial \$15 billion to \$30–40 billion,¹⁰⁰ as well as the uncertainties of the global gas market and continued disagreement over how to develop a complex field in a harsh environment exemplify the problems of any Arctic development. And in a country such as Russia, those risks are exacerbated by the complexity of domestic politics and the complication of having to manage both vested and commercial interests.¹⁰¹

Prirazlomnoye: The long road to Russia's first Arctic oil production

A similar, but ultimately more successful, story is that of the development of the Prirazlomnoye oil field in the Pechora Sea, on the southern edge of the Barents Sea. It is at this field – discovered one year later than Shtokman, in 1989 – that Russia has ultimately managed to pioneer the first significant offshore Arctic oil production, despite many issues for the partners involved in the project. In 1992 the first plan to bring the field on stream was developed by Rosshelf, a joint venture between Gazprom and a number of Russian contractors.¹⁰² By 1994 BHP had been invited to join the project as the first international participant; but the first signs of potential problems appeared when in the same year Sevmash, which until then had been a military shipyard constructing nuclear submarines, was appointed the main construction contractor. Despite this overtly political decision designed to preserve a key industrial complex in the north of the country, construction of the field infrastructure began in 1995; and the target date for completion was 1998. However, after multiple delays caused by design changes, technical difficulties and construction problems, that target was missed and BHP decided to leave the project.

In 2000 the German company Wintershall emerged as a new foreign partner, but its participation was short-lived: by 2002 it had left the project, along with most of the Russian contractors that had been the original partners in Rosshelf.¹⁰³ At this point, the operating company was changed

⁹⁶ 'Statoil writes off \$336 million Shtokman gas investment', Reuters, 7 August 2012.

⁹⁷ Gazprom (2013), p. 128.

⁹⁸ Front End Engineering and Design

⁹⁹ <http://bellona.org/news/fossil-fuels/gas/2013-06-russias-gazprom-mothballs-shtokman-gas-field-for-future-generations>.

¹⁰⁰ <http://www.2b1stconsulting.com/gazprom-total-and-statoil-redefine-shtokman-and-partnership/>.

¹⁰¹ Henderson (2014), p. 241.

¹⁰² Lunden and Fjaertoft (2012), p. 2.

¹⁰³ Lunden and Fjaertoft (2012), p. 4.



into a 50:50 partnership between Gazprom and the subsidiary Purneftegaz and renamed Sevmorneftegas. Moreover, the development concept had to be thoroughly revised owing to Sevmash's inability to construct a new platform; instead, it was decided to buy an old platform from the Hutton field in the North Sea, which had recently been decommissioned, and convert it for use in the Pechora Sea.¹⁰⁴ The conversion began in 2003, at which time total capital expenditure was estimated at \$1.1 billion and first oil planned for 2005.

However, Sevmash again failed to perform its tasks adequately; and in 2005 the ongoing problems persuaded Rosneft to exit the project, leaving Gazprom as the 100% owner. By 2008 the cost estimate had risen to \$3 billion and the first oil date had been pushed back to 2011. But three years later the amount spent had risen to \$4 billion and first production had been pushed back, yet again, to 2012. By this time, the field's environmental permit had expired, meaning that the bureaucratic process of acquiring another one had to begin; and first oil was postponed to 2013. In the end, it was Gazprom's oil subsidiary, GazpromNeft, which by this time was operating the field, that extracted the first of Prirazlomnoye's 530 mm bbls of reserves, in December 2013; and the initial cargo was exported to the global market in April 2014.¹⁰⁵ Production is expected to peak at 120,000 bpd by 2020, providing a relatively small return for more than 20 years of delay and cost overruns.¹⁰⁶ One small positive, however, is that the field is expected to act as a hub for other discoveries that have been made in the region and are now being appraised for development (see below for further discussion of those discoveries).

Despite its ultimately successful development, Prirazlomnoye exemplifies the difficulties of developing Arctic resources in Russia – including, not least, active campaigning by environmental lobby groups whose aim is to discourage any further developments across the region. In August 2012 Greenpeace activists climbed onto the Prirazlomnoye rig in an attempt to halt operations there;¹⁰⁷ and in September 2013, after a second attempt to stop first oil being produced at the platform, 30 activists were arrested and held in jail in Murmansk for a number of weeks.¹⁰⁸ Although the Greenpeace actions ultimately failed to stop oil being produced from the field, it highlighted the environmental issues involved in hydrocarbon production in the region and showed the lengths to which some organizations will go to undermine the operations of oil companies in the Arctic. Although the Russian company involved, Gazprom, managed to put a stop to the actions using the Russian judicial system, foreign companies finding themselves in the same circumstances may not be prepared to condone a similar approach, meaning that such protests could lead to lengthy delays in implementing projects.

Future activity in the Russian Arctic

Despite the problems encountered in the development of the Shtokman and Prirazlomnoye fields, Russian companies – specifically, Gazprom and Rosneft – continue to pursue opportunities in the Arctic region, encouraged by the Russian government, which has been continuing to issue licences to the two companies on an exclusive basis. Because of the preference for oil over gas, Rosneft has become the leading player: currently, it has a total of 46 offshore licences, of which 25 are located in Russia's Arctic seas.¹⁰⁹ Nevertheless, as noted above, it is Gazprom that

¹⁰⁴ <http://en.itar-tass.com/archive/659173>.

¹⁰⁵ 'First oil from Russian Arctic Shelf loaded', GazpromNeft press release, 18 April 2014.

¹⁰⁶ 'Alexei Miller: Gazprom has pioneered the Arctic shelf development', GazpromNeft press release, 20 December 2013.

¹⁰⁷ <http://www.theguardian.com/environment/2012/aug/24/greenpeace-activists-arctic-oil-russia>.

¹⁰⁸ <http://www.greenpeace.org/international/en/news/Blogs/makingwaves/10-reasons-to-take-action-to-stop-gazproms-pr/blog/46766/>.

¹⁰⁹ Rosneft (2014), pp. 38–39.



provided the first oil production from the region, via its subsidiary GazpromNeft; and the Russian gas company is actively attempting to tie new fields into its existing infrastructure at Prirazlomnoye.

In particular, drilling commenced in June 2014 at the Dolginskoye field, which is located in the Pechora Sea just north of Prirazlomnoye. The GSP Saturn rig has been installed to drill into a relatively shallow reservoir 3,500 feet below the earth's surface; and the international contractors Schlumberger and Weatherford are providing the key technical assistance.¹¹⁰ This continues a trend that has been consistently pursued by Gazprom (and its subsidiaries): namely, conducting the initial exploration and appraisal of offshore fields on a 100% basis, with the use of contractors to provide services, and bringing in foreign partners only when a field development plan is being contemplated. Following the completion of the 2014 well at Dolginskoye, another two wells are planned for 2015;¹¹¹ if these confirm initial estimates of a 1.7 bnbbl oilfield, international companies may be invited to join a consortium to develop the project. Despite the potential for huge reserves, however, current production estimates are relatively modest; Gazprom quoted a figure of 4.8 mmtpa (approximately 100,000 bpd) by 2027,¹¹² underlining the time it will take to develop projects in the Arctic and the difficulty of extracting significant volumes even from larger fields.

Rosneft's partnerships in the Russian Arctic

Despite Gazprom's ultimate success in bringing Prirazlomnoye on stream, Rosneft is rapidly becoming Russia's leading player in the Arctic region, despite the fact that it launched its Arctic strategy only in 2010. Although the company has been active offshore Sakhalin since the early 1990s, at the Sakhalin 1 project, this is not, strictly speaking, in Arctic waters. Moreover, as recently as 2009 Rosneft stated that its strategic priorities on the continental shelf of Russia were in the Black, Azov and Caspian seas, and it made no mention of the Arctic.¹¹³ The real catalyst for the company's move into Russia's northern waters was the negotiations with BP over a strategic alliance in 2010, which led to Rosneft applying for and receiving three licences in the South Kara Sea for the East Prinovozemelsky (EP) 1, 2, and 3 blocks in November of that year.¹¹⁴ The BP deal, which also included a share swap and the promise of international cooperation, ultimately collapsed in May 2011. However, it was superseded, at least from Rosneft's perspective, by a joint venture with ExxonMobil covering the same Arctic blocks as well as unconventional oil licences onshore Russia and some other international assets.¹¹⁵

The main short-term focus of the deal, though, is activity in the South Kara Sea blocks, where the commercial and operational terms have set a precedent for Rosneft's subsequent deals in the region and where the prospect of potentially enormous discoveries has not only excited investors in the companies but has also encouraged the Russian government to offer a new tax framework to encourage the long-term investment that will be required to exploit them. Map 6 shows the licence areas and compares them in size with the entire central and northern North Sea areas of the UK continental shelf, while the table insert shows the extent of the resources that have been initially identified.

¹¹⁰ 'GazpromNeft, Rosneft press ahead in the Arctic', *Nefte Compass*, 3 July 2014.

¹¹¹ *Nefte Compass*, 3 July 2014.

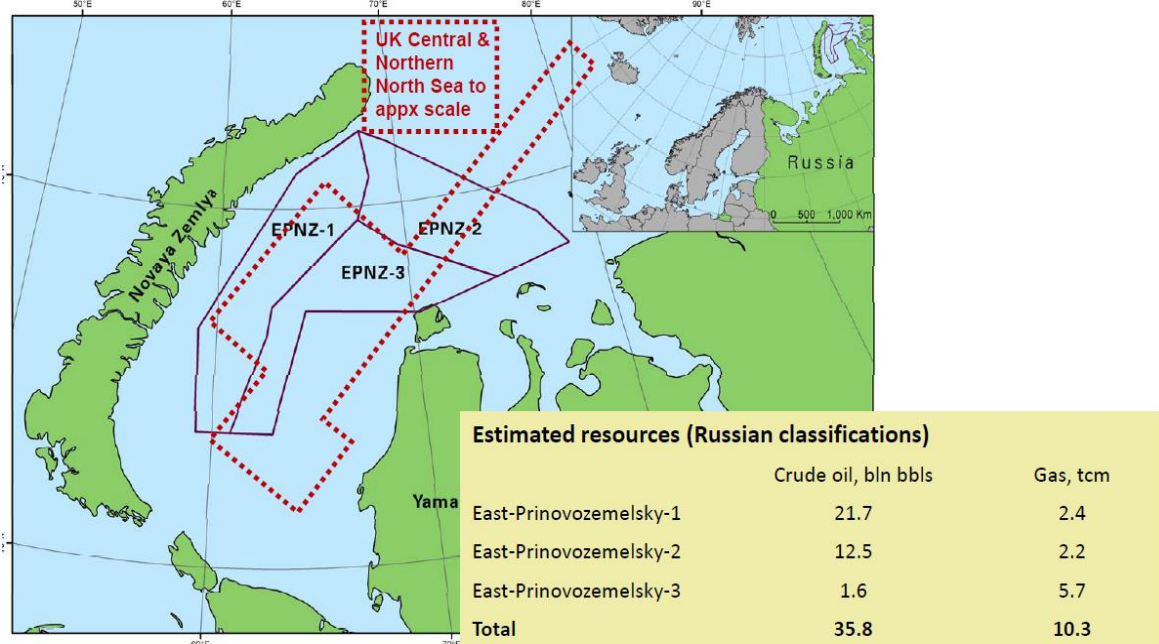
¹¹² Gazprom (2013), p. 128.

¹¹³ Rosneft (2010), p. 38.

¹¹⁴ Rosneft (2011), p. 7.

¹¹⁵ 'Rosneft and ExxonMobil to join forces in the Arctic and Black Sea offshore and enhance cooperation through technology sharing and joint international projects', Rosneft press release, 30 August 2011.

Map 6: East Prinovozemelsky licences in the South Kara Sea



Source: Rosneft.

