AMAP

ASSESSMENT 2007

Oil and Gas Activities in the Arctic –
Effects and Potential Effects

Volume One

1

Arctic Monitoring and Assessment Programme (AMAP), Oslo, 2010

Assessment 2007: Oil and Gas Activities in the Arctic – Effects and Potential Effects*

**Bold indicates chapters contained in this volume*

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Preface

This assessment report details the results of the 2007 Assessment of Oil and Gas Activities in the Arctic conducted under the auspices of the Arctic Council and coordinated by the Arctic Monitoring and Assessment Programme (AMAP).

It provide the accessible scientific basis and validation for the statements and recommendations made in the report 'Arctic Oil and Gas 2007' [1] *that was delivered to Arctic Council Ministers in April 2008. It includes extensive background data and references to the scientific literature, and details the sources for figures reproduced in the 'Arctic Oil and Gas 2007' report. Whereas the 'Arctic Oil and Gas 2007' report contains recommendations that specifically focus on actions aimed at improving the Arctic environment, the conclusions and recommendations presented in this report also cover issues of a more scientific nature, such as proposals for filling gaps in knowledge, and recommendations relevant to future monitoring and research work, etc.*

The assessment constitutes a compilation of the prevailing knowledge about oil and gas activities in the Arctic region to the middle of the decade and an evaluation of this information. It was prepared as far as possible in a systematic and uniform manner to provide a comparable knowledge base for the circum-Arctic countries that builds on earlier work and can be extended through continuing work in the future.

The assessment is published in three volumes. This volume, Volume I, includes Chapters 1, 2, 3 and 7 of the assessment:

Chapter 1 · Introduction

Chapter 2 · Oil and Gas Activities in the Arctic

Chapter 3 · Social and Economic Effects of Oil and Gas Activities in the Arctic

Chapter 7 · Scientific Findings and Recommendations

Chapters 1 and 7 of the assessment are included in all three volumes as they provide important information concerning the content and organization of the material and summarize the overall results of the assessment in case other volumes are not accessible to the reader.

The assessment presented in this report is the responsibility of the scientific experts involved in the preparation of the assessment. Lead countries for this Arctic Oil and Gas Assessment were Norway and the United States. The assessment is based on work conducted by a large number of scientists and experts from the Arctic countries (Canada, Denmark/Greenland/Faroe Islands, Finland, Iceland, Norway, Russia, Sweden, and the United States), together with contributions from indigenous peoples' organizations, from other organizations, and from experts in other countries.

AMAP would like to express its appreciation to all of these experts, who have contributed their time, effort, and data; and especially to the lead experts who coordinated the production of this report, and to referees who provided valuable comments and helped ensure the quality of the report. A list of the main contributors is included in the acknowledgments on page vi of this report. The list is not comprehensive. Specifically, it does not include the many national institutes, laboratories and organizations, and their staff, which have been involved in the various countries. Apologies, and no lesser thanks are given to any individuals unintentionally omitted from the list. Special thanks are due to the lead authors responsible for the preparation of the various chapters of this report.

The support of the Arctic countries is vital to the success of AMAP. AMAP work is essentially based on ongoing activities within the Arctic countries, and the countries also provide the necessary support for most of the experts involved in the preparation of the assessments. In particular, AMAP would like to express its appreciation to Norway and the United States for undertaking a lead role in supporting the Oil and Gas assessment. Special thanks are also offered to Canada, Denmark, Norway, United States and the Nordic Council of Ministers for their financial support to the work of AMAP, and to sponsors of projects that have delivered data for use in this assessment.

The AMAP Working Group that was established to oversee this work, and the Arctic oil and gas assessment expert group are pleased to present its assessment.

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[1] AMAP, 2008. Arctic Oil and Gas 2007. Arctic Monitoring and Assessment Programme (AMAP), Oslo, Norway. xiii+40 pp.

Chapter 1
Introduction

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1.1. Background

In 1997, the Arctic Monitoring and Assessment Programme (AMAP) presented the results of its first assessment of the pollution status of the Arctic. The reports (AMAP, 1997, 1998a) detailing the results of that assessment included a chapter on 'petroleum hydrocarbons', which described the regional development and transportation of petroleum resources, the environmental fate of petroleum hydrocarbons, and their levels and effects in the Arctic environment.

That first AMAP assessment of petroleum hydrocarbons in the Arctic was prepared at a time when, after a period of intense activity during the 1980s, largely driven by high oil prices following the oil crises of the early 1970s and early 1980s, interest in Arctic oil and gas resources was falling, or was at least being considered a low priority by governments and industry.

Major oil production activities were identified as an issue of 'sub-regional' environmental concern in parts of Western Siberia, and on the North Slope of Alaska where the *Prudhoe Bay* fields had been rapidly developed during the late-1970s and 1980s. As with the Prudhoe Bay development, oil production from fields in the Mackenzie Valley area of Canada were already past their peak by the beginning of the 1990s. Intensive exploration activities in the Canadian Arctic had revealed the presence of substantial quantities of oil, and in particular gas in the Mackenzie Delta/Beaufort Sea area, but the prevailing economic conditions meant that, with the exception of a small amount of oil production from the *Bent Horn* field, these were not commercially exploitable, and discovery wells were therefore capped for possible future production. Offshore, significant exploration activities had been, or were being conducted in the Bering, Beaufort, Norwegian and Barents Seas. Building on its North Sea operations, outside of the Arctic, Norway was just starting production from Norwegian Sea fields, with good prospects of discoveries in the Barents Sea.

Despite the limited extent of Arctic oil and gas development at the time of the first AMAP assessment, two major oil spill events occurring just prior to the publication of the AMAP assessment had focused considerable international attention on the potential threats for environmental impacts associated with oil and gas activities in northern areas. These were the *Exxon Valdez* accident in Prince William Sound in southern Alaska, and the well-publicized 'Komi spill' in Russia, from a pipeline near Usinsk in the lower Pechora Basin.

The first AMAP assessment of petroleum hydrocarbons in the Arctic presented 15 major conclusions, together with the following (main) recommendations:

In regions of existing or developing oil and gas exploitation and transportation in the Arctic:

- *Steps should be taken to harmonize the monitoring of petroleum hydrocarbon levels and effects.*
- *Nautical charts and environmental sensitivity mapping for the Arctic area should be improved as an important counter-measure for oil spills.*
- *Methods and techniques for combating oil spills in ice-covered areas should be developed to reduce damage when spills occur.*

These conclusions and recommendations were reported to Ministers of the eight Arctic countries at the Third Ministerial meeting of the Arctic Environmental Protection Strategy (AEPS) in Tromsø, Norway in 1997.

Work has also been conducted under other Arctic Council Working Groups relating to oil and gas activities in the Arctic, partly in response to these recommendations. This has resulted in reports prepared by the Arctic Council Working Group on Emergency Prevention, Preparedness, and Response (EPPR) on the *Arctic Shoreline Clean-up Assessment Technique (SCAT) Manual* (Owens et al., 2004), the *Arctic Guide for Emergency Prevention, Preparedness and Response* (EPPR, 2008) and the *Circumpolar Map of Resources at Risk from Oil Spills in the Arctic* (EPPR, 2002); and reports prepared by the Working Group on Protection of the Arctic Marine Environment (PAME) on *Arctic Offshore Oil and Gas Guidelines* (PAME, 1997, 2002, 2009), *Arctic Marine Strategic Plan* (PAME, 2004a) and *Guidelines for Transfer of Refined Oil and Oil Products in Arctic Waters* (PAME, 2004b).

1.2. Arctic Council's 2006 assessment of Oil and Gas Activities in the Arctic

In 2002, AMAP proposed to the Arctic Council that an update to its 1997 assessment of Petroleum Hydrocarbons in the Arctic be produced, for delivery in 2006. In the period since the publication of the first AMAP assessment, significant changes have occurred in the global economy with respect to demand for energy, and energy security considerations, which mean that renewed attention is being given to Arctic oil and gas resources. At the same time, assessments of the impacts of climate change (for example, the Arctic Climate Impact Assessment; ACIA, 2004, 2005) were indicating that, under scenarios for the not too distant future, Arctic conditions might be more favorable for resource development, and perhaps more importantly for the associated transportation of resulting production.

Recognizing this situation, and also recognizing that a comprehensive assessment of oil and gas activities in the Arctic should address issues beyond just the potential pollution threats from such development, the Arctic Council therefore requested that relevant working groups, under the lead of AMAP, prepare an assessment of Oil and Gas Activities in the Arctic.

1.2.1. Scope of the assessment

The Arctic Council Ministers (Arctic Council, 2004) directed that this assessment should build on and expand the AMAP assessment completed in 1997, and evaluate four types of impacts or effects associated with oil and gas activities in the Arctic:

- social and economic consequences
- environmental impacts from pollution

- environmental effects from physical impacts and disturbances
- effects on human health

These four components of the assessment constitute the framework for much of the information presented in this assessment report.

The assessment specifically does *not* include the relation between Arctic oil and gas development and global carbon dioxide (CO_2) emissions and greenhouse warming. This topic is addressed in other assessments, for example those by ACIA, the UN Intergovernmental Panel on Climate Change, and national assessments.

Similarly, this assessment focuses on petroleum hydrocarbons associated with oil and gas resource development activities, and not, for example, on use of petroleum products in the Arctic, or petroleum hydrocarbons in a more general sense. Chapters dealing with oil and gas activities (past, present and future), and socio-economic aspects of Arctic oil and gas development are, by definition, limited to addressing oil and gas activities. The chapter dealing with pollution aspects of petroleum hydrocarbons addresses sources associated with oil and gas activities, but includes information on other sources (natural sources, and sources associated with pollution from petroleum products, etc.) for comparative purposes. More information on, for example, polycyclic aromatic hydrocarbons (PAHs) associated with combustion sources can be found in the AMAP assessments on Persistent Organic Pollutants in the Arctic (AMAP, 1998b, 2004). In relation to the 'effects of contaminants', it is generally not possible to isolate effects due to petroleum hydrocarbons released as a result of oil and gas activities, from those released from other natural and anthropogenic sources. However, in connection with effects due to, for example, noise and physical disturbance, the impacts of oil and gas activities can be more readily distinguished and separately considered. Effects on human health are also only considered in this assessment in relation to non-occupational exposures resulting from oil and gas activities.

The possible consequences of increased Arctic oil and gas activity on climate change or other widespread environmental problems, such as ocean acidification or eutrophication is also outside the scope of this assessment.

Finally, the majority of the data presented in this assessment cover the time period up to around 2004/2005 – the latest data available at the time this assessment report was drafted. Some parts of the assessment, however, were subsequently updated to include more recent data where this could readily be included and where this complemented the assessment.

1.2.2. Geographical scope of the assessment

The geographical scope of this assessment is essentially a modified version of the 'AMAP area'. The AMAP area (see Figure 1.1) is a non-formal definition of the Arctic, but is based on several relevant physical and biological definitions, plus political designations, which together delimit an Arctic region that is appropriate for the purposes of AMAP assessments.

The oil and gas assessment area includes the Arctic production areas on the North Slope of Alaska, the Mackenzie Valley, the Norwegian offshore, and the West Siberian and Timan-Pechora basins of northern Russia – some of which have a long history of oil and gas development.

More generally, the assessment covers onshore oil and gas activities:

- in the United States (Alaska), north of the Arctic Circle;
- in Canada, in the petroleum provinces of the Yukon, the Northwest Territories and Nunavut, north of 60° N; and
- in Russia, in the petroleum hydrocarbon basins north of 60° N.

Offshore areas that fall within the assessment area include:

- the Norwegian Sea (the Norwegian continental shelf from 62° N to approximately 70° N, centered on the Haltenbanken area);
- the Barents Sea on the Norwegian-Russian continental shelf, which is a focus of increasing development and an area where marine transport of oil is expected to increase in coming years;
- the Pechora, Kara, Laptev and East Siberian Seas on the Russian shelf;
- on the continental shelf between Russia and the United States, the Bering Sea (the area north of the Aleutian Island chain) and the Chukchi Sea;
- on the US-Canada continental shelf, the Beaufort Sea; and
- the marine areas of the Canadian Arctic Archipelago.

Parts of the assessment area that were not considered in the first AMAP assessment of petroleum hydrocarbons include areas of West Greenland, especially the offshore waters between Greenland and Canada, and the Faroese shelf, where new exploration for oil and gas reserves has been ongoing during the 1990s. All areas around Greenland, Iceland and the Faroe Islands are considered to be within the assessment region.

Chapter 2 of the assessment discusses Arctic oil and gas activities within the above mentioned areas, presenting statistical and descriptive information according to the main oil and gas provinces and basins around the Arctic (see Chapter 2, Figure 2.9). Chapter 3 considers socio-economic aspects of oil and gas development, within certain case study areas (see Chapter 3, Figure 3.3).

Chapter 6 of the assessment considers the status and vulnerability of Arctic ecosystems to oil and gas development according to defined Large Marine Ecosystems (LMEs) (see Figure 1.1), and major terrestrial ecosystems.

Oil and gas resource development is still restricted to certain parts of the Arctic, and in that sense oil and gas remains a sub-regional issue of concern. However, the increasing interest in Arctic oil and gas resources; exploration in new Arctic areas; plans for new pipeline routes in the Arctic; the potential use of Arctic seas for shipping oil and gas; and, not least, the potential impacts of oil and gas related pollution on vulnerable Arctic ecosystems all mean that a circumpolar perspective to Arctic oil and gas development is emerging.

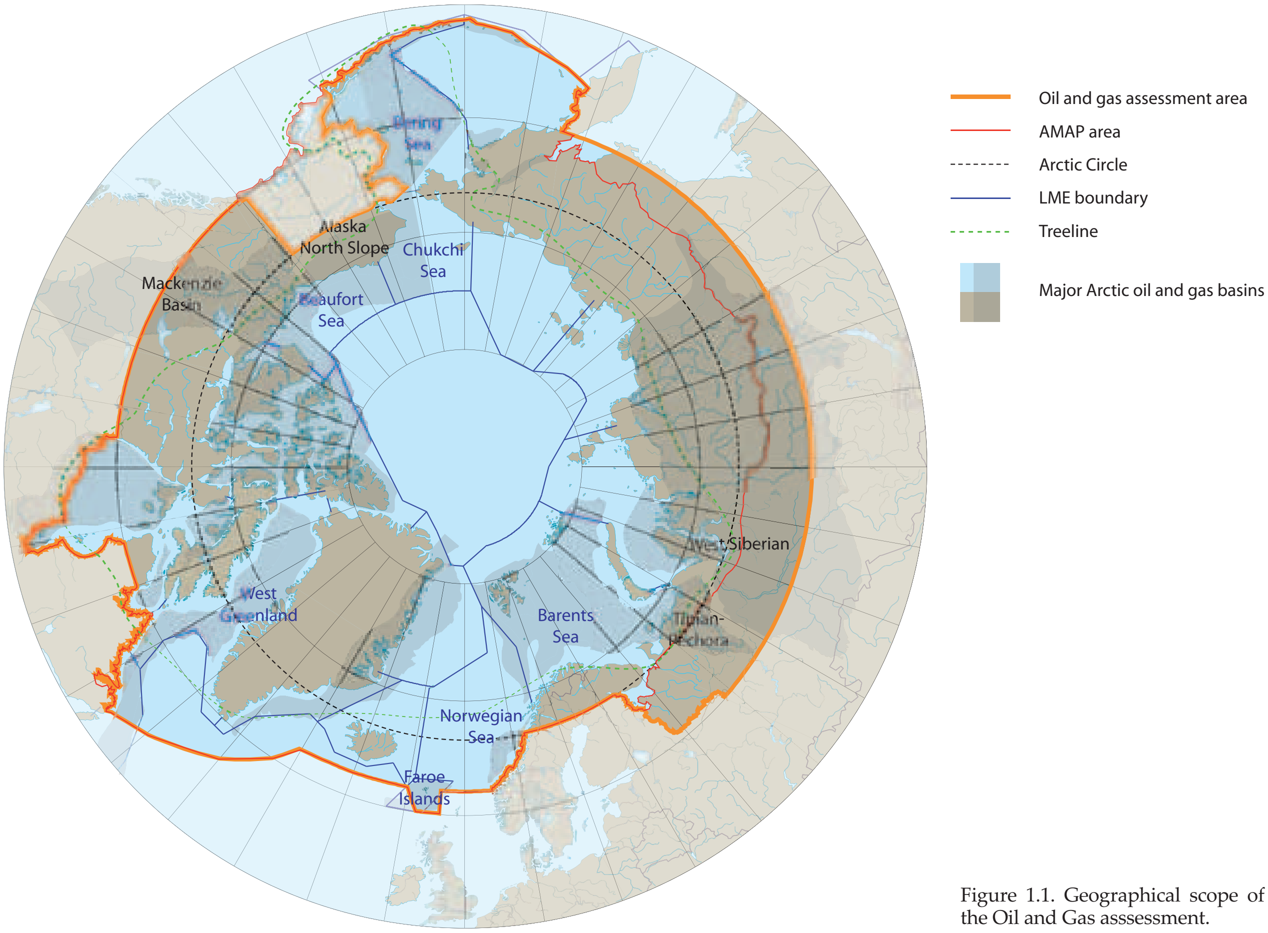

Figure 1.1. Geographical scope of the Oil and Gas asssessment.

1.2.3. Assessment process

For each of the key science chapters (Chapters 2 to 6), one or more countries undertook a 'lead' role, which included the nomination of one or more 'lead authors' for the chapter. The lead country responsibilities were assigned according to Table 1.1.

In order to produce this assessment of oil and gas activities in the Arctic, experts in the various disciplines relevant to each chapter were nominated as lead authors and national experts by the eight Arctic countries. The lead authors, in turn, solicited contributors from the non-Arctic community. An Assessment Steering Group (with membership including, among others, one or more representatives from each participating Arctic Council working group, and the Lead Authors of the chapters) was responsible for the completion of the assessment, reporting directly to the AMAP Working Group and indirectly to all other participating Arctic Council working groups.

The product of this assessment is a fully-validated scientific and technical assessment report (this report) that provides the accessible and fully-referenced basis for statements made in a related overview report. The overview report *Arctic Oil and Gas 2007* (AMAP, 2008) was produced for a wider audience, presenting a concise summary of the results of the assessment, including recommendations addressed to Ministers and decision-makers. The content of the scientific report is the responsibility of the Assessment Steering Group and the lead authors and experts that have been involved in its production (see Acknowledgements). The overview report is prepared under the responsibility of the Arctic Council Working Groups that have been charged with the delivery of the Assessment of Oil and Gas Activities in the Arctic.

This assessment has been subjected to both peer and national review to ensure that it conforms to the highest possible scientific and technical standards with respect to the quality of the material presented.

1.2.4. Readers guide

This assessment is published in three volumes. *Volume I* includes Chapters 2 and 3, providing much of the background that sets the scene for the assessments in other chapters. *Volume II* includes Chapters 4 and 5, the assessments of 'contamination' resulting from oil and gas activities in the Arctic, and the effects of exposure of the environment, biota and humans to this contamination. *Volume III* presents Chapter 6, the assessment of the status and vulnerability of Arctic ecosystems to oil and gas development in the region. Chapters 1 (Introduction) and 7 (Scientific Findings and Recommendations) of the assessment are included in each volume.

A more detailed description of the content and relationship between the different chapters of the assessment is as follows:

Chapter 1, this chapter, sets the stage for the assessment, describes its scope and the processes by which it was accomplished.

Chapter 2 presents statistical and descriptive information characterizing past and current Arctic oil and gas activities, and activities that are likely to occur over the period to 2015 to 2020. These data provide context for assessing effects related to historic activities and provide a basis from which to project future levels of activity and

Table 1.1. Lead countries for the assessment.

Chapter	Lead
Chapter 2: Oil and Gas Activities in the Arctic	USA and Russia
Chapter 3: Social and Economic Effects of Oil and Gas Activities in the Arctic	USA
Chapter 4: Sources, Inputs and Concentrations of Petroleum Hydrocarbons, Polycyclic Aromatic Hydrocarbons, and Other Contaminants Related to Oil and Gas Activities in the Arctic	Norway and Russia
Chapter 5: Effects of Oil and Gas Activity on the Environment and Human Health	Canada
Chapter 6: Status and Vulnerability of Arctic Ecosystems	Norway

effects. In this assessment, the use of the word 'activities' is taken to mean leasing/licensing, seismic and drilling exploration, production drilling and development construction, continuing production operations, all facets of transportation, and eventual decommissioning of facilities. Chapter 2 also presents sections on resource economic drivers for activities, past practices and current best practices and technology, physical impacts and disturbance, and sections on noise from oil and gas activities, oil spill preparedness and response in the Arctic, and monitoring and research programs in each country.

Although Chapter 2 does not include any 'assessment' of the regulatory framework for managing Arctic oil and gas development, this issue is of critical importance for sustainable and environmentally sound development of Arctic oil and gas resources. It was therefore decided that an overview of the existing legal-regulatory systems in the different countries should be prepared for inclusion in this assessment. A reasonably comprehensive referenced review of the main laws and legislation and the implementing regulations, agreements, and procedures for governing oil and gas activities (including, for each country and internationally, preparedness, prevention and response issues and Occupational Health/Safety Regulations) is therefore compiled as an Appendix to the assessment.

Chapter 3 considers the socio-economic strand to the assessment, including the social and economic consequences of the oil and gas activities in the Arctic that are described in Chapter 2. It evaluates historical data and also projects forward as far as possible. It also includes a consideration of the social and economic consequences of environmental effects of pollution and physical impacts and disturbances as examined in Chapters 5 and 6. The intent of Chapter 3 is to provide a comprehensive and balanced view of the positive and negative socio-economic consequences associated with oil and gas development in the Arctic. Chapter 3 includes a series of case studies and mini-case studies that are intended to illustrate diverse situations that exist in the Arctic countries, reflecting different stages in the life cycle of oil and gas activities, differences in political and economic systems, and differences in types of development. Several of these case studies focus on the impacts of oil and gas activities on indigenous population groups in the different countries.

Chapter 4 addresses the pollution strand, identifying sources of contaminant input, environmental concentrations, and contaminant pathways and fates. The information in Chapter 4 builds on information presented in Chapter 2 concerning the petroleum industry, together with available information on other contaminant sources. Chapter 4 also includes a first attempt to quantify a petroleum hydrocarbon budget for the Arctic.

Chapter 5 continues the pollution strand, considering biological effects at the organism level. The chapter comprises two main sections, concerned with effects on terrestrial and aquatic biota, respectively. A third main part of Chapter 5 addresses human health issues, updating and expanding where relevant the information presented in the AMAP Assessments on Human Health (AMAP, 1997, 1998c, 2003). The consideration of human health in this assessment is limited to assessing implications of exposure for health of general populations; occupational health associated with the oil and gas industry is not addressed, although information from occupational exposure is used where relevant to gain possible insight into effects on health of the general population.

Chapter 6 considers vulnerability to, and environmental impacts of oil and gas activities at the levels of species, populations, habitats and ecosystems. The chapter provides brief descriptions of Arctic regional terrestrial and freshwater ecosystems and Large Marine Ecosystems (LMEs) in relation to potential impacts from oil and gas activities. It gives examples of environmental impact assessment and oil spill risk assessment procedures used in several Arctic countries prior to permitting exploration or development. The chapter then assesses the vulnerability of species and populations of plants and animals and of habitats to oil and gas activities, ultimately providing an assessment of vulnerable sites and areas in terrestrial, freshwater, and marine ecosystems. In general, although based on an ecosystem approach, the discussion in Chapter 6 is limited to the direct effects of oil and gas activities, and does not consider potential indirect effects that oil and gas activities may have on other activities in the Arctic, such as commercial fishing or traditional hunting in more localized areas.

Information on certain themes is split between several chapters, to reflect the logical context for presentation of information, for example, the strand on physical impacts and disturbances starts with information on the physical activities (construction work, land use, pipelines, roads, noise etc.) responsible for these impacts/disturbances, presented in Chapter 2, and then goes on to consider their biological effects on organisms in Chapter 5. Consequences for species, populations, habitats and ecosystems are then examined in Chapter 6. Some topics are therefore covered from different perspectives in different chapters, however, section headings and cross-referencing between sections should provide a clear indication of where information on related strands can be found in the respective chapters.

Chapter 7, brings the various strands together to provide an 'overall assessment' of the information presented in Chapters 2 to 6, including a series of conclusions and recommendations based on the science as presented in the assessment. These recommendations will be further considered by the Arctic Council Working Groups, prior to their submission to the Arctic Council Ministers for their consideration in developing a response to the assessment.

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Chapter 2
Oil and Gas Activities in the Arctic

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2.1. Introduction

This chapter compiles statistical and descriptive information characterizing past Arctic oil and gas activities, current Arctic oil and gas activities, and Arctic oil and gas activities that are likely to occur over the next decade or so. These data provide context for assessing effects related to historic activities and provide a basis from which to project future levels of activity and effects.

In this assessment, the description of Arctic oil and gas activities and associated data takes into account areas of similar Arctic operational conditions, which in some cases include areas that extend south of the Arctic Circle (see Chapter 1, section 1.2.2). In this chapter, the word 'Arctic' may not always be used, but all discussions refer to the Arctic regions as defined in Chapter 1 unless otherwise stated. The chapter is organized into nine main sections.

Section 2.2 provides a short discussion of resource economics, which is important to the understanding of the context and timing of Arctic activities. Interest in Arctic oil and gas deposits depends on many factors. A critical factor for all countries in deciding to open areas and for companies conducting exploration or development activities is the price of oil and the costs associated with those activities.

Section 2.3 presents a number of oil and gas activity indices, such as leasing, seismic acquisition, and drilling measures plotted on a series of maps as a function of time. These maps illustrate the spatial and temporal distribution of oil and gas activities throughout the Arctic, providing a framework for the interpretation of current and historical environmental monitoring data and sociological studies. Also included in this section are some important production statistics compiled as a function of time for each operating area. This information, presented in graphical form, illustrates the scale of development activities, the frequency and size distribution of discoveries, reservoir depletion, and waste management techniques for Arctic regions through time.

Section 2.4, the largest part of the chapter, concerns a country-by-country historical narrative that describes in detail the chronology of key events within each country. Each country was asked to provide its history of activities; a discussion of infrastructure; a summary of laws, legislation, regulations or guidelines to reduce and mitigate impacts and conserve resources; the use and evolution of technology; an outlook for the next ten years of possible activities; a speculative look beyond ten years, including unconventional resources; and a summary of scientific and technological research relevant to oil and gas activities.

Section 2.5 provides a general overview of past practices and technology used in Arctic areas, a summary of current Best Available Technology and practices, and a brief overview of some of the new technologies under development that will have application in Arctic areas.

Section 2.6 provides a summary of documented and potential physical impacts on and disturbance to terrestrial and marine habitats from oil and gas activities. A more detailed description and assessment is contained in Chapter 5 of this Report. Impacts on the terrestrial environment include impacts on soils, vegetation, freshwater drainage, lakes, streams, and fish, birds, and land mammals and their habitats. Disturbance to marine mammal habitats is also discussed. Examples from past and current oil and gas activities of the area and habitat disturbed, are estimated.

Section 2.7 describes the noise from oil and gas activities, both onshore and offshore. The marine acoustic environment is summarized including noise from natural elements such as wind, waves, rain, ice and animals. Further discussion examines noise from anthropogenic sources other than oil and gas activities, including shipping, local vessel traffic, aircraft, and cultural activities.

Section 2.8 reviews the measures in place for each Arctic country's oil spill preparedness and response. The descriptions are primarily for offshore response and include countries that, although not currently having any offshore operations, may be impacted owing to oil transport near to their coasts by third-party countries. It describes the oil spill response system characteristics by identifying each set of national spill response authorities, regional response organizations, spill response technologies, and regional distribution of equipment.

The last major section, section 2.9, illustrates Arctic monitoring and research activities and programs. Monitoring is an important analytical tool used to assist in conserving and protecting ecological and socioeconomic resources and human health. Monitoring programs can involve research to detect trends or thresholds, or can comprise prescribed studies or measurements required for regulatory compliance. This section presents examples of various research and compliance monitoring programs conducted in different Arctic countries that have oil and gas activities.

Oil and gas data are reported in the literature using a range of units. The conversion factors used to standardise these data to barrels (oil) and cubic feet (gas) for this assessment are specified in a table at the end of this report.

2.2. Resource economics

2.2.1. Introduction

Evaluation of resources is a critical factor in exploration, development, and production strategies and it is an iterative process – beginning with initial rough estimates

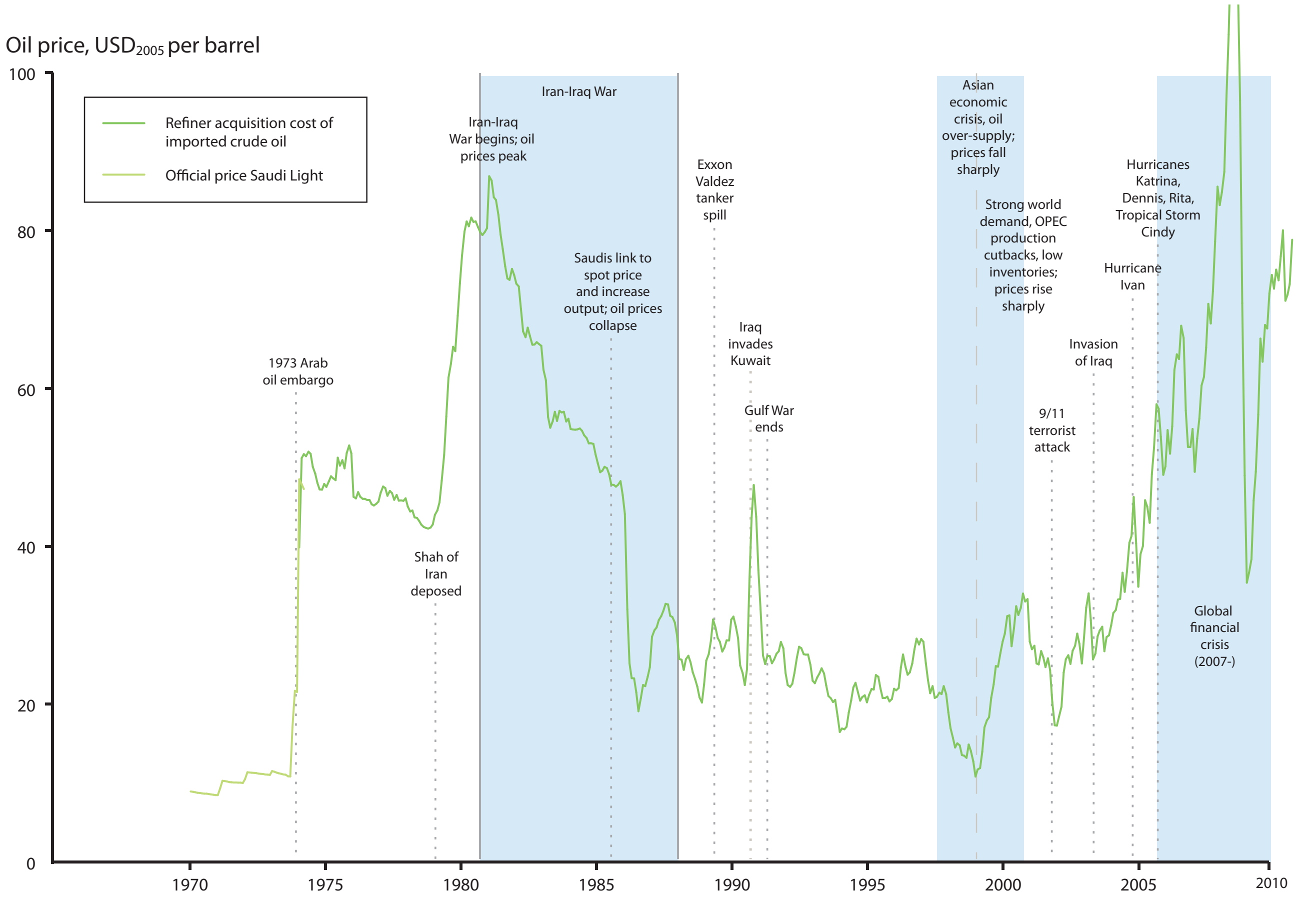


Figure 2.1. Oil prices 1970-2007: Oil price curve inflation-adjusted to 2005 U.S. dollars showing major world events (EIA, 2006, 2010).

and continuing through all phases of exploration, production, and decommissioning. Petroleum economics, an integral part of the field of resource evaluation, encompasses a complex and often proprietary process that considers the many risks and rewards for exploration, development, and production of oil and gas. This assessment does not attempt to address matters of resource and economic evaluation in any detail, but does discuss some terms and concepts used in subsequent parts of the chapter and tries to use the relevant petroleum economics to underpin the timing and scope of the activities assessed. Examples from specific regions are used to illustrate general concepts and, in subsequent parts of the chapter, the discussion of each country's history of activities touches on specific conditions, both unique and global, that affect the economics of activities.

If cost estimates over the projected life of a field show that the expense of producing oil and gas is greater than possible money made in selling the oil and gas, then there will be no production. If the expense is less, then only the first criteria are met for even considering activities.

While oil and gas development risk has traditionally been mainly geological and financial in nature, many other risks are also essential to consider in the overall economic equation – such as political risk, market risk, environmental risk, and socio-cultural risk, among others.

Oil prices have fluctuated markedly over the period since 1970 (Figure 2.1) with further increases in recent years. The question for industry investors and government financial planners is whether this is yet another cycle with prices peaking and then dramatically declining, or whether a more fundamental change has occurred which will stabilize prices at current levels.

Peak oil and gas prices do not necessarily translate into surges of exploration and development activity and despite oil prices approaching record highs by 2007 (Figure 2.1) the Arctic did not see a rush of oil and gas activities. By comparing a range of petroleum activity indices against the oil price curve it is clear that complex relationships exist and that changes in the amount of leasing/licensing, seismic data acquisition, exploratory and production drilling, and oil production do not follow the price of oil consistently, either by country or by five-year interval.

In addition to price, oil and gas activities are influenced by political forces that determine whether to allow such activities and how much land to make available, by how much petroleum is believed to exist, and by economic and environmental considerations. Also, some activities take several years to institute and so necessarily lag any price swings. Some activities, such as leasing and licensing or production drilling, are planned years in advance and may not immediately respond to price changes.

The area leased, licensed, or otherwise made available for oil and gas exploration and development in the Arctic is shown in Figure 2.2a. Arctic countries use different methods for conveying land to industry for exploration, development, and production of oil and gas (see section 2.4). Whether through lease sales, license rounds, open tenders, concessions, production sharing agreements, or some other method, conveyance schedules are usually planned several years in advance. National authorities have attempted to make oil and gas lands available in response to market demands, but the offerings and awards may lag peak oil prices. Most countries have long-range conveyance plans (see section 2.4); such as the five-year plan in the United States (Outer Continental Shelf, OCS) and Russia's 2006 – 2020 plan. Therefore, apparent correlation of high/low oil prices with correspondingly high/low amounts of land conveyed may in some cases be coincidental or may in other cases represent a correct anticipation of oil price swings when planning the licensing or lease schedule.

One thing is clear however: the amount of land conveyed by Arctic governments has reached its highest level in recent years, with over 40% of all lands leased or licensed having been transferred between 2000 and 2005 (Figure 2.2a). Drawing conclusions on trends related to oil prices based on aggregate area conveyed for all countries is difficult however, because Russia dominates the five-year intervals since 1990 and did not have a system of conveying exploration and production rights before 1992. Also, each country has unique factors that affect the amount, timing, and terms of land conveyed.

Closer examination of the correlation between oil prices and the area of oil and gas lands conveyed shows that it is only in the United States that the leased area totals appear to track fairly closely with oil prices, but only since about 1980 and with some time delay. Russian exploration and development licenses and agreements started in 1992 and these also appear to follow the price of oil with some lag. The amount of Faroese licensing also seems to track oil prices. Canada's Arctic leasing seems to have spiked at times of low oil prices and to have effectively stopped during the high prices of 1975 – 1985 due government policy (see section 2.4.2). Norway has licensed progressively more area but follows a program established by the national authorities and is not directly influenced by market prices. The same is true in Greenlandic waters, where the largest periods of conveyance were during low-price environments and reflect planned national programs (see section 2.4.3). Information on seismic data acquisition was available for all countries except Russia (Figure 2.2b) and shows clear differences between the various countries over time. 2-D seismic activities peaked in the Canadian and U.S. Arctic in the early 1980s and fell to very low levels in the 1990s, although a small amount of 3-D activity has taken place. The Faroe Islands and Greenland have had relatively stable acquisition activity except during the 1980s when activities dropped off. Activity in the mid-1990s offshore in the Faroe Islands showed a slight increase in 2-D and 3-D seismic data acquisition. Norway has had a steadily increasing amount of seismic activity, with 3-D acquisition having dominated since the early 1990s.

Exploration drilling has increased and decreased at different times in different countries seemingly without any direct relation to oil prices (Figure 2.2c). In Canada, exploration drilling peaked in the period 1970 – 1975 and then dropped to a low in the early 1990s, followed by a slight increase, while exploration drilling peaked in Alaska during the early 1980s. In Russia, exploration drilling peaked in the late 1980s and then fell to its lowest level since the pre-1960s in the late 1990s. In Norway, exploration activities peaked in the late 1980s and subsequently leveled off.

A comparison of the numbers of production wells drilled in relation to oil prices is relatively limited (Figure 2.3a) because data for Russia were incomplete before 2000. But from 2000, Russian Arctic production well drilling seems to have increased because the reported number

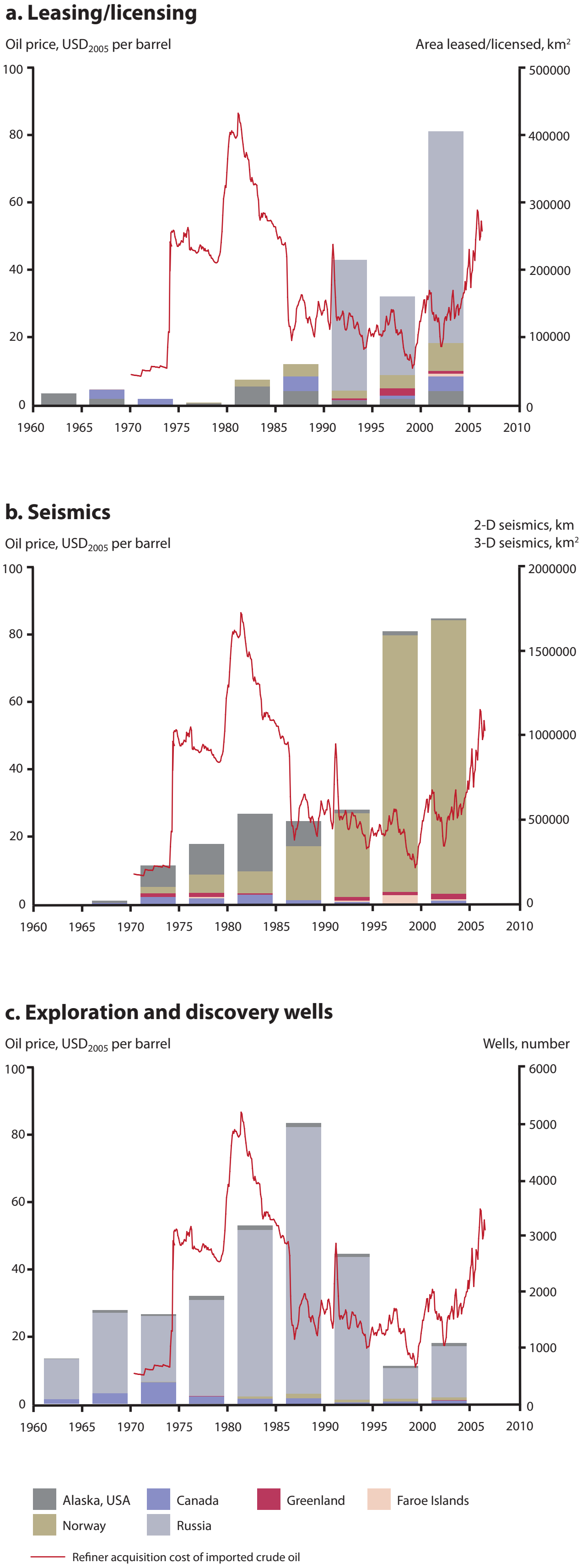
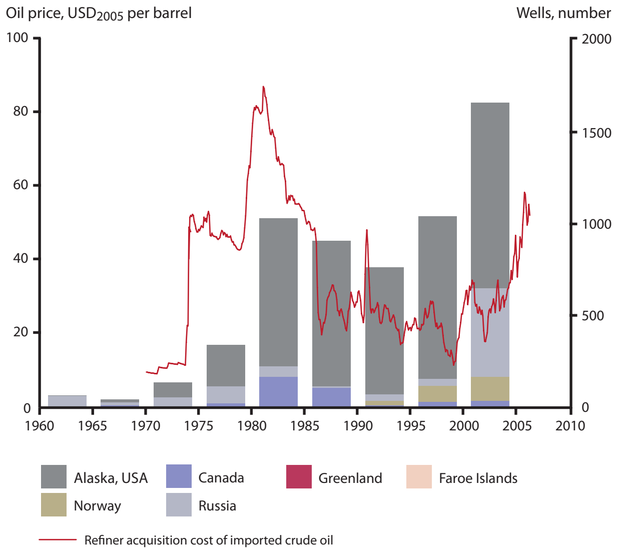


Figure 2.2. Changes in the oil price curve against (a) area leased or licensed within Arctic countries, (b) seismic data acquisition in Arctic countries (data for Russia are lacking) and (c) the number of exploration and discovery wells drilled in Arctic countries.

a. Production wells



b. Production of oil and gas

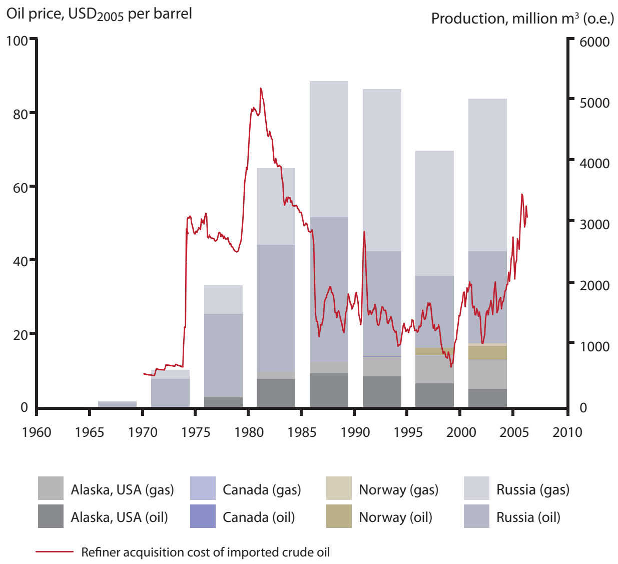


Figure 2.3. Changes in the oil price curve against (a) the number of production wells drilled in Arctic countries (incomplete data for Russia before 2000), and (b) oil and gas production in Arctic countries.

of wells drilled in 2006 is almost the same as that for the previous five years combined. Production well drilling in Alaska has remained at a high level since the 1980s. Norway's production well drilling has steadily increased since the early 1990s, whereas Canada's production well drilling peaked in the early 1980s.

Although the total amount of Arctic Alaska oil and gas production combined appears to have remained relatively stable over the last couple of decades (Figure 2.3b), this is deceptive because Alaskan gas is not sold but re-injected. In fact, Alaskan oil production is declining despite the high number of production wells drilled (Figure 2.3a). Russian Arctic oil and gas production peaked in the late 1980s, fell in the late 1990s, and is now rising again with increasing oil production and fairly steady gas production. Norway's production has been increasing since the late 1990s.

2.2.2. Resource economic evaluation

A major factor that determines if, when, where, and how exploration and development activities take place is petroleum resource economic evaluation. As a first step, resource economic evaluation takes into account the existence of oil and gas in the ground, its volume, and its degree of certainty. This is achieved through the collection and analysis of data on the geology and geophysics of potential deposits. Early on, these data came from summer geological field parties that collected rock samples and mapped geological structures and stratigraphy. Analysis of these data provided a rough idea of where oil or gas accumulations may occur and a highly risked estimate of how much might be there. This formed the basis for a follow-up exploration drilling program. With the addition of more sophisticated geophysical prospecting, particularly seismic data, to the ever-growing set of well data, most of the giant and large onshore Arctic fields had been discovered or identified by the 1970s. Since then, the process has remained essentially the same, but more and better data are now available, for example a large number of exploration, discovery and field delineation wells, 2-D seismic profiles, and 3-D seismic surveys, allowing the level of certainty to rise significantly – whether in estimating undiscovered resources or in defining the quantity and producibility of known reserves. As smaller, more remote or more complex petroleum accumulations are sought, resource evaluation analysis becomes more complex and employs more sophisticated and expensive tools, such as 3-D and 4-D (which measures changes in hydrocarbons in a field over time) seismic data, reservoir modeling, and rigorous application of geological and economic risk factors.

2.2.2.1. Petroleum resources and reserves

The terms 'resources' and 'reserves' are often used interchangeably. This is partly the result of there being no universally accepted definitions for either term. However, it is generally accepted that 'resources' refers to all of the known and potential volumes of oil and gas, while 'reserves' refers to the known and producible amounts of oil and gas (Figure 2.4).

Since the only truly 'known' volumes of oil and gas are those that have actually been produced, all other resources and reserve values are, to varying degrees, estimated. There are many conditions placed on these estimates. The term 'petroleum resources' can generally be applied to all oil and gas in the earth. The existence of these resources may be estimated or known to varying degrees of certainty and are classified accordingly, but by many different methods and standards. There are no universally accepted definitions.

Total Petroleum Initially in Place (PIIP), although part of the resource base, is not fully recoverable and some will remain in the ground. A large amount of the estimated PIIP is contained in small, scattered accumulations that will be too difficult to find and extract and therefore will never be economically viable. Another part of this resource base cannot be produced even when it occurs in commercially viable volumes because it cannot be extracted due to technical limitations – often only 30% of the oil initially in place can be produced from a reservoir, although in recent years this proportion can be larger, even above 50%. Removing this unproducible portion leaves the producible resource base. But another portion of this producible resource base may not be extracted due to

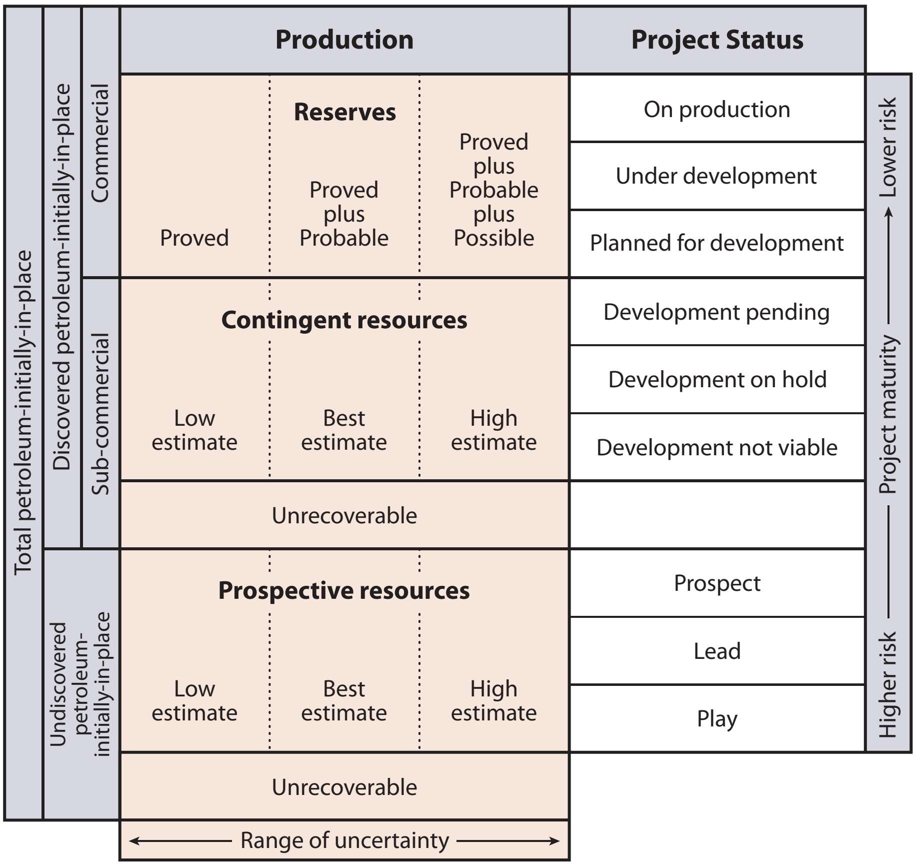


Figure 2.4. Resource classification scheme of the Society of Petroleum Engineers, World Petroleum Congress, and the American Association of Petroleum Geologists. This is a recommended classification system that accounts for the major elements of petroleum assessment.

unfavorable current or projected economic conditions or due to immutable physical or environmental conditions. The recoverable resource base is then what is left and what is important to industry, governments, and society. 'Recoverable resources' is a broad category, encompassing estimates of both proved and undiscovered volumes that would be economically extractable under specified price-cost relationships and technological conditions. By definition, there is a lower level of certainty attached to resource estimates than to proved reserve estimates.

2.2.2.2. Undiscovered resources

The undiscovered category is variously referred to as forecasted, prospective, recoverable, or undiscovered resources; the common denominator being the term 'resources' as opposed to reserves (see Box 2.1). In estimating these undiscovered resources, many methods

> Box 2.1. U.S. Geological Survey resource definitions (Bird and Houseknecht, 2001)
>
> **In-place resources.** The amount of petroleum contained in accumulations of at least 50 million bbl of oil without regard to recoverability.
>
> **Technically recoverable resources.** Volume of petroleum representing that proportion of assessed in-place resources that may be recoverable using current recovery technology without regard to cost.
>
> **Economically recoverable resources.** That part of the technically recoverable resource for which the costs of discovery, development, and production, including a return to capital, can be recovered at a given well-head price.

are used to describe different aspects of potential oil and gas deposits. Field and seismic data are often used to locate geological structures and exploratory wells are drilled to look for signs of petroleum and to determine rock properties. These data are used to evaluate the potential for oil and gas source rocks and generation of petroleum, possible migration paths, possible reservoir rocks and their suitability for hosting accumulations of petroleum, and trapping mechanisms for holding deposits.

Generally, undiscovered resources are categorized as 'undiscovered in-place', which estimates the total amount of petroleum in a reservoir, field, or region. As already stated, this volume is never fully recoverable. Undiscovered resources may include unconventional resources such as heavy oil or tar sands, and methane hydrate, which are not technically or commercially viable to produce under current and foreseeable future technology or economic conditions. 'Undiscovered, conventionally recoverable resources' or 'undiscovered technically recoverable resources' estimate the amount of petroleum in undiscovered accumulations that can be produced using existing or conventional technology but that may or may not be commercially recoverable under current economic conditions. The category 'undiscovered, economically recoverable resources' refers to the portion of the undiscovered technically recoverable resources that is potentially recoverable for a profit under a given set of economic and technological conditions.

As an example of the relationship between oil prices and economic resources, a recent analysis of undiscovered resources on the U.S. Arctic Shelf (MMS, 2006b) compared risked economically recoverable undiscovered resources based on different oil prices ranging from USD 8/bbl to USD 80/bbl. In the case of USD 46/bbl, risked mean

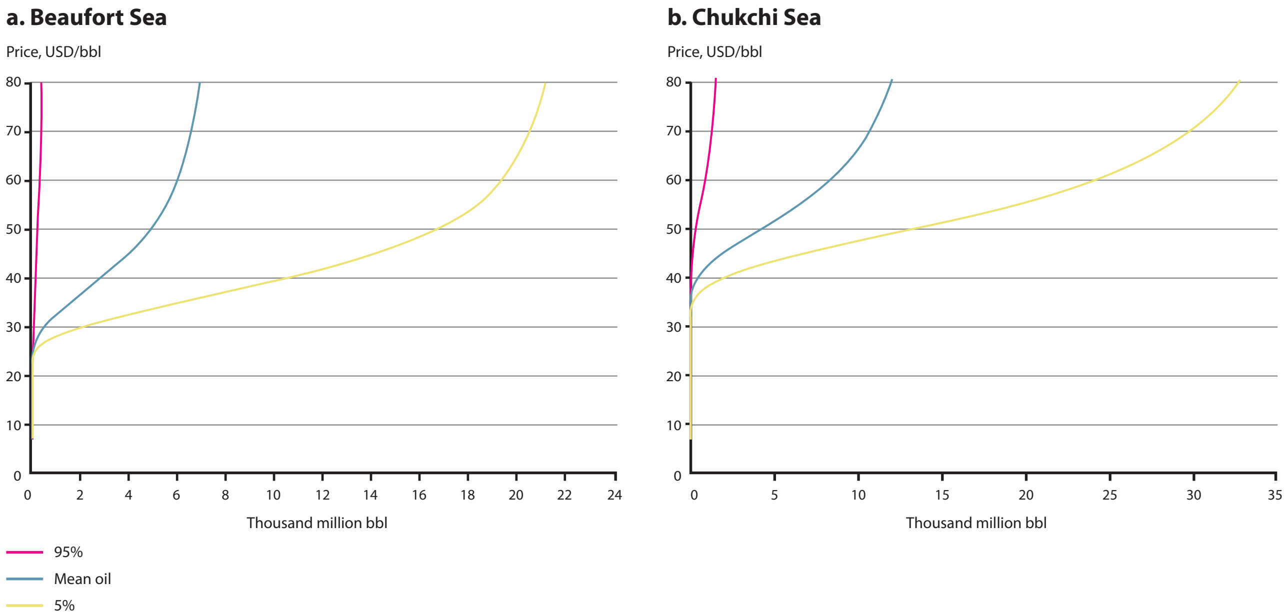


Figure 2.5. Price-supply curves for undiscovered risked oil resources in (a) the Beaufort Sea and (b) the Chukchi Sea.

economically recoverable resources on the Beaufort Sea were estimated at 4120 million bbl of oil and in the Chukchi Sea at 2370 million bbl (Figure 2.5). However, at USD 72/bbl, the Beaufort Sea risked mean economically recoverable resources were 6650 million bbl and the Chukchi Sea 11 000 million bbl.

One reason that the undrilled Chukchi Sea risked resources grew larger than the Beaufort Sea resources is that the Chukchi Sea has large geologic structures and stratigraphic prospects/traps. At USD 46/bbl, the Chukchi Sea risked undiscovered resources were not as economic even with large geologic structures, because of the huge costs required to operate in the harsh and remote offshore area. The Beaufort Sea contains smaller geologic structures but they are all much closer to existing petroleum infrastructure, transport facilities, and known reserves, making their smaller potential field size comparatively more economic to develop. At the higher price, the minimum economic field size is well exceeded by the large structures with potential oil accumulations in the Chukchi Sea.

It is important to note that cost assumptions for exploration and development are not adjusted for inflation or for the increase in costs for fuel, transport, operational expenditures, or rig availability that would also increase with the price of oil. Also, the price supply curves should not be read to imply that petroleum resources will be discovered or produced in a specific time frame. The general message is that more oil will be produced at higher projected prices. The price supply curves generally increase steadily and then increase dramatically at the high end of the price projection. In reality, oil prices have a history of dramatic short-term spikes, followed by varying periods of decline rather than a steady trend. The dramatic price increases do not occur at regular intervals.

Furthermore price supply curves, like resource estimates, inherently assume that there is equal access across the entire area. Practice shows that political, cultural, and competitive surface-resource concerns defer or eliminate exploratory access to areas. In addition, oil and gas resources are considered spread out uniformly across this area in potential prospects that usually include a few large and numerous smaller ones. With equal and unencumbered access to the assessment area, the larger prospects are explored and developed first. Price supply curves can be read/misread to suggest that an increasing number of the smaller prospects will become economically viable at higher oil prices. In reality, however, there are a number of geologic and economic reasons why this graphical extrapolation is not entirely valid. But nonetheless, it is useful in understanding the relationship between commodity prices and economically viable resources.

2.2.2.3. Reserves

Once a discovery of petroleum is made, the volume and extent of the deposit are determined. The estimates of recoverable discovered resources are called 'reserves' and generally include 'proved reserves' and 'other reserves'. Proved reserves are estimates of the amount of oil or gas recoverable from known reservoirs under current economic and operating conditions (EIA, 2004).

Different countries and different petroleum and financial industry associations have many different conventions and methods for categorizing reserves, which differ in technical ways. A comparison of the major petroleum classification schemes for the four Arctic countries discussed here shows that they all define three major categories: undiscovered, discovered non-commercial, and discovered (Table 2.1).

The discovered sub-commercial category is variously termed 'contingent resources' or 'contingent (or marginal) reserves'. The regulatory agencies typically define a subset of the total reserves and resources for public disclosures; the Canadian (CSA: Canadian Securities Administration) guidelines also allow the option to report contingent and/or prospective resources. The Norwegian Petroleum Directorate's classification does not include in-place categories.

A comparison of the terminology used for discovered volumes based on technical certainty classes (Table 2.2) shows that most classifications recognize three cumulative estimates or scenarios based on decreasing technical

Table 2.1. Correlation of the major petroleum classification schemes for four Arctic countries (modified from SPE, 2005).

	U.S. Geological Survey/Minerals Management Service	Canadian Securities Administration	Norwegian Petroleum Directorate	Russian Federation
In Place				
Total Petroleum Initially-in-Place (PIIP)	Total PIIP	Total PIIP	** [a]	Total PIIP
Discovered Petroleum Initially-in-Place	Discovered PIIP	Discovered PIIP	** [a]	Geological reserves
Undiscovered Petroleum Initially-in-Place	Undiscovered PIIP	Undiscovered PIIP	** [a]	Geological resources
Recoverable				
Discovered + undiscovered	__	Resources	Recoverable resources	__
Produced	Remaining recoverable	Production	Historical production	Produced reserves
Discovered	Identified resources	Discovered	** [a]	Recoverable reserves
Discovered commercial	Economic reserves	Reserves	Reserves	Economic-normally profitable reserves
Discovered subcommercial	Marginal reserves	Contingent resources	Contingent resources	Contingently profitable and sub-economic reserves
Discovered unrecoverable	Demonstrated sub-economic resources	(Discovered) unrecoverable	** [a]	Unrecoverable reserves
Undiscovered	Undiscovered resources	Prospective resources	Undiscovered resources	Recoverable resources
Undiscovered unrecoverable	__	(Undiscovered) unrecoverable	** [a]	Unrecoverable resources

[a] Recoverable quantities only based on development projects.

Table 2.2. Correlation of certainty classes of discovered volumes (modified from SPE, 2005).

Recoverable		U.S. Geological Survey/ Minerals Management Service	Canadian Securities Administration (CSA)	Norwegian Petroleum Directorate	Russian Federation
Commercial low estimate	Increment Cumulative	Measured –	Proved Proved	– Low estimate	A+B+C1 A+B+C1
Commercial best estimate	Increment Cumulative	Indicated –	Probable Proved+Probable	– Base estimate	C2 –
Commercial high estimate	Increment Cumulative	Inferred –	Possible Proved+Probable+Possible	– High estimate	C2 –
Sub-economic low estimate	Increment Cumulative	Measured –	– Low estimate	– Low estimate	– Low estimate
Sub-economic best estimate	Increment Cumulative	Indicated –	– Best estimate	– Base estimate	– Best estimate
Sub-economic high estimate	Increment Cumulative	Inferred –	– High estimate	– High estimate	– High estimate

The CSA uses the terms low/best/high estimates for prospective resources, with the understanding that these recoveries are conditional on discovery. They have no terms for incremental volumes. The Russian classification: A=Reasonably Assured; B=Identified; and C1=Estimated, is roughly equivalent to proved developed producing; proved developed non-producing; and proved undeveloped.

certainty: low/best/high estimates. Many agencies apply specific terms to the associated incremental volumes. While the same low/best/high estimates are applied to contingent and prospective resources, only the U.S. Geological Survey provides terms for the incremental estimates.

The rest of this section compares four of the classification systems used by Arctic countries.

In the U.S. classification (Figure 2.6), the overall movement of petroleum resources within the scheme is upward as development and production ensue. The degree of uncertainty as to the existence of resources decreases to the right. The degree of economic viability decreases downward and also implies a decreasing certainty of technological recoverability (Sherwood et al., 1996). The United States uses slightly different definitions for onshore and offshore resource classifications (U.S. Geological Survey definitions onshore and the Minerals Management Service definitions offshore). The terms and associated definitions listed in Box 2.2 are used on the Outer Continental Shelf (OCS). Although these are not universally accepted definitions, they give a good idea of the categories of resources that may be defined based on the knowledge of the existence of petroleum and the degree of certainty for which they are known.

Canada has no single national system for classification of resources and reserves, but has generally similar categories for defining resources and reserves. The National Energy Board of Canada reports oil and gas resources in two major categories subdivided by degree of certainty (NEB, 2003). These are shown in Box 2.3. An example of the Canadian Securities Administration classification system is shown in Tables 2.1 and 2.2.

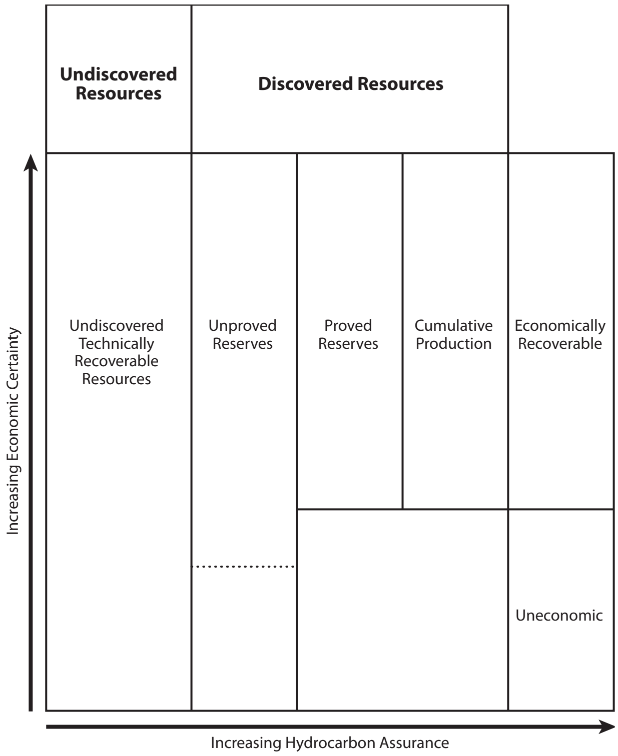


Figure 2.6. The U.S. scheme of classifying conventionally recoverable hydrocarbons. This scheme is dynamic, with resources migrating from one category to another over time. Resource availability is expressed in terms of the degree of certainty about the existence of the resource and the feasibility of its economic recovery. With increasing geological assurance, hydrocarbons advance from undiscovered resources to discovered resources to unproved reserves (after Sherwood et al., 1998a).

Box 2.2. U.S. resource definitions for assessing resources on the Outer Continental Shelf

Undiscovered resources. Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Also included are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

Undiscovered technically recoverable resources (UTRR). Hydrocarbons that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance (gas or water injection), or other secondary recovery methods, but without any consideration of economic viability. The UTRR do not include quantities of hydrocarbon resources that could be recovered by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates, or oil and gas that may be present in insufficient quantities or quality (low permeability 'tight' reservoirs) to be produced via conventional recovery techniques. Also, the UTRR are primarily located outside of known fields.

Undiscovered economically recoverable resources (UERR). The portion of the UTRR that is potentially recoverable at a profit under imposed economic and technologic conditions.

Reserves. The quantities of hydrocarbon resources anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty.

Proved reserves. The quantities of hydrocarbons estimated with reasonable certainty to be commercially recoverable from known accumulations under current economic conditions, operating methods, and government regulations. Current economic conditions include prices and costs prevailing at the time of the estimate. Estimates of proved reserves do not include reserves appreciation.

Unproved reserves. Quantities of hydrocarbon reserves that are assessed based on geologic and engineering information similar to that used in developing estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainty precludes such reserves being classified as proved.

Reserves appreciation. The observed incremental increase through time in the estimates of reserves (proved and unproved) of an oil and/or natural gas field. It is that part of the known resources over and above proved and unproved reserves that will be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. It is also commonly referred to as reserves growth or field growth.

Box 2.3. Canada: major categories oil and gas resources subdivided by degree of certainty

Undiscovered Resources
- Original Oil in Place
- Ultimately Recoverable Resources
- Undiscovered Recoverable Resources

Discovered Recoverable Resources
- Cumulative Production
- Remaining Established Reserves
- Future Improved Recovery

The third is the Norwegian classification system, shown diagrammatically in Box 2.4 together with the associated definitions.

The Russian scheme also accounts for the same basic categories of resources and reserves. Reserves of oil, gas, and condensate having commercial value are subdivided into Categories A (reasonably assured), B (identified), C-1 and C-2 (estimated). Undiscovered resources are subdivided into prospective D-0, and predicted D-1 and D-2. The definitions (after Clark, 2000) are given in Box 2.5.

Total global proved reserves have been estimated at approximately 1 trillion barrels since the late 1980s

Box 2.4. Norwegian resource definitions

Discovered resources comprise Resource Categories 0 to 7 and the term is used for petroleum volumes proven through drilling.

Contingent resources refers to discovered resources that have not yet been approved for development.

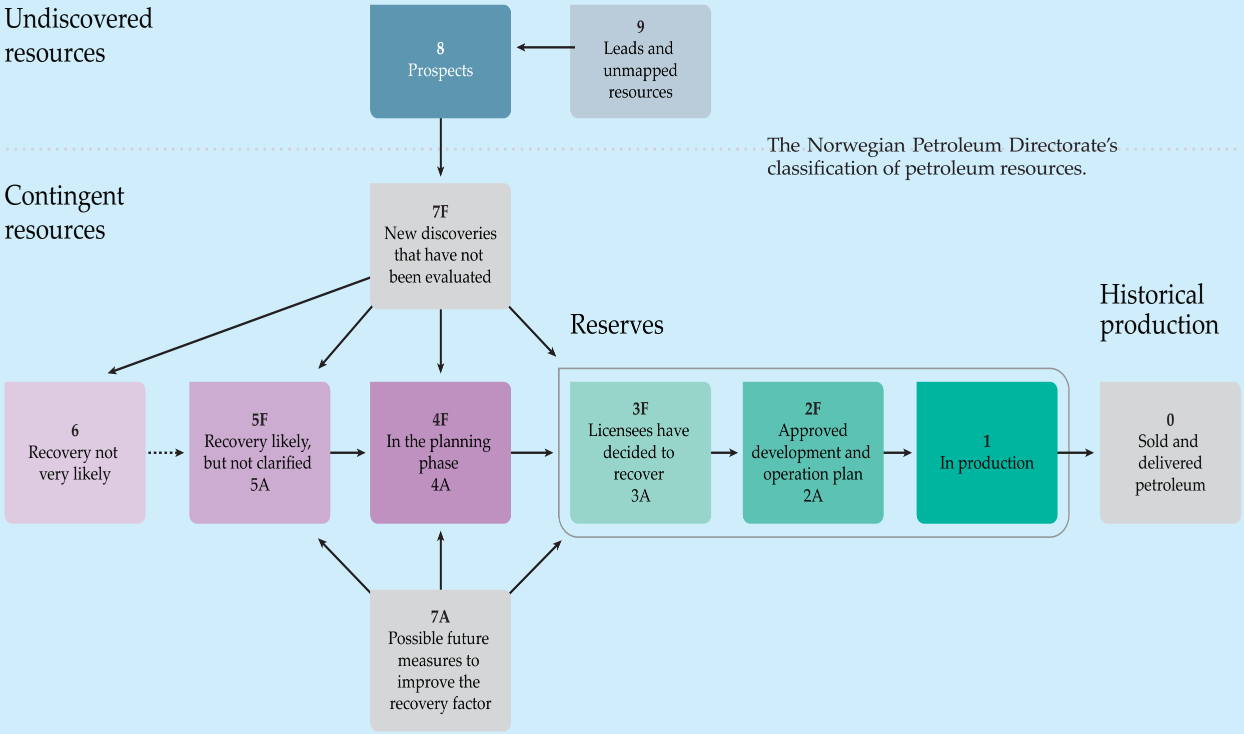
Undiscovered resources are petroleum resources that are presumed to be in place in defined play models, confirmed or unconfirmed, but that have not yet been proven through drilling (Resource Categories 8 and 9). There is always great uncertainty associated with estimates of undiscovered resources. The resource estimate stated for undiscovered resources is the statistical expected value.

Reserves are remaining recoverable, marketable petroleum resources that the licensees have decided to develop, and for which the authorities have approved a Plan for Development and Operation (PDO) or granted a PDO exemption. Reserves also include petroleum resources in deposits which the licensees have decided to develop, but which have not yet been considered by the authorities in the form of a PDO or PDO exemption. Reserves are distributed among Resource Categories 1 to 3.

A **petroleum deposit** is an accumulation of petroleum in a geological unit, delimited by rocks with structural or stratigraphic boundaries, contact surfaces between petroleum and water in the formation, or a combination of these, so that the overall petroleum included is in pressure communication through liquid or gas.

A **discovery** is one or more petroleum deposits together which were discovered in the same well and which through testing, sampling or logging have shown probable mobile petroleum (includes both commercial and technical discoveries). There is only one discovery well for each discovery. This means that new wells that prove resources that are part of, or that will be incorporated in, the resource estimate for an existing discovery are not regarded as being new discovery wells. The discovery year is the year the discovery well was temporarily abandoned or completed.

A **field** is one or more discoveries together which are covered by an approved PDO or have been granted an exemption from the PDO requirement.



The Norwegian Petroleum Directorate's classification of petroleum resources.

Box 2.5. Russian resource definitions

Category A reserves are those of pools or parts thereof that are in production. These have been studied in detail with determination of dimensions of pools, effective thickness, oil-gas saturation, composition and properties of the hydrocarbons, drive, productivity of wells, formation pressure, etc.

Category B reserves are those of pools or parts thereof that are not in production but otherwise have had the same properties determined as for the Category A reserves.

Category C-1 reserves are those of pools or parts thereof that are not yet ready for production, but their productivity has been established on a basis of recovery of commercial flows of oil or gas. Also, geological and geophysical data have been positive for wells that have not yet been tested. Dimensions of pools have been determined by delineation wells. Extensive studies have been completed on properties of reservoirs and the hydrocarbons.

Category C-2 reserves are those of non-delineated parts of pools adjacent to sectors with reserves of a higher category. Dimensions of the pool, reservoir properties, and composition of the hydrocarbons are known in general based on geological and geophysical data.

Category D-0 prospective resources are those of areas that are ready for deep drilling. Strata that are productive in other areas have not yet been drilled here. Various properties have been determined by geophysics and by analogy with delineated pools.

Category D-1 predicted resources are those of lithologic-stratigraphic complexes assessed within large regional structures that have demonstrated commercial petroleum potential. Assessment is based on analogy with delineated fields within the region.

Category D-2 predicted resources are those of large regional structures where no discoveries have yet been made. Assessment is by analogy with regions where discoveries have been made.

Table 2.3. Estimated world oil resources, 1995 – 2025 in billion m^3 (billion barrels in parentheses). Modified from EIA 2005a (6.28 bbl oil = 1 m^3 oil).

Region	Proved Reserves	Reserve Growth	Undiscovered	Total
Mature Market Economies				
United States	3.5 (21.9)	12.1 (76.0)	13.2 (83.0)	28.8 (180.9)
Canada	28.4 (178.8)	2.0 (12.5)	5.2 (32.6)	35.6 (223.9)
Mexico	2.32 (14.6)	4.01 (25.6)	7.3 (45.8)	13.7 (86.0)
Western Europe	2.5 (15.8)	3.1 (19.3)	5.5 (34.6)	11.1 (69.7)
Japan	0.016 (0.1)	0.016 (0.1)	0.05 (0.3)	0.08 (0.5)
Australia/New Zealand	0.24 (1.5)	0.43 (2.7)	0.94 (5.9)	1.61 (10.1)
Transitional Economies				
Former Soviet Union	12.4 (77.8)	21.9 (137.7)	27.2 (170.8)	61.5 (386.3)
Eastern Europe	0.24 (1.5)	0.24 (1.5)	0.22 (1.4)	0.70 (4.4)
Emerging Economies				
China	2.9 (18.3)	3.1 (19.6)	2.3 (14.6)	8.35 (52.5)
India	0.86 (5.4)	0.60 (3.8)	1.1 (6.8)	2.5 (16.0)
Other Emerging Asia	1.7 (11.0)	2.3 (14.6)	3.8 (23.9)	7.88 (49.5)
Middle East	116.2 (729.6)	40.2 (252.5)	42.9 (269.2)	199.25 (1251.3)
Africa	16.1 (100.8)	11.7 (73.5)	19.9 (124.7)	47.6 (299.0)
Central and South America	16.0 (100.6)	14.5 (90.8)	20.0 (125.3)	50.4 (316.7)
Total World	203.4 (1277.7)	116.20 (730.2)	149.6 (938.9)	469.1 (2946.8)

(Table 2.3), because additions to reserves from new discoveries and from revisions to previous estimates have approximately matched the annual volume of oil produced (or withdrawn) (see http://www.eia.doe.gov/emeu/international/reserves.html). As a reservoir is depleted of oil or gas, the pressure declines and greater volumes of water are produced making the oil and gas costlier to produce until eventually further production becomes uneconomic. A typical example of a mature oil field and the relative increase in the amount of water produced over the life of the field is shown in section 2.3 (Figure 2.22). However, as discussed later in this chapter (see section 2.5), recent advances now allow greater recovery from old reservoirs through water-flood and miscible gas recovery techniques, the economic recovery of heavier oil, and production at new smaller fields such as by utilizing directional/extended-reach drilling, horizontal drilling, and multiple completions from a single well bore (Figure 2.7).

2.2.2.4. Factors affecting petroleum activities

Environmental, technological, and economic conditions in the Arctic are similar in many ways between countries and regions, as are operational conditions and oil and gas transportation issues. The need to keep the reserves base steady or increasing is also similar among all countries.

2.2.2.4.1. Drivers

Drivers are situations that move exploration and development activities forward. Although price is a driver, today's high prices are not the only consideration for development of a discovery. The long-term price projection is important, because Arctic discoveries require a significant length of time for field delineation, development (which may include building new onshore facilities, island construction or platforms for offshore, drilling of production wells, etc.), building of connecting pipeline infrastructure, ports, tankers, and so forth. A large discovery can be a driver for exploration and development, as with the discovery of the giant *Prudhoe Bay* oil field, where leasing, seismic, and exploration drilling all increased in addition to production activities (see section 2.4.1.3.1). Conversely, the depletion of a large field may also be a driver for new exploration and development activities as smaller and more distant fields are sought to replace the older production. Figure 2.8 shows the diminshing flow through the Trans-Alaska Pipeline System (TAPS) over time as the *Prudhoe Bay* field matures and output drops. When throughput reaches certain threshold levels, costs to refit TAPS for low volume and low flow will probably be prohibitive; although the number varies, at somewhere between 400 000 bbl/d depending on the price of oil (considered by some as the economic limit) and 200 000 bbl/d (considered by some as the technological limit), TAPS will have to be shut down or refitted at enormous cost at some stage in the future. This is a major driver for searching for and producing additional oil resources.

Incentive programs offered by host governments that encourage activities by discounting royalties or taxes or granting favorable terms for leases can be another driver. Socio-economic drivers such as public acceptance and perceived need or support from public and political arenas are also factors in whether and how oil and gas activities are undertaken.

The need to keep a reserves base is an exploration and production incentive for industry to replace what is produced with new reserves from enhanced recovery, direct purchase of someone else's reserves, acquisition of assets, or discovering new reserves. In recent years, many mergers and acquisitions have taken place in the international oil and gas industry. This reshuffling of reserves has in most cases enhanced or replaced reserves of the merged or parent company. Some of these companies have, therefore, not necessarily discovered new oil and gas reserves, but rather acquired them. But there are only so many purchases to be made or companies to be bought or merged. Eventually, keeping up reserves will be a factor in a company's decision to explore and develop new fields. In this case, exploration activity may not have increased as the price of oil rose.

Over half of the Arctic countries have a national oil or gas company. The trend of national companies to participate in industry activities has been more or less a driver of activities. This could change, however, possibly resulting in competing interests and/or stricter controls on the activities of private companies in the future. The activities of national petroleum companies also may not follow oil prices or other world events but be determined by national factors and concerns unrelated to petroleum prices.

2.2.2.4.2. Restrictions

Restrictions or 'bottlenecks' are conditions that resist or stop oil and gas developments. These can be permitting issues, rig or crew availability and cost, or transportation limitations, among other things. In Russia, a lack of pipeline capacity has hampered some production. The size of a project necessary to support high costs will require regulatory reviews and approvals, often at several levels (local community, State, Federal government, tribal/indigenous), which can often lead to project delays. Delays can interrupt or stop projects since unanticipated schedule slippages can be costly, and can postpone production and expected revenues.

2.2.2.4.3. Costs

As the price of oil increases, so do the costs for operating in the remote Arctic regions, where costs are already the highest in the world. Some general oil and gas cost figures for exploration, development, and production are

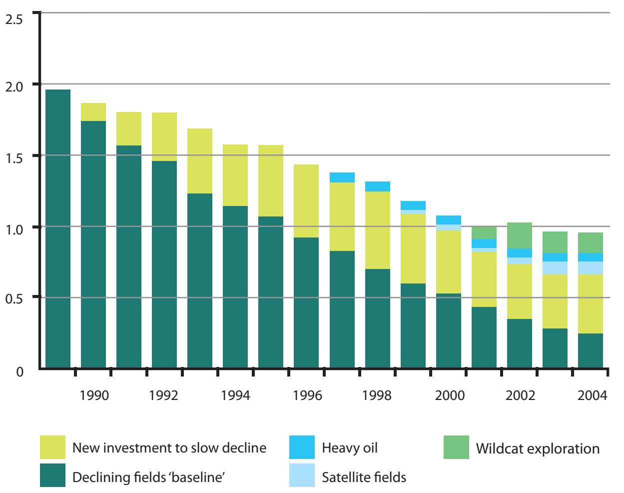


Figure 2.7. Decline in production from North Slope Alaska fields. Without the enhanced recovery, satellite field development, production of heavy oil and new oil from wildcat drilling, the production from the North Slope might be well below 500 thousand bbl/d (after Brady, 2005).

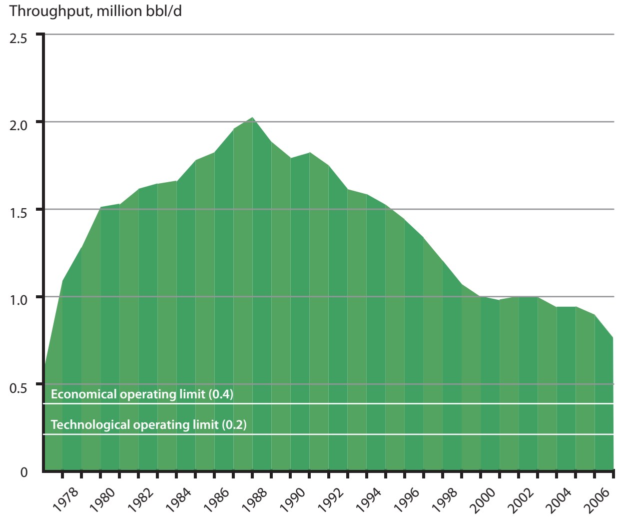


Figure 2.8. Trans-Alaska Pipeline daily throughput 1977-2006. This graph shows the diminshing flow through the pipeline over time as the *Prudhoe Bay* field matures and output drops (after Alyeska, 2007).

given below. As an example, Table 2.4 shows the costs for exploration, development, and completion for U.S. wells in the Arctic and at other U.S. locations for both onshore and offshore activities. Exploration and development costs from other offshore oil and gas fields under development in the Arctic are similar to the high costs for Alaska.

Projected Arctic shelf exploration expenditures from the Russian Government for the period 2006 – 2020 are also high. In 2006 – 2010, Russia plans to collect 85 000 line-km of 2-D seismic data at a cost of USD 100 719 000 (2790 million RUB), which is about USD 1185 per kilometer, and to conduct 3500 m of exploration drilling at a cost of USD 35 378 000 (980 million RUB) or about USD 10 108 per meter. In 2011 – 2020, Russia plans to collect 278 000 line-km of seismic data at a cost of USD 329 430 000 and 45 900 line-meters for orientation drilling at a cost of USD 463 957 200 (see section 2.4.7). The average well is 3800 m deep based on 49 500 m divided by the 13 wells projected for the entire period to 2020. This equates to an estimated cost of USD 38 410 400 per well.

Development costs for offshore Arctic projects are similarly high. The *Snøvhit* gas field in the Norwegian Barents Sea (see section 2.4.6) involves a sub-sea template with 20 wells and an expected investment of USD 2.8 billion (2006 values). Total investments, including the land facilities, are expected to be nearly USD 9 billion (2006 values) (MPE, 2006).

In the Russian part of the Barents Sea, the *Prirazlomnoe* oil field located 60 km from land will be developed in the next few years utilizing 40 directional wells drilled from a single platform in shallow water (Ocean Futures, 2006). The cost estimate for drilling these wells is nearly USD 290 million (see section 2.4.7) or an average of USD 7.25 million per well.

The *Shtokman* gas-condensate field, also in the Russian part of the Barents Sea, is planned for development sometime in the next few years and is likely to be developed from sub-sea completions (Ocean Futures, 2006). Estimates of the investment needed for production range from USD 11 – 20 billion.

Other restrictive conditions that may be common to many countries but are amplified in the Arctic include the following:

- non-existent or insufficient infrastructure for transportation;
- harsh operating conditions;
- long distances to supply points and infrastructure;
- short winter ice road/construction/operating season;
- fragile environment and extensive mitigation and environmental costs;
- development of needed technology;
- indigenous land claims;
- overlapping permit restrictions;
- lengthy permitting process;
- legal challenges; and
- cost over-runs (higher costs than planned for).

Although large worldwide energy demand in recent years has caused prices to rise and created an incentive for oil and gas activities, the high price of oil may also act as a deterrent to new exploration activities because the already high costs of Arctic operations are amplified by associated high fuel and transportation costs. This same driver has resulted in more efficient and enhanced recovery from existing fields and the tendency for members of international industry to consolidate. Decisions on whether to invest in oil and gas projects, and ultimately advance petroleum discoveries to the production phase, are underlain by a complex set of factors and risks. Their evaluation varies between and within countries and between and within companies; the evaluation is also tailored to specific oil and gas regions and may change through time.

Table 2.4. Comparison of U.S. development and completion costs for onshore and offshore activities in the Arctic and at other U.S. locations (modified from NPC, 2007; James Craig, 2007, unpublished estimates for costs of U.S. Beaufort and Chukchi Sea wells and development from MMS Alaska).

Region	Water depth, m	Average drill depth, m[a]	Development drilling and completion cost, USD 1000/well	Exploration drilling cost, USD 1000/well
Denver Basin, Park Basins, Las Animas Arch	onshore	1500/3000	231/485	162/279 [b]
E. Texas, S. Arkansas, N. Louisiana	onshore	1500/3000	132/472	82/357 [b]
Onshore Coastal Plain Shallow	onshore	2200	5000	20 000
Eastern Gulf of Mexico (Shallow)	0 – 40	4060 [c] – 4600 [d]	8000 [e]	7000
Central and Western Gulf of Mexico	0 – 40	2700 [c] – 3100 [d]	5000 [e]	4000
Offshore Beaufort Shallow Water	50	1900	10 000	50 000
Chukchi Sea	50	2600	15 000	60 000

[a] Where there are two different average well depths this is reflected in the cost columns as two corresponding values; [b] dry hole well cost; [c] exploration; [d] production; [e] platform.

2.3. Overview of Arctic oil and gas activities

This section presents a summary of historical oil and gas activities throughout the Arctic as represented by various activity indices. These indices are presented on maps and standarised graphics through intervals of time, generally five-year increments. The locations of the major oil and gas provinces (OGP) and basins in the circumpolar Arctic are shown in Figure 2.9. These OGPs and basins occupy an area of 13 000 000 km², or 20% of the land area and 17% of the marine area north of 60° N.

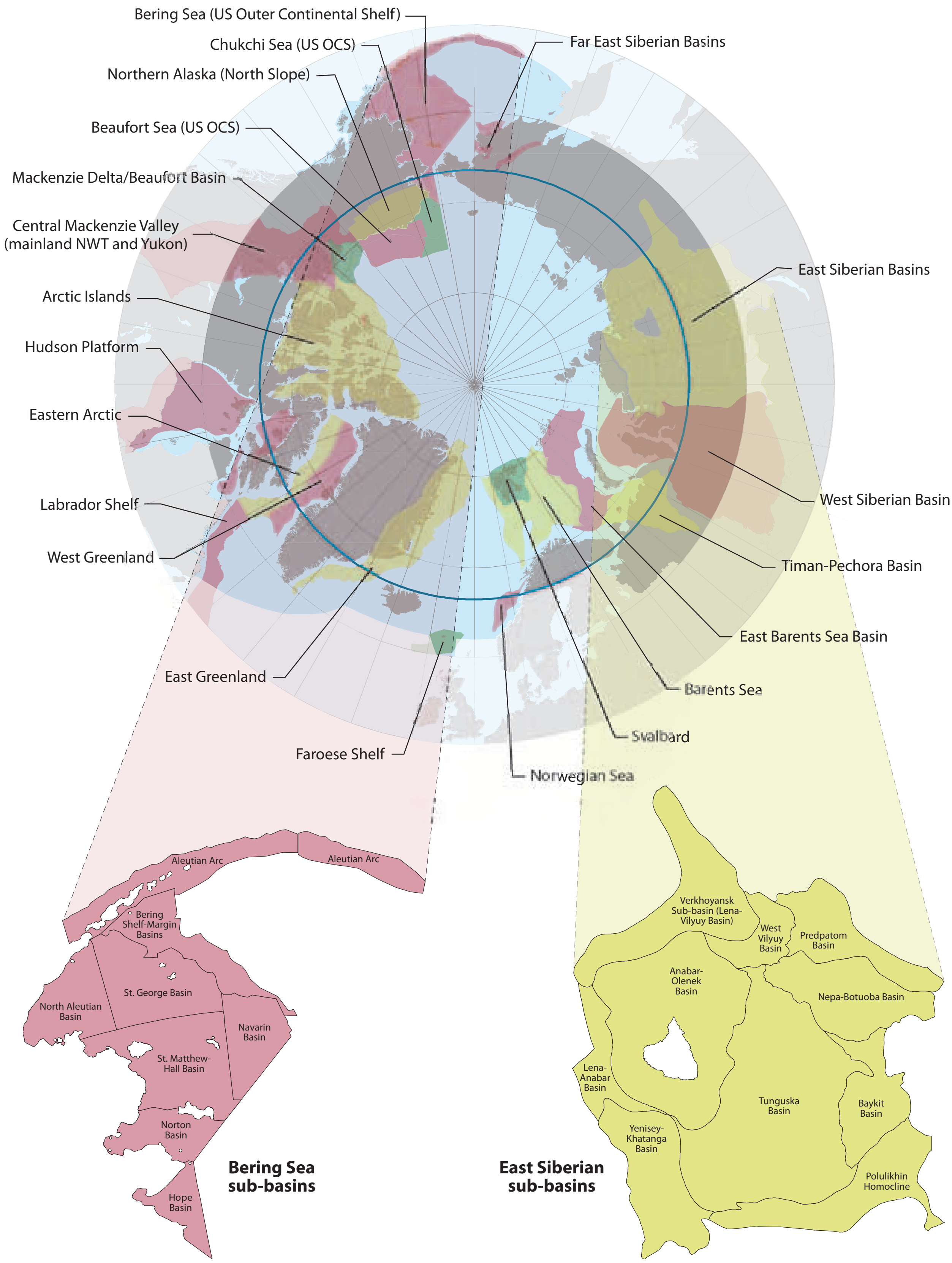
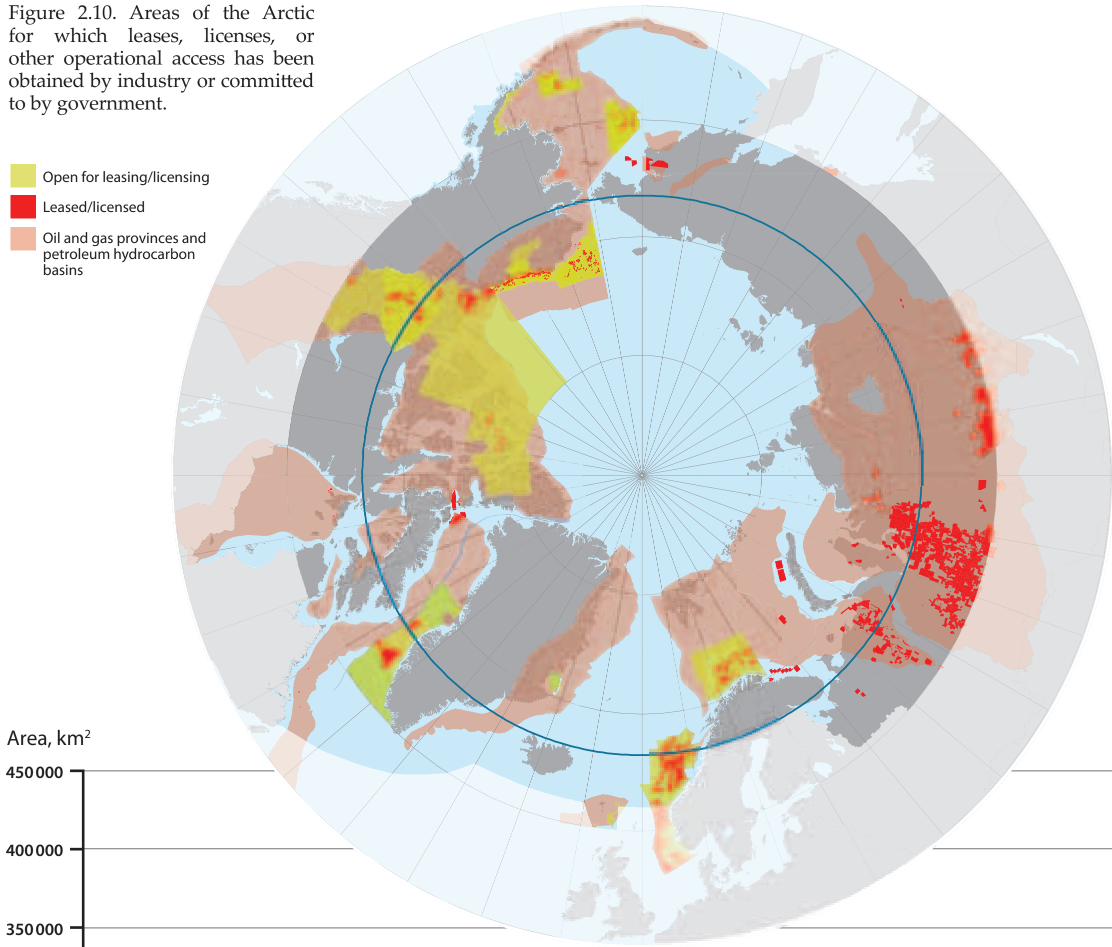


Figure 2.9. Major oil and gas provinces (OGP) and basins around the Arctic.

Licensing and Leasing

As a measure of the potential area available for exploration in relation to oil and gas deposits, Figure 2.10 shows the size of areas in the Arctic that have been made available for leasing, licensing, or government-sponsored access for the United States, Canada and Russia (since 1992). The size of the areas for which leases, licenses, or other operational access have actually been obtained by industry or have been committed to by government in these countries is provided in Figure 2.11. Russian data for this graph were only available for 1992 onwards, but clearly show the large contribution of Russia in relation to the other Arctic countries.

Figure 2.10. Areas of the Arctic for which leases, licenses, or other operational access has been obtained by industry or committed to by government.



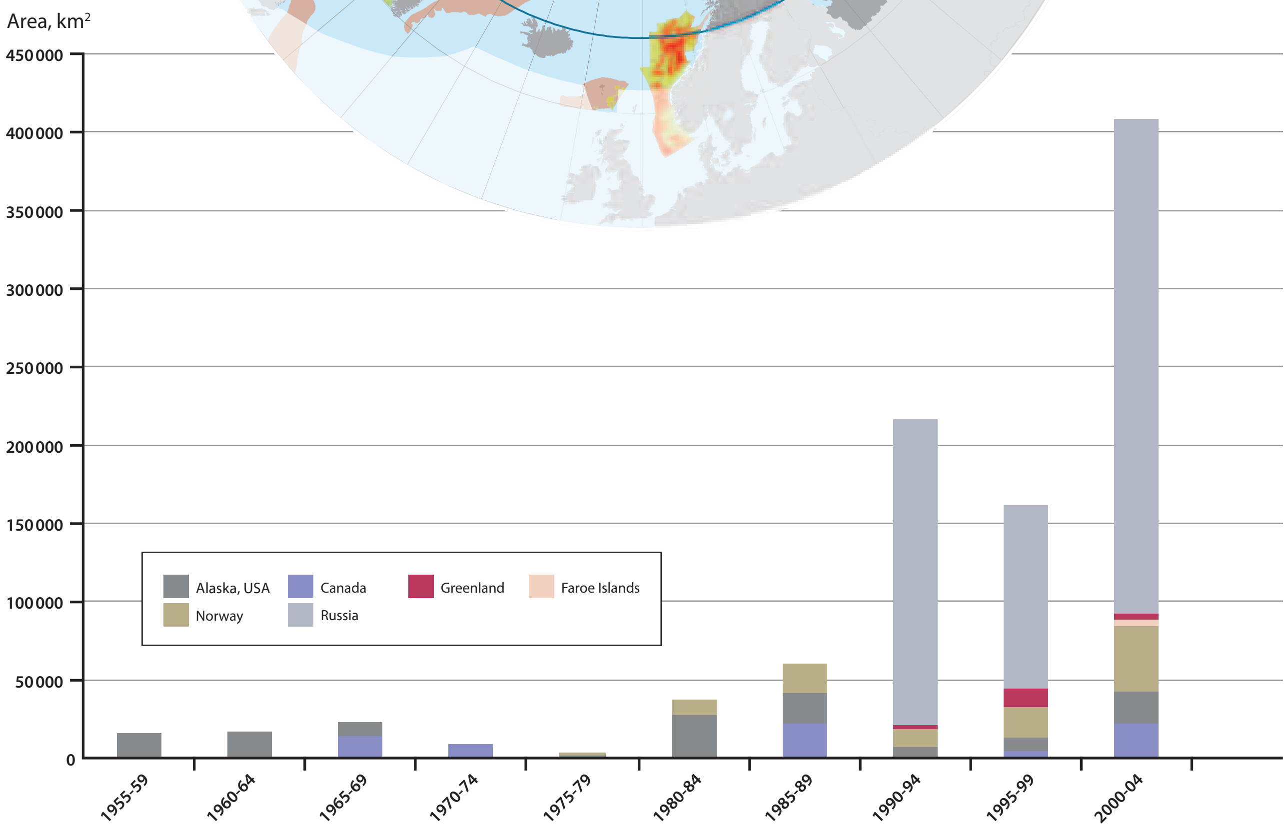
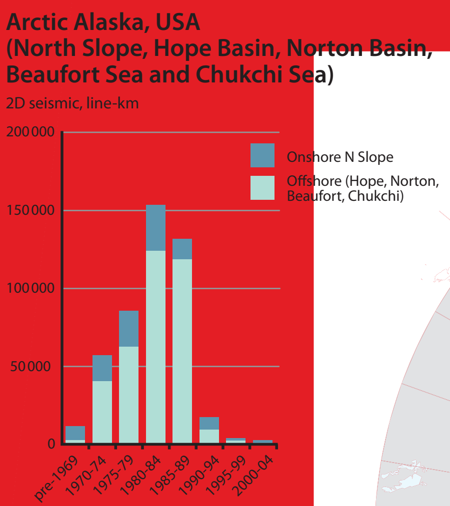


Figure 2.11. Size of areas for which leases, licenses, or other operational access has been obtained by industry or committed to by government.

The acquisition of seismic data provides a measure of exploratory activity in relation to hydrocarbon deposits. Figure 2.12 shows the extent of seismic 2-D exploration in the Arctic from available information. Although incomplete, this map clearly illustrates that much of the Arctic has been subjected to seismic investigation over the past 60 or so years. Figure 2.13 indicates the number of line-km of 2-D seismic data that have been obtained for all Arctic countries except Russia, as categorized into sub-regional areas and onshore or offshore locations. More intensive exploration by the acquisition of 3-D seismic data, a more modern but also more expensive technique, is replacing 2-D seismic acquisition, as illustrated in Figure 2.74.



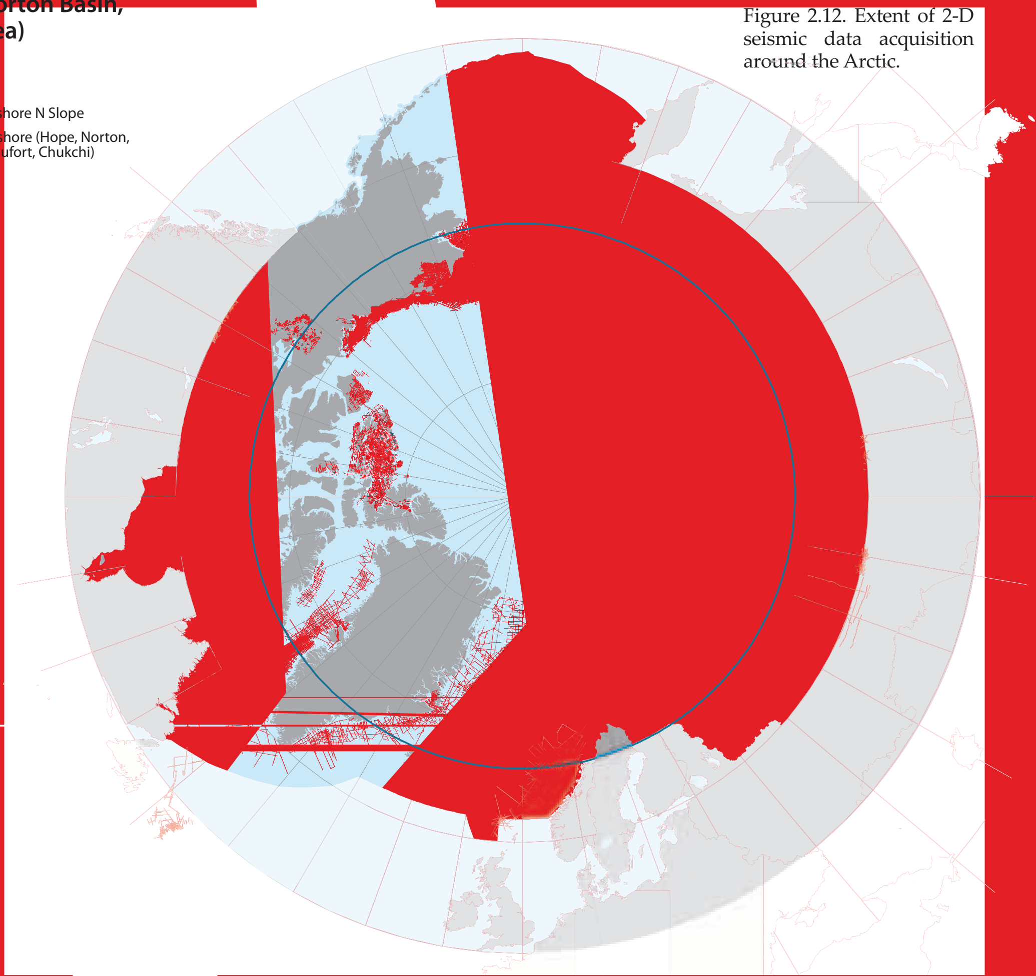
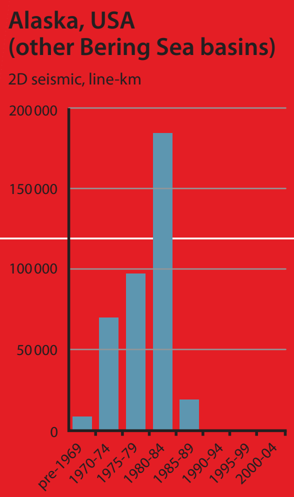
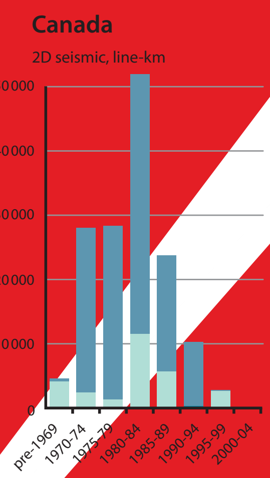
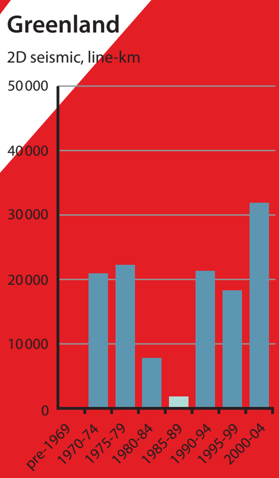
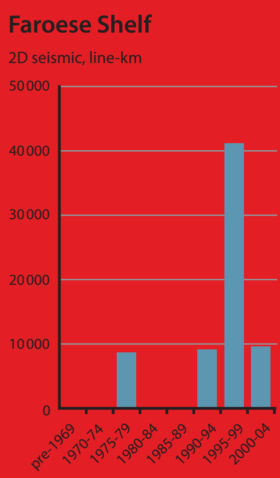


Figure 2.12. Extent of 2-D seismic data acquisition around the Arctic.









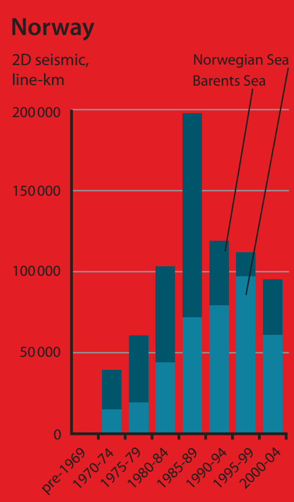


Figure 2.13. 2-D seismic acquisition over time in various Arctic areas (data not available for East Greenland and Russia) (Note difference in scales).

Drilling

The drilling of exploration wells has been the traditional next step in exploration activities, although the increasing use of 3-D seismic surveys and complex geologically based computer models have substantially decreased the need for exploratory drilling in recent years, resulting in increased efficiency of drilling operations.

The development and expansion of exploration drilling activity, together with the locations of discoveries and ultimately production wells, is clearly evident on a circumpolar Arctic basis in Figure 2.14, covering the years up until 2004. Oil exploration was conducted in the Mackenzie Valley, and on the Alaskan North Slope and Yamalo-Nenets Autonomous Okrug area prior to the Second World War. However extensive oil and gas exploration in northern Alaska, northern Canada and northern Russia only started after the Second World War, expanding considerably through the 1960s and 1970s with the discovery of large oil and gas reserves in the Yamalo-Nenets Autonomous Okrug and the Nenets Autonomous Okrug in Russia, on Alaska's North Slope, and in the Mackenzie Delta. In Alaska, exploration extended offshore, initially in the Beaufort Sea and later in the Bering and Chukchi Seas, leading to development of Alaskan North Slope nearshore fields. The 1980s saw exploration drilling in Norway's offshore areas in the Norwegian Sea, and later in the Barents Sea, and the first exploration drilling in Faroese waters. Exploration drilling in the Russian offshore area also resulted in discoveries. New exploration wells continue to be drilled and discoveries made throughout the main Arctic oil and gas development regions. New exploration areas since 1990 include offshore areas in Greenlandic waters. These developments are discussed in detail for each Arctic country in section 2.4.

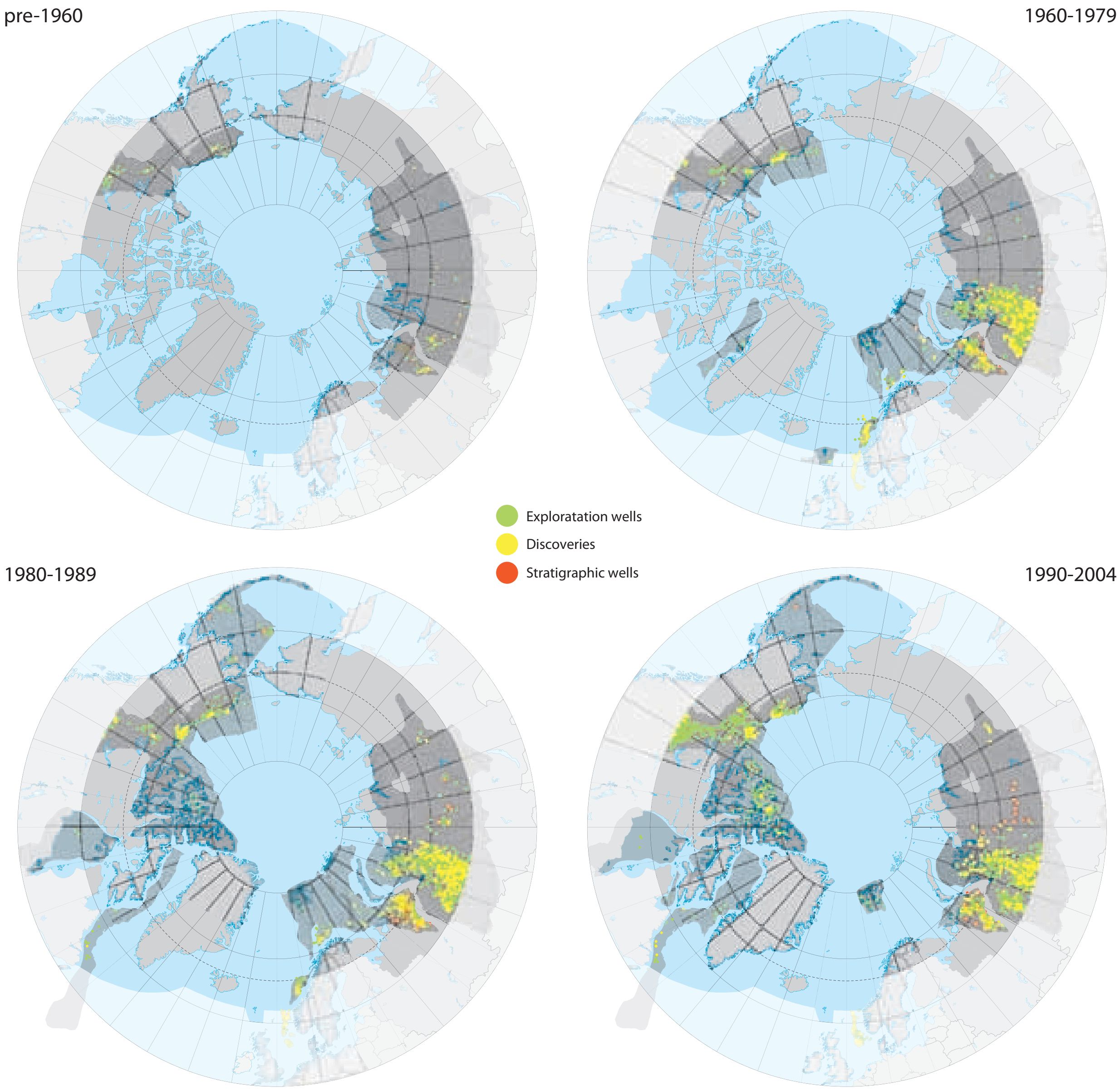
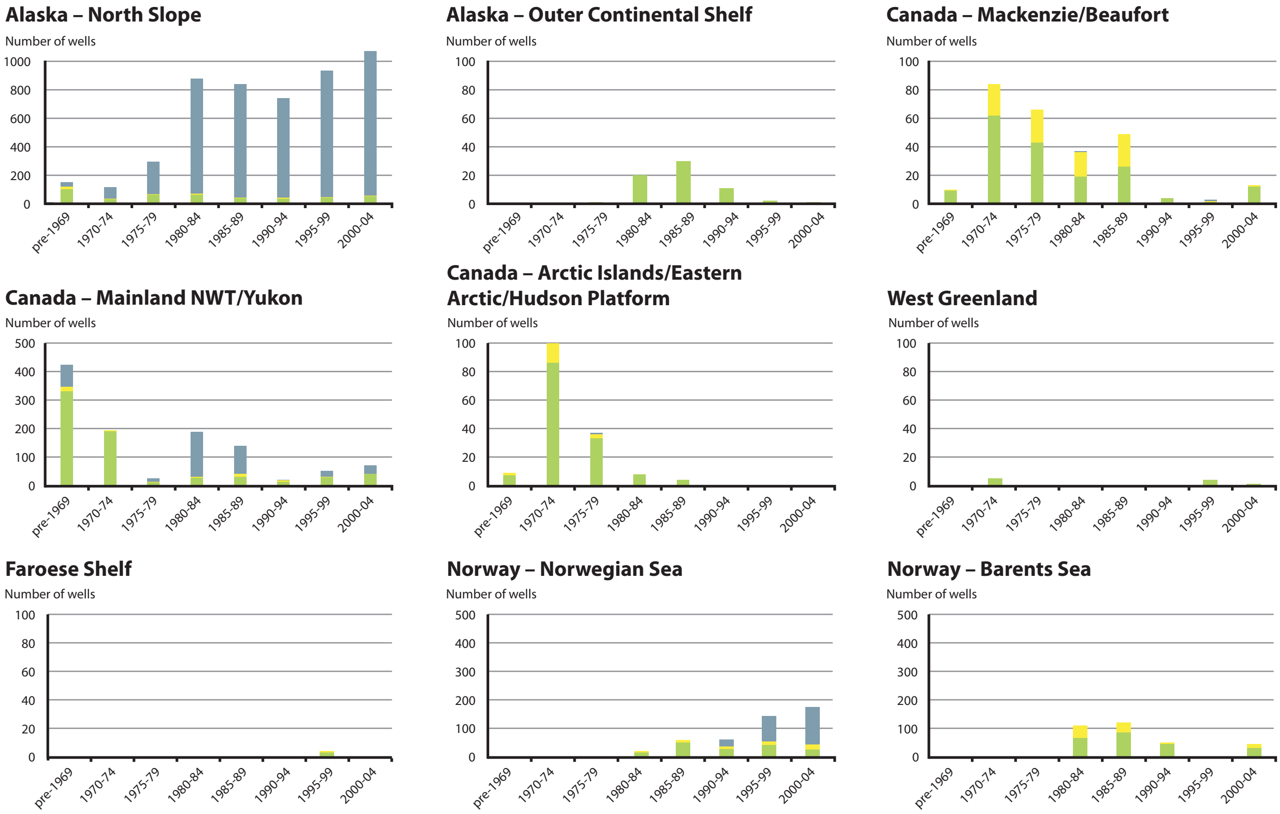


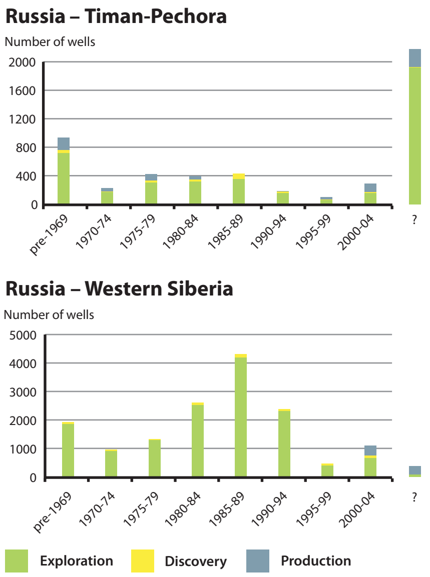
Figure 2.14. Locations of exploration and discovery wells drilled during different time periods.

Drilling (continued)

The numbers of exploration, discovery and production wells drilled in various Arctic sub-regions since 1960 are depicted in Figure 2.15. Data for Russian production wells are incomplete prior to 2000. Peak exploration drilling activity in Russia occurred from 1985 to 1989, with over 4000 exploration wells drilled during this period. The number of discovery wells drilled in Russia also peaked during this period, while peaks in discovery wells drilled in Canada occurred between 1970 and 1974 and in Norway between 2000 and 2004.

In addition to the number of wells drilled, another measure of oil and gas exploration and production activity is the number of meters of wells drilled. Figure 2.16 summarises available information on metres of exploration, discovery and production wells drilled in the Arctic since 1960. Data for the number of meters of exploration, discovery, and production wells by Arctic sub-region are presented in later descriptions of oil and gas activities in the various countries (see Figures 2.30, 2.54, 2.75 and 2.83).





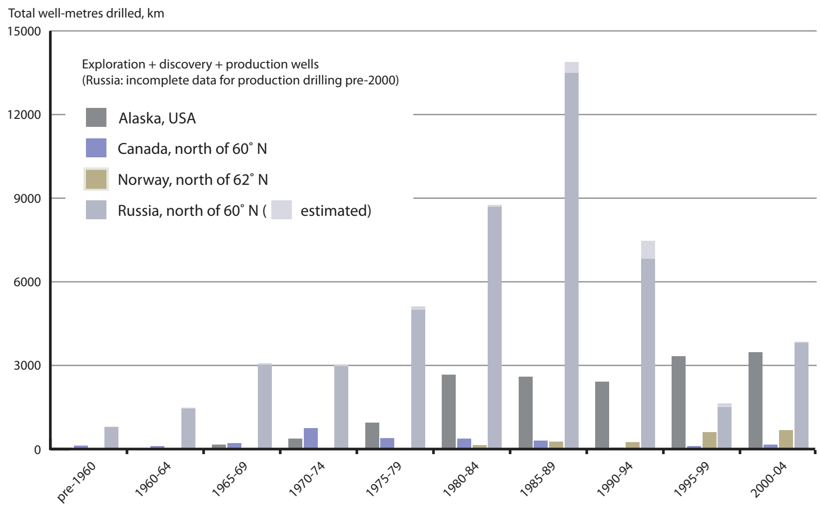


Figure 2.15. Numbers of exploration, discovery and production wells drilled in different Arctic sub-regions over time (note the difference in scales). The bars with question marks equate to drilling with dates unknown.

Figure 2.16. Metres of exploration, discovery and produciton wells drilled in Arctic regions over time (data on Russian produciton wells incomplete pre-2000). West Greenland: 15667 m in 1975-79, 5003 m in 1995-99 and 2937 m in 2000-04; Faroese shelf: 16447 m in 2000-04.

The total volume of Original Oil in Place (OOIP) in the Arctic territories of the four producing countries (USA (Alaska), Canada, Norway, and Russia) to 2004 is estimated at 34.2 billion m³ (ca. 215 000 million bbl), with cumulative production to 2004 amounting to 13.4 billion m³ (ca. 84 300 million bbl). Figure 2.17 presents the distribution of these resources between the countries together with the cumulative production for each country.

The development in oil production between 1960 and 2004 from Arctic fields in the various producing countries can be seen in Figure2.18. The *Norman Wells* field in Arctic Canada started producing oil in the 1920s, but major production from other Arctic fields did not take place until the 1960s. Oil was discovered at Prudhoe Bay on the Alaskan North Slope in 1968, but development of the North Slope fields only took off after 1977 when the Trans-Alaska Pipeline came on-stream. In Russia, Arctic fields in the Yamalo-Nenets region (West Siberian Basin) began producing in 1972, with development extending to the Nenets region (Timan-Pechora Basin) in the 1980s. The first oil production in the High Arctic took place with the development in 1985 of *Bent Horn*, a small field in the Arctic Island Archipelago, which produced oil for over a decade before decommissioning. Norwegian oil production from fields in the Norwegian Sea (Haltenbaken) began in the late-1990s. Production from individual fields is presented in graphics depicting oil and gas activities in the various countries (see Figures 2.31, 2.55a and 2.76).

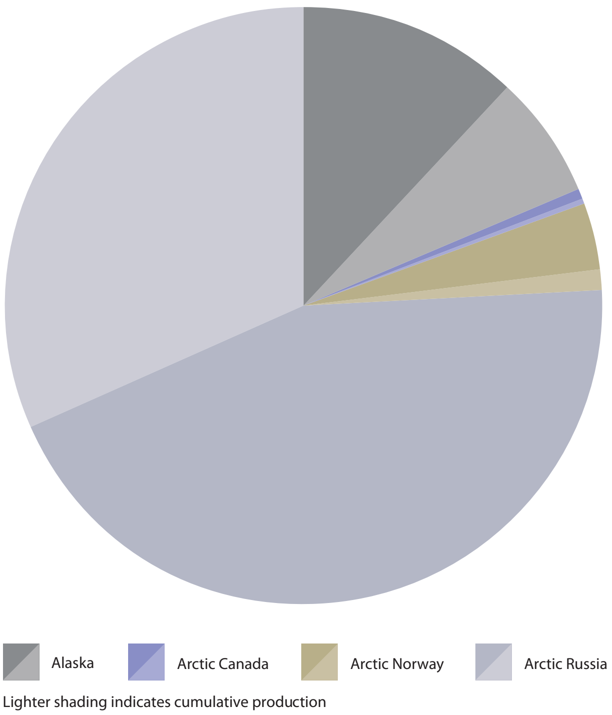


Figure 2.17. Original Oil in Place (OOIP) for Arctic areas; cumulative production is shown in a lighter shade. Oil is defined as oil + condensate + natural gas liquids. Reported data: Alaska – oil in place; Canada – discovered recoverable oil; Norway – oil in place + associated liquids in place; Russia – oil in place + condensate in place (Source: IHS). Canada also reported 11 070 million bbl of 'undiscovered' oil.

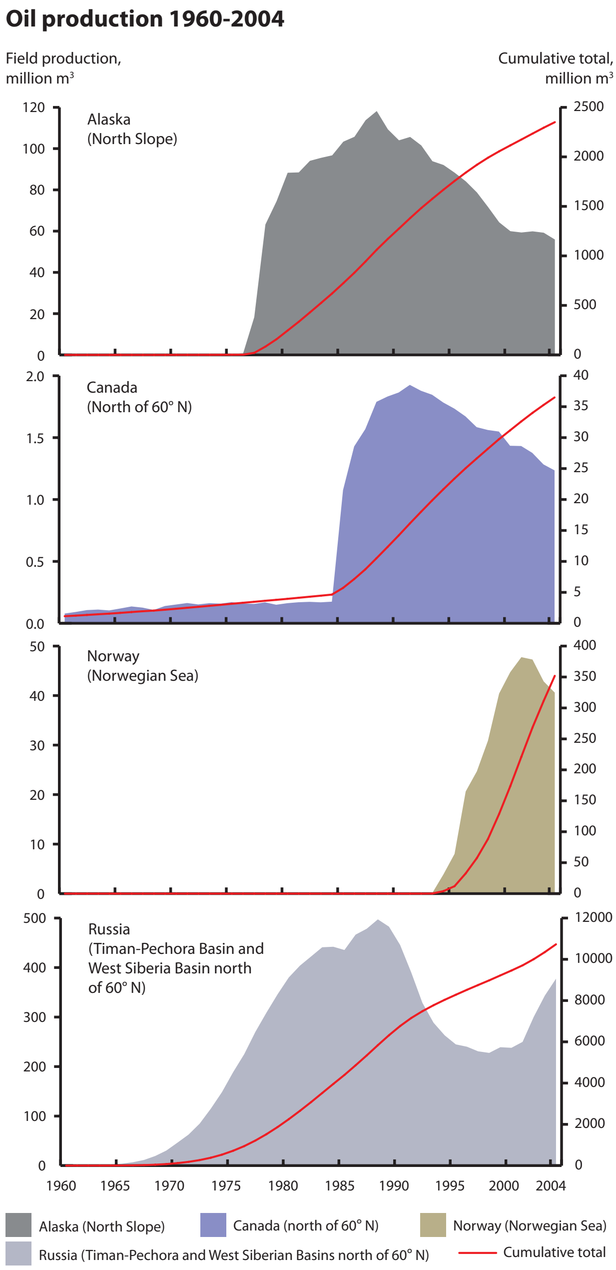


Figure 2.18. Annual and cumulative oil production from fields in Arctic regions of the USA (Alaska), Canada, Norway and Russia over time (note difference in scales).

Gas Resources and Production

The total volume of Original Gas in Place (OGIP) in the Arctic territories of the three main producing countries (Canada, Norway, Russia) and the USA (Alaska) to 2004 is estimated at 55 600 billion m^3 (ca. 1 963 000 billion cu.ft.), with cumulative production to 2004 amounting to 12 250 billion m^3 (ca. 432 400 billion cu.ft.). Figure 2.19 presents the distribution of these resources between the countries together with the cumulative production for each country.

The development in gas production between 1960 and 2004 from Arctic fields in the various producing countries can be seen in Figure 2.20. Gas fields in Canada (mainly the *Pointed Mountain* field that produced from 1972 to 2001) and the West Siberian Basin and Timan-Pechora Basin of Russia were developed from the early 1970s. Fields in the Norwegian Sea began producing gas in the late 1990s, with production extending into the Barents Sea with the development of the *Snøhvit* field in 2007. Production from individual fields is presented in graphics depicting oil and gas activities in the various countries (see Figures 2.55b and 2.77).

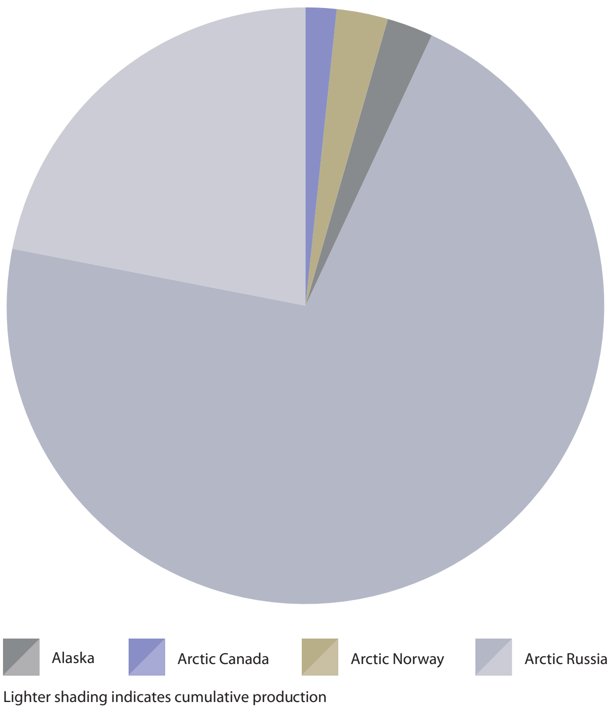


Figure 2.19. Original Gas in Place (OGIP) for Arctic areas; cumulative production is shown in a lighter shade. Reported data: Canada – discovered remaining recoverable gas; Norway – free gas in place + associated gas in place; Russia – gas (Source: IHS). Canada also reported 219 150 billion cu.ft. of 'undiscovered' gas. USA also reported 65 200 billion cu.ft. of 'undiscovered' technically recoverable (non-associated) gas (mean estimates) beneath Federal and related lands of the Alaska North Slope (NRPA and ANWR1002 areas).

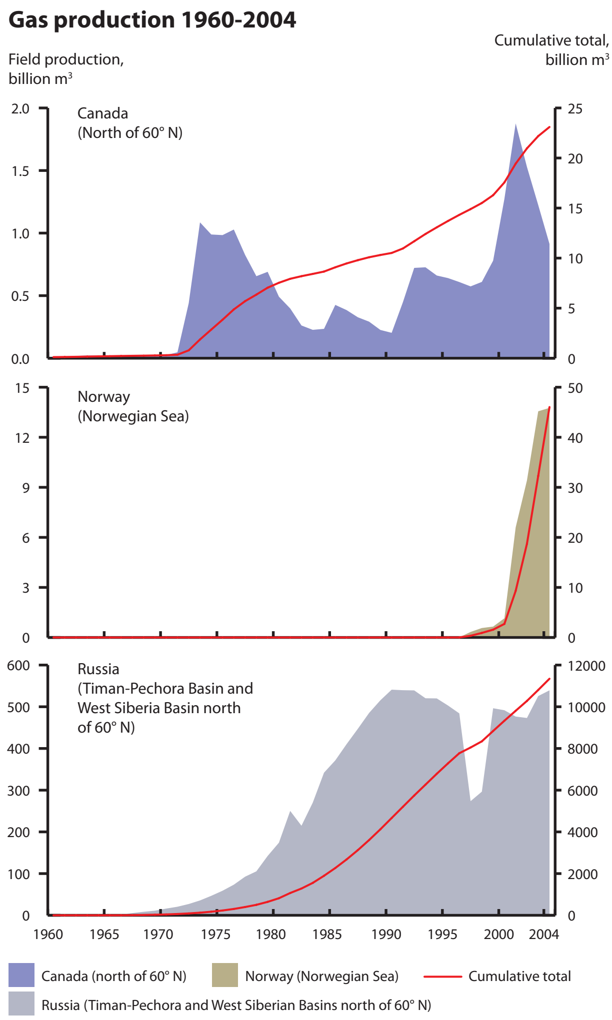


Figure 2.20. Annual and cumulative gas production from fields in Arctic regions of Canada, Norway and Russia over time. Alaskan gas production is re-injected.

Oil and Gas Production

Four countries currently produce oil and gas from their Arctic territories; USA (Alaska), Canada, Norway and Russia (Figure 2.21). The first Arctic field to be developed was at Norman Wells in the Mackenzie Valley (Canada), where oil was produced commercially from the 1920s. However, it was not until the late 1960s that production started in other Arctic regions. Production from fields in the Arctic is strongly dependent on the development of infrastructure, especially pipelines, to transport oil and gas to refineries and markets at more southerly latitudes.

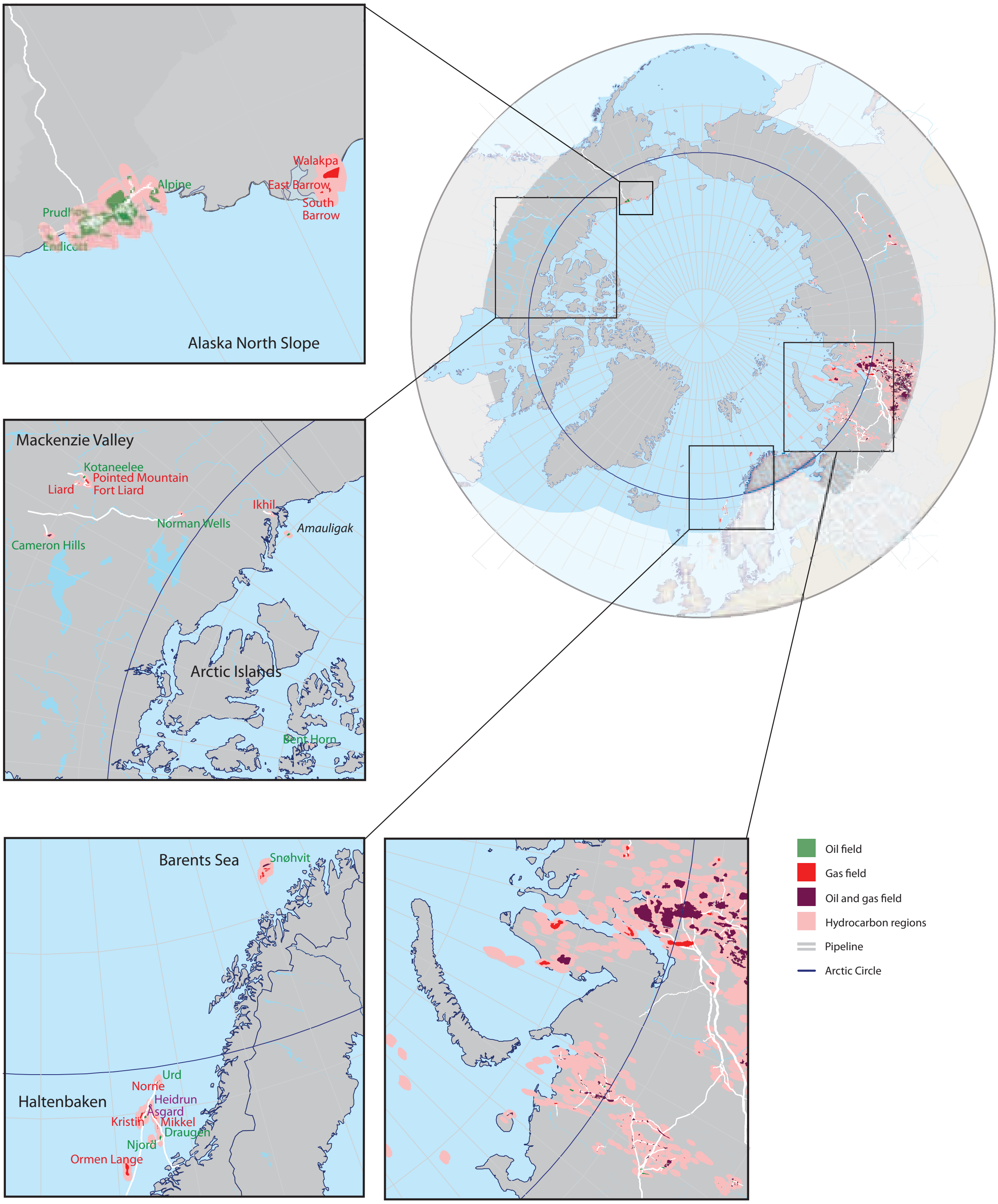


Figure 2.21. Location of oil and gas producing fields in the Arctic territories of the USA (Alaska), Canada, Norway and Russia.

Fluid Production and Re-injection

Oil and gas are not the only fluids extracted from production wells. As fields mature an increasing amount of production water is extracted. Figure 2.22 shows the overall development of the production of fluids, including oil and gas as well as produced water, from fields in Alaska, Arctic Canada, Arctic Norway, and Arctic Russia. In Alaska, all gas and much of the produced water are re-injected to provide pressure support for enhanced recovery of the oil or for disposal purposes (Figure 2.23). In Arctic Norway, produced water is discharged to the sea at three fields, while it is re-injected at the other fields; most waste gas is also re-injected, with very small quantities being vented or flared (Figure 2.24).

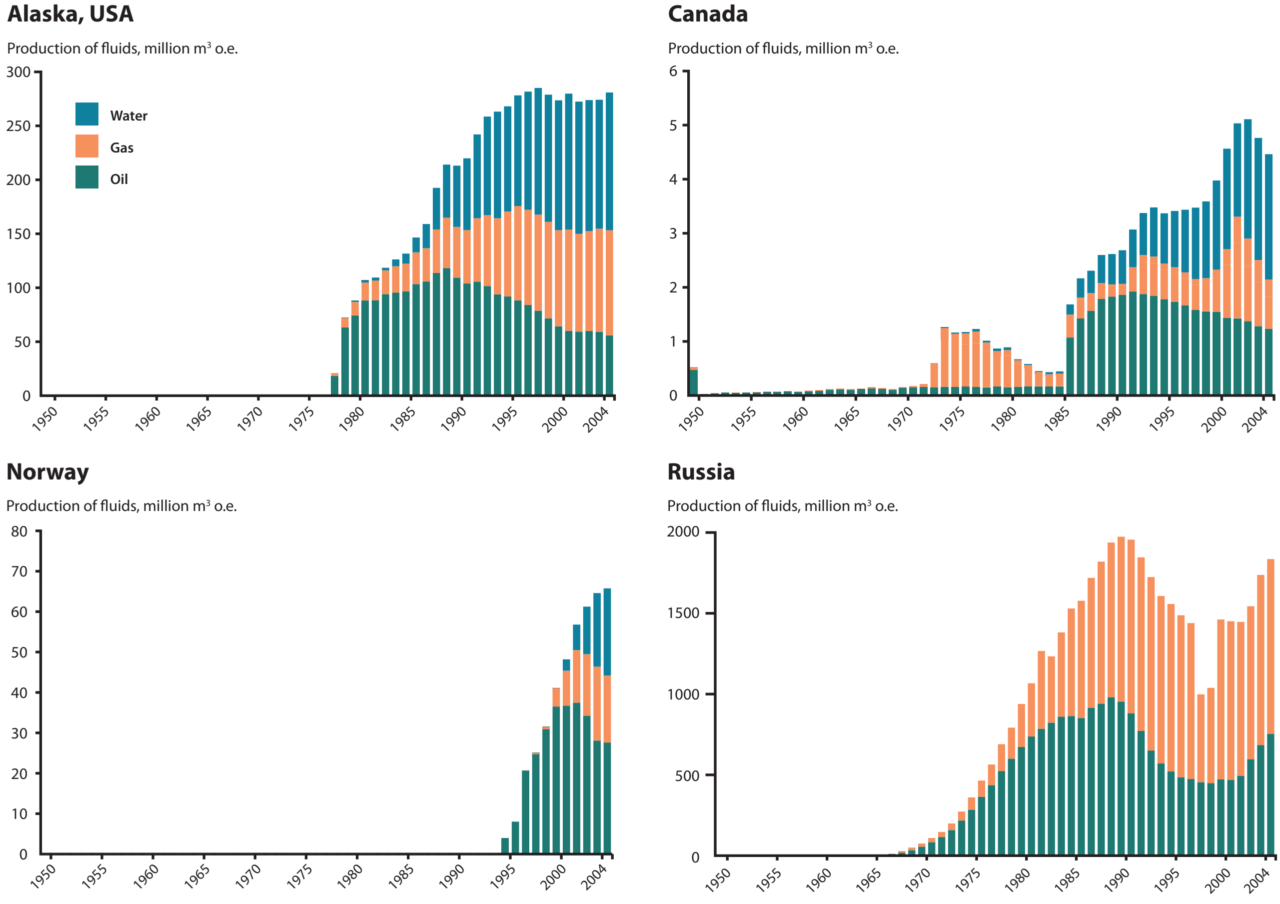


Figure 2.22. Production from Alaska, Arctic Canada, Arctic Norway and Arctic Russia showing relative amounts of oil, gas, and water produced over time. The fraction of water has increased significantly. Data on produced water for Russia are unavailable.

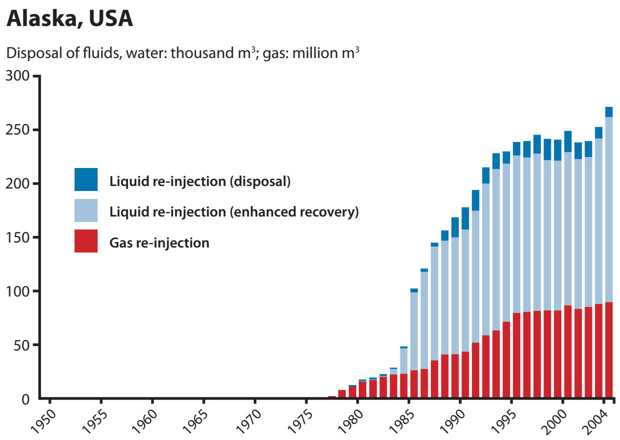


Figure 2.23. Disposal re-injection projects over time for Alaska.

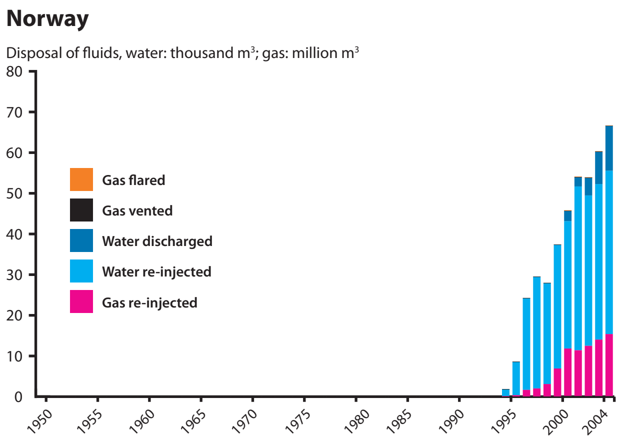


Figure 2.24. Disposal re-injection projects plus flaring over time for Norway.

2.4. Oil and gas activities in the Arctic countries

This section provides a chronologically based discussion of key events that have strongly affected the Arctic oil and gas industry in the countries conducting or contemplating such activities. The basis for the conduct of oil and gas activities is found in the legal and regulatory systems of the countries, and where relevant states or provinces, concerned. These regulatory systems provide stipulations regarding access to the resource and regulate the activities associated with exploration, development, production, transportation, and decommissioning. They also provide for the protection of oil and gas workers' health and safety and for the preservation of national financial, environmental, social, and cultural interests. Although there are many similarities, the regulatory systems relating to oil and gas activities are somewhat different for each country covered. Key aspects of these systems are briefly described in this section for each country, with more detailed coverage contained in Appendix 2.1.

Appendix 2.1 also provides an overview of international conventions and agreements that are relevant to oil- and gas-related activities. These conventions concern: marine pollution from ships; oil spill preparedness, response, and cooperation with regard to both ships and offshore facilities; liability and compensation for damage from pollution incidents; minimum standards for the construction and operation of ships, the training and certification of seafarers, and rules to prevent collisions at sea that are relevant, among others, to the transport of oil; nature conservation and environmental protection, including the need for environmental impact assessment for major projects; the rights of indigenous peoples; and occupational safety and health requirements for the working environment. For the Arctic countries that are parties to these conventions, they provide an additional basis for national laws and regulations.

Following a description of the regulatory systems for each country, this section provides information, divided into petroleum provinces where applicable, about the historical and current oil and gas activities, including pre-exploration issues, exploration activities, and the discoveries made and their development. The infrastructure associated with these activities and the means of transportation for bringing the resultant oil and gas to market is also covered. Future plans, mainly concerning the near term (up to about 2015) are described when applicable.

The ten-year projection of activities for each country is based on current activity levels and public statements from oil and gas operators and involved governments. The ten-year time frame is relatively short for oil and gas developments and so comprises an inventory of projects that have government support or firm financial commitments. Anticipated impacts associated with the list of projects form the basis for recommendations for policy considerations. Each 'national' section ends with comments about what is 'on the horizon' and includes information about promising new technologies that appear to have the potential to strongly influence Arctic oil and gas operations in the greater than ten-year time frame, and about potential challenges and opportunities due to climate change, technology, and resource discovery.

2.4.1. Alaska, United States

The Arctic part of the United States lies entirely within the State of Alaska and its offshore Federal waters. The area described in this assessment generally includes all lands north of the Continental Divide, commonly referred to as the North Slope; all lands to the west and north of the Aleutian Chain, commonly referred to as Southwestern, Western, and Northwestern Alaska (or simply western Alaska); and all adjacent marine waters, the Beaufort, Chukchi and Bering seas, respectively. The maritime boundary begins at the United States–Canada maritime boundary in the east, extends 200 nm to the north in the Beaufort and Chukchi Seas, and extends to the United States–Russia Provisional Maritime Boundary to the west in the Chukchi and Bering Seas. The eastern Arctic maritime boundary between the United States and Canada is disputed. Three categories of surface and subsurface ownership occur within these lands: Federal, State, and private (mostly Native lands). No private land ownership is permitted in offshore marine waters. Marine ownership is divided between the State (seaward to approximately 5 km) and the Federal Government (5 km seaward to 200 nm or an adjacent international boundary – Canada and Russia).

Discussion of U.S. Arctic regions is generally organized in terms of the Arctic Alaska oil and gas province (OGP) and the Bering Sea OGP (see Figures 2.9 and 2.25).

Arctic Alaska OGP:

- North Slope:
    - State Lands: Consist of the central North Slope and marine waters from the coastline seaward to 5 km. The Arctic National Wildlife Refuge (ANWR) and the National Petroleum Reserve – Alaska (NPRA) provide some exceptions to the latter jurisdictional rule.
    - Federal Onshore Lands: Consist of NPRA to the west and ANWR to the east. These Federal withdrawals contain some nearshore marine waters, but do not deprive the State of Alaska of its 5-km marine entitlement.
    - Private Lands: Consist of private lands primarily owned by the Native corporations on the North Slope.
- Federal Outer Continental Shelf (OCS): Consists of all marine waters offshore of the State of Alaska from 5 km seaward of the coastline to 200 nm/the EEZ from the maritime boundary with Canada westerly through the Beaufort and Chukchi Seas.

Bering Sea OGP:

- State Lands: Consist of State lands in western Alaska, primarily the Alaska Peninsula and nearshore marine waters.
- Federal OCS: Consists of all marine waters offshore of the State of Alaska from 5 km seaward of the coastline to the U.S.–Russia Provisional Maritime Boundary in the Bering Sea.

Archeological evidence suggests that oil shale was used for fuel by the indigenous peoples of the Arctic. Early traders on the North Slope also reported seeps along the

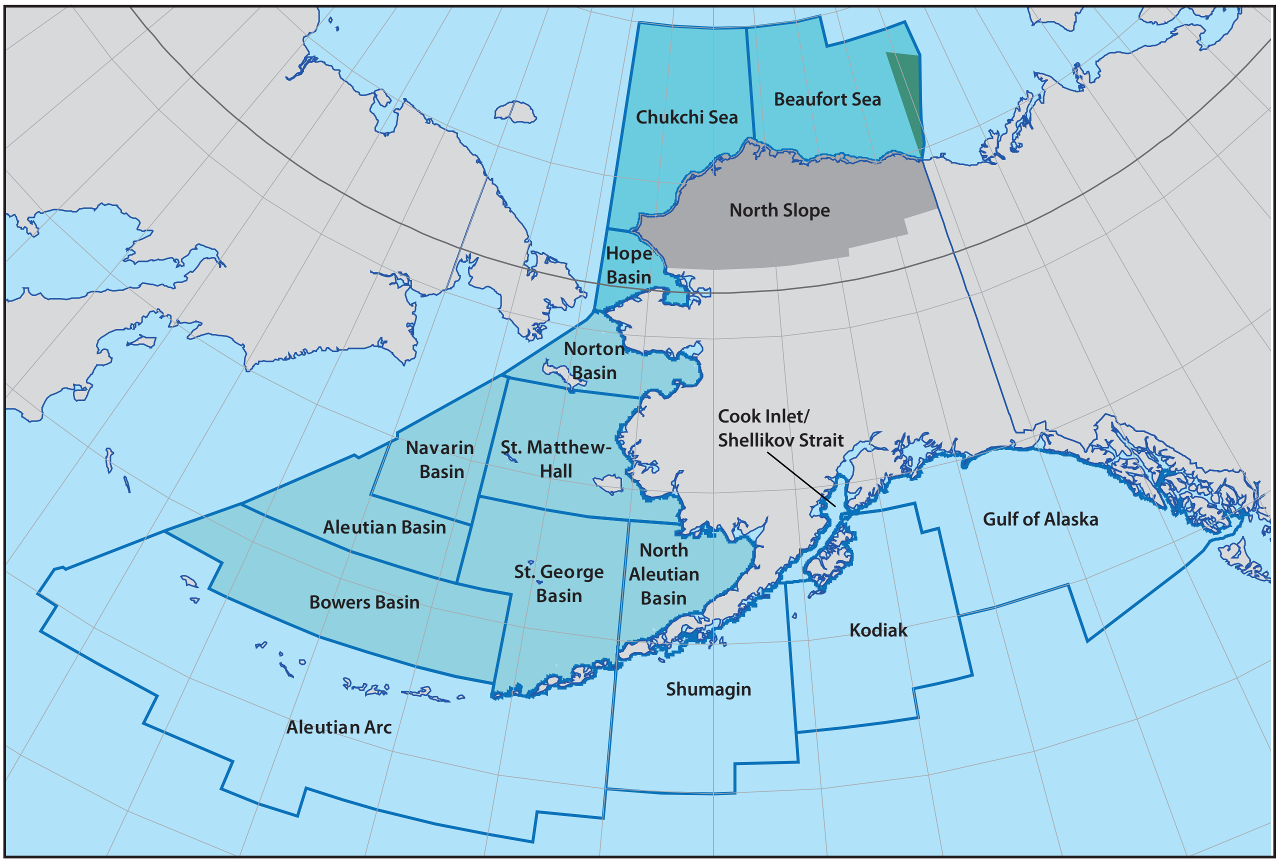


Figure 2.25. Alaska planning areas for oil and gas leasing. Shaded areas are in the Arctic.

coast (ADNR, 2004). Oil seeps found near Cape Simpson in what is now the NPRA spurred interest in the oil and gas potential of the Arctic Coastal Plain and North Slope of the Brooks Range (known as the North Slope). In 1909, exploration to evaluate these seeps began.

Over the next sixty years, large financial investments and exploration by the U.S. Government and the petroleum industry resulted in the discovery of two of the four largest oil fields in the United States and one of the top twenty largest oil fields in the world: *Prudhoe Bay* (over 2 billion m^3 [over 13 billion bbl]) and *Kuparuk* (413 thousand m^3 [2.6 billion bbl]) (Gibson, 2006). Together they account for 44.3% of the combined volumes of the top ten largest fields in the United States. When combined with fields in the greater Prudhoe Bay area, they account for 17% of the U.S. daily production and are largely responsible for Alaska being the third largest producing state (EIA, 2005b).

As of 1 January 2005, cumulative North Slope production totaled more than 2.34 billion m^3 (14.7 billion bbl) from 27 oil fields. Proven gas reserves exceeded 991 billion m^3. An additional 31 currently undeveloped oil and gas fields had been discovered.

The history of exploration and development in Arctic Alaska is summarized in Table 2.5.

U.S. Arctic leasing activity is controlled by a complex interplay between global and regional political, environmental, and economic factors and so has proceeded somewhat sporadically since 1958. In the past 25 years, both the responsible Federal agencies – the Bureau of Land Management (BLM) and the Minerals Management Service (MMS) – and the State Department of Natural Resources (DNR) have developed and followed systematic leasing schedules.

Since the late 1950s, 140 000 km^2 of both onshore and offshore Arctic land have been leased for oil and gas exploration in Alaska, bringing in over USD 7.7 billion in bids. After more investment, these areas have mostly been explored and evaluated, some being developed and others relinquished back to the State or Federal Government. Many areas given back to the government have been re-offered and re-acquired by industry after a change in economic or technological conditions. Some areas have gone through this cycle more than once.

2.4.1.1. Regulatory and legislative systems relevant to Arctic oil and gas activities in Alaska

In the United States, there are Federal and State jurisdictions, each regulated by similar Federal and State laws. Different laws and agencies are involved in the regulatory process depending on where the activity is taking place: onshore or marine areas, State, Federal, Native or private lands, wilderness, parks or forests, or under rivers and wetlands. In the U.S. Arctic, lands and subsurface rights belong to various individuals, entities, and governments. Oil and gas resources under State lands, including marine areas out to 5 km from shore, and privately owned lands belong to and are regulated by the State of Alaska. Marine areas beyond 5 km from shore are regulated by the Federal Government. Some oil and gas activities, such as drilling, conducted on Federal lands located within the boundaries of the State are regulated concurrently by both State and Federal agencies. Resources beneath Native lands are owned by the Native Corporation, or local government, and are regulated by the State of Alaska and also possibly by the Federal Government. There are many agencies involved in regulating oil and gas activities in the U.S. Arctic (for further details of U.S. laws and regulations, see Appendix 2.1).

The regulatory framework in Alaska has evolved continuously at both the State and Federal level. A timeline of key Federal legislation (Table 2.6) illustrates the timing and scope of the legislative action that underlies the current regulatory environment.

Table 2.5. Chronology of significant events in the evolution of the oil and gas exploration and development of Arctic Alaska (modified from National Research Council, 2003).

	Exploration/Development milestones
Before recorded history	Oil seepages used by Native inhabitants of the North Slope
1882	U.S. Government representatives learn of oil seeps
1909	First description of Cape Simpson oil seeps is published
1914	First oil-related claim is staked
1922	First industry-sponsored geological investigations of North Slope oil potential
1923	Naval Petroleum Reserve No. 4 (NPR-4) is established
1923 – 1926	First analysis of NPR-4 hydrocarbon potential
1943	Territory of Alaska Bureau of Mines sends field party to the North Slope to investigate oil and gas seepages, land north of the drainage divide of the Brooks Range withdrawn from public entry by the Secretary of the Interior – Public Land Order 82
1944	Start of NPR-4 petroleum exploration program with Navy landings at Barrow
1945 – 1952	Navy-sponsored geophysical studies across NPR-4 result in exploration drilling with non-economic discoveries of oil and gas. South Barrow gas field discovered in 1948
1953	NPR-4 unexpectedly recessed
1953 – 1968	Federal geological field parties continue in NPR-4, major oil companies begin exploration on the North Slope (1958)
1958	Public Land Order 82 rescinded, Alaska Statehood Act passed
1958 – 1966	First of four Federal lease sales held in 1958, the last in 1966
1959	Alaska formally admitted as a state
1960	Establishment of the Arctic National Wildlife Range (now ANWR) with 36 422 km^2, about half the size of ANWR today
1962	First industry-sponsored seismic program
1963 – 1967	First industry exploration on the North Slope, 11 unsuccessful wells drilled, industry interest in the North Slope wanes
1964	First State of Alaska lease sale on the North Slope
1964	First OCS seismic exploration permits issued
1965	Area that eventually includes Prudhoe Bay oil field leased
1967	Drill rig moved from Susie to Prudhoe Bay St. No. 1 location and well spudded
1967	Barrow receives gas from the South Barrow gas field
1968	ARCO announces the discovery of the Prudhoe Bay oil field, the largest in North America
1969	Discovery of Kuparuk, West Sak, and Milne Point oil fields, lease sales suspended on the North Slope for ten years because the Secretary of the Interior imposes freezes due to Native land claims
1970	National Environmental Policy Act passed
1971	Alaska Native Claims Settlement Act (ANCSA) passed
1974 – 1982	Federally sponsored exploration along the Barrow Arch within NPRA (NPR-4)
1976	NPR-4 is transferred to the Department of the Interior and renamed National Petroleum Reserve-Alaska (NPRA)
1977	Trans-Alaska Pipeline System (TAPS) becomes operational. Point Thomson gas and light oil field discovered
1978	Discovery of Endicott field
I979	Initial leasing of parts of the State and Federal outer continental shelf (OCS) waters of the Beaufort Sea
1980	Alaska National Interest Lands Conservation Act (ANILCA) passed
1981 – Present	Arctic Slope Regional Corporation (ASRC) negotiates exploration agreements with petroleum companies and converts selected acreage to leases – approximately ten exploration wells are drilled
1981	First Arctic OCS exploration well drilled
1982	Initial leasing of parts of NPRA, Chevron drilled the Livehorse No. 1 on ASRC lands within NPRA
1983	OCS well in the Beaufort Sea, Mukluk No. 1, was the most expensive dry hole ever drilled in the world (USD 227 million to lease and USD 120 million to drill)
1984	The fourth of four scheduled lease sales in NPRA was cancelled due to lack of industry interest, ending the first episode of NPRA leasing
1984 – 1985	Seismic surveys conducted in 1002 area of the Arctic National Wildlife Refuge (ANWR)
1984 – 1985	24 exploration wells drilled in the Bering Sea OCS (Navarin, Norton and St. George basins) – all dry holes
1985	First industry well drilled on Federal leases NPRA – Brontosaurus No. – was a dry hole
1986	Chevron/BP KIC well drilled on ASRC lands within the 1002 area of ANWR
1988	Discovery of Pt. McIntyre field
1989 – 1990	Four exploratory wells drilled in the Chukchi Sea. No commercial discoveries
Early 1990s	Last of the NPRA leases were relinquished
1991 – Present	Satellite field exploration and development gains prominence
1994	Discovery of the Alpine field – opens up new plays in the Jurassic
1999 – Present	Renewal of leasing in the NPRA – exploration drilling at a pace of 4–6 wells per drilling season
2001	The Beaufort Sea, Northstar field begins production
2002	Last of 31 wells drilled in the Beaufort Sea OCS between 1981 and 2002 – including 11 discoveries
2004	Legislation to facilitate gas pipeline construction passed
2005	Beaufort Sea OCS Sale 195 brings in USD 46 735 081 for 1013 km^2, the largest amount in 15 years; State sale in North Aleutian/Bristol Bay Basin, first in many years, brings in USD 1 268 122 for drilling rights to 862 km^2 of onshore land
2006	State area-wide sales are held in the Beaufort Sea, Foothills, and North Slope leasing 4359 km^2 for USD 32.8 million and a pared down Federal NPRA sale leased 3800 km^2 for USD 13.9 million
2007	Beaufort Sea Sale 202, 18 April 2007; bids USD 42 017,145.40, area leased 198 579.62 ha/1985.8 km^3 90 blocks
2008	Chukchi Sea Sale 193, 6 February 2008: bids USD 2662 059 883.00: area offered 11 893 422.38 ha/118 934.2 km^2: area leased 1116 287.93 ha/11 162.9 km^2: 488 blocks

Table 2.6. Timeline of key Federal legislation.

1960s	
	National Historic Preservation Act (1966)
	National Environmental Policy Act (1969)
1970s	
	Resource Conservation and Recovery Act (1970)
	Clean Air Act (1970)
	Clean Water Act (1972)
	Marine Protection, Research and Sanctuaries Act (1972)
	Marine Mammal Protection Act (1972)
	Coastal Zone Management Act (1972)
	Endangered Species Act (1973)
	Safe Drinking Water Act (1974)
	Resource Conservation and Recovery Act Amendment (1976)
	Clean Water Act Amendment (1977)
	Outer Continental Shelf Lands Act Amendment (1978)
1980s	
	Comprehensive Environmental Response, Compensation and Liability Act (1980)
	Marine Protection, Research and Sanctuaries Act Amendment (1984)
	Resource Conservation and Recovery Act Amendment (1984)
1990s	
	Oil Pollution Act (1990)
	Coastal Zone Management Act Amendment (1990)
	Clean Air Act Amendment (1990)
	National Historic Preservation Act Amendment (1992)
	Coastal Zone Management Act Amendment (1996)

2.4.1.1.1. Major Federal laws and Executive Orders

A number of Federal laws and Executive Orders are relevant to oil and gas exploration and production activities (sees also Appendix 2.1).

Federal laws relating to land and mineral resource use include the Outer Continental Shelf Lands Act (OCSLA), the Coastal Zone Management Act (CZMA), the Mineral Leasing Act, and the Federal Land Policy and Management Act (FLPMA).

- The Outer Continental Shelf Lands Act (OCSLA) 1953, 1978, governs exploration and development of the OCS, including protection of the environment, establishment of procedures for approving oil- and gas-related activities, conducting onsite inspections, and imposing civil penalties for failure to comply with regulations.
- The Coastal Zone Management Act (CZMA) 1972, 1990, 1996, promotes wise use and protection of coastal land and water resources via State coastal management programs based on consistent procedures and standards.
- The Mineral Leasing Act of 1920 and amendments, promotes the mining of coal, phosphate, oil, oil shale, gas, and sodium on the public domain.
- The Federal Land Policy and Management Act (FLPMA), 1976, provides for multiple use of public lands while protecting them from unnecessary or undue degradation. The BLM, under the authority of the Secretary of the Interior, has the authority to grant permits to meet this objective, including the responsibility for managing the NPRA.

Under Public Law 96-514, 1980 (Fiscal Year 1981 Department of the Interior Appropriations Act NPRA Dec.12, 1980), Congress authorized the Department of the Interior to conduct 'an expeditious program of competitive leasing of oil and gas' in the NPRA.

Federal laws relating to environmental protection and pollution prevention include the National Environmental Policy Act (NEPA), the Oil Pollution Act (OPA), the Clean Air Act (CAA), the Clean Water Act (CWA), the Safe Drinking Water Act (SDWA), the Toxic Substances Control Act of 1976 (TSCA), the Resource Conservation and Recovery Act (RCRA), and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA).

- The National Environmental Policy Act (NEPA) 1969 aims to prevent or eliminate damage to the environment by requiring that environmental concerns are considered in decision-making, including by evaluating the environmental impact of major Federal actions through environmental impact statements or environmental assessments.
- The Oil Pollution Act (OPA), signed into law in August 1990 largely in response to increasing public concern following the *Exxon Valdez* accident, expanded the Federal Government's ability to prevent and respond to oil spills, provides money and resources for oil spill response, and developed new requirements for contingency planning by both government and industry, under which the National Oil and Hazardous Substances Pollution Contingency Plan (NCP) has been expanded (see Appendix 2.2).
- The Clean Air Act (CAA) 1955, 1970, 1990 protects and enhances air quality by setting ambient air quality and emission standards for the protection of public health and welfare. As the CAA requires the States to design and implement programs to achieve the ambient air quality standards, Alaska has developed regulations (18 AAC 50) to address air quality onshore. The U.S. Environmental Protection Agency (EPA) regulates air quality in OCS areas offshore in Alaska.
- The Clean Water Act (CWA) 1948, 1972, 1977 regulates pollution to restore and maintain the chemical, physical, and biological integrity of waterways. Under its regulation of point sources of pollution, pollutants generated by OCS operations and discharged into U.S. waters must comply with the standards included in a National Pollutant Discharge Elimination System (NPDES) permit.
- The Safe Drinking Water Act (SDWA) 1974, 1986, 1996 assures the provision of safe drinking water in public water supply systems, by requiring that all public water systems meet minimum water quality standards (including for bacteria, organic pesticides, inorganic compounds, and radioactive materials), and by developing a program to protect underground sources of drinking water (USDWs). This is a Federal/State cooperative effort, based on federally set minimum standards and regulations administered by the States. The EPA develops minimum State requirements for the protection of USDWs which, among others, require

any underground injection to be authorized by permit issued by the State with specific conditions; however, this does not cover (a) underground injection of brine or other fluids brought to the surface in conjunction with oil and gas production, or (b) underground injection for secondary or tertiary recovery of oil unless such requirements are essential to assure that USDWs are not endangered. The EPA determines which States need an underground injection program to protect drinking water sources and administers the programs if the State does not obtain primary enforcement authority. The Alaska Class II Underground Injection Control (UIC) program is administered by the Alaska Oil and Gas Conservation Commission (AOGCC), while all other classes of injection wells (Classes I, III, IV, and V) in Alaska are administered by the EPA.

- The Toxic Substances Control Act of 1976 (TSCA) is intended to protect human health and the environment from hazardous chemicals by authorizing the EPA to track industrial chemicals currently produced or imported into the United States and to require testing of new and existing chemical substances that may pose an environmental or human-health hazard. The EPA can ban the manufacture and import of those chemicals that pose an unreasonable risk. TSCA also regulates the treatment, storage, and disposal of certain toxic substances.
- The Resource Conservation and Recovery Act (RCRA) 1970, 1976, 1984 regulates the disposal or recovery of hazardous waste; however, RCRA includes a special exemption for oil and gas exploration and production activities from the definition of hazardous waste. The State of Alaska is not authorized to administer the RCRA hazardous waste program.
- The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) 1980 authorizes the recovery of damages from parties responsible for injuries to natural resources owing to the release of hazardous substances, and requires full restoration of natural resources to pre-injury conditions and compensation for environmental damage.

Federal laws relating to the protection of species and habitats include the Endangered Species Act (ESA), the Marine Mammal Protection Act (MMPA), the Migratory Bird Treaty Act, the Magnuson-Stevens Fishery Management and Conservation Act (M-SFMCA), the Marine Protection, Research and Sanctuaries Act (MPRSA), the Alaska National Interest Lands Conservation Act, and the Rivers and Harbors Act.

- The Endangered Species Act (ESA) 1973 protects and promotes the conservation of plants and animals listed as endangered or threatened and their critical habitats by, for example, prohibiting the taking of such species and requiring Federal agencies to consider the impacts of their proposed actions on any threatened or endangered species.
- The Marine Mammal Protection Act (MMPA) 1972 promotes the conservation of marine mammals by, among other provisions, regulating or prohibiting the taking of marine mammals and protecting their habitats, while allowing exemptions for subsistence uses by Alaska and Northwestern Natives.
- The Migratory Bird Treaty Act (Title 16 U.S.C. 703) is intended to protect birds that have common migration patterns between the United States and Canada, Mexico, Japan, and Russia. In addition, Executive Order 13186 on Responsibilities of Federal Agencies to Protect Migratory Birds directs all Federal agencies to avoid or minimize the impacts of their actions on migratory birds and to take active steps to protect birds and their habitat, with emphasis on species of concern.
- The Magnuson-Stevens Fishery Management and Conservation Act (M-SFMCA) establishes national standards for fishery conservation and management within the EEZ and oversees the preparation of fishery management plans, including the delineation of Essential Fish Habitat.
- The Marine Protection, Research and Sanctuaries Act (MPRSA) 1972, 1984 identifies and protects marine environments of special national significance and requires the designation and management of national marine sanctuaries.
- The Alaska National Interest Lands Conservation Act of 1980 created the National Wildlife Refuges in Alaska. The Arctic Wildlife Range was enlarged from 8.8 million acres to 19 million acres and renamed the Arctic National Wildlife Refuge (ANWR).
- The Rivers and Harbors Act of 1899 requires that a permit be obtained from the U.S. Army Corps of Engineers for construction of a dam, dike, or other structure in or affecting navigable waters.

Federal laws relating to the preservation of historic or archeological sites include the National Historic Preservation Act (NHPA) 1966, 1992, which protects historic and prehistoric sites from Federally-funded or permitted activities, and the Archeological Resources Protection Act of 1979 (ARPA), which secures the protection of archeological resources and sites on public and Indian lands.