In accordance with the contractual terms under which the EP blocks will be explored and ultimately developed, the licence remains 100% owned by Rosneft but operated by a company jointly owned by the Russian oil monopoly (66.7%) and ExxonMobil (33.3%). That company will fund all expenditures and receive all cash flows, which will then be shared between the partners in accordance with their equity interest. However, during the exploration phase ExxonMobil will fund the entire cost of the first six wells, which are scheduled to be drilled on the blocks by the end of 2020 at a likely cost of more than \$3 billion.¹¹⁶ Once FID has been taken on any discoveries, the companies will share the costs of development on a pro rata basis, and the joint operating company will control the sale of the oil and the distribution of post-tax profits via dividends. In this way, Rosneft, on behalf of the Russian state, will retain control of the sub-soil resources, while ExxonMobil will have enough control over the revenues from oil production to allow it to book any reserves on its balance sheet. Moreover, Rosneft will benefit from the fact that during the exploration phase it will have, in effect, a risk-free carry, since there will be no expenditures until reserves have been discovered.

However, because of its risk exposure during the exploration phase and the long-term capital investment programme that will be required for any field development, ExxonMobil was not prepared to progress any investment without suitable tax terms. The current tax model for most onshore fields in Russia is one dominated by a royalty on production (mineral extraction tax) and a tax on export revenues (export tax) that, combined, take 66% of revenues at current tax rates, without any allowance for costs or profitability. When corporate and other taxes are added, the tax take increases to more than 70%,¹¹⁷ but most important, there is no allowance for accelerated cost recovery in the early years of production, which has a huge impact on high-cost

¹¹⁶ Henderson (2012), p. 7.

¹¹⁷ Assumes an oil price of \$100/bbl, at which the marginal tax rate is as high as 82% owing to the sliding scale nature of both the mineral extraction tax and the export tax.



projects such as those envisaged in the Arctic offshore. Both Rosneft and ExxonMobil lobbied the Russian government to change the tax rules for offshore fields; those efforts were rewarded in 2012, when the Russian government announced a new profit-based regime in which tax rates are to be based on a rate-of-return calculation that itself is related to the difficulty of developing fields in various regions.

Table 3: Tax rates for Russian offshore

Group	Location	IRR target	Royalty rate
1	Baltic/Azov Seas	16.5%	30%
2	Shallow waters of the Black Sea, Pechora and White Sea, southern part of the Okhotsk Sea, offshore Sakhalin	18.5%	15%
3	Deep waters of the Black Sea, the northern part of the Okhotsk Sea, southern part of the Barents Sea	20.5%	10%
4	Offshore projects in the Arctic (includes Kara Sea), the northern part of the Barents Sea, the Eastern Arctic	22%	5%

Source: Russian Tax Service.

As can be seen from Table 3 above, projects in the Kara Sea are placed in Group 4, which comprises the most complex projects, and are therefore subject to the lowest royalty rate and the highest IRR target. The projects will pay no mineral extraction tax or export tax; as a result, profit tax (at a rate of 20%) will be the main generator of tax revenue for the government, although it will be taken only after costs have been accounted for. Thus companies investing in the Russian offshore, but particularly in the Arctic region, can now have more confidence that they will be able to make a reasonable rate of return assuming they can control costs and deliver projects on time.

Once this tax change had been agreed Rosneft and ExxonMobil not only confirmed their partnership but extended it to cover new licences in the Kara, Laptev and Chukchi seas.¹¹⁸ Seven new blocks have been added to the joint venture (one in the Kara Sea and three each in the Laptev and Chukchi seas), adding 600,000 square km of new exploration acreage in waters to the north and northeast of Russia. Although initial estimates put resources as high as 53 bnbbbls of crude oil and 6.7 tcm of gas,¹¹⁹ it is unrealistic that those blocks can be developed sooner than over the next 20–30 years, given the remoteness of the region and the very preliminary nature of the exploration to date. Nevertheless, the extended deal emphasizes both companies' long-term commitment to the development of Arctic resources in Russia and vindicates President Putin's hope, expressed in 2012 that 'major world corporations will act as partners of Russian companies in the development of offshore projects'.¹²⁰

Meanwhile, the most immediate source of interest is the first well in the original three South Kara Sea blocks, which began in August 2014 on the Universitetskaya prospect of the EP-1 block. The preliminary resource estimates suggest that this one prospect could yield as much as 7–9 bnbbbls of oil, although the fact that the geology of the South Kara Sea is essentially an extension of that of the gas-prone Yamal peninsula highlights the risk of gas rather than oil being discovered. As explained above, a gas discovery at this stage would essentially be worthless not only because of the difficulties of transporting the production to market from such a hostile environment but also because Russia already has an oversupply of gas and ample future supply in much less

¹¹⁸ 'Rosneft and ExxonMobil expand strategic cooperation', Rosneft press release, 13 February 2013.

¹¹⁹ 'Rosneft starts Arctic surveys', Nefte Compass, 10 April 2014.

¹²⁰ 'Russian govt [sic.] decides to zero new shelf project export duty', Interfax, 12 April 2012.



challenging (and therefore less expensive) regions – namely, onshore to the south in the heartland of West Siberia.¹²¹

Despite the obvious risks, which are compounded by the fact that this well will be one of the most expensive ever drilled in the history of the global oil industry – it is estimated to cost \$600–700 million – the West Alpha rig was prepared in the Norwegian yards at Olen, Norway, and commenced operations in the South Kara Sea on schedule, in mid- to late August 2014. The challenges are considerable, however, as the South Kara Sea has an ice-free window of only 45 days, water depths of 40 to 350 metres, ice thickness of 1.2–1.6 metres and winter temperatures that can fall as low as -46 degrees centigrade.¹²² Furthermore, the remoteness of the region means that supply ships will have a minimum four-day journey from Murmansk to the drilling platform; and the proximity of the Russian Arctic National Park around the Novaya Zemlya archipelago means that the highest level of environmental protection measures must be observed.

The well reached its target depth in October 2014; and although difficult weather conditions mean that full testing cannot take place until 2015, preliminary results suggest that a new field has been discovered. Rosneft CEO Igor Sechin has said that preliminary reserves of 338 bcm of gas and 100 mmt of oil (c. 750 mm bbls) have been found at the first well,¹²³ which underlines not only the potential of the area but also the gas-prone nature of the reservoirs. It is too early at this stage to state categorically that this find will be commercial, and the impact of US and EU sanctions (discussed below) may mean that full appraisal is delayed for some time. Nevertheless, it can be said at least that the initial results are encouraging.

However, despite the fact that both Rosneft and ExxonMobil have committed themselves to fulfilling all their environmental obligations, Greenpeace activists, among others, have already started to demand an end to their operations in the Arctic region. In March 2014 climbers from the organization appeared on the West Alpha rig during its initial preparations in Norway;¹²⁴ and in June 2014 there were protests close to the rig as it was being readied in Olen for final embarkation to the drilling site.¹²⁵ As yet, the Greenpeace actions have not elicited any response from the companies, but it is possible that more active protests could create enough negative sentiment to cause some delay, especially now that an oil discovery has been confirmed.

US and EU sanctions: A major issue at present

Despite the initial success of the Universitetskaya-1 well, ExxonMobil has been forced to cut short its operations in the Kara Sea owing to the sanctions imposed on the Russian oil industry – and, more specifically, on Rosneft and its CEO – by the US authorities owing to the on-going Ukraine crisis. Having already placed Igor Sechin on its list of Russian officials banned from entering the US,¹²⁶ in July 2014 the US imposed stricter financial sanctions on Russian energy companies,¹²⁷ including Rosneft. Furthermore, both the US and EU sanctions explicitly targeted various technologies that could be used in the development of Russia's unconventional and Arctic

¹²¹ For a full description of Russia's gas resources and production, see Henderson and Pirani (2014), Chapters 11 and 12.

¹²² 'Exxon drilling plans in Russia', Greenpeace media briefing, 2014.

¹²³ 'Rosneft discovered a new hydrocarbon field in the Kara Sea', Rosneft press release, 27 September 2014.

¹²⁴ 'Activists scale ExxonMobil rig on 25th anniversary of Exxon Valdez', Greenpeace Norway press release, 24 March 2014.

¹²⁵ 'Greenpeace protesting against ExxonMobil's Kara Sea drilling plans', Offshore Energy Today, 11 June 2014.

¹²⁶ 'Rosneft chairman added to US sanctions list', *The Guardian*, 28 April 2014.

¹²⁷ 'Prepay deals in question after Rosneft sanctions', *Financial Times*, 18 July 2014.



resources.¹²⁸ Since ExxonMobil is providing new technology and management expertise as well as funding 100% of the exploration costs at the EP blocks (although this is not directly mentioned in any sanctions list), it immediately found itself in a difficult situation.

Initially, the drilling of the first Universitetskaya well slipped through the sanctions restrictions because all the equipment had been contracted before the 1 August deadline; but that loophole was closed in a second round of sanctions announced on 12 September. The US Treasury Department's Office of Foreign Assets Control and the US Commerce Department's Bureau of Industry and Security issued new orders related to the directives included in Executive Order 13662,¹²⁹ which governs US sanctions against Russia, as well as to US export controls. Those new orders introduced a series of tougher sanctions that appeared to be aimed at undermining the future development of the Russian oil sector as well as continuing to curb the activities of companies with close relations to the Kremlin. In particular, it tightened the rules on US company involvement in projects involving the development of resources in the Arctic, deep-water offshore (defined as a water depth of more than 500 feet or 130 metres) and shale oil and expanding the list of companies facing restrictions on the raising of finance.¹³⁰ Furthermore, US companies were given a 26 September 2014 deadline to cease all activities in the areas identified.

That last directive implied that Exxon would be forced to end its involvement in the well being drilled in the South Kara Sea by that date. Indeed, a US representative confirmed this by commenting 'there is no contract sanctity',¹³¹ which meant that Exxon and other US companies could no longer reference contracts signed before the sanctions were imposed as justification for their activities. Exxon has managed to win one concession – namely, an extension of the 26 September deadline into October in order to ensure the safe plugging of the well; but unless sanctions are lifted in the meantime, it will now find it very difficult indeed to return to complete any testing in 2015.¹³²

As regards the impact of the sanctions on European companies, there is a significant overlap between the EU and US measures given the focus on the Arctic, tight oil and deep-water activities, although the US sanctions have now gone further in terms of the companies named and the directive to halt all current activity. But the EU sanctions have a narrower corporate focus – Rosneft, Transneft and GazpromNeft – and still allow activity in areas where contracts were signed before the original sanctions date of 1 August.¹³³ Interestingly, though, the EU sanctions are tougher in terms of finance raising, as they have reduced the maturity of debt that can be raised to 30 days, in contrast with the 90 days that energy companies are still allowed under US rules. However, despite these differences European companies will no doubt be inhibited in planning any activities covered by the US sanctions, given the possibility of the EU sanctions being expanded to match the US ones at some point. As a result it would seem that any Arctic activity planned by European companies with Rosneft or other Russian partners is unlikely to proceed any more rapidly than Exxon's undertakings in the Kara Sea.

Rosneft's other Arctic partners

As Table 4 below shows, ExxonMobil is not Rosneft's only foreign partner in the Russian Arctic. Activity with other IOCs is planned over the next few years – sanctions permitting – and could

¹²⁸ 'US sanctions not mere trifles for Russia's oil industry', *Financial Times*, 10 August 2014.

¹²⁹ <http://www.treasury.gov/resource-center/sanctions/programs/pages/ukraine.aspx>.

¹³⁰ 'Russia counts cost of sanctions', *Nefte Compass*, 18 September 2014.

¹³¹ 'Fresh sanctions will freeze big foreign oil projects in Russia', *Reuters*, 14 September 2014.

¹³² 'Exxon winds down in Russian Arctic', *Nefte Compass*, 25 September 2014.

¹³³ http://europa.eu/newsroom/highlights/special-coverage/eu_sanctions/index_en.htm.



give a clear indication of the extent to which the region can be expected to lay the foundation of the country's future oil production.