Federal law and Executive Orders relating to relations with and the rights of indigenous peoples include the Alaska Native Claims Settlement Act (ANCSA), Executive Order 12898 on Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, and Executive Order 13175 on Consultation and Coordination with Indian Tribal Governments.

- The Alaska Native Claims Settlement Act (ANCSA) 1971 recognized Alaska Native Land Entitlements by the creation of Native corporations with Alaska Natives as shareholders and the conveyance of approximately 44 million acres of land; about 10% of the entire State.
- Executive Order 12898 on Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations directs Federal agencies to develop environmental justice strategies to identify and address disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations (including Native American Tribes), with the goal of achieving environmental protection for all communities.
- Executive Order 13175 on Consultation and Coordination with Indian Tribal Governments directs

Federal agencies to establish regular and meaningful consultation and collaboration with tribal officials in the development of Federal policies that have tribal implications.

In addition, the Alaska Statehood Act (1959) entitled the State to select Federal lands not already within existing Federal land management status.

2.4.1.1.2. Relevant Alaska State laws

The management of the use of Alaska's public land and water resources occurs under the Alaska Public Land Act. There are several right-of-way, water rights, and land use permits associated with this Act.

The Alaska Coastal Management Program Act of 1977 (ACMP) provides a balance through its guidelines and regulations for conservation of the coastal zone along with the development and use of natural resources. Under this law, coastal districts develop coastal management programs with enforceable policies. Although Federal lands are excluded from the coastal zone under the CZMA, uses and activities on Federal lands that affect State coastal zones and their resources must be consistent with the State's management plan.

The Alaska Fishway Act requires that an individual or governmental agency obtain authorization from the Alaska Department of Natural Resources (ADNR) for activities within or across a stream used by fish if the department determines that such uses or activities could represent an impediment to the efficient passage of fish.

Under the Alaska Anadromous Fish Act, an individual or governmental agency is required to obtain authorization from the ADNR for all activities within or across a specified water body used by anadromous fish as well as all in-stream activities affecting such a water body.

2.4.1.1.3. Regulations and permitting

Permits for various activities associated with oil and gas exploration, development, and production are required by the State of Alaska and/or the Federal government (see also Appendix 2.1).

Federal Government

Federal Government agencies with responsibilities in relation to the regulation and permitting of oil- and gas-related activities include the U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers, the Bureau of Indian Affairs, the U.S. Department of the Interior Bureau of Land Management, the U.S. Department of the Interior Minerals Management Service, and the U.S. Coast Guard.

<u>U.S. Environmental Protection Agency.</u> Under the terms of the Federal Clean Water Act, the National Pollutant Discharge Elimination System (NPDES) ensures that discharges comply with technology requirements and water quality standards set by the State and the U.S. Environmental Protection Agency (EPA). Discharges either directly into a natural water system or into a wastewater collection system require NPDES permits. Currently, the Alaska State Government is not authorized to administer NPDES permitting, thus permit applications need to go through the EPA; however, the State applied to the EPA on 30 June 2006 to gain primacy of the NPDES program. NPDES permits for OCS and onshore areas are obtained from the EPA either as an individual permit or coverage under a general permit. General permits are available for the North Slope offshore including OCS and State waters. General permits set the requirements for the activity. Authorization to discharge is granted provided the applicant meets the conditions of the permit. A general permit authorizes a category of discharges within a geographic area and is not tailored to an individual discharger.

Under the terms of the Federal Resource Conservation and Recovery Act, the treatment, storage, and disposal of hazardous waste is managed by the EPA. The EPA manages corrective actions of releases from TSD (treatment, storage, and disposal) facilities including solid wastes that also include drilling muds and hazardous waste.

The Federal Safe Drinking Water Act is intended to protect underground sources of drinking water (USDWs); it sets the basic guidance under which the EPA must develop minimum State requirements. At present, Classes I, III, IV and V of injection wells in Alaska are administered by the EPA. Granting of an Aquifer Exemption for injection into USDWs (with less than 10 000 mg/L of total dissolved solids) must also be approved by the EPA.

Under the Clean Air Act, the EPA is responsible for conducting consistency updates to ensure that permitted actions on the OCS are similar to those onshore. In addition, the EPA is responsible for issuing all air permits on the OCS.

Any onshore drilling operation requires a spill prevention control and countermeasure (SPCC) plan specifying the spill prevention and control measures for the operation. This SPCC plan must be available to the EPA for on-site review and inspection.

Under the terms of the Federal Clean Water Act and the Oil Pollution Act of 1990, the operator of a facility that could cause 'substantial harm' to the environment by discharging oil into navigable waters or adjoining shorelines must prepare and submit a Facility Response Plan to the EPA. This plan must meet a number of specific requirements to ensure rapid and appropriate response to an oil discharge and must also be consistent with the National Contingency Plan and area contingency plans. A facility response plan is normally part of the oil discharge prevention and contingency plan required by the Alaska Department of Environmental Conservation.

A project that involves the Federal Government in any way comes under the terms of the National Environmental Policy Act (NEPA). NEPA may require an environmental assessment or an environmental impact statement. For oil and gas exploration on Federal lands, the relevant Federal agency will normally issue an environmental impact statement prior to a lease sale.

<u>U.S. Army Corps of Engineers.</u> The U.S. Army Corps of Engineers regulates activities that impact on U.S. navigable waters and wetlands. Under the Rivers and Harbors Act of 1899, a permit is required to do any work in, over or under navigable waters, or to do work that affects the course, location, condition or capacity of such waters. Under the Federal Clean Water Act, a permit from the Corps of Engineers is also required to discharge dredged or fill material into the waters of the United States. Depending on the situation, a Corps of Engineers

individual nationwide or regional general permit may be required. The Corps of Engineers issues individual permits for specific projects. The permitting procedure involves a public review process.

An individual permit is not necessary if a project falls within the terms of a nationwide permit. The Corps of Engineers headquarters issues these nationwide permits to authorize certain activities that are minor in scope and that result in no more than minor adverse impacts. Work done under a nationwide permit must meet regional conditions specific to Alaska as well as the general, nationwide terms of the permit.

Projects involving a permanent development and requiring a Corps of Engineers permit will normally also require an environmental assessment under the terms of the NEPA. An environmental impact statement may be required.

The Bureau of Indian Affairs. Permission is required to cross or work in a Native allotment or surface use land grant. The Bureau of Indian Affairs has ultimate responsibility for the administration of access to Native allotments in Alaska. However, it generally contracts this administrative role to a recognized Native non-profit organization such as a regional Native non-profit or a village council, which would be responsible for issuing an access permit.

U.S. Department of the Interior, Bureau of Land Management. The Bureau of Land Management (BLM) has authority to issue permits for geophysical exploration on Federal lands in Alaska. These permits last for one year and enable companies to conduct seismic surveys and other geophysical work without having to first purchase an oil and gas lease. Permits are subject to review under the NEPA and may contain restrictions and conditions to mitigate adverse impacts on the environment.

Drilling on Federal land is subject to Onshore Oil and Gas Order No. 2. Before drilling a well on Federal land, an application for a permit to drill, known as an APD, must be filed with the BLM. The APD includes the drilling plan, a surface use plan, and plans for reclaiming the land. Before approval of the APD, the BLM will require a bond and conduct a site inspection. Changes in the drilling plan may be imposed to mitigate environmental impacts or to ensure that the plan complies with Federal regulations.

Oil and gas development proposals are submitted by sundry notice if the proposal is on a lease or a right of way. Projects on Federal lands come under the terms of NEPA and require the preparation of an environmental assessment or an environmental impact statement.

U.S. Department of the Interior, Minerals Management Service.[2] The Minerals Management Service (MMS) has authority to issue permits for geological and geophysical exploration on the OCS. These permits enable companies to conduct seismic surveys and other geological and geophysical work without having to first purchase an oil and gas lease. Applications for permits are handled by the MMS Alaska OCS office in Anchorage, Alaska. If the exploration involves shallow drilling not requiring a drilling permit, there may be a requirement to submit a drilling plan to MMS and, possibly, to the appropriate coastal zone management agency.

Exploration activities associated with an OCS oil and gas lease require an exploration plan approved by the MMS. The exploration plan needs to include information on the activities to be carried out, the type of drilling equipment to be used, the proposed locations of wells, and the safety precautions that will be taken.

Before drilling a deep well on the OCS, an application must be filed for a permit to drill, known as an APD, with the MMS. The APD includes a specification of the drilling equipment to be used, the drilling plan, and the safety precautions to be used.

Development of an oil or gas field on the OCS will require an MMS-approved development plan. The development plan must include details of planned activities, locations of proposed wells, and descriptions of structures to be constructed. The development plan can be used to permit the construction of field structures and facilities. However, a pipeline that is not part of the field gathering system will require a right-of-way permit.

The owner or operator of an oil handling, storage, or transportation facility located seaward of the coastline is required to submit a spill-response plan to the MMS for approval; this spill-response plan must demonstrate that a rapid and effective response will occur whenever oil is discharged from the facility. The plan must be consistent with the National Contingency Plan and the appropriate Area Contingency Plans. Facilities operating in State waters within the 5-km limit can use the oil discharge prevention and contingency plan required by the State, provided the plan meets MMS requirements.

MMS oil and gas leases normally include appropriate stipulations and conditions to mitigate potential adverse impacts on the environment. For example, the lessee may have to contact Native organizations to avoid conflicts with subsistence hunting and other activities.

U.S. Coast Guard. Under Federal law, the owner or operator of any marine transportation-related facility that could reasonably be expected to cause substantial harm to the environment by discharging oil into navigable waters, adjoining shorelines or the EEZ must prepare a facility response plan and submit it to the local U.S. Coast Guard captain of the port for approval. The Coast Guard requires specific contents for this plan. However, it is normally possible to prepare a single facility response plan that meets the requirements of several regulatory agencies. The plan needs to be consistent with the National Oil and Hazardous Substances Pollution Contingency Plan and any area contingency plans. There are also specific response requirements for a facility operating under the Trans-Alaska Pipeline Authorization Act in Prince William Sound. Vessels carrying oil as cargo also require a Coast Guard-approved vessel response plan.

State of Alaska Government

A number of Alaska State agencies have responsibilities in relation to the regulation and permitting of oil- and gas-related activities, these include the Alaska Department of Environmental Conservation, the Alaska Department of Natural Resources (particularly the Division of Oil and Gas, the Division of Mining, Land and Water, and the Office of Habitat Management and Permitting), the Alaska Coastal Management Program, the Alaska Department of

[2] The Minerals Management Service is now called the Bureau of Ocean Energy Management, Regulation and Enforcement.

Fish and Game, and the Alaska Oil and Gas Conservation Commission.

<u>Alaska Department of Environmental Conservation.</u> The Alaska Department of Environmental Conservation (ADEC) has a mission to conserve, improve, and protect Alaska's natural resources and environment and to control water, land, and air pollution, in order to enhance the health, safety, and welfare of the people of the State. Plans to drill in an area where there is a possibility of encountering oil require ADEC approval of an oil discharge prevention and contingency plan, or C-plan. Preparing and gaining approval for a C-plan can be a time-consuming component of permitting a project in the Alaskan Arctic. Operators of oil and gas facilities have to provide proof of financial responsibility for the cost of responding to the maximum likely oil spill at each facility. The State of Alaska has developed an Alaska Incident Management System for managing oil spill response. A number of communities in Alaska hold caches of pre-staged spill response equipment and have made formal agreements to provide spill response support (see also section 2.8).

ADEC has been delegated the authority to implement the Clean Air Act and is responsible for issuing major and minor New Source Review permits. Any industrial activity involving emissions into the air, including the operation of diesel or gasoline engines, requires an air quality permit from ADEC. ADEC also regulates the disposal of waste from industrial operations such as drilling; all waste disposal facilities need to be permitted by the State. Use of an existing facility also requires preparation of a waste disposal plan and a temporary waste storage permit.

<u>Alaska Department of Natural Resources.</u> The mission of the Alaska Department of Natural Resources (ADNR) is to develop, conserve and enhance natural resources for present and future Alaskans. As part of that mission, ADNR regulates the use of State-owned resources, including water. ADNR also oversees the protection of historical or cultural sites and of fish habitats. Most oil and gas activities on State lands will be associated with a State oil and gas lease. A State lessee must prepare a plan of operations for approval by ADNR's Division of Oil and Gas (DOG). The application for approval of a plan must contain sufficient information for ADNR to determine the surface use requirements and impacts directly associated with the proposed operations. The plan must include items such as the schedule of operations; specifications of the use of locations, facilities, sites, and equipment; and plans for rehabilitating the lease area. The plan must also describe operating procedures that will prevent or minimize impacts on natural resources other than oil and gas and that will minimize impacts on features such as fish and wildlife habitats; historical and archeological sites; and public use areas. When approving the plan, ADNR may attach stipulations that bring the plan into compliance with any mitigation measures specified in the lease and that address any site-specific concerns associated with the plan.

A geophysical exploration permit is necessary for conducting seismic surveys on State lands and waters. This is a type of land use permit and is issued by ADNR. In addition, a number of activities that involve temporary access to non-leased State lands require a land use permit from ADNR's Division of Mining, Land and Water. Land use permits range in duration from one to five years.

Pipeline construction across State land requires a right of way from ADNR. Rights of way for gathering lines are issued by the ADNR DOG as a component of a plan of operation approval for pipelines on oil and gas leases or within oil and gas units. Gathering lines outside leases or units will need a right of way from the Division of Mining Land and Water.

Use of a significant amount of water for an operation that continues for less than five consecutive years requires a temporary water use permit from ADNR's Division of Mining, Land and Water. This permit does not establish a water right but will avoid conflicts with fisheries and existing water right holders. Water use at a permanent site such as an oil and gas production facility will require a water right, also obtained from ADNR. A water right allows a specific amount of water from a specific water source to be diverted, impounded or withdrawn for a specific use. Public notice is required if the water appropriation is more than 5000 gallons per day, if the water comes from an anadromous fish stream or if the water source has a high level of competition among water users.

Notification of the ADNR's Office of Habitat Management and Permitting (OHMP) is required for any proposed activities within or across a stream used by fish. If OHMP determines that such activities could represent an impediment to the efficient passage of fish, a fish habitat permit is required. All activities within or across a specified water body used by anadromous fish and all in-stream activities affecting such a water body also require approval from OHMP. Some common activities that require a fish habitat permit include stream fords, heavy equipment operated on ice, water withdrawal, boat launch, dock construction, and culvert placement.

<u>Alaska Coastal Management Program.</u> The Alaska Coastal Management Program (ACMP) implements the Alaska Coastal Management Act, passed by the Alaska legislature in 1977 to implement the Federal Coastal Zone Management Act. The ACMP requires that projects in Alaska's coastal zone be reviewed by coastal resource management professionals and found consistent with the ACMP policies and standards. A finding of consistency with the ACMP must be obtained before permits can be issued for a project.

<u>Alaska Department of Fish and Game.</u> The Alaska State Legislature has classified certain special areas as being essential to the protection of fish and wildlife habitat. A special area may be classified as a State refuge, a State critical habitat area, a State sanctuary, or a State range. Working or operating in one of these areas requires a special area permit from the Alaska Department of Fish and Game.

<u>Alaska Oil and Gas Conservation Commission.</u> The mission of the Alaska Oil and Gas Conservation Commission (AOGCC) is to look after the public interest in oil and gas resources and to protect underground supplies of drinking water. Operators need permits from the AOGCC for any activity that involves drilling for oil and gas or injecting material into a well. In addition to regulating drilling operations, the AOGCC regulates oil and gas pool development rules. The AOGCC also

employs a team of petroleum inspectors who routinely inspect drilling, production, and metering equipment throughout the State.

Oil and gas drilling within lands of the State of Alaska requires an AOGCC permit to drill. The purpose of the permit is to ensure the use of appropriate equipment and the use of acceptable practices to maintain well control, protect groundwater, avoid waste of oil or gas, and promote efficient reservoir development. The AOGCC permits to drill do not consider issues such as land use. The issuance of a permit does not relieve the applicant from obligations to meet the permitting requirements of any other State, Federal or local government agency. The permit application needs to include information about the drilling site, the drilling targets, and the drilling techniques to be used.

Disposal of drill cuttings in a casing annulus requires an annular disposal permit. The Alaska administrative code places limits on the disposal, including the volume of cuttings that can be disposed of.

AOGCC orders most frequently apply to drilling and reservoir management operations. AOGCC orders include aquifer exemption orders, disposal injection orders, area injection orders, conservation orders (including pool rules and spacing exceptions), enhanced recovery injection orders, storage injection orders, and commission orders (including enforcement actions).The procedure for issuing an order usually includes a 30-day public notice period.

2.4.1.1.4. The National Environmental Policy Act and environmental impact statements

The National Environmental Policy Act (NEPA) of 1969 relates to any activity that involves a Federal action or approval. An action by the Federal Government itself can come under the terms of NEPA, as well as involvement of the Federal Government through Federal funding, licensing, permitting or the use of Federal lands as part of a project. In any of these situations, a designated Federal agency needs to ensure compliance with NEPA before the project can start. As a minimum, NEPA requires that the designated agency identify and disclose the potential environmental impacts of the activity. The agency may then require the development of an environmental assessment to document the impacts. If the agency determines that the environmental impacts are likely to be significant, it will mandate the development of an environmental impact statement (EIS).

The BLM manages the Federal onshore mineral estate and is normally the lead agency for NEPA compliance for mineral activities on Federal land onshore. The MMS is the lead agency for offshore activities in Federal waters beyond the State of Alaska's 5-km limit. When the Federal Government wishes to initiate an action requiring an EIS, the appropriate Federal agency will prepare the EIS, perhaps using external consultants. The agency will complete the EIS prior to a final decision on whether to proceed with the action. As an example, the application to renew the Trans-Alaska Pipeline right of way on Federal lands in 2004 resulted in the development of a major EIS for the BLM. When an application for funding, licensing or permitting triggers an EIS, the applicant itself may have to prepare the EIS for Federal review and approval.

An EIS is a document that describes the impacts on the environment of a proposed action. The standard government EIS format includes sections that describe: the purpose and need for action; potential alternatives to the proposed action; the affected environment; and the environmental consequences of the action. There are six steps associated with the development of an EIS (Box 2.6).

Projects that require an EIS must allow ample time for the EIS process. Environmental studies to gather data for the EIS document may take several field seasons to complete and the public review and agency approval process can take many months. The total time period required to complete the EIS process depends on the scale and complexity of the proposed action, the amount of environmental data that are already available, and the level of public interest. A major EIS can take two or more years to complete.

2.4.1.1.5. Financial responsibility and bonding requirements

The U.S. EPA established the Underground Injection Control (UIC) program under the authority of the Safe Drinking Water Act of 1974. In states that have chosen not to administer the program, the EPA is required by the Act to implement it. As part of this program, the owners or operators of Class I and II (and other classes of injection wells if applicable) must maintain a level of financial responsibility and resources to close, plug, and abandon the underground injection operation that are acceptable to the EPA. The Alaska Class II UIC program is administered by the AOGCC, while all other classes of injection wells (Classes I, III, IV, and V) in Alaska are administered by the EPA.

In states where the EPA administers the UIC program, Class I and II well owners or operators must satisfy the financial responsibility requirement by submitting a financial mechanism that meets the approval of the EPA Regional Administrator or his designated UIC Program Director. The owner/operator may choose one of several mechanisms to demonstrate that they maintain adequate financial resources to properly close, plug, and abandon an injection well. Options include financial instruments such

Box 2.6. Development of an EIS under NEPA

Regulations issued by the President's Council on Environmental Quality set out the steps involved in preparing an EIS. These steps safeguard the rights of both the public and the government to comment on the contents and proposals in the EIS. There are six steps.

- Issuing a Notice of Intent in the Federal Register. The notice of intent specifies a period during which public comments on the scope and potential content of the EIS can be gathered.
- Preparing a draft EIS for review by the public.
- Publishing in the Federal Register a Notice of Availability for the draft EIS, including a schedule for a public comment period and a specification of how the public can comment.
- Preparing a final EIS.
- Publishing in the Federal Register a Notice of Availability for the final EIS.
- Publishing a Record of Decision in the Federal Register 30 days or more after the final EIS is published. The Record of Decision describes the responsible Federal agency's decision on the proposed action.

as surety bonds, trust funds, and letters of credit, as well as financial statements. Financial statement demonstrations must be submitted annually, while the other mechanisms will be updated at the UIC Program Director's discretion.

In addition, a number of bonds are required for oil and gas leasing by State agencies in Alaska and by the Department of Interior BLM for Federal lands or the Department of Interior MMS for areas in the OCS (Box 2.7).

2.4.1.1.6. Framework of U.S. Arctic Alaska oil and gas leasing

The leasing activities of the Federal government (i.e., the MMS for the OCS and the BLM for the NPRA) and the State of Alaska (onshore and coastal waters) are combined because the fundamental aspects of the rights conveyed via a lease and the procedures used to arrive at the decision to lease are very similar. The leasing procedures are not identical as each managing jurisdiction has separate legislation and regulations governing their leasing framework.

The variance in frameworks does not, however, detract from the fact that all are strictly governed by legislation and regulations, and are subject to extensive public notice and review prior to any lease offering. This means that in the short and long term, the public has the opportunity to influence the size, timing, location, and terms of lease sales – and has done so. 'Public' in this context means everyone: individuals, government entities, non-governmental organizations, and private enterprise.

Both the State and Federal governments have divided their respective jurisdictions into administrative geographical subdivisions termed planning areas, (see Figure 2.25), to facilitate preparation for sales and management of activities pre- and post-sale. Individual planning areas often contain a commonality of respective geological, environmental, economic, and socio-cultural features.

The lease offering process begins with publication of a proposed schedule of one or multiple lease offerings, requesting public comment on any aspect of the proposal. The State and MMS prepare proposed five-year schedules for this purpose. Extensive economic, social, cultural, and environmental information and analysis are also made available in associated documents. Following period(s) for public comment, responses and any other new information are weighed and a decision is made on the schedule of lease offerings. A decision document is

Box 2.7. Bond requirements for oil and gas activities in Alaska

A number of bonds are required for oil and gas leasing by State agencies in Alaska and by Federal agencies for Federal lands or areas in the OCS. These are described in this box.

Alaska Department of Environmental Conservation. The ADEC requires proof of financial responsibility to respond to damage caused by an oil-related facility such as an oil terminal, oil production facility, oil pipeline, or oil-carrying vessel. The proof of financial responsibility required ranges from USD 1 million to USD 100 million, depending on the type and location of the facility.

Alaska Department of Natural Resources. The ADNR Division of Oil and Gas requires bonding of USD 100 000 for a single oil well and USD 500 000 for multiple wells State-wide. The bonding for a gas well is from USD 25 000 to USD 100 000 depending on the location and potential impact from the operation. The Commissioner of ADNR can require additional bonding in circumstances that indicate additional risk. A separate State-wide bond of USD 100 000 will also be required for a geophysical exploration permit.

Alaska Oil and Gas Conservation Commission. The AOGCC requires a bond of up to USD 200 000 for all oil and gas operators to ensure that each well is drilled, operated, maintained, repaired, and abandoned in accordance with AOGCC regulations.

U.S. Department of the Interior Bureau of Land Management. The BLM requires a bond of USD 100 000 prior to the issuance of an oil and gas lease in the National Petroleum Reserve-Alaska (NPRA). The bond is not required if the bidder for the lease already maintains or furnishes a bond of USD 300 000 for all of the bidder's leases in the NPRA. Alternatively, the bidder can furnish a rider on a nationwide bond to bring bond coverage for all of the bidder's NPRA leases to USD 300 000.

The BLM can also require additional bonds in the NPRA if the agency determines that additional security is required after operations or production has begun. Outside the NPRA, the bond requirement is USD 10 000 per lease. Alternatively, the lessee can furnish a bond of USD 25 000 to cover all of the lessee's BLM leases in Alaska outside the NPRA, or USD 150 000 to cover all BLM leases nationwide. The BLM can require additional bond amounts as a result of specific risk factors.

U.S. Department of the Interior Minerals Management Service. Each MMS Regional Office requires a bond of USD 50 000 prior to issuing an oil and gas lease on the OCS. The bond is not required if the bidder provides and maintains an area-wide bond of USD 300 000 to cover all of the bidder's oil and gas leases issued by a particular MMS Regional Office. These bonds are required on the basis of no activity.

The MMS will require a USD 200 000 lease exploration bond prior to approval of an exploration plan. This bond is not needed if the lessee maintains an area-wide exploration bond of USD1 million that covers all of the lessee's oil and gas leases with exploration activities in a particular MMS Region.

The MMS also requires a USD 500 000 lease development and production bond prior to approval of a development and production plan. This bond is not needed if the lessee maintains an area-wide development and production bond to the amount of USD 3 million that covers all of the lessee's oil and gas leases with development and production activities in a particular MMS Region.

The MMS may require additional security above the amounts prescribed if the agency determines that additional risk factors apply to proposed operations. On a case-by-case basis, to ensure compliance with the regulations and the obligations under the lease, the MMS may also require supplemental bonding after considering a lessee's cumulative potential obligations and liabilities.

The MMS also requires proof of financial responsibility for oil spill response plans. Nationwide oil spill response bonding can be used as proof of financial responsibility anywhere in U.S. offshore waters.

prepared explaining the basis for the decision and made available to the public. A schedule is adopted subject to further public and administrative review or litigation.

The Federal Government begins preparation for specific individual planning area lease offerings by completing an EIS according to NEPA. The EIS describes the post-sale effects of anticipated exploration, development, and production activities on the human, marine, and coastal environments which may result from lease issuance. The EIS also describes mitigating effects of the existing body of law and proposed special new requirements to address potential adverse environmental outcomes unique to particular areas. Typically, an EIS takes about two years to prepare and is open to public comment and consultation with interested affected parties at multiple times throughout the process. Collective public review commonly results in modification of the size, timing, location, or terms of the proposed offering.

The MMS also publishes a tentative 'or proposed' Notice of Sale for public comment. The notice sets out all proposed terms and conditions of the offering: area to be offered, or deferred from leasing; bidding system; minimum bid; royalty rate; lease term; special requirements and advisories a lessee must be aware of in order to conduct safe and compliant operations on a leasehold; date, time, and location of the public offering; methods, means, and time of bidders and leaseholder payments. Thereafter, public comment is considered and a (final) Notice of Sale is issued in modified or original terms. A decision document explaining the basis for the decision is also made publicly available.

The final step in the U.S. Arctic oil and gas offering process is sale day. State and Federal jurisdictions have both chosen the lease (as opposed to, for example, a license or agreement) as the legal instrument to convey oil and gas rights to third parties. Both also have chosen the competitive sealed bid auction with a cash bonus bid variable as the primary means of awarding leases. (There is one exception, discussed later in this section.) Study and experience have indicated that these approaches tend to promote expeditious exploration, development and production, and higher revenues to the public, given the decision to grant rights in a particular area. Bids submitted in Federal sales must pass a rigorous fair market value test. Fair market value is determined for each tract (which becomes a lease) for each sale. This minimum 'bid acceptance' value may be equal to or greater than the minimum bid specified in the sale notice. These values are NOT public information prior to the bid acceptance/rejection decision.

An oil and gas lease grants the exclusive right to explore, develop, and produce oil and natural gas for a specific period and for a specific tract. Leases contain no permits for lease operations. Lease operations require applications for drilling and approval of permits described earlier in this chapter. The lease may be extended beyond its initial term (usually ten years) for as long as oil and/or natural gas is produced in paying quantities or approved operations are being conducted. Lessees must comply with new laws and regulations promulgated subsequent to lease issuance.

As noted earlier, the one exception to the preferred competitive sealed bid auction in awarding leases is the State of Alaska's exploration licensing system. The State may issue exploration licenses in areas other than designated competitive sale areas. The North Slope and Alaska Peninsula are competitive areas off limits to the licensing system. Licensing areas consist of several large sedimentary basins within interior Alaska, some of which are virtually unexplored.

An area selected for exploration licensing must be between 10 000 and 500 000 acres in size. A qualified and successful applicant who has committed the largest amount of money to an exploration program will be awarded a license with a term of up to ten years. The licensee must post a bond in the amount of the work commitment and pay one U.S. dollar per acre license fee. No additional charges are levied. After receiving an acceptable application, the State will solicit public comments and competing proposals. Following this solicitation, the State will determine whether license issuance is in the best interests of the State. The application(s) may be denied or modified to include limitations, conditions, stipulations, or other changes necessary to conform the license provisions to the best interests of the State.

The State has issued four exploration licenses covering 1.66 million acres and has received three applications for other areas. All are onshore, largely in interior Alaska. One license is pending conversion to a lease; no production has resulted to date.

U.S. Arctic conveyance processes are lengthy, complex, rigorous, and open to public review at multiple points throughout the process. Thus, the public has the opportunity to influence the terms, size, timing, and location of potential exploration, development, and production areas and operating requirements prior to award of any right. Offering proposals are routinely modified from initial to final form as a result of public comment, sometimes significantly. As an example, the North Aleutian Basin OCS area was removed entirely from consideration by Congressional and Presidential moratoria for almost twenty years based largely upon the public's concern for threats to fisheries and other resources of Bristol Bay. Planning sub-areas are routinely deferred from consideration. Areas near Barrow (Beaufort and Chukchi Seas OCS) and Kaktovik have been deferred based largely upon subsistence activities; the State has also deferred nearshore Beaufort Sea areas. The northern part of the NPRA Northeast planning area was deferred, as well as many deferrals in Federal OCS planning areas in the Chukchi and Bering Seas – usually for environmental reasons.

A similar pattern occurs regarding pre-sale modification of existing special operating requirements, or additions of new operating requirements. These are special requirements in addition to the existing body of law and regulation. Examples include conflict avoidance agreements, rules on timing of specified operations, surface occupancy, structure design, and requirements for consultation tailored to special areas, as applicable.

Thus, the public (including government agencies, non-governmental organizations, individuals, and private enterprise) is a viable and influential force in shaping U.S. Arctic oil and gas activities along with geology, economics, technology, and other determining factors of events.

From 1958 through April 2007, industry has leased approximately 140 000 km^2 of onshore and offshore Arctic oil and gas exploration lands for bonus bids exceeding USD 7.7 billion (Tables 2.7 and 2.8, see also Figures 2.26 and 2.27). Out of those lands, currently about 12% of the leases (16 143 km^2, ADNR 2004, MMS website, 2007) were still active as of 2005, and only 3% (4142 km^2) are in North Slope development units (ADNR, 2006a).

Table 2.7. Arctic Alaska oil and gas lease sales.

Competitive sale area	Sale	Date	Offered, km^2	Leased, km^2	Bonus received, USD
Federal BLM North Slope Gubik area	1st North Slope sale	1958	65	65	
Federal BLM[a] **North Slope** E/SE of NPR-4 & S of Mikkelsen	1st North Slope offering	1958	16 317	16 317	
Federal BLM[a] **North Slope** Between E & W segments of 1958 sale	2nd North Slope offering	1964	14 918	14 918	
North Slope East of Colville River delta	State Sale No. 13	1964	2 527	1 881	
Federal BLM[a] **North Slope** E, S, & W of prior BLM offerings	3rd North Slope offering	1965	33 067	4 434	
North Slope Prudhoe West to Canning R.; offshore/ uplands	14	07/65	3 051	1 631	6 145 473
Federal BLM[a] **North Slope** West of NPR-4	4th North Slope offering	1966	12 232	0	
North Slope Beaufort Katalla, Prudhoe; offshore/ uplands	18	01/67	193	177	1 479 906
Ak Pen Port Heiden & Port Moller; offshore	21	03/68	1 403	668	3 009 224
North Slope Colville to Canning R.; offshore/ uplands	23	09/69	1 825	1 670	900 041 605
Beaufort Sea (Joint Federal & State Sale): offshore Milne Pt. east to Flaxman Is.	30	12/79	1 381	1 199	567 391 497
Beaufort (OCS) Joint Federal/State Sale	BF	12/79	702	347	488 691 138
North Slope Prudhoe Uplands: Kuparuk R. to Mikkelsen Bay	31	09/80	794	794	12 387 470
NPRA	821	1/27/82	6 136	2 735	58 351 262
Beaufort Sea: Pt. Thomson area; offshore/uplands	36	05/82	230	230	32 583 452
NPRA S & SE portions	822	5/26/82	14 243	1 119	9 741 022
North Slope Prudhoe Uplands: Sagavanirktok R. to Canning R.	34	09/82	4 984	2 315	26 713 018
Beaufort (OCS)	71	10/82	7 389	2 682	2 055 632 336
Norton Sound Bering Sea (OCS)	57	3/83	9 630	1 359	317 873 372
St. George Basin Bering Sea (OCS)	70	4/83	10 881	2 189	426 458 830
Beaufort Sea: Qwydyr Bay to Harrison Bay; offshore/uplands	39	05/83	858	858	20 998 101
NPRA Northern Portions	831	7/20/83	8 886	1 685	16 666 659
Navarin Basin Bering Sea (OCS)	83	4/84	113 510	3 755	516 317 331
Beaufort Sea	43	5/84	1 206	1 140	32 214 794
North Slope Colville R. Delta/Prudhoe Bay Uplands Exempt: West of Kavik R.; offshore/uplands	43A	05/84	308	308	1 612 583
NPRA	841	7/18/84	6 437	0	0
Beaufort Sea (OCS)	87	8/84	31 458	4 887	866 860 327
Bristol Bay Uplands: Kvichak River to Port Heiden	41	09/84	5 817	1 128	843 965
North Slope Exempt: Canning R. to Colville R.; offshore/uplands	45A	09/85	2 454	667	4 657 478
North Slope Kuparuk Uplands: South of Prudhoe Bay	47	09/85	779	739	11 645 003
Kuparuk Uplands: South of Kuparuk Oil Field	48	02/86	2 128	1 079	2 444 342
North Slope Beaufort Mikkelsen Exempt: Mikkelsen Bay, Foggy Is. Bay; offshore/uplands	48A	02/86	170	170	510 255
North Slope Prudhoe Bay Uplands: Canning R. to Sagavanirktok R.	51	01/87	2 396	407	289 625
Beaufort Camden Bay: Flaxman Is. to Hulahula R.; offshore	50	06/87	478	478	6 621 723
North Slope Kuparuk Uplands: Colville River Delta	54	01/88	1 707	1 371	4 683 388
Beaufort Sea (OCS)	97	3/88	73 968	4 495	115 261 636
Chukchi Sea (OCS)	109	5/88	103 725	8 000	478 032 631
Beaufort Demarcation Point: Canning R. to U.S./ Canadian border; offshore	55	09/88	816	391	14 700 602

Table 2.7. Cont.

Competitive sale area	Sale	Date	Offered, km^2	Leased, km^2	Bonus received, USD
North Slope Kuparuk Uplands Exempt: Canning R. to Colville R.	69A	09/88	3 139	1 491	6 119 135
North Aleutian Basin Bering Sea (OCS)	92	10/88	22 677	493	95 439 500
Beaufort Sea: Pitt Point to Tangent Point; offshore	52	01/89	712	212	1 737 513
North Slope Oliktok Point Exempt: Uplands	72A	01/89	3	3	454 977
North Slope Kuparuk Uplands Exempt: Canning R. to Colville R.	70A	01/91	2 153	1 702	27 707 541
North Slope Kavik: Canning R. to Sagavanirktok R.; uplands	64	06/91	3 053	138	242 389
Beaufort Sea: Pitt Point to Canning R.; offshore	65	06/91	1 987	700	6 993 949
Beaufort Sea (OCS)	124	6/91	75 097	1 121	16 807 025
Chukchi Sea (OCS)	126	8/91	76 842	644	7 117 304
North Slope White Hills: Colville R. to White Hills uplands	61	01/92	4 011	1 054	2 429 551
Beaufort Sea: Nulavik to Tangent Point; offshore	68	06/92	621	0	0
North Slope Kuparuk Uplands: Between NPRA and Sagavanirktok R.; Colville R. Delta ASRC lands	75	12/92	879	505	9 750 111
North Slope Nanushuk: North Slope Foothills, Chandler R. to Ivashak R	77	05/93	5 100	185	1 164 555
North Slope Kuparuk Uplands Reoffer: Between Canning R. and Kavik R.; onshore	70A-W	05/93	152	114	1 358 027
North Slope Foothills: Brooks Range foothills, Sagavanirktok R. to Killik R	57	09/93	4 181	0	0
North Slope Colville River Exempt: Colville River Delta onshore	75A	09/93	58	58	449 847
North Slope Beaufort Shaviovik: Sag R. to Canning R., southern Kaparuk Uplands, Gwydyr Bay, Foggy Island Bay, onshore/offshore	80	12/95	3 850	613	3 337 485
Beaufort Sea (OCS)	144	9/96	29 472	405	14 429 363
North Slope Beaufort Colville River Exempt: Colville R, offshore, state/ASRC onshore/offshore	86A	10/96	63	24	2 026 247
Central Beaufort Sea: Harrison Bay to Flaxman Island	86	11/97	1 477	1 311	27 985 125
North Slope Areawide: All acreage between NPRA and ANWR north of the Umiat Baseline	87	06/98	20 639	2 099	51 794 173
Beaufort Sea (OCS)	170	8/98	3 727	349	5 327 093
North Slope All available acreage between NPRA and ANWR north of the Umiat Baseline	NS Areawide	02/99	20 639	708	2 596 838
NPRA Northeast portion	991	1999	15 783	3 497	104 635 728
Beaufort Sea All available acreage within the Beaufort Sea region.	BS Areawide 2000	11/00	8 094	105	338 922
North Slope All available acreage within the North Slope region.	NS Areawide 2000	11/00	20 639	2 640	10 052 665
North Slope All available acreage within the North Slope Foothills region.	NS Foothills Areawide 2001	05/01	31 565	3 475	9 799 277
Beaufort Sea All available acreage within the Beaufort Sea region.	BS Areawide 2001	10/01	8 094	147	3 447 734
North Slope All available acreage within the North Slope region.	NS Areawide 2001	10/01	20 639	1 760	6 911 572
North Slope State acreage between NPRA and ANWR, south of the Umiat Baseline	NS Foothills Areawide 2002	05/02	31 565	863	2 889 532
North Slope State acreage between NPRA and ANWR north of the Umiat Baseline	NS Areawide 2002	10/02	20 639	131	579 728
Beaufort Sea State acreage within the 3-mile limit, between Dease Inlet and Barter Island	BS Areawide 2002	10/02	8 094	78	506 405
NPRA Northeast portion	2002	2002	12 349	2 344	63 811 496
North Slope State acreage between NPRA and ANWR, south of the Umiat Baseline	NS Foothills Areawide 2003	05/03	31 565	23	36 576
Beaufort Sea (OCS)	186	9/03	38 282	736	8 903 538

Table 2.7. Cont.

Competitive sale area	Sale	Date	Offered, km²	Leased, km²	Bonus received, USD
North Slope State acreage between NPRA and ANWR north of the Umiat Baseline	NS Areawide 2003	10/03	20 639	850	3 586 400
Beaufort Sea State acreage within the 3-mile limit, between Dease Inlet and Barter Island	BS Areawide 2003	10/03	8 094	150	1 358 187
North Slope Foothills areawide	NSF 2004	5/04	31 565	80	106 305
NPRA Northwest portion	2004	6/04	23 472	5 680	53 904 491
Beaufort Sea Areawide	BS Areawide 2004	10/04	8 094	459	4 190 782
North Slope Areawide	NS Areawide 2004	10/04	20 639	801	7 599 193
Beaufort Sea (OCS)	OCS Sale 195	3/05	37 630	2 457	46 735 081
North Slope Foothills Areawide	NS Foothills Areawide 2005	5/05	31 565	225	319 959
Alaska Peninsula Areawide	AP 2005	10/05	20 234	771	1 149 253
North Slope Areawide	NS Areawide 2006	3/06	20 639	2 284	15 741 677
Beaufort Sea Areawide	BS Areawide 2006	3/06	8 094	826	7 685 032
North Slope Foothills	NS Foothills Areawide 2006	5/06	31 565	997	1 849 229
NPRA Northwest portion	2006	9/06	20 234	3 804	13 860 135
North Slope Areawide	NS 2006A	10/06	31 565	717	2 530 534
Beaufort Sea Areawide	BS Areawide 2006	10/06	8 094	135	684 723
Alaska Peninsula Areawide	AP 2007 Areawide	2/07	20 234	23	38 995
Beaufort Sea (OCS)	202	4/07	35 361	2 032	42 165 195
Chukchi Sea (OCS)	193	2/08	118 934	11 163	2 662 059
Total				140 307	7 701 546 140[b]

[a] Non-competitive offering; [b] excluding Chukchi Sea Sale 193.

Table 2.8. Overview of U.S. Arctic lease sales.

Province	Lease sales, km²											
	1955/59	1960/64	1965/69	1970/74	1975/79	1980/84	1985/89	1990/94	1995/99	2000/04	2005[a]	Total
Arctic North Slope												
State On/ Offshore	0	1 881	3 478	0	1 199	5 645	7 008	4 456	4 755	11 562	5 184	45 168
Federal/NPRA	16 382	14 918	4 434	0	0	5 539	0	0	3 497	8 024	3 804	56 598
Federal OCS												
Beaufort Sea	0	0	0	0	347	7 568	4 494	1 121	754	736	4 488	19 508
Chukchi Sea	0	0	0	0	0	0	8 000	644	0	0	0	8 644
Bering Sea												
State AK Peninsula	0	0	668	0	0	1 128	0	0	0	0	794	2 590
Federal OCS												
Navarin	0	0	0	0	0	3 755	0	0	0	0	0	3 755
Norton	0	0	0	0	0	1 359	0	0	0	0	0	1 359
St. George	0	0	0	0	0	2 189	0	0	0	0	0	2 189
N. Aleutian	0	0	0	0	0	0	493	0	0	0	0	493
Total	16 382	16 799	8 580	0	1 546	27 183	19 995	6 221	9 006	20 322	14 270	140 304

[a] This is not a five-year interval but is from 2005 to date (mid-2007).

2.4.1.2. Development of oil and gas activity in the U.S. Arctic

This section presents various indices for oil and gas activity in the oil and gas provinces of Arctic Alaska (see section 2.3 for a comparison with oil and gas activity in the Arctic as a whole). Figures 2.26 and 2.28 show development in the areas offered for lease by region in Arctic Alaska, together with the areas for which leases have been sold, conveying the right to explore for oil and gas in Arctic Alaska. Revenues associated with these leases are given in Figure 2.27. The activity appears to peak roughly every 20 years, with the highest level of leasing occurring in the early 1980s. The areas leased are shown in Figure 2.28.

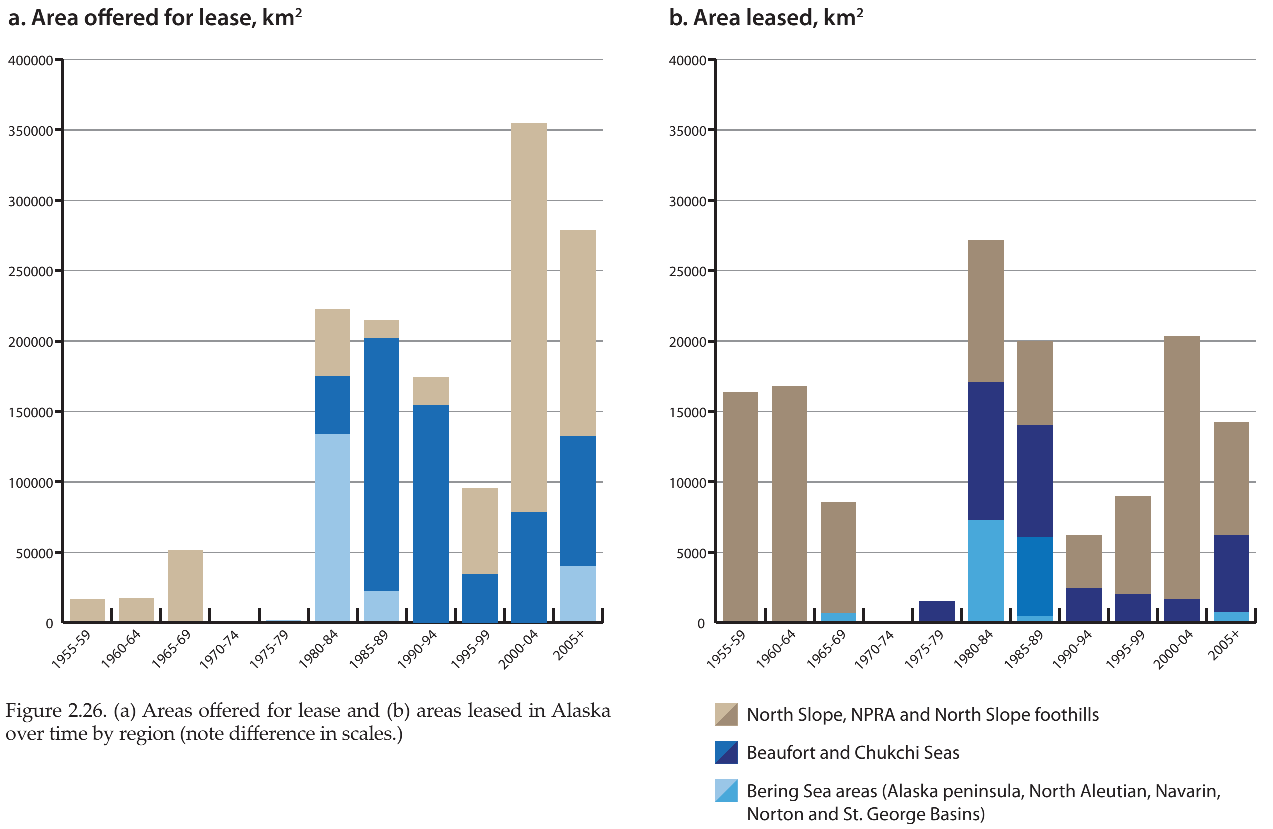


Figure 2.26. (a) Areas offered for lease and (b) areas leased in Alaska over time by region (note difference in scales.)

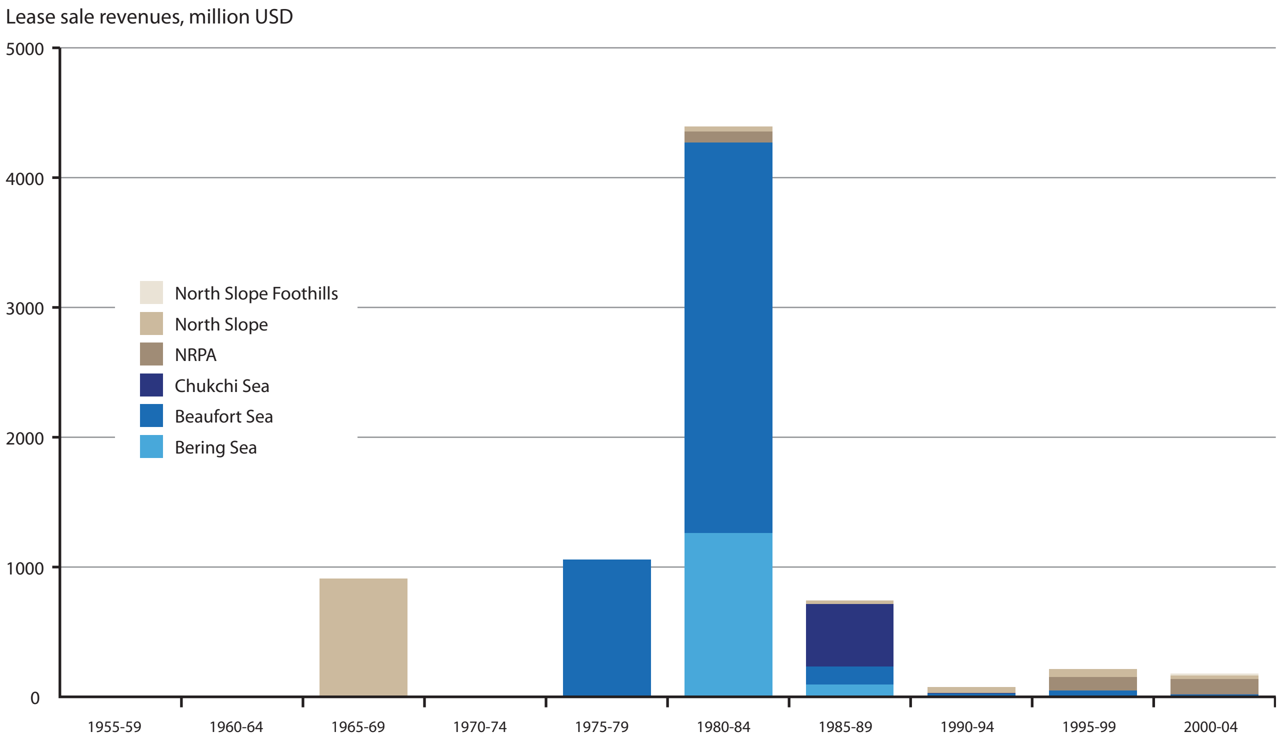


Figure 2.27. Arctic USA lease revenues over time.

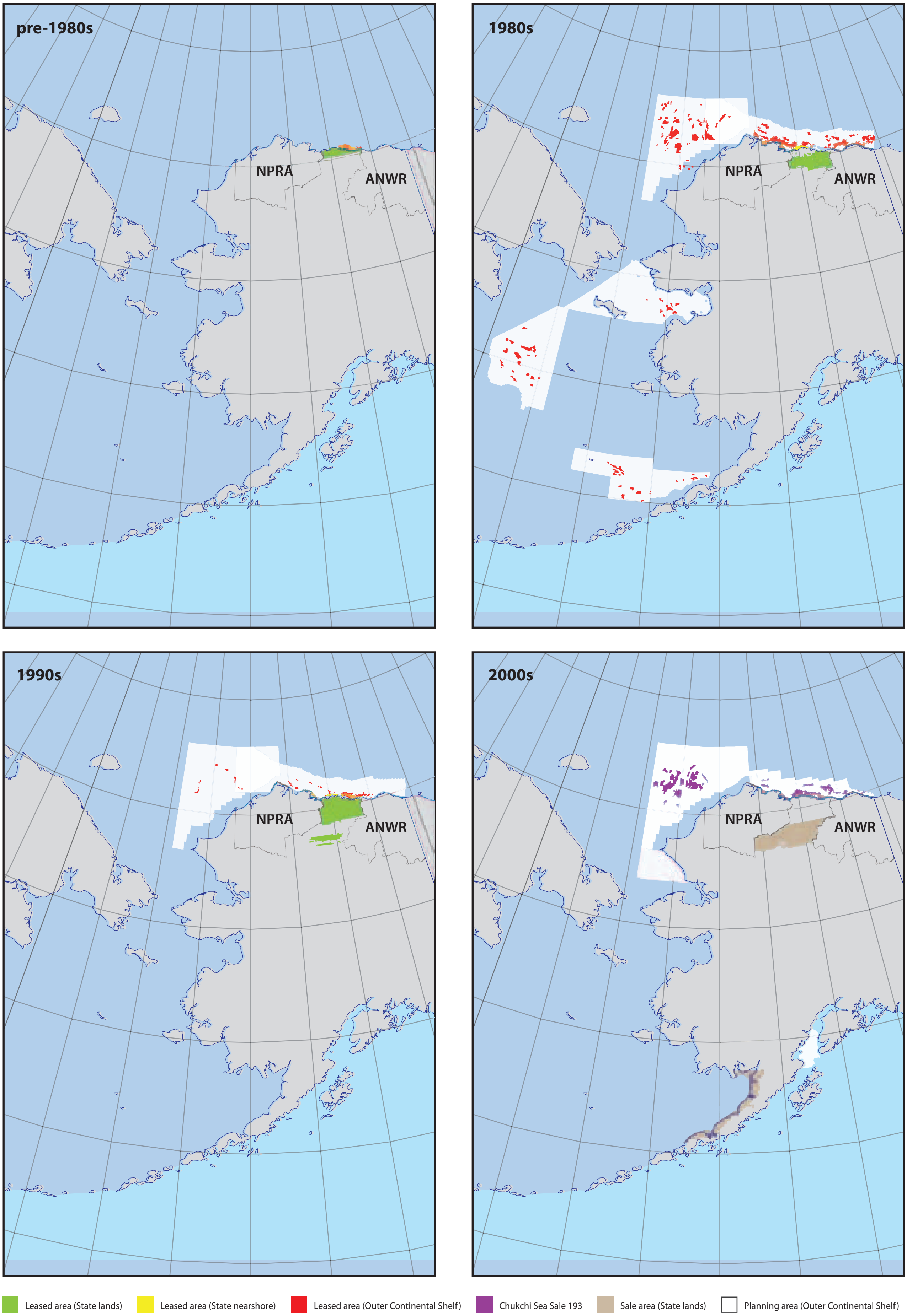


Figure2.28. Areas leased for the right to explore for oil and gas in Arctic Alaska. The areas shown in purple show the Chukchi Sea Sale 193, which was not included in the plots in Figure 2.26.

Exploration activities such as seismic surveys and exploratory drilling clearly peaked in the early 1980s (Figures 2.29 and 2.30). The drilling of discovery and production wells at the *Prudhoe Bay* oil field and associated North Slope fields increased after 1977 when the Trans-Alaska Pipeline was built and remains fairly steady to present (Figure 2.30), while oil production peaked in 1988 (Figure 2.31).

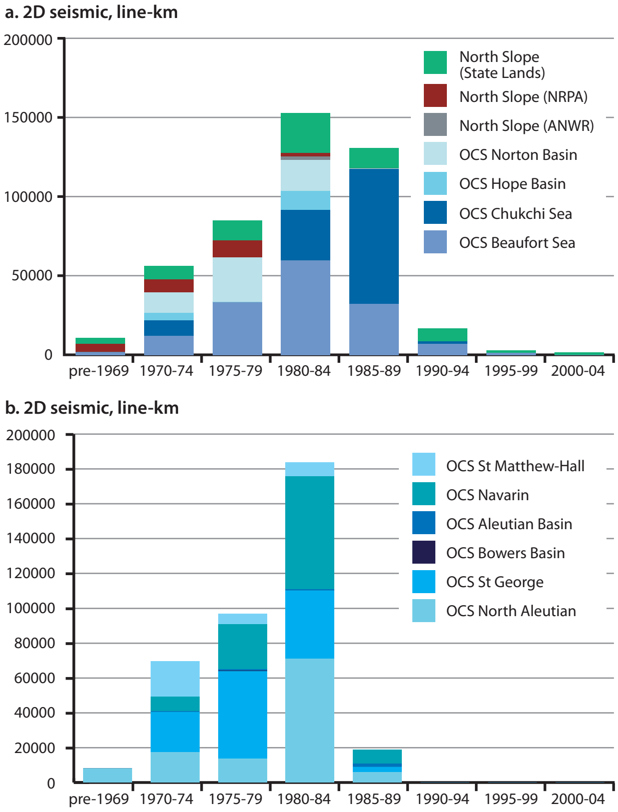


Figure 2.29. (a) Arctic Alaska and (b) Bering Sea seismics over time.

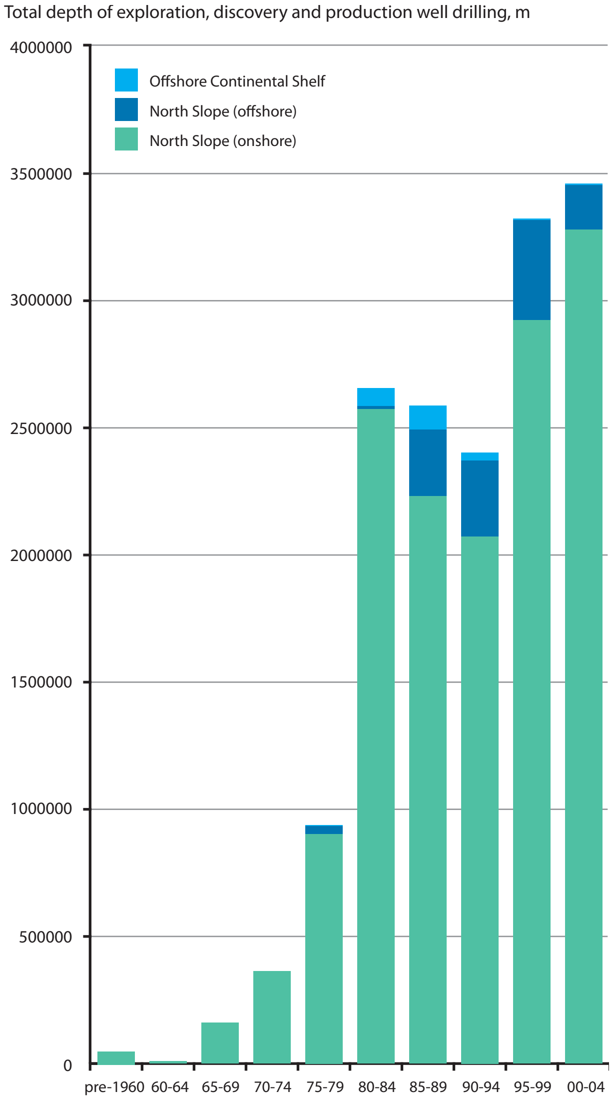


Figure 2.30. Total depth of exploration, discovery and production wells drilled offshore and onshore in Arctic Alaska

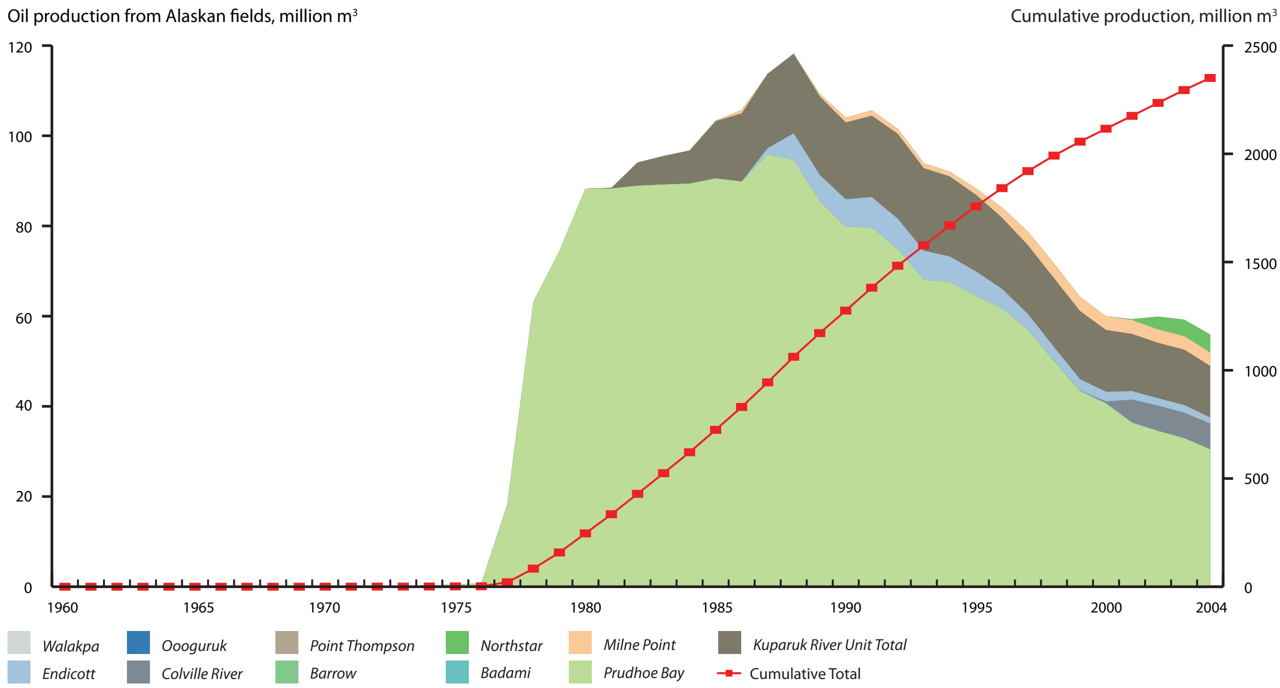


Figure 2.31. Arctic USA oil production over time by field.

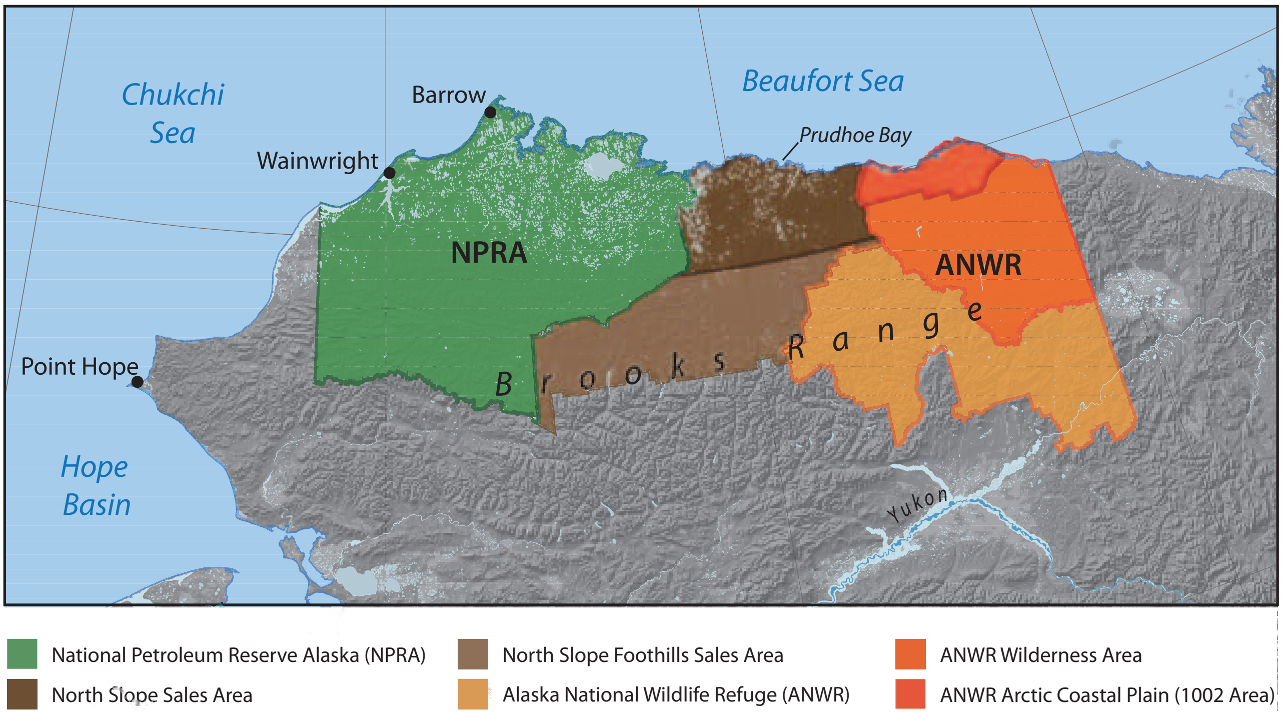


Figure 2.32. Index map of northern Alaska with major rivers, refuges, and oil fields.

2.4.1.3. North Slope

2.4.1.3.1. Historical to present

There are many excellent sources of historical information on Alaska Arctic oil and gas activities (Reed, 1958; Jamison et al., 1980; Bruynzeel et al., 1982; Gryc, 1985, 1988; Dutro, 1987; Weimer, 1987; Schindler, 1988; Kornbrath, 1995; Sherwood et al., 1996; BLM, 1998, ADNR, 2004; Bradwell et al., 2004).

Pre-Statehood activities

The first geological and topographical studies of the North Slope date back to 1901 and the first formal descriptions were recorded by the U.S. Geological Survey (USGS) in 1919 (ADNR, 1999). Reports between 1919 and 1921 by the USGS and other government agencies (Paige et al., 1925; Smith and Mertie, 1930; Moffit et al., 1927) noted oil seeps in Smith Bay (Cape Simpson) (Figure 2.33) and concluded that there may be petroleum at many places on the Arctic Coastal Plain, and that possibly there may be a more-or-less continuous oil-bearing belt extending across northern Alaska (Martin, 1921 cited in BLM, 1998).

Prior to the Mineral Leasing Act of 1920, over 100 oil claims were staked on the North Slope in what is now the NPRA (BLM, 1998; National Research Council, 2003) but no exploration proceeded from these claims. In response to potential fuel shortages for the Navy and because of the perceived great potential for oil, President Harding established the Naval Petroleum Reserve No. 4 (NPR-4) by Executive Order No. 3797-A, in February 1923, encompassing public lands in roughly the western third of the Alaskan Arctic.

Exploration

In the 1920s through the mid-1950s, oil exploration was conducted by the Federal Government in and near NPR-4 on lands reserved for that purpose. During that time, geological studies were also being carried out in the eastern part of the Alaskan Arctic to the Canadian border. These parties reported oil seeps and oil-stained sandstone in the northeastern part of the coastal plain in what is now the Arctic National Wildlife Refuge (ANWR) (Figure 2.32).

The Secretary of the Interior issued Public Land Order 82 in January 1943, during the Second World War, which withdrew the entire North Slope from any sort of mineral entry, subject to pre-existing rights, for use in the prosecution of the war. This included all the generally recognized possible petroliferous areas of Alaska including all of Alaska north of the drainage divide of the Brooks Range.

Gravity and magnetic mapping were done primarily over the northern half and eastern NPR-4. About 5370 line-km of seismic-reflection surveys and 625 line-km of seismic-refraction surveys were completed within and adjacent to the reserve. Early seismic exploration used shallow shot holes (rarely more than 30 m deep) and explosive charges. This early exploration program expired in 1953. Seismic surveys in northern Alaska had to overcome logistical

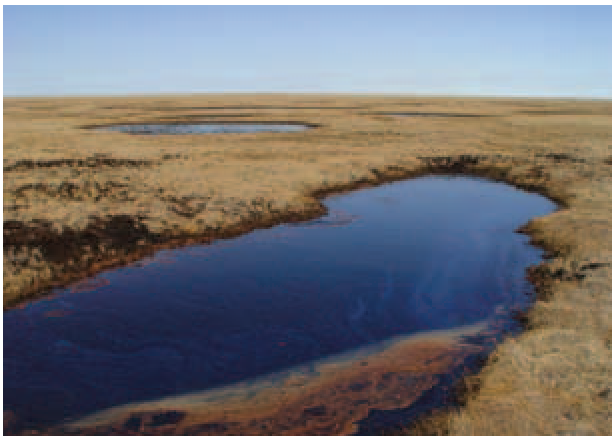


Figure 2.33. Oil seep in pond near Cape Simpson, North Slope, Alaska (BLM).

Box 2.8. *South Barrow* gas field

Even though small, the *South Barrow* gas field was important at the time and for the region. The South Barrow No. 2 Well, along with Umiat Test Well No. 1 (located more than a hundred miles [161 km] to the southeast) and drilled by a different Navy drill rig during the same year, marked the first deep penetrations by a rotary drill rig in the Alaskan Arctic. Furthermore, the South Barrow No. 2 Well was the first well drilled in Naval Petroleum Reserve Number 4 (Pet-4) that was capable of significant oil or gas production.

The *South Barrow* gas field was discovered with the drilling of the South Barrow No. 2 Well in 1948. The No. 2 well, located five miles (~ 8 km) inland from the Navy/USGS camp (later to become the Naval Arctic Research Laboratory, NARL), began producing gas for the camp in mid-1949. In 1950 after a well fire, gas for the camp was thereafter supplied by the South Barrow No. 4 well.

The four-inch (~ 10 cm) diameter pipeline which transported the gas from the *South Barrow* field to the Navy/USGS camp was laid above ground on timbers and horizontally-placed 55-gallon (~ 200 L) drums. By 1967, gas-fired power plants and low-pressure distribution pipelines were being installed in Barrow. This pipeline was used by the Navy/USGS and later by UIC NARL (Ukpeaġvik Iñupiat Corporation and Naval Arctic Research Laboratory) and the DEW (Distant Early Warning) radar site for almost 50 years. The line has only recently (1997) been abandoned, dismantled, and removed.

Box 2.9. Onshore seismic data acquisition

Onshore seismic data are acquired using a vibrator seismic sound source. The vibrator is a mechanical device that is mounted on a heavy truck or other vehicle. The vibrator has a plate which is placed in contact with the ground and transmits the vibration into the underlying soil and rock. It can be compared to the vibratory compactors that are often seen and experienced at or near a construction site. Several vibrators are generally used simultaneously to produce the desired sound. The sound produced is relatively modest, but modern acquisition and processing techniques permit the use of this system as a viable and environmentally acceptable substitute for explosives (see Box 2.13).

Vehicles and operating procedures used in the winter on the North Slope have evolved over the many years that oil and gas exploration has been conducted (see also sections 2.5.1 and 2.5.2). Some of the most dramatic changes have been in the vehicles. Nearly all vehicles used in early exploration used steel tracks. Very large rubber tires were found to have less impact or ground load and their flexibility allowed them to conform more to the terrain, so the tires were phased into the equipment fleet. Now with new materials that can withstand the cold, there has been a move back to rubber tracked vehicles that create even less ground load and the least risk of disturbing the delicate tundra.

problems: weather, terrain, and a dawning realization that the vegetation and soils were fragile and that damage to the environment was slow to recover (see also section 2.5.2). In addition, there were unique and vexing processing problems with acquiring seismic data on the North Slope and surrounding waters. Ice, permafrost, and many lakes and waterways complicate the acquisition and processing of seismic data to this day

From 1944 through 1952, 45 shallow-core test holes and 36 relatively shallow test wells were drilled for a total of 51 587 m of borehole (see also section 2.5.2). The first exploration wells were drilled to a depth limit of about 3000 m because it was thought to be the economic limit for development in the Arctic. During this time, Naval exploration sites were simple in design (Box 2.8). A site was prepared, a drill rig erected, and drilling commenced. Today, the Navy sites generally comprise a pipe surrounded by natural vegetation. A number of Navy sites in the planning area require maintenance or completion (reclamation, abandonment, plugging, or other tasks). Responsibility for clean-up of these well sites rests with the Federal Government. The bulk of material left behind by Navy operations was cleaned up by the USGS and its contractors beginning in 1976 (Schindler, 1988).

Discoveries

Three small, sub-economic oil and gas fields were discovered: *Umiat*, *Fish Creek*, and *Simpson* (Reed, 1958; Bird, 1981; Schindler, 1988; Banet, 1991). *Umiat* is the largest with estimated oil reserves of 500 million bbl (ADNR, 2006a). Five small gas fields were also discovered: *Gubik*, *Barrow*, *Meade*, *Square Lake*, and *Wolf Creek*. *Gubik* is the largest with reserves of approximately 17 billion m^3.

Government subsidies funded the development of gas fields near Barrow that are currently producing for local use.

Post Statehood activities

In the late 1950s and early 1960s, two factors contributed to the entry of the industry into the North Slope: encouraging regional geological studies and the NPR-4 exploration program; and the end of the moratorium on land availability on the North Slope. Public Law 1621 reopened North Slope lands to mineral entry. The Alaska Statehood Act (1959) entitled the State to select Federal lands not already within existing Federal land management status (such as the Arctic Wildlife Range in the eastern part of the State and predecessor to the ANWR).

The Federal Government offered a total of 76 599 km^2 for lease in sales held in 1958, 1964, 1965, and 1966 (Jamison et al., 1980; Thomas et al., 1991). Under the Statehood Act (1958), the State of Alaska selected 6543 km^2 between the Colville and Canning Rivers and north of the Federal offerings of 1958 and 1964. The State subsequently offered these lands in three sales between 1964 and 1967. The largest fields yet to be developed on the North Slope were leased at this time.

The acquisition of geological and geophysical data was either concurrent with or preceded leasing activities. With the opening of the North Slope to leasing, industry began to acquire proprietary geological and geophysical data. Two fundamental types of data were acquired: geological data through summer field programs and geophysical data, primarily seismic, by winter operations (see Box 2.9).

State of Alaska onshore and nearshore lands

Seismic activities. Previous geophysical exploration left an approximately 130 mile-wide gap of unmapped land between the Colville and Canning rivers. The next phase of exploration on the Arctic North Slope was conducted in this area. The exploration was funded and conducted by the petroleum industry. The focus of seismic surveys in 1961/62 was the foothills of the Brooks Range (BP and Sinclair partnership). During the winter of 1962/63, many companies conducted seismic surveys between the Colville and Sagavanirktok rivers. Activity moved east of the Sagavanirktok River in the winter of 1963/64. Although most seismic surveys were focused on the foothills, seismic surveying continued to the coast of the Beaufort Sea with the initial identification of the Prudhoe Bay structure made in 1963 and confirmed by detailed seismic surveys in 1964. The first well on the structure was drilled in 1967.

Jamison et al. (1980, fig. 3) drew up a chart of exploration activity spanning the interval from 1958 to 1977 or the start-up of the Trans-Alaska Pipeline System (TAPS).

A summer seismic program was initiated shortly after the Prudhoe Bay discovery. It was, by all accounts, very damaging to the tundra and summer seismic data acquisition was not attempted again. The seismic surveys on the Arctic North Slope have been conducted during the winter months to avoid damage to the fragile Arctic tundra. Seismic surveys were, and still are, conducted in the remote Arctic using self-contained camps comprising trailers, generally on skids, pulled along the frozen, snow-covered ground by tracked vehicles (Figure 2.34).

Onshore, vibrators have been gradually replacing explosives as the sound source of choice (Figure 2.35). The transition has been occurring over a longer period than in the marine environment. This is because, under certain circumstances, chemical explosives are more effective onshore. With careful regulatory review and appropriate restrictions, chemical explosives may be used safely and with a minimum disturbance to the environment.

Leasing. The State of Alaska has held many onshore and nearshore Arctic Alaska lease sales, beginning in 1964; see Table 2.9 for details of oil and gas lease sales in the onshore Beaufort Sea area of the North Slope and Table 2.10 for details of oil and gas lease sales in the nearshore North Slope.

With the success at Prudhoe Bay, the State announced an additional sale in the Prudhoe Bay area scheduled for the autumn of 1969. Alaska State Lease Sale No. 23, often called 'the billion dollar sale', drew widespread attention and was among the most financially rewarding sales the State has ever conducted. A total of 1670 km^2 (see Table 2.7) were leased in and around the Prudhoe Bay area.

The impending oil and gas lease sale in an area with a huge new discovery caused a significant increase in exploratory activity on the North Slope. Whereas geological and geophysical activities had declined to exceptionally low levels prior to the Prudhoe Bay discovery, they increased dramatically in 1968 and 1969.

Drilling. Industry-sponsored exploration drilling on the North Slope began in 1963, after five years of leasing, geological field work, and seismic data acquisition. Eleven dry holes were drilled prior to the Prudhoe Bay discovery.

Photograph: Gerald Shearer

Figure 2.34. Prime mover on rubber tracks pulling a trailer on skids.

Photograph: Gerald Shearer

Figure 2.35. Modern tracked vibrator with the plate down.

The first exploration well was drilled by Colorado Oil and Gas Company in 1963. The Gubik No. 1 well and the seven subsequent wells were all drilled on leases acquired in the first round of Federal leasing and were located in the Brooks Range foothills within 48 km of either the Gubik or Umiat discoveries.

After the modest successes of exploration drilling in the foothills, the industry focus shifted to the north and east. The third well drilled north of the Brooks Range Foothills, was the ARCO-Humble Prudhoe Bay No. 1. The well was deemed a significant discovery in January 1968 and a confirmation well drilled 11 km to the southeast of the discovery location was quickly drilled. Based on the limited subsurface data available at the time, initial reserve estimates for the Permo-Triassic reservoir at Prudhoe Bay were 9.6 billion bbl of oil and 736 billion m^3 of gas (National Research Council, 2003).

The focus of industry activity after 1969 was largely determined by proximity to exploratory success and land availability. There were no lease sales held on the North Slope or in the adjacent waters of the Beaufort Sea for a ten-year period, 1970 to 1979. This hiatus was due to the uncertainty regarding indigenous peoples' land status throughout Alaska. For that ten-year interval, drilling activity was confined to the areas previously leased. A total of 233 exploration wells were drilled during the 1970s. This includes wells drilled in NPRA, the central part of the coastal plain on the North Slope of the Brooks Range, and in State and Federal waters of the Beaufort Sea.

Table 2.9. Arctic Alaska oil and gas lease sales for the North Slope onshore by the State of Alaska.

Competitive sale area	Sale	Date	Planning area, km²	Offered, km²	% planning offered	Leased, km²	% offered leased	Bonus received, USD	Bonus USD/km² leased
North Slope East of Colville River delta	State Sale No. 13	1964	NA	2 527	NA	1 881	74.4	NA	NA
North Slope Prudhoe West to Canning R.; offshore/ uplands	14	Jul-65	NA	3 051	NA	1 631	53.5	6 145 473	3 768
North Slope Colville to Canning R.; offshore/ uplands	23	Sep-69	NA	1 825	NA	1 670	91.5	900 041 605	538 947
North Slope Prudhoe Uplands: Kuparuk R. to Mikkelsen Bay	31	Sep-80	NA	794	NA	794	100.0	12 387 470	15 601
North Slope Prudhoe Uplands: Sagavanirktok R. to Canning R.	34	Sep-82	NA	4 984	NA	2 315	46.4	26 713 018	11 539
North Slope Colville R. Delta/Prudhoe Bay Uplands Exempt: West of Kavik R.; offshore/uplands	43A	May-84	NA	308	NA	308	100.0	1 612 583	5 236
North Slope Exempt: Canning R. to Colville R.; offshore/uplands	45A	Sep-85	NA	2 454	NA	667	27.2	4 657 478	6 983
North Slope Kuparuk Uplands: South of Prudhoe Bay	47	Sep-85	NA	779	NA	739	94.9	11 645 003	15 758
Kuparuk Uplands: S of Kuparuk Oil Field	48	Feb-86	NA	2 128	NA	1 079	50.7	2 444 342	2 265
North Slope Prudhoe Bay Uplands: Canning R. to Sagavanirktok R.	51	Jan-87	NA	2 396	NA	407	17.0	289 625	712
North Slope Kuparuk Uplands: Colville River Delta	54	Jan-88	NA	1 707	NA	1 371	80.3	4 683 388	3 416
North Slope Kuparuk Uplands Exempt: Canning R. to Colville R.	69A	Sep-88	NA	3 139	NA	1 491	47.5	6 119 135	4 104
North Slope Oliktok Point Exempt: Uplands	72A	Jan-89	NA	3	NA	3	100.0	454 977	151 659
North Slope Kuparuk Uplands Exempt: Canning R. to Colville R.	70A.	Jan-91	NA	2 153	NA	1 702	79.1	27 707 541	16 279
North Slope Kavik: Canning R. to Sagavanirktok R.; uplands	64	Jun-91	NA	3 053	NA	138	4.5	242 389	1 756
North Slope White Hills: Colville R. to White Hills uplands	61	Jan-92	NA	4 011	NA	1 054	26.3	2 429 551	2 305
North Slope Kuparuk Uplands: Between NPRA and Sagavanirktok R.; Colville R. Delta ASRC lands	75	Dec-92	NA	879	NA	505	57.5	9 750 111	19 307
North Slope Nanushuk: North Slope Foothills, Chandler R. to Ivashak R	77	May-93	NA	5 100	NA	185	3.6	1 164 555	6 295
North Slope Kuparuk Uplands Reoffer: Between Canning R. and Kavik R.; onshore	70A-W	May-93	NA	152	NA	114	75.0	1 358 027	11 913
North Slope Foothills: Brooks Range foothills, Sagavanirktok R. to Killik R	57	Sep-93	NA	4 181	NA	0	0.0	0	0
North Slope Colville River Exempt: Colville River Delta onshore	75A	Sep-93	NA	58	NA	58	100.0	449 847	7 756

Table 2.9. Cont.