Table 4: Rosneft's partnerships in the Russian Arctic

IOC Partner	Arctic Component	Other Offshore	Total Offshore Resources (gross bn boe)	Other Russian Assets	IOC Stake in Exploration JVs	International Assets
Exxon	3 licences in South Kara Sea, 1 block in Kara Sea, 3 blocks in Laptev Sea, 3 blocks in Chukchi Sea	1 licence in Black Sea	Oil - 46, Gas - 90, Total - 136	Tight oil assets in West Siberia	33.33%	West Texas (unconventional oil), Alberta (unconventional oil), Gulf of Mexico (deep water exploration)
ENI	2 licences in Barents Sea	1 licence in Black Sea	36	None	33.33%	Access of ENI North African assets, other international projects to be discussed
Statoil	1 licence in Barents Sea	3 licences in Sea of Okhotsk (edge of Arctic)	26	North Komsomolsky (heavy oil), Stavropol licence (shale oil)	33.33%	Access to Statoil Norwegian licences in North Sea and Barents Sea
CNPC	1 block in Barents Sea and 2 blocks in Pechora Sea		13		33.33%	Oil sales and pre-purchases through ESPO spur
INPEX		2 blocks in Sea of Okhotsk	12		33.33%	

Sources: Company data, authors' research.

At the time of the finalization of the ExxonMobil deal in April 2012, two other IOCs – Statoil and ENI were concluding similar agreements with Rosneft for licences on the Russian continental shelf.¹³⁴ Although the licence terms and components clearly differed (as can be seen from Table 4 above), many of the details of the deals were based on the ExxonMobil model – that is, the foreign partners have a 33.3% stake and are to fund the exploration phase, while taking other interests in Russia and offering some international reciprocity. Statoil's JV has one licence (Perseevsky) in the Barents Sea, close to the Norwegian-Russian border in the area that was previously disputed by the two countries, and three in the Sea of Okhotsk in the Russian Far East just below the Arctic Circle. The logic of the Norwegian state oil company and the Russian state oil company joining forces to explore neighbouring waters is clear; and Rosneft has now entered a Norwegian licence in the 22nd licensing round.¹³⁵ But Statoil's decision to explore the waters off the Russian Far East is more surprising and less evidently logical but may well be related to the company's desire to deepen its relationship with Rosneft rather than pursue a specific goal in the East.

¹³⁴ Press releases by Rosneft and ExxonMobil on 16 April 2012, by Rosneft and ENI on 25 April 2012 and by Rosneft and Statoil on 5 May 2012.

¹³⁵ 'Rosneft enters Norwegian continental shelf in the Barents Sea following results of 22nd licensing round', Rosneft press release, 13 June 2013.



Meanwhile, ENI's experience in the Norwegian sector, where it operates the Goliat field and has had recent exploration success, made it another obvious candidate for partnership in the Barents Sea, where it has a stake in two licences with Rosneft to the south of the Statoil block. ENI also has a stake in a Black Sea licence, but its real focus is on the Arctic. Indeed, it commenced 2D seismic activity in both the Fedynsky and Central Barents blocks in 2013.¹³⁶ The Fedynsky block appears particularly interesting, since nine prospects have already been identified and, according to the initial estimate, 19 bnboe of potential resources are in place. Future activity under the licence agreement includes a total of 6,500 km of 2D seismic and 1,000 km of 3D seismic by 2018 and one exploration well and one appraisal well by 2020; if initial results are positive, another exploration well is to follow by 2025.¹³⁷ While there is significant potential for major discoveries, it is clear, once again, that progress is likely to be slow – not least since many of the issues that the Shtokman project faced are also relevant as regards this licence. Water depths of 200–350 metres, iceberg risks, strong winds and high waves, combined with the large distances to relevant infrastructure, all make this a very difficult environment on which to work; and it is obvious that this will lengthen the timescale of any future field developments.

ENI's Central Barents block also has significant prospectivity: to date, three prospects have been identified on seismic studies and 7 bnboe of hydrocarbon resources may be in place.¹³⁸ 2D and 3D seismic is proceeding up to 2018 and the drilling of a first well is planned by 2021; a second is to follow by 2026 if the first proves successful. A similar timescale is outlined for Statoil's Perseevsky block to the north of the ENI acreage. 2D seismic commenced earlier this year on prospects that may contain up to 15 bnboe of hydrocarbons; a first well is scheduled to be drilled by 2020. Table 5 below shows the current timetable for seismic and drilling activity at all three of Rosneft's major Arctic JVs (although sanctions could clearly delay these dates significantly) and provides some details of activity in two additional partnerships which Rosneft recently formed with the Asian companies CNPC and INPEX.

As can be seen, only limited data are available for the CNPC and INPEX deals, both of which were signed in 2013. Rosneft's agreement with CNPC was announced in March 2013 and confirmed when Rosneft CEO Igor Sechin travelled to Beijing in May of the same year. Although it is assumed that CNPC will take a 33% stake and pay for initial exploration costs, no specific details of the deal have been released.¹³⁹ Meanwhile, during the same trip in May, Sechin visited Tokyo, where he signed an agreement with INPEX that could see first seismic activity on the Magadan 2 and 3 blocks later this decade before the drilling of a first well in the mid-2020s.¹⁴⁰

¹³⁶ 'Rosneft starts fields seismic prospecting and environmental studies with its partner ENI in the Barents Sea', Rosneft press release, 8 July 2013.

¹³⁷ 'Rosneft and ENI sign completion deed on three offshore projects in Russia', Rosneft press release, 25 April 2012.

¹³⁸ Rosneft press release, 25 April 2012.

¹³⁹ 'China: Rosneft, CNPC Execs sign deal on Arctic Seas', Offshore Energy Today, 30 May 2013.

¹⁴⁰ 'Rosneft, Japan's INPEX in deal to hunt for oil, gas off Russia', Reuters, 29 May 2013.

Table 5: Activity planned in Rosneft's Arctic partnerships

IOC Partner	Licences	Initial Exploration	First Well	Other planned wells	Exploration Expense (\$bn)	Potential development cost (\$bn)	Possible First Oil*
Exxon	East Prinovozomelskiy 1 (Kara Sea)	Seismic 2012-16	2014				2026
	East Prinovozomelskiy 2 (Kara Sea)	Seismic 2012-16	2016			200-300	2028
	East Prinovozomelskiy 3 (Kara Sea)	Seismic 2012-16	2018				2030
	Kara Sea, Laptev Sea and Chukchi Sea Licences	Aerial gravity-magnetic surveys begun in 2014	2025		3.2		
	Tuapse (Black Sea)		2014/15			50	2024
ENI	Fedynsky (Barents)	2D Seismic to 2017, 3D by 2018	2020			57	2032
	Central Barentsevsy Barents)	2D Seismic to 2016, 3D by 2018	2021		2.0		2033
	West Chernomorsky (Black Sea)	Seismic 2012-13	2015/16			50-55	2025
Statoil	Perseevsky (Barents)	2D seismic begins in 2014	2020				2032
	Magadan 1 (Okhotsk)		2016		2.5-3.0*	100	2028
	Lisyansky (Okhotsk)		2017				2029
	Kashevarovsky (Okhotsk)		2020				2032
Total					7.7-8.2	457-562	
CNPC	Zapadno Prinovozemelsky	No data yet. Initial JV agreement signed in March 2013, but yet to be finally confirmed.					
	Yuzhno Russky	No data yet. Initial JV agreement signed in March 2013, but yet to be finally confirmed.					
	Medinsko-Varandeysky	No data yet. Initial JV agreement signed in March 2013, but yet to be finally confirmed.					
INPEX	Magadan 2	Initial seismic 2017/18	2023-5				2035-40
	Magadan 3	Initial seismic 2017/18	2023-5				2035-40

* Author' estimates

Sources: Company data, press reports.

Realistic timetable for first oil would be at least a decade from initial discovery

Table 5 above also includes an estimate of first oil production from Rosneft's three more active joint ventures, on the assumption that the geological potential of the region and the enthusiasm with which IOCs have entered the agreements yield discoveries. The intention is to highlight that, even ignoring the impact of sanctions, the process of moving those discoveries from initial exploration success to first oil is likely to be a lengthy one. Estimating just how long it will take is difficult given that there are very few assets to which a comparison can be made. However, an arguably comparable field is Hibernia, which is in the Arctic region offshore Canada and is operated by an ExxonMobil consortium. The Hibernia field was discovered in 1979 by the 10th well drilled in the basin where it is situated (although exploration in the Grand Banks region off Newfoundland began in the 1960s and the first well in the Jeanne d'Arc basin, where Hibernia is located, was drilled in 1971). A development plan was submitted in 1986 and first production commenced in November 1997, more than 18 years after the field had been discovered and 26 years after first drilling in the surrounding basin. By comparison, it has been suggested that,



following a first exploration well in 2014 in the East Prinovozomelskiy 1 licence, a final investment decision on full field development could be taken in 2016 with first oil in the period 2018-2020.¹⁴¹

Although no exploration wells have yet been completed in the Kara Sea, it would be inaccurate to suggest that the area is completely unexplored since it is essentially on trend with existing discoveries in the West Siberia basin, especially those on the Yamal peninsula, and 2-D seismic has been shot. However, no drilling has yet taken place; therefore, even if one makes the optimistic assumption that the first exploration well is a commercial success (and as discussed, the initial signs are encouraging) and that the time from discovery to first oil could thus be 50% faster than at Hibernia owing to ExxonMobil's experience in the Arctic, it is unlikely that initial production would commence before 2026. Some test oil from appraisal wells might flow before then, but it is hard to imagine a full field development in less than 10–12 years from the first successful exploration well. Of course, this estimate also assumes no significant delay caused by the current US and EU sanctions against Russia, which, as discussed above, do have the potential (as things stand at present) to interrupt the initial exploration programmes at all Rosneft's JVs.

Two relevant developments in neighbouring Norway reinforce this analysis, as does the Sakhalin example in Russia. The Snohvit field, an Arctic LNG development, was discovered in 1984, but first LNG was not produced until 2007. Activity at the field was hampered by various technical and commercial issues that extended the timeline, but it is certainly not inconceivable that such issues could affect any Kara Sea development, given its remote location and geographical challenges. On the other hand, the Ormen Lange gas field, located in the southern section of the Norwegian sea and therefore much easier to develop than any northern Arctic asset, took only 10 years to move from discovery to first production (in 2007), while the Exxon-led Sakhalin 1 project in the Russian Far East, discovered in 1977, began appraisal drilling in 1995 and produced first oil in 2005. This would suggest that a decade is the absolute minimum timescale from first exploration to initial production, although 15 years is a more realistic estimate in the harsh Arctic conditions associated with the key licences in Rosneft's new JVs. Thus it is very unlikely that the first significant oil from Russia's Arctic region will be produced before 2026 – while 2030 is a more realistic target.

Prospects for gas in the Russian Arctic

If oil production from the Russian Arctic appears a long-term prospect only, the outlook for gas seems even more remote, given the current oversupply in the country caused by Gazprom's decision to develop the Yamal peninsula at a time when both domestic and export demand is stagnant and independent producers in Russia are increasing output.¹⁴² However, the investments of Statoil and INPEX in Magadan licences close to Sakhalin Island are one possible outlet for gas, while Gazprom has plans for the development of gas fields in the Ob/Taz Bay to the east of the Yamal peninsula, suggesting that in some cases Arctic gas may not be worthless in Russia.

In the Russian Far East, the Sakhalin 2 project, developed by Shell and now operated and controlled by Gazprom, is currently producing 10.5 mtpa of LNG and marketing that fuel into the Asian gas market, having produced its first gas in February 2009.¹⁴³ Although the offshore field is not in Arctic waters, it is nevertheless ice-bound for a significant part of the year and bears many

¹⁴¹ Comment at joint Exxon-Rosneft investor conference, as quoted in Mamedov, G., 'Rosneft/Exxon alliance outlines long-term opportunities', 19 April 2012, p. 3

¹⁴² Henderson and Pirani (2014), pp. 376–90.

¹⁴³ <http://www.gazprom.com/about/production/projects/lng/sakhalin2/>.



of the other geographical and environmental hallmarks of more northern field developments. For that reason, it is often regarded as an 'Arctic' project by the Russian authorities. Similarly, the development of any new gas in the Magadan blocks could benefit from the favourable tax terms that result from such a classification. If gas is discovered, however, it is unlikely that it would go to the Sakhalin 2 LNG plant, as Rosneft has plans for a competing facility that it intends to build to supply LNG from its Sakhalin 1 fields. Its JV with Exxon plans to bring a stand-alone 5 mtpa plant online by 2018/19,¹⁴⁴ although the cost estimate of \$15billion would suggest that the project will be cost competitive only if it can be expanded. Gas from the Magadan blocks could be the source for such an expansion, allowing the LNG plant to achieve 10–15 mtpa through the addition of one or more trains. The synergy benefits from expansion would improve the commercial outlook of the overall project.

Gazprom also has gas reserves offshore in the Russian Far East: its Sakhalin 3 licence contains the Kirinskoye and South Kirinskoye fields, where recent drilling has revealed reserves estimated at some 750 bcm of gas – in addition to the 600bcm at the existing Sakhalin 2 project.¹⁴⁵ The new Sakhalin 3 reserves could be used to expand the liquefaction plant currently being used by the Sakhalin 2 fields or to supply gas to the proposed Vladivostok LNG plant; in either case, there is a clear route to commercial production if the field development challenges can be overcome.¹⁴⁶

The same is less true of Gazprom's other Arctic offshore gas plans in the Ob/Taz Bay, which lies to the east of the Yamal peninsula. Here the company has plans to develop the Severo-Kamenomyskoye and the Kammenomyskoye-Sea fields and to use the gas to supplement declining production from its onshore supergiants in West Siberia. However, given that demand for Russian gas in Western markets remains stagnant and other domestic producers in Russia are planning to increase output sharply over the next few years, it remains to be seen whether these offshore plans will be implemented on schedule.¹⁴⁷ The example of the Shtokman field, whose development has been indefinitely postponed owing to worsening gas market conditions and the high costs, would appear pertinent for any gas fields located in the northern offshore regions of Russia.

Conclusions on the Russian Arctic

Russia's Arctic region has huge hydrocarbon potential that both the Russian government and the state oil and gas companies are keen to exploit. Tax incentives have been offered, IOCs have been invited to form joint ventures and exploration activity has commenced. In the sub-Arctic waters around Sakhalin Island, production has already commenced, but the more northerly waters appear to pose more significant challenges, suggesting that both oil and gas production may be some way off, despite the current enthusiasm. The remoteness of the region means that costs will be high, while the challenges include not only mitigation of oil spill and other environmental safety risks but also resistance from environmental groups that are keen to halt all hydrocarbons activity in the Arctic. To date, the response of the Russian government to any protests has been robust; but foreign companies, which are essential to the development of the region, may take a different view if the protests continue and become more vociferous.

The impact of IOC decisions is vital because of the project management capacity and the finance that such companies bring. However, both of those benefits are now under threat because of the US and EU sanctions imposed against Russia in response to the Ukraine crisis. Both the Arctic

¹⁴⁴ 'Sakhalin 1 partners outline LNG project goals', Offshore Magazine, 27 May 2014.

¹⁴⁵ <http://www.gazprom.com/about/production/projects/deposits/sakhalin3/>.

¹⁴⁶ Henderson and Pirani (2014), pp. 233–36.

¹⁴⁷ Henderson and Pirani (2014), pp. 314–46.



region and the state oil company Rosneft have been targeted in particular; and although some initial activity has commenced – namely, drilling in the South Kara Sea and seismic activity elsewhere – it now seems clear that this activity will not be able to continue until the more stringent sanctions introduced in September 2014 are lifted. Thus there is a clear risk that all activity could come to a halt if the situation is not resolved. But even if the geopolitical issues are dealt with in the meantime, the handful of examples of other remote and northerly field developments suggest no oil will be produced until at least one decade after any initial discovery has been confirmed as commercially viable, meaning that first oil would be produced no earlier than 2026; however, 2030 is a much more likely target date now that it appears inevitable that sanctions will cause delays.

That said, the Russian Arctic will remain an area of significant interest for both domestic and international oil companies owing to its huge potential and for the Russian government because of the importance, from a geopolitical perspective, of being seen as a leader in one of the world's emerging hydrocarbon provinces.



6. The Norwegian Arctic: High hopes for the Barents Sea

In contrast to Russia, where there are several potential petroleum regions to be developed and large existing onshore reserves of conventional resources, Norway has few alternatives to developing the Arctic offshore shelf if its petroleum era is to continue on a track similar to that of previous decades. Given declining production elsewhere, development of petroleum resources in the Norwegian Barents Sea above the Arctic Circle is considered the essential next horizon in the exploitation of the Norwegian Continental Shelf (NCS). That means it is set to be a key focus area over the coming years.¹⁴⁸

The importance of the petroleum sector to Norway

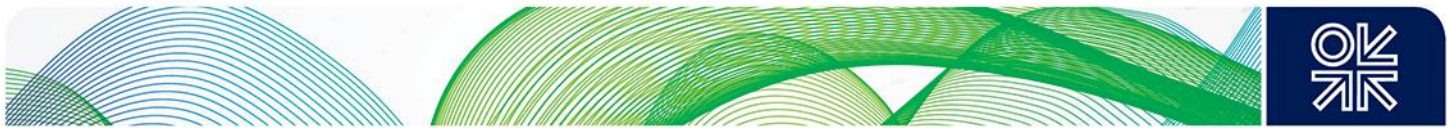
The Norwegian oil sector is the country's largest industry measured in terms of state income, value creation and export revenues. As such, it has been of decisive importance for the country's long-lasting economic growth and the financing of its welfare state.¹⁴⁹ Norway's petroleum history started with the discovery of the Ekofisk field in 1969, and production from the field started in 1971.¹⁵⁰ During the following years, several large discoveries were made in the North Sea, which remains Norway's main oil province today. However, besides the North Sea, the NCS comprises the Northern ocean areas of the Norwegian Sea and the Barents Sea, of which only the latter is entirely located above the Arctic Circle. This study looks only at the Barents Sea, in line with the approach of most other studies of the Norwegian Arctic. However, it is the least developed of all the Norwegian seas: currently there are 60 fields producing oil and gas in the North Sea, 16 in the Norwegian Sea and just one in the Barents Sea¹⁵¹ – namely, the Snøhvit (Snow White) field, providing the only Arctic LNG so far.

¹⁴⁸ *Barents Sea Gas Infrastructure* (2014), Oslo: Gassco (see <http://www.gassco.no/Documents/099808.pdf>).

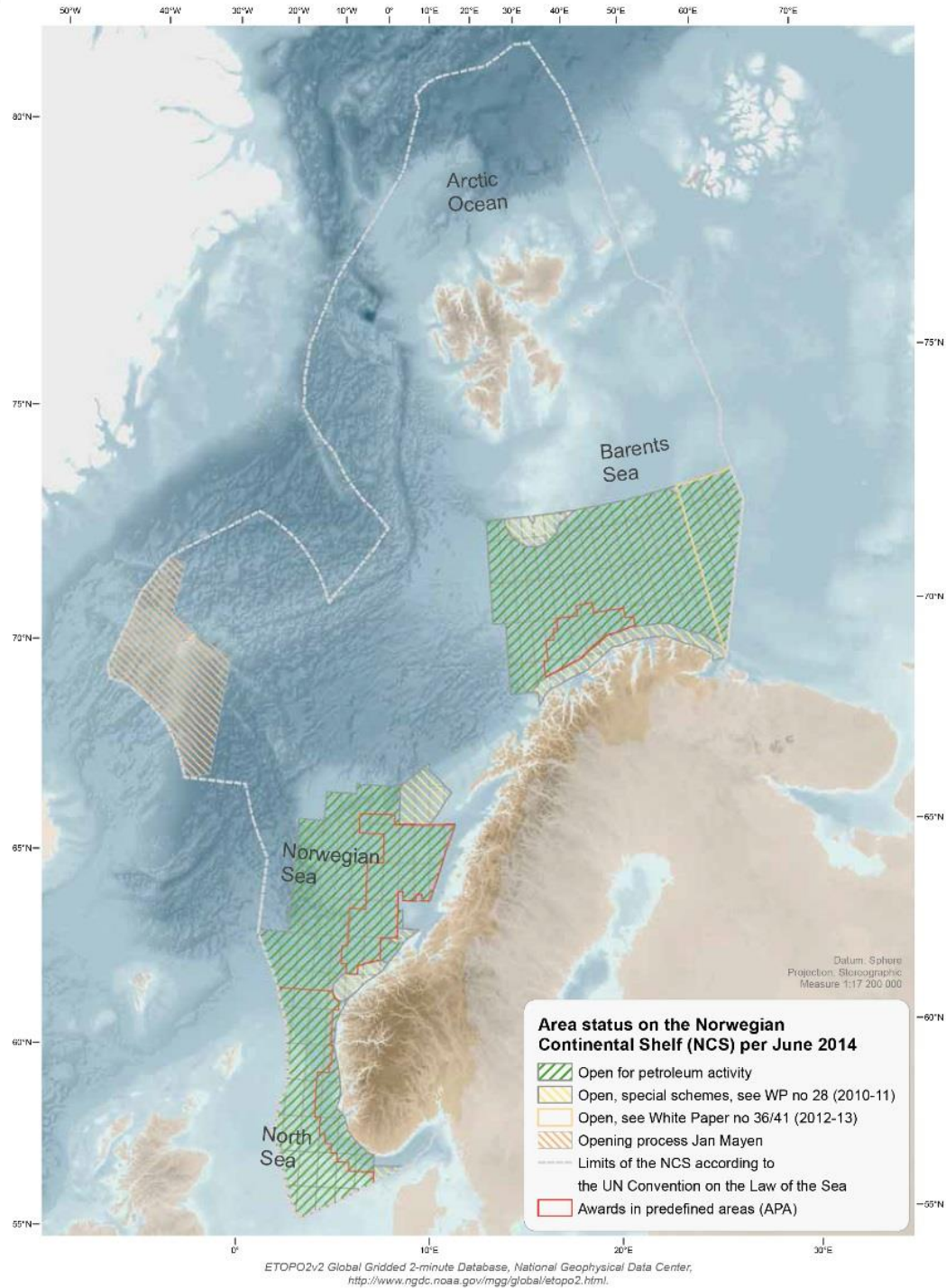
¹⁴⁹ Ministry of Petroleum and Energy (2014), *Facts 2014: The Norwegian Petroleum Sector* (see http://www.regjeringen.no/upload/OED/pdf%20filer/Faktaheftet/Fakta2014OG/Facts_2014_net.pdf).

¹⁵⁰ http://www.regjeringen.no/nb/dep/oed/tema/olje_og_gass/norsk-oljehistorie-pa-5-minutter.html?id=440538.

¹⁵¹ Ministry of Petroleum and Energy (2014), p. 16.