Competitive sale area	Sale	Date	Planning area, km^2	Offered, km^2	% planning offered	Leased, km^2	% offered leased	Bonus received, USD	Bonus USD/km^2 leased
North Slope Areawide: All acreage between NPRA and ANWR north of the Umiat Baseline	87	Jun-98	20 639	20 639	100	2 099	10.2	51 794 173	24 676
North Slope All available acreage between NPRA and ANWR north of the Umiat Baseline	NS Areawide	Feb-99	20 639	20 639	100	708	3.4	2 596 838	3 668
North Slope All available acreage within the North Slope region.	NS Areawide 2000	Nov-00	20 639	20 639	100	2 640	12.8	10 052 665	3 808
North Slope All available acreage within the North Slope Foothills region.	NS Foothills Areawide 2001	May-01	31 565	31 565	100	3 475	11.0	9 799 277	2 820
North Slope All available acreage within the North Slope region.	NS Areawide 2001	Oct-01	20 639	20 639	100	1 760	8.5	6 911 572	3 927
North Slope State acreage between NPRA and ANWR, south of the Umiat Baseline	NS Foothills Areawide 2002	May-02	31 565	31 565	100	863	2.7	2 889 532	3 348
North Slope State acreage between NPRA and ANWR north of the Umiat Baseline	NS Areawide 2002	Oct-02	20 639	20 639	100	131	0.6	579 728	4 425
North Slope State acreage between NPRA and ANWR, south of the Umiat Baseline	NS Foothills Areawide 2003	May-03	31 565	31 565	100	23	0.1	36 576	1 590
North Slope State acreage between NPRA and ANWR north of the Umiat Baseline	NS Areawide 2003	Oct-03	20 639	20 639	100	850	4.1	3 586 400	4 219
North Slope Foothills Areawide	NSF 2004	May-04	31 565	31 565	100	80	0.3	106 305	1 329
North Slope Areawide	NS Areawide 2004	Oct-04	20 639	20 639	100	801	3.9	7 599 193	9 487
North Slope Foothills	NS Foothills Areawide 2005	May-05	31 565	31 565	100	225	0.7	319 959	1 422
North Slope Areawide	NS Areawide 2006	Mar-06	20 639	20 639	100	2 284	11.1	15 741 677	6 892
North Slope Foothills	NS Foothills Areawide 2006	May-06	31 565	31 565	100	997	3.2	1 849 229	1 855
North Slope Areawide	NS 2006A	Oct-06	20 639	20 639	100	717	3.5	2 530 534	3 529

Table 2.10. Arctic Alaska oil and gas lease sales for the North Slope nearshore (Beaufort Sea) by the State of Alaska.

Competitive sale area	Sale	Date	Planning area, km²	Offered, km²	% planning offered	Leased, km²	% offered leased	Bonus received, USD	Bonus USD/ km² leased
North Slope Beaufort Katalla, Prudhoe; offshore/ uplands	18	Jan-67	NA	193	NA	177	91.7	1 479 906	8 361
Beaufort Sea (Joint Federal & State sale): offshore Milne Pt. east to Flaxman Is.	30	Dec-79	NA	1381	NA	1199	86.8	567 391 497	473 221
Beaufort Sea: Pt. Thomson area; offshore/uplands	36	May-82	NA	230	NA	230	100.0	32 583 452	141 667
Beaufort Sea: Qwydyr Bay to Harrison Bay; offshore/ uplands	39	May-83	NA	858	NA	858	100.0	20 998 101	24 473
Beaufort Sea: Pitt Point to Harrison Bay	43	May-84	NA	1206	NA	1140	94.5	32 214 794	28 259
North Slope Beaufort Mikkelsen Exempt: Mikkelsen Bay, Foggy Is. Bay; offshore/uplands	48A	Feb-86	NA	170	NA	170	100.0	510 255	3 002
Beaufort Camden Bay: Flaxman Is. to Hulahula R.; offshore	50	Jun-87	NA	478	NA	478	100.0	6 621 723	13 853
Beaufort Demarcation Point: Canning R. to U.S./Canadian border; offshore	55	Sep-88	NA	816	NA	391	47.9	14 700 602	37 597
Beaufort Sea: Pitt Point to Tangent Point; offshore	52	Jan-89	NA	712	NA	212	29.8	1 737 513	8 196
Beaufort Sea: Pitt Point to Canning R.; offshore	65	Jun-91	NA	1987	NA	700	35.2	6 993 949	9 991
Beaufort Sea: Nulavik to Tangent Point; offshore	68	Jun-92	NA	621	NA	0	0.0	0	NA
North Slope Beaufort Shaviovik: Sag R. to Canning R., southern Kaparuk Uplands, Gwydyr Bay, Foggy Island Bay, onshore/ offshore	80	Dec-95	NA	3850	NA	613	15.9	3 337 485	5 445
North Slope Beaufort Colville River Exempt: Colville R, offshore, state/ ASRC onshore/offshore	86A	Oct-96	NA	63	NA	24	38.1	2 026 247	84 427
Central Beaufort Sea: Harrison Bay to Flaxman Island	86	Nov-97	NA	1477	NA	1311	88.8	27 985 125	21 346
Beaufort Sea All available acreage within the Beaufort Sea region.	BS Area wide 2000	Nov-00	8094	8094	100	105	1.3	338 922	3 228
Beaufort Sea All available acreage within the Beaufort Sea region.	BS Area wide 2001	Oct-01	8094	8094	100	147	1.8	3 447 734	23 454
Beaufort Sea State acreage within the 3-mile limit, between Dease Inlet and Barter Island	BS Area wide 2002	Oct-02	8094	8094	100	78	1.0	506 405	6 492
Beaufort Sea State acreage within the 3-mile limit, between Dease Inlet and Barter Island	BS Area wide 2003	Oct-03	8094	8094	100	150	1.9	1 358 187	9 055
Beaufort Sea Areawide	BS Area wide 2004	Oct-04	8094	8094	100	459	6.0	4 190 782	9 130
Beaufort Sea Areawide	BS Area wide 2006	Mar-06	8094	8094	100	826	10.2	7 685 032	9 304
Beaufort Sea Areawide	BS Area wide 2006	Oct-06	8094	8094	100	135	1.7	684 723	5 072

Federal onshore lands

There was an early Federal role in North Slope exploration (Table 2.11). The first North Slope offering comprised a competitive offering (Gubik, where 65 km^2 was offered) and a 'simultaneous' offering. The latter is in effect a non-competitive lottery wherein an application is submitted and an award of rights is made following a draw. The offerings in 1964 through 1966 also took the form of this non-competitive lottery.

National Petroleum Reserve-Alaska

The BLM has held eight lease sales in the NPRA since 1982 (Table 2.12). The modern history of oil and gas activities in the NPRA in the western North Slope follows.

Exploration – The Naval/National Petroleum Reserve. The USGS coordinated the post-1973 phase of NPR-4 exploration, resulting in 28 exploration wells (Bird, 1988 in Gryc, 1988: table 15.2) and 21 058 km of seismic data (Schindler, 1988: table 2.1). Between 1975 and 1976, the Navy began a more modern exploration program, which is conceptually described in the Final Environmental Impact Statement for continuing exploration and evaluation of NPR-4 (Zone A) (U.S. Department of the Navy, 1975).

The National Petroleum Reserve Production Act (NPRPA) of 1976 (PLO 94-258) created the NPRA, transferring the oversight of the reserve from the Navy to the Department of the Interior, and authorized the Secretary of the Interior to divide management responsibilities between BLM (surface) and the USGS (subsurface). It is the single largest contiguous federally managed land entity. In Areas of Operations, the USGS had surface and subsurface authority. BLM's responsibilities to manage these lands came under the authority of two laws passed in 1976: the NPRPA and the Federal Land Policy and Management Act (FLPMA).

There was also one well drilled on Native lands within the 1002 area of ANWR in the eastern North Slope. After the initial surge of drilling activity associated with the Prudhoe Bay discovery, the level of exploration drilling decreased substantially.

Table 2.11. Arctic Alaska oil and gas lease sales on the North Slope by the Federal Government Bureau of Land Management.

Sale Area	Sale	Date	Planning area, km^2	Offered, km^2	% planning offered	Leased, km^2	% offered leased	Bonus Received, USD	Bonus USD/km^2 leased
North Slope Gubik Area	1st North Slope Sale	1958	NA	65	NA	65	100	NA	NA
North Slope E/SE of NPR-4 S of Mikkelsen	1st North Slope Sale	1958	NA	16 317	NA	16 317	100	NA	NA
North Slope Between E/W segments of 1958 sales	2nd North Slope Sale	1964	NA	14 918	NA	14 918	100	NA	NA
North Slope E, S&W of Prior Offerings	3rd North Slope Sale	1965	NA	33 067	NA	4 434	13.4	NA	NA
North Slope W of NPR-4	4th North Slope Sale	1966	NA	12 232	NA	0[a]	0	NA	NA

[a] No leases issued.

Table 2.12. Arctic Alaska oil and gas lease sales on the North Slope in the Federal National Petroleum Reserve-Alaska.

Competitive sale area	Sale	Date	Planning area, km^2	Offered, km^2	% planning offered	Leased, km^2	% offered leased	Bonus received, USD	Bonus USD/km^2 leased
NPRA	821	1/27/82	NA	6 136	NA	2 735	44.6	58 351 262	21 335
NPRA S & SE parts	822	5/26/82	NA	14 243	NA	1 119	7.9	9 741 022	8 705
NPRA northern parts	831	7/20/83	NA	8 886	NA	1 685	19.0	16 666 659	9 891
NPRA	841	7/18/84	NA	6 437	NA	0	0.0	0	NA
NPRA Northeast part	991	1999	18 211	15 783	86.7	3 497	22.2	104 635 728	29 922
NPRA Northeast part	2002	2002	18 211	12 349	67.8	2 344	19.0	63 811 496	27 223
NPRA Northwest part	2004	6/2/04	35 612	23 472	65.9	5 680	24.2	53 904 491	9 490
NPRA Northwest part	2006	Sep-06	NA	20 234	NA	3 804	18.8	13 860 135	3 644

Exploration – The Department of the Interior Period. The Department of the Interior was charged with exploring the NPRA between 1976 and 1982. The Secretary of the Interior appointed the USGS the responsible party for the exploration program under Section 104 of the NPRPA (see Figure 2.36 for a map of 2D and 3D seismic data collection). The USGS contracted for exploration operations with Husky Oil Company. The well sites generally comprised a camp pad, drilling pad (normally all one pad), reserve/mud pit, a flare pit, a fuel-storage pit, and the well head consisting of a pipe (Christmas tree) surrounded by the cellar (corrugated metal chamber or timber cribbing). Although most well sites were serviced by ice airstrips, three included gravel airstrips. Drilling operations in areas of unknown underground pressures sometimes used pits to allow for a safe way to contain high pressure formation fluids. The USGS/Husky exploration operations ended in 1981. Responsibility for final closeout of the NPRA Areas of Operations remains with the USGS. The USGS began continuous well-site cleanup and rehabilitation in 1978. The USGS/Husky used an approved solid-waste-disposal site at Lonely.

Today, there are 28 wells under USGS jurisdiction. All of these wells were the subject of an intensive revegetation program. Since then, the sites continue to be reclaimed naturally by local species. The sites with compacted gravel pads have taken considerably longer to show signs of natural vegetation takeover than the soil-based pads. The USGS wells have deep permanent plugs generally at about 600 m; in addition, all zones of petroleum fluids or pressure are isolated by permanent plugs. At the surface, the wells have Christmas tree valve (abandonment head) assemblies. This allows a small valve to be opened for temperature logging as part of an ongoing program of climate research.

In 1983, due to Departmental reorganizations involving BLM, USGS, and MMS, BLM was given management responsibility for both the surface and subsurface. These decisions were consistent with the Secretarial Orders of the time and with oil and gas activities in other parts of the United States. According to the NPRPA, all oil and gas leasing in the NPRA takes place under the same methods as those utilized in the OCS (this includes tract nominations, sealed bids, requisite bonding, and economic tract evaluation for bid acceptance or rejection). Lease terms are for ten years in the NPRA.

Exploration – The Private Period. Private exploration began with the passage of the Interior Appropriations Act of December 1980. An oil and gas leasing program was initiated by the Department of the Interior, and the first sale was held in 1982. One well, ARCO's Brontosaurus Well No. 1, was drilled as a result. The Cape Halkett land exchange transferred the W.T. Foran well to the Arctic Slope Regional Corporation (ASRC) and allowed the ASRC to drill the Livehorse well on private land within the NPRA. Wells in the Barrow area (such as the *South Barrow* gas field and the Walakpa exploration wells) developed by the Federal Government were later passed to the North Slope Borough through the Barrow Gas Field Transfer Act. The *Walakpa (Ualiqpaa)* field is developed and now produces more than 90% of Barrow's annual consumption of natural gas (North Slope Borough, 1998).

Well designs and seismic techniques have evolved since the early days of Government exploration in the NPRA. Modern well designs generally call for recirculating mud systems without pits. The disturbed area is minimal. Modern completed wells under any future leasing should resemble Brontosaurus, where a closed pipe marks the location and little else is visible; the ground area has a natural appearance. Seismic exploration programs now use vibrating equipment rather than explosives (Figure 2.35) and benefit from the considerable experience of early Government programs.

The NPRA has been the subject of several studies since its creation more than a quarter of a century ago. Section

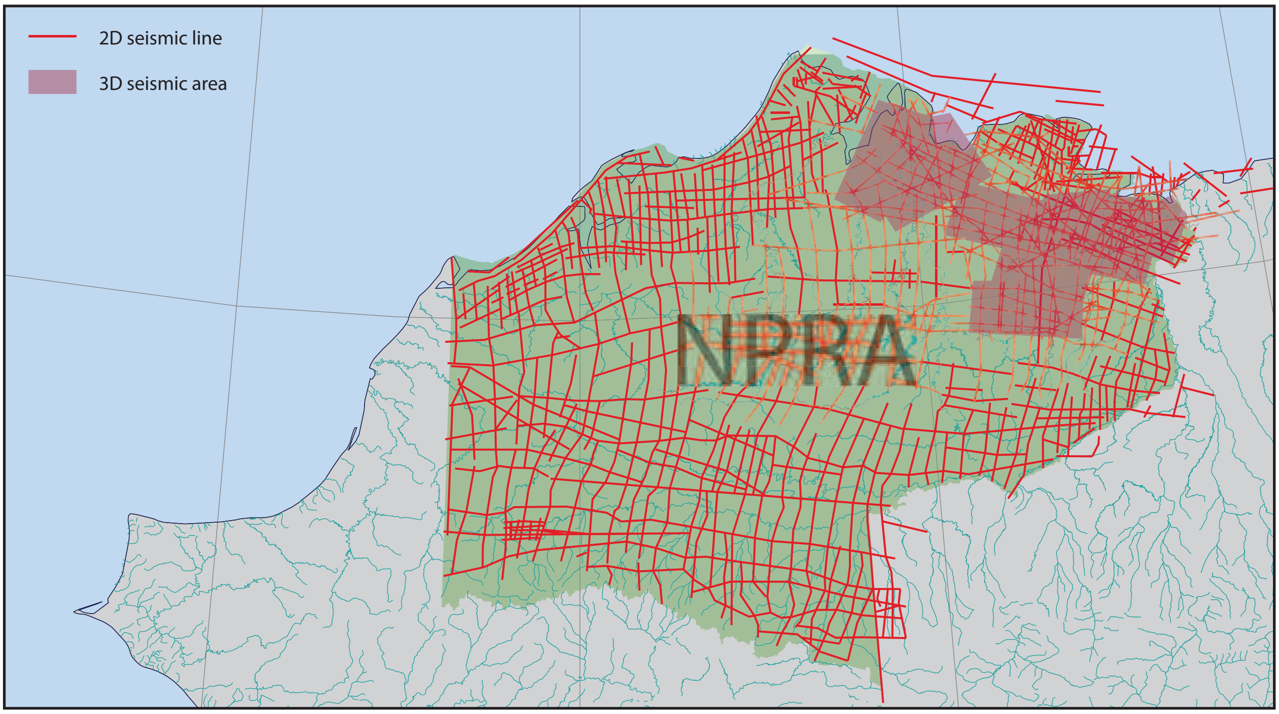


Figure 2.36. Lines (2D surveys) and areas (3D surveys) for which seismic data have been collected in the NPRA.

105(c) of the NPRPA mandated studies of the resources of the NPRA, which were published in 1978 and 1979.

In 1980, with continued regional NPRA exploration, the drilling of the Walakpa No. 1 well, located about 12 km southwest of Barrow, identified a potential large gas accumulation. Follow-up drilling in 1981 of the Walakpa No. 2 well, 8 km to the south of the discovery well, continued to indicate the strong possibility of a large natural gas reservoir. Although the USGS identified the accumulation as a potential gas source for Barrow, the area remained undeveloped.

Leasing. Congress first authorized 'an expeditious program of competitive leasing of oil and gas' in the NPRA in the Department of the Interior and Related Agencies' Fiscal Year (FY) 1981 Appropriations Act (P.L. 96-514, Dec.12, 1980). To meet the provisions of the National Environmental Policy Act (NEPA) to conduct lease sales, the BLM completed an Environmental Assessment of the NPRA in 1981 and a more comprehensive Environmental Impact Statement (EIS) in 1983 (BLM, 1983). The 1983 EIS recommended stipulations for certain areas including Teshekpuk Lake.

Four competitive lease sales were conducted between 1982 and 1984. These sales offered 35 702 km^2, of which 5539 km^2 were leased, yielding bonus bids of about USD 85 million. Although Sale #844 offered lands for lease, no bids were received. All the leases issued by the BLM in 1982 and 1983 have now expired. According to the NPRPA, all Federal revenues from bonus bids, rentals, and royalties are split with the State.

In 1985, the BLM completed separate habitat and mineral evaluations of the Teshekpuk Lake Special Area (BLM, 1985a,b). Current planning draws from these studies and incorporates data from research and monitoring conducted since that time.

In 1997, the BLM began planning for the Northeast NPRA sale, including all lands in the NPRA east of the Northwest NPRA Planning Area. The Northeast NPRA Integrated Activity Plan/Environmental Impact Statement (IAP/EIS) culminated in a Record of Decision in October 1998 that superseded the decisions of the 1983 EIS and included a decision to make 15 783 km^2 available for oil and gas leasing (see also Chapter 6). Two lease sales were held in the Northeast Planning Area: sales 991 and 2002 leased 3497 and 2344 km^2, respectively, which were 22% and 19% of what was offered in these focused lease sales (Tables 2.7 and 2.12).

Analogous to the Northeast NPRA plan, the Northwest NPRA plan adopted at completion of the IAP/EIS (see Chapter 6) established guidelines for future management of the Northwest NPRA Planning Area and superseded management guidelines developed under the 1983 EIS. Sale 2004 leased 5680 km^2 for bonus bids of nearly USD 54 million.

In January 2006, the U.S. Department of the Interior signed a Record of Decision for an amended IAP/EIS for Northeast NPRA that opened lands around Teshekpuk Lake to oil and gas leasing (see Chapter 6). In the September 2006 lease sale, 3804 km^2 were leased for USD 13 860 135 in bonus bids.

The lease sale was originally set to offer tracts within the Northwest and Northeast Planning Areas of the NPRA totaling 32 375 km^2. Owing to a final decision from the U.S. District Court in Anchorage, tracts in the Northeast Planning Area around Teshekpuk Lake were withheld from the lease sale. The sale contained only tracts in the northwest part of the petroleum reserve encompassing more than 20 234 km^2.

Arctic National Wildlife Refuge

Exploration. This section reviews the history of oil and gas exploration in Federal lands in the eastern North Slope (see Figures 2.9 and 2.25).

The Alaska National Interest Lands Conservation Act (PL 96-487) (ANILCA) of 1980 created the National Wildlife Refuges in Alaska. The Arctic Wildlife Range was enlarged from 35 612 to 76 890 km^2 and renamed the Arctic National Wildlife Refuge (ANWR). Of particular interest is the coastal plain area which is described under Section 1002 of ANILCA. This 6070 km^2 area includes the village of Kaktovik and its land selection pursuant to the Alaska Native Claims Settlement Act. It also includes several of the largest oil seeps on the North Slope after those of the Cape Simpson area in the NPRA.

Section 1002 recognizes the area's potential for oil and gas resources. It mandates a comprehensive study of the oil, gas, cultural, and wildlife resources. Legislative Environmental Impact Statements (Clough et al., 1987) are reports to Congress as mandated in Section 1002 of ANILCA describing the baseline environment, resource potential, and potential impacts from oil and gas development.

After the Legislative Environmental Impact Statement was released, regulations were developed governing exploration activities to ensure that there were no significant adverse effects on fish or wildlife, their habitats, or the environment (see Appendix 2.1). During the summers of 1983 through 1985, field parties from 15 companies explored the 1002 area geology by hand sampling, observation, and surface measurements supported by helicopters. No surface vehicles were allowed. In summer 1983, a helicopter-supported gravity survey was conducted collecting data in a 1.6 × 3.2 km grid over the entire 1002 area. During the winters of 1983/84 and 1984/85, one company, representing a consortium to minimize potential effects, collected a total of 2092 km of seismic data. These activities were strictly overseen by the Fish and Wildlife Service to avoid any sensitive areas or habitats (Clough et al., 1987).

These exploration efforts greatly increased knowledge of the potential for oil and gas resources. The information was used in the preparation of the 1987 Legislative Environmental Impact Statement (LEIS). The report concluded that the area described under Section 1002 has significant oil, gas, and wildlife resources. From the LEIS report, the Secretary of the Interior recommended to Congress that it enact legislation to conduct an orderly oil and gas leasing program for the 1002 area. The LEIS also recognized the wildlife and cultural resources of the 1002 area and subsequently recommended that leasing in the 1002 area occur at a pace and under stipulations to avoid unnecessary adverse impacts on the environment.

The opening of the ANWR coastal plain (as defined under Section 1002 of ANILCA) continues to be debated in Congress. Oil seeps within the ANWR, oil and gas discoveries on State lands west of the ANWR coastal plain, and discoveries offshore of the ANWR indicate that components of an active petroleum generating system are present. Interpretations of preliminary and reprocessed 2-D

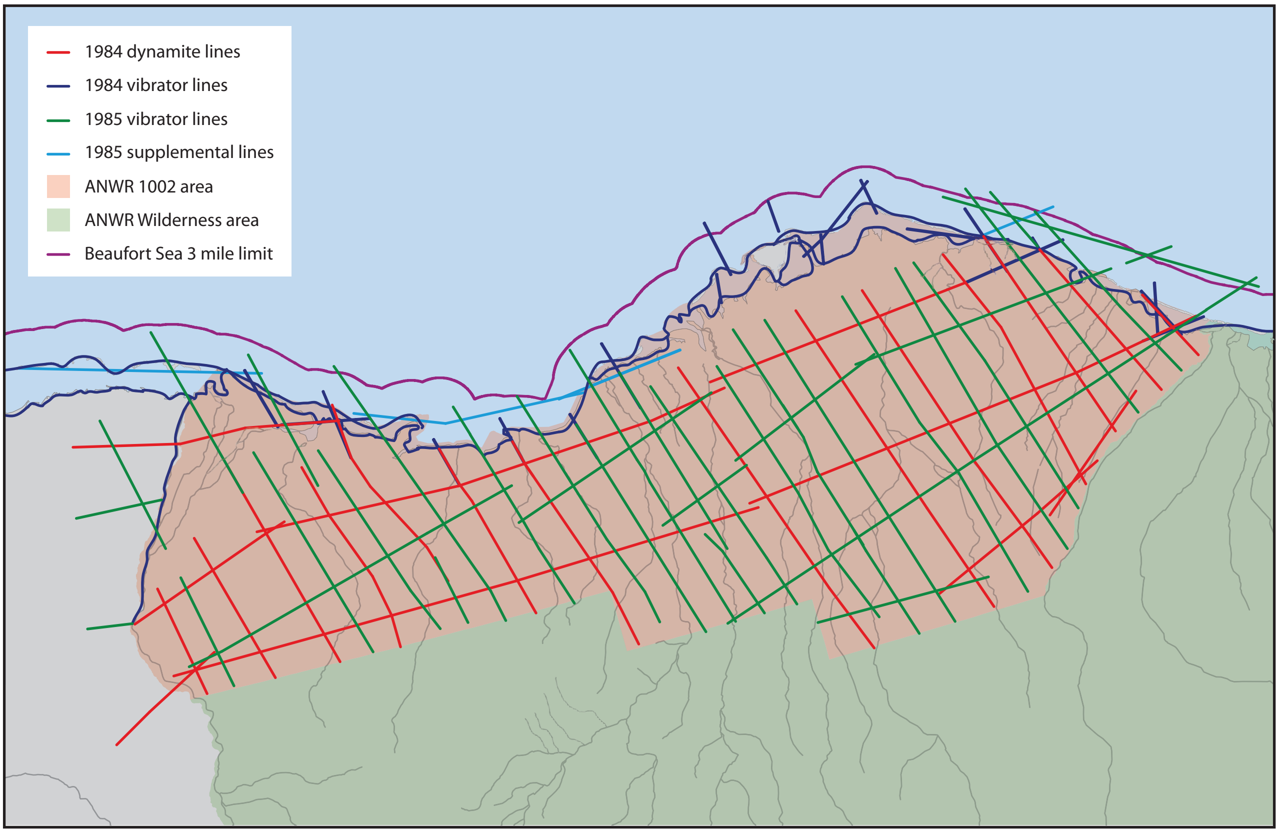


Figure 2.37. Seismic data collected on the Arctic National Wildlife Refuge Coastal Plain (1002) Area.

seismic data gathered in 1984 and 1985 (Figure 2.37) show a number of potentially oil-rich plays in the subsurface of the ANWR coastal plain. If opened for exploration, the coastal plain of the ANWR could provide opportunities to test some of the largest undrilled anticlinal features remaining in the United States. These features have the spatial extent to have resources rivaling those of the *Prudhoe Bay* field. However, the probability of successfully discovering world-class accumulations is less than about 5%.

Although the 1002 area of the ANWR has never been made available for leasing, there are Native corporation inholdings and a land trade between the Federal Government and several Native corporations was strongly considered in the mid-1980s. At various times, the Arctic Slope Regional Corporation (ASRC) has made all or parts of their land-holdings available to companies through exclusive exploration/leasing agreements.

Discoveries and development

During the ten years of industry activity preceding the Prudhoe Bay discovery, only eleven wells had been drilled. In 1968 and 1969, 33 wells were drilled and completed (ADNR, 2000). These 33 exploration wells resulted in twelve discoveries. Most of these are now productive oil fields.

The oil discoveries in 1968 and 1969 are listed as follows with cumulative production as of 1 January 2006:

- Prudhoe Bay Permo-Triassic Oil Pool (10.8 billion bbl)
- Lisburne Oil Pool (143 million bbl)
- Orion Oil Pool (5.5 million bbl)
- Ugnu Oil Pool (<1.0 million bbl)
- Kuparuk River Oil Pool (2.0 billion bbl)
- West Sak Oil Pool (20.2 million bbl)
- *Milne Point* field (237.3 million bbl)
- Borealis Oil Pool (38.4 million bbl)
- Aurora Oil Pool (15.1 million bbl)
- Polaris Oil Pool (4.9 million bbl)
- *Kavik* gas field (not developed)
- *Gwydyr Bay* field (not developed)

While these discoveries were all made in the 1968 to 1969 drilling seasons, the first discovery, Prudhoe Bay, did not begin commercial production until 1977 and Aurora, Borealis, Orion, Polaris, and Ugnu did not begin production until 2000 or later.

During this early period, the North Slope produced only small quantities of oil for refining and local consumption at the small Prudhoe Bay refinery. In 1970, a consortium of production companies determined that the most feasible means to transport commercial quantities of oil, including condensate and natural gas liquids (NGLs), to market was via a 1300-km trans-Alaska pipeline to a navigable port in southern Alaska where it could be shipped by tanker to refineries in the continental United States (ADNR, 2004).

From 1970 through 1989, there were 14 discoveries north of the Brooks Range on onshore and offshore State leases. Nine were onshore and five were either entirely or partially in State waters of the Beaufort Sea. The 15th discovery at Seal Island No. 1 (now Northstar) straddled the Federal-State boundary. Eight of the discoveries are currently producing and two may be developed in the near future (Pt. Thomson and Colville Delta). The discoveries are listed as follows with cumulative production as of 31 December 2004:

- North Prudhoe Bay (2.0 million bbl)
- *Kemik* gas field (not developed)
- Flaxman Island (not developed)

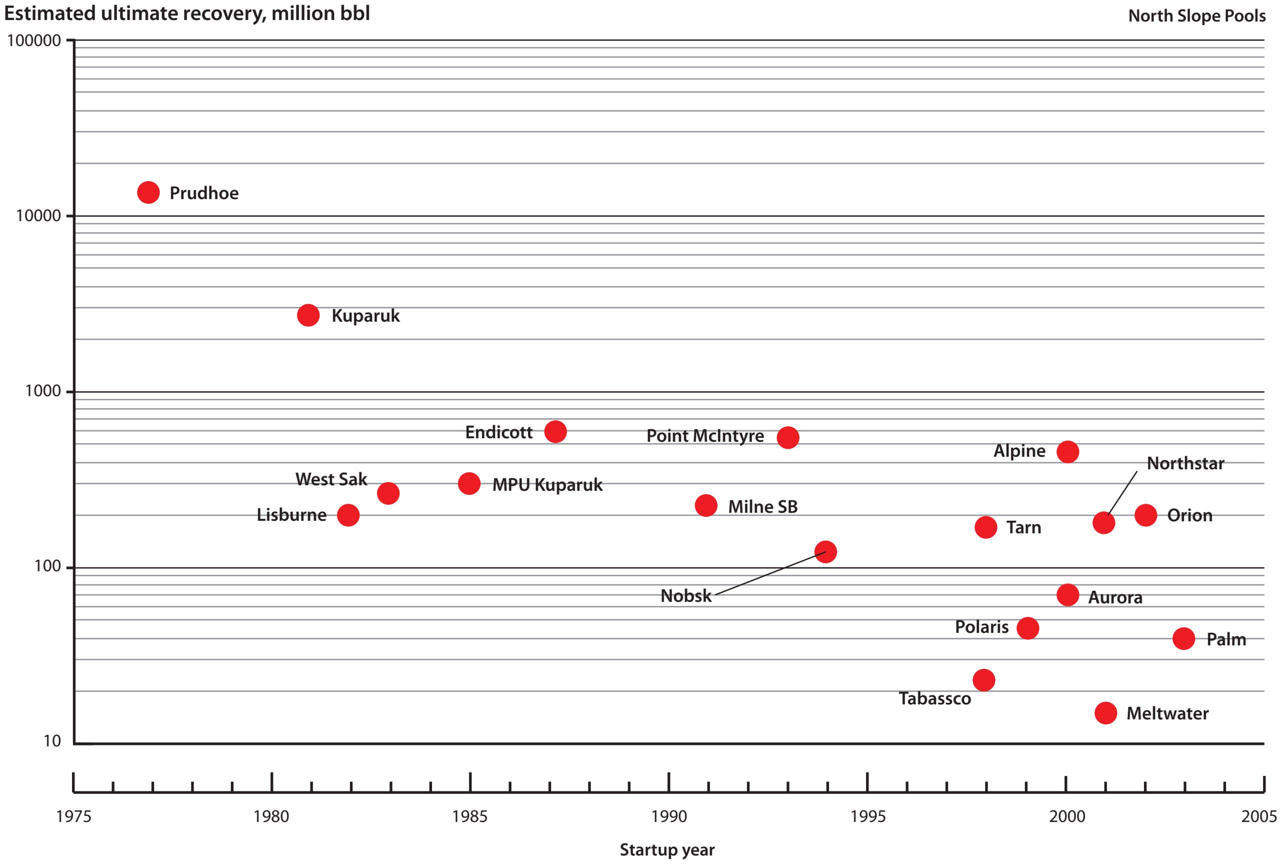


Figure 2.38. Field size versus date of first production for all Arctic Alaska producing fields.

- West Beach (3.6 million bbl)
- *East Karupa* gas field (not developed)
- Point Thomson Gas/condensate (light oil) (not developed)
- Endicott (446.1 million bbl)
- Mikkelsen (not developed)
- Sag Delta North (7.9 million bbl)
- Northstar (58.1 million bbl)
- Hemi Springs (not developed)
- Niakuk (80.2 million bbl)
- Colville Delta (not developed)
- Tabasco (9.1 million bbl)
- Pt. McIntyre (379.6 million bbl)

The *Alpine* field was discovered in 1994 on State and Native land adjacent to the northeastern NPRA and began producing in November 2000. It is estimated to produce 500 million bbl of oil over its 25-year life (ADNR, 2004). ConocoPhillips is using enhanced oil recovery techniques to increase recovery from the *Alpine* field and estimates that water alternating with gas will increase oil recovery by 6%. Two new satellites to the *Alpine* field are under construction and three more are planned for construction prior to 2010. Several new exploration units have been formed, including Southeast Delta west of the *Kuparuk* field and the Ooguruk Unit northwest of Oliktok Point. And new 'satellite' fields are being developed around the *Prudhoe Bay* field including *Meltwater North*, *Meltwater South*, *Midnight Sun*, *Aurora*, *Borealis*, *Polaris*, and the heavy oil prospect at Schrader Bluff (ADNR, 2003). Field size versus date of first production for all the Arctic Alaska producing fields is shown in Figure 2.38.

The first Arctic offshore field, *Northstar*, began flowing oil in October 2001. At 60 000 bbl of peak oil production per day, the field is expected to produce 170 million bbl over field life. BP's Northstar oilfield project employed innovative construction technologies to lay 10 km of offshore pipeline and to complete main work on the 20 234 m^2 (5 acre) gravel island before the end of the winter construction season in April. Modified backhoes on pontoon tracts dug a 2- to 3-m pipeline sub-sea trench from ice work pads in water depths up to 12 m (Figure 2.39). The project employed over 700 people at its peak. The field includes Federal (OCS) land and represents the first production from the Alaska OCS.

Figure 2.39. Northstar pipeline trenching operation (MMS).

Table 2.13. Past development: Physical footprint of infrastructure and facilities on the North Slope (modified from BLM, 2003; Table IV-09).

Unit or Area / Field	Gravel roads, pads, and airstrips km²	Pipelines, Gathering, Common Carrier, Unspecified, km²			Gravel mines		Wells	Pads	Reserve pits		Prod. centers	Camps-base & contruct.	Facilities and plant: power, topping, gas, seawater	Docks and causeways	Airports and airstrips	Roads, km²	River crossings
		G	C	U	No	km²			No	km²							
Duck Island																	
Endicott	1.59	5	42	-	1	0.72	129	2	0	0	0	0	3	2	0	24	1
Prudhoe Bay Unit																	
Prudhoe Bay	18.21	-	-	233	6	2.9	1764	38	106	2.27	6	4	4	2	2	322	3
Lisburne	0.86	80	-	-	0	0	80	5	10	0.06	1	1	1	0	0	29	-
Niakuk	0.09	8	-	-	0	0	19	-	0	0	-	-	-	-	-	-	-
West Beach	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-
N. Prudhoe Bay	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-
Pt. McIntyre	0.13	19	-	-	0	0	84	-	0	0	-	-	-	-	-	-	-
Aurora	0	0	0	0	0	0	6	0	0	0	0	0	0	0	0	0	0
Borealis	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Polaris	-	-	-	-	-	-	-	1	0	0	0	0	0	0	0	0	0
Kuparuk River																	
Kuparuk River	5.81	156	60	45	5	2.28	810	39	126	0.65	3	2	4	1	1	151	1
West Sak	-	-	-	-	0	0	69	4	0	0	0	0	0	0	0	-	0
Palm	0.02	0	0	-	-	-	17	1	0	0	0	0	0	0	0	-	0
Meltwater	0.32	16	0	-	-	-	20	1	0	0	0	0	0	0	0	16	0
Milne Point																	
Milne Point	0.83	48	16	-	1	0.17	182	4	20	0.08	1	0	2	0	0	31	1
Cascade	0.13	-	-	-	0	0	-	-	0	0	-	-	-	-	-	-	-
Schrader Bluff	-	-	-	-	-	-	52	-	-	-	-	-	-	-	-	-	-
Sag River	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-
Badami	0.34	-	-	-	1	0.36	10	2	0	0	1	1	0	1	1	7	5
Alpine	0.39	-	55	-	0	0	110	4	0	0	1	2	1	1	1	5	0
West of Kuparuk																	
Tarn/ Tabasco	0.29	-	-	-	-	-	51	3	0	0	0	0	0	0	0	16	0
Northstar	0.07	-	-	-	-	-	-	-	0	0	1	1	0	0	0	0	0
Totals	29.08	327	131	278	14	6.43	3409	104	262	3.06	14	11	15	7	5	601	11

Infrastructure

Nearly 40 years of development activities on the North Slope have led to the establishment of a network of supporting infrastructure. One estimate for the North Slope (BLM, 2003) has 3409 wells, 90 drilling pads, 262 reserve pits covering 3 km², 13 production centers, 14 support facilities, 6 docks and causeways, 5 airports or air strips, almost 600 km of roads, and over 700 km of pipelines, covering almost 30 km² of tundra, and 22 stream crossings. An overview of the infrastructure and facilities on the North Slope is summarized in Table 2.13.

The *Prudhoe Bay/Kuparuk* fields are mature production areas that are supported by an extensive network of access roads and crude-oil-gathering lines. This network is constantly expanding as new and satellite crude-oil-production sites are identified and developed. A new production site, the Alpine project, has brought the expanding North Slope infrastructure farther west to the edge of the NPRA. Oil and gas transportation and land routes (Dalton Highway, North Slope oil roads, associated trails, and rights-of-way), airports and airstrips, and cargo-docking facilities are discussed in this section (BLM, 1998).

Transportation

Roads – Dalton Highway. The Dalton Highway (also known as the Haul Road) is a north–south, 668-km, all-weather gravel road that connects Livengood with the Deadhorse airstrip at Prudhoe Bay. Located north of Fairbanks, the community of Livengood is connected to Fairbanks by a 121-km section of the Elliot Highway. The Dalton Highway is the sole overland route connecting Prudhoe Bay to Alaska's other major highway systems. The Dalton Highway is 8.5 m wide with an average of 1 to 2 m of gravel surfacing. Historically, only the section of the highway from Livengood to the Yukon River Bridge, and later Disaster Creek, was open to the public. In 1995, the highway was opened to public access as far as the security gate at Deadhorse. Beyond the security gate, the oil roads are privately owned and maintained.

The majority of the vehicles traveling the Dalton Highway are commercial freight vehicles associated with oil field activities, although privately owned vehicles and commercial tour operators also travel the Dalton Highway. Not unexpectedly, summer (June-August) traffic levels for the Dalton Highway are substantially higher than traffic levels for the rest of the year. During summer 2000, the monthly average daily traffic count at milepost 134 (the Yukon River Bridge) was 450 vehicles; however, the annual average daily traffic (AADT) count at the same checkpoint was 245. Farther north on the Dalton Highway, AADT levels fell somewhat. In 2000, the Atigun River checkpoint AADT value was 230 (DOTPF, 2001). This decline continued and in 2004, the AADT value at milepost 254 Atigun River was 238, in 2005 it was 167, and in 2006 it was 175 (DOTPF, 2007).

Annual Dalton Highway truck traffic (loaded and unloaded combined) in 1996 was 45 236 trucks, with a monthly average of 3770. While numbers of trucks increased substantially between FY 1990 and FY 1996, by FY 2000, monthly truck volume had fallen to around 2500 (DOTPF, 2001).

The main road within the Prudhoe Bay/Kuparuk operations area is called the Spine Road. This road provides access from Deadhorse west to the Kuparuk Base Camp and east to the *Endicott* oil field. *Milne Point*, the *Oliktok* field, and other satellite fields and facilities within the Prudhoe Bay/Kuparuk Operating Area are connected to the Spine Road by gravel road. The recently discovered *Alpine* field in the Colville River Delta is connected to the Spine Road by an ice road in winter rather than a standard gravel road. Exploratory drilling of the Alpine prospect was also assisted by ice-road connections to the Prudhoe/Kuparuk complex, with no gravel roads emplaced. Gravel roads are typically 11 m wide and embanked approximately 1.5 m above the ground.

Each 1.6 km of road occupies about 0.03 km^2 and requires about 30 582 m^3 of gravel (U.S. Department of the Interior, 1987).

Within Prudhoe Bay's Eastern and Western Operating Areas are around 322 km of interconnected gravel roads. There are around 151 km of other interconnected roads within the Kuparuk River unit. There are also 13 km of causeways providing access to facilities and drilling sites, including the 8-km causeway to the satellite production and main production islands at the *Endicott* field. Traffic data are not available on the roads within the Prudhoe Bay/Kuparuk Operating Area.

The Alaska Department of Transportation and Public Facilities has been studying road projects on the North Slope to support oil and gas activities. Resource Transportation Analysis (RTA)-Phase I 2002 (McKinnon, 2005) looked at energy and mineral deposits to see whether State investment in transportation systems could accelerate resource development. It determined that for oil-field development on the North Slope, all-season mainline gravel roads, in lieu of seasonal ice roads, can improve existing operations and encourage new field development.

Roads – Foothills Access Road. This project is the east-to-west section of the long route to the NPRA. It is a 72-km all-season road west off the Dalton Highway to the Kuparuk River area. Its purpose is to access basin and foothills leases. The project scope has been revised to include analysis of a route north of the White Hills into the primarily oil-prone basin area and an analysis of an aviation-based approach to exploration activities for both the oil-prone basin area and the gas-prone foothills area.

Nuiqsut and other North Slope communities have gravel roads accessing the airstrip, housing, and community facilities. During winter, the roads are covered with ice and transportation is by cars, trucks, snow machines, and other all-terrain vehicles. Residents also use snow machines and frequently drive vehicles and snow machines on the frozen tundra and frozen rivers to access areas off the village road system. During summer, cars, trucks, and all-terrain vehicles use the roads. Data are not available for traffic volume on Nuiqsut's road system.

Outside the villages described above, surface transportation routes take the form of ice roads or Rolligon trails. The winter transport routes utilized by oil companies vary, using nearby lakes as water sources for ice-road construction. The BPXA route north to the Trailblazer exploratory well was built largely offshore. The ConocoPhillips ice roads and an ice bridge across the Colville River are constructed each winter to connect the Alpine operations facility with the Spine Road. Additional ice roads may be constructed to support the company's Alpine satellite development or exploration program. These roads are north and west of Nuiqsut and are connected to Nuiqsut by an ice road spur to the community. ConocoPhillips allows residents unrestricted access to its gravel and ice roads as long as safety and environmental requirements are met.

Historically, the Iñupiat navigate from Barrow to the Nuiqsut region along a cluster of coastal and landfast ice routes. Weather and ice conditions often dictate the route used. Along these routes, the Iñupiat travel to Teshekpuk Lake, the Colville River Delta, and Nuiqsut, as well as to many hunting and under-ice fishing areas. Since 1983, ice bridges have been constructed across the Colville River. The first bridge was built to facilitate drilling on a lease held by the ASRC. The second bridge, built by the people of Nuiqsut in 1984, helped the village respond to a fuel crisis (Smith et al., 1985, as cited in Tremont, 1987).

Since the construction of Alpine in late 1999, an ice road from the community to the Alpine winter re-supply ice road has been constructed as part of ConocoPhillips' ice road contract scope. Villagers have annually constructed an ice road from Nuiqsut to Oliktok or the nearest oil-exploration ice road, whichever is closer. The road is created by blading the snow off the river's ice cover, once sufficient thickness has been reached. The road is used for

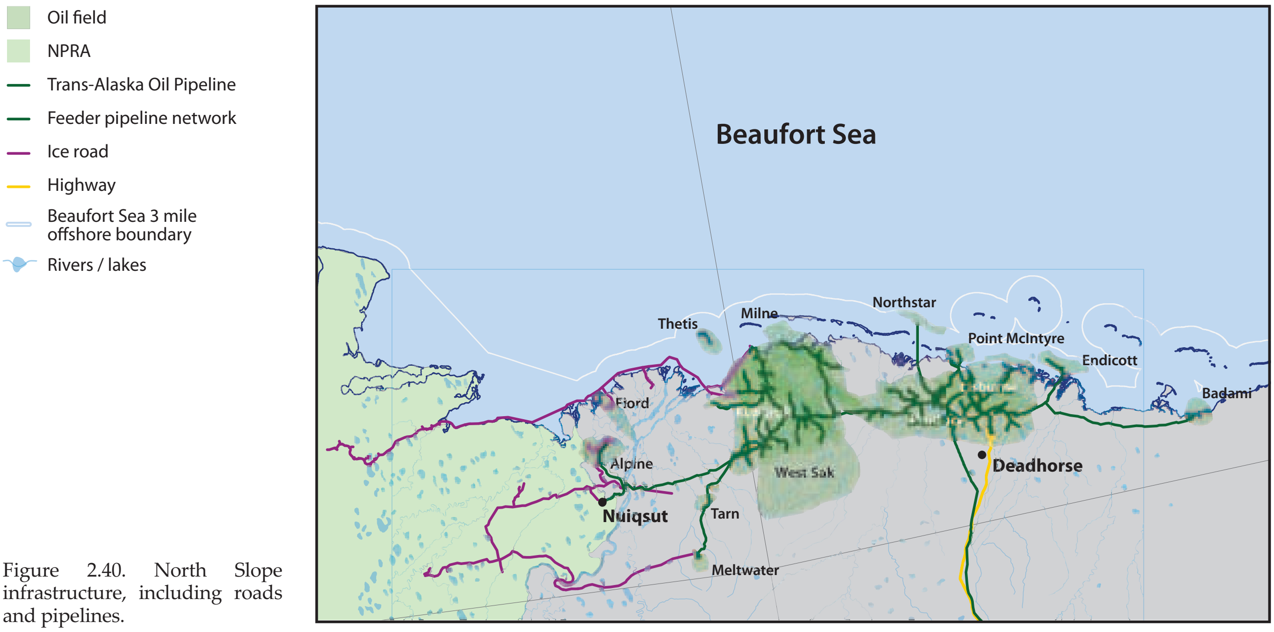


Figure 2.40. North Slope infrastructure, including roads and pipelines.

the overland transport of fuel and other material; it also provides residents with access to the Dalton Highway (Sec. V, North Slope Borough, Comment 1669-028 in BLM, 1998).

Some of the infrastructure on the North Slope, including roads and pipelines, is shown in Figure 2.40.

Aviation systems. There are two major airstrips in the Prudhoe Bay/Kuparuk area: the State-owned and operated Deadhorse airport and the privately owned and operated Kuparuk airstrip (BLM, 1998). Deadhorse airport is served by a variety of aircraft and can accommodate Boeing 737 jet aircraft. The Deadhorse facility has an asphalt airstrip approximately 2000 m long by 50 m wide. The airport has a small passenger terminal and hangars, storage warehouses, and equipment for freight handling. Annual passenger counts for scheduled flights (Alaska Airlines) into Deadhorse are estimated at 140 000 persons. Total annual passenger counts for Aviation Shared Services for both arriving and departing personnel ranged between 205 000 and 220 000 persons during 1992 to 1996 (Ahern, 1997, pers. comm. in BLM, 1998). Aviation Shared Services transports only oil and gas industry employees, contractors, and cargo. Commercial cargo service is also provided into Deadhorse and to satellite oil field strips. Annual freight tonnage shipped by air into the Prudhoe/Kuparuk complex is difficult to estimate. A range of 250 to 500 tons is likely, because most cargo tonnage is carried over the Dalton Highway.

The Kuparuk airstrip is owned and operated by Aviation Shared Services. The airstrip at Kuparuk is approximately 2000 m long and 50 m wide. It is used primarily by Aviation Shared Services for scheduled flights several times a week (Morrison, 1997, pers. comm. in BLM, 1998). Leased commercial aircraft transporting industry personnel (ConocoPhillips and BP Exploration employees and contractors) also use these airstrips.

A former airstrip at Prudhoe Bay is no longer in service. Airstrips also exist at Alpine and Badami, and a helipad at Northstar.

Barrow has a State-owned airport with an asphalt runway approximately 2000 m long and 50 m wide. Barrow is the transportation hub for villages on the North Slope. Alaska Airlines provides regular scheduled jet passenger flights into Barrow from Anchorage and Fairbanks, and other air companies offer shuttle service to various North Slope communities. The Barrow airstrip is accessible year-round with use constraints involving severe weather, an occasionally obstructed runway, and migratory waterfowl that may be present in the area in spring and autumn. Available airport services include minor airframe and power-plant repairs. Airport facilities include two large hangars, storage warehouses, and equipment for freight handling.

Nuiqsut is serviced by a 1371-m long gravel airstrip located adjacent to the village. The runway is unmanned and is not monitored. The community is served by twice-daily flights that bring passengers, cargo, and mail. These commercial flights connect Nuiqsut with Barrow and Deadhorse. Chartered aircraft also use the airport on a regular basis.

Unattended gravel runways serve the communities of Wainwright, Atqasuk, Point Lay, Point Hope, Anaktuvuk Pass, and Kaktovik. The Wainwright and Atqasuk airstrips, which are typical of smaller North Slope villages removed from oil and gas activity, are 1371 m long and 27 m wide and 1332 m long and 34 m wide, respectively. Kaktovik airport will undergo a USD 30 million renovation in the near future.

Within the NPRA there are three airstrips: at Lonely, Umiat, and Inigok. Lonely is the site of a remotely controlled DEW-Line station that also doubled as an oil field support base for Husky Oil during the 1974 to 1982 NPRA exploration period. At that time, the Lonely camp contained a well-maintained gravel runway 1585 m long by 50 m wide, runway lighting, and beacons as well as navigational aids, fuel supplies, and warehousing. At the end of the Husky Oil exploration period, the Husky Oil logistics facility at Lonely was decommissioned, put up for public bid, and purchased by Cook Inlet Regional Corporation. Lonely's airport is functional and Lonely is being used as a staging area for oil industry exploration. The Lonely DEW-Line station has a short pipeline for offshore oil deliveries from tanker barges and a gravel barge-landing site (Meares, 1997, pers. comm. in BLM, 1998).

The Umiat facility is a public airstrip operated by the State of Alaska. During summer months, the airstrip is maintained by Umiat Enterprises, a private contractor; however, there is no winter maintenance. The airstrip is 1646 m long by 23 m wide, has some navigational aids and runway lights, and can accommodate Hercules-class cargo aircraft (Meares, 1997, pers. comm. in BLM, 1998). Privately owned facilities are located next to the airstrip.

Inigok, the third major airstrip, is located at a former Husky Oil drilling site. The airstrip, estimated at 2134 m by 30 m, was constructed in 1977 and experienced its first loaded cargo aircraft (C-130) landing in June 1978. The Inigok facility is an insulated gravel airstrip. Approximately 0.33 m below the gravel surface, the runway is underlain by polystyrene foamboard. Below the foamboard to a depth of 2 m from the runway top is a layer of permanently frozen sand fill (Kachadoorian and Crory, 1988). Due to the nature of its construction, the Inigok strip remains useable some 18 years after its abandonment and is routinely used by the BLM during the summer (Meares, 1997, pers. comm. in BLM, 1998).

Marine transportation systems. Marine transportation on the North Slope is generally freight-orientated with the exception of relatively small, inboard- and outboard-engine watercraft used privately by villagers and less frequently for scientific research and for spill response training and maintenance activities by the oil industry. Marine transportation provides an economical means of transporting heavy machinery and other cargo with a low value-to-weight ratio. Marine shipments to the North Slope are limited to a seasonal window between late July and early September, when the Arctic coast is sea-ice free. Port facilities on the North Slope range from shallow-draft docks with causeway-road connections to facilities located at Prudhoe Bay to beach-landing areas in North Slope communities. Because there is no deep-water port, cargo ships and ocean-going barges are typically offloaded to shallow-draft or medium-draft ships for lightering to shore. Occasionally, smaller craft are also used to transport cargo upriver to areas not located on the coast.

There are three dockheads for unloading barges at Prudhoe Bay: one at East Dock and two at West Dock. A 335-m causeway connects East Dock to a 30-m by 82-m long wharf constructed from grounded barges (U.S. Army Corp of Engineers, 1984). This dock is no longer used. West Dock, a 4000-m long by 12-m wide, solid-fill, gravel causeway, is located along the northwestern shore of Prudhoe Bay east of Point McIntyre. There are two unloading facilities off the gravel causeway at West Dock. One facility is located 1372 m from shore and has a draft of 1.5 to 2 m. The second facility is located about 2438 m from shore and has a draft of 2.5 to 3 m. Water depths around the causeway average 2.5 to 3 m (U.S. Army Corp of Engineers, 1984).

There is another dock at Oliktok Point; extending 229 m from the original shoreline. At the dockface, water depths reach 3 m, while at the bottom of the dock's boat ramp, water depths draw at least 2.7 m. The Oliktok facility also doubles as a seawater-treatment plant (Rookus, 1997, pers. comm. in BLM, 1998).

Marine sealifts bring oil field supplies and equipment to the Prudhoe Bay/Deadhorse area as the expansion or construction of additional facilities are required. Arrival and offloading are affected by the presence of sea ice.

There are no port facilities in Barrow. Supplies and cargo are brought into the area by barges and larger cargo ships and taken to shore by smaller vessels. Supplies are either offloaded directly onto the beach or are lifted off by crane. The primary area used for offloading supplies is located north of the community. Nuiqsut is roughly 29 km upriver from the sea on a channel of the Colville River. Supplies and cargo are brought to the shoreline of the Beaufort Sea by barges and larger cargo ships and then taken upriver by smaller vessels.

Tankers carrying North Slope oil leave the Marine Terminal and Port of Valdez for destinations in the United States including Alaska's Kenai Peninsula.

Pipeline systems. Construction on the Trans-Alaska Pipeline System (TAPS) began in March 1975, and was finished in June 1977. From Pump Station No. 1, the TAPS heads south for more than 1287 km to an oil trans-shipment terminal at Valdez. The oil pipeline has a 1.2 m diameter with a 10-m-wide work pad adjacent to it. Approximately 605 km of the pipeline are buried to a depth of 1 to 4 m; the other 676 km of the pipeline run above ground, mounted on vertical support members.

Crude oil began flowing in the pipeline on 20 June 1977, and the first tanker, filled with North Slope crude oil, left Valdez, the northernmost ice-free port in the United States, on 1 August 1977. At the time, construction of the pipeline was the largest privately financed construction project ever attempted, and cost over USD 8 billion when completed (Alyeska, 2007).

From startup in 1977 until late 2003, a total of 18 000 tankers were loaded (Alyeska, 2007) and by 2006 that number had increased to 19 000 based on an average of 26 loadings per month (Alyeska, 2007). Over 2.4 billion m^3 (15 billion bbl) of oil have been loaded onto tankers at the Valdez Terminal.

The TAPS throughput maximum capacity is approximately 334 000 to 350 000 m^3 (2.1 to 2.2 million bbl) per day. Production peaked at 334 000 m^3/d (2.1 million bbl/d) in 1988 (ADNR, 2004; EIA, 2005b) and declined to current levels of an average 2006 throughput of 121 000 m^3/d (759 081 bbl/d) for a total of 44 million m^3 (277 million bbl) (Alyeska, 2007). Declining throughput has reduced the number of pumping stations from an historic high of 11 to 6.

Figure 2.40 shows the locations of North Slope fields and infrastructure, including the northern part of TAPS and pipelines that feed into it.

Refining

The primary buyers of Alaskan crude oil are located in the State of California. Their combined crude oil distillation capacity totals more than 318 000 m^3 (2 million bbl) per day, with Alaska supplying California with 21.7% of its crude oil demand, 69 160 m^3 (435 000 bbl) (California Energy Commission, 2004). Users in Hawaii are another buyer of Alaskan crude oil. Alaska crude contributes 22% of these crude oil needs.

The North Slope supplies Alaska with 80% of its crude oil demand, with the majority of the oil refined for jet fuel. The remaining 20% comes from Cook Inlet. Alaskan refineries together utilize 47 700 m^3/d (300 000 bbl/d) of North Slope crude for products (EIA, 2005b).

Based on the North Slope crude oil markets, there is adequate demand for expanded North Slope production.

Figure 2.41. Locations of refineries in Alaska (ADNR, 1999).

Alaskan oil accounts for only 22% of both California and Hawaii's oil demand.

Alaska has six operating refineries with an atmospheric crude oil distillation capacity of 59 500 m^3 (373 500 bbl) per calendar day (EIA, 2005b). Only two topping plants are located in Arctic Alaska near the *Kuparuk* and *Prudhoe Bay* Fields. The capacities of the operating refineries are as follows:

- BP Exploration Inc. (Prudhoe Bay at 1990 m^3/d; 12 500 bbl/calendar day)
- Petro Star Inc. (Valdez at 7632 m^3/d; 48 000 bbl/calendar day)
- Petro Star Inc. (North Pole at 2700 m^3/d; 17 000 bbl/calendar day)
- ConocoPhillips Alaska, Inc. (Kuparuk at 2230 m^3/d; 14 000 bbl/calendar day)
- Tesoro Petroleum Corp. (Kenai at 11 465 m^3/d; 72 000 bbl/calendar day)
- Flint Hills Resources Alaska LLC. (North Pole at 33 440 m^3/d; 210 000 bbl/calendar day).

Locations of the refineries in Alaska are shown in Figure 2.41.

2.4.1.3.2. Future

Future activities have been projected in two phases; the near term (2005 to 2015) and long term (2015 to 2050) (Thomas et al., 2007). The near term is likely to be predominantly oil-related with gas development activities becoming the major focus for exploration and development activities in the long term.

The USGS completed a resource assessment of the Central North Slope for State of Alaska lands (Table 2.14) that showed a risked mean resource of almost 4 billion bbl of oil and near 1 trillion m^3 of non-associated gas (Bird et al., 2005).

Near term (up to 2015)

State of Alaska onshore and nearshore lands

The best indicators of possible future activities are probably from the plans declared by the State of Alaska in its Five-Year Oil and Gas Leasing Program. Under this program, a total of 19 lease sales are proposed in the Alaskan Arctic over the five years beginning in 2006: five in each region of northern Alaska and four on the Alaska Peninsula.

Sale areas in 2004 through 2008 held annually:
Onshore:

- North Slope Foothills Area-wide in May
- North Slope Area-wide in October
- Alaska Peninsula in October (beginning in 2005)

Offshore Lease Sales (less than 5 km from shore):

- Beaufort Sea Area-wide State Lease Sale: Scheduled for each October in 2005, 2006, and 2007.

The area for these five proposed sales consists of all unleased State-owned tidal and submerged lands lying between the Canadian border and Point Barrow, and some coastal uplands located along the Beaufort Sea between the Staines and Colville rivers. The gross proposed sale area is in excess of 8094 km^2.

Projects in Arctic Alaska with strong commitments from operators and governments (Myers, 2005) that are likely to occur in the next ten years include:

- by 2016 the North Slope will have a 127 Mm^3/d gas line (built with Federal and State help);
- 32 000 m^3/d (200 000 bbl/d) of new production from the NPRA;
- 32 000 m^3/d (200 000 bbl/d) of new viscous oil production, with the level of total production from Kuparuk and Prudhoe below what it is now, due to field declines;
- the giant gas condensate reservoir Point Thomson will be developed;
- offshore State waters, Alpine to Milne Point development of Kuparuk, Jurassic (Alpine sandstone type), and Sag River reservoirs producing 13 000 m^3/d (80 000 bbl/d);
- Beaufort Sea, Nikaitchuq: In State waters. Will include all of proposed Nikaitchuq and Tuvaaq Units as well as parts of the Kuparuk River Unit. Expected final design capacity of 9500 m^3/d (60 000 bbl/d). Anticipated 2006/07 drilling start date;
- Beaufort Sea, Oooguruk: Harrison Bay in State waters. Estimated peak oil production of 3200 m^3/d (20 000 bbl/d) for a 20 to 30 year production life with a 2007 drilling start date;
- Onshore exploration will be active with a number of large 'independents' drilling wells in the west and south of current developments;
- The producibility of methane hydrates in the Milne Point Unit will be determined.

Federal onshore lands

<u>National Petroleum Reserve-Alaska.</u> The USGS completed a resource assessment of NPRA lands (Table 2.15) that

Table 2.14. Resource estimates for the Central North Slope of Alaska (Bird et al., 2005).

Central North Slope	F_{95} oil, million bbl	Mean oil, million bbl	F_{05} oil, million bbl	F_{95} Non-associated gas, trillion cu. ft	Mean non-associated gas, trillion cu. ft	F_{05} Non-associated gas, trillion cu. ft
Aggregated totals	2565	3984	5854	23 959	33 318	44 873

F_{95}: the resource quantity having a 95% probability of being met or exceeded; Mean: resource quantities at the mean in cumulative probability distributions; F_{05}: the resource quantity having a 5% probability of being met or exceeded.

Table 2.15. Resource estimates for NPRA undiscovered technically recoverable oil and gas (modified from Bird and Houseknecht, 2002).

NPRA	F_{95} oil, billion m^3 (billion bbl)	Mean oil, billion m^3 (billion bbl)	F_{05} oil, billion m^3 (billion bbl)	F_{95} Non-associated gas, trillion m^3 (trillion cu. ft)	Mean non-associated gas, trillion m^3 (trillion cu. ft)	F_{05} non-associated gas, trillion m^3 (trillion cu. ft)
Aggregated totals	1.06 (6.673)	1.68 (10.558)	2.39 (15.007)	1.14 (40.372)	1.74 (61.351)	2.42 (85.317)

F_{95}: the resource quantity having a 95% probability of being met or exceeded; Mean: resource quantities at the mean in cumulative probability distributions; F_{05}: the resource quantity having a 5% probability of being met or exceeded.

Table 2.16. Development time frame for a typical oil field (from BLM, 2005).

Project Phase	Duration of activity, years	Activities
Exploration	1 to 10	• conduct seismic surveys to define prospects • conduct well-site surveys and permitting • drill exploration wells
Discovery	Can occur anytime during or after exploration	• determine producible well • drill delineation well(s) • conduct additional seismic survey (3-D) • appraise and engineer reservoirs • complete project design and environmental studies/factors • apply for permits
Development	Normally takes 3 to 6 years after the initial discovery	• establish construction base camp • set up environmental monitoring programs • install gravel pads for facilities • design and build production modules • begin drilling development wells • install pipelines and pump stations • install production facilities and hookup
Production	10 to 30 years post-development	• continue development-well drilling • ramp-up production (2 to 5 years) • reach peak production plateau (3 to 8 years) • expect production declines • well workovers (every 3 to 5 years) • conduct infill drilling (well spacing reduced) • employ tertiary recovery methods • progressively shut in wells • reach an economic limit
Abandonment	Individual wells can take 2 to 5 years	• plug and abandon wells • remove production equipment • dismantle facilities • decommission pipeline • restore and re-vegetate sites • phase out environmental monitoring

showed a risked mean resource of over 1.5 billion m^3 (10 billion bbl) of oil and over 1.74 trillion m^3 (61 trillion cu. ft) of non-associated gas (Bird and Houseknecht, 2002).

There is no current leasing schedule for the South NPRA. The Colville River Management Plan is scheduled for completion in early 2010. The BLM is preparing a supplemental EIS for the Northeast NPRA with a proposed sale date of June 2008.

Table 2.16 shows the timeline and activities that might be expected in a modern exploration and development program for a new field on the North Slope. Delineation and development activities could take from four to ten years prior to production start-up (BLM, 2005). Production activities would last between ten and fifty years, depending on the size of the field. Abandonment activities, including well sealing and site restoration, could last two to five years after the end of production. This representative time frame suggests that new oil production would not be expected for at least five years following the lease sale, and it is more likely that eight to twelve years would elapse before production would begin from leases sold in the next Planning Area sale. The discovery and development of commercial fields is likely to be staggered over a ten-year period, and petroleum activities could continue for decades after a lease sale.

'Discovery' refers to a pool with unproven resources that has not been developed. Some discoveries require additional drilling to confirm that oil or gas is commercially recoverable. After a field has been discovered and confirmed to be of commercial size by delineation wells and seismic surveys, a number of construction activities are required to establish a permanent production operation. A new field would contain production well pads that could potentially support tens to hundreds of wells, a

Table 2.17. Estimated area of surface disturbance and amount of gravel needed for oil and gas facilities for a field consisting of a Central Production Facility field with five satellite fields (modified from BLM, 2003).

Facility/Disturbance	Number of facilities/km/km^2	Total amount of impact
Development/Operational facilities		
Central production facilities (2 pads, road, airstrip)	1.0	0.4 km^2
Satellite pad (0.04 km^2 each)	5.0	0.2 km^2
Satellite airstrip (396 m × 1524 m; 0.04 km^2 each)	1.0	0.04 km^2
Roads to satellite fields (0.02 km^2 per 1.6 km)[a]	80.47 km	1.00 km^2
Total area – pads, roads, and airstrips		1.64 km^2
Staging areas (0.2 km^2 each)	1.0	0.2 km^2
Ice roads (16 km per satellite pad)[b]	80.47 km	946 353 000 L
Gravel consumption		
Central production facilities (7646 m^3 per 4046 km^2)	0.4 km^2	764 555 m^3
Satellite pad (7646 m^3 per 4046 km^2)	0.2 km^2	382 277 m^3
Satellite airstrip (7646 m^3 per 4046 km^2)	0.04 km^2	84 101 m^3
Staging area (7646 m^3 per 4046 km^2)	0.2 km^2	382 277 m^3
Roads (31 346 m^3 per 1.6 km)	80.47 km	1 605 565 m^3
Total gravel consumption		3 211 130 m^3
Field pipeline rights-of-way		
Vertical support members (VSMs; 96 per 1.6 km)	85.30 km	5 088 VSMs

[a] Assumes that there are 16 km between each satellite pad and 5 km between each Central Production Facility pad; [b] assumes that 16 km of road are constructed for each satellite pad and that roads are constructed annually for five years.

pipeline gathering system to a Central Production Facility, infield roads, a crew support camp, and an airstrip. Table 2.17 shows the estimated area of surface disturbance and amount of gravel needed for oil and gas facilities for a typical field.

Any new North Slope oil production will be transported to Pump Station No.1 of the TAPS for delivery to Valdez Terminal (BLM, 1998). There are several major trunk pipeline systems carrying crude oil to the TAPS: Prudhoe Bay East, Prudhoe Bay West, Milne Point, Endicott, Lisburne, Kuparuk, Badami, Northstar, and Alpine. These systems combined are over 600 km long (BLM, 1998) and of various types of crude-oil carrier. The pipelines are all above ground, elevated on vertical support members. Serving these major TAPS gathering lines are many production-pad feeder lines. Often pipelines are 'bundled' with different crude and non-crude lines occupying the same right-of-way. Access roads run along each of the pipelines (except Badami and Alpine) supporting operations, maintenance, and repair.

Crude oil produced within the NPRA would be transported to Pump Station No. 1 through the 35-km Kuparuk Pipeline.

Arctic National Wildlife Refuge. The USGS completed a resource assessment of Alaska National Wildlife Refuge lands (Tables 2.18 and 2.19) that shows a risked mean in-place resource of around 4.42 billion m^3 (28 billion bbl) of oil and 145 billion m^3 (5.12 trillion cu. ft) of non-associated gas (ANWR Assessment Team, 1999).

The opening of the ANWR coastal plain to any oil and gas activities requires approval by the United States Congress. This or associated legislation will determine the leasing pattern, schedule, tract size, royalty rates, rentals, and the method for leasing. It may be similar to the sealed bids and royalty program used in the NPRA. Or it could resemble the oral bidding system similar to the program used in the lower 48 States, which hold oil and gas leases under the Mineral Leasing Act (1920, as amended). Estimated oil resources for the coastal plain (1002) area rival those of the entire NPRA (Tables 2.15 and 2.18).

Oil and gas activities in the coastal plain would start with mapping efforts including geological field work and sampling and seismic data collection.

Long term (2015-2050)

Currently, there are no transportation systems for getting natural gas from the North Slope to market. In that sense, the gas is 'stranded'. The following concepts are in the forefront for commercializing the stranded gas resources in northern Alaska and the Mackenzie Delta (Sherwood and Craig, 2001).

- A new pipeline connecting to the Canadian gas pipeline network. This would involve the building of a conventional or high-pressure gas pipeline to carry the gas from Prudhoe Bay to northern Alberta or British Columbia, where the new pipeline would join the Canadian pipeline network and supplement ongoing transmission of gas exports to the United States. The pipeline capacity would probably be between 70.8 million m^3/d (25.5 billion m^3/y) [2.5 billion cu. ft/d (0.9 trillion cu. ft/y)] and 113 million m^3/d (41.3 billion m^3/y) [4.0 billion cu. ft/d (1.46 trillion cu. ft/y)].
- Liquefied natural gas (LNG) to the Asian Pacific Rim. This would involve the building of a conventional or high-pressure gas pipeline to carry the gas from Prudhoe Bay-area fields to a port in southern Alaska, where the gas would be chilled to LNG and loaded onto special LNG tankers for transport to the Asian Pacific Rim or perhaps the U.S. West Coast via return pipeline from a hypothetical port in western Mexico. System throughput for current proposals ranges from

Table 2.18. Resource assessment of oil in Alaska National Wildlife Refuge lands (Bird and Houseknecht, 1998).

	95% billion m³ (billion bbl)	Mean billion m³ (billion bbl)	5% billion m³ (billion bbl)
Oil in-place			
Entire area	2.48 (15.6)	4.42 (27.8)	6.73 (42.3)
Fed 1002 lands (coastal plain)	1.84 (11.6)	3.29 (20.7)	4.85 (30.5)
Technically recoverable oil			
Entire area	0.91 (5.72)	1.65 (10.36	2.54 (15.96)
Fed 1002 area (coastal plain)	0.68 (4.25)	1.22 (7.67)	1.89 (11.80)

Table 2.19. Resource assessment of conventional gas/non-associated gas in Alaska National Wildlife Refuge lands (Bird and Houseknecht, 2001).

	95% billion m³ (trillion cu. ft)	Mean billion m³ (trillion cu. ft)	5% billion m³ (trillion cu. ft)
Gas in-place			
Entire area	0	145 (5.12)	411 (14.5)
Fed 1002 area (coastal plain)	0	130 (4.6)	379 (13.4)
Technically recoverable gas			
Entire area	0	109 (3.84)	309 (10.9)
Fed 1002 area (coastal plain)	0	99 (3.48)	282 (10.0)

42.5 million m^3/d (14.1 billion m^3/y) [1.5 billion cu. ft/d (0.5 trillion cu. ft/y)] to 70.8 million m^3/d (25.5 billion m^3/y) [2.5 billion cu. ft/d (0.9 trillion cu. ft/y)].

- Gas to liquids (GTL) and tankers to the U.S. West Coast. This would involve the building of a new facility in the Prudhoe Bay area that would use GTL technology to convert natural gas to middle-distillate (diesel-like) liquids. The GTL product would be pumped in segregated batches through the Trans-Alaska Oil Pipeline and then transported by tanker to the U.S. West Coast. A 50 000 bpd 14.2 million m^3/d (5.7 billion m^3/y) [(0.5 billion cu. ft/d or 0.2 trillion cu. ft/y)] plant has been promoted by one group, but BP-Amoco, a major owner of the gas at Prudhoe Bay, has built a small experimental GTL plant at Nikiski in Cook Inlet, Alaska (operational in 2002).

Of the proposed routes for gas pipelines carrying northern Alaska gas to LNG facilities at Alaskan shipping ports (Figure 2.42), the Yukon-Pacific Corporation ('TAGS') system carrying gas 1300 km from Prudhoe Bay to Valdez forms the traditional route, although a line to export terminals in Cook Inlet is possible. Speculative northwest Alaska pipeline routes carrying gas to Wainwright or Kivalina are also shown. Proposed pipelines for linking to the existing pipeline network in the North American Arctic are shown in Figure 2.43.

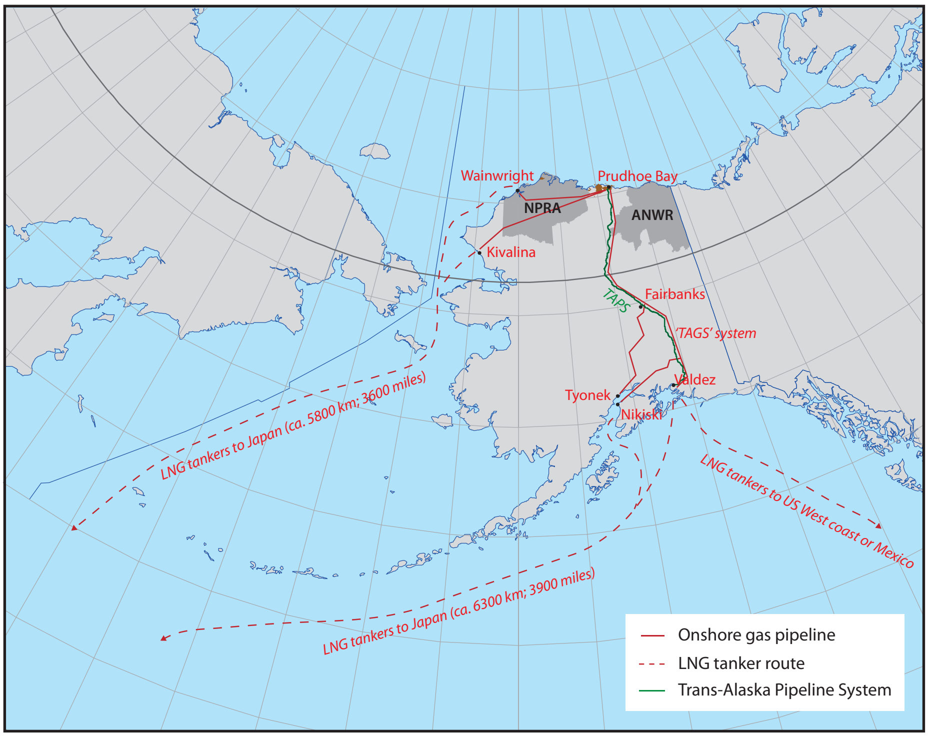


Figure 2.42. Proposed routes for gas pipelines carrying northern Alaska gas to liquefied natural gas (LNG) facilities at Alaskan shipping ports. Craig and Sherwood, 2001.

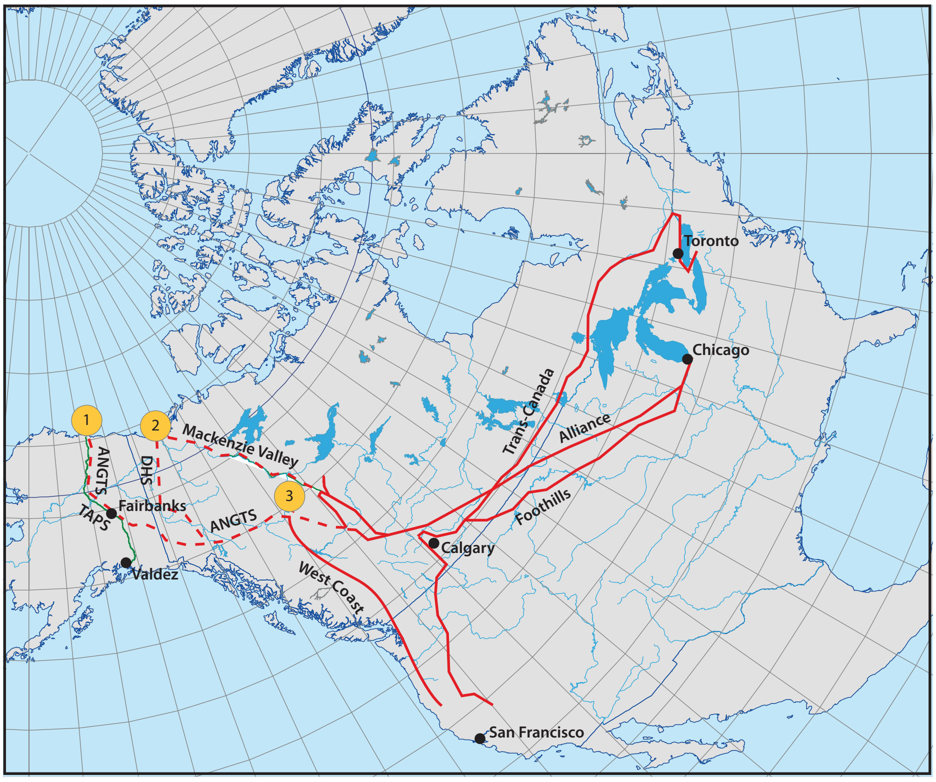


Figure 2.43. Proposed pipelines for linking to the existing gas pipleine network in North America. Craig and Sherwood, 2001.

2.4.1.4. Arctic Alaska OCS (Beaufort and Chukchi Seas)

2.4.1.4.1. Historical to present

Exploration

Arctic Alaska OCS areas can be characterized as belonging either to the Arctic Ocean or to the Bering Sea provinces. The Beaufort and Chukchi seas and Hope Basin are located in the Arctic Ocean OGP and the Norton, Navarin, St. George, and North Aleutian basins are parts of the Bering Sea OGP (see Figures 2.9 and 2.25). These provinces differ greatly in geography, climate, oceanography, geology, and biology, and so in operational techniques needed to investigate them.

Seismic activities. Early exploration in Arctic Alaska offshore basins consisted primarily of marine seismic reflection data. The subsurface well control resulting from onshore drilling activity and secondarily outcrop geology is tied into the seismic grids to extend the existing geological framework into offshore areas. The first seismic program in Federal waters (5 km or more offshore) was in 1964 and was sponsored by British Petroleum. The sound source was dynamite. The use of dynamite in a marine setting continued until 1967 when it was replaced by other sound-generating sources.

Improvements in recording and processing seismic data necessitated more frequent detonations than the use of chemical explosives allowed. A single marine seismic survey might use as much as a million pounds of explosive in one month. This presented logistical problems, unacceptable risks, and undesirable environmental consequences. Offshore, a variety of substitute systems were tried but nearly all were quickly discarded with the exception of the airgun. The airgun is a mechanical device that is charged with compressed air which is released quickly through a valve to create the desired sound. A number of these airguns can be arrayed in a manner to maximize the desired frequencies, dampen undesirable frequencies, and focus the sound. (See section 2.5.2.1 for more detailed information on marine seismic operations and section 2.7.3.2 for sources and levels of sound from offshore oil and gas activities.)

Starting from 1969 there was an increase in marine seismic reflection surveys by the government, primarily by the USGS, by universities (e.g., Texas A&M University, University of Washington, Scripps Institute of Oceanography, and others) and by industry. Government and academic surveys were aimed at a broader understanding of the regional geology, whereas seismic data collected by industry were used to map regional geology and geological structures that may contain oil and gas.

From 1964, when the first seismic permits were issued, until 2002, over 500 000 line-km of 2-D (Figure 2.44) and over 700 km^2 of 3-D seismic data were acquired by the Federal Government from industry seismic surveys (Dellagiarino et al., 2004) out of the more than 700 000 line-km collected by industry in the Arctic.

In 1969, industry was issued 28 geophysical permits and in 1970, 36 permits were issued for geophysical data acquisition. Between 1971 and 1975, the number of permits for geophysical data acquisition rose to 193. In subsequent years, permit applications increased to a maximum in the early 1980s. The corresponding number of line-kilometers of data shot (see Figure 2.44) is a better indicator of activity level and has more bearing on the noise levels released into the marine environment. From 1969 to 2002, 856 permits were issued for geophysical data collection resulting in over 700 000 line-km of geophysical data in offshore basins of Alaska – the vast majority collected in Arctic basins. Over this period, the USGS and academic institutions collected approximately 20 613 line-km of deep seismic reflection data (NOAA, 2005).

Leasing. Since 1979, the Federal Government has held twelve lease sales in Arctic Alaska in the Beaufort and

Chukchi Seas on the Federal OCS (Table 2.20). Over 324 000 km² of the OCS have been offered for lease in the Arctic since 1979, some areas multiple times, and 32 477 km² have been leased, some multiple times (see Table 2.7). Since 1979, industry has paid the Federal Government over USD 5.46 billion in bonus bids just for the right to explore in these offshore basins. Fifty-nine exploration wells and six stratigraphic test wells have been drilled in these basins since 1976.

The first Arctic OCS area to be offered was the Beaufort Sea in the joint State/Federal lease sale of 1979. This and subsequent sales provided access to waters beyond the 5 km limit, extending from Point Barrow in the west to the U.S.–Canadian border in the east. Since 1979, most continental-shelf areas of the High Arctic Alaska offshore were offered in eight additional lease sales in the Beaufort Sea and two lease sales in the Chukchi Sea.

Beaufort Sea: The first lease sale on the Beaufort continental shelf was in 1979. Since then, there have been eight more lease sales bringing in a total of more than USD 3.6 billion for the right to drill on 145 687 km². Initial bidding in the early 1980s was high, but interest dropped dramatically in the late 1980s until recently. The last three lease sales in the Beaufort Sea have shown that interest is growing again. Sales in 2003 by the Federal Government and 2004 by the State each brought around USD 10 million for the right to drill on 736 km² and 912 km², respectively. The Federal sale in 2005 resulted in the receipt of almost USD 47 million for exploration on 2504 km². There have been 31 exploration wells drilled in the Beaufort Sea (5 km or more from shore) since 1980 of which nine are considered discoveries. Only one however, BP's Northstar, is in production.