Map 7: Area status on the NCS

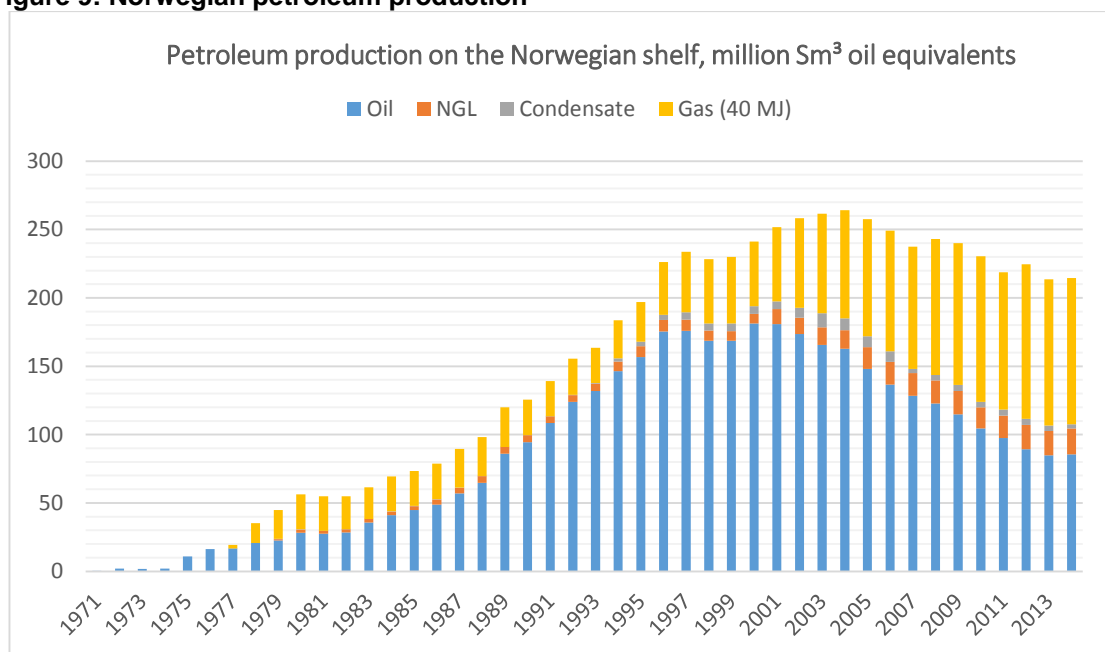


Source: Norwegian Petroleum Directorate (NPD) (2014).



Norwegian oil production peaked in 2001 but has almost halved since then (see Figure 9 below). The drop in production has largely been compensated for in revenue terms by higher oil prices and increased production of natural gas. However, new discoveries and developments are now necessary to make up for falling output from existing fields.

Figure 9: Norwegian petroleum production



Source: NPD (2014).¹⁵²

Norwegian tax system: A significant incentive for oil exploration, albeit on less favourable terms since 2013

Revenues from petroleum produced on the NCS are subject to the high marginal profit tax rate of 78%, which comprises a 28% corporate tax and a 50% special petroleum tax.¹⁵³ However, the Norwegian tax system allows annual refunds of 78% of all direct exploration costs and other generous deductions for investments. The refunds are part of Norway's incentive system for oil-sector development, which, introduced in the early 2000s, aims at attracting companies to the NCS. However, in 2013 the Norwegian government decided to increase the special petroleum tax by 1% while lowering the rate of corporate tax for all companies by the same percentage, in an effort to redress imbalances between the dominant petroleum sector and the overall mainland economy. This means that the marginal tax rate for the petroleum industry has remained the same, but a further change means that certain deductions for investments made by oil and gas companies offshore are now restricted, as a result of which companies in effect pay more tax than before.¹⁵⁴ The long-term impact of those changes remain unclear; but the Norwegian oil company Statoil has already cited them as part of the reason for putting off an investment

¹⁵² <http://www.npd.no/no/Tema/Ressursregnskap-og-analyser/Temaartikler/Norsk-sokkel-i-tall-kart-og-figurer/Petroleumsproduksjon/>

¹⁵³ <http://www.noreco.com/en/investors/analytical-information/tax/norway/>

¹⁵⁴ <http://www.regjeringen.no/en/archive/Stoltenbergs-2nd-Government/Ministry-of-Finance/Nyheter-og-pressemeldinger/pressemeldinger/2013/reduced-uplift-in-the-petroleum-tax-syst.html?id=725999>

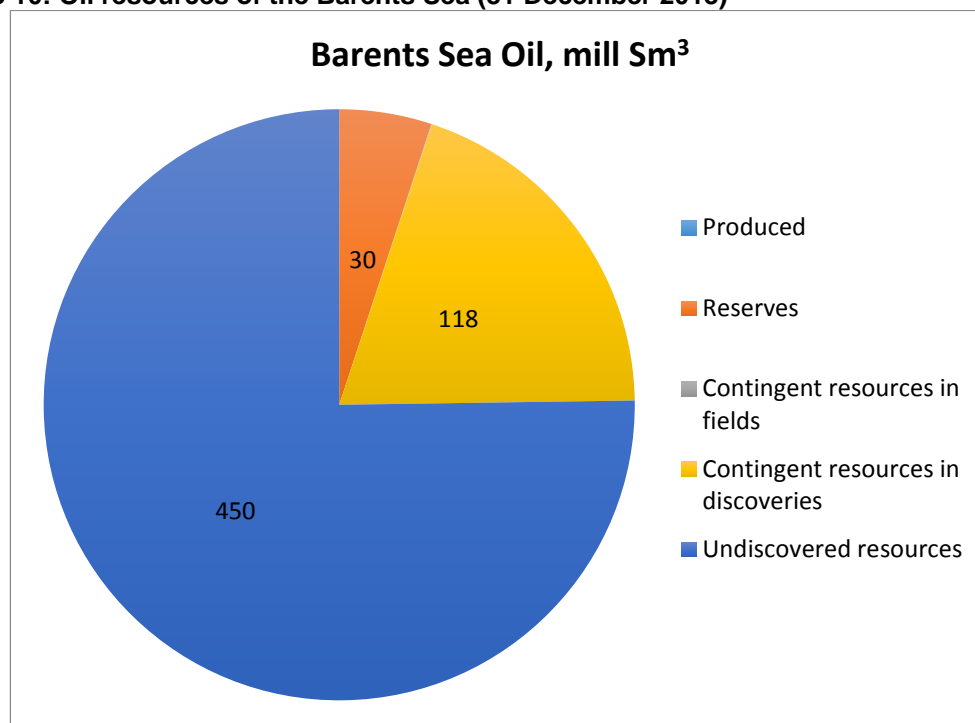


decision in a Barents Sea project, suggesting that they could have a lasting effect on the development of the Norwegian Arctic.¹⁵⁵

The Barents Sea

The Barents Sea, which was first opened for exploration in 1981, is considered an immature petroleum province with huge potential¹⁵⁶ – one whose identified prospects could compensate for falling reserves in the North and Norwegian seas.¹⁵⁷ Companies exploring in the Barents Sea are looking primarily for oil, as it is cheaper and easier to develop than natural gas. However, current estimates of the Barents Sea resources suggest there is more gas than oil in the region (see Figures 10 and 11 Figure 11 below). Nevertheless, it is possible that if any discoveries are large enough, the development of new infrastructure to connect the region to existing pipelines or LNG facilities in Norway may be justified. And this could ultimately be of significance for Norway's position as a secure energy supplier, allowing it to maintain stable gas deliveries to the European market over the long term.

Figure 10: Oil resources of the Barents Sea (31 December 2013)



Source: NPD.¹⁵⁸

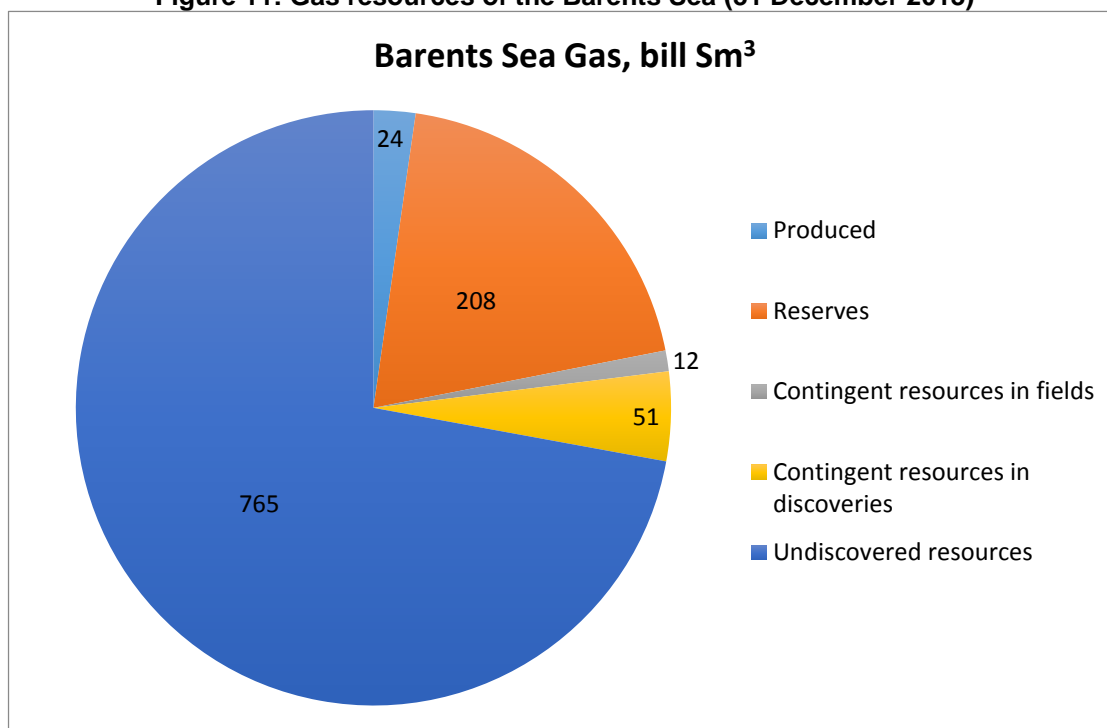
¹⁵⁵ Another main factor is the cost increase in field development.

¹⁵⁶ Katherine Keil, K. (2014), *The role of Arctic hydrocarbons for future energy security*, a NAPSNet Special Report, at <http://nautilus.org/napsnet/napsnet-special-reports/the-role-of-arctic-hydrocarbons-for-future-energy-security/>

¹⁵⁷ Ernst & Young (2013), p. 11.

¹⁵⁸ http://www.regjeringen.no/upload/OED/pdf%20filer/Faktaheftet/Fakta2014OG/Facts_2014_nett.pdf. USE INSTEAD: Ministry of Petroleum and Energy (2014)?

Figure 11: Gas resources of the Barents Sea (31 December 2013)



Source: NPD.¹⁵⁹

A positive factor in terms of anticipated costs is that, in contrast with other parts of the Arctic, the south-western part of the Barents Sea is almost ice-free and conditions are similar to those of the Norwegian and North seas.¹⁶⁰ This means that the weather window for drilling is long. To date, more than 100 wells have been drilled in the Norwegian part of the Barents Sea; Statoil is the operator of most of those wells.¹⁶¹ The Norwegian state-controlled oil company, clearly excited by the prospectivity of the region, has estimated that gross production from oil fields in the Barents Sea could reach 500,000 bpd by 2020 through the development of known fields, the opening up of new fields currently being prepared for development and the new discoveries that are expected to be made.¹⁶²

Table 6 below details the discoveries that have already been made. A number of fields have been discovered in the past three to four years as activity has picked up. The Snohvit, Goliat and Johan Castberg fields dominate the existing reserves base in terms of volume of resources, as these assets have been the subject of comprehensive analysis during their appraisal and development phases. All three are discussed in more detail below.

¹⁵⁹ http://www.regjeringen.no/upload/OED/pdf%20filer/Faktaheftet/Fakta2014OG/Facts_2014_net.pdf.

¹⁶⁰ Økt skipsfart i polhavet p. 26

http://www.regjeringen.no/upload/UD/Vedlegg/Nordomr%C3%A5dene/Oekt_skipsfart_i_Polhavet_rapport.pdf

¹⁶¹ In a presentation at a Statoil conference in June 2014, Dan Tuppen said that Statoil is operator of 72 of the 109 exploration wells drilled to date.

¹⁶² Stolen (2012), quoted by Keil (2014), *The Role of Arctic Hydrocarbons for Future Energy Security*.