Chukchi Sea/Hope Basin: The first sale in the Chukchi Sea was in 1988 and resulted in the leasing of 8000 km² for USD 478 032 631. The second sale was in 1991 and received USD 7117 304 for the right to drill on 644 km². Land in Hope Basin has never been leased. The last offering, in 2003, was cancelled due to lack of industry interest. There have been four exploration wells drilled in the Chukchi Sea from 1989 to 1990. All wells were plugged and abandoned.

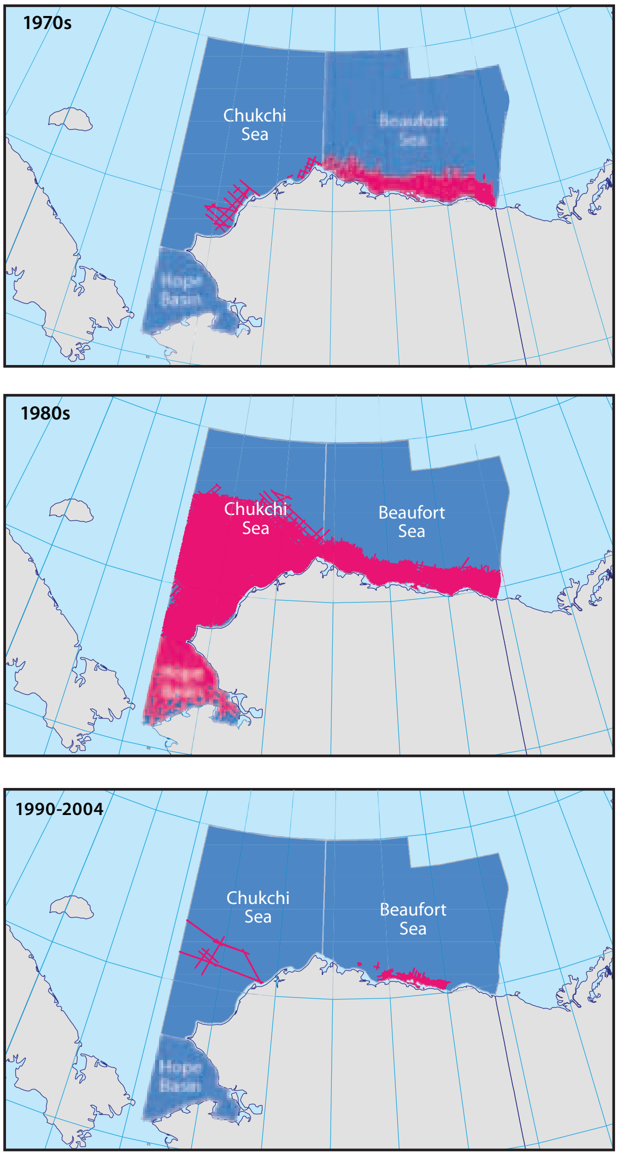


Figure 2.44. 2-D seismic line coverage for the US Beaufort and Chukchi Seas collected from 1969-2004. Source of data: U.S. Bureau of Ocean Energy Management, Regulation and Enforcement.

Table 2.20. Arctic Alaska oil and gas lease sales on the North Slope in the Federal OCS (Beaufort and Chukchi Seas) from 1979-2007.

Competitive sale area	Sale	Date	Planning area, km²	Offered, km²	% planning offered	Leased, km²	% offered leased	Bonus received, USD	Bonus USD/km² leased
Beaufort (OCS) Joint Federal/State Sale	BF	Dec-79	263 269	702	0.3	347.0	49.4	488 691 138	1 408 332
Beaufort (OCS)	71	Oct-82	263 269	7 389	2.8	2682.0	36.3	2 055 632 336	766 455
Beaufort Sea (OCS)	87	Aug-84	263 269	31 458	11.9	4887.0	15.5	866 860 327	177 381
Beaufort Sea (OCS)	97	Mar-88	263 269	73 968	28.1	4495.0	6.1	115 261 636	25 642
Chukchi Sea (OCS)	109	May-88	253 231	103 725	41.0	8000.3	7.7	478 032 631	59 752
Beaufort Sea (OCS)	124	Jun-91	263 269	75 097	28.5	1121.0	1.5	16 807 025	14 993
Chukchi Sea (OCS)	126	Aug-91	253 231	76 842	30.3	644.0	0.8	7 117 304	11 052
Beaufort Sea (OCS)	144	Sep-96	263 269	29 472	11.2	405.0	1.4	14 429 363	35 628
Beaufort Sea (OCS)	170	Aug-98	263 269	3 727	1.4	349.0	9.4	5 327 093	15 264
Beaufort Sea (OCS)	186	Sep-03	263 269	38 282	14.5	736.0	1.9	8 903 538	12 097
Beaufort Sea (OCS)	195	Mar-05	263 269	37 630	14.3	2458.0	6.5	46 735 081	19 013
Beaufort Sea (OCS)	202	Apr-07	263 269	35 197	13.4	2032.0	5.8	42 165 195	20 751

Table 2.21. Estimated resources on the OCS off Arctic Alaska (Sherwood et al., 1998b; Sherwood and Craig, 2000).

	Oil and NGL, billion m³ (billion bbl)			Gas, trillion m³ (trillion cu. ft)			BOE, billion m³ (billion bbl)			MPhc
	F_{95}	Mean	F_{05}	F_{95}	Mean	F_{05}	F_{95}	Mean	F_{05}	
Arctic Ocean Region										
Chukchi Shelf	1.37 (8.60)	2.46 (15.46)	3.99 (25.03)	0.38 (13.56)	1.70 (60.11)	4.37 (154.31)	1.80 (11.32)	4.17 (26.21)	7.90 (49.60)	1.00
Beaufort Shelf	0.57 (3.56)	1.103 (6.94)	1.89 (11.84)	0.36 (12.86)	0.91 (32.07)	1.79 (63.27)	0.99 (6.21)	2.01 (12.64)	3.53 (22.16)	1.00
Hope Basin	0.00	0.01 (0.09)	0.04 (0.28)	0.00	0.10 (3.38)	0.31 (11.06)	0.00	0.11 (0.69)	0.36 (2.25)	0.61
Entire Arctic Province	2.29 (14.36)	3.58 (22.49)	5.26 (33.03)	0.99 (35.00)	2.71 (95.56)	5.6 (197.78)	3.46 (21.76)	6.30 (39.54)	10.26 (64.45)	1.00

BOE, total oil and gas in billions of energy-equivalent barrels (5620 cu.ft of gas = 1 energy-equivalent barrel of oil); MPhc: marginal probability for hydrocarbons for basin, i.e., chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and Mphc. Mean: resource quantities at the mean in cumulative probability distributions; F_{95}: the resource quantity having a 95% probability of being met or exceeded; F_{05}: the resource quantity having a 5% probability of being met or exceeded; Mean values for provinces may not sum to values shown for sub-regions or region because of rounding.

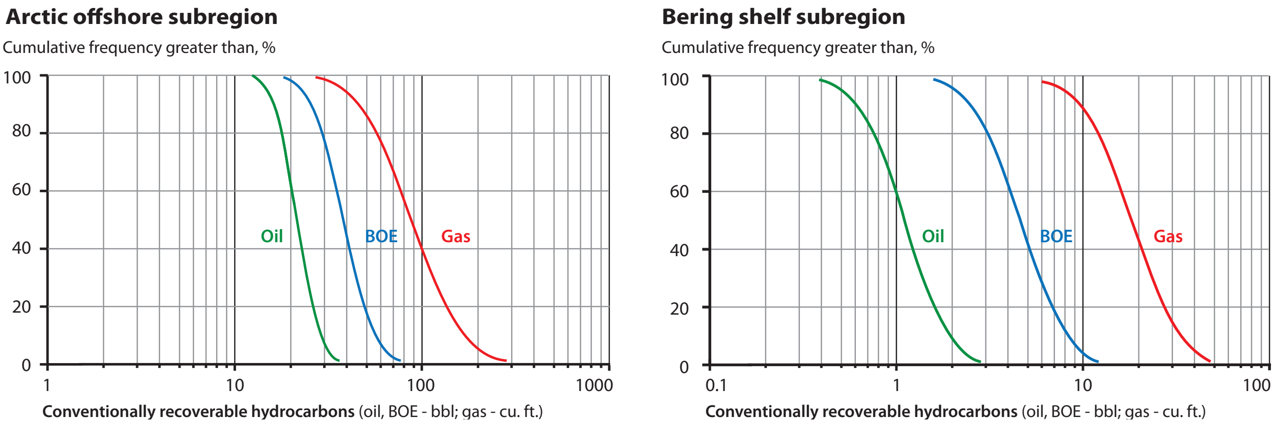


Figure 2.45. Cumulative probability distributions for risked, undiscovered conventionally recoverable oil, gas, and total hydrocarbon energy in BOE for the Arctic offshore sub-region and the Bering shelf sub-region (Sherwood et al., 1998b).

Drilling. A total of 59 exploratory wells were drilled in Arctic Federal waters between 1980 and 2006, resulting in the discovery of several sub-commercial pools of oil. Northstar (Seal Island) field, estimated by BP-Alaska to contain 21 million m³ (130 million bbl) of recoverable oil, straddles State of Alaska and Federal offshore lands about 8 km north of the Prudhoe Bay field.

2.4.1.4.2. Future

Near term (up to about 2015)

Federal offshore

The Alaska Federal offshore region is estimated to contain mean undiscovered, conventionally recoverable resources of 24 billion bbl of oil and 3.6 trillion m³ of gas (Sherwood, et al., 1998b; Sherwood and Craig, 2000). Approximately 90% of these resources occur in areas offshore of Arctic Alaska, specifically the Chukchi shelf and Beaufort shelf (Table 2.21 and Figure 2.45).

Most of the undiscovered oil and gas occurs in pools that are too small to justify economic development. Two Arctic provinces offer significant quantities of undiscovered recoverable oil: the Beaufort shelf and the Chukchi shelf. These provinces might also offer economically recoverable gas under certain future conditions. However, the lack of transportation infrastructures designed for the export of natural gas may deter significant gas production from these areas and from the greater Alaska offshore for many years. Figure 2.28 shows the planning areas for oil and gas leasing in Alaska.

A Federal sale was held in the Beaufort Sea on 18 April 2007 and offered around 38 000 km² for bids that lie 5 to 110 km offshore in 8 to 60 m of water. Estimated conventionally recoverable resources are 572 million to 1.9 billion m³ (3.6 to 12 billion bbl) of oil, with a mean of 1.1 billion m³ (6.9 billion bbl), and 368 to 1783 billion m³, with a mean of 906 billion m³, of gas (the ranges reflect 95% – 5% probabilities). Two more sales are being considered for 2009 and 2011 in the new 5-Year Leasing Plan (MMS, 2007a) for 2007 – 2012 (Table 2.22).

The sale scheduled in the Chukchi Sea for February 2008[3] offered 118 934 m³. Areas for lease are located 16 to 322 km from shore in water depths of 10 to 70 m. Conventionally recoverable resources are estimated at 385 to 4360 billion m³ of gas, with a mean of 1700 billion m³, and 1.4 to 4 billion m³ (8.6 to 25 billion bbl) of oil, with a mean of 2.5 billion m³ (15.5 billion bbl) (ranges reflect 95% – 5% probabilities). Two more sales are being considered for 2010 and 2012 in the Five-Year Leasing Plan for 2007 – 2012[4] (Table 2.22).

[3] The lease sale was completed on 6 February 2008.

[4] The Five-Year Leasing Plan is currently suspended while a review of offshore leasing takes place.

Table 2.22. Federal offshore (5 km offshore) five-year leasing schedule to 2012.

Lease sale area	Sale	Date of sale
Chukchi Sea	193[a]	2008
Beaufort Sea	209	2009
Chukchi Sea	212	2010
Beaufort Sea	217	2011
North Aleutian Basin	214	2011
Chukchi Sea	221	2012

[a] Sale 193 was held in February 2008 with winning bids exceeding USD 2.6 billion.

Table 2.23 shows the projected number of seismic surveys for the U.S. and State Governments for Alaska Arctic marine areas from 2006 to 2010. Other developments that may occur include:

- Beaufort Sea, Liberty Prospect: 19 million m^3 (120 million bbl). Discovered in 1983. May be developed by extended-reach drilling from shore (Nelson, 2005) or by production from an artificial island with a pipeline to shore (MMS, 2002a).
- Beaufort Sea, Sandpiper: 7.1 million m^3 (45 million bbl) of oil. Located west of Northstar.
- Beaufort Sea, Kuvlum: 25.4 to 47.7 million m^3 (160 to 300 million bbl) oil.
- Beaufort Sea, Hammerhead: 15.9 to 31.8 million m^3 (100 to 200 million bbl) of oil.
- Chukchi Sea, Burger: 398 billion m^3 (14.038 trillion cu. ft) and 115 million m^3 (724 MMB) condensate, mean values for most likely case.

The following is a discussion of a typical modern development scenario for the Beaufort Sea (MMS, 2003).

For the size range of remaining fields to be discovered and developed in the Beaufort Sea, it is assumed that they could each be produced by one production platform and located near another producing facility possibly as a satellite field with minimal onsite processing facilities. Each platform would contain one rig for development well drilling and well-workover operations. In water depths of less than 15 m, gravel islands would probably be used for production facilities; in water depths up to around 35 m, bottom-founded platforms would be employed for production facilities. Extended-reach drilling may allow some oil to be produced from deeper water.

The route selection and installation of offshore pipelines would take one to two years, and could occur either in the summer open-water season, during mid- to late winter when landfast ice has stabilized, or both. New onshore pipeline sections would take one year to complete, with construction activities taking place simultaneously with the installation of the offshore pipeline. It is assumed that offshore pipelines would be trenched as a protective measure against damage by ice in all water depths less than 50 m. Onshore pipelines would be elevated 1.5 m above ground level on vertical support members. The onshore pipeline corridor and shore-facility construction would be concurrent with the offshore platforms installation.

Owing to their relatively small size, new offshore projects would use existing infrastructure (processing facilities and pipeline-gathering systems) wherever possible. Produced oil would be gathered by existing pipeline systems within the *Prudhoe Bay*/*Kuparuk* field areas and transported to Pump Station 1 of the TAPS. It is assumed that Oliktok Point (using the *Kuparuk* or *Milne Point* field infrastructure), the Northstar pipeline landfall, West Dock (using the *Prudhoe Bay* field infrastructure), and the *Badami* field would be the primary landfalls.

Production rates would quickly increase to peak production for three years before declining. A typical field cycle from discovery to abandonment lasts 21 years; with around five years from discovery to startup, 15 years of production, and a one-year abandonment phase. Considering the staggered discovery times of the fields, activities could last until 2033 (MMS, 2003).

It should be noted, however, that prospects exist both east and west of the smaller-sized prospects mentioned in this scenario, but these potential fields must be larger to be economic since they are farther from established infrastructure.

2.4.1.5. Bering Sea

2.4.1.5.1. Historical to present

Pre-exploration

The Bering Sea OGP consists primarily of State of Alaska lands and nearshore waters of the Alaska Peninsula and Federal OCS waters of the Bering Sea. The Bering shelf is a broad continental platform underlain by deformed

Table 2.23. Projected number of marine seismic surveys for the U.S. and State Governments for Alaska Arctic marine areas from 2006 to 2010 (MMS, 2006a).

	2-D/3-D seismic surveys		High-resolution site-clearance surveys		State water surveys, 2-D/3-D seismic surveys[a]	
	Beaufort Sea[b]	Chukchi Sea[c]	Beaufort Sea	Chukchi Sea	Beaufort Sea	Chukchi Sea
2006	4	4	3	0	1	0
2007	3	4	2	0	0	0
2008	3	4	2	0	1	0
2009	2	3	2	1	0	0
2010	2	3	2	1	1	0

[a] No high-resolution site-clearance surveys are predicted to occur; [b] survey is likely to be a streamer type, but ocean bottom cable surveys could also occur; [c] owing to deeper water, surveys are more likely to be all streamer type.

Mesozoic and Cenozoic and older rocks and contains several large- to medium-size geologic basins. Roughly from north to south they are Norton, Navarin, St. Matthew-Hall, North Aleutian, St George, Aleutian, and Bowers basins (see FIgure 2.25). Limited exploratory drilling the early 1980s indicated that this province is gas prone.

Exploration

Compared to the level of activity which has occurred in the Arctic Alaska OGP, activity in the Bering Sea OGP has been limited to seismic surveys, stratigraphic well testing, and exploration drilling. There have been no activities since the mid-1980s. To date, no discoveries have been announced.

Leasing

The State of Alaska began leasing on the Alaska Peninsula in 1968, holding three subsequent sales, the most recent in 2007. The Federal Government began leasing in OCS waters in 1983 in Norton Sound, holding subsequent sales in the St. George, Navarin, and North Aleutian Basins.

In recent years, the petroleum industry has expressed limited interest in exploring the State of Alaska's Alaska Peninsula and Federal OCS North Aleutian Basin planning areas. Industry's interest coupled with qualified local support – by no means unanimous – prompted the State and Federal Governments to reconsider leasing in these areas. The State held its first modern sale of the Alaska Peninsula planning area in 2005. The Federal Government is considering its first OCS sale of the North Aleutian Basin since 1988.

State lands. Since 1968, four sales have been held in the Alaska Peninsula planning area (Table 2.24). The State imposed the following two requirements, among others, on lease operators for the two most recent sales: 'Drilling in offshore tracts will only be conducted directionally from onshore locations' and 'Pipelines that must cross marine waters will be constructed beneath the marine waters using directional drilling techniques, unless the Director, in consultation with the Office of Habitat Management and Permitting and the local borough and Coastal Resource Service Areas, approves an alternative method based on technical, environmental, and economic justification' (ADNR, 2005).

Drilling

Federal OCS. The Federal Government has held four OCS Bering Sea lease sales since 1983 (Table 2.25). Estimated resources on the OCS off Arctic Alaska are listed in Table 2.26.

Two stratigraphic test wells were drilled in Norton Basin in 1980 and 1982. A lease sale was held in 1983 and 1359 km^2 were leased for USD 317 873 372. Six exploration wells were drilled from 1984 to 1985. All wells were plugged and abandoned. Two 'calls for interest' were made to determine whether a sale should be held; no response was received and no sales are planned at least through 2012.

One stratigraphic test well was drilled in Navarin Basin in 1983. A lease sale was held in 1984 and 3755 km^2 were leased for USD 516 317 331. Eight exploration wells were drilled in 1985. All wells were plugged and abandoned. No sales have occurred since 1984 and no sales are planned at least through 2012.

Two stratigraphic test wells were spudded in St George Basin in 1976 and 1982. The only lease sale was held in 1983 and 2189 km^2 were leased for USD 426 458 830. Ten exploration wells were drilled in 1984 to 1985. All wells were plugged and abandoned. There are no sales planned at least through 2012.

A stratigraphic test well was drilled in North Aleutin Basin in 1982 to 1983. A single sale was held in 1988 and 493 km^2 were leased for USD 95 439 500. No exploration wells were ever drilled. The leases were eventually bought back by the Federal Government after the State and others objected to the sale. No drilling was accomplished due to a moratorium.

2.4.1.5.2. Future

The State has scheduled annual Alaska Peninsula Area-wide lease sales each February from 2007 through 2011 (ADNR, 2007).

North Aleutian Basin oil and gas leasing moratorium

A Federal moratorium was established by Executive Order for North Aleutian–Bristol Bay (NA/BB) in October 1989. It was extended several times in the 1990s by Federal legislation and on 12 June 1998 the U.S. President extended the moratorium until 30 June 2012.

After the moratorium was put in place, leaseholders brought lawsuits against the government. In 1995, in a settlement with leaseholders, the Federal Government bought back the North Aleutian Basin OCS leases.

The State of Alaska, one of the original proponents of the Federal OCS moratorium, had maintained an ad hoc moratorium in NA/BB State waters from the late 1980s through 2004. In response to the change in local Bristol Bay economic conditions, the State of Alaska has begun an oil and gas leasing program in the NA/BB (see Table 2.7).

The North Aleutian Basin is being considered in the Final Plan for 2007 – 2012 for the possibility of one sale in 2011. On 9 January 2007, the U.S. President lifted the moratorium to allow leasing in the North Aleutian Basin planning area offshore in Alaska in response to requests from officials with the State of Alaska and local governments, and the Department of Interior included one proposed sale in the area for 2011 (Table 2.22). This moratorium, in place since 1998, was due to expire in 2012.

2.4.1.6. Unconventional resources

Alaska's Arctic North Slope holds potentially vast resources of unconventional oil and gas. The USGS has estimated that the U.S. Arctic contains in-place volumes of gas of up to 16.71 trillion m^3 onshore (Collett, 2004) and 3017 trillion m^3 offshore (Collett, 1995; Collett and Kuuskraa, 1998) in methane hydrates (Bird, 1995). The Prudhoe Bay area of the North Slope may contain as much as 5.7 billion m^3 (36 billion bbl) of viscous oil in place (Anna, 2005). With around 40% of the U.S. coal resources located in the NPRA, the USGS has estimated that these resources could contain up to half a billion cubic meters of undiscovered technically recoverable coal-bed methane (Roberts et al., 2006).

For the next ten years, forecasts call for increased funding and research for both gas hydrates and viscous oil. The U.S. Energy Policy Act of 2005 addressed the need for incentives to industry for production of natural gas hydrates. Industry is also stepping up research and development for increased extraction of viscous oils. Many of these unconventional resources are close to existing

Table 2.24. Arctic Alaska oil and gas lease sales in the Bering Sea by the State of Alaska.

Competitive Sale Area	Sale	Date	Planning area, km²	Offered, km²	% planning offered	Leased, km²	% offered leased	Bonus received, USD	Bonus USD/ km² leased
Alaska Peninsula Port Heiden & Port Moller; offshore	21	Mar-68	NA	1403	NA	668	47.6	3 009 224	4 505
Bristol Bay Uplands: Kvichak R. to Port Heiden	41	Sep-84	NA	5817	NA	1128	19.4	843 965	748
Alaska Peninsula Areawide	AP 2005 Areawide	Oct-05	NA	20234	NA	771	3.8	1 149 253	1 491
Alaska Peninsula Areawide	AP 2007 Areawide	Feb-07	NA	20234	NA	23	0.1	38 995	1 695

Table 2.25. Arctic Alaska oil and gas lease sales in the Federal OCS areas of the Bering Sea.

Competitive sale area	Sale	Date	Planning area, km²	Offered, km²	% planning offered	Leased, km²	% offered leased	Bonus received, USD	Bonus USD/ km² leased
Norton Sound Bering Sea (OCS)	57	Mar-83	98 225	9 630	9.8	1359	14.1	317 873 372	233 902
St. George Basin Bering Sea (OCS)	70	Apr-83	284 159	10 881	3.8	2189	20.1	426 458 830	194 819
Navarin Basin Bering Sea (OCS)	83	Apr-84	137 644	113 510	82.5	3755	3.3	516 317 331	137 501
North Aleutian Basin Bering Sea (OCS)	92	Oct-88	131 323	22 677	17.3	493	2.2	9 5439 500	193 589

Table 2.26. Estimated resources on the OCS off Arctic Alaska (after Sherwood et al., 1998b).

Area	Oil and NGL, billion m³ (billion bbl)			Gas, trillion m³ (trillion cu. ft.)			BOE, billion m³ (billion bbl)			MPhc
	F_{95}	Mean	F_{05}	F_{95}	Mean	F_{05}	F_{95}	Mean	F_{05}	
Bering Sea Region										
Navarin Basin	0.00	0.08 (0.50)	0.19 (1.21)	0.00	0.17 (6.15)	0.51 (18.18)	0.00	0.25 (1.59)	0.70 (4.41)	0.88
North Aleutian Basin	0.00	0.04 (0.23)	0.09 (0.57)	0.00	0.20 (6. 97)	0.49 (17.33)	0.00	0.23 (1.44)	0.58 (3.62)	0.72
St. George Basin	0.00	0.02 (0.13)	0.07 (0.41)	0.00	0.08 (3.00)	0.28 (9.72)	0.00	0.11 (0.67)	0.34 (2.14)	0.94
Norton Basin	0.00	0.01 (0.05) (NGL)	0.02 (0.15)	0.00	0.08 (2.71)	0.25 (8.74)	0.00	0.08 (0.53)	0.27 (1.70)	0.72
St. Matthew – Hall Basin	0.00	0.0 (< 0.01) (NGL)	0.0 (<0.01)	0.00	0.0 (0.16)	0.02 (0.69)	0.00	< 0.01 (0.03)	0.02 (0.13)	0.44
Entire Bering Province	**0.06** (0.36)	**0.14** (0.91)	**0.29** (1.81)	**0.20** (6.98)	**0.53** (18.80)	**1.09** (38.64)	**0.27** (1.65)	**0.68** (4.25)	**1.36** (8.57)	1.00

BOE, total oil and gas in billions of energy-equivalent barrels (5620 cubic feet of gas = 1 energy equivalent barrel of oil); F_{95}: the resource quantity having a 95% probability of being met or exceeded; Mean: resource quantities at the mean in cumulative probability distributions; F_{05}: the resource quantity having a 5% probability of being met or exceeded; MPhc: marginal probability for hydrocarbons for basin, i.e., chance for the existence of at least one pool of undiscovered, conventionally recoverable hydrocarbons somewhere in the basin. Resource quantities shown are risked, that is, they are the product of multiplication of conditional resources and Mphc. Mean values for provinces may not sum to values shown for sub-regions or region because of rounding. All liquid resources in Norton basin and St. Matthew-Hall basin are natural gas liquids that would only be recovered by natural gas production.

infrastructure and would cause little if any additional surface disturbance.

2.4.1.6.1. Coal-bed methane

When coal is formed it generates large volumes of methane-rich gas. The gas content generally increases with coal rank, burial depth, and reservoir pressure. Coal-bed gas is mainly composed of methane but may contain small amounts of other hydrocarbons. Coal-bed methane (CBM) is generally produced from shallow (< 1000 m), low-pressure, underground coal formations rather than from deeper formations as is the case for most conventional natural gas. The thermal energy equivalent (~ 1000 Btu per standard cu. ft) for CBM is comparable to conventional natural gas, and in many cases CBM may be transported by existing natural gas pipelines with limited treatment for impurities (Clough, 2001).

Alaska has estimated coal reserves as high as 5.5 trillion short tons (4535 923 700 000 tonnes), which is roughly half the coal resources of the United States (Flores et al., 2004). Coal deposits in northern Alaska have the potential for undiscovered CBM resources of between 0.2 and 1 billion m^3, with an average of 0.51 billion m^3 (Roberts et al., 2006) (Figure 2.46).

2.4.1.6.2. Areas of high CBM potential

In a study by the State of Alaska Division of Geological and Geophysical Surveys and the Texas Bureau of Economic Geology it was estimated that at least 25 rural communities in Alaska have potential for CBM resources (Tyler et al., 2000). The study identified two highly prospective CBM coal basins in Arctic Alaska: the western North Slope Basin near Wainwright and the Yukon Flats Basin at Fort Yukon.

Villages in these areas may have advantageous proximity to thick coal beds that would allow economic use of CBM produced from shallow wells. This reduces the cost of drilling and the cost of transportation infrastructure such as pipelines and roads. In one community of about 600 residents on the Chukchi Sea coast (Wainwright), coal quality and gas studies indicated that subsurface coals have favorable methane gas generation and holding capacity.

In 2001, the State of Alaska Division of Geological and Geophysical Surveys and the Kansas Geological Survey collected approximately 13.7 line-km of high-resolution shallow reflection seismic survey data at Fort Yukon to assess further the extent of the high grade coal and the presence of shallow geological structures that would impede CBM production.

There has been no commercial production of CBM in the U.S. Arctic to date. Furthermore, it is unlikely that Arctic North Slope CBM deposits will see any development in the near future other than for local use.

2.4.1.6.3. Heavy oil

The Ugnu, West Sak, and Schrader Bluff formations overlie the main producing zones at the *Prudhoe* and *Kuparuk* fields and represent a huge potential resource containing as much as 5.7 billion m^3 (36 billion bbl) of original-oil-in-place (Anna, 2005). These deposits represent the largest undeveloped oil accumulations in North America and are in an area with existing transportation and

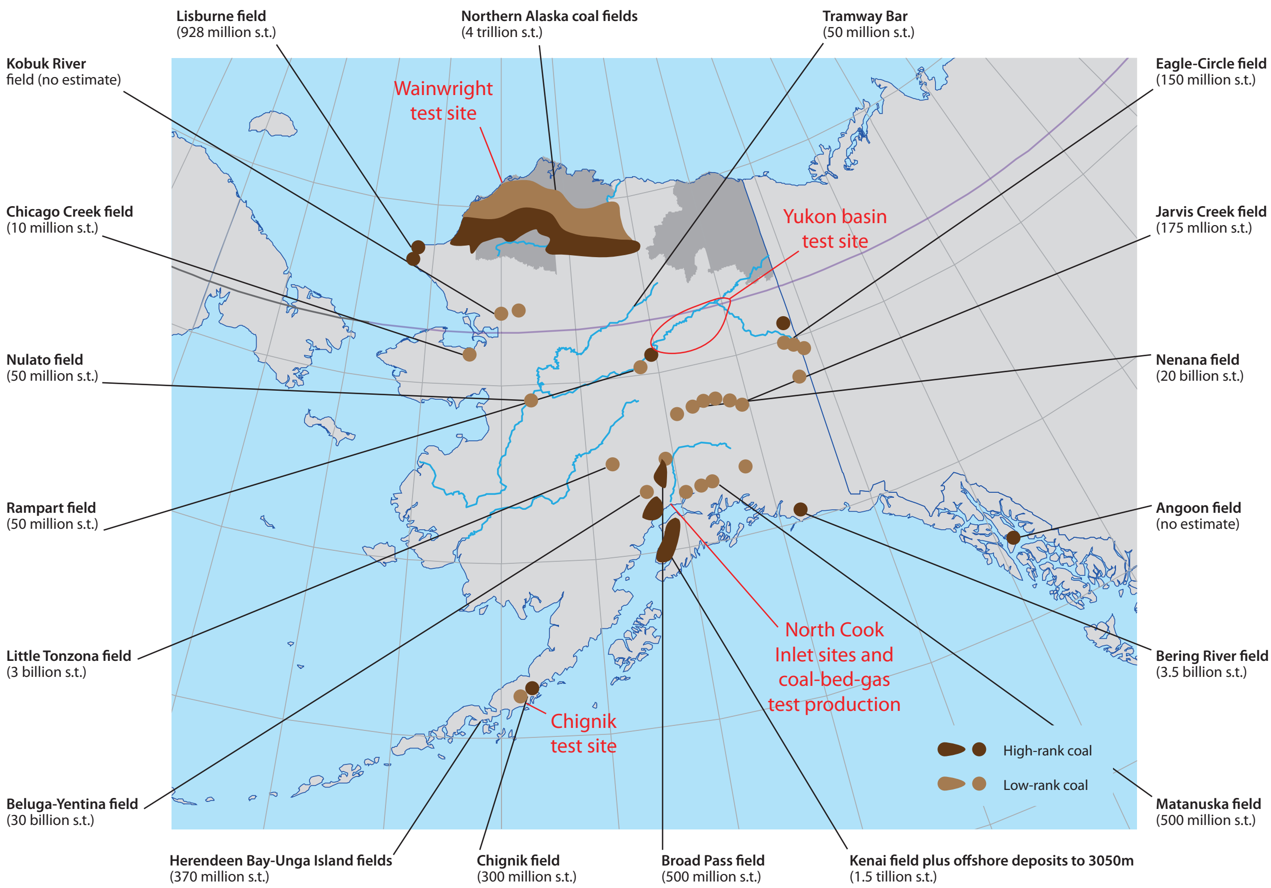


Figure 2.46. Alaska coal and coal-bed methane deposits (data in short tons) (Sherwood and Craig, 2001).

support infrastructure. But their recovery is difficult and challenging. Owing to the shallow depths (1000 to 1200 m) of reservoirs and the presence of subsurface permafrost, the low gravity oil becomes viscous. Furthermore, fluid flow characteristics of these shallow formations are not favorable.

There has been production from less viscous crude oils in the West Sak and Schrader Bluff formations by injecting slugs of water alternating with gas (WAG) into the reservoirs (Anna, 2005). The gas partially dissolves the oil reducing its viscosity, and the flood of water pushes the crude to the wells. Combined original-oil-in-place volumes for these two formations total about 1.6 to 3.2 billion m^3 (10 – 20 billion bbl) (Anna, 2005). In many cases, using WAG in horizontal wells as opposed to vertical wells greatly increased production rates (Mohanty, 2004). The same research showed that well productivity for these viscous oil reservoirs can be doubled by electromagnetic heating.

In future, these heavy oil deposits could provide a source of new oil for the declining production on the North Slope. New research and technology may someday allow commercial production of this massive but problematic resource (Anna, 2005).

2.4.1.6.4. Methane hydrates

Gas hydrate is a crystalline molecular complex, composed of frozen water with interstitial gas, usually methane. Hydrates have been found on all of the world's continental slopes and both onshore and offshore in the Arctic regions. The United States may have estimated in-place methane resources in methane hydrates of about 9056 trillion m^3 (statistical mean estimate; see Figure 2.47) (Collett, 2001). Approximately half of this resource occurs offshore of Alaska, and most of the remainder is beneath the continental margins of the lower 48 States.

Natural gas hydrates were discovered on the North Slope of Alaska in 1972 in a well drilled in the northwestern part of the Prudhoe Bay oil field (Collett, 2002). Studies indentified three gas hydrate-bearing lithologic units in the ARCO/Exxon 2 Northwest Eileen State well (Collett, 1993). Based on correlation to the known gas hydrate occurrences in the ARCO/Exxon 2 Northwest Eileen State well, gas hydrates may also occur in another 50 exploratory and production wells in northern Alaska (Collett, 2002) (Figure 2.48). Wells showed up to six gas hydrate-bearing units

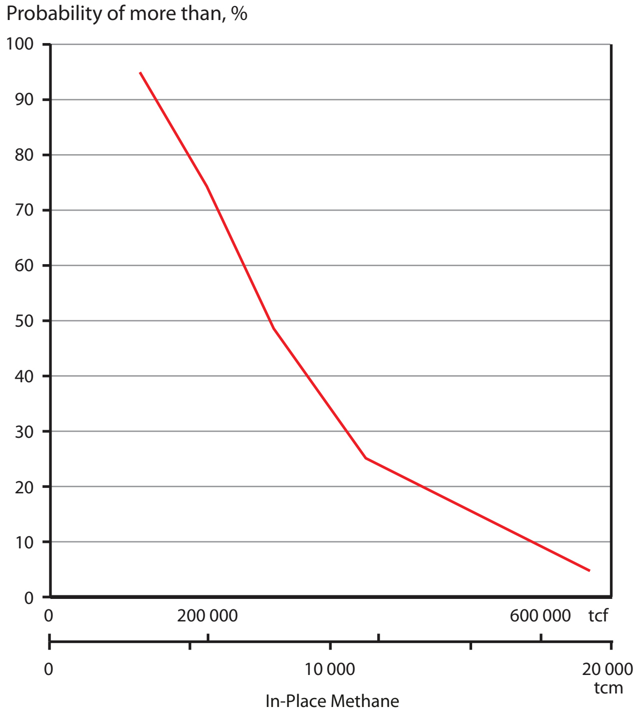


Figure 2.47. Cumulative probability curve showing the estimated in-place methane resources within the methane hydrates of the United States. tcf, trillions of cu.ft; tcm, trillion m^3. There is a 95% chance (F_{95}) that the resource is greater than 112 765 tcf (3193 tcm), and there is a 5% chance (F_5) that the resource is greater than 676 110 tcf (9069 tcm) (Collett, 2001).

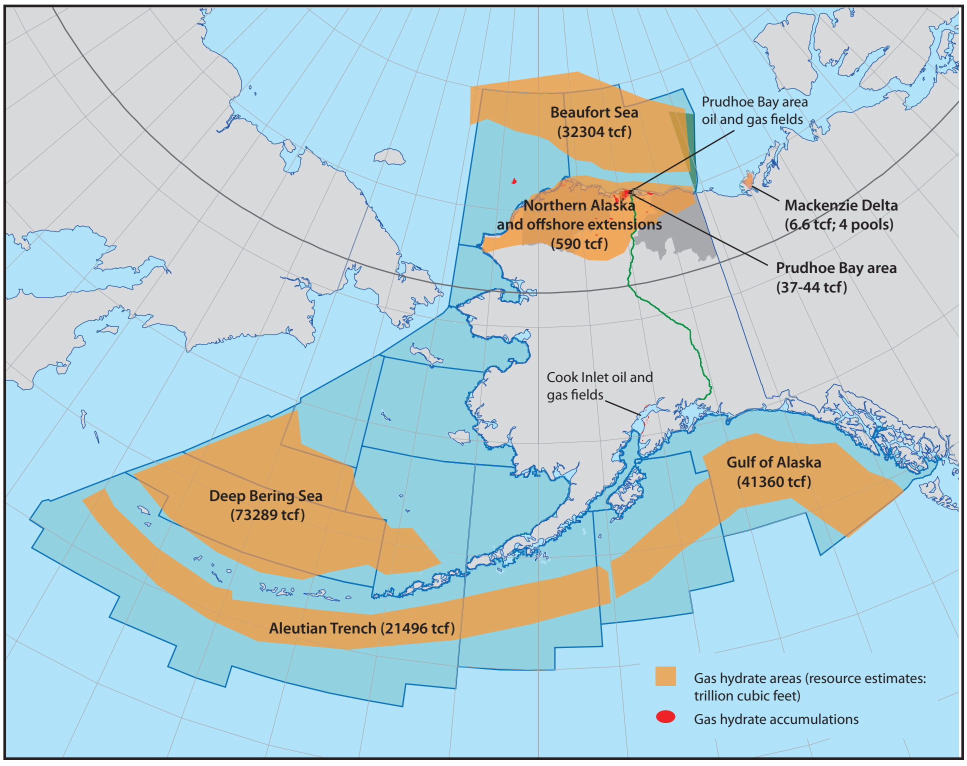


Figure 2.48. Gas hydrate methane resources (in place volumes) for Alaska and Alaska offshore areas. Resource estimates from USGS (1995 Hydrates plate 21), Collett and Kuuskraa (1998, table 1), and Collett (1998). Total for Alaska = 169 039 tcf. Mackenzie Delta gas hydrate resources for four accumulations on Richards Island (Mallik, Ivik, North Ovik, and Taglu), as reported by Collett and others, 1998) (Sherwood and Craig, 2001).

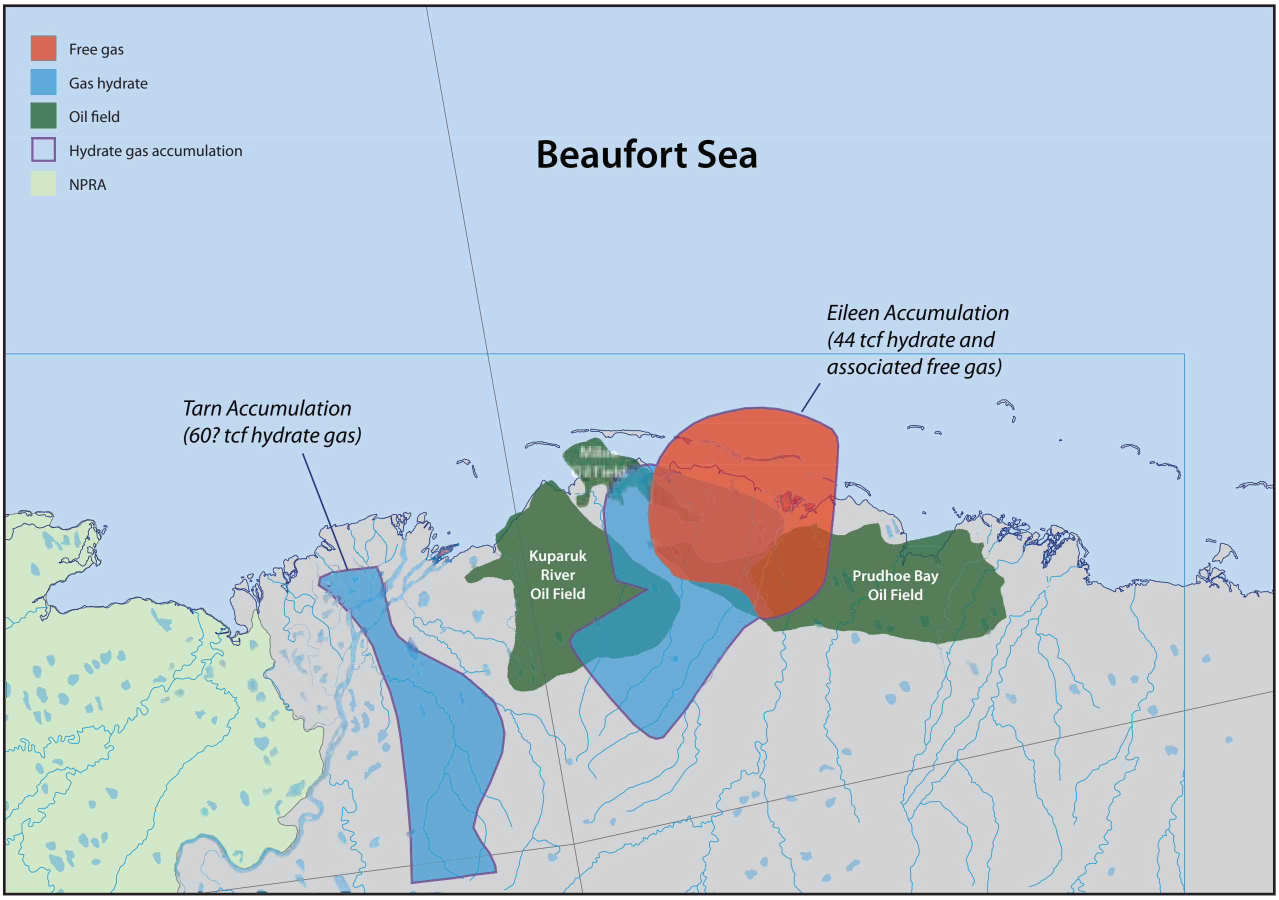


Figure 2.49. Known gas hydrate accumulations and hydrate-associated free gas in the vicinity of the major North Slope oil fields. The USGS estimates up to 100 tcf in-place of hydrates in the Eileen and Tarn trends (modified from Collett, 2004).

ranging from 3 to 30 m thick in the area of about 1643 km^2 (Figure 2.49) overlying the eastern part of the *Kuparuk River* field and the western part of the *Prudhoe Bay* field (Collett, 2002). It is estimated that the in-place volume of gas could be as high as 1 to 1.2 trillion m^3 of methane in the Eileen and Tarn accumulations (Collett, 2002). Joint research involving British Petroleum, the Department of Energy, the USGS and others (Hunter et al., 2007), from the Mount Elbert well in this area indicated that 0 to 0.34 trillion m^3 of gas may be technically recoverable from 0.92 trillion m^3 of gas-in-place beneath the Eileen trend and industry infrastructure within the Milne Point Unit, Prudhoe Bay Unit, and Kuparuk River Unit areas on the North Slope.

In deep-water areas of the western Bering Sea, seismic features suggest the presence of gas hydrates across a vast area (Figure 2.48) of over 400 000 km^2 in water depths of 1000 to 2400 m on the continental slope and between 3700 to 4000 m in the Bering Sea oceanic basin (Collett, 1995). Collett and Kuuskraa (1998) estimated that the Bering Sea gas hydrates may hold 2074 trillion m^3 of gas in-place (Sherwood and Craig, 2001).

In water depths of between 300 and 700 m on the continental slope of the Beaufort Sea an area of 7500 km^2 is underlain by seismic features that suggest the presence of gas hydrate deposits (Kvenvolden and Grantz, 1990). Collett (1995) identified a much larger area for a gas hydrate play in the deep Beaufort Sea km^2. An in-place gas resource of 914 trillion m^3 has been estimated to be trapped within the Beaufort Sea gas hydrates (Collett and Kuuskraa, 1998). An additional 2 trillion m^3 has been estimated for the shelf areas of the Beaufort and Chukchi seas adjoining northern Alaska.

Commercial production of gas from hydrates is not yet possible and until recently little has been known about the availability and production potential of gas hydrates. The most common methods being investigated involve dissociating in-situ gas hydrates by heating and/or depressurizing the reservoir. An economically promising method is considered to be the depressurization scheme (Collett, 2002).

Japan, India, Russia, Canada and the United States, among other countries, are undertaking research to develop technology to access and commercially produce this enormous potential resource. Recent test wells have been drilled in Japan, Canada, and Alaska. In 2002 the Canadian Mallik research well successfully flowed gas from hydrates. In the United States, onshore research is currently being undertaken at the Mount Elbert well (Hunter, 2007). In August 2005, Congress reauthorized the Methane Hydrate Research and Development Act of 2000 for an additional five years.

The construction of natural gas pipelines in both Arctic Alaska and Canada will enhance the possible development of methane hydrates by providing a means of transportation for the gas to markets (Morehouse, 2003).

As a result of higher oil prices, higher demand, and shortage of supply, it is possible that gas hydrates may become an economic source of natural gas within the next ten to 15 years.

2.4.2. Canada[5]

2.4.2.1. Regulatory and legislative systems relevant to Arctic oil and gas activities in Canada

Canada's northern and Arctic lands comprise the territories of Yukon in the far western Arctic, the Northwest Territories (NWT), and in the eastern Arctic Canada's newest territory, Nunavut, created in 1999 – a total land area of 3 823 556 km^2. These territories lie north of the northern border of Canada's provinces at 60° N, and extend to the Arctic Ocean. The northern tip of Canada's most northerly Arctic island lies at 83.3° N.

Canada's territorial seas and exclusive economic zone extend across the continental shelf bordering the Arctic Ocean in the north, and the continental shelf of Baffin Bay, Davies Strait, and the Labrador Sea in the east. Enclosed within Canada's fragmented northern land mass are large inland water bodies such as Hudson Strait, Ungava Bay, Foxe Basin, Hudson Bay, and Lancaster Sound. Canadian jurisdiction abuts that of the United States in the Beaufort Sea (extending oceanward from the international border between the State of Alaska and Yukon). In the eastern Arctic, a line roughly equidistant from their respective coastlines separates Canadian from Greenland jurisdiction in the Lincoln Sea, Nares Strait, Kane Basin, Baffin Bay, and Davis Strait.

Oil and gas resources in the Canadian territories belong to the Federal Crown (whereas the provinces are owners of their own resources). Exceptions are certain lands where subsurface title is held by Aboriginal groups. In the NWT and Nunavut, oil and gas are managed by the Federal Government. In Yukon this responsibility was devolved to the Yukon Territorial Government in 1998. Offshore lands are managed by the Federal Government, except offshore Labrador where there is a joint Federal-Provincial management regime administered by the Canada-Newfoundland and Labrador Offshore Petroleum Board.

Canada has a vast endowment of petroleum resources contained in large sedimentary basins spread throughout the country and contiguous offshore areas. The best known is the Western Canada Sedimentary Basin (WCSB) which lies mostly south of 60° N in the provinces of Manitoba, Saskatchewan, Alberta, and British Columbia. Only its northern fringe extends into the NWT and Yukon. With the exception of this northern extremity, the WCSB has been extensively explored with a long history of production. However, several other petroleum-bearing regions, larger geographically than the WCSB, are situated in northern Canada (Figure 2.50). The resources of these regions have barely been developed.

These northern Canadian 'petroleum provinces' are very immature compared to that of the WCSB, with only 1584 wells having been drilled north of 60° N (including Hudson Bay), compared to over 300 000 conventional wells south of 60° N, in British Columbia, Alberta, Saskatchewan, and Manitoba. Yet of Canada's remaining conventional recoverable resources of natural gas and light crude oil roughly 33% of the gas and 24% of the oil are estimated to occur in Canada's northern petroleum provinces (INAC,

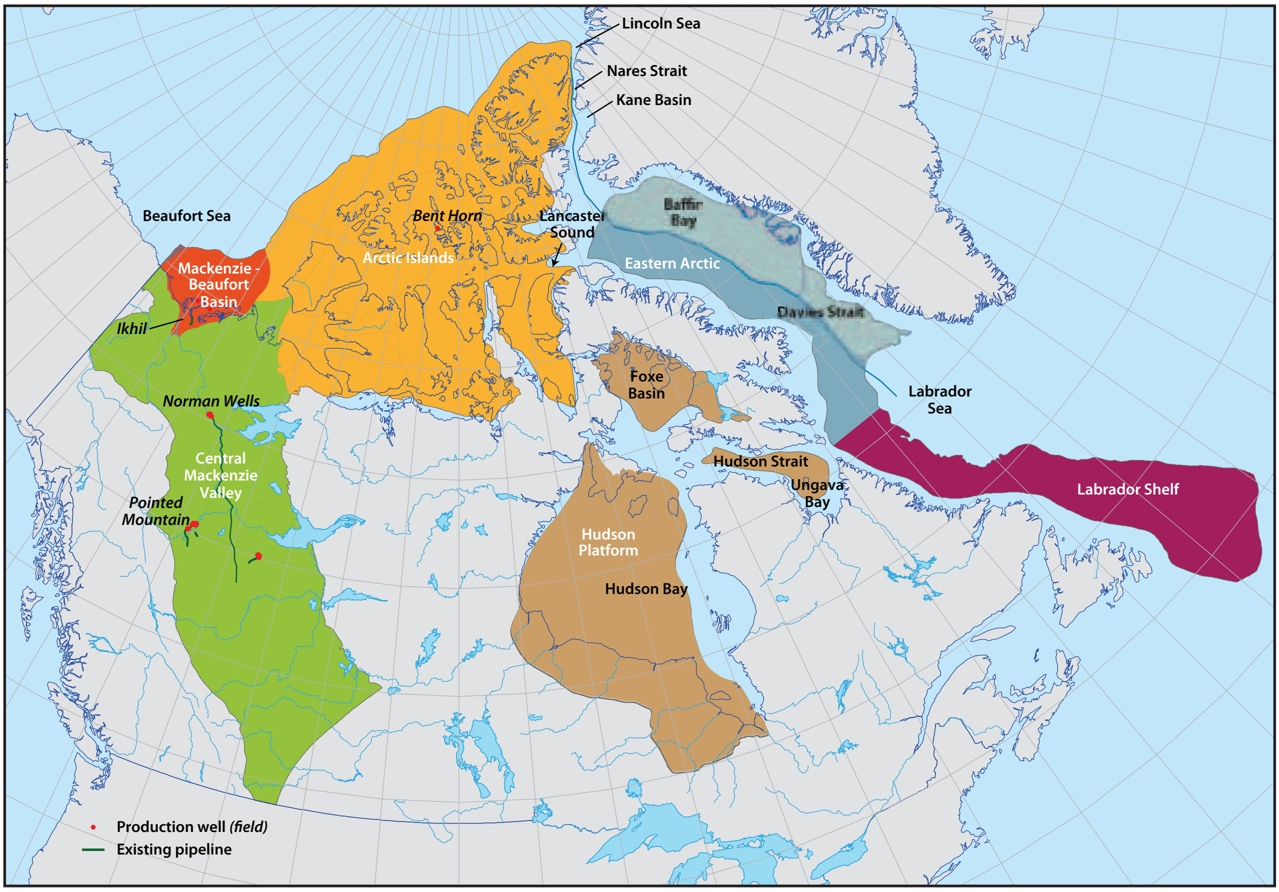


Figure 2.50. Northern Canada showing the six oil and gas provinces.

5 The last year for Canadian data in this report is 2004. Where appropriate more recent developments are mentioned in the text.

2004). If greater discounting of conceptual plays and a more optimistic view of western Canadian potential are applied these percentages are lower. For instance, the National Energy Board (NEB, 2004) indicated 24% of ultimate conventional gas potential in northern Canada.

Over the latter half of the 20th century, Canada became a major producer and the principal exporter of crude oil and natural gas to the lower 48 United States. By the end of 2003, Canada was supplying 7% of oil demand and 16% of natural gas demand in the U.S. energy market (www.eia.doe.gov). The 1990s saw rising oil prices in the global marketplace, followed towards the end of the decade by tightening supplies of natural gas for North American markets. These factors have favored sustained elevated prices into the 21st century for both crude oil and natural gas. Consequently, there has been renewed interest in northern Canada's petroleum resources by national and international concerns. As commodity prices have increased so too has the economic viability of major infrastructure development in northern Canada: the Mackenzie Gas Project, comprising a 1220-km pipeline from the Arctic Ocean to Alberta and gas field development on the Mackenzie Delta is expected to be in-service in the middle of the next decade, contingent on regulatory approvals and a decision to build.

The factor driving northern Canadian oil and gas development in the coming decades will be investor confidence in buoyant commodity prices sustained by demand growth in North America. Reinson and Drummond (2004), using data from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), and the Canadian National Energy Board (NEB), demonstrated that of the remaining ultimate (i.e., discovered plus undiscovered) gas resource (2.97 x 10^{13} m^3 – 1050 trillion cu. ft) for Canada and the United States (Lower 48), 70% is yet to be discovered and booked as reserves. At the rate of demand of 7.9 – 9.9 x 10^{11} m^3 (28 – 35 trillion cu. ft) per year, growth in continental gas supply is not sustainable beyond 2010 unless the potential of non-conventional and frontier resources are unlocked. Canada's Arctic basins potentially form an important part of the answer to this challenge.

2.4.2.1.1. Policy and petroleum exploration cycles

Exploration for petroleum north of 60° N has a long history dating back to the early 1900s and the cyclical nature of this activity has mostly been policy driven. These political drivers (see NOGD, 1995; Grey and Krowchuk, 1997; Gray, 2000; Bott, 2004) are summarized here.

Oil was officially discovered in 1920 at Norman Wells in the NWT. However, surface hydrocarbon deposits, in the form of seeps and tar pits, had long been known to occur and had been used by indigenous peoples for many years. Alexander Mackenzie recorded these occurrences and activities during his exploration of the river that was to later to take his name – the Mackenzie River – in 1789. The Norman Wells seepages first attracted commercial interest in 1891 from the Northern Trading Company, but it was not until the Imperial Oil Company acquired the prospect in 1919, that the first well was drilled. Led by Ted Link, legendary Imperial Oil geologist, a crew of six drillers embarked on a six-week 1900-km journey northward by rail, riverboat and on foot, finally arriving in late autumn at a site now known as Norman Wells on the banks of the Mackenzie River close to the Arctic Circle. Drilling began in late 1919, was suspended for the winter, and resumed in the spring, continuing until 23 August 1920, when the initial commercial discovery was made (Petroleum History Society, 2005).

Norman Wells, in 1920, became the northernmost producing field in North America. Production was then local and minimal, increasing in 1939 when an 840 bbl/d straight-run refinery was installed 52 miles downstream from the old trading post at Fort Norman (Tulita). At the time, three wells were sufficient to supply annual production needs (3029 m^3 – 24 000 bbl) for the area (Miller, 1996). The refinery operated in summer months only and additional wells were capped because of distance to southern markets, and the prohibitive logistics in trying to access such markets.

A large increase in production occurred at *Norman Wells* following the Japanese bombing of Pearl Harbor, the invasion of the Aleutian Islands, and the expansion of the Second World War into the Pacific theatre (Miller, 1996). The U.S. Military believed that Japan soon planned to invade Alaska. Consequently, the United States and Canada agreed in 1942 to build the Alaska Canadian Highway (ALCAN) as a means of transporting supplies and equipment to Alaska in the event of an invasion attempt. Because defense of the northwestern coasts of the continent would require secure petroleum supplies the Canadian Oil (CANOL) Project was born. Miller (1996) described the project in detail. Briefly, the U.S. Military (Northwest Service Command) was charged with overseeing the following: drilling of additional wells to increase *Norman Wells* oil production to 476 m^3/d (3000 bbl/d); building a refinery at Whitehorse in Yukon; building a crude oil pipeline from Norman Wells to Whitehorse; and building a pipeline which would carry the refined product north and south along the ALCAN Highway to Fairbanks, Alaska and Watson Lake, Yukon, respectively.

The project was completed in 1944 and crude oil flowed from Norman Wells to Whitehorse in April of that year. The CANOL Project took only twenty months to complete, but by then the perceived need for it had ceased to exist, and the project was shut down in 1945. Imperial Oil bought the Whitehorse refinery, dismantled it, and then reconstructed it near Edmonton, Alberta, following the discovery of the giant *Leduc* oil field in February, 1947.

The Leduc discovery assured Canada's place as a major petroleum producer and exporter of crude oil. Subsequently, industry refocused exploration efforts in western Canada and particularly in Alberta. The extensive exploration of the WCSB that occurred in the 1950s temporarily diverted attention from northern Canada. By the early 1960s, however, exploration had extended north of 60° N into the NWT and Yukon. An early result was the discovery of the large natural gas field at Pointed Mountain in the southern NWT in 1966, but the search for further oil riches north of 60° N was initially disappointing.

Issues with respect to Canadian sovereignty over the Arctic and the contiguous offshore region rose to the forefront in the 1960s. The first offshore gas discovery in the North Sea in 1965 showed countries with extensive bordering continental shelves, that these could potentially contain enormous undiscovered resources. Parallel work by the Geological Survey of Canada (i.e., Operation Franklin, Operation Norman, Operation Porcupine) in mapping the geology and documenting resources in the Arctic Islands and Mainland NWT and Yukon increased interest in the petroleum potential in the High Arctic and

Mackenzie Delta/Beaufort Sea. At this time, J.C. Sproule was the principal advocate for Arctic exploration (Grey and Krowchuk, 1997) and lobbied the Federal Government to grant exploration permits in the far north.

In 1961, Canada passed the Land Order No 1 regulation which opened the way for extensive permitting for oil and gas exploration across northern Canada and offshore. These factors, plus the giant Alaskan Prudhoe Bay oil discovery in 1968, combined to generate a surge in exploration activity through the 1970s which resulted in many discoveries in the Mackenzie/Beaufort and Arctic Islands regions. The discoveries included several major gas fields and one major oil field among some 41 discoveries deemed 'significant' under Canadian legislation, in that they demonstrated sustained flows of hydrocarbons on testing.

During the early 1970s, the discoveries at Prudhoe Bay and in the Beaufort Sea/Mackenzie Delta region prompted competing proposals for the transport of oil and gas to southern markets. A Mackenzie Valley oil pipeline was considered as an option for linking the *Prudhoe Bay* field to the southern United States (the 'lower 48'). This was rejected, however, in favor of the Trans-Alaska Oil Pipeline Project – an all-U.S. pipeline from Prudhoe Bay to Valdez, Alaska – which was constructed in the mid-1970s.

In the same era, the Arctic Gas Pipeline proposal called for the construction of a gas pipeline from Prudhoe Bay, across northern Yukon, and up the Mackenzie Valley while Foothills Pipelines proposed a gas pipeline from the Delta up the Mackenzie Valley (the 'Maple Leaf' project). Both pipelines were to have been linked to existing pipeline systems in northern Alberta and British Columbia. The Mackenzie Valley Pipeline Inquiry (the 'Berger Inquiry') was established in 1974 to review the impact of the Arctic Gas Pipeline proposal on the indigenous culture and the environment. Its mandate was later expanded to include the Maple Leaf Project.

The Berger Inquiry held formal hearings across the western NWT and Yukon from March 1975 to November 1976. In April 1977, the Inquiry submitted Volume I of its findings to the Minister of Indian Affairs and Northern Development. It recommended that the route across northern Yukon should not be allowed and that construction of a Mackenzie Valley pipeline should be delayed for ten years to allow time to settle Aboriginal land claims. Volume II, issued in November 1977, outlined socio-economic and environmental terms and conditions to guide future pipeline construction.

The recommendations of the Berger Inquiry came at a time when low prices for natural gas prevailed, due to increasing appreciation of the continent-wide 'gas bubble' in conventional producing areas which would not diminish until demand for natural gas increased in the 1990s. As a result, all major natural gas transportation projects from the Canadian Arctic during this period were shelved.

Two international crises, the Arab Oil Embargo of 1973 and the Iranian Revolution in 1978, caused concern about security of supply. New concepts were launched proposing the development of Canada's Arctic gas. These included the Polar Gas Project in 1977 – a 3763-km pipeline from Melville Island to Longlac Quebec, and the Arctic Pilot Project in 1981 – a proposal for liquefied natural gas shipment from newly discovered gas on Melville Island in the High Arctic to the Gulf of St. Lawrence. Both fell foul of persistent low commodity prices and huge capital investment costs.

In response to the national concerns about energy supply and cost, the Canadian Government intervened in industry exploration and production activity through institution of the National Energy Program (NEP) in 1980. The NEP decreed a made-in-Canada oil price policy and provided cash incentives to those companies (based on the level of Canadian ownership) who continued to explore north of 60° N and in the High Arctic, where undiscovered potential was believed by some (Grey and Krowchuk, 1997) to rival that of the Middle East. Drilling activity was intense until the mid-1980s when high interest rates and severe recession rendered many companies insolvent because of high debt loads tied to massive borrowing in order to take advantage of the NEP incentive program.

The deregulation of the Canadian petroleum industry in 1984 and the implementation of the North American Free Trade Agreement marked a major shift for the Canadian petroleum industry. The dismantling of the National Energy Program and the move to a market-based approach, and the enunciation of a new 'Frontier Energy Policy' created a new framework for offshore and northern exploration and development. Petroleum companies could now obtain market prices for their products, yet lost major subsidies for northern and frontier exploration. Furthermore, relatively low commodity prices, the persistence of the 'gas bubble', and high interest rates through the mid-1980s rendered northern exploration almost non-existent.

In 1985, the commissioning of an oil pipeline from Norman Wells to connect to the northern Alberta main trunk pipeline allowed exports of oil from the Canadian Arctic to southern markets. Production from the *Norman Wells* field increased five-fold over the previous year and continued to build over the next seven years as around 300 infill wells were drilled and facilities expanded.

Beginning in the mid-1980s, the settlement of aboriginal land claims in the Canadian Arctic, starting in the Mackenzie Delta/Beaufort Sea region (Inuvialuit) in 1984, in northern Yukon (Vuntut Gwich'in in 1993), in the Mackenzie Valley corridor (Sahtu in 1993, Gwich'in in 1995) and in the eastern Arctic (Nunavut in 1993), opened the way for renewed issuance of exploration rights. Land claim settlements were complemented by the transfer of responsibility for oil and gas management to Yukon in 1998, and the creation of the territory of Nunavut in 1999.

The settlement of aboriginal land claims has also created extensive private oil and gas lands held by northern indigenous groups. Since 2000, Inuvialuit and Sahtu private lands in the NWT have seen active exploration under private concession agreements between indigenous groups and companies.

Uptake of new exploration lands by companies in the southern NWT and central Mackenzie Valley in 1994, followed in 1999 by a strong return to the Mackenzie Delta, signaled industry's recognition of new opportunity in northern Canada.

Rising commodity prices and impending North American supply/demand problems are driving renewed investment in exploring and developing Canada's northern petroleum resources. However, the high cost of operating in northern Canada combined with environmental, regulatory, and socio-economic issues are important constraints on the expansion of petroleum activities not least because these directly affect the lands of indigenous people and their way of life, in regions where Canada's northern peoples have increasing political authority.

2.4.2.1.2. History of permitting and leasing

The drive from the 1950s onwards to develop the resources of northern Canada, and to establish Canadian sovereignty and economic rights on Canada's continental shelves and in the High Arctic, led to extensive acquisition of oil and gas exploration permits first under the Territorial Oil and Gas Regulations and then under the Canada Oil and Gas Lands Regulations (1961). Permits were acquired by filing an application with the Federal Government and retained by work credits. Permits enabled companies to hold exploration lands for periods (including the original terms plus renewals) of between nine and fourteen years, with the longer permits issued for progressively more remote regions of the Canadian Arctic. The more remote the region, the more generous were the royalty rates. Permits were a half grid in size with expenditures on the lands offsetting required annual deposits. (The Canada Oil and Gas Lands Regulations define the grid system used for oil and gas lands management in northern Canada. Grids are defined by lines of latitude and longitude and vary in area from approximately 23 000 ha at 60° N to 15 500 ha at 82° N.)

Fifty percent of the area of the original permits could be selected by the holder and converted to leases for production of oil and gas. Rentals that applied to leases could be offset by work credits. Leases were for a renewable term of 21 years, renewable if production was occurring.

From the mid-1950s to 1961, limited permitting occurred in the Mainland NWT and Yukon, through lands sales exclusively on a cash bonus basis. In 1961, the issuance of permits on the basis of proposed work expenditures (work bonus) was introduced, and after 1969 became the sole basis for the competitive issuance of rights in the north (INAC, 1984).

From the early 1960s until the watershed discovery at Prudhoe Bay in Alaska, the level of exploration permitting in the north remained relatively stable at about 100 million acres (40 million ha), although from 1964 onwards, an increasing number of permits were converted to leases. Permitted Lands started to increase markedly from 1968 and by 1971, there were 9100 permits and 673 leases held in the North for an extraordinary total of 186 435 004 ha in permits and 1 957 359 ha in leases (a total of 188 million ha of exploration lands) (INAC, 1984). Companies were able to hold permits covering extensive areas and to seek up to six years of permit extensions for minimal expenditure on exploration. Drilling on permits was not required and the breadth of land holdings (Figure 2.51) meant that many permits were not explored and eventually reverted to the Crown.

Following the oil crisis of the early 1970s, there was a new urgency to determine the scale of Canada's northern resources. In 1972, over CAD 94 million were spent on northern exploration, representing over 30% of the total expenditure in Canada as a whole (INAC, 1984). In 1976, the Canadian Government issued a policy designed to accelerate domestic oil and gas activity. This change allowed issuance of exploration lands under exploration agreements (over much larger areas than permits) with drilling requirements and provisions for relinquishment, and for existing permits to be renewed as 'special renewal permits' subject to a 25% transfer of interest to the then newly created state oil company Petro-Canada.

Subsequently, the Canada Oil and Gas Act came into force in 1981, and in 1982 Canada established the Canada Oil and Gas Lands Administration, a single body governing all aspects of oil and gas regulation for all offshore and northern lands. As an example of the effect of this change in land administration policy, in 1977 there were over 1000 exploratory rights in the NWT (at that time including those lands now known as Nunavut), but by 1981 this had reduced to 110 due to consolidation into more extensive exploration agreements.

Exploration agreements contained work program commitments and relinquishment provisions which saw lands return to the Crown during the term of the agreement. These terms, together with large subsidies for exploration under the Petroleum Incentives Program, saw a major upsurge in northern and offshore activity: at its peak in 1984, over CAD 1169.3 million was spent on northern exploration.

Following the termination of the National Energy Program and its associated exploration incentives in 1984, the Canadian Government passed the Canada Petroleum Resources Act and Canada Oil and Gas Operations Act. These laws, deriving from the Frontier Energy Policy of 1984, define the regime which now applies on Crown lands in northern Canada except for Yukon. (Responsibility for oil and gas management was transferred to the Yukon Government in 1998 but the territorial legislation remains consistent with the Federal regime and shares many comparable features.)

The current Federal regime grants exploration licenses (which include exclusive drilling rights) to companies for fixed terms not exceeding nine years. In many respects the exploration license maintains several of the characteristics of the early exploration agreements and permits from which it has evolved. The exploration license is issued as a result of a competitive call for bids. Typically the bid is the amount the company proposes to expend during a fixed first period of the license ('work expenditure bid'). A well is a requirement during the first period of the license to avoid surrender and allow the company to enjoy its exclusive rights to full term. Should a discovery be made the holder of an exploration license may apply for a successor right – the significant discovery license – which allows the company to hold the rights to the area of the discovered pool until the discovery becomes commercial, at which time the company may apply for a production license which confers the rights to produced oil and gas.

Under the Yukon Oil and Gas Act, exploration rights are conferred as Yukon *permits* for terms and conditions

Figure 2.51. Distribution of exploration permits as of 1970. (Department of Indian affairs and Northern Development, 1970.)

comparable to the Federal *exploration license*. The Yukon Government also issues production leases, similar to Federal production licenses.

For those areas where land claims have been settled with aboriginal groups some 3.7 million ha of lands including subsurface rights to petroleum are held privately by these aboriginal groups. For these areas oil and gas leasing is managed by the appropriate aboriginal authority. In the Mackenzie Delta and in the central Mackenzie Valley, companies have entered into concession agreements to explore some of these lands.

In 2004, in northern Canada, around 1.6 million ha were held under exploration licenses, 720 000 ha under 133 significant discovery licenses, and 55 000 ha under 29 production licenses (numbers including Yukon equivalent permits and leases, but excluding concession agreements).

Statistical information on oil and gas lands may be found in the various reports and publications of Indian and Northern Affairs, Canada (Oil and Gas Statistical Reports 1920 to 1981); the Resource Management Branch of Energy, Mines and Resources Canada (up to 1991); the Canada Oil and Gas Lands Administration (Annual Reports 1982 to 1990); the Northern Oil and Gas Directorate of Indian and Northern Affairs Canada (Annual Reports 1991 to 2004); statistical and annual reports of the Canada-Newfoundland Offshore Petroleum Board, and publications of the Oil and Gas Management Branch of the Yukon Government.

2.4.2.1.3. Regulation of petroleum operations in northern Canada

Authorization of operations

In the NWT, Nunavut and northern Canada's offshore region, petroleum industry operations are authorized under Federal legislation, the Canada Oil and Gas Operations Act and Regulations (COGOA) (see Appendix 2.1 section A4.2 for further details of relevant Canadian laws and regulations). The Yukon Oil and Gas Act applies in Yukon, and for offshore in Labrador, the pertinent legislation is the Canada-Newfoundland Offshore Accord Act. Both these pieces of legislation have evolved from the Federal model.

Operations under the COGOA are authorized by Canada's National Energy Board (NEB), based in Calgary, Alberta. NEB authority in operational matters extends to both Crown and private lands. The NEB provides the Yukon Government with technical advice on oil and gas activities in the Yukon Territory in accordance with a services agreement. The comparable function offshore in Labrador is the responsibility of the Canada-Newfoundland and Labrador Offshore Petroleum Board, based in St John's, Newfoundland.

In addition to specific operations, these regulators also review and approve development plans for field development projects. Where these involve transport of petroleum products between provincial jurisdictions or internationally, other Federal legislation comes into play, specifically the National Energy Board Act for pipelines, and the Canadian Shipping Act and the Arctic Waters Pollution Prevention Act for offshore Arctic tanker transportation.

The COGOA and the equivalent legislation in other jurisdictions treats operational regulatory matters including the granting of operating licenses to companies; authorization of specific programs (such as drilling a well or conducting a seismic acquisition program); approval of development plans (for development of an oil or gas field, including surface facilities and gathering systems), production arrangements to ensure conservation of oil and gas resources and to optimize overall recovery; approval of emergency response plans; the setting of financial liability, and for ensuring the fiscal capacity of operators to meet the demands of emergency response. Operational authorizations also confer responsibilities for worker safety under the Canada Labour Code. Regulations under COGOA deal with geophysical, drilling, development and production operations and related activities. Operation authorizations issued under this legislation are subject to compliance with these regulations and any terms and conditions which may be attached to the authorization. The NEB has powers to inspect and shut down operations which do not conform with regulations or which are breaching terms and conditions of the authorization.

The COGOA also requires companies to submit benefits plans in relation to specific authorized activities. These plans address fair opportunity for employment and business in relation to the operation. They also address matters of training and compensation. Application of benefits provisions in relation to northern and indigenous communities is discussed in Chapter 3.

Regulations under COGOA require that operators submit reports (and geological samples where appropriate) to government during operations and submit final program reports following the conclusion of activities. These reports and samples are held confidential for periods prescribed in legislation. After the prescribed periods, most information is available for public inspection. The Frontier Information Office of the NEB in Calgary provides this service for access to records of all northern oil and gas activities (including Yukon). Records and samples for offshore Labrador are available for inspection through the Canada-Newfoundland and Labrador Offshore Petroleum Board. Facilities for examination of core and samples are available in Calgary and St John's, respectively.

An authorization to conduct an activity is a primary requirement but companies are also obliged to ensure that all legal requirements for certification, licensing, and permitting under other relevant legislation are met. For instance, most operations onshore will require a land use permit and water license (for use of surface waters).

Environmental assessment

Prior to issuing the primary authorization, proposed activities undergo environmental assessment and review under the Canadian Environmental Assessment Act (CEAA) for Federal jurisdictions (see also Chapter 6 for further information on environmental assessment and an example from Canada). Compliance with the provisions of this Act is required where an activity is to be authorized by a Federal regulatory authority. The general model for environmental assessment is an escalating scale of review depending on the scope and potential impact of the project. On receipt of an application, regulators conduct a preliminary screening to ascertain the degree of significance or public concern. For types of project listed in the Comprehensive Study List Regulations under CEAA, proposals are required to undergo comprehensive study. Above certain thresholds of significance or public concern identified by screening or comprehensive study, proposals may be referred to a mediator or for panel review.

Proposals of high significance and concern undergo public review with hearings before a review board appointed by the responsible Ministers. Recommendations from the environmental assessment process are submitted to the Federal Minister for approval and inclusion in project authorizations by the appropriate regulatory authorities.

The details of environmental assessment differ across northern Canada. The association of indigenous peoples with the land and wildlife has ensured that environmental assessment has been an important matter in the agreement of land claims. Final land claim agreements have created specific regimes for environmental review which ensure local participation in the assessment of projects under legislation specific to land claim areas.

For example, pursuant to land claims, specific environmental legislation applies in the Mackenzie Valley (The Mackenzie Valley Resource Management Act) which established regional boards charged with making recommendations to address environmental and socio-economic concerns. In the Inuvialuit Settlement Region, the Environmental Impact Screening Committee reviews proposals and may refer applications for public review. Key to these regional boards is indigenous representation.

Similarly, the Mackenzie Valley Resource Management Act established an environmental review process for the Mackenzie Valley where regional land and water boards (and the Mackenzie Valley Land and Water Board for projects of trans-regional scope) screen project applications and can refer them for more detailed environmental assessment to the Mackenzie Valley Environmental Impact Review Board. This body is charged with making recommendations to address environmental and socio-economic concerns and may recommend a full public review of a project by the Federal Minister of the Environment. The Minster of Indian and Northern Affairs, after considering the report of the environmental review board, either confirms the recommendations for incorporation into regulatory permits issued by the land and water boards or refers the project to the Minster of the Environment for public review.

In Nunavut, an equivalent structure for environmental assessment was established by the Nunavut Land Claim Agreement (1993). In Yukon, environmental assessment is governed by the Yukon Environmental and Socio-economic Assessment Act, passed in 2003.

Key to these regional boards is assurance of local and indigenous representation with the power to make recommendations to regulatory authorities.

The establishment of boards with regionally limited authority poses special problems for large trans-boundary projects such as pipelines which may cross several jurisdictions. Special mechanisms may be required to ensure cooperation and collaboration between the various authorities. An example is the Cooperation Plan devised for the review of the Mackenzie Gas Project.

Land use planning

Where these have been concluded, zoning under regional land use plans will influence terms and conditions applied to oil and gas operations. Proposals are screened for compliance with these plans.

Although land use plans have been completed for extensive areas of the North, in many areas plans are still in draft form or have yet to be started. In the NWT, land use plans have been completed for the Gwich'in settlement area, and are in draft form for areas further south in the Mackenzie Valley. In Nunavut, the North Baffin, Kitikmeot and Keewatin, regional land use plans have been completed. Elsewhere and offshore, land use sensitivities are addressed through a variety of initiatives. In the Mackenzie Delta, community conservation plans have been drawn up: these together with government research by Federal departments and by territorial government provide a framework for identifying environmental sensitivities, and for adapting industry activities accordingly.

Offshore, obligations under the Federal Oceans Act require Federal departments to work together to integrate knowledge of offshore environmental sensitivities in relation to commercial activities. The Oceans Act also requires the establishment by regulation of a network of marine Protected Areas. However, this long-term goal presupposes a period of research to identify and delineate such areas. In the interim, and where particular concerns of local and indigenous populations intersect with industry operations, management plans for particular species have been established. The Beaufort Sea Beluga Management Plan is one such example.

In the absence of land use plans or established zoning schemes for the offshore environment, the Federal Government relies on consultative processes in determining lands open for oil and gas activities in the north.

For areas with particular environmental and cultural values, a number of Federal and Federal-territorial and territorial programs are in place to identify and establish areas for special protection. Canada has a program to establish national parks and marine conservation areas representative of all Canada's eco-regions. To date, eleven national parks have been established in northern Canada. Territorial parks, national wildlife areas, migratory bird sanctuaries, national heritage sites, and marine protected areas are all designations under Canadian legislation which may be applied to protect a sensitive area. Not all are exclusive of oil and gas operations although terms and conditions of such authorization may be stringent.

Identification and establishment of these areas is underway. The NWT, northern and indigenous communities, informed by government and environmental non-governmental organizations, are working to identify candidate areas for protection under the NWT Protected Area Strategy. Many candidate areas have already been identified.

In summary, the environmental and regulatory review process for the oil and gas industry is complex and has regional variations, particularly in environmental assessment, which respect the necessity of local and indigenous involvement. Mapping of the regulatory requirements for oil and gas projects has been completed for many areas. (These regulatory road maps may be viewed at www.oilandgasguides.com.)

Recent trends in Canadian regulation have been towards goal-orientated rather than prescriptive regulation, and towards developing collaborative mechanisms between regulators. Non-regulatory approaches such as bi-lateral agreements between industry and communities and land-claim organizations are also being explored. These, like the establishment of protected areas, are works in progress. Parallel advance on both fronts is essential to the sustainable growth and long-term presence of the oil and gas sector in the Canadian Arctic.

2.4.2.2. Development of oil and gas activity in Canada

The indices presented here for the oil and gas provinces (OGPs) in Canada can also be viewed in relation to the overall indices of oil and gas activity in the Arctic presented in section 2.3. With regard to the areas in Arctic Canada for which leases and licenses have been obtained (Figure 2.52) and explored by seismic acquisition (Figure 2.53), the indices show the number of meters of exploratory, discovery, and production wells drilled in all regions of Arctic Canada (Figure 2.54), and the amount of oil and gas produced in Arctic Canada (Figures 2.55a and 2.55b, respectively).

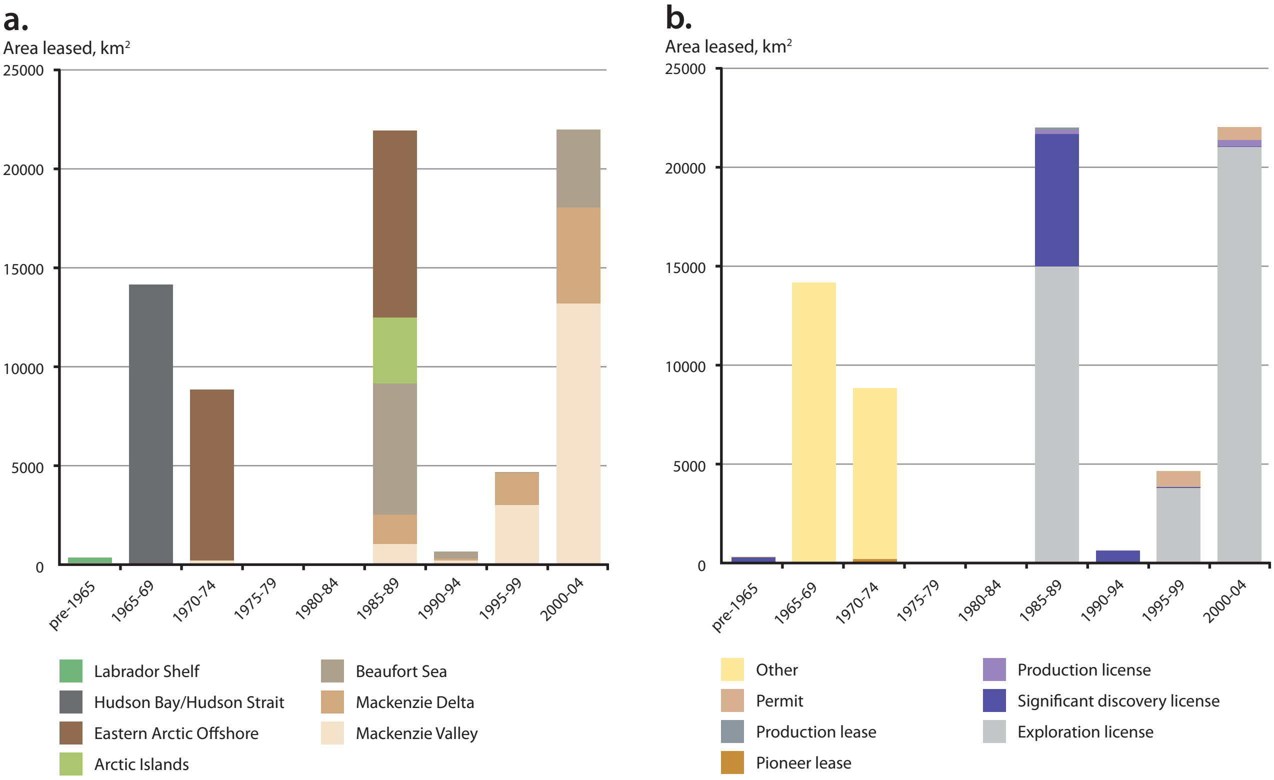


Figure 2.52. Arctic Canada leases and licenses obtained over time (a) by region and (b) by type. 'Other' refers to exploration permits or exploration agreements that have not been converted to exploration licenses under the existing legislation. Usually the reason for this is a moratorium (real or perceived) or a lack of interest in the area either because of poor prospectivity and/or remoteness.

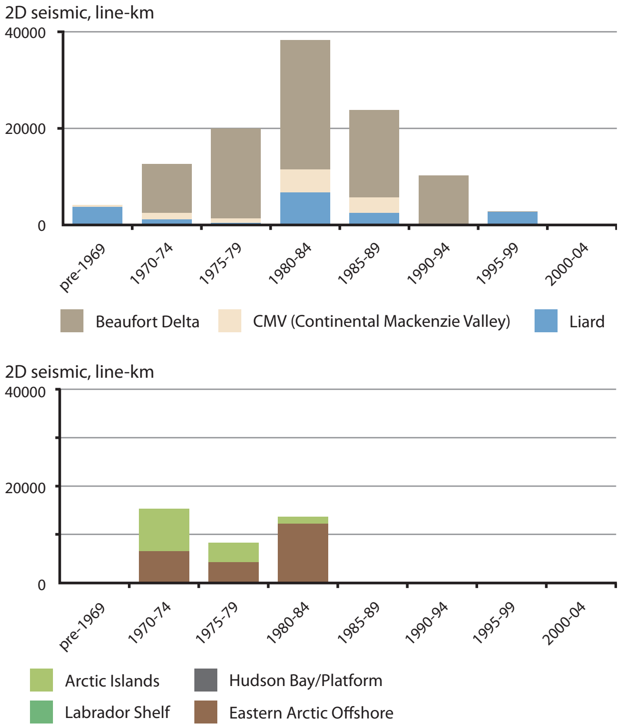


Figure 2.53. Arctic Canada seismic acquisition over time by region.

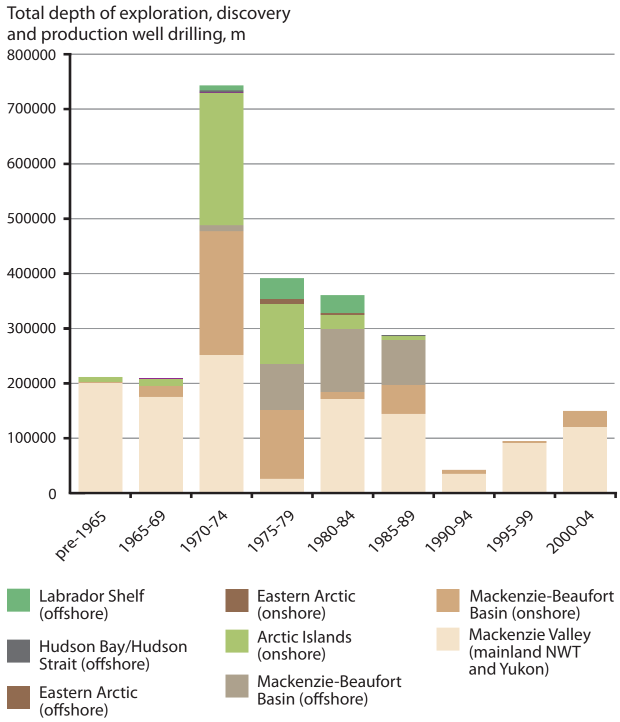


Figure 2.54. Arctic Canada meters wells drilled over time by region.

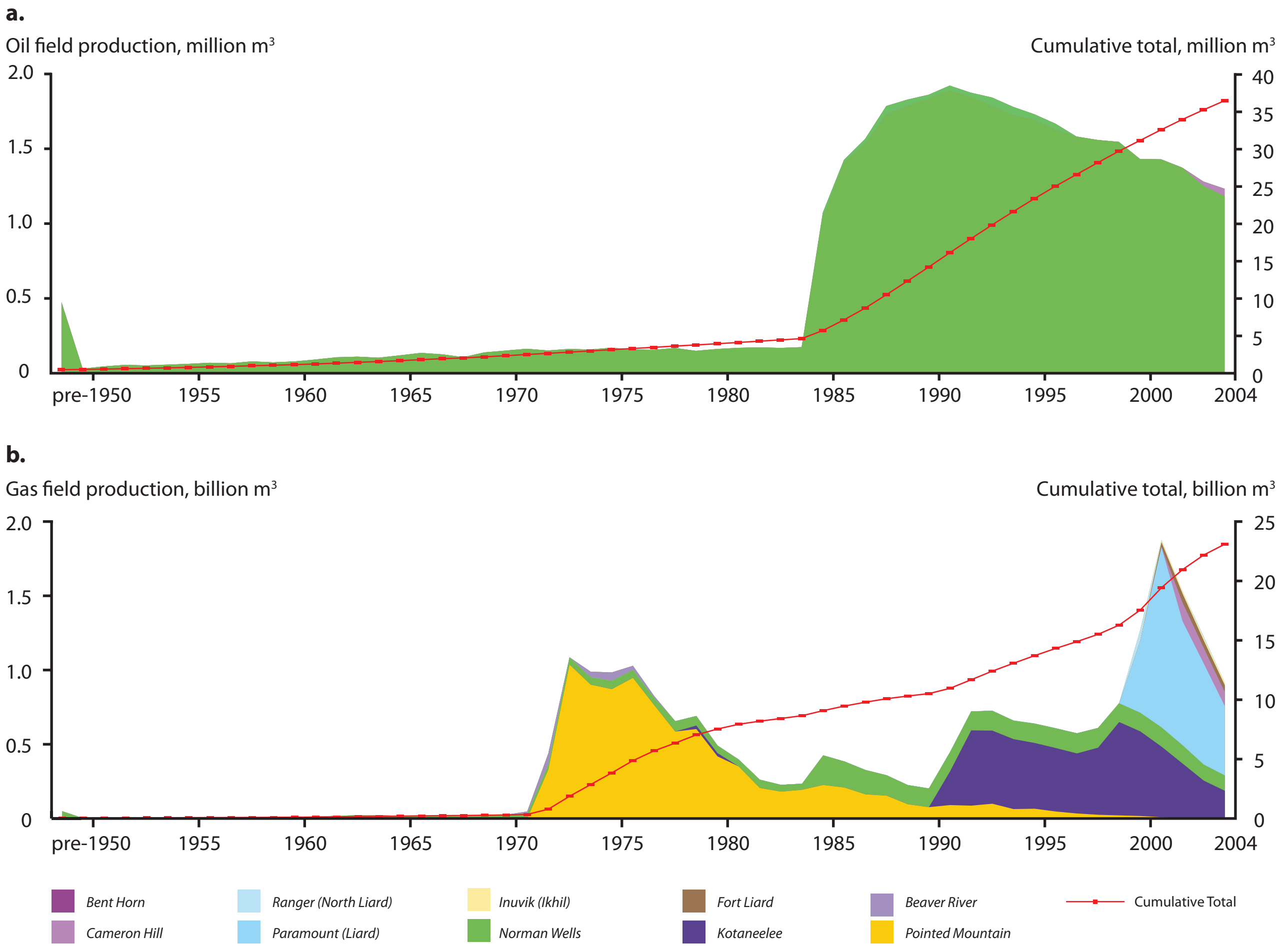


Figure 2.55. Arctic Canada (a) oil and (b) gas production over time by field.

2.4.2.3. Oil and gas provinces of northern Canada and exploration sub-regions

Northern Canada is divided into six oil and gas provinces (OGPs): Mainland NWT and Yukon; Mackenzie Delta / Beaufort Basin; Arctic Islands; Eastern Arctic; Hudson Platform; and Labrador Shelf (Figure 2.50). Only the first two contain producing fields; the other four have undeveloped discoveries and differing potential for future production. One oil field – now abandoned – has been developed in the Arctic Islands.

The division into OGPs is based on large-scale physiographic/geological controls. Procter et al. (1984), the Canadian Gas Potential Committee (CGPC, 2001), and the National Energy Board (NEB, 2004) follow a similar classification. Within each OGP occur exploration sub-regions based on geological and physiographic controls which define individual sedimentary basins and influence exploration and development (Table 2.27).

Of the 1584 wells in northern Canada, the majority were drilled onshore in the Mainland NWT and Yukon OGP, with fewer in the Mackenzie Delta / Beaufort Basin and Arctic Islands OGPs. Only five wells have been drilled in the Eastern Arctic OGP and five in the Hudson Platform OGP. The Labrador Shelf OGP has seen greater activity in past years in view of its contiguity with more southerly areas of active exploration on the Grand Banks of Newfoundland: with 28 offshore wells drilled.

Historical geophysical activity reflects this focus on petroleum province but relative to the pattern of drilling, has been more intensively used in the Mackenzie Delta / Beaufort Basin and Arctic Islands OGPs (Table 2.28). The prominence of offshore exploration in these two petroleum provinces favors seismic data as an exploration tool: on land, seismic data acquisition costs are higher and logistics more difficult while well costs are relatively lower.

There have been many oil and gas discoveries in the Mainland NWT and Yukon, Mackenzie Delta / Beaufort Basin, Arctic Islands, and Labrador Shelf OGPs (Table 2.29). With a handful of important exceptions, most discoveries remain poorly delineated and undeveloped. Significant oil production has until very recently been limited to Norman Wells, but gas production has been occurring in the Liard exploration sub-region of the Mainland NWT and Yukon OGP for decades, with the number of fields in production increasing from two to seven between 1999 and the end of 2004 (Table 2.30).

Since the 1920s, a total of 1359 wells have been drilled in the Mainland NWT and Yukon and Mackenzie Delta / Beaufort Basin OGPs (Table 2.31), with over 2 million meters drilled.

Several organizations have estimated conventional hydrocarbon resource potential for northern Canada over the past few decades. These include the National Energy Board (NEB, 1994a,b, 1996, 1997, 1999), the Geological

Table 2.27. Northern Canadian oil and gas provinces and exploration sub-regions.

OGP and exploration sub-region	Geological setting	Percent of area offshore
Mainland NWT and Yukon		
Great Bear Plain	Mesozoic foreland basin over Paleozoic continental margin	0
Great Slave Plain	Mesozoic foreland basin over Paleozoic continental margin	0
Liard Plateau	Laramide deformed belt	0
Mackenzie Plain	Cretaceous–Tertiary foreland basin over Paleozoic continental margin	0
Colville Hills	Intracratonic basin (Lower Paleozoic)	0
Peel Plain and Plateau	Cretaceous foreland basin over Paleozoic continental margin	0
Anderson/Horton Plains	Cretaceous interior basin over Paleozoic platform	0
Yukon Basins	Intermontane compressional or back-arc accretional basins	0
Mackenzie/ Beaufort Basin		
Mackenzie Basin Margin	Rifted continental margin	20
Mackenzie Delta	Tertiary deltaic complex	2
Beaufort Sea	Tertiary deltaic-prodeltaic complex	99
Arctic Islands		
Sverdrup Basin	Rifted continental margin with subsequent thermal subsidence	54
Arctic Fold Belt	Ellesmerian deformed belt	36
Arctic Platform	Cratonic margin	52
Arctic Coastal Plain	Cretaceous to Recent continental margin	84
Eastern Arctic		
Lancaster Basin	Mesozoic rift basin	100
Baffin Bay / Davis Strait	Passive margin with Mesozoic rifted sub-basins	100
Hudson Platform		
Hudson Bay Basin	Paleozoic intracratonic basin	70
Foxe Basin	Paleozoic intracratonic basin	66
Hudson Strait / Southhampton Basin	Paleozoic intracratonic basin, with Mesozoic rifting	97
Labrador Shelf		
Labrador Shelf	Passive margin with Mesozoic rifted sub-basins	100

Table 2.28. Wells and 2-D seismic lines in northern Canada by OGP.

	No. wells	Seismic lines, km[a]
Mainland NWT and Yukon	1119	36 529
Mackenzie Delta / Beaufort Basin	254	86 599
Arctic Islands	174	14 174
Eastern Arctic	5	23 164
Hudson Platform	4	42 736
Labrador Shelf	28	75 000
Total	1584	278 202

[a] Kilometer totals may significantly underestimate total seismic reflection coverage because details of pre-1970 data were inconsistently reported and may not be included in databases.

Table 2.29. Discovered oil and gas resources by OGP.

	Recoverable oil, million bbl	Recoverable gas, billion cu. ft
Mainland NWT and Yukon	314.6	2 230.60
Mackenzie Delta / Beaufort Basin	1015.6	9 694.70
Arctic Islands	334.9	17 383.00
Eastern Arctic	-	2 300.00
Hudson Platform	-	-
Labrador Shelf	-	4 245.10
Total	1665.1	35 853.40

Survey of Canada (Procter et al., 1984; Osadetz et al., 2000), the Canadian Gas Potential Committee (CGPC, 1997, 2001), and the Yukon Department of Economic Development (Hannigan et al., 1999; Hannigan, 2001). There are significant differences between these estimates which to some extent reflect differences in methodology and assumptions. The estimates have been assessed and adjustments made where necessary to reduce effects of differing methodologies and assumptions to improve the consistency of inter-regional comparison (Drummond, 2002a,b; Reinson and Drummond, 2002; Drummond and Reinson, 2004). The resource potential estimates presented in the following sections are those that the present authors consider to be the most comparable based on quantitative and qualitative considerations.

Estimates of discovered oil and gas resources were compiled from several sources, including the NEB and the Canadian Potential Gas Committee (www.drummondconsulting.com). These estimates may or may not be based on adequate or recent information (depending on factors such as when the discovery was made, how many wells were drilled to delineate the field,

Table 2.30. Producing fields to 31 October 2004.

	Exploration sub-region	Discovery date	Cumulative production, oil (million bbl) gas (billion cu. ft)	Producing status
Oil fields				
Norman wells	Mackenzie Plain	1920	225.092	Ongoing
Bent Horn	Arctic Fold Belt	1974	2.836	Ceased 1997
Amauligak	Beaufort Sea	1983	0.317	Production test, 1986
Cameron Hills	Great Slave Plain	2001	0.443	Ongoing
Total			228.688	
Gas fields				
Beaver River	Liard Plateau	1969	7.695	Ceased 1977
Pointed Mountain	Liard Plateau	1967	315.731	Ceased 2001
Kotaneelee	Liard Plateau	1964	210.412	Ongoing
Liard K-29	Liard Plateau	1999	128.203	Ongoing
Liard P-66	Liard Plateau	1998	2.547	Ceased 2003
Fort Liard F-36	Liard Plateau	1987	7.208	Ongoing
S.E. Fort Liard N-01	Liard Plateau	1987	6.638	Ongoing
Cameron Hills	Great Slave Plain	1968	10.849	Ongoing
Ikhil	Mackenzie Delta	1986	2.487	Ongoing
Total			691.770	

Table 2.31. Numbers of wells drilled and meters drilled by exploration sub-region over time in the Mainland NWT and Yukon and Mackenzie Delta / Beaufort Basin OGPs.

	Anderson/ Horton Plains	Colville Hills	Great Slave Plain	Great Bear Plain	Liard Plateau	Mackenzie Plain	Peel Plain and Plateau	Yukon Basin	Beaufort Sea	Mackenzie Delta	Mackenzie Basin Margin	Total
Number of wells drilled (excluding stratigraphic test holes)												
1920			2			7						9
1940			6			87	2		95			
1950			65		1	5		2		73		
1960	5	5	157	7	12	14	24	24		1	4	253
1970	11	7	80	13	17	45	26	24	30	49	71	373
1980	3	10	25		7	272		2	54	3	26	402
1990			22		18	27	6		1	4	3	81
2000	1	8	26		15	10	5		3	5	73	
Total	20	30	383	20	70	467	63	52	85	60	109	1 359
Meters drilled (all wells)												
1920			768			3 565						4 333
1940			1 253		55 139	2 959		59 351				
1950			47 009		428	2 832		5 559		55 828		
1960	6 569	1 217	166 259	10 104	39 830	20 047	42 280	46 845		3 861	9 371	346 383
1970	18 045	10 537	96 027	11 307	44 973	66 359	61 264	60 908	103 833	161 529	197 376	832 157
1980	3 055	13 152	44 550		24 120	224 459		3 641	193 096	10 826	54 850	571 749
1990			37 737		37 758	32 209	6 345		2 693	1 614	3 982	122 338
2000	1 146	10 721	48 681		36 579	15 956	5 672		11 390	14 404	144 549	
Total	28 815	35 627	442 284	21 411	183 688	420 566	118 520	116 953	299 622	189 220	279 983	2 136 689

Table 2.32. Ultimate petroleum resources of the Mainland NWT and Yukon OGP.

	Recoverable oil, million bbl			Recoverable gas, billion cu. ft		
	Discovered	Undiscovered	Ultimate	Discovered	Undiscovered	Ultimate
Great Slave Plain	1.25	60.70	61.95	80.1	3343.5	3423.6
Peel Plain and Plateau	-	35.32	35.32	-	3149.5	3149.5
Yukon Basins	11.71	50.64	62.35	83.7	3342.4	3426.1
Mackenzie Plain	301.64	107.00	408.64	156.0	1500.0	1656.0
Colville Hills	-	28.00	28.00	619.5	4586.0	5205.5
Anderson/Horton Plains	-	15.00	15.00	-	633.3	633.3
Liard Plateau	-	-	-	1291.3	4248.3	5539.6
Total	314.60	296.66	611.26	2230.6	20 803.1	23 033.7

and flow test results). In many cases actual resources may be much higher or much lower. Furthermore, this list does not imply that quoted resource numbers are endorsed by companies holding the rights to these resources.

2.4.2.4. Mainland NWT and Yukon OGP

2.4.2.4.1. Historical to present

Pre-exploration

Eight exploration sub-regions are recognized in the Mainland NWT and Yukon OGP (Table 2.27): Great Bear Plain, Great Slave Plain, Liard Plateau, Mackenzie Plain, Colville Hills, Peel Plain and Plateau, Anderson/Horton Plains, and Yukon Basins. Divisions between them are based on regional-scale geological controls. Yukon Basins includes Eagle Plain, Kandik, Old Crow, Bonnet Plume and Whitehorse Trough (extending into British Columbia). In this assessment, Great Slave Plain includes the southern NWT which, northward to about 62° N, is geologically part of the Alberta Basin situated in the Western Canada Sedimentary Basin south of 60° N (Mossop and Shetsen, 2004). The geology of the Mainland NWT and Yukon OGP has been covered in comprehensive texts (McCrossan, 1973; Stott and Aitken, 1993; NOGD, 1995; Norris, 1997).

Estimates of undiscovered resource potential for the various exploration sub-regions of the Mainland NWT and Yukon OGP (Table 2.32) indicate that large volumes of conventional gas resources remain to be discovered in the Liard Plateau (extending into southeast Yukon), Great Slave Plain south of 61°30′ N, the Colville Hills and the Mackenzie Plain, and in Yukon Basins. The ultimate oil resource is considered more localized in the Mackenzie Plain exploration sub-region (which is host to the *Norman Wells* field) and in the southeastern Great Slave Plain. In these exploration sub-regions, estimates of undiscovered potential are supported by successful drilling. The Peel Plain and Plateau, Anderson/Horton Plains, and Great Bear Plain exploration sub-regions are sparsely drilled and lack discoveries to date: their potential falls within the conceptual category but may be realized through new exploration.

Exploration

Federal Crown lands in the mainland NWT

In 1944, when the Norman Wells oil discovery was first put into large-scale production, an agreement was negotiated between Imperial Oil and the Canadian Government granting rights to sell produced petroleum from specific lands known as the proven area at Norman Wells. This agreement also defined a one-third Crown share in the field and a royalty rate. The agreement is still in force (with amendment) as production from the field continues. It represents the first, and a unique, production arrangement in northern Canada.

From the early 1960s until the mid-1970s, oil and gas permits issued under the Canada Oil and Gas Lands Regulations covered most of the petroleum basins of the Mainland NWT and Yukon. Exploration of these areas by seismic data acquisition and drilling culminated in the high activity levels of the early 1970s. Over this period, permits for the *Kotaneelee* gas field (SE Yukon) and *Pointed Mountain* gas field were converted to production leases: these fields were subsequently put on production. The leases have been renewed with their terms of production (including fixed royalty rates) continuing to the present day, surviving later changes in legislation and (for *Kotaneelee* field) the transfer of administrative responsibility to Yukon.

The negotiation of exploration agreements committed companies to drill and to relinquish lands. The relinquishment provisions of this period ensured that lands which were not actively explored returned to the Crown land bank. Companies who made discoveries were able to apply for significant discovery areas covering the extent of the discovery with no stratigraphic limitation. As exploration agreements terminated, activity levels decreased. However, an overriding factor prevented issuance of new exploration rights. This was the start of negotiations for comprehensive land claims with the Dene-Metis of the Mackenzie Valley: one feature of these negotiations was Canada's agreement not to issue new exploration rights while negotiations (including selection of private lands) were underway. The hiatus in land issuance and activity which extended from the mid-1980s to 1994 in the Mackenzie Valley coincided with a downturn in industry investment in northern exploration generally.

In 1994, following settlement of land claims in the central and northern Mackenzie Valley, the Canadian government began annual cycles of rights issuance under the Canada Petroleum Resources Act. With the support of local communities, calls for nomination to industry leading to bidding rounds were issued over extensive areas of the Sahtu and Gwich'in settlement areas in the central Mackenzie Valley. From 1994 to present (2004), this has resulted in the issuance of 30 new exploration licenses for work expenditure bids of CAD 188 million covering a total area of 2.6 million ha (INAC, 1994, 1995, 1996, 1997, 1998, 1999, 2000, 2001, 2002, 2003, 2004). Each annual call has seen issuance of new exploration rights, ensuring differing vintages of license. These are in different stages of exploration and so sustain opportunities for employment and business development.

Annual issuance cycles are continuing in the Sahtu and Gwich'in regions. Exploration success announced by certain companies is causing building interest in acquisition of exploration lands. In 2004, over 1.4 million ha were held under 19 exploration licenses, ensuring exploration activity into the next decade. In the bidding round that closed 17 May 2005, seven additional blocks were up for bid, amounting to approximately 400 000 ha.

Also in 1994, the Canadian government, with support and vision from indigenous leadership, launched new calls for nomination in the southern NWT on the traditional lands of the Acho Dene Koe (Fort Liard). In issuance cycles in 1994 and 1995, 14 exploration licenses were issued for total work expenditure bids of CAD 43 million covering a total area of 300 000 ha. No new issuance cycles have occurred since 1995. The result was a burst of exploration activity which had petered out by 2004, as the exploration licenses expired. The decline in activity does not reflect the petroleum potential of the region but rather the continuing uncertainty deriving from the lack of a land claim agreement with the Deh Cho First Nations of the southern NWT. Successful conclusion of a land claim would facilitate renewed issuance and activity in this area.

Indigenous private lands in the mainland NWT

Following the conclusion of land claim agreements for the Gwich'in and Sahtu regions of the central Mackenzie Valley, indigenous groups entered into concession agreements with companies to explore certain private lands. These concession agreements typically contained work program requirements, including drilling. Concession agreements which saw drilling programs commence in 2002 lie in the Colville Hills region (K'ahsho Got'ine District) and in 2005, in the Tulita District of the Sahtu region of the central Mackenzie Valley.

Crown lands in Yukon

In Yukon, throughout the 1990s, the process to settle land claims with indigenous groups coincided with negotiations on transfer of Federal administration to the territorial government. Over this period no new exploration licenses were issued. The sole remnants of the early wave of exploration under the permit system were three significant discovery licenses in the Eagle Plain basin of northern Yukon and the leases covering the *Kotaneelee* field in the southeastern corner of the territory.

Starting in 1999, the Yukon Government has issued four new exploratory permits totaling 146 421 ha in the Eagle Plain and Peel Plateau regions of northern Yukon. Three of these surround existing Yukon significant discovery licenses at the Chance, Birch, and Blackie discoveries in Eagle Plain.

Seismic activities

Since 1960, around 36 529 km of 2-dimensional (2-D) seismic line data have been acquired in the Mainland NWT and Yukon OGP. Data for the period 1960 to 1990 were primarily from reconnaissance surveys and aimed at developing basin-scale understanding of subsurface structure, with programs typically designed as open grids to allow identification of possible closures on subsurface structures. These were often drilled on the basis one or two crossing seismic lines.

The technology of the day required seismic lines to be as straight as possible. Lines were cut through forested areas and driven across winter tundra with little understanding of the long-term scarring of the landscape. Thirty to forty years later, the linear cut lines of old seismic programs remain clearly visible from the air and are an enduring reminder of past practices.

The focus of geophysical operations was in the southernmost part of the NWT in the Great Slave Plain and neighboring Liard Plateau and in Mackenzie Plain exploration sub-regions. However, over this period reconnaissance lines were also acquired across many more remote areas and in many cases still form the primary basis for the limited understanding of the subsurface structure. The Liard Plateau and Mackenzie Valley seismic operations occurred primarily in the 1970s and 1980s, reflecting the extension of exploration activity northward from Alberta and the development of the *Norman Wells* oil field (Figures 2.53 and 2.58). The level of activity was relatively high in the 1990s on the Liard Plateau because of the upward surge in gas prices and the presence of the prolific *Pointed Mountain* gas field in that region.

Drilling

Although the Mackenzie Delta / Beaufort Basin is considered a separate OGP, it is included in Figures 2.56 and 2.57 to illustrate how much of the drilling activity

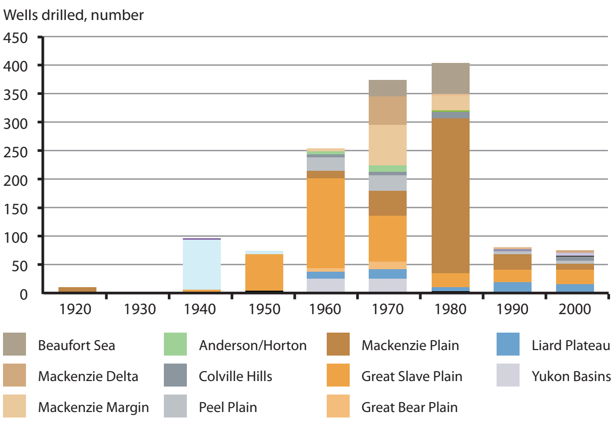


Figure 2.56. Number of wells drilled in exploration regions of the Mainland NWT and Yukon and Mackenzie Delta/Beaufort Sea OGPs by decade.

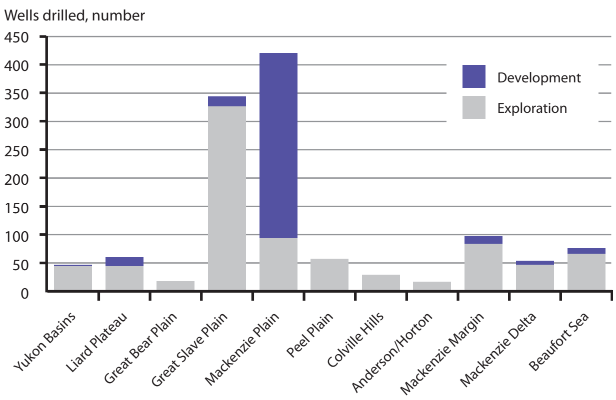


Figure 2.57. Number of development and exploration wells drilled in each of the Mainland NWT and Yukon and Mackenzie Delta/Beaufort Sea OGPs.

in that area was either concurrent with, or immediately following, the pulse of activity in the Mainland NWT and Yukon OGP immediately to the south.

When drilling is analyzed with respect to exploration sub-region and period of highest activity (Figure 2.56), two major trends are evident: that development drilling at Norman Wells in the Mackenzie Plain took place in two phases (1940s and 1980s), and that a sustained period of drilling activity (1950s, 1960s, and 1970s) occurred in the Great Slave Plain exploration sub-region. This activity reflected the extension of exploration northward from Alberta / British Columbia into the southern NWT south of 62° N. The *Cameron Hills* oil and gas field was discovered as a result of this activity.

Discoveries and development

In this assessment, the term 'field' is used to designate an area that produces, or is capable of producing, hydrocarbons from a single or multiple pools at different stratigraphic levels (Reinson et al., 1992), generally grouped within a discrete geological feature. Most discovered fields in the Arctic have never produced and many are discoveries made by a single well with field limits loosely delineated. For these discoveries, Canadian government sources use the term 'discovered resources' rather than 'reserves' (NEB, 1998; INAC Annual Reports). The technical requirement for sustained flow-on-test qualifies a discovery for declaration as a 'significant discovery' under Canadian legislation, which then permits a company to hold rights to the discovery under a 'significant discovery license'.

To January 2005, 29 oil and gas discoveries were declared in the Mainland NWT and Yukon OGP (listed by exploration sub-region in Table 2.33). Data for ten discoveries made between 2003 and 2005 (eight in the Fort Liard area and two in the central Mackenzie Valley) remain confidential and no discovered resource has been calculated.

Table 2.33. Oil and gas discoveries in the Mainland NWT and Yukon OGP.

Field/Pool	Exploration sub-region	Location	Oil, million bbl		Gas, billion cu. ft		Year
			Recoverable	Cumulative production [a]	Remaining reserves	Cumulative remaining reserves	
Bele	Colville Hills	Onshore	0	0	169.23	0	1986
Tedji Lake	Colville Hills	Onshore	0	0	35.99	0	1974
Tweed Lake	Colville Hills	Onshore	0	0	414.25	0	1985
Birch	Eagle Plain	Onshore	Not estimated	0	9.30	0	1965
Blackie	Eagle Plain	Onshore	0	0	23.30	0	1964
Chance	Eagle Plain	Onshore	11.71	0	51.10	0	1959
Beaver River (YU)	Liard Plateau	Onshore	0	0	7.75	7.70	1969
Bovie Lake J-72	Liard Plateau	Onshore	0	0	6.30	0	1967
Kotaneelee	Liard Plateau	Onshore	0	0	264.00	204.73	1964
La Biche F-08 (NWT)	Liard Plateau	Onshore	0	0	59.71	0	1971
La Biche F-08 (YU)	Liard Plateau	Onshore	0	0	3.14	0	1971
Ranger Fort Liard P-66A	Liard Plateau	Onshore	0	0	5.00	2.20	1998
Paramount Fort Liard F-36	Liard Plateau	Onshore	0	0	35.00	6.87	1987
Paramaount SE Fort Liard N-01	Liard Plateau	Onshore	0	0	20.00	5.19	1987
Chevron Fort Liard K-29	Liard Plateau	Onshore	0	0	575.00	114.23	1999
Pointed Mountain	Liard Plateau	Onshore	0	0	316.00	315.73	1967
Norman Wells	Mackenzie Plain	Onshore	301.64	218.85	156.00	0	1920
Arrowhead B-41	Great Slave Plain	Onshore	0	0	8.80	0	1989
Arrowhead G-69	Great Slave Plain	Onshore	0	0	3.80	0	1985
Cameron F-51	Great Slave Plain	Onshore	0	0	1.17	0	1969
Cameron M-31	Great Slave Plain	Onshore	0	0	2.13	0	1979
Cameron Hills	Great Slave Plain	Onshore	1.25	0.19	20.50	8.10	1968
Celibeta H-78	Great Slave Plain	Onshore	0	0	4.97	0	1960
Grumbler G-63	Great Slave Plain	Onshore	0	0	1.21	0	1969
Netla C-07	Great Slave Plain	Onshore	0	0	21.10	0	
Rabbit Lake O-16	Great Slave Plain	Onshore	0	0	11.29	0	1955
S. Island River M-41	Great Slave Plain	Onshore	0	0	1.70	0	1964
Tathlina N-18	Great Slave Plain	Onshore	0	0	2.49	0	1973
Trainor Lake C-39	Great Slave Plain	Onshore	0	0	0.96	0	1965
Total			314.6	219.0	2231.2	664.7	

[a] Cumulative oil production from the start of production to 31 December 2003.

Several discoveries have been made in the southern NWT area of the Great Slave Plain exploration sub-region. Gas and oil produced at the *Cameron Hills* field just north of the Alberta border are from Devonian shoal/platform and reef margin reservoirs similar to those present in northern Alberta (Reinson et al., 1992).

Three discoveries in the Colville Hills exploration sub-region have been designated to date, all from the same geological play (Table 2.33). Extensive low-relief anticlines have rendered the ubiquitous porous basal Cambrian sandstone of the Mount Clarke Formation a favorable reservoir for the accumulation of gas in three areas (Hamblin, 1990; Maclean and Cook, 1992; NOGD, 1995).

With regard to the Yukon Basins exploration sub-region, only Eagle Plain has seen extensive exploration with three discoveries resulting; Birch, Chance, and Blackie (Table 2.33). Gas was discovered in conglomeratic sandstones of the Permian Jungle Creek Formation at Blackie, and both gas and oil in sandstones of the Hart River Formation at Chance and Birch (pipe recovery only). The reservoirs are of the combination structural-stratigraphic type, with Laramide folding creating closure in the Carboniferous and Permian reservoirs. Stratigraphic pinch-out at the sub-Cretaceous unconformity also contributes to the reservoir occurrence.

By far the largest reserves of oil and gas occur in the Mackenzie Plain and Liard Plateau exploration sub-regions, respectively. The oil and gas production trends reflect this, with *Norman Wells* the more significant of two oil-producing fields, and Liard Plateau containing seven of the eight fields that are producing, or have produced, gas to date (Table 2.30).

Boxes 2.10 and 2.11 describe two fields; the largest oil field under production (*Norman Wells*) and the largest gas field so far produced (and depleted) in northern Canada (*Pointed Mountain*). These fields are used as examples but are in no way representative of the great geological diversity of the Mainland NWT and Yukon OGP.

Box 2.10. The *Norman Wells* oil field

Oil was produced at Norman Wells during the Second World War and flowed through a pipeline to Whitehorse in Yukon. Only a few hundred thousand barrels were produced before the pipeline was dismantled after the war. In the 1980s, a pipeline was built from Norman Wells to the Rainbow-Zama area 900 km to the south in northern Alberta. Since then, the field has delivered an average of 4800 m^3/d (30 000 bbl/d) through the 30-cm diameter pipeline.

Norman Wells lies 45 km east of the main front range of the Cordillera. Deep-rooted thrust sheets extend east of the mountains beneath the Mackenzie Plain, a broad north–south syncline containing a thick sedimentary sequence of Cambrian to Tertiary age. The thrust sheets rise to outcrop a few kilometers east of Norman Wells carrying the Norman Wells reservoir to near surface. Oil-bearing Devonian source rocks (which drape and seal the Norman Wells reservoir) outcrop at the surface on the banks and beneath the river.

The reservoir zone in the *Norman Wells* field occurs in the Devonian Kee Scarp Formation, an atoll-type reef which attains thicknesses of 150 m above a regional limestone platform (Ramparts Formation). The Devonian reef sequence lies within a Cambrian to Tertiary succession up to 2800 m thick comprising Paleozoic platform limestones, sandstones, and shales overlain by Cretaceous and Tertiary clastics. Reservoir porosity and permeability variations are governed by within-reef complex facies zonations (Fischbuch, 1984). Chalky micro-porosity, formed through leaching, ranges from 12–20% with fine but consistent pore throat size (Morrell, 1995).

The field extends beneath the Mackenzie River at depths of 700–1000 m below surface. It has been developed partly from onshore locations on the eastern bank of the river, partly from natural islands within the river, and from wells drilled from artificial islands. The town of Norman Wells has developed, in association with field facilities, on the eastern bank of the Mackenzie River.

Good horizontal permeability but poor vertical permeability has rendered the reservoir favorable for Enhanced Oil Recovery (EOR) using a water flood injection scheme instituted in the mid-1980s (Yose et al., 2001). Pressure is maintained in 180 producing wells by water injection into 152 injector wells. Wells were drilled on a 6.5 ha spacing (16 acre) in elongated 5-spot patterns to take advantage of the natural fracture system within the reservoir. Most of the development wells have been slant-drilled from artificial islands in the Mackenzie River, or from the eastern bank. Wells drilled from these sites are deviated above the reservoir, but near vertical within the reservoir, so taking advantage of the horizontally-directed flow units.

To 2003, 225 million bbl of oil had been produced from Normal Wells out of 301 million bbl recoverable (Table 2.33). Production is now declining at a rate of about 5560 m^3/y (35 000 bbl/y), which suggests that the reservoir is likely to be depleted in the latter half of the next decade (Figure 2.58). Ongoing EOR strategies, based on detailed reservoir modeling (Chase et al., 1997; Yose et al., 2001), have proved highly successful at Norman Wells.

The structural and stratigraphic controls which combine at Norman Wells may make the potential for the existence of fields similar to *Norman Wells* less likely than might otherwise be expected and none have yet been discovered.

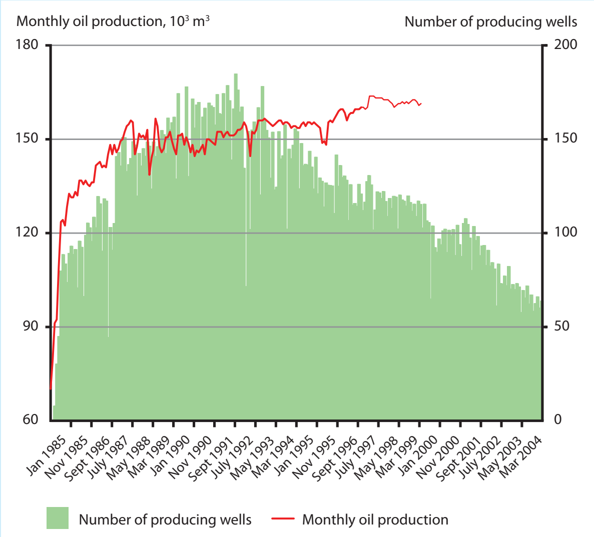


Figure 2.58. Oil production and number of producing wells by year at the *Norman Wells* field, Canada from 1985 to 2004. Cumulative oil production to December 2004 was 36 million m^3.

Box 2.11. *Pointed Mountain* gas field

The *Pointed Mountain* gas field is situated on the Liard Plateau, a highly faulted and folded foothills belt within which several isolated and fractured reservoirs have recently been encountered (Drummond and Reinson, 2004). The reservoir zone comprises Manetoe dolomite facies within the Middle Devonian Nahanni Formation. Multiple episodes of hydrothermal dolomitization characterize the highly fractured reservoir, which is located in a north–south trending double-plunging, faulted anticline 26 km long (Morrow et al., 1990; Taylor et al., 2003).

Gas production from *Pointed Mountain* began in 1972 with the completion of a pipeline connector to the West Coast system. Production ceased in September 2001 after a steady decline in flow rates from the late 1970s (Figure 2.59). Final cumulative production totalled ca. 8.87 billion m^3 (316 billion cu.ft) (Table 2.30). There is continuing production, however, from two other fields in the same geological trend – *Kotaneelee* in Yukon and *Liard* in the adjoining NWT.

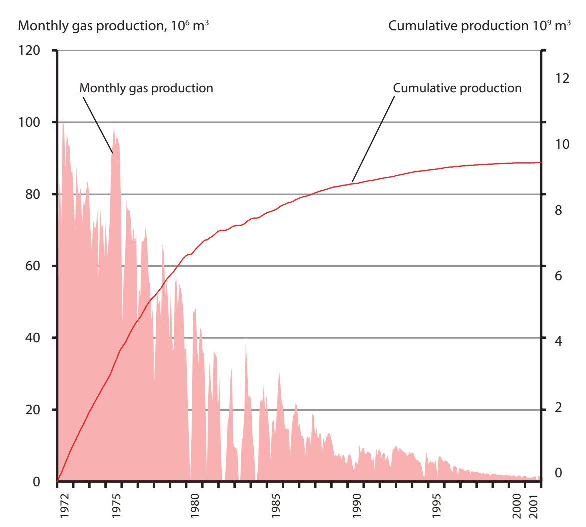


Figure 2.59. Monthly and cumulative gas production from *Pointed Mountain*, Canada from when it began in 1972 until it ceased in 2001.

2.4.2.4.2. Future

Near-term

Exploration in the southern NWT increased again from 1994 onwards as activity began to move northwards from northeastern British Columbia and Alberta. Exploration success in the Rocky Mountain foothills of northeastern British Columbia, progressive development of smaller fields in the plains areas, the northward growth of production infrastructure (e.g., pipelines, gas processing plants) towards and beyond the northern borders of the Provinces, the pursuit of existing and new gas plays into the southern NWT and southeastern Yukon, and more recently the development of 'resource plays' in the plains areas of British Columbia and Alberta have fueled interest in exploration north of 60° N, in the northern extension of the WCSB (to about 61° N).

From 2000 to 2002, five new gas fields were put on stream, a result of exploratory drilling initiated after new rights issuance in 1994/1995 in the Fort Liard region of the southern NWT. However, since 2004, and despite exploration success and good potential, exploration activity in the southern NWT ended following the termination of exploration licenses issued in the mid-1990s. Successful resolution of the current process between the Deh Cho First Nation and the Federal Government to resolve land issues should ensure future support for renewed issuance of exploration rights, although areas open for exploration may be more limited by land use zoning and by the creation of protected areas.

On the basis of economic factors alone, it is likely that much of the gas potential in the Liard Plateau and southern NWT would be drilled and developed, given that both areas already contain pipeline infrastructure.

There has been a recent surge in exploration in the Mackenzie Valley due to the prospect of a Mackenzie Valley pipeline project, and the potential opportunities such a pipeline would offer to lateral connections for new production. In this context, the focus has been on gas exploration in areas north of Norman Wells – the current terminus of the Norman Wells pipeline, but in areas adjacent to the existing oil pipeline exploration is targeting both oil and gas. Explorers are lured by the vision of a second *Norman Wells* field but, to date, these hopes have not materialized. As of 2005, exploration is active south of Norman Wells and west of the Mackenzie River. If new oil were to be discovered in this sub-region, the proximity of the Norman Wells oil pipeline favors the economics of extraction. In April 2005, a new oil and gas discovery was announced in this region as a result of this exploration program (Nickle's Daily Oil Bulletin March 30, 2005). This was subsequently declared a significant discovery by the NEB (NEB, 2007).

Since 2002, the Colville Hills exploration sub-region has been a focus of new exploratory drilling to find new gas to supplement discovered resources in three existing gas discoveries. This activity has been sustained over several operating seasons (2002–2005) and promising indications have been announced by operators, although actual results remain confidential. As of 2005, drilling in the Nogha and Lac Maunoir areas was causing anticipation and excitement at the future prospects of gas development of this exploration sub-region; a lateral pipeline to join a future Mackenzie Gas Pipeline would be in the order of 120 km.

A total of 71 wells have been drilled in Yukon Basins, mainly in the 1970s and 1980s (Yukon Department of Energy, Mines and Resources, 2004). Since 1999, however, fourteen geo-science exploration licenses have been issued in three land sales totaling work expenditure bids of CAD 24 million, and five 2-D seismic surveys have been completed. Several resource potential studies and aeromagnetic surveys have been jointly undertaken by the Yukon Government and the Geological Survey of Canada. Winter 2005 saw one new well drilled in Eagle Plain in northern Yukon but was subsequently abandoned. (Well and related information is updated on the Yukon Energy Mines and resources website www.emr.gov.yk.ca/oilandgas.) Future success may increase discovered resources past an economic threshold when a lateral connection to the Mackenzie Delta (around 200 km away) might be contemplated.

The Canadian Association of Petroleum Producers (CAPP) reported that from 2000 to 2003, a total of 71 wells were drilled in the territories of NWT, Yukon and Nunavut, for a total capital expenditure of CAD 1.26 billion (CAPP, 2005a) (both data sets also include the Mackenzie Delta / Beaufort Basin OGP). In 2003 alone, a total of 36 wells (including dry, service, oil and gas) were completed at a cost of CAD 0.27 billion. CAPP also reported that industry had committed to spend CAD 725 million and to drill 22 wells in the three northern territories in the immediate future CAPP (2005a). It is anticipated that exploration and development activity will increase dramatically should a Mackenzie Valley Pipeline Project be formally approved.

2.4.2.5. Mackenzie Delta / Beaufort Basin OGP

2.4.2.5.1. Historical to present

Pre-exploration

Three exploration sub-regions are recognized in the Mackenzie Delta / Beaufort Basin OGP: the Mackenzie Basin Margin, Mackenzie Delta, and Beaufort Sea. The subsurface geology has been well documented (Lerand, 1973; Young et al., 1976; Dixon, 1982, 1994, 1996; Dixon et al., 1992, 1994; Dietrich and Dixon, 1997) and so detailed geological reviews are not presented here.

The total ultimate potential of oil and gas in the Mackenzie/Beaufort Basin is estimated at 1.0213 x 10^9 m^3 (6.4 billion bbl) and 1.78 x 10^{12} m^3 (63 trillion cu. ft), respectively (Table 2.34). These numbers compare favorably with those estimated by the Geological Survey of Canada (Dixon et al., 1994): 1.13 x 10^9 m^3 (7.1 billion bbl) and 1.84 x 10^{12} m^3 (65 trillion cu. ft), respectively. The Canadian Gas Potential Committee (CGPC, 2001) estimated the ultimate gas potential for the Mackenzie Delta / Beaufort Basin OGP at 9.34 x 10^{11} m^3 (33 trillion cu. ft) recoverable. This volume is somewhat low, especially if the Mackenzie Delta is compared to similar off-lapping deltaic settings where substantial gas resources are known to occur (e.g., the Mississippi and Niger Deltas – Reinson and Drummond, 2000).

Compared to other assessments, it is likely that the potential given in Table 2.34 may even be somewhat conservative; particularly as the Mackenzie Basin Margin exploration sub-region is relatively under-explored with respect to the Paleozoic section underlying thick Cretaceous off-lapping strata.

Exploration

The history of granting permits and exploration licenses for northern Canada as a whole has been discussed above. This is now placed in the context of the Mackenzie Delta / Beaufort Basin OGP.

By the early 1990s, most of the exploration licenses in the Beaufort Sea and Mackenzie Delta had expired except for certain licenses in the western Beaufort Sea region. Exploration on these lands has been frozen since 1987 under a work prohibition order issued by the Canadian Government in view of Canada–U.S. disagreement over the international maritime boundary in the Beaufort Sea. These licenses are shown on current oil and gas disposition maps but do not signify active interest or plans to undertake work.

Although exploration licenses eventually expired or were surrendered by the early 1990s, rights to the 52 discoveries which had been made in the preceding decades continued to be held under significant discovery licenses but no exploration activity was occurring.

Following the signing of the Inuvialuit Final Agreement in 1984, certain lands were transferred to the Inuvialuit. Existing exploration agreements which extended over these lands – located principally on the Tuktoyaktuk Peninsula – were renegotiated as long-term concession agreements between the Inuvialuit and the oil companies. These concession agreements formed the basis for exploration on certain Inuvialuit private lands.

The signing of the Inuvialuit Final Agreement in 1984 paved the way for the Federal Government to renew issuance of exploration rights to Crown lands in the Inuvialuit Settlement Region. The first issuance cycle was held in 1989; this signaled the start of an annual pattern of calls for nominations. Three exploration licenses totaling 110 000 ha were issued in the Beaufort Sea as a result of this call. These were the first to be issued in twenty years. Subsequently, in 1991 four further parcels were bid: one offshore in the Beaufort Sea and three onshore in the Mackenzie Delta exploration sub-regions. None were validated by drilling and were surrendered in 1995. From 1992 to 1998, annual calls for nominations received no response.

In 1999 and 2000, industry signaled a strong interest in re-investing in exploration. Following the 1999 and 2000 Calls for Bids, 13 exploration licenses were issued for a total of approximately one million hectares. The lands issued covered most of the prospective onshore basin (Mackenzie Delta) and large areas of the adjacent shallow Beaufort Sea up to 12 m water depth. Following the 1999 Crown sale, the Inuvialuit had a successful land sale in 2000 and issued four concession agreements for cash bonus bids totaling CAD 75 million. These recent Inuvialuit agreements have ten-year terms, contain work program commitments which may include seismic activity and drilling, and incorporate penalties for failure to perform. They are issued for cash bonus, contain a provision for back-in on 25% of any discovery, set a royalty of between 5% in year 1 rising to 15%, and require companies to sign a comprehensive cooperation and benefits agreement (James Thorburne, Inuvialuit Lands Administration, pers. comm., 2005).

Table 2.34. Ultimate petroleum resources of the Mackenzie Delta / Beaufort Basin OGP.

	Recoverable oil, million bbl			Recoverable gas, billion cu. ft		
	Discovered	Undiscovered	Ultimate	Discovered	Undiscovered	Ultimate
Mackenzie Basin Margin	69.36	492.38	561.74	1604.2	4 375.1	5 979.3
Mackenzie Delta	78.55	557.62	636.17	3137.3	8 556.2	11 693.5
Beaufort Sea	867.69	4339.10	5206.79	4953.2	40 368.7	45 321.9
Total	1015.60	5389.10	6404.70	9694.7	53 300.0	62 994.7

The issuance of these new rights with work commitments on both Crown and Inuvialuit lands has been the basis for new seismic and drilling activity since 2000. In a recent update, major oil companies have signaled an interest in the deeper water areas of the central Beaufort Sea, specifically on the outer continental shelf extending across the shelf/slope break. New exploration licenses issued in 2007 and 2008 carry drilling commitments which are likely to see new wells offshore in the 2012 to 2013 window (INAC, 2007).

Seismic activities

Since 1960, a total of 86 599 km of 2-D seismic lines have been shot, both onshore and offshore, in the Mackenzie Delta / Beaufort Basin OGP (Table 2.28). Most data were acquired in the 1970s and 1980s when the level of oil and gas exploration activities was high.

Following the issuance of new exploration licenses, an intensive phase of 3-D seismic data acquisition began across much of the Mackenzie Delta and shallow fringing waters of the Beaufort Sea; in the period 2000 – 2003 companies acquired over 11 000 km^2 of 3-D data.

Drilling

Extensive drilling occurred from the late 1960s to the beginning of the 1990s in the Mackenzie Delta / Beaufort Basin OGP (Figure 2.56). Eighty-three of the 240 wells in this petroleum province were drilled offshore in the Beaufort Sea exploration sub-region (Figure 2.57).

A variety of offshore drilling platforms were used for exploration, with the system chosen largely dictated by water depth and ice resistance. In very shallow waters of a few meters depth, thickened ice islands were built for winter operations. Further offshore in depths of up to about 25 m, large artificial islands were constructed from dredged sand and gravel. These were used for both summer and winter operations. A variety of custom steel caissons were developed for use in combination with dredged berms and as stand-alone platforms which could ballast down onto the seabed. Further offshore, in water depths generally exceeding 40 m, summer season drilling from drill-ships and barges was the preferred option. At the height of offshore activity, companies such as Dome, Gulf, and Imperial Oil maintained large fleets of vessels, including dredgers, icebreakers, support vessels, and drilling platforms expressly for Beaufort Sea operations.

Issuance of new exploration rights in 1999 and 2000 triggered a rapid build-up in exploration effort, resulting in renewed drilling activities onshore in the Mackenzie Delta. Drilling is continuing at a rate of two to four new wells per year. In the winter drilling season 2005/2006, the first offshore well in fifteen years was drilled from a steel drilling caisson (the 'SDC') in 16 m water depth. The Paktoa C-60 well was subsequently declared a significant discovery (INAC, 2007). Success in discovering additional offshore oil and gas may spur sustained offshore exploration in the Beaufort Sea, but the high cost of operations and worldwide competition for Arctic offshore drilling units and support vessels are likely to keep offshore drilling at relatively low levels compared with previous decades.

Discoveries and development

Oil and gas discoveries in the Mackenzie Delta / Beaufort Basin OGP totaled 52 to the end of 2004. Thirty of these are offshore, 25 in the Beaufort Sea exploration sub-region, four in the Mackenzie Delta exploration sub-region (in very shallow water); and one just offshore on the Mackenzie Basin Margin exploration sub-region. The rest are onshore; ten in the Mackenzie Basin Margin and 12 in the Mackenzie Delta (Table 2.35). Exploration drilling since 2004 has scored several additional discoveries, four in the Mackenzie Delta and one in the Beaufort Sea (INAC, 2005, 2006, 2007, 2008).

According to Dixon et al. (1994), the most dominant geological play types in the Mackenzie Delta / Beaufort Basin OGP are Tertiary, off-lapping deltaic clinoform deposits, ranging from proximal distributary and distributary mouth bars to delta front, shoreface and prodelta pinch-outs offshore. All the Mackenzie Delta and Beaufort Sea discoveries are of this Tertiary deltaic type.

The play types in the Mackenzie Basin Margin exploration sub-region are more varied geologically. Discoveries along the Tuktoyaktuk Peninsula occur in thick, truncated marginal marine to fluvial deposits of Lower Cretaceous age. Four discoveries in the southern part of the delta occur in Jurassic and Lower Cretaceous sandstones of marginal marine origin. In the same region, underlying Upper Paleozoic sandstones have been penetrated by 11 wells only, with one discovery to date. Southern Mackenzie Delta exploration is at a very immature stage, because deeper horizons have not yet been adequately tested.

Discovered resources exceed 1.6×10^8 m^3 (1 billion bbl of oil) and 2.5×10^{11} m^3 (9 trillion cu. ft) of gas to date (Table 2.34). These are high volumes relative to the number of wells drilled, which is very low compared to other delta settings such as the Mississippi Delta (Reinson and Drummond, 2000).

Several of the more significant fields of varying geological age and play type (Dixon et al., 1994) are reviewed in Box 2.12.

There has been no sustained production of oil from the Mackenzie Delta / Beaufort Basin OGP and only very limited development of natural gas (Table 2.30). There has been no permanent development of offshore discoveries, and an export pipeline has yet to reach the basin. Oil was produced at Amauligak in 1986, when 50 400 m^3 (317 000 bbl) were flowed into a tanker during extended production testing and subsequently exported for a refining evaluation. In 1999, the *Ikhil* gas field, a small onshore discovery just east of the Mackenzie Delta, was developed and a 50-km pipeline built to supply gas to the town of Inuvik for power generation and domestic heating. Consequently, natural gas has displaced diesel oil in this community as the primary fuel for these purposes. A second well was put on-stream in 2000 with total production to 31 October 2004 of almost 2.5 billion cu. ft (Table 2.30 and Figure 2.60). The cyclical production pattern reflects the greater use of gas during the cold weather months as opposed to the warmer summer months.

Development of discovered resources in the Mackenzie Delta / Beaufort Basin OGP has received growing attention by Canada's petroleum industry over the past decade. Given the high cost of natural gas, and its abundance both in this petroleum province and in the adjoining Alaskan Coastal Plain/shelf region, industry and government attention has focused on the concept of constructing a natural gas pipeline that would run the 1100 km length of the Mackenzie River Valley from the Beaufort Sea southward to link with the major trunk pipelines in Alberta and British Columbia. A parallel line for natural

Table 2.35. Oil and gas discoveries in the Mackenzie Delta / Beaufort Basin OGP.

Field/pool	Exploration sub-region	Location	Oil, million bbl		Gas, billion cu. ft		Year
			Recoverable	Cumulative production [a]	Remaining reserves	Cumulative remaining reserves	
Adgo F-28	Mackenzie Delta	Offshore	38.91	0.00	119.73	0.00	1974
Atkinson H-25	Mackenzie Basin Margin	Onshore	42.40	0.00	0.00	0.00	1970
Garry N. G-07	Mackenzie Delta	Offshore	0.00	0.00	10.99	0.00	1978
Garry S. P-04	Mackenzie Delta	Onshore	57.17	0.00	274.28	0.00	1976
Hansen G-07	Mackenzie Delta	Offshore	4.33	0.00	172.78	0.00	
Ikhil K-35	Mackenzie Basin Margin	Onshore	0.00	0.00	27.47	2.04	1986
Imnak J-29	Mackenzie Basin Margin	Onshore	10.36	0.00	0.00	0.00	1975
Ivik J-26	Mackenzie Delta	Onshore	5.95	0.00	0.00	0.00	
Ivik K-54	Mackenzie Delta	Onshore	4.25	0.00	0.00	0.00	1973
Kamik D-48	Mackenzie Basin Margin	Onshore	1.15	0.00	0.00	0.00	1975
Kugpik O-13	Mackenzie Basin Margin	Onshore	3.99	0.00	0.00	0.00	1973
Kumak J-06	Mackenzie Delta	Onshore	12.15	0.00	26.62	0.00	1974
Mallik L-38	Mackenzie Delta	Onshore	0.00	0.00	28.18	0.00	1972
Mayogiak J-17	Mackenzie Basin Margin	Onshore	4.11	0.00	0.00	0.00	1971
Niglintgak H-30	Mackenzie Delta	Onshore	21.35	0.00	504.41	0.00	1973
Parsons Lake F-09	Mackenzie Basin Margin	Onshore	0.00	0.00	1334.43	0.00	1973
Pelly B-35	Mackenzie Delta	Offshore	0.00	0.00	110.31	0.00	1975
Reindeer F-36	Mackenzie Delta	Onshore	0.00	0.00	16.71	0.00	1973
Taglu G-33	Mackenzie Delta	Onshore	0.00	0.00	2269.94	0.00	1971
Titalik K-26	Mackenzie Delta	Onshore	0.00	0.00	59.35	0.00	
Tuk J-29	Mackenzie Basin Margin	Onshore	1.23	0.00	0.00	0.00	1985
Tuk M-09	Mackenzie Basin Margin	Onshore	0.00	0.00	203.34	0.00	1984
Unak L-28	Mackenzie Basin Margin	Onshore	0.00	0.00	38.94	0.00	
Unipkat N-12	Mackenzie Delta	Onshore	34.85	0.00	14.23	0.00	1990
W. Atkinson L-17	Mackenzie Basin Margin	Offshore	6.12	0.00	0.00	0.00	1982
Ya Ya N. A-28	Mackenzie Delta	Onshore	0.00	0.00	56.01	0.00	1974
Ya Ya S. P-53	Mackenzie Delta	Onshore	0.00	0.00	51.54	0.00	1973
Adlartok P-09	Beaufort Sea	Offshore	112.59	0.00	0.00	0.00	1985
Amauligak J-44	Beaufort Sea	Offshore	235.01	0.32	1516.97	0.00	1983
Amerk O-09	Beaufort Sea	Offshore	0.00	0.00	21.43	0.00	1985
Arnak K-06	Beaufort Sea	Offshore	2.69	0.00	41.72	0.00	1986
Havik B-41	Beaufort Sea	Offshore	37.21	0.00	0.00	0.00	1983
W Amauligak I-65A/O-86	Beaufort Sea	Offshore	19.62	0.00	66.33	0.00	1986
Isserk E-27	Beaufort Sea	Offshore	0.00	0.00	3.58	0.00	1978
Issungnak O-61	Beaufort Sea	Offshore	30.04	0.00	1195.99	0.00	1980
Itiyok I-27	Beaufort Sea	Offshore	5.06	0.00	96.13	0.00	1983
Kadluk O-07	Beaufort Sea	Offshore	0.00	0.00	75.30	0.00	
Kenalooak J-94	Beaufort Sea	Offshore	0.00	0.00	194.78	0.00	1979
Kiggavik A-43	Beaufort Sea	Offshore	0.00	0.00	127.10	0.00	1982
Kingark J-54	Beaufort Sea	Offshore	16.13	0.00	48.02	0.00	1989
Koakoak O-22	Beaufort Sea	Offshore	81.47	0.00	280.39	0.00	1981
Kopanoar M-13/2I-44	Beaufort Sea	Offshore	68.29	0.00	28.81	0.00	1979
Minuk I-53	Beaufort Sea	Offshore	0.00	0.00	89.73	0.00	1986
Nektoralik K-59	Beaufort Sea	Offshore	14.11	0.00	70.28	0.00	1976
Nerlerk M-98	Beaufort Sea	Offshore	30.55	0.00	0.00	0.00	1979
Netserk F-40	Beaufort Sea	Offshore	0.00	0.00	121.44	0.00	1975
Nipterk L-19	Beaufort Sea	Offshore	16.83	0.00	14.92	0.00	1985
Nipterk P-32	Beaufort Sea	Offshore	12.05	0.00	130.33	0.00	1989
Pitsiulak A-05	Beaufort Sea	Offshore	25.12	0.00	0.00	0.00	1984
S. Isserk I-15	Beaufort Sea	Offshore	13.95	0.00	116.66	0.00	1990
Tarsiut A-25	Beaufort Sea	Offshore	46.56	0.00	31.17	0.00	1979
Ukalerk C-50	Beaufort Sea	Offshore	0.00	0.00	104.38	0.00	1977
Total			1015.6	0.3	9694.7	2.0	

[a]Cumulative oil production from the start of production to 31 December 2003.

Box 2.12. Significant fields in the Mackenzie Delta / Beaufort Basin OGP

Atkinson Point field, the first discovery in the Mackenzie Delta / Beaufort Basin OGP, is located along the Tuktoyaktuk Peninsula margin in the Mackenzie Basin Margin exploration sub-region. Oil is the primary hydrocarbon contained in two pools (Table 2.35). The reservoir consists of inter-bedded conglomerates and sandstones which form part of a small fan delta that comprises the Lower Cretaceous Atkinson Point Formation (Dixon, 1979). Porosity and permeability values are highly variable and lithofacies dependent – the best porosities reaching 15–20% in the clean coarse-grained sandstones and conglomerates. Similar to *Parsons Lake* field, the trapping mechanism relates to closures resulting from normal fault movements in the Eskimo Lakes Fault Zone.

Taglu field situated onshore in the Mackenzie Delta, has estimated gas reserves of 5.77 x 10^{10} m^3 (2.3 trillion cu.ft) (Table 2.35). Five other discoveries geologically similar to Taglu are nearby. Taglu is a multi-zoned reservoir comprising a series of stacked, 3–50 m thick, deltaic sandstones (delta front, channel, and distributary mouth bars) contained within the off-lapping Eocene Taglu sequence (Morrell, 1996). Average porosity of the reservoir units is in the 15–20% range. The trapping mechanism is created by a large listric fault with a basinward down-throw of up to 1500 m juxtaposing younger sealing clays against the reservoir sandstones.

Parsons Lake gas field is located in the Mackenzie Basin Margin exploration sub-region and contains an estimated recoverable gas volume of almost 3.96 x 10^{10} m^3 (1.4 trillion cu.ft) (Table 2.35). Gas is contained in stacked fluvial to marginal-marine sandstones (a few to tens of meters thick) of the several hundred meter thick Lower Cretaceous Parsons Group (Dixon et al., 1994). Porosity values are around 15–20% for the quartz arenites and somewhat less for the lithic sandstones. The trapping mechanism is associated with closures formed against 'basement' normal faults of the Eskimo Lakes Fault Zone (Dixon et al., 1992).

The *Amauligak* field, offshore in the Beaufort Sea, has estimated oil and gas reserves of 235 million bbl and 4.25 x 10^{10} m^3 (1.5 trillion cu.ft), respectively (Table 2.35). Amauligak is a multi-zonal reservoir consisting of stacked 5–15 m thick, proximal delta front sandstones contained in the thick off-lapping Kugmallit clinoform sequence of Oligocene age. Average porosity of the sandstone units is 21%, but 30% is not uncommon. The trapping mechanism is related to down-to-basin listric faulting with throws in the order of thousands of meters (Enachescu, 1990; Morrell, 1996).

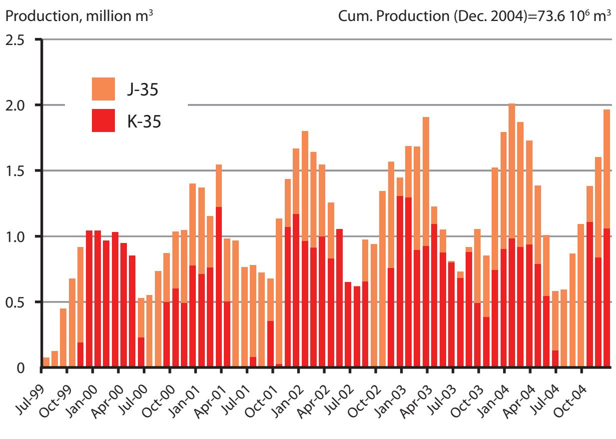


Figure 2.60. Production of natural gas at the *Ikhil* gas field. The second of the two producing wells (K-35) came onstream in 2000.

gas liquids would run half this distance to connect to the northern terminus of the Norman Wells oil pipeline.

This concept was not new to the 1990s, but was first considered in the early 1970s following the Federal Government's 1970 Pipeline Guidelines paper which put forward the idea of a pipeline corridor from the North. Two detailed submittals, proposed by consortia comprising multinational producers and major pipeline companies, involved traversing the Mackenzie Valley with a pipeline extending from the Arctic Ocean to Alberta. The many environmental, socio-economic, geotechnical, and engineering studies generated during this period have been archived by the Arctic Institute of North America at the University of Calgary.

In response to these submittals, a Federal Royal Commission, led by Thomas Berger, was appointed in 1977 to examine the impact a pipeline would have on indigenous culture and the environment as a whole. The Berger Commission recommended that no pipeline be built for a period of ten years to allow for the settling of indigenous land claims (Berger, 1977). This recommendation became Federal Government policy, and in the late 1980s after several land claims were settled, or were under negotiation, the pipeline project was again put forward and has been endorsed by the majority of indigenous groups in the Mackenzie Valley.

An Alaska Gas pipeline has been proposed to run from Prudhoe Bay through Whitehorse, Yukon and northeast British Columbia, to connect with the extensive northern Alberta system at Boundary Lake (Burden, 2005). Most industry observers believe that by the time these projects reach fruition, southern markets will be more than capable of absorbing all the Alaskan and Canadian Arctic gas that the pipeline systems will be able to deliver (Burden, 2005).

From a Canadian perspective, the current exploration levels in the Mackenzie Delta and Beaufort Sea anticipate the realization of a Mackenzie Valley gas pipeline. The exploration focus is on discovering additional natural gas in new stratigraphic and structural plays revealed by 3-D seismic data which would supplement resources already discovered. This is evident by activities of the major multinational explorers; for example, Devon Canada Corporation has identified several new and exciting plays such as turbidite fans and channels, and wrench-related structures in the shallow offshore (Eaton, 2005).

In response to the issuance of exploration licenses in the Mackenzie Delta exploration sub-region in the late 1990s, 19 exploration wells have either been completed, spudded, or licensed to drill since 1998 (INAC, 1998, 1999, 2000, 2001, 2002, 2003, 2004).

2.4.2.5.2. Future

Near-term (up to about 2015)

The Mackenzie Gas Project (www.mackenziegasproject.com) was formed in 2000, and comprises major companies with gas reserves on the Mackenzie Delta (Imperial Oil, ConocoPhillips, Shell Canada, Exxon Mobil) together with the Aboriginal Pipeline Group (APG). The Mackenzie Gas Project proposes to develop natural gas fields in the Mackenzie Delta of Canada's NWT and to deliver the natural gas and natural gas liquids to markets in Canada and the United States. The Project proposes: the development of around 1.7 x 10^{11} m^3 (6 trillion cu. ft) of gas in three natural gas fields (*Taglu*, *Parsons Lake*, *Niglintgak*); a gathering pipeline system; a gas processing facility near Inuvik (the Inuvik area facility); a natural gas liquids pipeline from the Inuvik area facility to Norman Wells; and a natural gas pipeline from the Inuvik area facility to northwestern Alberta.

Applications for the main regulatory approvals were submitted in October 2004 (Imperial Oil Resources, 2004) to the boards and agencies responsible for assessing and regulating energy developments in the NWT. Pending approval of the comprehensive plan, the three fields (*Niglintgak*, *Taglu*, *Parsons Lake*) together can supply about 0.8 billion cu. ft/d of natural gas over the life of the Project. Other natural gas fields in the western Canadian Arctic are likely to be connected to the gathering system or to the main pipeline to make up throughput volumes to meet design capacity. These are likely to be in the Mackenzie Delta / Tuktoyaktuk Peninsula and immediate offshore areas, and in the Colville Hills of the central Mackenzie Valley region, and may comprise existing and new discoveries. In total as much as 1.2 billion cu. ft/d of natural gas could be available initially to move through the Mackenzie Valley natural gas pipeline. The Mackenzie Gas Project also envisages expansion of the system to 1.9 billion cu. ft/d through the addition of compression (Mackenzie Gas Project, 2004).

Exploratory drilling in this region is highly contingent on a decision to proceed with the Mackenzie Gas Project or similar proposal for a Mackenzie Valley gas pipeline. Such a commitment would sustain levels of onshore drilling for gas followed by a move to offshore locations. Of particular interest in this area is the likelihood of exploration (and production projects) that will straddle onshore and offshore regions. The shallow-water margins of the Mackenzie Delta present operational challenges for semi-permanent offshore drilling platforms; thus drilling by extended-reach drilling from coastal locations is a likely option for developing nearshore fields.

2.4.2.6. Arctic Islands OGP

2.4.2.6.1. Historical to present

Pre-exploration

The Arctic Islands OGP contains four exploration sub-regions (Table 2.27) based on major tectono-stratigraphic controls (Procter et al., 1984). This four-fold subdivision (Sverdrup Basin, Arctic Fold Belt, Arctic Platform, Arctic Coastal Plain) has been more or less adhered to in subsequent petroleum resource studies (NOGD, 1995; Chen et al., 2000; CGPC, 2001; NEB, 2004). The compendium edited by Trettin (1991) is an additional source of information on the geology of the Arctic Islands.

Ultimate oil and gas resource potential in the Arctic Islands OGP is estimated at 6.04 x 10^8 m^3 (3.8 billion bbl) and 3.34 x 10^{12} m^3 (118 trillion cu. ft), respectively (Table 2.36). Seventy-three percent of the ultimately recoverable gas occurs within the Sverdrup Basin exploration sub-region (2.44 x 10^{12} m^3 - 86 trillion cu. ft). This is high compared to the CGPC estimate of 7.93 x 10^{11} m^3 (28 trillion cu. ft) for the Sverdrup Basin alone (CGPC, 2001). However, conceptual plays are heavily discounted in the latter study. Chen et al. (2000) proposed ranges of 1.27–2.23 x 10^8 m^3 (0.8–1.4 billion bbl) of ultimately recoverable oil, and 0.99–1.13 x 10^{12} m^3 (35–40 trillion cu. ft) of ultimately recoverable gas for the Sverdrup Basin.

Exploration

Oil and gas permitting in the Arctic Islands began in 1960 and peaked in 1971 when over 108 million ha were held under 1435 permits (INAC, 1984, Table 1). Numbers declined steadily until, by 1981, all permits were either surrendered or consolidated into exploration agreements. By the late 1980s, most exploration lands had been surrendered except for significant discovery licenses covering 18 significant discoveries in the Arctic Islands.

Since 2000, the Federal Government has been offering lands for nomination within the Sverdrup Basin of the Arctic Islands (Call for Nominations – The Arctic Islands of Nunavut). Areas offered include lands with high potential surrounding significant discoveries made during the 1970s. Extensive blocks may be nominated with terms of nine years and drilling commitments delayed for six years. This opportunity is being offered annually but companies have yet to acquire new exploration commitments in this region.

Seismic activities

Since 1960, a total of 14 174 km of 2-D seismic lines were shot in the Arctic Islands OGP (Table 2.28). Most of these data were acquired to enhance exploration drilling in the Sverdrup Basin exploration sub-region and a large proportion was acquired offshore. Most seismic surveys were undertaken in the 1970s and 1980s. These data form a basin-scale grid, but new exploration is likely to entail 3-D seismic surveys to better resolve the complex structure of the southern margin of the basin.

Drilling

One hundred and seventy-four wells were drilled (with a total depth penetration of nearly 462 km) in the Arctic Islands OGP from 1962 to 1987 (Table 2.37). Of the 174

Table 2.36. Ultimate petroleum resources of the Arctic Islands OGP.

	Recoverable oil, million bbl			Recoverable gas, billion cu. ft		
	Discovered	Undiscovered	Ultimate	Discovered	Undiscovered	Ultimate
Sverdrup Basin	332.10	1189.20	1521.30	17 383.0	68 909.0	86 292.0
Arctic Fold Belt	2.84	564.50	567.34	-	7 796.7	7 796.7
Arctic Platform	-	1163.00	1163.00	-	8 968.8	8 968.8
Arctic Coastal Plain	-	566.10	566.10	-	14 901.6	14 901.6
Total	334.94	3482.80	3817.74	17 383.0	100 576.1	117 959.1

Table 2.37. Numbers of wells and kilometers drilled by exploration sub-region in the Arctic Islands OGP.

	Arctic Platform	Coastal Plain	Fold belt	Sverdrup Basin	Total
Number of wells					
1962	1	-	-	-	1
1963	-	-	1	-	1
1964	-	-	1	-	1
1969	-	-	-	3	3
1970	-	-	1	4	5
1971	2	-	4	9	15
1972	4	2	-	14	20
1973	2	5	3	13	23
1974	2	2	6	13	23
1975	4	-	2	8	14
1976	-	2	5	5	12
1977	-	-	5	3	8
1978	-	-	4	5	9
1979	3	-	-	7	10
1980	-	-	-	5	5
1981	-	-	1	4	5
1982	1	-	-	4	5
1983	-	-	-	4	4
1984	-	-	-	4	4
1985	-	-	-	3	3
1986	-	-	-	2	2
1987	-	-	1	-	1
Total	19	11	34	110	174
Kilometers drilled					
1962	3.823	-	-	-	3.823
1963	-	-	1.475	-	1.475
1964	-	-	3.048	-	3.048
1969	-	-	-	5.951	5.951
1970	-	-	1.562	10.814	12.375
1971	4.034	-	12.328	24.802	41.164
1972	6.749	6.857	-	38.120	51.726
1973	7.060	12.462	7.664	33.756	60.941
1974	3.503	6.456	16.479	37.638	64.076
1975	10.801	-	6.828	19.353	36.982
1976	-	5.007	18.534	6.375	29.915
1977	-	-	17.519	5.184	22.702
1978	-	-	14.383	9.684	24.067
1979	8.786	-	-	18.057	26.843
1980	-	-	-	12.661	12.661
1981	-	-	3.220	8.192	11.412
1982	3.512	-	-	9.342	12.854
1983	-	-	-	12.563	12.563
1984	-	-	-	12.888	12.888
1985	-	-	-	6.185	6.185
1986	-	-	-	4.940	4.940
1987	-	-	3.176	-	3.176
Total	48.267	30.781	106.215	276.505	461.768

Table 2.38. Oil and gas discoveries in the Arctic Islands OGP.

Field	Exploration sub-region	Location	Oil, million bbl		Gas, billion cu. ft		Year
			Recoverable	Cumulative production	Remaining reserves	Cumulative remaining reserves	
Bent Horn	Arctic Fold Belt	Onshore	2.84	2.84	0.00	0.00	1974
Drake Point	Sverdrup Basin	Onshore	0.00	0.00	5 369.00	0.00	1969
Hecla	Sverdrup Basin	Offshore	12.05	0.00	3 720.00	0.00	1972
Whitefish	Sverdrup Basin	Offshore	0.00	0.00	2 131.00	0.00	1979
Kristoffer	Sverdrup Basin	Onshore	0.00	0.00	1 107.00	0.00	1972
Jackson Bay	Sverdrup Basin	Offshore	0.00	0.00	1 074.00	0.00	1976
Thor	Sverdrup Basin	Onshore	3.00	0.00	715.00	0.00	1972
Cape Allison	Sverdrup Basin	Offshore	44.50	0.00	614.00	0.00	1985
Maclean	Sverdrup Basin	Offshore	48.75	0.00	604.00	0.00	1981
King Christian	Sverdrup Basin	Onshore	0.00	0.00	588.00	0.00	1971
Roche Point	Sverdrup Basin	Offshore	0.00	0.00	427.00	0.00	1978
Char	Sverdrup Basin	Offshore	3.00	0.00	377.00	0.00	1980
Skate	Sverdrup Basin	Offshore	29.00	0.00	221.00	0.00	1981
Cisco	Sverdrup Basin	Offshore	175.20	0.00	204.00	0.00	1981
Wallis	Sverdrup Basin	Onshore	0.00	0.00	98.00	0.00	1973
Macmillan	Sverdrup Basin	Offshore	0.15	0.00	76.00	0.00	1983
Sculpin	Sverdrup Basin	Offshore	0.00	0.00	58.00	0.00	1982
Baleana	Sverdrup Basin	Offshore	16.45	0.00	0.00	0.00	1980
Total			334.94	2.84	17 383.00	0.00	

wells, 34 occur offshore and 140 onshore (Figure 2.61). Almost two-thirds occur within the Sverdrup Basin (Figure 2.62), reflecting the high prospectivity (and early drilling success, Table 2.38) of this exploration sub-region relative to the other three. In fact, of the 29 wells drilled in the 1980s, only three were not located in the Sverdrup Basin.

Offshore drilling in the deep waters of the Sverdrup Basin exploration sub-region was from thickened ice platforms – an exploration method unsuitable for development due to ice movement from year to year.

Trends in drilling activity are shown in Table 2.37, and Figures 2.61 and 2.62. The most active drilling period was from 1971 to 1975, and almost all drilling activity occurred within the 1970s and 1980s. The most recent drilling – development drilling related to the *Bent Horn* oil field – took place in the early 1990s. The increase in the number of wells drilled in the Sverdrup Basin in the 1980s may reflect the interest generated by the Polar Gas Pipeline Project or the Arctic Pilot Project (proposed projects involving feasibility studies pertaining to southward pipeline routes for Arctic gas and/or liquefaction and shipment of Arctic gas (LNG)). Neither project came to fruition. Exploration history, particularly drilling activity, has been reviewed in more detail by the NOGD (1995).

Discoveries and development

Eighteen fields were discovered in the Arctic Islands OGP from 1962 to 1985, seventeen in the Sverdrup Basin and one in the Arctic Fold Belt (Table 2.38). Of the eighteen discoveries, twelve are located offshore.

The Sverdrup Basin discoveries occurred in structural traps resulting from east-west compression during Eurekan Orogenesis with folding and faulting

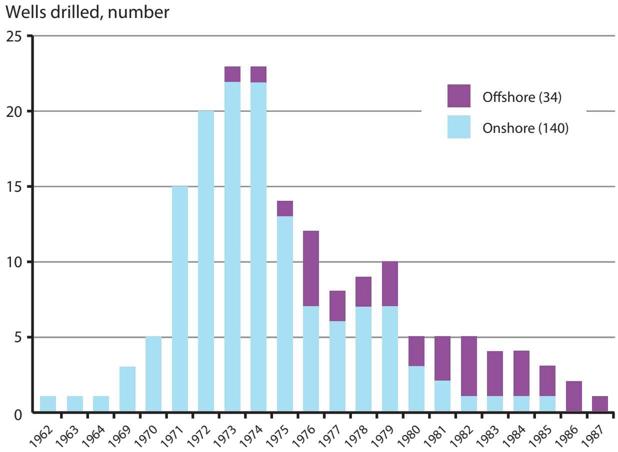


Figure 2.61. Number of wells drilled offshore and onshore in the Arctic Islands OGP over time.

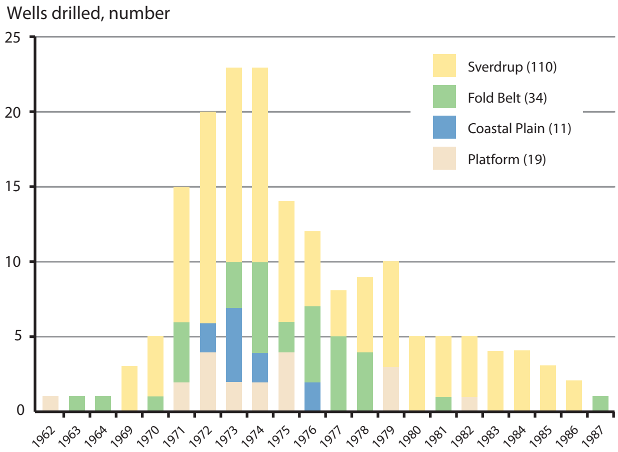


Figure 2.62. Number of wells drilled in the four exploration subregions of the Arctic Islands OGP over time.