Table 6: Reserves and resources in the Barents Sea

Field	Status	Oil	Gas	NGL	Cond.	Total	Year discovered
		(mill Sm3)	(bill Sm3)	(mill tonne)	(mill Sm3)	(mill Sm3)	
Snøhvit ^a	In production	0 (0)	225.1 (201)	7.3 (6.1)	29.1 (24.9)	268.2 (237.5)	1981
Goliat	Under development	30.2	7.3	0.3	0.0	38.1	2000
7122/6–1 (Tornerose)	Planning phase	0.0	3.7	0.0	0.2	3.9	1987
7220/8–1 (Johan Castberg) ^b	Planning phase	78.1	9.7	0.0	0.0	87.7	2011
7120/12–2 (Alke) ^c	Probable, but not clarified	0.0	11.4	0.6	0.4	12.9	1981
7120/1–3 (Gotha)	Not evaluated	15.7	11.9	0.0	0.0	27.5	2013
7120/2–3 S (Skalle)	Not evaluated	0.0	5.0	0.0	0.0	5.0	2011
7219/8–2 (Iskrystall)	Not evaluated	0.0	2.3	0.0	0.2	2.5	2013
7220/7–2 S (Skavl)	Not evaluated	6.1	0.9	0.0	0.0	7.0	2013
7222/11–1 (Langlitinden)	Not evaluated	0.0	6.0	0.0	0.0	6.0	2008
7324/8–1 (Wisting Central)	Not evaluated	17.9	0.7	0.0	0.0	18.6	2013

^a Remaining reserves in parentheses

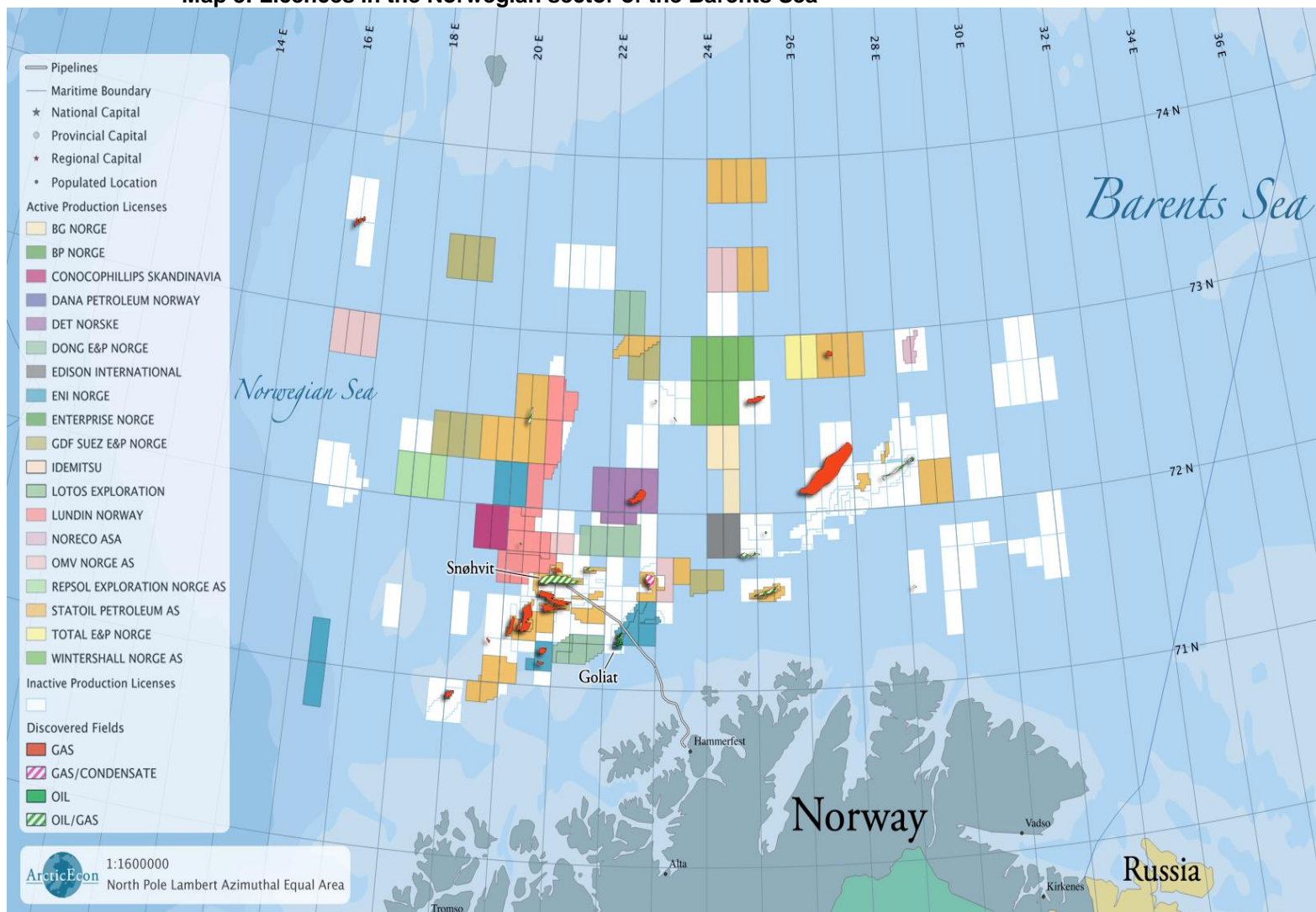
^b Includes 7220/8–1 Skrugard and 7220/7–1 Havis (discovered 2012)

^c Includes 7120/12–3 (discovered 1983)

Source: NPD.



Map 8: Licences in the Norwegian sector of the Barents Sea



Source: ArcticEcon (2012).¹⁶³

Snøhvit – the first discovery in the Barents Sea to be developed

So far, only one field is in operation in the Norwegian sector of the Barents Sea: the natural gas field Snøhvit, which was discovered in 1984 and came on stream in 2007.¹⁶⁴ The field, operated by Statoil, is not only the world's first offshore gas development north of the Arctic Circle but also the first European LNG project.¹⁶⁵ Estimated recoverable reserves are 193 bcm of natural gas, 113 mm bbls of condensate, and 5.1 mmt of natural gas liquids. Estimated production from

¹⁶³ <http://arcticecon.wordpress.com/2012/07/10/barents-sea-oil-gas-license-blocks-and-fields-norway-2012-map/>.

¹⁶⁴ Fakta, 2013, Norsk Petroleumsverksemd

¹⁶⁵ Lunden, Lindgren, Loe, Fjærtøft, (2011), *Commerciality of Arctic offshore gas: A comparative study of the Snøhvit and Burger fields*, Geopolitics in the High North working paper 2, 2011



Snøhvit in 2013 was 5.36 bcm of gas, 0.27 mmt of NGL, and 0.86 mmt of condensate.¹⁶⁶ Snøhvit also has an oil zone, but the development solution chosen for the much bigger gas deposits currently precludes oil production.

Gas from the Snøhvit field, which includes several discoveries and deposits in the Askeladd and Albatross structures,¹⁶⁷ is transported 140 km via undersea pipeline to the Melkøya facility in the municipality of Hammerfest. There it is processed into LNG before being transported to market by purpose-built LNG carriers.¹⁶⁸ The complexity of the project and the difficulty of operating in the Arctic region are underlined by the fact that from the discovery of Snøhvit to the final development decision for the field, a total of 18 years elapsed. Initially, a significant amount of time was spent in search of feasible technological solutions; but by 2001 it had become clear that the project would not have a sound financial basis without a more favourable tax regime. The Norwegian government refused to make any direct changes to the tax system but instead proposed special depreciation rules that encouraged the project sponsors to move ahead. However, just when it appeared that the project would be implemented, the environmentalist organization Bellona filed a state aid complaint with EFTA, in the hope of putting a stop to what it regarded as potentially harmful oil and gas activities in the Arctic region. In response, the Norwegian government tightened the rules surrounding its fiscal incentive by introducing a regional development requirement. The revised proposal stated that only LNG plants in the remote, northernmost parts of the country would be eligible for the reduced depreciation period. Once the law was passed, the Snøhvit partners finally agreed to implement the project.

Since then, there have been significant delays and cost overruns owing to the pioneering nature of the project. These began as early as 2002, just one year after the field development plans had been approved. Even at this early stage, Statoil was forced to announce that a four-month halt to work at the Melkøya gas plant would lead to a cost increase of between NOK500 million and NOK1 billion;¹⁶⁹ three years later, in 2005, the delay in first gas had been extended to eight months while the cost estimate had risen to NOK58 billion – a NOK7 billion increase over the original budget.¹⁷⁰ The main reasons for the postponement continued to relate to the onshore LNG plant, where quality flaws and delays to modules being constructed in Europe meant that work had to be transferred to Norway. In addition, Statoil admitted that the scope of electrical engineering required had been underestimated and that the unique nature of the project had thrown up unexpected challenges to which the company was being forced to respond in a way that it had not been able to predict when the initial investment decision had been made. One positive, though, is that part of the project's value is the transferable experience and expertise accumulated during its implementation and operation. Although the owners decided in October 2012 to put expansion plans on hold until new gas discoveries are made in the area, this experience and expertise could eventually be used in new projects or in expanding the Snøhvit project itself through a second train.¹⁷¹

In addition, the Snøhvit project has shown that it is important to involve the local population in order to gain support for oil and gas projects in the Norwegian Arctic. Many of the indigenous people are keen to see facilities developed onshore so that the local economy is given a boost.

¹⁶⁶ <http://www.npd.no/en/Publications/Facts/Facts-2013/Chapter-10/Snohvit/>.

¹⁶⁷ Fakta, 2013, Norsk Petroleumsverksemd

¹⁶⁸ Ministry of Petroleum and Energy (2014), p. 21.

¹⁶⁹ 'Snøhvit delays resulted in extra costs of up to NOK1 billion', *Nordic Business Report*, August 2002.

¹⁷⁰ 'Increased costs and delayed start for Snøhvit', Statoil stock market announcement, September 2005.

¹⁷¹ http://www.statoil.com/en/NewsAndMedia/News/2012/Pages/02October_Snohvit.aspx.



The Melkøya gas facility is a good example: because it is located only a few kilometres from the centre of Hammerfest, the local population has been able to follow developments closely and become involved in the running of the site and its ancillary services. Statoil frequently arranges visits to the facilities for school children and local groups. Support among the local population for oil and gas development is strong, not least owing to the employment opportunities and the other financial benefits for the population. Moreover, when Snøhvit was developed, the local authorities introduced property taxes, which provide Hammerfest with annual revenues of NOK 155 million from the Melkøya facility. Those funds have been used to take out loans to give the town centre a facelift and build new schools and kindergartens as well as an Arctic cultural centre. As a result of all those efforts, opposition to oil and gas development on environmental grounds has been limited mainly to national organizations, while the indigenous population has remained very supportive of such development in the region.

Goliat – Norway's first Arctic oil field

Norway's first Arctic oil field, Goliat, is currently being developed with a floating production, storage and offloading (FPSO) facility that will eventually be located approximately 85 km northwest of Hammerfest. The licence was awarded in the 'Barents Sea round' of 1997, a project initiated by the Norwegian authorities to increase interest in oil and gas production in the Barents Sea region. Goliat was discovered in 2000 through the first exploration well drilled in the area.¹⁷² The field, operated by ENI, contains approximately 174 mm bbls of oil and 8 bcm of gas.¹⁷³

The start of production was initially planned for 2013, which would have made Goliat the first Arctic oil field in production; however, that accolade was awarded to Prirazlomnoye in Russia, which began producing oil in December 2013 (see above). The start-up date for Goliat is now mid-2015, following a series of delays and significant cost overruns that have seen the overall cost of the project increase from the original estimate of NOK31 billion in 2009 to NOK45 billion in 2014.¹⁷⁴ According to the operator, this is mostly due to the complexity of implementing new and innovative technologies for the production facility, which is custom-made for Arctic conditions, as well as to the marked increase in activities in the supplier industry since the development plan was first presented in 2009, which have led to significantly higher costs and longer delivery times.¹⁷⁵ ENI now hopes that the additional time now available for testing the FPSO in South Korea will translate into a fast ramp-up to production once the production facility is in place in the Barents Sea.