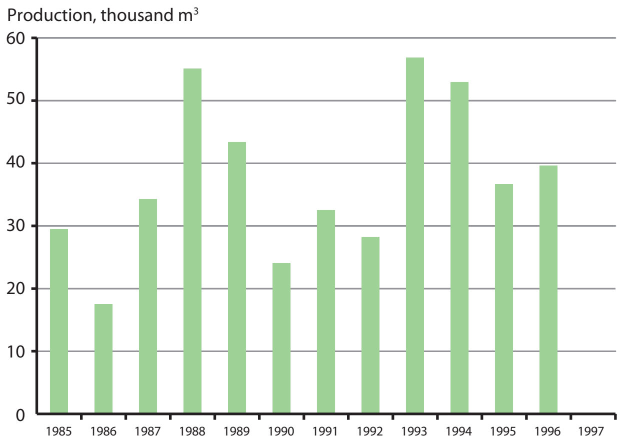


Figure 2.63. Oil production at *Bent Horn*, the only producing oil field in the Arctic Islands OGP. Production ceased in 1997 and the field was abandoned.

of the younger sedimentary succession above diapiric deformation of Carboniferous evaporites (Embry et al., 1991). Several clastic units within the Cretaceous, Jurassic and Triassic stratigraphic successions comprise the reservoirs, with the most prolific petroleum-bearing units occurring in quartzose fluvial, paludal, and shoreface sandstones of the Upper Triassic to Lower Jurassic Heiberg Group (Chen et al., 2000).

The Drake Point discovery towards the southern margin of the Sverdrup Basin is a major gas field in Triassic sandstone reservoirs. About two-thirds of the field lies onshore of the Sabine Peninsula of Melville Island. Combined discovered resources in the *Drake Point* and *Hecla* field about 50 km to the west are estimated at 2.46 x 10^{11} m^3 (8.7 trillion cu. ft) of natural gas.

The lone discovery (oil) in the Arctic Fold Belt exploration sub-region is at Bent Horn on Cameron Island. The reservoir is formed of vuggy bioclastic limestone in the upper Blue Fiord Formation of Lower Devonian age (Embry et al., 1991). The field is formed by structural trapping where an east-west trending Ellesmerian fold intersects the Lower Devonian carbonate shelf margin. Although this is the only Paleozoic discovery in the Arctic Fold Belt out of 50 wells penetrating to the Lower Paleozoic, there is still cause for optimism that similar and larger fields are likely, given the complicated structural deformation, diversity of potential reservoir and source rocks present in this exploration sub-region.

Discovered resources total 5.33 x 10^7 m^3 (335 million bbl) of oil and over 4.81 x 10^{11} m^3 (17 trillion cu. ft) of gas (Table 2.36).

The *Bent Horn* oil field is the only discovery which has been developed in the Arctic Islands OGP. Six wells were drilled into the Bent Horn pool but only one was deemed capable of production (NOGD, 1995). This well was put on production in 1985 and produced a total of 4.4 x 10^5 m^3 (2.8 million bbl) of 45° API oil until 1997 when production ceased (see Figure 2.63). Oil was produced year round and stored at the production site. Twice a year, the site was visited by the Arctic-class tanker MV *Arctic*, for loading and transportation of crude to a refinery in Montreal. The field has since been abandoned and the production site restored.

2.4.2.6.2. Future

Near-term

Oil and gas activities in the Arctic Islands OGP are currently dormant. Although opportunities to acquire new exploration rights in the Sverdrup Basin are offered annually by the Federal Government, no new commitments to explore have been taken up. Given the very large gas and oil potential of this petroleum province, the continuing high price of natural gas, and the tight supply/demand balance in the North American market, renewed interest in Arctic Islands gas is likely, perhaps following the establishment of gas production from the western Canadian Arctic (Mackenzie Delta).

Production from the Arctic archipelago offers marine transport alternatives to pipeline construction (oil from *Bent Horn* was transported by tanker). Similarly, scenarios for natural gas production from *Drake Point* and *Hecla* include LNG or compressed natural gas by Arctic-class tanker, and gas to liquids technologies. There are no projects currently planned; however, a research study released by the Canadian Energy Research Institute (Chan et al., 2005) suggested that under strong and sustained commodity prices, such projects could become economically feasible within the next fifteen years. Changing ice patterns in the High Arctic may facilitate (or continue to hinder) year-round tanker transport from this region.

2.4.2.7. Eastern Arctic OGP

2.4.2.7.1. Historical to present

Pre-exploration

Two exploration sub-regions are recognized in the Eastern Arctic OGP: Baffin Bay / Davis Strait and Lancaster Basin (Table 2.27). The margin of Baffin Bay and Davis Strait forms a continuous continental shelf, about 1400 km long, 50 km wide off northeast Baffin Island and up to 125 km in width off southeast Baffin Island. The shelf is underlain by up to 6 km of Cretaceous and Tertiary sediments overlying Precambrian basement and Mesozoic oceanic crust (Hea et al., 1980; Rice and Shade, 1982; MacLean et al., 1990). Extensive Mesozoic basement-faulting has dissected the shelf succession into depocenters favorable for accumulation of fluvial to marginal marine clastic reservoir deposits.

Lancaster Basin, at the north end of Baffin Bay is an east-west orientated Mesozoic rift basin, containing Cretaceous/Tertiary sediments up to 8 km thick, that thin eastward to less than 2 km due to an underlying 'basement' high (Sherard Ridge) at the entrance to Baffin Bay. Continuing eastward, the Mesozoic sediment thickens dramatically (up to 14 km) in Baffin Bay (Hea et al., 1980). The NOGD (1995) pointed out that Lancaster Basin is similar in size and sedimentary succession to the North Sea Viking Graben; a prolific hydrocarbon-bearing basin.

The most tenuous potential numbers in this assessment are those for the Eastern Arctic OGP (Table 2.39). No assessment was given for the Eastern Arctic by the CGPC (2001). Procter et al. (1984) estimated ultimate gas and oil potentials (average expectation) at 2.69 x 10^{11} m^3 (9.5 trillion cu. ft) and 55 x 10^6 m^3 (345 million bbl), respectively. These values are comparable to those presented here; differences are the result of statistical manipulation rather than a reassessment of the petroleum geology (Table 2.39).

Table 2.39. Ultimate petroleum resources of the Eastern Arctic and Hudson Platform Petroleum OGPs.

	Recoverable oil, million bbl			Recoverable gas, billion cu. ft		
	Discovered	Undiscovered	Ultimate	Discovered	Undiscovered	Ultimate
Eastern Arctic						
Lancaster Basin	-	96.0	96.0	-	3 700.0	3 700.0
Baffin Bay/ Davis Strait	-	312.0	312.0	2300.0	7 736.0	10 036.0
Total	-	408.0	408.0	2300.0	11 436.00	13 736.0
Hudson Platform						
Hudson Bay Basin	-	419.3	419.3	-	3 422.3	3 422.3
Foxe basin	-	83.0	83.0	-	331.8	331.8
Hudson Strait/ Southampton Basin	-	150.0	150.0	-	985.2	985.2
Total	-	652.3	652.3	-	4 739.3	4 739.3
Labrador Shelf	-	843.0	843.0	4245.1	28 295.0	32 540.1

Exploration

There are no current oil and gas leasing activities in Canadian waters of the Eastern Arctic north of 60° N.

One significant discovery license (SDL5, 11184 ha) maintains rights to the Hekja O-71 discovery offshore southeastern Baffin Island, until such a time as this field becomes economic to develop.

There are no exploration licenses current in this region. The most recent activity related to Exploration license EL297 in Lancaster Sound (between Devon Island and Bylot Island). This reached term in 2007 and has expired. Certain oil and gas lands are also held in this area under permits issued in the 1970s; these are not currently active and would need to be re-negotiated into modern tenure instruments for exploration to proceed.

Seismic activities

Since 1960, a total of 23 164 km of 2-D seismic line data have been collected offshore in the Eastern Arctic. These data were all collected in the 1970s and early 1980s.

Drilling

Only five wells have been drilled in the Eastern Arctic OGP, all in the Baffin Bay / Davis Strait exploration sub-region off southeast Baffin Island and north of Hudson Strait (Table 2.40). All wells were drilled between 1969 and 1982.

Discoveries and development

There was one discovery out of the five exploration wells. Hekja O-71, in the Davies Strait offshore of southeastern Baffin Island, encountered gas and condensate in Paleocene conglomeratic sandstones at a depth of 3200 m (Klose et al., 1982). Klose and co-workers estimated recoverable reserves of 6.48×10^{10} m^3 (2.3 trillion cu. ft) on the basis of a single well (Table 2.39). In contrast, the CGPC estimated recoverable gas in *Hekja* at only 1.5×10^{10} m^3 (0.53 trillion cu. ft). The well was never produced.

There are no oil and gas activities in Canada's Eastern Arctic OGP at this time, with the exception of regional seismic surveys that have extended into Canadian waters from exploration programs offshore in Greenland. These surveys have extended into Canadian territory, recognizing that the petroleum basins in Davis Strait and Baffin Bay straddle both jurisdictions with significant wells drilled in Canadian waters in past decades. Development in these exploration sub-regions remains a distant possibility which awaits a major oil discovery such as might warrant development of production facilities in an offshore area swept by ice-laden currents.

2.4.2.8. Hudson Platform OGP

2.4.2.8.1. Historical to present

Pre-exploration

The Hudson Platform OGP is divided into three exploration sub-regions: Hudson Bay Basin, Foxe Basin, and Hudson Strait / Southampton Basin (Table 2.27). Hudson Platform is a large (approximately 2.5 million km^2) amalgamated Paleozoic intra-cratonic basin which is largely offshore. Foxe Basin and Hudson Bay Basin contain up to 600 m and 2000 m of Paleozoic strata, respectively. The two basins are separated by a northwest-southeast oriented rift system (the Southampton Basin / Hudson Strait linear trend) in which a thick Cretaceous clastic wedge up to 2000 m thick is preserved (NOGD, 1995). The geology of the Hudson Platform region is documented in detail by Sanford and Norris (1973), Norris (1993a,b), and Sanford and Grant (1998).

There are strong geological similarities between the Hudson Bay Basin and the Michigan Basin which straddles parts of the northeastern United States and southern Ontario. Although there has been much development in the latter, the nature of the oil and gas plays suggests that analogous targets in remote offshore areas such as Hudson Bay would be uneconomic to develop. However, rich oil-source rocks are known from both Hudson Bay and Foxe Basins which may merit further exploratory studies.

The undiscovered resource potential of the Hudson Platform OGP was estimated by Procter et al. (1984) to be 90×10^9 m^3 (3.2 trillion cu. ft) of gas and 130×10^6 m^3 (820 million bbl) of oil. Sanford and Norris (1973) gave in-place estimates of 3.85×10^{11} m^3 (13.6 trillion cu. ft) and 3.66×10^8 m^3 (2.3 billion bbl) which roughly equate to 3.11×10^{11} m^3 (11 trillion cu. ft) and 95×10^6 m^3 (600 million bbl) recoverable. These estimates compare favorably with those in Table 2.39 (except for the recoverable gas estimate of 11 trillion cu. ft, which appears optimistic).

Table 2.40. Drilling activity in the Eastern Arctic and Hudson Platform OGPs.

	Location	Latitude	Longitude	Total depth, m	Year
Eastern Arctic					
Akpatok Island F-26	Offshore	60.424° N	68.337° W	371	1969
Ralegh N-18	Offshore	62.300° N	62.549° W	3858	1982
Hekja O-71	Offshore	62.181° N	62.980° W	4566	1979
Gjoa G-37	Offshore	62.941° N	59.109° W	3998	1979
Rowley N-14	Onshore	69.066° N	79.063° W	512	1971
Hudson Platform					
Narwhal South O-58	Offshore	58.133° N	84.134° W	1323	1974
Polar Bear C-11	Offshore	58.501° N	86.788° W	1576	1974
Hudson Walrus A-71	Offshore	58.501° N	87.180° W	1197	1974
Beluga O-23	Offshore	59.215° N	88.558° W	2215	1985
Netsiq N-01	Offshore	59.847° N	87.517° W	1040	1985

Exploration

There are no current oil and gas leasing activities in the Hudson Platform OGP.

The period 1968 to 1970 saw extensive permitting in Hudson Bay, Hudson Strait, and Foxe Basin. Three unsuccessful wells were drilled on these leases. By the end of 1980, some permits in the central part of Hudson Bay had been grouped into leases. Elsewhere, most permits had been surrendered with the exception of some areas in the northern part of the bay. In 1981, a large exploration agreement was issued covering much of the central part of Hudson Bay. The two wells drilled on these lands were also unsuccessful. The exploration license was subsequently surrendered and no significant discovery licenses issued.

A few residual permits remain in northern Hudson Bay near Southampton Island; these would need to be renegotiated into modern exploration licenses should interest in the basin revive. The Federal Government has no immediate plans to issue calls for industry to nominate lands in this region.

Seismic activities

Seismic work began in this area in the mid-1970s and in the central Hudson Bay from 1982 to 1984. A total of 42 736 km of seismic line data were acquired. There has been no recent activity.

Drilling

One well was drilled on Akpatok Island in Hudson Strait in 1969 and one in Foxe Basin on Rowley Island in 1970. Five offshore wells have been drilled in Hudson Bay Basin: three in 1974 and two in 1985 (Table 2.40).

Discoveries and development

All four wells in the Hudson Bay Basin were unsuccessful; no promising hydrocarbon shows were encountered in any of the boreholes.

There is no current activity being conducted by the oil and gas sector in the Hudson Platform OGP. Although oil-prone source rocks are present, and lower Paleozoic carbonates with reservoir potential are present throughout the basin, other petroleum provinces of northern Canada with substantial hydrocarbon resources already proven are likely to see development before exploration resumes in the Hudson Platform OGP.

The Michigan Basin is a petroleum province that shares many similarities with the Hudson Platform and contains many discoveries both of oil and gas in Paleozoic platform carbonates. Field sizes in the Michigan Basin are relatively small, and so there is an expectation of relatively small discoveries in the Hudson Platform. Moreover, this region is predominantly offshore and more remote, raising costs and discouraging exploration for potentially modest rewards.

2.4.2.9. Labrador Shelf OGP

2.4.2.9.1. Historical to present

Pre-exploration

The Labrador Shelf OGP extends from the most eastward extension of the Labrador coast in the south to Hudson Strait in the north, and covers the continental shelf seaward from the shore zone to the 400 m isobath. The shelf is underlain by up to 3000 m of Cretaceous/Tertiary clastic strata overlying Ordovician carbonates and Precambrian basement (Bell et al., 1989; Bell and Campbell, 1990). Extensive horst-graben basement faulting, which occurred during Cretaceous time, initiated clastic sedimentation that filled the 'lows' and blanketed the 'highs' with fluvial and marine sediments. A thick prograding Upper Cretaceous to Lower Tertiary clastic wedge, containing several potential reservoir sandstones, was deposited. The thick sequence is dominated by organic-rich shales which serve as both source rocks and seals.

Overall resource potential for the Labrador Shelf OGP has been estimated by the CGPC (2001), Canada-Newfoundland Offshore Petroleum Board (CNOPB), Drummond (2002a,b), and Procter et al. (1984). The value for the ultimate potential for gas in Table 2.39, 9.20 x $10^{11}m^3$ (32.5 trillion cu. ft), which includes an undiscovered volume of 8.01 x $10^{11}m^3$ (28.3 trillion cu. ft), is consistent with that of the CNOPB, but the CGPC – excluding conceptual plays – gave a much lower value (CGPC, 2001) of around 2.55 x $10^{11}m^3$ (9 trillion cu. ft). The CGPC value is considered conservative for the potential of this basin.

Exploration

By 1971, exploration rights to most of the continental shelf offshore in Labrador were held under permit. These were grouped into leases, and by 1983 into exploration agreements. Gradual relinquishment and ultimately surrender of exploration agreements during the 1970s and early 1980s resulted in most exploration lands returning to the Crown. A few petroleum rights continue to exist offshore as significant discovery licenses. These maintain rights indefinitely to five gas and gas condensate discoveries offshore in Labrador until such time as the fields become economic to develop.

There has been no recent industry response to calls by the CNOPB for interest in the offshore Labrador exploration sub-region within the AMAP study area.

Seismic activities

Geophysical activity began on the Labrador Shelf with a 14 000 km aeromagnetic survey by Tenneco in 1966. Since 1968, the industry has acquired over 75 000 km of seismic reflection data. Most of the seismic surveys were conducted in the 1970s.

Drilling

Twenty-eight wells were drilled on the Labrador Shelf from 1971 to 1983 (Table 2.41). There has been no more recent drilling.

Discoveries and development

Five fields were discovered from the drilling of 28 exploration wells (Table 2.41). The Labrador Shelf discoveries at Bjarni, North Bjarni, and Hopedale occur in the Lower Cretaceous Bjarni Formation sandstones which form traps in onlap and sedimentary drape attitudes over high-standing basement fault blocks. The Gudrid discovery occurs as a gas condensate pay zone in Paleozoic dolomitized carbonate situated at the tilted crest of a horst block. The reservoir in the *Snorri* field occurs in a Paleocene sandstone trap resulting from onlap and drape over a raised basement fault block. Paleozoic carbonates also form a second reservoir zone in the *Hopedale* field (Bell and Campbell, 1990).

No recoverable oil volumes were encountered in the five Labrador Shelf discoveries, but the total recoverable gas volume is estimated to be 1.20 x $10^{11}m^3$ (4.25 trillion cu. ft) (Table 2.42).

2.4.2.9.2. Future

Near-term

There has been no hydrocarbon exploration activity on the Labrador Shelf since the early 1980s. Since 1983, the only exploration activities undertaken on the Labrador Shelf are reported to have been non-exclusive 2-D geophysical

Table 2.41. Drilling of exploration wells in the Labrador Shelf OGP.

	Location	Latitude	Longitude	Total depth, m	Year
Leif E-38	Offshore	54.292° N	55.097° W	1084.2	1971
Leif M-48	Offshore	54.296° N	55.121° W	1879.1	1973
Bjarni H-81	Offshore	55.508° N	57.701° W	2514.6	1973
Gudrid H-55	Offshore	54.908° N	55.875° W	2838.0	1974
Freydis B-87	Offshore	53.937° N	54.710° W	2314.1	1975
Snorri J-90	Offshore	57.329° N	59.961° W	3209.9	1975
Karlsefni A-13	Offshore	58.871° N	61.777° W	4149.0	1976
Indian Harbour M-52	Offshore	54.364° N	54.397° W	3958.2	1976
Cartier D-70	Offshore	54.651° N	55.674° W	1927.0	1975
Cabot G-91	Offshore	59.840° N	61.733° W	289.9	1976
Herjolf M-92	Offshore	55.532° N	57.747° W	4086.2	1976
Verrazano L-77	Offshore	52.444° N	54.197° W	459.9	1976
Skolp E-07	Offshore	58.440° N	61.768° W	2992.0	1978
Hopedale E-33	Offshore	55.874° N	58.847° W	2069.4	1978
Roberval K-92	Offshore	54.860° N	55.742° W	3874.0	1979
Tyrk P-100	Offshore	55.497° N	58.230° W	1739.0	1979
Bjarni O-82	Offshore	55.530° N	57.709° W	2650.0	1979
Gilbert F-53	Offshore	58.874° N	62.139° W	3608.0	1980
Roberval C-02	Offshore	54.852° N	55.767° W	2823.0	1980
South Labrador N-79	Offshore	55.813° N	58.441° W	3571.0	1980
Ogmund E-72	Offshore	57.525° N	60.443° W	3094.0	1980
North Leif I-05	Offshore	54.411° N	55.252° W	3513.0	1981
North Bjarni F-06	Offshore	55.592° N	57.763° W	2812.0	1981
Rut H-11	Offshore	59.171° N	62.279° W	4474.0	1983
Corte Real P-85	Offshore	56.080° N	58.202° W	4395.0	1983
Pothurst P-19	Offshore	58.815° N	60.525° W	3992.0	1983
Pining E-16	Offshore	54.756° N	55.046° W	573.0	1983
South Hopedale L-39	Offshore	55.809° N	58.846° W	2364.0	1983

Table 2.42. Oil and gas discoveries in the Eastern Arctic and Labrador Shelf OGPs.

		Location	Oil, million bbl		Gas, billion cu. ft		Year
			Recoverable	Cumulative production	Remaining reserves	Cumulative remaining reserves	
Hekja	Eastern Arctic	Offshore	0.00	0.00	2300.0	0.0	1979
North Bjarni	Labrador Shelf	Offshore	0.00	0.00	2246.8	0.0	1981
Gudrid	Labrador Shelf	Offshore	0.00	0.00	922.8	0.0	1974
Bjarni	Labrador Shelf	Offshore	0.00	0.00	862.5	0.0	1973
Hopedale	Labrador Shelf	Offshore	0.00	0.00	106.5	0.0	1978
Snorri	Labrador Shelf	Offshore	0.00	0.00	106.5	0.0	1975
Total			0.00	0.00	6545.1	0.0	

surveys in 2003 and 2004 CAPP (2005b), both by seismic acquisition company Geophysical Services Inc. and totaling 1148 km and 8907 km, respectively. Nevertheless, exploration drilling carried out prior to 1983 indicates the occurrence of significant gas resources offshore, sufficient to support development. The Labrador Shelf, however, is only accessible for a short period of the year despite the fields being relatively close to shore (75 km) (Chipman, 1997). Cold-climate technology involving floating platforms and seasonal production will need to be considered. Development of the Labrador Shelf gas resources is not expected to occur until well into the 21st century (Chipman, 1997).

2.4.2.10. Unconventional resources

Northern Canada's unconventional hydrocarbon resources are unlikely to be of major significance for several decades. They are relatively inaccessible and more expensive to develop than conventional resources, and some cases remain unproven from the viewpoint of commercial production.

Oil shale deposits are known to occur in Ordovician strata on Southampton Island, and in Cretaceous strata in the southern Mackenzie Delta /Anderson Plains region (Macauley, 1981), and oil sands in Triassic strata on Melville Island were reported by Trettin and Hills (1996). However, the development potential of such occurrences must be viewed against the vast bitumen resource in the Athabasca Oil Sands region of northeast Alberta which are the largest such deposits in the world. Synthetic crude oil derived from Alberta bitumen upgrading is expected to become Canada's major source of oil supply in future decades (NEB, 2003). Future oil exported from the Canadian Arctic will almost certainly be from conventional accumulations.

Unconventional gas resources comprise coal-bed methane, tight gas sands, gas hydrates, and gas shales (a summary of unconventional gas is available at www.centreforenergy.com). Of these, coal deposits containing coal-bed methane, and gas hydrates are known to occur extensively in parts of the Canadian Arctic. Tight gas and gas shales also occur and may be developed in certain areas in concert with conventional production as infrastructure is developed, such as in the southern NWT.

2.4.2.10.1. Coal-bed methane

Coal measures abound through much of the Tertiary, Mesozoic, and Carboniferous successions in the intermontane basins of the Yukon, and also in the foreland basin deposits of the mainland NWT (Cameron, 1993). Cameron summarized fifteen stratigraphic occurrences of extensive coal beds, four of which are estimated to contain over 590 million tonnes of mostly high-volatile bituminous rank.

Coal deposits also occur extensively throughout the Arctic Islands, ranging in age from Late Devonian to Late Tertiary (Bustin and Miall, 1991). Bustin and Miall estimated total coal resources to be in the order of 51 000 million tonnes, with most occurring in Tertiary strata of the Sverdrup Basin. About 80% is lignitic to sub-bituminous, with the remaining 20% high-volatile bituminous.

Given the large quantities of high-rank coal, production of coal-bed methane in Canada's north appears technically feasible. To date, however, coal-bed methane has not been pursued as a potential source of natural gas north of 60° N. Significant levels of production are probably a distant proposition, although projects for local use or for specific industrial operations may be feasible depending on location.

2.4.2.10.2. Gas hydrates

Gas hydrates are frozen crystalline solids comprising gas and water molecules. Mainly comprising methane, these are very concentrated forms of energy containing 164 times their solid volume of natural gas upon dissociation. Hydrates form from natural gas and water under particular conditions of temperature and pressure and dissociate as either of these increase beyond the bounds of the stability field.

Gas hydrates also occur extensively worldwide in deep water on the continental slopes. In the Canadian Arctic hydrates also occur beneath permafrost where this is of sufficient thickness to depress temperatures at depths where pressures are high enough for hydrate formation.

In the Mackenzie Delta / Beaufort Basin OGP hydrates occur below thick permafrost at depths of several hundred meters. Natural Resources Canada has established a major initiative – the Natural Gas Hydrates Project – to investigate their potential as a new energy source. The impetus for this project resulted from an international consortium which was formed to investigate continental gas hydrates in the Mackenzie Delta. The consortium chose the *Mallik* field site (where Imperial Oil Ltd encountered hydrates in a 1971–72 exploration well) to drill a 1150 m deep research well in 1998 from which the first ever terrestrial gas hydrate cores were collected.

Following this beginning, 'Mallik 2002', a CAD 25 million international program led by Natural Resources Canada and involving scientists from Canada, the United States, Japan and Germany, was initiated. The aims were to evaluate the technical, economic, and environmental viability of gas hydrate production (Dallimore et al., 2003, 2004). Three research wells were drilled: two observation wells and one gas hydrate production well (Dallimore et al., 2004). The gas hydrate well cored and recovered gas hydrates over a depth interval of 880 to 1150 m. Various geochemical and microbiological analyses were undertaken on the cored hydrates and sediments. Thermal heating and depressurization procedures were conducted as part of controlled production experiments which could eventually lead to development of simulation models for predicting long-term reservoir response.

A potentially large natural gas resource is thought to be present in Mackenzie Delta hydrates; a minimum in-place volume of 2.4 x 10^{12} m^3 has been estimated by Majorowicz and Osadetz (2001). These hydrates are of interest because they overlie or are near to conventional gas fields proposed for the Mackenzie Gas Project and subsequent development on the Mackenzie Delta. This co-location may create a future opportunity to supplement the production of gas from conventional fields in the Mackenzie Delta with gas derived from hydrates.

Risk factors for hydrate production include unproven technology, many remaining uncertainties as to distribution and production qualities of hydrate-rich deposits, and potential environmental concerns related to the shallow production depths.

The Council of Canadian Academies has examined the challenges for an acceptable operational extraction of gas hydrates in Canada (Council of Canadian Academies, 2008). The report describes the state of knowledge on the distribution of hydrates and their resource potential. In particular, the Council noted that, despite uncertainties surrounding gas hydrates as an economic resource, well testing at the Mallik site on the Mackenzie Delta successfully demonstrated proof-of-concept for gas production from gas hydrate by depressurization.

2.4.3. Greenland

2.4.3.1. Regulatory and legislative systems relevant to Arctic oil and gas activities in Greenland

Hydrocarbon activities in Greenland are regulated by the Danish Parliamentary Act, Order no. 368 of June 18, 1998 on the Act on Minerals Resources in Greenland (the Mineral Resources Act). The Joint Committee on Mineral Resources in Greenland (the Joint Committee) follows the development within the field of mineral resources in Greenland. The Joint Committee comprises an equal number of politicians from Greenland and Denmark, and a chairman directly appointed by the Queen of Denmark following nomination by the governments of Greenland and Denmark for periods of four years. The principal tasks of the Joint Committee are to follow mineral-resources developments in Greenland and to submit recommendations to the governments of Denmark and Greenland, both on matters of principle and on the granting of prospecting, exploration and exploitation licenses or amendments to such licenses. The Joint Committee can also submit statements to the two governments on other matters concerning mineral resources in Greenland.

In accordance with the recommendation of the Joint Committee on Mineral Resources in Greenland, in June 2003 the Government of Greenland and the Danish Government approved a new strategy concerning exploration and exploitation of hydrocarbons in Greenland.

The incentive to prepare a new hydrocarbon strategy was principally that most of the objectives of the hydrocarbon strategy adopted in 1999 had been achieved, not least the acquisition and compilation of a greatly enlarged body of seismic and other geophysical data offshore in West Greenland. This resulted in a license round in part of this region and the award of a new exploration license in the area in 2002.

There is broad political consensus in Greenland that efforts should be made to develop the mineral resources sector into a sustainable industry that can make a positive contribution to the economic development of the country and the creation of new jobs. This goal is an important element in the long-term economic policy, which aims at supporting the development of industries other than fishing, with a view to reducing Greenland's present heavy dependence on yearly appropriations from Denmark.

The development of the hydrocarbon sector must proceed in a way that is of the greatest possible benefit to the Greenlandic society. This society must be assured of a reasonable share of the profits accruing from the exploitation of hydrocarbons, just as local communities must be assured of insight and information concerning hydrocarbon activities, in order among other things that the local work force and local firms are involved to the greatest possible extent.

A clear political condition for all activities related to the development of mineral resources in Greenland, not least exploration for and exploitation of hydrocarbons, is that these activities must be carried out with due regard for safety and the environment. The Arctic environment is very vulnerable, and Greenland's economic life and culture are closely bound to nature and the environment.

It is thus with a view to increasing income and employment that hydrocarbon activities will be encouraged. However, if discoveries are to be made that can be exploited, it is necessary that exploration activity is maintained at a sufficiently high level. The central aim of the strategy is therefore to provide a competitive framework in order to generate not only industry interest but also a willingness to invest in petroleum exploration in Greenland.

2.4.3.2. Historical to present

2.4.3.2.1. Pre-exploration

Exploration for hydrocarbons in the maritime area offshore in West Greenland began at the beginning of the 1970s. Over the following years, five exploration wells were drilled in areas with moderate water depths, but only in one well, Kangâmiut-1, were traces of hydrocarbons found.

In 1992, the Geological Survey of Denmark and Greenland (GEUS) discovered oil seeps on the southwestern side of Nuussuaq Peninsula, and in the following years seeps were recorded over a wide area extending from northern Disko through Nuussuaq to the southern part of Svartenhuk Peninsula (70°–71°30′ N). In 1996, the Canadian company GrønArctic Energy Inc. drilled an exploration well on Nuussuaq Peninsula in which traces of hydrocarbons were found.

In 2000, a group led by Statoil drilled an exploration well offshore in central West Greenland. Even though the well, Qulleq-1, did not strike hydrocarbons, it provided much new information of importance for the planning of future exploration activities.

In the period 1999–2002, commercial geophysical companies acquired extensive new speculative seismic data offshore in West Greenland in preparation for the 2002 and 2004 license rounds and anticipated later rounds.

The recently acquired seismic data have revealed the existence of hitherto unknown sedimentary basins offshore in West Greenland (Figures 2.64 and 2.65). A provisional integrated evaluation of seismic, gravity, and magnetic data has indicated the presence of an interconnected basin system along the so-called Ungava Fracture Zone. This basin system may link the petroleum-prospective areas off Labrador on the east coast of Canada with the observed oil seeps on Disko and Nuussuaq.

It is anticipated that the announcement of a license round in Greenland will draw attention to the hydrocarbon potential of the areas on offer. Furthermore, it is expected that the announcement of a coming license round will provide an incentive for seismic companies to acquire new data for use by oil companies in their assessment of the area.

In Greenland, an open-door procedure, allowing for applications for licenses to be made at any time, will still be used for less attractive areas which are unlikely to attract competitive bids. The open-door procedure is used in areas with a scant cover of seismic data or areas where promising geological structures have not yet been observed.

2.4.3.2.2. Exploration

West Greenland between ca. 63° and 69° N

Acquisition of more than 24 000 km of seismic lines in the period 1999–2002 was focused mainly on providing a broad regional cover of the sedimentary basins and structures offshore in southern West Greenland, together with a more detailed grid in the former license areas Fylla

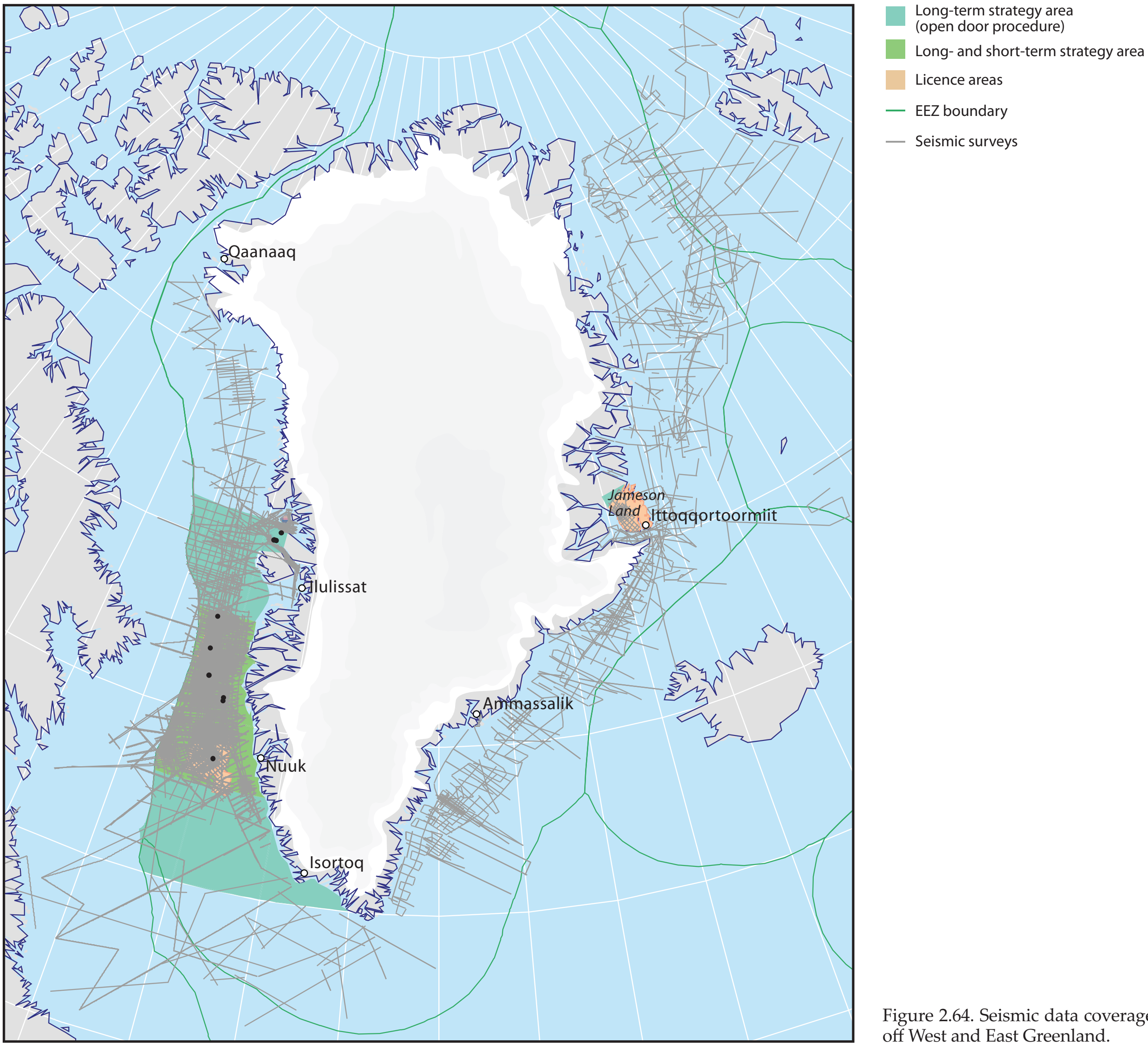


Figure 2.64. Seismic data coverage off West and East Greenland.

and Sisimiut-West. In all, more than 77 000 km of new data have been acquired off West Greenland since 1990.

The areas with thick sedimentary basins offshore in central West Greenland extend over a total area of more than 130 000 km^2, a large part of which is expected to have a considerable petroleum potential. Within these areas several different leads and prospects have been identified, some with a potential for giant hydrocarbon discoveries.

West Greenland between ca. 69° and 71° N

Data coverage in the offshore area between about 69° N and the southern boundary of the KANUMAS preference area at about 71° N has been improved in recent years, not least in connection with seismic acquisition in the years 2000–2002 and 2005. A provisional evaluation of data acquired in this area in 2002 was undertaken in April 2003, and indicated some very large potential trap structures in parts of the area. It is expected that the discovery of these very large structures in an area with known active oil seeps onshore will increase industry interest in this area, both offshore and onshore.

Southwest Greenland (south of ca. 63° N)

Data coverage offshore in southwest Greenland is still sparse, and so there is limited knowledge about the subsurface geology. Furthermore, the area is characterized by difficult operative conditions, chiefly due to deep water. However, basins and structures observed north of 63° N appear to continue southward and so the Bureau of Minerals and Petroleum in co-operation with the geophysical company TGS-NOPEC has acquired nearly 2000 km of new seismic data in the area between 62° and 63° N which, combined with data from the early 1990s, provide improved cover in this area. In the area between 62° and 63° N, there are some interesting basins and structures. However, there is still a need for more knowledge about the area as a whole before it is mature enough for inclusion in a license round.

Other areas

In 2006 and 2007, seismic and aeromagnetic data were acquired by the industry in northwest and northeast Greenland.

During 2006 and 2007, there was a positive dialogue with the so-called KANUMAS companies, concerning future plans for hydrocarbon exploration in the areas offshore in northeast and northwest Greenland. The KANUMAS consortium is a group of companies which, against the background of considerable exploration-obligations in the past, has a special preferential position.

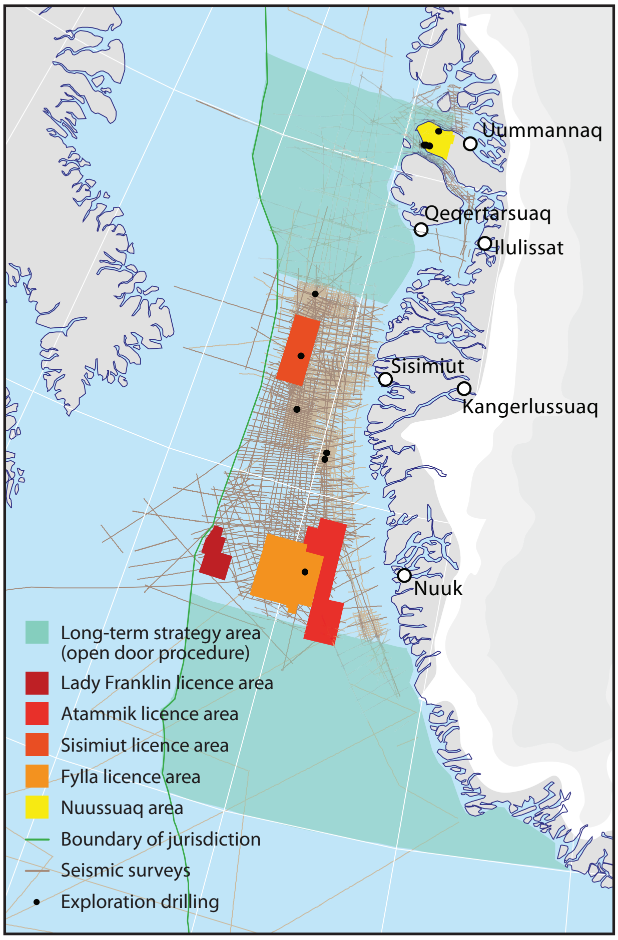


Figure 2.65. Detail of seismic data coverage off West Greenland.

This preferential position will be activated if the right to hydrocarbon exploration in northeast and northwest Greenland is put up for licensing. In this connection the Bureau of Mines and Petroleum (BMP) hosted a meeting in Copenhagen on 5 December 2007 which focused on the ice, climate and environmental conditions in the KANUMAS areas. Representatives from all the KANUMAS companies and other interested companies were present at the meeting. The KANUMAS consortium comprises BP, Chevron, ExxonMobil, JOGMEC, Shell, StatoilHydro and NUNAOIL.

A final strategy for hydrocarbon exploration in the KANUMAS areas will be presented by the end of 2008.

No significant industry interest in commercial exploration is expected in the near future for all onshore areas with the exceptions of the Disko-Nuussuaq area in West Greenland and Jameson Land on the east coast.

Priority areas

The hydrocarbon strategy operational in the coming years will focus mainly on areas where a regional geological evaluation and exploration to date have revealed the greatest petroleum potential and where exploration and exploitation can be carried out in a responsible manner with regard to safety and the environment. Namely, areas offshore in West Greenland between about 63° and 68° N that presently have the best data coverage and greatest exploration potential, and selected areas both onshore and offshore of central West Greenland between about 68° and 71° N where the newest data suggest a greater prospectivity than previously supposed.

Health, safety and environment (HSE) in petroleum exploration

Physical and biological environmental conditions are vitally important factors for consideration when hydrocarbon activities are initiated. From a biological perspective, the area offshore in West Greenland south of about 71° N is the most productive maritime area in Greenland (see Chapter 6). The area is important for birds and marine mammals, and most of Greenland's fishing takes place here. Since fishing has an important social and economic role, particular attention must be paid to this industry in the future development of exploration activities offshore.

Prior to the 2002 license round, an oil spill sensitivity atlas (see Chapter 6) was prepared for the coastal region of West Greenland between 62° and 68° N. This provides a substantial source of information when drawing up contingency plans for combating oil spills resulting from accidents in the area.

Licensing

2002 licensing round

In 2002, a licensing round was implemented offshore in West Greenland, covering the area between 63° and 68° N. As a result, the Canadian oil company EnCana Corporation, with Nunaoil A/S as a carried partner, obtained a new exploration and exploitation license for hydrocarbons in Greenland. The license covers 3985 km^2 in a sea area about 200 km northwest of Nuuk in West Greenland. In the western part of the area, sea depth is typically 500–1000 m, while in the eastern part it is generally 200–500 m. No wells have previously been drilled in this area.

2004 licensing round

In 2004, a licensing round was implemented offshore in West Greenland, covering four license areas, each having two or three large structures with hydrocarbon potentials. The selection of the license areas was based – through analyses of all seismic data collected in the area since 1999 – on the Bureau of Minerals and Petroleum and the Geological Survey of Denmark and Greenland being able to map a number of large geological structures in the region which may hold oil or gas. Of these, the most promising areas were selected for the licensing round. The following factors were also considered: knowledge from other geophysical surveys, for instance, gravimetric and magnetic data; new knowledge on for instance sedimentology, biostratigraphy, and organic geochemistry; satellite studies of naturally-occurring oil seepages on the surface of the sea, which may reveal possible seepage at the seabed; and mapping of areas with favorable ice conditions.

In the planning process, account was also taken of industry's views on delimitation and timing, for instance by visits to a number of large international oil companies in Europe, and a seminar for specially invited oil companies in spring 2003.

From these deliberations, four areas were selected for the 2004 licensing round, located off West Greenland, and covering a total area of 32 000 km^2 (Figure 2.65):

- parts of the Lady Franklin Basin between about 63° and 65° N, an area of around 10 500 km^2;
- the Kangaamiut Basin and the ridge west of the basin, at about 66° N, an area of around 4900 km^2;

- parts of the Ikermiut fault zone / Sisimiut Basin from about 67° to 68° N, an area of around 5600 km^2;
- parts of the Fylla area from about 63° N to about 64° N, an area of around 11 200 km^2.

The 2004 licensing round resulted in a new license for exploration and exploitation of hydrocarbons in Greenland for the Canadian oil company EnCana Corporation and Nunaoil A/S. The license covers 2897 km^2 in an offshore area about 250 km west of Nuuk, West Greenland. Geologically, the area includes part of the Lady Franklin Basin. 4500 km of 2-D seismic data have been collected in the area. Sea depths range from about 750 m in the northern part of the license area to 1750 m in the southernmost part. No wells have previously been drilled in this area.

2006 licensing round

The Home Rule Government and the Danish Government approved in January 2005, after recommendation from the Joint Committee on Mineral Resources in Greenland, that the licensing policy in the coming years, in accordance with the Hydrocarbon Strategy of 2003, shall focus on the Disko-Nuussuaq area. This is due to the initial geological evaluations for the Disko-Nuussuaq area, which point towards the possible presence of some even very large hydrocarbon reservoirs. In addition, as is well known, a series of natural oil seeps has been registered on Disko Island and the Nuussuaq and Svartenhuk peninsulas.

The BMP and the national oil company NUNAOIL A/S collected 3100 km of seismic lines west of Disko-Nuussuaq. The seismic data were collected in collaboration with the geophysical company TGS-NOPEC during summer 2005 in preparation for the coming licensing round. The results were presented for selected oil companies in spring 2006.

In addition, the BMP and the National Environmental Research Institute conducted a comprehensive environmental study that focused on the environmental consequences of oil activities in the Disko area. The study included possible impacts on fish and shrimps; measurements of natural levels of hydrocarbons; the importance of sea ice; population studies for whales, birds and walruses, and modeling of the consequences of an oil spill. A similar project has been initiated which aims to evaluate the consequences of hydrocarbon investigations for the land areas and coastal areas of the Nuussuaq peninsula.

In 2006, the Disko West Licensing Round, covering eight blocks with a total area of approximately 92 340 km^2 offshore in the Disko-Nuussuaq region of West Greenland, was implemented.

Phase 1 of the Disko West Licensing Round was opened on 18 July 2006 and finished on 15 December 2006. By the closing date the BMP had received applications from the Canadian oil company Husky, the American company ExxonMobil, and from a partnership consisting of the American company Chevron and the Danish company DONG Energy.

The results of the Disko West Licensing Round phase 1 was that Husky and NUNAOIL A/S were granted two licenses for hydrocarbon exploration and exploitation, one covering an area of 10 138 km^2 and one covering an area of 10 929 km^2. In addition, a partnership comprising Husky, ExxonMobil and NUNAOIL A/S, and a partnership comprising DONG Energy, Chevron, ExxonMobil and NUNAOIL A/S were granted licenses for hydrocarbon exploration and exploitation, covering areas of 13 213 km^2 and 13 957 km^2.

Phase 2 of the Disko West Licensing Round was opened on 1 August 2007. The deadline for oil companies wishing to apply for licenses in this phase of the licensing round was 1 February 2008. By the closing date the BMP had received three applications for the blocks on offer; one from the Swedish oil company PA Resources and two from the British company Cairn Energy plc. Two licenses have now been granted to Cairn and NUNAOIL A/S. The two licenses cover a total area of 11 063 km^2 and 11 961 km^2 respectively. The application from PA Resources is still being processed.

On 6 December 2007, the BMP hosted a meeting in Copenhagen with the participation of all licensees in the Disko West area. Scientists from the National Environmental Research Institute, the Danish National Space Centre, the Danish Meteorological Institute and the Greenland Institute of Natural Resources presented the results of their studies on the environment and ice conditions in the area.

License holders are obliged to hold Operating Committee Meetings every three months where the BMP is present. Participation at these meetings ensures that the BMP is continuously updated about the activities of the license holders.

Open-door procedure

An open-door procedure will continue to operate in areas where industry interest has been modest and data coverage is limited. Within the open-door areas, applications for licenses can be submitted at any time between 1 October and 31 May. Applications received between 1 June and 30 September will be treated as having been delivered on 1 October.

The present terms for exploration and exploitation licenses are stipulated in a model license. These include surplus royalty, carried partnership, and fees. The main economic terms are: a corporate tax of 30%; that a surplus royalty of 5% shall be paid when the internal return exceeds 25% before tax, rising to 10% and 15% when the internal return exceeds 32.5% and 40%, respectively; standard taxes and fees; and that Nunaoil A/S shall be a carried partner in the exploration phase with a share of 8%.

The open-door procedure currently encompasses the area offshore in southwest Greenland between 60° and 63° N and Jameson Land in East Greenland. The open-door areas are characterized by a low degree of data coverage and consequently a high exploration risk. Furthermore, in the offshore area the operative conditions are difficult due to relatively deep sea depths and pack ice.

On 17 August 2007, the BMP received applications for two areas in the open-door area offshore in southwest Greenland between 60° and 63° N from the British oil company Cairn Energy PLC. On 9 January 2008, Cairn, together with NUNAOIL A/S, was awarded two licenses for hydrocarbon exploration and exploitation in this area, covering a total area of 10 090 km^2 and 12 031 km^2, respectively.

The BMP has experienced a growing interest for the offshore area south of 63° N. Therefore, in December 2007, the BMP recommended to the Joint Committee on Mineral Resources in Greenland that the current open-door area between 60° and 63° N be expanded to cover the area south of 60° N. The Joint Committee approved the recommendation and the area is expected to be opened for applications during 2008.

2.4.4. Iceland

Unless otherwise stated, the information in section 2.4.4 was obtained from The National Energy Authority of Iceland (Orkustofnun) website in 2007 (www.nea.is).

2.4.4.1. Regulatory and legislative systems relevant to Arctic oil and gas activities in Iceland

Offshore hydrocarbon accumulations in the Icelandic territorial sea and exclusive economic zone (EEZ) and the Icelandic continental shelf are owned by the Icelandic State. Petroleum activities are subject to general Icelandic laws and regulations on taxation, environmental protection, health and safety. Exploration for oil and gas in Icelandic waters is regulated by an Act of the Althing (parliament) on prospecting, exploration, and production of hydrocarbons (Hydrocarbon Act of 2001 as amended in 2007). This act is based on Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorizations for prospecting, exploration and production of hydrocarbons. Other relevant EU legislation, including issues of health, safety and environment, has been adopted in Icelandic law. As Iceland has ratified the OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic and the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 (the MARPOL protocol), provisions from these conventions also apply to oil and gas activities.

The general corporate income tax in Iceland is 15%. Taxes on profits and production fees on oil operations are currently under development and taxes and fees on activities will be determined before the Northern Dreki licensing round takes place in 2009.

Iceland has an 'open door' policy for companies that are interested in obtaining non-exclusive prospecting licenses, but does not at present grant exclusive licenses of any kind. The first offering of exclusive exploration and production licenses is scheduled for January 2009 in the Northern Dreki area on the Jan Mayen Ridge.

The petroleum administration in Iceland includes the Ministry of Industry, an Interministerial Committee, the National Energy Authority, and the Iceland GeoSurvey.

A license from the Ministry of Industry is required for prospecting, exploration, and production of hydrocarbons. The Interministerial Committee on Continental Shelf Matters and Petroleum Exploration (ICCSMPE) coordinates the response of Icelandic authorities to requests from oil companies for information regarding petroleum activities, including prospecting. The National Energy Authority (Orkustofnun) is responsible for monitoring hydrocarbon prospecting, exploration, and production activities and for archiving the data generated by such activities. The Iceland GeoSurvey provides geoscientific advice to ministries and the National Energy Authority in matters regarding petroleum exploration.

The Hydrocarbon Act has provisions for two types of license: a prospecting license and an exploration and production license. Non-exclusive prospecting licenses for geophysical surveys and shallow sampling of the seafloor are issued on the basis of Rules adopted on 18 July 2001. They are granted for a maximum period of three years at a time, with a ten-year period of confidentiality.

Exploration licenses can be granted for a period of up to 12 years and extended for up to two years at a time to a maximum total duration of 16 years. Once the holder of an exploration license has fulfilled the conditions specified in the license, they will have priority for an extension of the license for production for up to 30 years. Group applications (joint ventures) are welcome. These licenses are transferable subject to official approval. Phased work programs are possible, with each phase having separate specification of rights and obligations. There is no national oil company in Iceland.

In addition to issuing licenses, the National Energy Authority also coordinates the response of Icelandic authorities to requests from oil companies for information regarding petroleum activities. Safety of operations will be monitored by the Administration of Occupational Safety and Health of Iceland (MOII, 2007).

2.4.4.1.1. The Icelandic continental shelf maritime boundaries

200 nm limit

By Regulation No. 196, 9 May 1985, Iceland extended its continental shelf to cover parts of the Reykjanes Ridge and the Hatton-Rockall area south of Iceland (Figure 2.66). The extension is based on the provisions of the United Nations Convention on the Law of the Sea (UNCLOS). Iceland obtained its full 200-nm claim towards the island of Jan Mayen. All disputes regarding the 200-nm limit in the so-called Herring Loop Hole (Banana Hole), which is enclosed by the EEZs of Iceland, Jan Mayen, Norway and the Faroe Islands, have been resolved.

Continental shelf beyond 200 nm

According to the UNCLOS, coastal States shall submit information on the outer limit of their continental shelf beyond the 200-nm limit to the Commission on the Limits of the Continental Shelf (CLCS). The Commission will issue recommendations regarding the location of the outer limit of the continental shelf. If the coastal State establishes the outer limit on the basis of the Commission's recommendations, the limit becomes final and binding. Most coastal States are now in the process of preparing their submissions to the Commission. Iceland has until 2009 to deliver its submission.

2.4.4.1.2. Maximum limits of the continental shelf

The Jan Mayen Agreement

An agreement was reached with Norway in 1981 on an area of cooperation straddling the delimitation line between the economic zones of Iceland and Jan Mayen. Within this area, each country is entitled to a 25% stake in any hydrocarbon discoveries made in the other country's part of the area. The Governments of Norway and Iceland have jointly surveyed the agreement area and put seismic data packages up for sale.

Hatton-Rockall area

Reykjanes Ridge and the Hatton-Rockall area were deemed to be natural prolongations of the Icelandic continental shelf. Iceland has not yet established the outer limits of its continental shelf in the so-called Herring Loop Hole, in the Hatton-Rockall area where three other states have also made claims to continental shelf rights: Denmark on behalf of the Faroe Islands, the United Kingdom, and Ireland. The claims of Iceland and the Faroe Islands overlap with each other and with the British and Irish claims, whereas

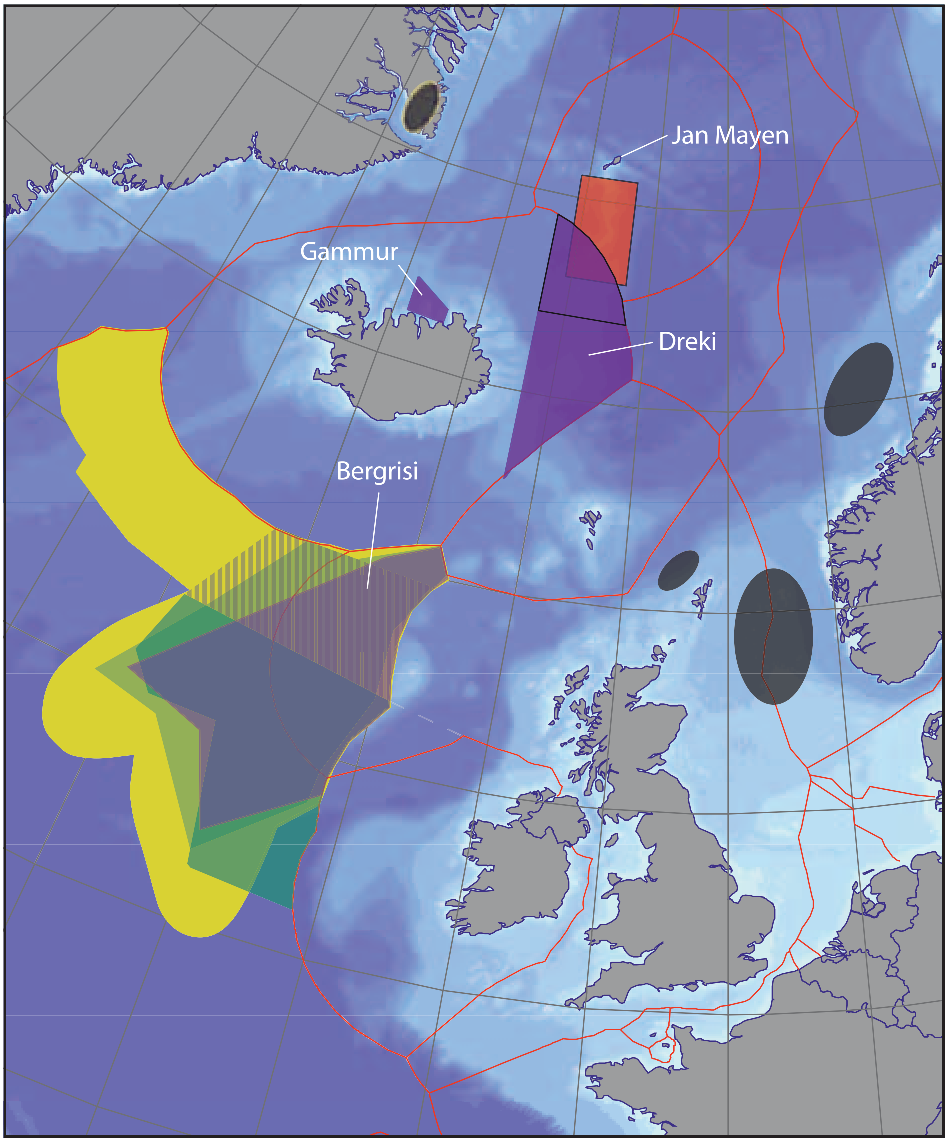


Figure 2.66. The Icelandic continental shelf showing the limits of the Exclusive Economic Zones, the extended Icelandic claim area beyond 200 nautical miles; the areas of overlapping claims by Iceland, the Faroe Islands, Ireland, and the United Kingdom; and the Jan Mayen Agreement Area. Also shown are the three areas on the Icelandic continental shelf with potential for commercial accumulations of oil and gas: Bergrisi, Gammur, and Dreki. A concession round is scheduled in 2009 for the northern Dreki area including the Icelandic part of the Jan Mayen joint development area defined in a 1981 continental shelf agreement between Iceland and Norway (Orkustofnun, 2007).

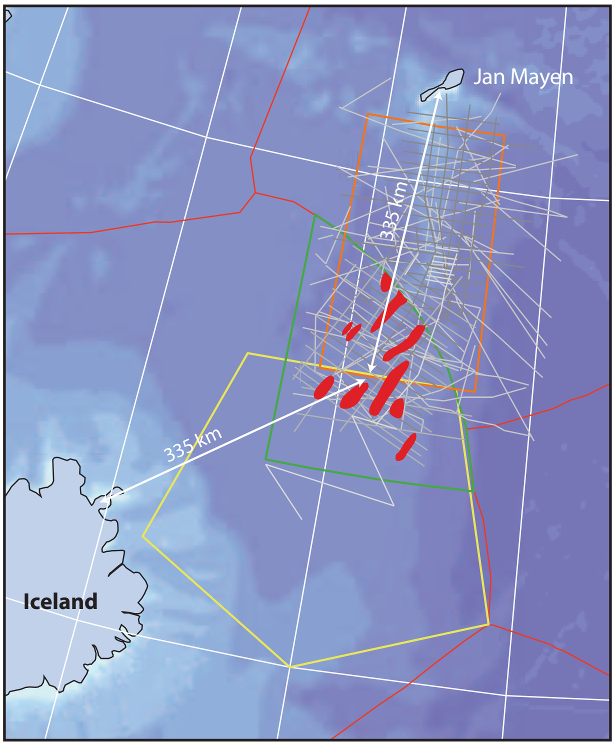


Figure 2.67. Bathymetric map of the Jan Mayen agreement area and the northern Dreki area. Water depths in the area mostly range from 1500 to 2000 m. The figure also shows recent 2-D seismic data coverage and academic and research surveys in the Jan Mayen area; license areas for 2-D seismic data surveys by InSeis/Wavetech and TGS-NOPEC; and areas with potential hydrocarbon traps (Orkustofnun, 2007 and references therein).

the UK and Irish claims do not overlap with each other. No development activities will take place in this area of overlapping claims (Figure 2.66) until the dispute between Iceland, Denmark / Faroe Islands, the UK, and Ireland has been resolved. To resolve this dispute, an outer limit for the entire area must be agreed to by all states as well as the method of delimiting the area between them.

Prospective areas

Three areas on the Icelandic continental shelf are thought to have commercial petroleum potential (Figure 2.66): Dreki located east and northeast of Iceland containing the Jan Mayen Ridge in its northern part, Gammur on the northern insular shelf of Iceland which includes the Flatey Basin, and Bergrisi in the Hatton-Rockall area south of Iceland. Iceland has announced that it will offer exclusive exploration and production licenses in the northern part of the Dreki area in early 2009.

2.4.4.2. Jan Mayen Ridge

2.4.4.2.1. Historical to present

Pre-exploration

Seafloor spreading in the area of Iceland during the opening of the Northeast Atlantic resulted in a shift in the plate boundary that split the Jan Mayen Ridge off from the continental shelf of East Greenland, stranding it in the middle of the ocean. The Jan Mayen Ridge is a sliver of continental crust – a microcontinent – bounded by rifted continental margins on both sides. The eastern margin developed as the outermost part of the continental shelf of Greenland during the initial breakup of the continent and the opening of the Norway Basin. It is characterized by an eastward thickening pile of basaltic lava flows which erupted over the pre-existing continent during the events leading to the creation of the ocean basin east of the ridge (Norway Basin). The western margin developed as a result of rifting within the Greenland continental shelf and seafloor spreading on the Iceland Plateau. It is characterized by tilted extensional fault blocks and an extensive complex of sills or lava flows which covers the deep basins west of the ridge.

The general geological structure of the Jan Mayen Ridge area varies from east to west (Figure 2.68). To the east the structure comprises the oceanic crust of the Norway Basin which is composed of wedge-shaped piles of lava flows. These formed at the beginning of seafloor spreading in the Norway Basin when the ridge was separated from the Norwegian Continental Shelf. The eastern flank of the ridge is covered by a belt of subaerial lavas and intrusives that represent two subsequent phases of volcanic activity, younger to the east and older to the west. West of the volcanics is a sedimentary basin that is relatively undeformed in the east and faulted in the west. The basin is flanked on the west by sill intrusives and the oceanic crust on the Iceland Plateau.

The main geological units in the Jan Mayen area are, in order of age, continental basement rocks, sedimentary rocks pre-dating the opening of the Norwegian-Greenland Sea, subaerial basaltic lavas extruded during initial breakup of the continent, oceanic crust in the Norway Basin, sedimentary rocks derived from Greenland and deposited prior to the onset of rifting within the Greenland shelf, sedimentary rocks deposited during rifting within the Greenland shelf, lava flows or a complex of flat-lying intrusives emplaced just prior to breakup within the Greenland shelf, oceanic crust on the Iceland Plateau, and sediments deposited after breakup west of the ridge during seafloor spreading on the Iceland Plateau.

Several factors indicate that the northern Dreki area may have significant hydrocarbon potential:

- the presence of sedimentary rocks of sufficient thickness and age;

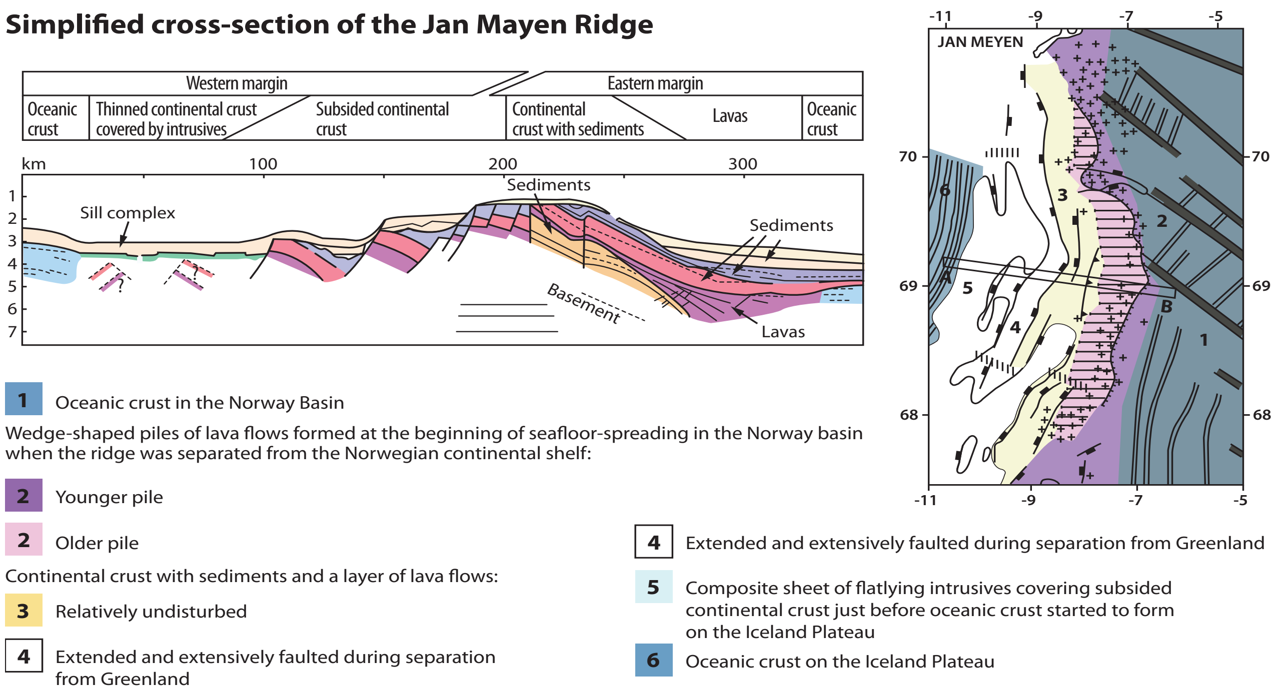


Figure 2.68. Simplified cross-section illustrating the main geological units of the Jan Mayen Ridge at the location shown by the Line AB on the map (after Gunnarsson et al., 1989).

- indications of the presence of sedimentary strata predating the initial opening of the Norwegian–Greenland Sea. Such sediments are likely to be analogous to those preserved in the Jameson Land Basin onshore in East Greenland where source rocks are present and oil is known to have been generated;
- reservoir rocks are likely to be present. Among the candidates are submarine fans derived from East Greenland;
- structures and stratigraphic configurations with potential to act as hydrocarbon traps are clearly present; and
- seismic reflection anomalies are observed which may indicate the presence of hydrocarbons.

Exploration

Seismic activities

Various academic seismic and geological surveys have been conducted in the Jan Mayen area. The data range from single-channel seismic profiles to crustal-scale seismic reflection/refraction surveys. The data are public, but there is no coordinated system for access. Most surveys were government or non-exclusive commercial surveys conducted under licenses.

In the Jan Mayen Agreement area, 600 km of 2-D seismic data were collected by the Norwegian Government in 1979. 2-D seismic were also acquired jointly by Iceland and Norway; 4000 km in 1985 and 950 km in 1988. In addition, 2800 km of seismic data were collected by the Norwegian company InSeis under an exploration license in 2001.

The Jan Mayen area is still in the initial stage of exploration. While sufficient seismic reflection data are available to conduct in-depth studies, no exploration wells have been drilled in the area to date. Calibration of lithology, physical properties, and age is therefore still lacking.

Prospecting licenses

Currently, two prospecting licenses have been awarded for Icelandic waters based on the new legal framework (Figure 2.66). InSeis (now Wavefield-InSeis) was awarded a three-year prospecting license on the southern Jan Mayen Ridge from July 2001. The company acquired nearly 2800 km of data. The geophysical company TGS-NOPEC was awarded a one-month prospecting license from April 2002 in a partly overlapping region further south on the Jan Mayen Ridge and acquired 800 km of data under this license. Both companies have put seismic data up for sale.

Infrastructure

The initial exploration activities can be served from existing infrastructure in the northeastern part of Iceland without specific incentives (Sagex, 2006).

2.4.4.2.2. Future

Near-term

The first oil and gas licensing round in Icelandic waters, in the Dreki area of the Jan Mayen Ridge, northeast Iceland shelf, is set to commence in January 2009. The northern part of the Dreki area covers 42 700 km^2 and is located from 67° N to 68°30′ N and 6°20′ W to 11°30′ W (Figure 2.66). The water depth in 80% of the license area is 1000 to 2000 m.

The license blocks are each approximately 390 km^2 (15′N–S, 20′E–W) and licenses may cover one or multiple block(s) or partial block(s). The northernmost 30% of the area, comprising 12 720 km^2, falls under the Treaty with Norway in accordance with which Norway may participate with up to a 25% share in exclusive licenses.

The final plan for this licensing round and the associated Strategic Environmental Assessment (SEA) have been completed following public hearings that closed in May 2007. No major obstacles were identified by the government of Iceland. Ongoing and future research programs on natural conditions will be based on the SEA.

The proposed start date of the licensing round is 15 January 2009 with a tentative deadline for applications on 15 April 2009. Assessment of applications and negotiations is expected to take at least two to three months thereafter.

Long-term

The petroleum potential of the Jan Mayen Ridge area is promising (Figures 2.67 and 2.68). Iceland anticipates that further exploration activities, including exploration drilling, will result from the 2009 licensing round.

Petroleum policy and plans for the future

Iceland does not, at present, grant exclusive licenses of any kind, but the legal and regulatory framework for exclusive exploration and production licenses will be complete before commencement of the licensing round scheduled for the northern Dreki area in January 2009. In addition to general license terms, important aspects that are being considered include requirements regarding health, safety, the environment, fees and taxation.

Preliminary findings about future exploration and production in the Jan Mayen area are as follows. The exploration phase will entail offshore operations as well as continuing exploration activities. The exploration phase will involve exploratory drilling from special drilling ships or floating drilling platforms. After exploratory drilling, well testing may take place. If exploratory drilling is promising, it may be advantageous to set up production equipment and necessary support facilities.

Activities associated with the production of oil or gas can impact on the surrounding environment. Drilling, laying of pipes, the handling of oil and/or gas, activities onboard a production unit, living quarters for employees and other habitation, logistics, pollutants brought up with oil or used in the production processes, waste handling, and transport of oil from the production area are all potential sources of pollution and other environmentally damaging effects that must planned for. Undersea construction, such as the laying of pipelines and the building of structures such as pumping stations, has a direct impact on the ocean floor and conditions for benthic species.

Many questions will remain unanswered until the environmental impact of individual operations in the area, such as the environmental impact assessment of particular wells, can be evaluated. However, there do not appear to be any technological limitations to producing oil and gas in the event that these are found to be present (MOII, 2007).

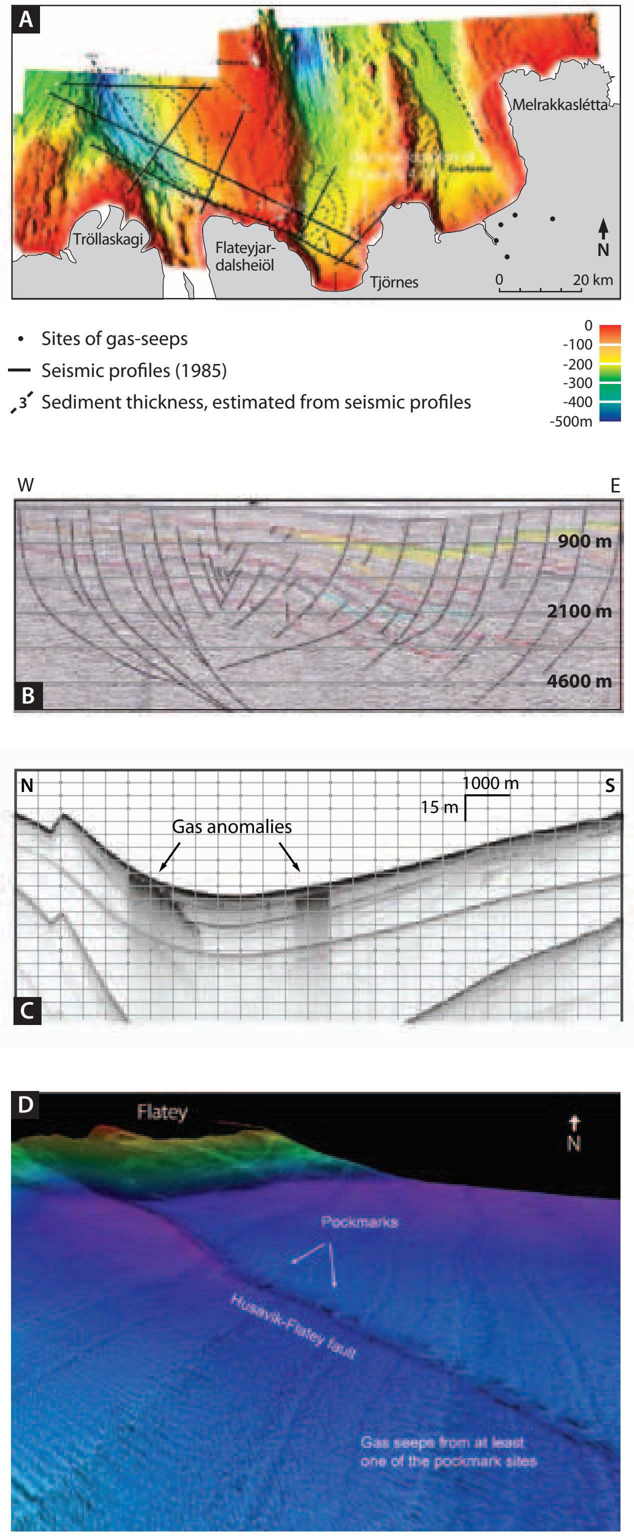


Figure 2.69. (a) Bathymetric map of the Flatey sedimentary basin offshore North Iceland with contour lines indicating the thickness of sedimentary rocks in kilometres. Dashed lines are seismic data from Western Geophysical 1978, solid lines are data from GECO 1985; (b) seismic profile in the Flatey Basin, showing sediments at least 4 km thick; (c) high-resolution seismic profile west of Tjörnes Peninsula showing gas anomalies; (d) multibeam fathometer composite of the seafloor showing the trace of the Husavik-Flatey fault and pockmarks aligned on the fault. General location of profiles in (b), (c) and (d) are shown in (a). (Orkustofnun, 2007).

2.4.4.3. Flatey Basin

2.4.4.3.1. Historical to present

Pre-exploration

Strong indications of an active petroleum system in the Flatey Basin are evidenced by the presence of gas-containing hydrocarbons seeps in the sands of Öxarfjörður (Figure 2.69a). Gas seeping up through the sands of Öxarfjörður contains methane, ethane, and heavier hydrocarbon gases of thermogenic origin. Isotope analysis indicates that the hydrocarbons are derived from coals in the bedrock beneath the sands. Coals are exposed on Tjörnes peninsula adjacent to the Flatey Basin.

Shallow seismic profiles in Skjalfandi Bay west of Tjörnes (Figure 2.69c) show acoustic anomalies known as wipeout zones, which occur in areas of gas-charged sediments. This gas may originate from the same sources as the terrestrial gas seeps at Öxarfjörður.

Further evidence of an active petroleum system is indicated by the presence of pockmarks on the shelf. These pockmarks (Figure 2.69d) line up along the trace of the deep-seated trans-current Husavik-Flatey Fault, which crosses Skjalfandi Bay. Gas has been observed bubbling up from a pockmark on the fault. The basin is faulted and contains up to 4 km of sedimentary strata, as seen in the seismic data in Figure 2.69b.

Exploration

Seismic activities

Western Geophysical collected 800 km of seismic data in 1978 on the northern insular shelf of Iceland, as a non-exclusive speculative survey. The data are owned by the Ministry of Industry. In 1985, the geophysical company GECO acquired 300 km of proprietary data also on the northern insular shelf of Iceland.

2.4.4.3.2. Future

No plans have been revealed, nor have any indications of current interest been received, for more activity in this area.

2.4.4.4. Hatton-Rockall area

2.4.4.4.1. Historical to present

Exploration

Seismic activities

Government surveys in the Hatton-Rockall area acquired 1800 km of 2-D seismic data in 1987 and 4100 km in the Herring Loophole area in 2000.

2.4.4.4.2. Future

Near-term

No plans have been revealed, nor have any indications of current interest been received, for more activity in this area. Moreover, no production activities will be allowed until the disputes over the overlapping boundaries between Denmark, the UK, Ireland, and Iceland are resolved.

2.4.5. Faroe Islands

2.4.5.1. Regulatory and legislative systems relevant to Arctic oil and gas activities in the Faroe Islands

The 1948 Home Rule legislation allowed natural resources in the subsoil to be transferred from Danish to Faroese authority. Such a transfer was agreed between the two governments in 1992, granting Faroese authorities full responsibility for legislation and administration of potential resources (Joensen, 2002).

The agreement coincided with the discoveries west of Shetland of the *Foinhaven* and *Schiehallion* oil fields, which meant that the oil industry subsequently became interested in petroleum exploration in Faroese waters. It soon became clear that one of the main obstacles to undertaking exploration activities on the Faroese continental shelf was the dispute between the United Kingdom and the Faroe Islands on the drawing of the continental shelf boundary between the two countries. In addition, there was no proper legal framework in place to govern petroleum exploration. In September 1993, the Faroese Parliament decided that petroleum licenses were not to be awarded before these issues were resolved.

The Faroese Government consequently appointed a Hydrocarbon Planning Commission in 1994 to prepare an oil and gas policy in which consideration for the protection of the environment and fisheries was included (á Hædd, 2002). The commission submitted its recommendations to the Government in 1997 (Hydrocarbon Planning Commission. 1997) along with a Draft Bill on Hydrocarbon Activities with Explanatory Notes. The Bill was passed in 1998 (Parliamentary Act no 31 of 16 March 1998 on Hydrocarbon Activities).

Agreement on the maritime delimitation between the Faroe Islands and the United Kingdom, which was considered the last impediment before proper preparations to launch the first licensing round could be undertaken, was signed in May 1999.

A summary of the legislation relevant to oil and gas activities is as follows (see also Appendix 2.1, section A4.5 on laws and regulations).

- Act No 31 of 16 March 1998 on Hydrocarbon Activities (Hydrocarbon Activities Act)
- Act No 26 of 21 April 1999 on Taxation of Revenues relating to Hydrocarbon Activities
- Act No 5 of 8 February 2000 on the First Licensing Round
- Act No 16 of 14 February 2000 on Hydrocarbon Tax Administration
- Act No 26 of 7 March 2000 on Amendments to the Hydrocarbon Tax Act
- Act No 27 of 17 May 2004 on the Second Licensing Round
- Act No 59 of 17 May 2005 on the Protection of the Marine Environment

2.4.5.1.1. Hydrocarbon Activities Act

The Hydrocarbon Activities Act is the all-encompassing legal framework for petroleum exploration and production in the Faroe Islands. In short the Act:

- states that hydrocarbons *in situ* belong to the Faroe Islands;
- prescribes the granting of petroleum concessions, that is, the requisite licenses for oil companies to carry out exploration and production of oil and gas;
- regulates all phases of oil and gas activities, that is, prospecting, exploration and appraisal, development and production as well as decommissioning;
- requires licensees to perform environmental impact assessments before undertaking projects assumed to have a major impact on the environment;
- adopts a functional and dynamic approach to safety, occupational health, and emergency procedures for offshore installations; and
- introduces a supplementary scheme on compensation to fishermen in addition to the general basis of liability.

Furthermore, the Act has the clear objective of making sure that Faroese businesses are given a fair opportunity to participate in the offshore activities (Joensen, 2002).

The Hydrocarbon Activities Act contains stipulations on conditions concerning health, safety and environment (HSE) in all phases of the exploration and production activities. This is based on the assumption that there is a great need for effective HSE regulation, control and coordination in offshore activities for which reason it is desirable that these matters are generally subject to the same legislative act. The Act establishes a general duty for both public authorities and licensees to plan the activities with due regard for "…fishing, navigation, the environment, nature and other interests of society" (see section 1, subsection 2 in the Hydrocarbon Activities Act).

The Act combines into one enactment provisions to be found in various Acts in the North Sea countries, in order to provide as simple and transparent a legislative basis as possible.

2.4.5.1.2. Protection of the Marine Environment Act

The purpose of the Act on the Protection of the Marine Environment is to protect nature and environment, to preserve human conditions of life, the ecological system and the flora and fauna thus ensuring sustainable development of society. The Act also aims at preserving a clean and rich sea and preventing and reducing pollution of the sea, the coasts, and the air. For offshore oil and gas projects, the Act authorizes the Minister to lay down rules concerning, for example, usage and disposal of chemicals and waste management.

2.4.5.1.3. Executive Orders

The following Executive Orders are relevant to oil and gas activities:

- Executive Order No 34 from 8 March 2001 on reimbursement of expenses in connection with hydrocarbon activities
- Executive Order No 35 from 8 March 2001 concerning Health, Safety and the Environment during all Phases of the Hydrocarbon Activities
- Executive Order No 37 from 8 March 2001 on Usage and Discharge of Substances and Material from Offshore Installations
- Executive Order No 113 from 20 November 2003 on Geological and Geophysical Matters in Connection with Approval of Deep Drilling

Executive Order No. 35

The Order on Health, Safety and Environment in the Exploration Phase contains functional and goal-setting requirements that stipulate what the duty holder shall see to or accomplish without stating the exact procedure as to how to achieve the desirable results. The philosophy is based on the assumption that it is the duty holder or the operator who is responsible for carrying out the activities in a safe and appropriate manner in accordance with good international practice. This is moreover based on the principle that licensees and operators have to demonstrate to the authorities how they plan to comply with the rules and regulations.

The Order on HSE in the Exploration Phase is arranged according to five main themes or topics covering subjects of importance in connection with the exploration activity. The themes are establishment of management systems, performance of integrated risk and emergency response analyses, technical requirements for offshore installations and equipment, operational requirements, and requirements in connection with information, documentation, and reporting.