In contrast with Snøhvit, Goliat will have no facilities on land, although ENI's presence is visible in the region through its district operations office in Hammerfest, which has around 50 employees. The project makes other contributions to the local economy, including by using local suppliers and supporting cultural projects. As a result, opposition to oil and gas development has been kept to a minimum, while environmental concerns have been addressed through strict controls administered by the Norwegian authorities and acknowledged as vitally important by the operator and field partners.¹⁷⁶

¹⁷² <http://www.eninorge.com/en/Field-development/Goliat/Facts/>.

¹⁷³ <http://www.eninorge.com/en/News--Media/News-Archive/2013/Goliat-er-godt-utrustet-for-Barentshavet/>.

¹⁷⁴ 'ENI delays Barents Sea Goliat field start-up to mid-2015', *Wall Street Journal*, 16 May 2014.

¹⁷⁵ <http://www.eninorge.com/en/News--Media/News-Archive/2014/Goliat-FPSO-to-depart-Hyundai-yard-in-South-Korea-in-early-2015--/>.

¹⁷⁶ <http://www.eninorge.com/en/Field-development/Goliat/HSE/>.



Johan Castberg field: Initial excitement fades as project difficulties increase

There have been several oil discoveries in the Barents Sea in recent years (see Table 6), with the two largest to date being Skrugard in 2011 followed by Havis in 2012. These two fields – which, combined, are estimated to contain 400–600 mm bbls – have since been given the joint name ‘Johan Castberg’. Statoil is the operator of the Johan Castberg field; it owns a 50% stake, while ENI has a 30% holding and Petoro, representing the Norwegian government, 20%. Johan Castberg is located approximately 100 km north of Snøhvit and 240 km from Melkøya. In February 2013 Statoil announced its estimated production start for the field was 2018. The initial plan was to use a floating production unit from which pipes would transport the oil to a land-based terminal at Veidnes (in the North Cape community), near the small town of Honningsvåg.¹⁷⁷ Statoil marketed the project concept as part of the ‘ambition to transform northern Norway into Norway’s next big petroleum region’.¹⁷⁸ The population in Honningsvåg was euphoric, hoping for employment opportunities and other benefits similar to those offered by Snøhvit at Hammerfest.

However, the project concept selection plans were put on hold in June 2013, following the unexpected increase in the tax rate for petroleum producers and owing to cost-related challenges in an oil sector where the capacity of the oil service industry has already been stretched. Statoil has since drilled for oil and gas in five prospects close to the two original discoveries, but the results have been disappointing. Consequently, the company announced in June 2014 that there is not enough oil to develop the field with a pipeline to land and that it is putting off the final development decision for another year.

Furthermore there is still significant uncertainty over costs. In an analysis by the financial think-tank Carbon Tracker Initiative, the Johan Castberg field is identified as one of the 20 most-expensive planned oil developments in the world. The analysis estimates that the oil price necessary to underpin the economics of the development is between US\$103/bbl and US\$151/bbl. Although other analyses are far more optimistic, cost reduction seems to be a prerequisite for the development to go ahead; as a result, the timing of the production start remains uncertain.¹⁷⁹

The significance of the Barents Sea delimitation agreement between Norway and Russia

In April 2010 it was announced that Norway and Russia had reached a maritime delimitation agreement over an area in the Barents Sea that had been the subject of territorial dispute for almost 40 years.¹⁸⁰ That announcement was made during a visit to Norway by then Russian President Dmitry Medvedev, opening up new opportunities for petroleum development in the Barents Sea. It was based on a compromise between the Norwegian and Russian claims whereby the previously disputed area was divided into two equal parts (see Map 9 below).

¹⁷⁷ Økt skipsfart i Polhavet p. 28.

¹⁷⁸ Økt skipsfart i Polhavet

http://www.regjeringen.no/upload/UD/Vedlegg/Nordomr%C3%A5dene/Oekt_skipsfart_i_Polhavet_rapport.pdf

¹⁷⁹ <http://e24.no/energi/statoil/ny-rapport-saa-dyr-kan-oljen-paa-johan-castberg-bli/23276723>.

¹⁸⁰ <http://barentsobserver.com/en/sections/spotlights/norway-and-russia-sign-maritime-delimitation-agreement>.

Map 9: The 2011 Barents Sea delimitation agreement between Norway and Russia



Source: BBC¹⁸¹ and UNEP.

The agreement was signed in September 2010 by the Norwegian and Russian foreign ministers, Jonas Gahr Støre and Sergey Lavrov, and ratified in 2011. In Russia opinions about the accord have been mixed; some think that Russia has ‘given away’ almost 90,000 square meters to Norway, and there have been proposals that Russia should ‘take back’ the area.¹⁸² In Norway the agreement was hailed as a great diplomatic achievement – the general view being that it was important not to have any unresolved border disputes with a much larger neighbour. But for the oil and gas industry, another issue was even more significant: as long as the border dispute was ongoing, Norway and Russia (previously the Soviet Union) had agreed not to carry out exploration activities in the area.¹⁸³ As soon as the delimitation agreement was ratified, seismic work began on the Norwegian side. Under the agreement, each country has the right to develop oil and gas on its side of the border. In the case of Norway, this means that the area is governed by the same regulatory framework as the rest of the NCS.¹⁸⁴

The delimitation agreement also includes an annex regulating the unitization of potential trans-boundary hydrocarbon deposits, based on analogues from the North Sea.¹⁸⁵ The parties are required to reach agreement on the joint exploitation of deposits that extend into the continental

¹⁸¹ <http://www.bbc.co.uk/news/business-11299024>.

¹⁸² See Hønneland, G. (2014), *Arctic Politics, the Law of the Sea and Russian Identity*. Basingstoke: Palgrave Macmillan.

¹⁸³ Fjærtøft and Loe, (2011), “Norway still dependent on Russia for Petroleum Development in the Former Area of Overlapping Claims”

¹⁸⁴ Ibid.

¹⁸⁵ A full English translation of the text of the delimitation agreement can be found here: http://www.regjeringen.no/upload/ud/vedlegg/folkerett/avtale_engelsk.pdf



shelf of the other country, and no party may start production from such deposits unilaterally.¹⁸⁶ This means that potential developments on the Norwegian side could be delayed or halted by Russia, which might have a different time perspective on exploitation. Furthermore, any big cross-boundary discovery will require extensive Norwegian-Russian cooperation and joint development in order to reach the critical volumes needed to make the discovery commercial. And common solutions for infrastructure development will have to be found too.

Blocks in the new area are being made available in the 23rd licensing round (for more details, see the next section). Meanwhile, several Norwegian-Russian cooperation agreements for other areas of the Norwegian section of the Barents Sea have been signed, suggesting there is potential for future cooperation. For example, LUKOIL, in partnership with Centrica and North Energy, was awarded participation in two licences in the 22nd licensing round,¹⁸⁷ while Rosneft was awarded a 20% interest in Licence No. PL713 in partnership with Statoil. Drilling of the first well under the Rosneft-Statoil licence was planned to start in September 2014 but was delayed when Greenpeace filed a complaint with the Norwegian Environment Agency, highlighting once again the sensitive issues surrounding oil activity in the Norwegian Arctic.¹⁸⁸ The well has the potential to add reserves to the Johan Castberg field development as it is located nearby.¹⁸⁹

NCS 23rd licensing round

In 2013, two years after the ratification of the delimitation agreement with Russia, the south-eastern part of the Norwegian Barents Sea was opened for petroleum activity in the 23rd licensing round. In total, 40 Norwegian and international oil companies have nominated blocks they would like to be included in the round. Out of a total of 160 blocks, 20 are located in the Norwegian Sea and 140 in the Barents Sea;¹⁹⁰ 86 blocks were nominated by two or more oil companies, and in particular there was considerable interest in the area bordering Russia.¹⁹¹

However, since the timeframe for licensing rounds in Norway is usually at least two years – including the nomination of the blocks, a public consultation process and the final decision being taken about the awards¹⁹² – it is unlikely that any announcement will be made before the end of the second quarter of 2015; nor can it be ruled out that it will be delayed, given the environmental sensitivity of many areas. Indeed, there have already been calls for some of the blocks to be removed from the licensing round;¹⁹³ if those calls are heeded, the delay could be extended into 2016. For their part, the Norwegian authorities estimate that a large early discovery in the southeastern part of the Barents Sea could not be developed until the mid-2020s at the earliest.¹⁹⁴

¹⁸⁶ Fjærtøft and Loe, (2011), “Norway still dependent on Russia for Petroleum Development in the Former Area of Overlapping Claims”

¹⁸⁷ ‘LUKOIL awarded two licences in Norway Sector of Barents Sea’, LUKOIL press release, 13 June 2013.

¹⁸⁸ ‘Statoil, Rosneft Arctic well off Norway held up by Greenpeace’, Bloomberg, 8 September 2014.

¹⁸⁹ ‘Rosneft enters Norwegian Continental Shelf in the Barents Seas following 22nd licensing round’, Rosneft press release, 13 June 2013.

¹⁹⁰ <http://www.regjeringen.no/en/dep/oed/press-center/press-releases/2014/23-konsesjonsrunde---nominasjon.html?id=749596>.

¹⁹¹ <http://www.regjeringen.no/en/dep/oed/press-center/press-releases/2014/23-konsesjonsrunde---nominasjon.html?id=749596>.

¹⁹² <http://fb.eage.org/publication/content?id=71510>.

¹⁹³ ‘Norway should pull Arctic oil blocks from next awards, NGOs say’, Bloomberg, 4 April 2014.

¹⁹⁴ <http://www.regjeringen.no/nb/dep/oed/pressesenter/pressemeldinger/2014/23-konsesjonsrunde---nominasjon.html?id=749596>.



Lack of gas transport infrastructure could be a major issue

Another key issue is that the Norwegian sector of the Barents Sea is expected to be mainly gas bearing. As a result, there will be significant challenges related to the lack of gas transport infrastructure. Today there is only limited capacity for transporting gas from the LNG plant in Melkøya; unless new solutions are found, Snøhvit will not be depleted before the mid-2040s, and there will be no spare capacity to transport gas from potential new finds in the area.¹⁹⁵ Two options are available: invest in an additional train for LNG at Melkøya or build a gas pipeline connecting supply from the Barents Sea to the transport infrastructure farther south in Norway.¹⁹⁶ While a study published in June 2014 concludes that the Barents Sea could play a central role in sustaining Norwegian gas production,¹⁹⁷ discoveries to date have not been big enough to support investment in new gas infrastructure for the region; and it is clear that more resources must be proved in order to lay a sound economic foundation for the construction of a new pipeline or an LNG facility.¹⁹⁸ However, any further delay in such investment could inhibit Norway's gas development as the incentive to explore for and produce gas would only increase if infrastructure were in place. A transport solution will also be needed for APG from oil fields,¹⁹⁹ and this similarly raises the fear that a lack of gas transport solutions could delay the development of oil production as well. As the timescale for the construction of a new pipeline is large, a decision would have to be made soon if the pipeline were to be available by the early 2020s. Finally, a Norwegian pipeline solution may be of interest to Russia as it considers the development of its share of the region, although there would be a major question mark over who should pay for it, as no individual discovery has yet been big enough to cover the cost on its own.²⁰⁰

Local support and environmental issues

There is strong local support for petroleum development in the Finnmark, Norway's most northerly county, whose economy has been struggling as the fishing industry – traditionally the mainstay of the local economy – has been substantially reduced over the past few decades. As noted above, the location of the Snøhvit LNG facilities onshore has been welcomed; and the local community in Honningsvåg is hoping for land-based production solutions for the Johan Castberg field that will have the maximum economic impact on the region.

With regard to the negative social impact, the fact that Norwegian oil and gas production takes place largely offshore means that the direct effect on the indigenous Sami population – part of which lives from reindeer herding – has been limited. Reindeer herding requires large areas and all land-based industrial activity limits the space available for it. From time to time, regional controversies over industrial development and the use of land flare up – including in the Hammerfest community, where reindeer pasture during the summer season. However, opinions vary significantly within the Sami population; only a minority still has a traditional livelihood, while the majority is increasingly understanding the benefits of more economic activity.

As noted above, though, the debate on the environmental impact of oil and gas development takes place at national level too. The Deepwater Horizon accident, for example, undoubtedly influenced the decision to keep ecologically sensitive areas around the Lofoten and Vesterålen

¹⁹⁵ Pedersen, S. and Magnussen, K. (2013), *Samfunnsøkonomisk analyse av utdypning til farleden inn til polarbase* [TRANSLATE INTO ENGLISH?], at http://www.vista-analyse.no/site/assets/files/6586/va-rapport_2013-23_samfunns_konomisk_analyse_av_utdyping_inn_til_polarbase.pdf.

¹⁹⁶ Pedersen and Magnussen (2013).

¹⁹⁷ Gassco Barents Sea Gas Infrastructure, 2014

¹⁹⁸ Gassco Barents Sea Gas Infrastructure, 2014 <http://www.gassco.no/Documents/099808.pdf>

¹⁹⁹ Associated Petroleum Gas

²⁰⁰ Gassco Barents Sea Gas Infrastructure, 2014



islands, located just above the Arctic Circle, closed to petroleum activities and to confine new exploration to waters farther north, in the southern part of the Barents Sea that is close to the Russian border. Other areas of special concern are the Archipelago of Svalbard, Jan Mayen Island and Bear Island, which are among the world's last wilderness regions.²⁰¹

To date Norway has not allowed drilling in ice-covered areas owing to the associated safety risks, particularly with regard to oil-spill containment. However, attempts are repeatedly made by stakeholders in both the industry and the government to redefine the term 'ice-covered' in order to be able to extend the boundaries of existing exploration zones. Unsurprisingly, Greenpeace and other environmental organizations continue to oppose any such moves, and the debate is one that will certainly lengthen the timescale of any oil and gas developments in the Norwegian Arctic.²⁰²

Concluding remarks about the Barents Sea

There are several factors suggesting the Barents Sea could become a successful oil and gas province over the next 20–30 years, the most important of which is geological prospectivity. However, to date this remains to be proven as exploration is at a relatively early stage. Sufficiently large discoveries must be made to justify the major investments that will be required, as currently there is a lack of infrastructure and many of the discoveries to date have been far from the shore. But when and if a big field has been developed, it will be much easier to realize other projects, as the marginal cost of satellite developments around an original hub would fall significantly.

Oil and gas prices are important too, of course. Any anticipation of lower prices, either owing to a stagnation in global oil demand or because of the development of new and cheaper sources of production, will mean even more reluctance to invest in the Barents region. In this context, the further development of shale oil in the US could be an important factor – if it is sustained over the long term.

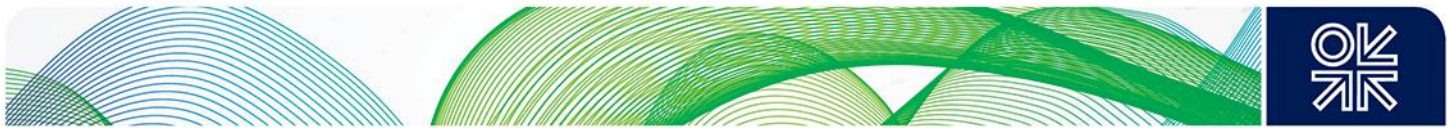
Another important factor is expenditure. The growth in costs experienced by the oil and gas industry over the past 10 years (which have continued under a stable oil price of around US\$100 per barrel for the past three years) both reduces the cash flow available for investment and undermines the economic outlook for new projects, especially in remote areas such as the Norwegian Barents Sea. Although conditions in this region are not as tough as in many other parts of the Arctic, challenges such as icing on installations, distances to land and the lack of infrastructure mean that production is considerably more expensive in the region than, for example, in the North Sea.

Given these price and cost issues, the Norwegian authorities may need to review the tax and regulatory framework if they want to encourage development in a region that could become an important producing area for the country. Recent changes in the tax rules have discouraged the early development of the Johan Castberg field; and since other recent exploration has been disappointing, it is possible that interest in the Norwegian Arctic could start to diminish. The announcement of the results of the 23rd licensing round in 2015 may be the catalyst required to rekindle both enthusiasm and activity, especially if cooperation with both Russia and Russian companies increases following the resolution of the border dispute.

However, the lack of infrastructure in the region, the likelihood of gas discoveries and the potential for renewed political dispute—with Russia all point to an uncertain future. Although

²⁰¹ <http://www.npolar.no/en/the-arctic/>.

²⁰² <http://www.greenpeace.org.uk/blog/climate/norways-sneaky-seismic-attack-arctic-20140818>.



Norway is not in the EU and is therefore not subject to its new sanctions against Russia it has agreed to abide by them, and it is unlikely that Norwegian companies with interests in North America will be keen to break the US sanctions either. Furthermore, from an operational perspective an important indicator for future trends will be whether the Goliat field is successfully developed, but at least one new major discovery is also likely to be needed before 2020 if the region is to become another heartland of Norwegian oil industry activity.



8. Conclusions

Although there is huge potential for making major oil and gas discoveries in the Arctic region, the difficulties in developing any finds are considerable. Onshore fields in the US and Russia north of the Arctic Circle, which have been producing both types of hydrocarbon for many years, hint at the prospectivity of the offshore regions. The USGS has quantified the potential under the Arctic waters at more than 400 bnboe, the majority of which is located in areas adjacent to Russian territory; however, the other littoral states – Canada, the US, Greenland and Norway – have the possibility of turning their Arctic regions into major hydrocarbon provinces too. At a time when global oil production has been increasingly focused on the volatile Middle East and North Africa, the attraction of developing new resources in more politically stable regions and countries is obvious. But, as our analysis has revealed, specific country concerns as well as more general industrial, commercial and environmental issues mean that the prospects for Arctic oil development are uncertain at best.

A primary concern is the cost of new developments in the Arctic owing to the remoteness of the region and the advanced technology that is needed to explore and produce oil and gas there. Specially constructed rigs that are able to resist ice flows and withstand harsh weather conditions are required; moreover, the drilling season is short owing to the extremes of temperature. Rosneft and ExxonMobil's first exploration well in the South Kara Sea exemplifies all these issues. At a cost of more than \$600 million, the well will be one of the most expensive ever in the history of the oil industry and will take at least two drilling seasons to complete owing to the short (three-four month) weather window (which means full testing cannot take place in 2014). Given the cost issue, it is clear that very large discoveries are needed to justify the billions of dollars in investment required not only in the fields themselves but also in the infrastructure to service them and transport the hydrocarbons to market.

The field developments to date demonstrate how difficult it is likely to be to make money in the region. Cost overruns and time delays have been seen at the Snøhvit field, which is the first Arctic LNG development (located in Norway), and at Prirazlomnoye, the first Arctic oil development (located in Russia). The Goliat field in Norway is two years behind schedule and significantly over its original budget, while Russia's Shtokman field has been postponed indefinitely owing to technical issues and changing market conditions. Of course, these experiences provide useful lessons for future developments, but they do not augur well for short-term success.

The Shtokman example highlights another risk for Arctic projects – namely, that as high-cost developments, such projects are significantly at risk to changing market circumstances. In the case of Shtokman, the emergence of shale gas in the US removed significant LNG demand from the world market and reduced European prices, undermining the development rationale for a field that was always at the top end of the cost curve. A similar risk faces Arctic oil developments over the next few years: for all the concerns about major suppliers of crude oil in the Middle East, there are equally compelling debates about the future of oil demand and about the emergence of shale oil as a fast-growing resource in North America and potentially elsewhere. Although this latter resource requires a relatively high oil price to underpin its economics, it is likely that Arctic oil will be more expensive, which means that if the oil price and/or oil demand falls, it will also be the more vulnerable. Given this uncertainty and the risk to the huge up-front investment required, companies may well be reluctant to accelerate developments north of the Arctic Circle.



Another risk stems from the environment – not just the potential consequences of an oil spill but also the pressure that will increasingly be applied by lobby groups such as Greenpeace. Indeed, former Total chief executive Christophe de Margerie warned of the disastrous potential consequences of an Arctic oil leak for any company involved with it,²⁰³ while the problems of Shell in the US Arctic over the past two years have demonstrated how the harsh climate and difficult operating conditions can magnify any operational problems and lead to lengthy delays, potentially high costs and reputational risk. Many companies have already been deterred from following Shell's lead in the US Arctic region, and any oil spills or safety problems in other regions could quickly spell the end of activity in the Arctic as a whole.

The strong likelihood of gas being discovered in the Arctic – the USGS estimates that it accounts for two-thirds of the region's total potential resource base – highlights another major issue for the industry. Not only is gas more difficult and expensive to transport than oil, requiring either dedicated pipelines to specific markets or high-cost LNG facilities, but the North American and European gas markets are also currently oversupplied with gas, meaning that the economics of any Arctic developments could hardly be justified, given the high cost estimates. LNG developments with an Asian target market are a possibility, but even in this case LNG is unlikely to be in short supply over the next two decades as projects as far afield as East Africa, Canada, Australia and the US come on line. In short, Arctic offshore gas is very unlikely to have any value for oil companies in the next two to three decades.

A final conclusion is related to the geo-politics of the Arctic region. It has been argued that oil produced in the region would derive from a more stable group of countries than those found in the Middle East;²⁰⁴ but in reality the Arctic is creating its own share of political issues as the various needs of the littoral states play a key role in influencing the future of the region. Norway and Russia seem to have a particular need to develop resources in the area, whereas the US has alternative hydrocarbon priorities and can use Arctic development as a political bargaining chip. Indeed, this is most evident in the targeting of the Russian Arctic in the sanctions imposed by the US and the EU over the Ukraine crisis – specifically, the sanctions are aimed at preventing the transfer of the technology and financial resources that could help Russia become a significant player in the region. It is not inconceivable that the Russian response will be robust, including the refusal to cooperate in the future with any companies from the US or the EU that pull out of the country as a result of the latest sanctions – although, in the long term, this could be counterproductive.

However, the clear need for partnership in the Arctic offers some hope for a positive long-term outcome in the region, once the current geo-political issues have stabilised. ExxonMobil, Statoil and ENI all want to continue to partner with Rosneft in the Russian Arctic (even if they may be prevented by sanctions from doing so in the short term) and all see their investments as long-term ventures that will outlive current geo-political tensions. Exxon, in particular, has potential investments that could see it exploring in the Russian Arctic until 2050 and producing well beyond that if commercial oil is discovered. Possible cooperation between Russia and Norway, which are neighbours in the Barents Sea, could provide another basis for successful oil – and possibly even gas – development, given the desire of both countries to see Arctic oil replace declining production in other regions. Although the potential of the formerly disputed area in the south-eastern Barents will be revealed only after drilling under licences yet to be awarded in Norway's 23rd licensing round, it is clear that the interest in the area, the forthcoming exploration drilling on

²⁰³ 'Total warns against oil drilling in Arctic', *Financial Times*, 25 September 2012.

²⁰⁴ 'Arctic oil draws money with stability, shallow seas', Reuters, 12 February 2013.



either side of the maritime boundary and the need for joint infrastructure development all point towards cooperation for mutual benefit.

Thus it seems very likely that, if the Arctic region is to become a major oil and gas province within the next two to three decades, it will be in Norway and Russia that the major activity takes place. Russia has by far the largest resource base but lacks the experience and technology to develop it alone. Norway has significant offshore experience and has at least started the long process of developing infrastructure in the Barents Sea. Moreover, both countries are highly motivated to find new oil (and gas) resources to bolster their economies in the long term. Beyond the geopolitical difficulties that Russia is currently facing, all these factors may provide the catalyst for the development of the Arctic as an oil-producing region, although the realistic timetable for significant output must surely be after 2030, not before.



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