A few requirements in the Order illustrate that it is the operator that has overall responsibility for ensuring that exploration is carried out in a safe and appropriate manner in accordance with good international practice. The party responsible for the activity shall:

- establish requirements for the systematic management of health, safety and environment and for the continuous improvement thereof (Article 3);
- establish and further develop a safety culture with the objective of preventing undesirable events and conditions (Article 4);
- measure and monitor technical, operational and organizational parameters of significance to health, safety and environment (Article 9);
- perform an integrated and total risk and emergency response analysis for the offshore installation and its operations. Defined risk acceptance criteria shall reflect all legal requirements and the Operator's own requirements for health, safety and environment (Article 16); and
- ensure that the offshore installation and its equipment is appropriate in terms of health, safety and environment (Article 22).

Executive Order No. 37

Executive Order No. 37 on Usage and Discharge of Substances and Materials at Offshore Installations is extremely important in regulating and controlling operational discharge. Aspects of the OSPAR Convention (see Appendix 2.1, section A3 on regional conventions) form part of the legislative basis. The Order governs the use and discharge of materials and substances that derive directly from any hydrocarbon activity at offshore installations. Usage and discharge may only occur according to prior permission granted by the Faroese Environmental Agency. The former Minister of Petroleum and the Environment empowered the Faroese Environmental Agency to administer the Act on the Protection of the Marine Environment and any executive orders issued in pursuance of the Act.

2.4.5.1.4. Licensing regime

The Hydrocarbon Activities Act specifies that licenses for exploration and production of hydrocarbons shall be granted following a public notice inviting applications (Section 7 (1)); that prior to inviting applications, the areas to be offered for licensing and the general terms and conditions on which licenses are to be granted shall be fixed by law (Section 7 (2)); that the Faroese Government, i.e. the Minister of Petroleum, grants licenses for exploration for and production of hydrocarbons (Section 6); and that exploration and production shall be carried out in a safe and appropriate manner in accordance with good international practice (Section 13). Consequently, a bill on the individual licensing round shall be presented in Parliament before a licensing round can be opened.

A precondition for the granting of licenses in the two first licensing rounds has been that applicants must have requisite expertise, experience, resources, and financial capacity. The main criteria for awarding licenses have been the applicants' geological understanding of the license area and the proposed work program, the extent to which the applicants are committed to investigations of relevance to future exploration in the Faroese area, and the applicants' willingness to involve Faroese nationals and undertakings in the activities.

2.4.5.2. Historical to present

2.4.5.2.1. Pre-exploration

The Faroese GEM Network and the EIA Program

Section 23 of the Hydrocarbon Activities Act stipulates that licenses or approvals regarding projects likely to have a major impact on the environment may only be granted after an assessment of the likely effects on the environment and after the affected public, authorities, and organizations have had an opportunity to express their opinion. This provision ensures that environmental impact assessments are carried out <u>before</u> the Government grants a license or an approval.

Encouraged by the Faroese Petroleum Administration (now the Faroese Earth and Energy Directorate), the GEM (Geotechnical Environmental Metocean Joint Industry Project) Network was established in 1997. The participating members were the oil companies that took an interest in the Faroese continental shelf. The primary purpose of GEM was to gather sufficient data on the Faroese environment to enable these companies to make the necessary preparations to drill in Faroese waters in a safe and environmentally acceptable manner. The GEM Network was managed by a steering committee with representatives from 23 participating oil companies as well as representatives from public authorities and Faroese institutions. The signing of the Boundary Agreement in May 1999 between the United Kingdom and the Faroe Islands served as a major stimulus for efforts to gather data on the Faroese environment.

The scope of the environmental impact assessment (EIA) program (see also Chapter 6) was established at a workshop in January 2000. Representatives from oil companies and environmental authorities, as well as independent scientists, identified outstanding environmental issues and impact factors and agreed on the EIA program. The workshop was an important milestone in the environmental preparations for oil exploration in the Faroe Islands, because it was the turning point for a cooperative and joint effort from both the oil industry and the environmental authorities in working to achieve objectives of common interest.

In October 2000, the program and design for an environmental baseline survey of the Faroese offshore oil exploration license area was agreed with the authorities. The baseline survey was later carried out in two stages.

The project phase of the regional EIA program consisted of a number of environmental studies covering various topics including, for example, coastal sensitivity, fish and fisheries, marine mammals, plankton, seabirds, drill cuttings and oil spill modeling. The outcome of these studies formed the basis of the baseline information needed for the assessments as well as for the EIA report.

The GEM Network was unique in that it was the first joint regional environmental project that had been undertaken prior to the award of any exploration licenses. In 2001, the GEM Network was replaced by FOIB, the Faroese Oil Industry Group, which builds on the work carried out under GEM. Oil companies that have been granted exploration licenses on the Faroese continental shelf comprise the members of FOIB.

Environmental issues in the first licensing round

According to the Hydrocarbon Activities Act, tasks on the individual licensing rounds shall include an assessment of the possible impact of hydrocarbon activities on navigation, fishing and other commercial activities, and on nature, the environment and other community interests. Prior to the first licensing round, several impact assessments were carried out, as briefly summarized here.

An assessment of the impact of exploration activities on navigation focused on two issues: that offshore installations occupy a certain acreage (i.e., the 500-m safety zone), and therefore may hinder navigation, and that exploration activities will increase traffic in Faroese waters and may consequently affect navigation and the fishing industry. The assessment concluded that exploration activities and the resulting ship traffic were unlikely to hinder navigation to any material degree.

An assessment of the impact of exploration activities on fishing identified the key issues as the location of exploration sites, the nature of any fishing activity in these areas, the number of operating offshore installations, and the size of the areas they would occupy (due to the 500-m safety zone or the anchor zone in the case of anchored installations). The assessment concluded that the exploration phase would not pose any serious obstacles to fishing, although exploration activities to the east and south of the Faroe Islands could affect fishing opportunities on certain fishing grounds. This is mainly because the depth in most of the area offered for licensing exceeds 500 m, whereas fishing vessels generally operate in shallower waters. Because only a few offshore installations will be present at any one time and only for a limited period, the exploration activities will not substantially reduce fishing opportunities.

In terms of impacts on nature, one direct impact of exploration activity would be the disturbance to the fauna of the exploration area, especially bottom dwellers, fish, seabirds, and marine mammals. But since these species migrate through or over the ocean, they can leave the area and return unhindered when the exploration activity is over. The impact on such species is therefore likely to be limited in the exploration phase.

Seasonal restrictions for seismic activities

The license holder of an exploration and production license is entitled to undertake prospecting activities, including seismic surveys, in the license area. If companies not holding an exploration and production license wish to undertake geophysical or geological surveys, a prospecting license must be acquired from the Faroese Earth and Energy Directorate.

The rules, which at any given time apply to prospecting activities, must be obeyed. The activities must be conducted with due regard to fishing operations and with due regard to the conservation of fish stocks. Regarding the conservation of fish stocks, the license area is subject to the general stipulation that no seismic activity should take place in the period from 1 November until 15 April. In addition, no seismic activities should take place in the area south of Faroe Bank and on Wyville-Thomsen Ridge between 1 April and 31 May. Reference is made to clause 5 of the model prospecting license regarding seasonal restrictions for seismic activities. Regarding fishing operations, the licensee is obliged to take a fishery representative onboard the survey vessel during seismic surveys (clause 6 of the model prospecting license).

Impact on the environment

The petroleum industry as a whole is regarded as a source of pollution, mainly due to the discharge of waste and other residues into the sea or air. The type and extent of environmental impact will depend on factors such as safety regulations and measures to protect the environment. Therefore, specific environmental requirements must be fulfilled before the licensee is allowed to commence activities. The Hydrocarbon Activities Act stipulates that the licensee must obtain a specific permit or approval before undertaking a particular operation. Thus, the drilling of a well is subject to approval by the petroleum authorities (see Section 15[1]). The authorities may also require the licensee to submit an assessment of the environmental impact (see also Chapter 6) of the proposed activities (see Section 23). Furthermore, the licensee is under an obligation to use only permitted drilling mud (see Executive Order No. 37).

Approval to drill

The licensee must obtain an approval to drill before actually commencing any exploration activity (see section 15[1] of the Hydrocarbon Activities Act). Furthermore, Executive Order No. 37 stipulates that operational usage and discharge of substances and materials on offshore installations requires a specific permit from the Faroese Environmental Agency in accordance with the requirements of the OSPAR Convention (see Appendix 2.1, section A3 on regional conventions).

Regarding approvals to drill, the Executive Order on HSE in the Exploration Phase stipulates in section 103 that the application to the Faroese Earth and Energy Directorate shall, among other things, contain as minimum a site-specific environmental impact assessment pursuant to section 23 of the Hydrocarbon Activities Act, an integrated and total risk and emergency response analysis, emergency response plans for people, the environment and material assets, and emergency response plans for the drilling of a relief well in case of a blow-out.

The approval to drill may impose environmental conditions on the applicant.

Approval to permit usage and discharge of chemicals
According to Executive Order No. 37, the application submitted to the Faroese Environmental Agency shall, among other things, contain information on environmental impact of the use or discharge of the specific materials and substances, processes and technology (Best Available Technology; BAT), ecology of the area, environmental management systems, ecotoxicological documentation of chemicals, and the operator's environmental assessment of the chemicals.

The Faroese Environmental Agency may attach conditions to the permit. For example, conditions may concern the type and quantities of chemicals used in the exploration activity, substitution to more acceptable chemicals, waste management, reporting and monitoring.

It is a prerequisite for operations in Faroese waters that the operator holds an approval to drill as well as a permit for usage and discharge of substances and materials.

2.4.5.2.2. Exploration

Environmental evaluations and lessons learned
After the completion of three exploration wells in 2001, the petroleum authorities initiated two lessons-learned meetings. The purpose of the meetings was to assess the legislative framework, the approval and permitting process, the conduct of the exploration activities, and the cooperation between authorities and operators and to identify issues that could be subject to improvement in the future.

The first lessons-learned meeting was arranged exclusively for the authorities involved in the process. One recommendation arising from this meeting was that future applications by operators for approvals to drill should not be of a general character but should focus on the specific drilling location, the specific rig to be used, and the specific well to be drilled. This recommendation was based on the fact that in general the applications received prior to the first wells did not fully reflect the particular challenges of exploration drilling in the Faroese area, and were more or less based on exploration drilling in neighboring countries.

Another matter of concern was the inconsistent use of terminology in the operators' emergency response plans. It is imperative for the authorities to obtain a definition of the various terminologies used by the companies.

The second lessons-learned meeting was arranged for the licensees and operators, rig owners, consultants and the relevant authorities. The main purpose of the meeting was to prepare a template to ensure that future operators could undertake their activities on the Faroese continental shelf in the best possible manner based on lessons learned. The meeting concentrated on what went well and what could be improved, as well as identifying necessary actions and clarifications for drawing up a comprehensive template on how to handle, for example, the application process in the future. This was based on the fact that it is demanding to be one of the first companies to operate in a new country with a different regime to the one to which they are accustomed. The workshop agreed that most of the work that should be done as a result of the lessons learned should be carried out by the licensees and operators within their cooperation forum FOIB.

Licensing

First licensing round. The first licensing round was opened on 17 February 2000 and the area on offer covered approximately 14 000 km^2 or ten times the land area of the Faroe Islands. Large parts of the Faroese continental shelf are overlain by thick layers of basalt that make exploration, and in particular seismic imaging, difficult. In the southeastern part of the continental shelf, however, there are areas with little or no basalt. Although many of the oil companies were focusing their interest on the southeastern areas, the petroleum authorities still decided to include a number of more challenging blocks closer to the Faroe Islands in the area offered for licensing. The areas were offered for a period of six or nine years. When the licensing round closed on 17 May 2000, 22 applications had been submitted from 17 oil companies and on 17 August 2000, seven licenses were awarded to 12 companies. The area awarded covered just about 30% of the area originally on offer.

The work program of the first licensing round covered eight firm well commitments, as well as a wide range of geological and geophysical programs. Four of the licenses were awarded in the southeastern corner each for a period of six years, while three 9-year licenses were awarded in the basalt-covered areas. The three latter licenses did not include firm well commitments, but were divided into two phases: an initial three-year phase for which a geophysical work program was agreed, leading to decision points of entering the next phase with a new work program or to exit the license. In addition, the license holders had committed to spending DKK 86 million on Faroese participation and DKK 38 million on research for future exploration of the Faroese continental shelf.

Four of the eight commitment wells have been drilled and the geophysical acquisition programs completed. The six-year licenses expired on 17 August 2006. New work programs for these licenses were agreed in December 2003. The work programs were targeted at enabling a decision on exploration drilling on the licenses in question focusing on mapping below the basalt and to the drilling of thick basalt sequences in order to reduce the risk of drilling an exploration well.

Second licensing round. Preparations for the second licensing round began in spring 2004. The aim of the second licensing round was to create a basis for continued exploration activities on the Faroese continental shelf and to expand the exploration activities to basalt-covered areas. The licensing round opened on 17 August 2004, and five months later seven new licenses were granted for exploration and production in Faroese waters. The authorities received nine applications representing eight companies, two of which were new to the Faroese continental shelf.

The license terms for the second round licenses were different from the first, in that the authorities had not determined the license term prior to the round. The result was terms that varied from three to eight years. These terms were divided into shorter sub-phases of two to five years with intermediate decision points where the license holders and authorities decide whether the license continues to the next phase of the license term, or whether the license is relinquished. A firm work program was agreed for the first phase. The areas under license and the license holders are shown in Figure 2.70.

No well commitments were part of the work programs of the second licensing round. However, two of the licenses contain stipulations on exploration wells for the subsequent phases of the license. The work programs cover seismic and other surveys with the purpose of maturing the areas for future exploration drilling. In addition, DKK 10 million was granted to projects of relevance to future investigation of the Faroese continental shelf and DKK 14 million to competence development of the Faroese business community.

Drilling

The results of the drilling operations on the Faroese continental shelf have been encouraging, but have not met the very high expectations prior to the licensing round. The first well, the Longan 6005/15-1 drilled in 2001 by Statoil to 4000 m, was declared dry but with traces of hydrocarbons. The same year, BP's well Svinoy 6004/12-1 was drilled to 4354 m and found hydrocarbons in non-commercial quantities. Also in 2001, the third well, the Marjun 6004/16-1z, was drilled to 4275 m and encountered light hydrocarbons over a 170 m gross interval in the lower Tertiary T10 sands. This well was deepened beyond the commitment depth and by encountering a continuous hydrocarbon column at the T10 level, opened up a new play for the West of Shetland area. The fourth well, the Marimas 6004/17-1 drilled by ENI to 3847 m in 2003, was dry. The fifth well, Brugdan 1, was drilled in July 2007 by Statoil to a total depth of 4201 m, more than 400 m past its original projected depth of 3780 m, in sub-basalt on License 006. The well encountered traces of gas and was abandoned.

In summary, after drilling five exploration wells within the Faroese area, an active petroleum system has been proven and one of the wells, the Marjun well, has been categorized as a discovery. The exploration drilling on the Faroese continental shelf has so far focused on Paleocene targets using a Foinhaven/Schiallion mindset and in some cases combined with seismic attribute technology. The discovery well however was drilled on a structural play, a four-way dip closure. The other three wells were targeting at prospects with a strong stratigraphic element in the trapping mechanism. The wells were all drilled in the Judd basin.

<u>Well transfer.</u> In spring 2005, the holders of License 004 initiated negotiations with the petroleum authorities on the possibility of transferring the two remaining commitment wells in License 004 into a sub-basalt exploration well on License 007. In autumn 2005, the Minister of Trade and Industry signed an agreement with the license holders of License 004 and License 007 on the drilling of an exploration well to commence in 2007 (FPA, 2005).

Statoil and Amerada Hess also submitted applications on the transfer of one well in Statoil-operated License 003 and one well in Amerada Hess-operated License 001 to License 006, which is operated by Statoil. This application was also approved. Licenses 003 and 004 were subsequently relinquished. And even though the Brugdan Number 1 well only encountered traces of gas, knowledge was gained about drilling in volcanic sub-basalt rock, which will be necessary in future Faroese exploration (IHS, 2006).

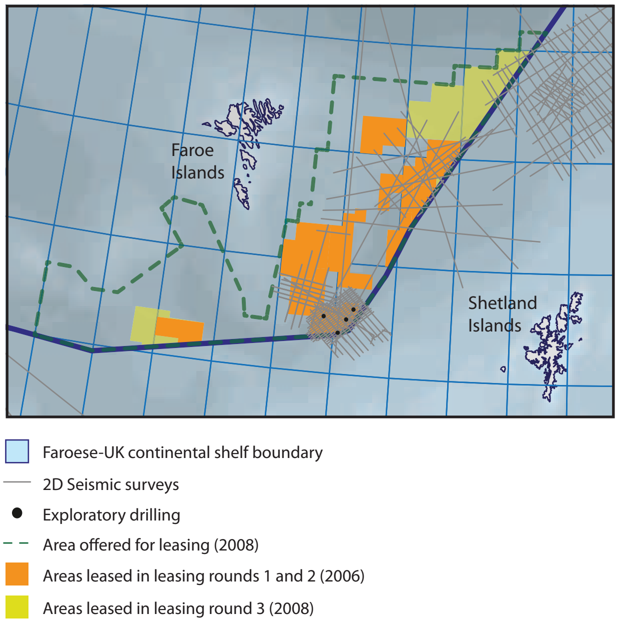


Figure 2.70. Faroe Islands licensing status.

There remains one well commitment in areas which were considered challenging when they were awarded in 2000 and still considered challenging, but following the work carried out under the license commitments, the license holders are learning more about drilling of wells in these areas.

This proves that the strategy of the first licensing round, which was to focus on less attractive areas and offer them for licensing on lenient terms, has worked. And although the first well on a basalt-covered area of the Faroese continental shelf was non-productive, a second well is expected to follow soon.

2.4.5.3. Future

One of the license award criteria is the oil companies' willingness to contribute to investigations of relevance to future exploration in the Faroese area.

Following the first licensing round, the Sindri Group (www.sindri.fo) was established as a forum for future exploration issues. The main objective of the Sindri Group is to carry out joint projects of relevance to the future investigation of the Faroese continental shelf. The work is *not* license specific; this means that the oil companies are joining forces in an effort for future exploration of the entire Faroese area, and not just focusing on their individual licenses. The primary topics for investigation are relevant technologies for imaging within basalt-covered areas, regional geology and evolution of the entire Faroese area, and definition of the hydrocarbon system of the entire Faroese area.

Following the second licensing round, although the set-up of the system for future exploration has changed somewhat, the aim remains the same.

The third licensing round will be open for offers in July 2008 with a deadline of November 2008 and awards at the end of 2008 (FEED, 2008).

2.4.6. Norway

2.4.6.1. Regulatory and legislative systems relevant to Arctic oil and gas activities in Norway

In the late 1950s, very few people believed that the Norwegian continental shelf might conceal rich oil and gas deposits. However, the discovery of gas at Groningen in the Netherlands in 1959 caused geologists to revise their thinking on the petroleum potential of the continental shelf of Norway.

Seismic investigations started in the early 1960s and the first well was drilled in the Norwegian part of the North Sea in 1965. With the discovery of the *Ekofisk* field in 1969, the Norwegian oil adventure began in earnest. Production from this field began in 1971, and in the following years a number of major discoveries were made. Today (spring 2006) there are 50 fields in production on the Norwegian continental shelf. Production from these fields corresponds to around 20 times the domestic consumption of petroleum and has established Norway as a key supplier to the global oil market and the European gas market. In connection with the development of the *Snøhvit* field in the Barents Sea, for the first time agreements have been signed for the sale of gas to markets outside Europe. Petroleum accounts for more than 20% of the Norwegian Gross Domestic Product and around 50% of the total exports, and is by far the most important industry in Norway in terms of economic value (MPE, 2006).

The Norwegian continental shelf is normally divided into three geographic areas: the North Sea, which extends northwards to approximately 62° N, the Norwegian Sea which extends from 62° N to the Lofoten Islands, and the Norwegian part of the Barents Sea (also referred to as the Norwegian Barents Sea or just the Barents Sea), which for this purpose extends northwards from the Lofoten Islands all the way to the area of overlapping claims with Russia (Figure 2.71).

The 'Arctic' is for the purpose of this assessment defined (offshore) as the area to the north of 62° N, which means that all the Norwegian Sea and all the Norwegian part of the Barents Sea are included in the Arctic. Norway's offshore regions are shown on Figure 2.71.

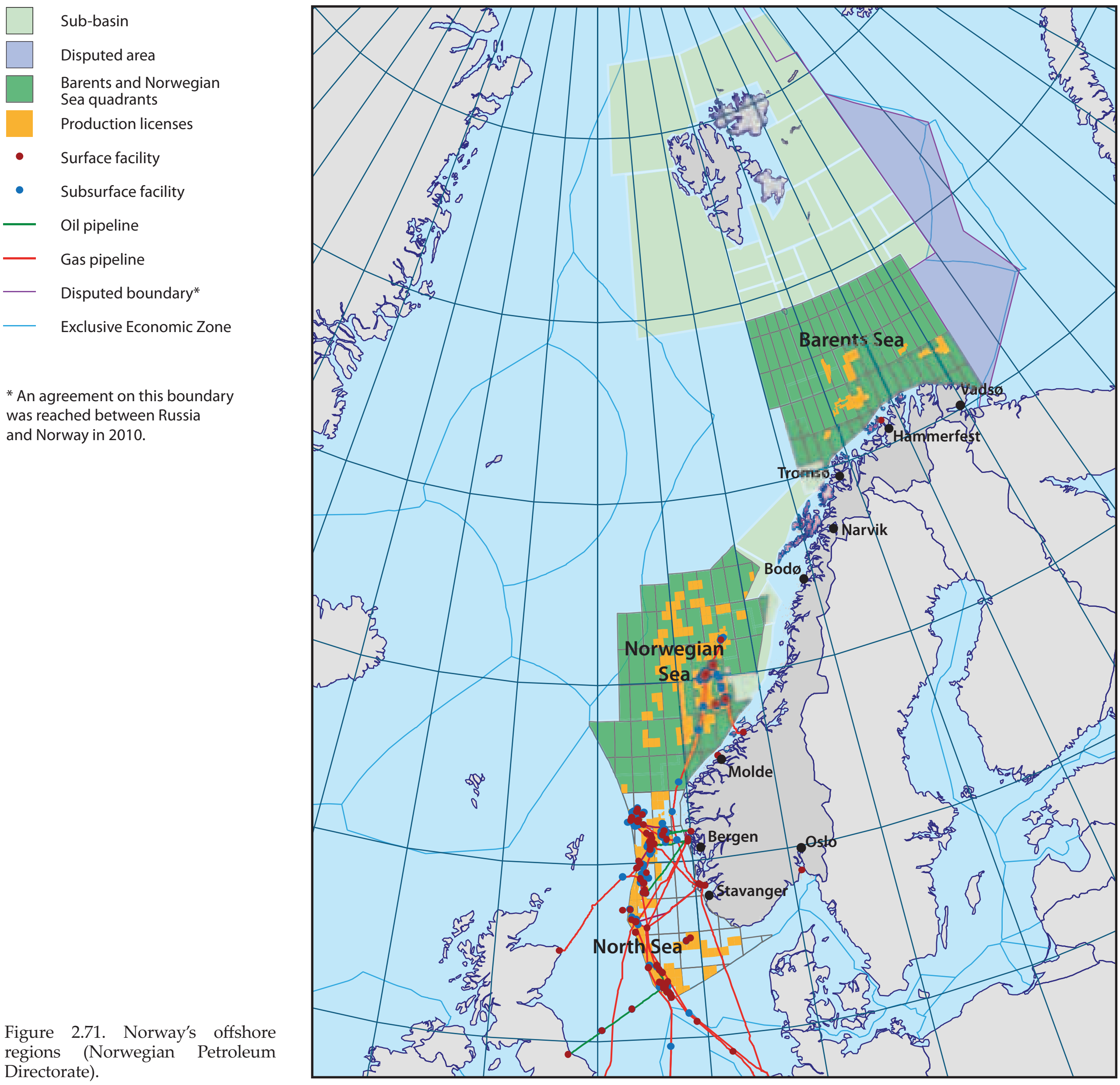


Figure 2.71. Norway's offshore regions (Norwegian Petroleum Directorate).

2.4.6.1.1. Regulatory framework

Important aspects of the petroleum policy

The utilization of petroleum resources is guided by a national petroleum policy, which applies to the whole country. There is no separate Arctic or northern petroleum policy, apart from somewhat stricter environmental regulations. The critical issue in the development of the petroleum industry is to ensure that the resources are utilized in an optimal manner. The chief objective of the petroleum policy in Norway, including northern Norway, is to maximize the long-term benefits from the industry for the good of Norwegian society as a whole. Fundamentally, this is achieved by regulating the pace of development of the industry. The petroleum sector is currently in a transition, where oil production has reached its maximum and will taper off over the next fifty years (MPE, 2004), while the production of gas will become increasingly important. With a maturing industry in the south, the need to boost exploration efforts in the north and to improve the utilization of existing fields in the south has become urgent.

The overarching objective of the Norwegian petroleum policy is to secure the largest possible share of revenue from the industry for the common good. To this end the country's petroleum policy has been based on a three-pronged strategy: national control over the development of the industry, the development of a domestic petroleum industry, and participation by the state in the activity.

National control has been achieved through the development of a comprehensive policy and institutional framework, dominated by a Ministry for Petroleum and Energy (MPE) and a Petroleum Directorate (NPD). The NPD was established in 1972 as a technical body under the then Ministry of Industry, and is tasked with supervising the activity in the industry and ensuring that it operates according to existing regulations and in keeping with the permits given. A standing committee of the Storting (Parliament) also plays an important role in the development of policy and the industry. The pace of petroleum development is formally decided on by the Storting, which decides on the opening of new areas for exploration and exploitation, though the Government may open smaller areas without Storting action. The Government issues the licenses for exploration and exploitation of petroleum.

Ever since the start-up of activities, there has been broad agreement that the petroleum industry should be developed in a gradual and considered manner, in order to secure maximum benefits over time. New areas are therefore opened up for exploration step by step.

An initial strategy was to ensure the participation of the large international petroleum companies with the necessary experience and know-how in order to develop a strong and competent petroleum sector in Norway. The development of a national petroleum industry, a means of influence over sector developments in itself, included the establishment of a national oil company – Statoil – in 1972, as well as a private company Saga, and a petroleum division of Norsk Hydro, Norway's biggest industrial conglomerate, in which the State is the major shareholder. (Saga was later taken over by Norsk Hydro.) An extensive industry providing goods and services to the petroleum companies was also cultivated. This national industry is largely privately owned, and in 2001 Statoil was privatized and is now listed on various stock exchanges. The State currently (2005) holds approximately 71% of Statoil.

An important part of the Norwegian petroleum policy has been to vest in the Government considerable power to regulate most aspects of the industry, from the issuance of permits to the manner of bringing petroleum to the market. These instruments have been adjusted according to the development of the industry and the general development of the national policies, and also in accordance with the relevant regulations and provisions that apply to Norway as a member of the European Economic Area. Since the 1980s the role of the State in the economy has become significantly reduced, and many state-owned companies have been wholly or partly privatized as part of government-led privatization programs – a development of which Statoil is a case in point.

Jurisdictional issues

A number of boundaries remain to be drawn in the marine areas of the Arctic. The Northeast Atlantic region is no exception to this. While the global legal framework for a settlement – the 1982 United Nations Convention on the Law of the Sea (UNCLOS) – has been in force for just over a decade, this has not proved sufficient to instigate solutions to the boundary problems.

In 1965, the countries bordering the northern part of the North Sea agreed on the delimitation of the continental shelf in that area. In the north, the boundary between Norway and Russia in the Barents Sea remains unresolved, because the two countries disagree on which principles to use in establishing a boundary line. The resulting area of overlapping claims is about 155 000 km^2 (Figure 2.71). The two countries have negotiated the boundary for 30 years. It has been suggested that one reason for the failure to agree on a boundary can be that there has not been a critical need for a solution (Kvalvik, 2004). The increasing level of petroleum activities on both sides of the unresolved border area in the Barents Sea may, however, make the reaching of an agreement on the delimitation of a boundary more urgent.

The status of the continental shelf around the Svalbard archipelago is also unsettled (Ulfstein, 1995). While the 1920 Svalbard Treaty states that Norway has sovereignty over the archipelago and its territorial waters, other provisions of the treaty give other parties to the treaty equal rights as regards economic activity (Arlov and Hoel, 2004). Subsequent developments in ocean law, most importantly the 1982 UNCLOS Convention, has provided for extended coastal state jurisdiction over natural resources. On the basis of this, Norway may claim jurisdiction over the continental shelf off Svalbard beyond the territorial waters of 12 nautical miles. A number of countries have, however, reserved their position in this regard.

The regulatory framework for the petroleum industry refers to the conditions and requirements governing licensees when pursuing petroleum operations. This framework is established by the Norwegian Storting and Government, and enshrined in statutes, regulations, and agreements (see also Appendix 2.1, section A4.6 on laws and regulations). Parts of the framework are the same as the regulatory regime which applies to land-based industry. The information here is to a large extent taken from Facts 2006 (MPE, 2006)

2.4.6.1.2. Main features of the licensing system

Act no. 72 of 29 November 1996 relating to petroleum activities (the Petroleum Act) provides the overall legal basis for the licensing system which regulates petroleum operations in Norway. The Petroleum Act and its regulations authorize the granting of permits and licenses to explore for, produce, and transport petroleum, and other relevant activities. Legal authority to tax this business is conferred by the petroleum taxation act 13/6-1975 No. 35. as amended (the Petroleum Taxation Act). The Petroleum Act specifies that the proprietary right to sub-sea petroleum deposits on the Norwegian Continental Shelf is vested in the state.

The Norwegian offshore licensing system comprises a number of documents which go into more detail on the rights and duties of the various parties in addition to those specified in the Petroleum Act with associated regulations. These documents are briefly outlined below.

It was decided in 1995 to incorporate Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on granting and using licenses to explore for and produce hydrocarbons (the Licensing Directive) into the European Economic Area agreement. The Norwegian licensing system complies with the requirements of the directive.

The decision to incorporate Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 (the Gas Directive) into the European Economic Area agreement was taken in 2001 and came into effect for Norway on 1 August 2002. The directive's provisions on upstream activities are incorporated in the Petroleum Act and the associated regulations.

A company can apply for a reconnaissance license to make geological, petrophysical, geophysical, geochemical, and geotechnical surveys, including shallow drilling. This license grants no exclusive rights in the areas covered and does not entitle the holder to conduct regular exploration drilling.

Before a production license which permits drilling and production can be awarded, the area in question must have been opened for petroleum operations. In that connection, an impact assessment covering such aspects as the environmental, economic, and social effects of such operations on other industries and adjacent regions must be carried out.

Production licenses are normally awarded through licensing rounds. The Government invites applications for a certain number of blocks. Companies can apply individually or in groups. Production licenses are awarded on the basis of objective, non-discriminatory, and published criteria.

The announcement specifies the terms and criteria on which awards will be based. On the basis of applications received, the MPE puts together a group of companies for each license or can make adjustments to a group which has submitted a joint application. The MPE appoints an operator for this partnership, who is responsible for the daily conduct of operations in accordance with the terms of the license.

From the award of the license covering the *Statfjord* field in 1973 to the thirteenth licensing round in 1991, State participation was a minimum of 50% in each license. The State's average share declined from the thirteenth to the sixteenth round.

The Storting made an addition to the Petroleum Act in 2001, which specifies the main features of the management system for the State's Direct Financial Interest (SDFI). As a result, Petoro AS was established as a wholly state-owned limited company to manage the SDFI. It serves as the licensee for the SDFI in relevant production licenses, pipelines, and plants.

2.4.6.1.3. Key documents and legal provisions in the licensing system

Production license

The production license regulates the rights and duties of licensees in relation to the State. This document supplements the provisions of the Petroleum Act and specifies detailed terms for each license. A production license entails an exclusive right to explore for and produce petroleum within its specified geographical area. Ownership of the petroleum produced rests with the licensees.

Each license is awarded for an initial exploration period, which can last for up to ten years. A specified work obligation must be met during this period, including for example, seismic surveying and/or exploration drilling. Providing that the work obligation has been completed by the end of the period, the licensees are generally entitled to retain up to half the acreage covered by the license for a specified period, generally 30 years.

An area fee is charged per square kilometer, as specified in detailed regulations. Providing all the licensees agree, a license can be relinquished once the work obligation has been fulfilled.

Joint operating agreement

The award of a production license is conditional upon all the licensees concluding a joint operating agreement. Similar in many respects to company agreements made under civil law, this joint operating agreement regulates relations between the partners. It forms the basis for day-to-day organization and operation of the license and for allocating any earnings, and requires the licensees to establish a management committee as their ultimate decision-making body. All licensees are represented on this committee. The agreement also regulates the operator's duties and obligations on behalf of the partnership, and specifies the group's voting rules.

Accounting agreement

As a condition of an award, the licensees are also required to conclude an accounting agreement with detailed provisions on the accounting and financial aspects of the partnership.

Offer letter

Before awarding production licenses, the MPE will recommend to the government that specified companies receive interests in the acreage being offered. An offer letter is sent to each company with details of the interests being offered and of possible operatorships. It also specifies the terms which will apply to the license on offer, and is thus regarded as a key document in the award process.

Various agreements

If a discovery extends across more than one production license, the licensees are obliged to conclude a unitization agreement which ensures appropriate utilization of these resources and regulates rights to the discovery. Interests in a unitized field are normally allocated in line with the way resources in the discovery divide between the production licenses concerned. Licensee interests in a unitized field will thereby differ from their holdings in the separate production licenses covering the field. A unitization agreement requires the MPE's approval.

A licensee can also conclude a pass-through agreement with its foreign parent company which transfers rights and obligations in a license to the Norwegian branch of the parent company. Such agreements require the consent of the MPE.

2.4.6.1.4. Other key legal provisions

The Petroleum Act requires licensees to submit a plan for development and operation (PDO) to the MPE for approval before they can start developing a petroleum deposit. The MPE is also authorized to approve plans for the installation and operation (PIO) of facilities not covered by an approved PDO. The MPE should also approve any use of such installations by third parties. To the extent that this relates to the most important pipelines for landing gas (the upstream gas transport network), however, the Act specifies that natural gas companies and qualified customers have the right of access to these facilities.

The most important pipelines for transporting natural gas and transport-related facilities have been integrated in a unified transport system (Gassled). This organization became operational on 1 January 2003. A new chapter in the petroleum regulations came into force on the same date which establishes new rules about access to gas pipelines from the Norwegian Continental Shelf (NCS) and facilities providing associated technical services.

Where Gassled is concerned, the regulations specify that Gassco – established as a wholly state-owned limited company in May 2001 – as operator for Gassled will not only be responsible for operating the system but also for ensuring that the regulations concerning access to Gassled are observed. Tariffs in Gassled are governed by a special regulation on determining such tariffs, issued by the MPE in 2003.

According to the Petroleum Act, the Government decides where and how petroleum is to be brought ashore.

The Petroleum Act also requires licensees, as a general rule, to submit a cessation plan two to five years before a license expires or is relinquished, or the use of a facility is terminated. The MPE will then decide on the disposal of these facilities.

The Regulations under the Petroleum Act also specify the requirements for environmental monitoring of the petroleum activities, which includes monitoring of the seabed sediments and the water column, as well as a quality assurance program, reporting, and the use of international standards.

2.4.6.1.5. Environmental regulations

Exploration for, and production of, petroleum entails a number of activities that have environmental consequences. Activities on the Norwegian shelf are subject to a regulatory regime that is relatively strict. Act of the 13 March 1981 No.6 concerning protection against pollution and concerning waste (the Pollution Control Act), most recently amended by Act of 12 June 1996 No.36, imposes a number of regulations on all types of emissions and the Petroleum Act requires an operator to perform a detailed environmental impact assessment before a permission to develop a field can be issued.

In terms of discharges to sea, organic compounds, oil, and chemicals used in production are the most important. Among these, water from the reservoir following the oil and gas ('produced water') containing oil is the most significant discharge today. The levels of discharges set by domestic regulations are mandated mainly by international agreements. In the case of the petroleum industry, the 1992 Convention for the Protection of the Marine Environment of the North-East Atlantic (the OSPAR Convention) (see Appendix 2.1, section A3 on regional conventions) is the most important. The work under the OSPAR Convention has resulted in measures regarding the disposal of disused offshore installations (OSPAR Decision 98/3) and the management of produced water from offshore installations (OSPAR Recommendation 2001/1).

The objective of zero harmful discharges to sea was introduced in 1996, in a Report to Storting (ME, 1997). Subsequent reports to the Storting have reconfirmed and elaborated upon this objective, and all existing production facilities are required to meet this target by the end of 2005 (ME, 2003). The preference for new field developments is re-injection of produced water. This is a prerequisite for developments in the Barents Sea. Drilling operations in that region are also required to have zero discharges, except for those resulting from the drilling of the top-hole section for surface casing.

Regarding emissions to air – carbon dioxide (CO_2), nitrogen oxides (NO_x) and non-methane volatile organic compounds (nmVOC) – the contributions of the petroleum industry are significant in a national context. For CO_2, for example, 28% of the national emissions are from the petroleum industry (MPE, 2004). The main source for these emissions is the production of energy at the production installations. Also in this area, domestic measures are mandated by international agreements, the 1992 United Nations Framework Convention on Climate Change and its 1997 Kyoto Protocol being the most significant, along with the 1979 UNECE Convention on Long-range Transboundary Air Pollution (LRTAP) and its subsequent protocols (see Appendix 2.1, section A2 for information on relevant international conventions). Allocating cuts required by the Kyoto Protocol among industries is a matter for domestic politics, and is not specified in the protocol itself.

An important environmental measure is the CO_2 tax introduced in 1991. This applies to all burning of fossil fuels entailing emissions of CO_2. In 2005 the CO_2 tax was NOK 0.78 per liter of petroleum/ Sm^3 (standard cubic meter) of gas.

Norway has from the early days of petroleum activities had very strict rules for flaring of gas. The Petroleum Act specifies that flaring as a general rule is not allowed. It may be done in an emergency or in extraordinary operational situations. Norway has among the lowest volumes of flared gas in the world, compared to the size of the production.

For the Svalbard archipelago, where some minor petroleum exploration projects were undertaken in the 1960s and 1970s (Arlov, 2003), the 2001 Svalbard Environmental Protection Act prohibits exploration for and exploitation of petroleum in the area, on land as well as in the waters out to the territorial limits. This applies universally and therefore does not conflict with the equal treatment provisions of the Svalbard Treaty.

The only difference between the national petroleum regime and that for the northern regions is found with regard to environmental regulations: there shall be no discharges of produced water during regular operations and, except for the drilling of the top-hole, produced water and other drilling debris shall be re-injected or taken onshore, if no better solution exists. Special measures are introduced to protect the fisheries. Among other things, there are geographical and temporal restrictions on drilling and seismic activity.

2.4.6.1.6. Environmental impact assessments

Norway's Petroleum Act calls for environmental impact assessments to be carried out as part of the input for decision-making at several stages in petroleum operations (see also Chapter 6). Such studies are required before an area is opened to exploration, in connection with field and transport system developments, and when disposing of abandoned installations.

The MPE is responsible for ensuring that environmental impact assessments are performed before an area is opened for the award of exploration licenses. Because the issue of opening new areas ranks as very important in terms of an overall social evaluation and for local interests, it calls for comprehensive and detailed consideration. An impact assessment is intended to clarify the environmental consequences of petroleum operations and possible pollution threats as well as the economic and social effects which could follow from the exploitation of petroleum reserves in the area.

On the basis of such an assessment, the Storting undertakes an overall assessment of the advantages and disadvantages of pursuing petroleum operations in an area. Production licenses will not be awarded where the disadvantages are greatest. Both the Storting and the Government can also impose special conditions on an area, such as prohibiting drilling in certain periods.

An environmental impact assessment must have been carried out when an operator seeks official approval of development plans (PDO/PIO) for field installations, transport or landfall pipelines, and other petroleum facilities. This assessment must include a description of the environmental effect of expected emissions from the project, and must review the cost-benefit of alternative measures for reducing this impact. The assessment is sent out for public hearing to ensure that all consequences of a project are identified as fully as possible. Measures to be implemented are determined as part of the final approval of a project by the Storting or the Government.

Before a license expires or an installation is abandoned, the licensees must submit a decommissioning plan. This must be accompanied by an impact assessment covering relevant methods for disposing of the installations concerned. The authorities will consider the plan before reaching an abandonment decision.

2.4.6.1.7. Tax and royalty system

Petroleum activity is subject to ordinary corporate tax, currently 28%. An additional special tax of 50% on the extra profitability of petroleum production ('super profit') is levied on the oil companies. When calculating taxable income for both ordinary and special tax, investment is subject to depreciation on a straight-line basis over six years from the date it was made. An uplift of 30% of the investment – 5% for six years from the date of the investment – protects the companies' normal return from the special tax. Companies can also deduct all relevant costs, including exploration and net financial expenses. In addition, there is full consolidation for all fields.

The most important duties levied on petroleum operations are royalty on oil production, the area fee, and the CO_2 tax. Royalty has now (since 2005) been phased out in Norway.

All production licenses must pay the area fee after the exploration period has expired. The annual fee for most licenses increases from NOK 7000 to a maximum of NOK 70 000 per square kilometer over the subsequent decade. If companies renounce the right of pre-emption in the production license, they can apply for a 40% reduction in the area fee. Special rules apply for the oldest licenses, and for licenses in the Barents Sea.

The CO_2 tax was introduced primarily as a 'green tax' and is levied at a rate per Sm^3 of gas burned or directly released and per liter of petroleum burned. The rate for 2005 was NOK 0.78 per liter of petroleum/Sm^3 of gas.

2.4.6.1.8. State's Direct Financial Interest

The SDFI was established in 1985 by dividing Statoil's holding in most Norwegian offshore licenses into an equity share for the company and a direct interest for the State. An SDFI interest is also incorporated in a number of licenses awarded after 1985. As a result, the State now has a direct interest in most petroleum fields and transport systems on the Norwegian continental shelf. In connection with Statoil's partial privatization, the Government sold SDFI assets corresponding to 15% of the portfolio's value to the company. A further 6.5% was sold to other companies in spring 2002.

Under the SDFI arrangement, the State pays a share of all investment and operating costs in a project corresponding to its direct interest. It also receives a corresponding proportion of production and other revenues on the same terms as other licensees. Petoro manages the SDFI portfolio on behalf of the Government.

2.4.6.1.9. Petroleum resources

Norway's total petroleum resources add up to (a mean value of) 13.1 billion Sm^3 o.e. (standard cubic meters of oil equivalents), of which 4.3 billion Sm^3 o.e. have been produced, remaining proven petroleum resources comprise 5.4 billion Sm^3 o.e., and the yet-to-find is estimated at 3.4 billion Sm^3 o.e. (as of 1.1.2006). There is, of course, a large uncertainty range on these numbers and the range of the remaining total resources is between 6.3 and 12.0 billion Sm^3 o.e. ($P_{90} – P_{10}$) (NPD, 2006; MPE, 2006). Table 2.43 illustrates how these resources are divided between the different areas and resource categories.

Exploration for oil and gas in Norway started in the North Sea in 1965, where the first commercial discovery was made in 1969. The first areas in the Norwegian Arctic were opened for exploration in 1979 in the fifth licensing round, which included areas in the Norwegian Sea and in the southern part of the Barents Sea. Licenses were awarded in three batches in 1980 and 1982. The first discovery was made in 1981.

Table 2.43. Petroleum resources on the Norwegian continental shelf (MPE, 2006).

	Oil, million Sm^3	Gas, billion Sm^3	Natural gas liquids, million tonnes	Condensate, million Sm^3	Total, million Sm^3 o.e.
Produced	3018	1033	90	81	4302
Remaining reserves	1231	2412	138	47	3953
Contingent resources in fields	310	156	17	4	503
Contingent resources in discoveries	138	494	30	37	727
Potential from improved recovery [a]	137	100			237
Undiscovered	1160	1900		340	3400
Total	5995	6094	275	509	13122
North Sea					
Produced	2668	973	79	64	3855
Remaining reserves	958	1577	75	4	2682
Contingent resources in fields	262	118	10	4	404
Contingent resources in discoveries	87	161	15	18	293
Undiscovered	615	500		75	1190
Total	4590	3329	179	165	8425
Norwegian Sea					
Produced	350	60	11	17	447
Remaining reserves	273	675	57	24	1080
Contingent resources in fields	48	38	7	0	99
Contingent resources in discoveries	45	325	16	19	418
Undiscovered	235	810		175	1220
Total	951	1907	90	235	3264
Barents Sea					
Produced	0	0	0	0	0
Remaining reserves	0	161	6	18	191
Contingent resources in fields	0	0	0	0	0
Contingent resources in discoveries	7	8	0	1	16
Undiscovered	310	590		90	990
Total	317	759	6	109	1197

[a] Resources from future measures for improved recovery are calculated for the total recoverable potential and have not been broken down by area.

2.4.6.2. Development of oil and gas activity in Norway

The indices presented here for the oil and gas provinces in Norway can be viewed in relation to the overall indices of oil and gas activity in the Arctic as a whole (see section 2.3). With regard to the areas in Arctic Norway the indices show the area licensed for oil and gas activities (Figure 2.72) and explored by 2-D and 3-D seismic acquisition (Figures 2.73 and 2.74 respectively), the number of meters of exploratory, discovery, and production wells (Figure 2.75), and the amount of oil production and gas production generated in Arctic Norway (Figures 2.76 and 2.77, respectively).

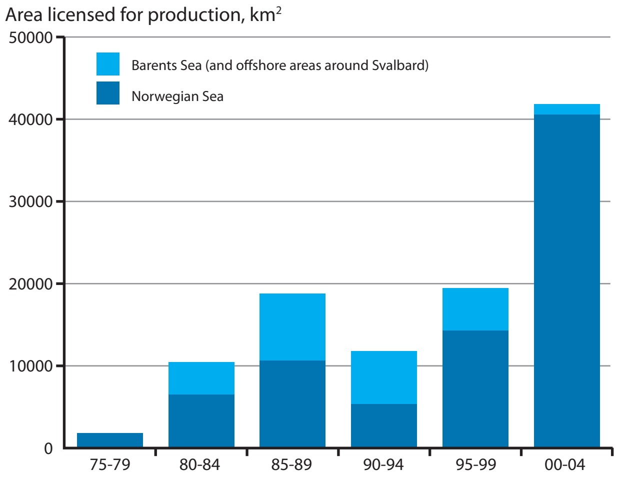


Figure 2.72. Arctic Norway leases and licenses over time by region.

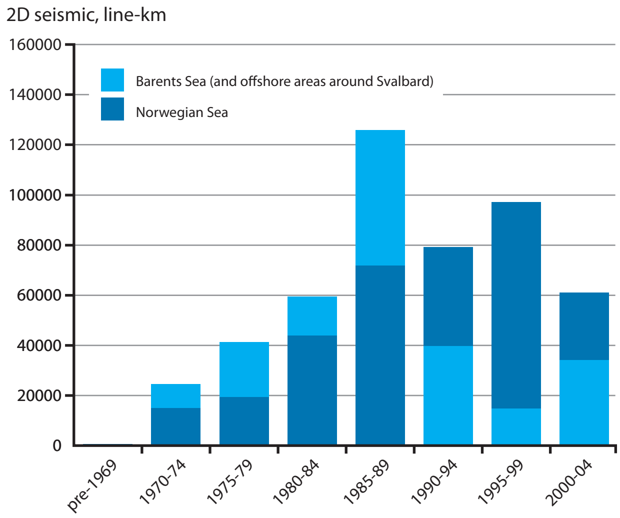


Figure 2.73. Arctic Norway 2D seismic data acquisition over time by region.

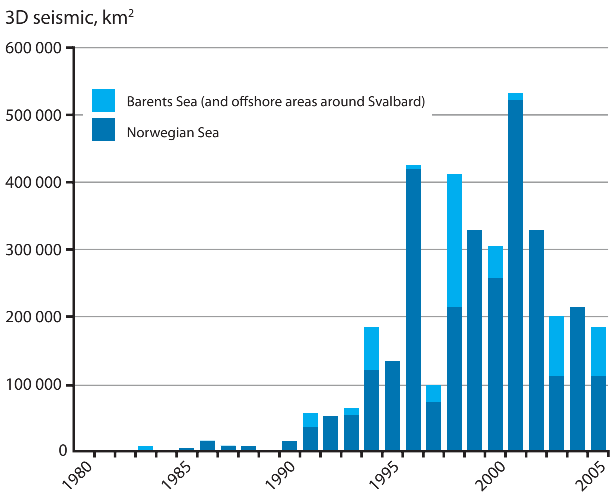


Figure 2.74. Arctic Norway 3D seismic data acquisition over time by region.

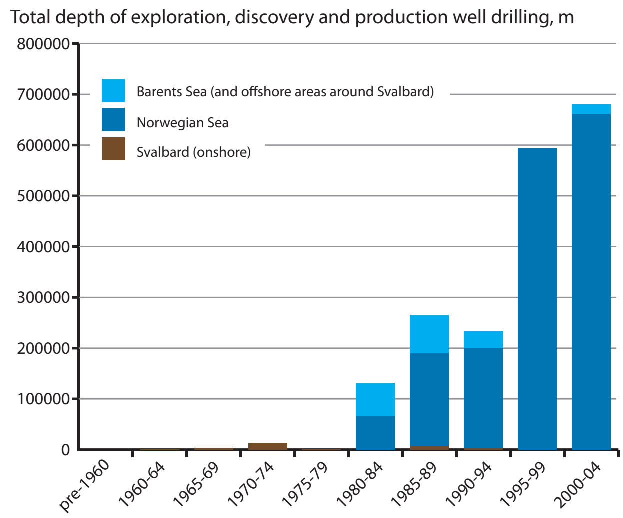


Figure 2.75. Arctic Norway meters wells drilled over time by region.

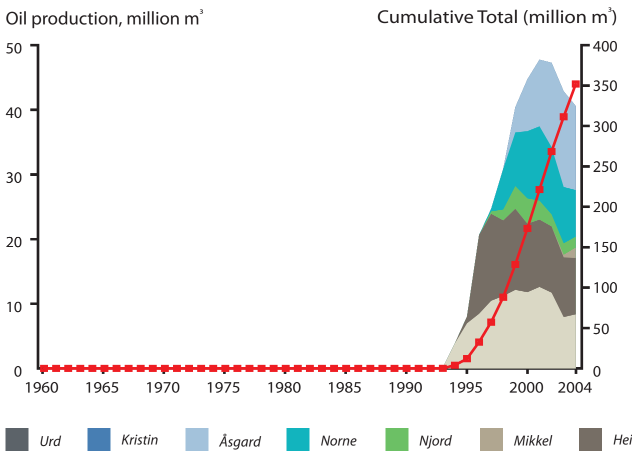


Figure 2.76. Arctic Norway oil production over time by field.

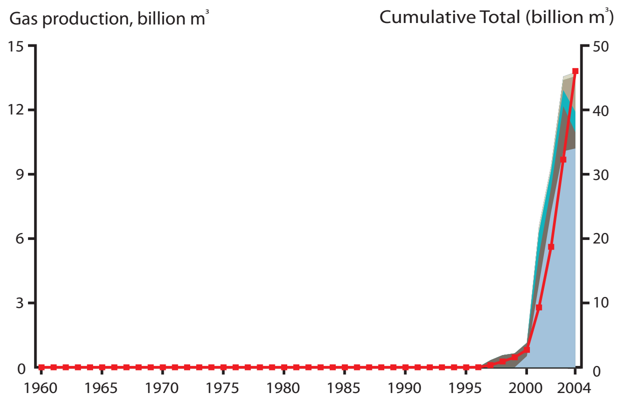


Figure 2.77. Arctic Norway gas production over time by field.

2.4.6.3. The Norwegian Sea

2.4.6.3.1. Historical to present

Pre-exploration

Exploration for oil and gas in the Norwegian Sea started in 1980. Activity increased in 1994 when the Storting opened larger parts of the Norwegian Sea, including the deep-water areas in the west. The areas around Lofoten and some areas close to the coast were not opened or opened on special conditions that include limitations on the size of the activity.

Exploration

There have been 196 exploration and appraisal wells drilled to date (1.1.2006) in the Norwegian Sea, in addition to 264 production wells. The first discovery was 6507/11-1 Midgard (now part of the *Åsgard* field), made in 1981. Since then more than 40 discoveries of oil and gas have been made. More detailed descriptions of the exploration activity can be found in reports by the Norwegian Petroleum Directorate and the Norwegian Ministry of Petroleum and Energy (NPD, 2003, 2005, 2006; MPE, 2006).

The *Draugen* oil field was the first to be approved for development, in 1988. First oil from the field was delivered in 1993. Since then the *Heidrun*, *Njord*, *Norne*, *Åsgard*, *Mikkel*, *Urd*, and *Kristin* fields have come on stream. One additional large field has been approved for development; the *Ormen Lange* field (gas), which is expected to come on stream in 2007, in addition to the smaller *Tyrihans* gas/condensate and oil field. Oil and gas are transported from the Norwegian Sea both by tanker and by pipeline.

An activity map that includes fields, pipelines, and terminal facilities is shown in Figure 2.78. Detailed descriptions are published each year by the Norwegian Ministry for Petroleum and Energy (MPE, 2006).

2.4.6.4. The Norwegian part of the Barents Sea

2.4.6.4.1. Historical to present

Pre-exploration

The Norwegian Barents Sea is generally regarded as less prospective than the more mature offshore areas in the North Sea and the Norwegian Sea. This is due to less favorable geological conditions for generation and

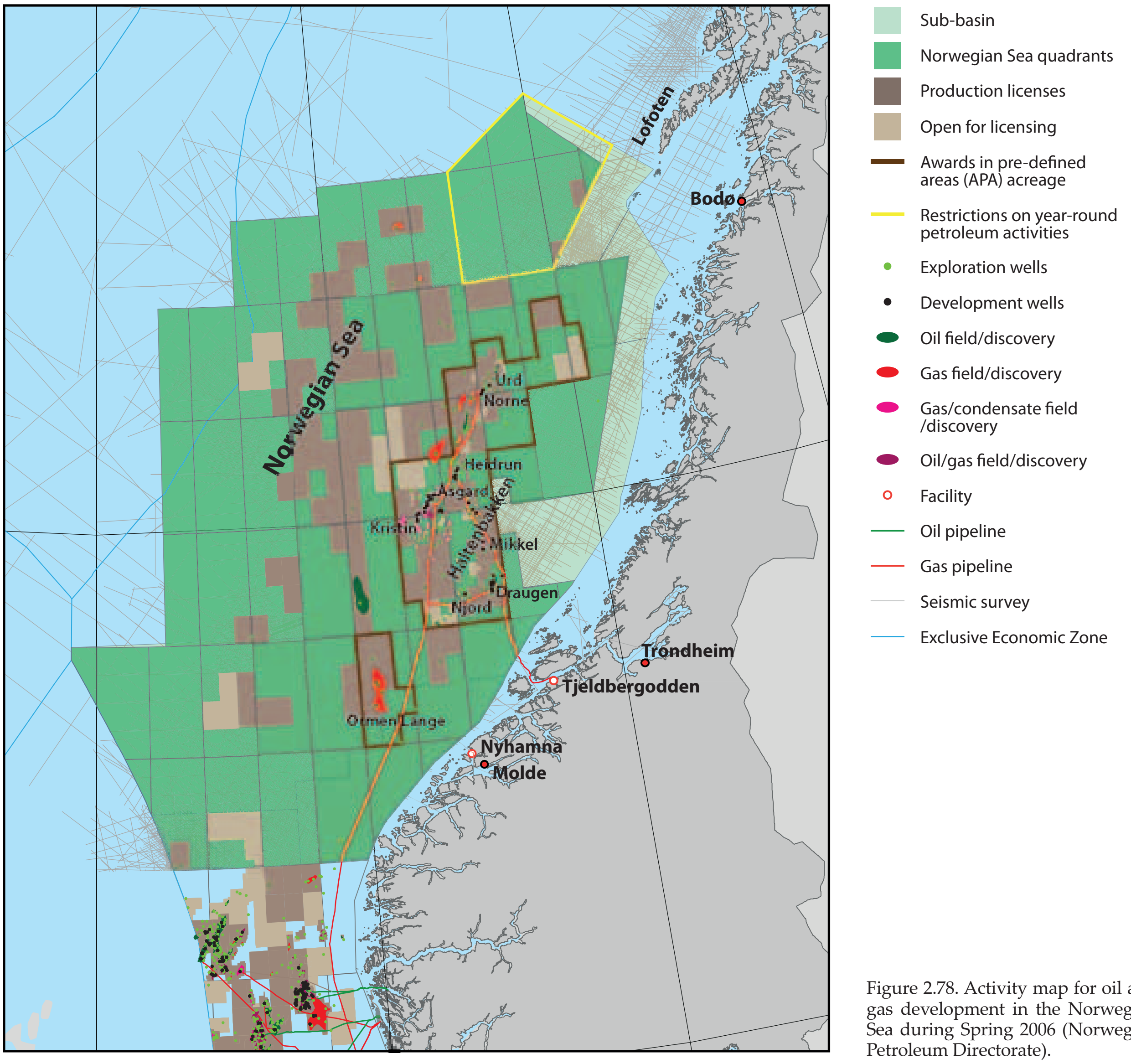


Figure 2.78. Activity map for oil and gas development in the Norwegian Sea during Spring 2006 (Norwegian Petroleum Directorate).

retention of oil and gas. However, only a limited part of the Barents Sea has been efficiently explored, and the uncertainties regarding prospectivity in the remaining areas are significant.

Long distances to potential markets for the oil and gas, climatic conditions which demand extra precautions regarding safety and pollution control, and the relationships with other activities in the area have significantly influenced the commerciality of oil and gas activities here. Together with a step-by-step licensing approach by the authorities, limited exploration success, and periods of low oil prices these factors have resulted in a relatively modest activity level in this part of the Norwegian continental shelf.

Parts of the Norwegian Barents Sea were opened for exploration by the Storting in 1979. The Government decided in 2001 to temporarily stop exploration drilling in the Barents Sea until the Government had carried out a new impact assessment of all-year petroleum activity in the area ('ULB'). Based on that assessment, the Government re-opened the southern part of the Norwegian Barents Sea for all-year activity, apart from the areas closest to the coast and certain particularly valuable areas in terms of environmental sensitivity and fishery interests. The Storting decided on 15 June 2006 that (with just a few exceptions) the southern part of the Barents Sea should be re-opened for petroleum activity, while there will be no petroleum activity in the areas outside Lofoten and Vesterålen at least until 2010.

Exploration

A total of 64 exploration and appraisal wells have been drilled to date (1.1.2006) in the Norwegian Barents Sea. Nine production wells have been drilled. The first discovery was made in 1982; 7120/7-1 (now part of the *Snøhvit* field). Since then nine other discoveries of oil and gas have been made. The discoveries are almost entirely confined to the Hammerfest Basin, which is the only part of the Norwegian Barents Sea that can be called 'mature' in terms of exploration. The wells have primarily discovered gas, and the Norwegian Barents Sea has for some time been regarded as a gas province. The discovery of significant amounts of oil in 7122/7-1 Goliat has increased attention to oil in this area again. Although gas is regarded as the most abundant phase, uncertainties regarding the hydrocarbon phase that may be discovered in the little-explored regions remain large. A more detailed description of the exploration activity can be found in reports by the Norwegian Petroleum Directorate (NPD, 2003, 2005).

An activity map that includes fields, pipelines, and terminal facilities is shown in Figure 2.79. Detailed descriptions are published each year by the Norwegian Ministry for Petroleum and Energy (MPE, 2006).

One field has been approved for development in the Norwegian part of the Barents Sea: the *Snøhvit* gas/condensate field. This field includes several nearby discoveries that will be developed entirely through sub-sea installations. Gas and condensate will be transported in a pipeline to Melkøya, near Hammerfest (Figure 2.79), where the gas will be processed to liquefied natural gas (LNG) and shipped to the market on LNG tankers. Production start-up is planned for 2007.

<u>Licensing.</u> A total of 155 production licenses have been issued (by 1.1.2006) in the Norwegian Sea and the Barents Sea and of these 89 are still active. Nine so-called 'seismic licenses' also exist, which are large areas where the oil companies only undertake seismic acquisition and where the extent of the production license area will be decided at a later stage. Thirteen new licenses were awarded in the nineteenth licensing round in 2006 and annual awards

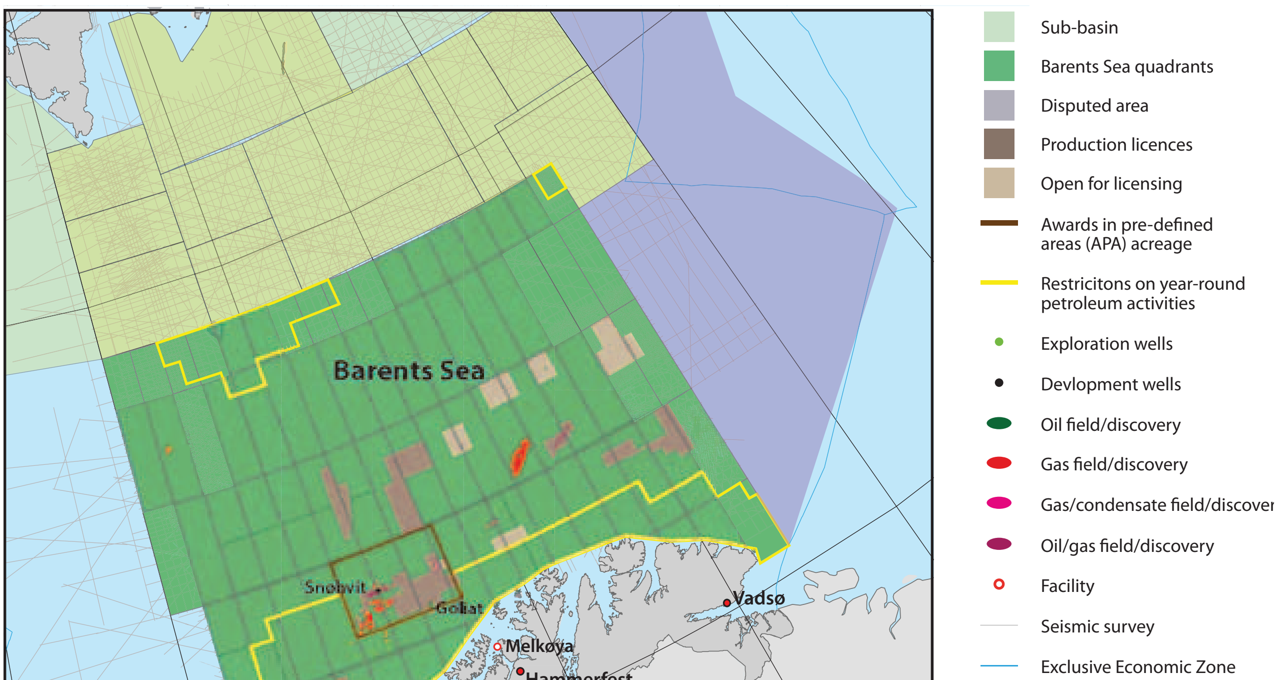


Figure 2.79. Activity map for oil and gas development in the southern part of the Barents Sea during Spring 2006 (Norwegian Petroleum Directorate).

in pre-defined areas (APA) will continue. The license situation in Spring 2006 is shown in Figures 2.78 and 2.79.

Drilling. Ten exploration and appraisal wells have been drilled in the Norwegian Sea and three wells in the Norwegian Barents Sea during 2004 and 2005. The exploration targets include both oil and gas prospects.

Discoveries and development

Snøhvit. The *Snøhvit* field was the first field development in the Norwegian part of the Barents Sea. The development includes Europe's first export facility for LNG. It is also an example of modern offshore field development in the Arctic, where all the field installations are sub-sea and controlled from shore. The *Snøhvit* field is therefore described in some detail as an example of state-of-the-art offshore development. Most of the text and illustrations were provided by Statoil.

Snøhvit is located approximately 140 km northwest of Hammerfest. It comprises three discoveries that will be developed together using only sub-sea production facilities. There will be no surface installations. Natural gas, condensate, and natural gas liquids (NGL) will be transported in a multiphase pipeline to the Melkøya terminal and processing plant outside Hammerfest. The products will be treated at the processing plant and exported on ships as LNG, condensate, and liquefied petroleum gases (LPG). Production start-up is planned for late 2007. The operator is Statoil ASA. Some of the key facts are shown in Table 2.44.

Snøhvit was discovered in 1984. The reservoirs contain natural gas with small quantities of condensate. Parts of *Snøhvit* also have a thin layer of oil underneath the gas. A decision as to whether to produce this oil is being discussed. The field extends across seven production licenses, and the interests in these were unitized after negotiations in 1999–2000. When the authorities approved this unitization agreement in July 2000, the licenses were extended until 2035.

An attempt was made in the early 1990s to establish a basis for developing *Snøhvit*. Statoil initiated a planning process in 1991 under Norwegian legal provisions for impact assessments relating to a possible project. Plans then embraced an offshore field development and a gas liquefaction plant at Slettnes on Sørøya near Hammerfest. They depended on selling LNG to the Italian market. A proposed program of impact assessments was submitted to the MPE, which circulated the proposal for comments in September 1991. Due to cost and market factors, the operator halted the planning process and the MPE never specified an assessment program.

Statoil did not abandon its plans for LNG exports based on gas resources in the *Snøhvit* area, but development costs needed to be reduced. A new development concept for the field was proposed, with a landfall on the island of Melkøya and sub-sea production installations remotely operated from shore. Planning resumed in 1997, with a new proposal for assessments submitted to the MPE in the following year. This embraced both new impact assessments and upgrading of preparatory work done in the previous development process. On behalf of the licensees, Statoil submitted a plan for development and operation of the field in September 2001, and this was approved by the Storting (the Norwegian Parliament) in March 2002.

Less than two weeks after the Storting go-ahead, the EFTA (European Free Trade Association) Surveillance Authority (ESA) – which monitors the European Economic Area (EEA) – wanted to establish whether the special depreciation rules adopted for *Snøhvit* might breach the provisions on state subsidies in the EEA agreement between Norway and the European Union. This issue had been raised with the ESA by Bellona, a Norwegian environmental organization which had campaigned to halt offshore operations in the Barents Sea. The ESA

Table 2.44. Facts about the *Snøhvit* Project (Statoil, 2006).

Recoverable reserves:	190 billion m^3 of natural gas 113 million bbl of condensate (light oil), corresponding to 17.9 million m^3 5.1 million tonnes of NGL
Water depths:	250–345 m
Development solution:	Remotely-operated sub-sea installations and pipeline transport to land
Pipeline:	143-km line with multiphase flow
Land plant:	Melkøya, just outside the shipping channel into Hammerfest
Annual exports:	5.67 billion Sm^3 of LNG, corresponding to 4.1 million tonnes 3.1–5.7 million bbl of condensate, corresponding to 500–900 000 Sm^3 150–250 000 tonnes of LPG
Annual shipments:	About 70 cargoes of LNG
Project schedule:	Construction started in the first half of 2002, with contractual gas deliveries scheduled to commence on 1 December 2007
Investment:	NOK 58.3 billion (2007) for field development, pipeline and land plant (excluding costs associated with LNG ship construction)
Jobs:	In the production phase: 350–400 new jobs in Hammerfest, including 160 at the gas liquefaction plant
Local deliveries:	During the development phase, 2002–2007: NOK 2.8 billion for industry in the north Norwegian counties of Nordland, Troms and Finnmark up to August 2005, including NOK 2.2 billion for Finnmark (the estimate for north Norwegian deliveries when the project started was NOK 600 million) NOK 240 million per year in regional/local deliveries during the production phase
Production period:	2007–2035

intervention meant that site preparations on Melkøya were suspended until the Authority announced in early June that it had approved the revised tax terms for *Snøhvit*.

All installations on the *Snøhvit* field will be sub-sea, which means that no part of the development will be visible at the sea surface. The seabed facilities are designed to be over-trawlable, so that neither they nor fishing equipment will suffer any damage from physical contact. A total of nine wells are planned on *Snøhvit*, including eight for production and one for injecting CO_2 back below ground. Four templates have been installed to provide a framework for drilling the wells (see Figure 2.140). In addition, one control distribution unit (CDU) and one pipeline end manifold (Plem) have been installed.

The six seabed structures were installed on the field during summer 2004. Each template is fixed in place with the help of suction piles attached to legs beneath the structure. The wells drilled through the template will also help to hold it in position. Hatches on top of the templates can be opened to permit the deployment of manifolds and other equipment once installation is complete. In the event of maintenance which cannot be carried out on the seabed, the hatches can be opened again and the equipment retrieved to the surface.

The field will be tied to the land-based plant by several links. The largest is the gas pipeline, which will be 143 km long and have an internal diameter of 65.5 cm. In addition, there will be two chemical lines, an umbilical, and a separate pipeline for transporting CO_2 (see Figure 2.141). Gas from the *Snøhvit* area contains 5–8% CO_2, which will be separated out at the land plant and returned in a separate line for storage beneath the seabed.

Snøhvit's sub-sea installations will be operated via an umbilical. Both sub-sea production on the field and pipeline transport will be monitored and controlled from the control room at the gas liquefaction plant on Melkøya in northern Norway (see Figure 2.138). Operators will be able to open and close valves on the seabed 140 km away with signals transmitted along fiber-optic cables, and with high-voltage electrical and hydraulic power lines.

The unprocessed well stream arriving at Melkøya outside Hammerfest must be separated before the gas can be cooled to liquid form and exported in special carriers. Carbon dioxide removed from the well stream will be returned offshore for storage underground. Condensate and natural gas liquids (butane and propane) must also be separated out for export by sea. After this, the resulting lean gas is cooled to −163 °C in the liquefaction plant. The LNG will be stored in dedicated tanks before being shipped out.

Some of the world's largest LNG carriers (Figure 2.142) will load every six days at the Melkøya plant. That makes about 70 consignments per year. Five LNG carriers, each 290 m long and able to carry about 140 000 m^3, are required to handle this export volume.

Ormen Lange. The *Ormen Lange* field is the second largest gas field in Norway, second only to *Troll* in the North Sea. The current estimate of recoverable reserves is 375 billion Sm^3 gas and 22 million Sm^3 of condensate. It is located approximately 140 km northwest of Kristiansund. The water depth is between 800 and 1100 m and the field will be developed using only sub-sea facilities. The gas and condensate will be piped to a new terminal at Nyhamna in Møre og Romsdal County (see Figure 2.78). The products will be treated at Nyhamna and exported in a 1200-km pipeline to Easington in the United Kingdom. The export capacity is 70 million Sm^3 gas per day. Production start-up is planned for 2007. The operator in the development phase is Norsk Hydro Produksjon a.s. In the production phase, the operator will be A/S Norske Shell (MPE, 2006).

Tyrihans. The *Tyrihans* field includes two discoveries (Tyrihans North and Tyrihans South). Recoverable reserves total 30 million Sm^3 of oil, 30 billion Sm^3 of gas, and 5.5 million tonnes of condensate. The field is located 25 km southeast of the *Åsgard* field. The two reservoirs contain condensate-rich gas with underlying oil columns. The field will be developed with sub-sea installations through tie-in to the *Kristin* field. Recovery is based on gas injection from the Åsgard B facility into Tyrihans South in the first years. In addition, sub-sea pumps will be used to inject seawater to further increase recovery.

Infrastructure and transportation

Pipelines. Pipelines in Arctic Norway are shown in Figure 2.78. Åsgard Transport starts at the *Åsgard* field and ends at Kårstø in Rogaland, southern Norway, a distance of 707 km. It was put on production in 2000. The pipeline has a 42-inch diameter and a capacity of 69–71 million Sm^3 per day. The operator is Gassco AS. The Heidrun Gas Export pipeline ties the *Heidrun* field to Åsgard Transport. It is 37 km long and has a diameter of 16 inches. The operator is Statoil ASA. The Norne Gas Transportation System connects the *Norne* field to Åsgard Transport. The distance is 126 km and the diameter is 16 inches. The operator is Gassco AS. Draugen Gas Export connects the *Draugen* field to Åsgard Transport. It is 75 km long and the diameter is 16 inches. The operator is AS Norske Shell. Haltenpipe transports gas from the *Heidrun* field to Tjeldbergodden Terminal in Møre og Romsdal County. It has a diameter of 16 inches and a capacity of 6 million Sm^3 per day. The operator is Gassco AS.

Terminals. Tjeldbergodden is located in Møre og Romsdal County, central Norway. It is the landing point of the Haltenpipe gas pipeline and comprises four industrial units: a methanol plant, a gas receiving station, an air separation plant, and a gas liquefaction facility. The methanol plant has an annual production of about 830 000 tonnes.

Melkøya is located outside the city of Hammerfest in Finnmark County. It will be Europe's first export facility for LNG. It is the production control facility and landing station for the gas and liquid production from the *Snøhvit* field.

Ship transportation. Table 2.45 shows the volume of oil and the number of shipments in 2004 from the fields in the Norwegian Arctic. Around 70 shipments of LNG plus seaward shipments of other products is expected each year from Melkøya, and shipments of methanol and other products from Tjeldbergodden.

Petroleum shipments from ports in the Kola and Archangelsk regions of northwestern Russia through the Barents Sea and along the north Norwegian coast have increased. Beginning in earnest in 2002 with a volume of 2 million tonnes, shipments increased to 12 million tonnes in 2004 and are likely to increase ten-fold over the next decade. While the frequency of petroleum shipments in

Table 2.45. Ship cargos in 2004 from producing fields in the Norwegian Sea (Norwegian Petroleum Directorate).

Field	Number of cargos	Oil, Sm^3	Condensate, Sm^3
Draugen	58	7760 670	
Heidrun	16	2047 026	
Njord	21	1683 147	
Norne	50	7194 309	
Åsgard	82	5811 513	3956 101

the region is not yet as high as for the major facilities in southern Norway, it is likely to increase substantially as a result of operations on the Russian side of the border (Bambulyak and Frantzen, 2005). In the near future, these shipments will remain based on oil from Siberia that is piped to the Kola Peninsula (Hønneland, 2006). In the longer term, petroleum from fields in northwestern Russia, including the Barents Sea, may come to dominate (Barlindhaug, 2005).

2.4.6.5. Future

2.4.6.5.1. Near-term (up to about 2015)

Yet-to-find estimates

The NPD estimates that the yet-to-find oil and gas resource in the Norwegian Arctic is around 2.2 billion Sm^3 o.e. (14 billion bbl o.e.) (Table 2.43). Of this, 65% is expected to be gas. This estimate includes all resources that can be technically recovered. There are large parts of the area that have been very little explored, and the estimate carries a large uncertainty. The estimate does not include the area of overlapping claim with Russia. See also NPD (2005) and MPE (2006).

Exploration prognoses

The Norwegian Government has stated that it will continue to award licenses in the Norwegian Arctic through concession rounds and awards in pre-defined areas at a scale that is proportionate to the need for further exploration activities in the area. This implies that exploration and appraisal wells will be drilled, and that discoveries are likely to be made in the years to come.

Possible new field developments

Three fields are currently being considered for development in the Norwegian Arctic (March 2006). Two lie in the Norwegian Sea: 6507/3-3 *Idun* and 6507/5-1 *Skarv*. The development concepts have not yet been decided, but it is estimated that a decision about development will be made within the next few years. *Goliat* may be the first oil field in the Norwegian Barents Sea. It is expected that further appraisal will be required before any decision is made. A total of twenty other discoveries are listed by the NPD as relevant for development sometime in the future, two in the Norwegian Barents Sea, although no direct plans exist for these developments at the moment (MPE, 2006).

2.4.7. Russian Federation

2.4.7.1. Regulatory and legislative systems relevant to Arctic oil and gas activities in the Russian Federation

Russia is a Federal state (the Russian Federation, RF) comprising 89 administrative jurisdictions (constituent units): 21 Republics, six Krais, 49 Oblasts (regions), one autonomous Oblast, ten autonomous districts, and two metropolitan areas of Federal subordination.

The territory of the Russian Federation is divided into seven Federal Okrugs (districts) that were established in May 2000. Each Federal Okrug is headed by a representative of the Russian Federation President. The Okrugs' main function is to ensure coordination between the Federal and regional authorities. The creation of the Federal Okrugs has assisted in restricting laws and practices of the constituent units, and is central to former President Putin's re-assertion of Federal authority.

The President, the Federal Assembly, and the Government represent the institutional system at the Federal level. The state power in the constituent entities of the Russian Federation (subjects of federation) is vested in the state bodies created by them. Pursuant to the Constitution of the Russian Federation, local bodies (administrations in municipal units) are not included in the system of state authorities and function independently.

The Russian Federation has two levels of state power: Federal and regional. At each level, the state power comprises three branches: representative (legislative), executive, and judicial authorities.

The principal concept regarding the division of power and responsibility among Federal, regional, and municipal authorities is to assign clearly defined, financially secured functions to each of these levels. Recent decrees stipulate that the Federal institutional system incorporates Federal ministries, Federal services, and Federal agencies as the basis for defining these functions (Table 2.46).

2.4.7.1.1. Federal level

Within the Russian Federation, the responsibility for managing natural resources, protecting the surrounding environment, protecting public health, and ensuring the safety of those engaged in related activities is divided among several key Federal authorities (Table 2.46). These include:

- Federal authorities for natural resources management and environmental protection: the Ministry of Natural Resources and the Federal services and agencies it supervises; the Federal Service for Environmental, Technological and Nuclear Supervision (RosTekhNadzor); and the Federal Hydrometeorology and Environmental Monitoring Service (RosGidromet).
- Federal authorities for public health and social development: the Ministry of Public Health and Social Development of the Russian Federation (MinZdravSotsRazvitiya) and the agencies and services

Table 2.46. Hierarchy of legislation and responsible bodies for environmental protection in the Russian Federation (Makeev et al., 2000).

Instrument	Responsible body
Constitution	
Federal Constitutional Act	Duma, President
Federal Act	Duma, President
Presidential Edict (Ukaz)	President
Governmental Decree (Postanovlenie)	Government of the Russian Federation
State Standard	Ministry of Industry, Science and Technology
Construction Norms and Regulations	State Construction Committee
[General Union] Regulatory Document	Ministries
Code of Regulations	State Construction Committee
Sanitary Regulations	Ministry of Health
Sanitary Norms	Ministry of Health
Hygienic Norms	Ministry of Health
Sanitary Norms and Regulations	Ministry of Health
Inter-Sectoral Health and Safety at Work Regulations	Ministry of Labour
Sectoral Standard	Federal bodies of executive power
Construction Guideline	State Construction Committee
Departmental Construction Norms	Federal bodies of executive power
Regional Construction Norms	State Construction Committee
Instructions and Departmental Norms	Federal bodies of executive power
Guidelines	Federal bodies of executive power
Safety Regulations	Federal bodies of executive power
Regulations for Organisation and Safe Operations	Federal bodies of executive power
Sectoral Regulations for Health and Safety at Work	Federal bodies of executive power
Model Sectoral Regulations for Health and Safety at Work	Federal bodies of executive power
Recommendations, Methodical Instructions, Statutes etc.	Federal bodies of executive power

it supervises: the Federal Consumer Rights Protection and Human Welfare Supervision Service; the Federal Public Health and Social Development Supervision Service; the Federal Labor and Employment Service; the Federal Public Health and Social Development Agency; and the Federal Physical Education, Sports and Tourism Agency.

- Federal authorities for industrial safety: RosTekhNadzor; the Ministry of Industry and Energy and agencies and services it supervises; and the Ministry of Civil Defense, Emergency Situations, and Natural Disaster Response of the Russian Federation (Ministry of Emergencies of the Russian Federation).

A brief outline of the structure, functions, and key responsibilities associated with each of these Federal authorities follows, including the ministries and agencies within these authorities and summaries of their jurisdiction and responsibilities. Excise taxes in the Russian Federation are summarised in Table 2.47.

Ministry of Natural Resources and Ecology

Currently, the Ministry of Natural Resources and Ecology (MNRE) is the main Federal ministry responsible for environmental management; it is authorized to independently adopt regulatory acts. In addition, the MNRE develops State policy and legal regulations regarding the investigation, use, regeneration, and environmental protection of natural resources, including: Federal subsoil resources management; forestry management; water resources use and protection; forest resources use, protection and regeneration; operation and safety maintenance of multi-purpose water storage systems and protective hydropower engineering facilities; use of wildlife and the habitat (except fauna species regarded as game animals); specially protected natural territories; and environmental protection.

The MNRE also coordinates and supervises activities of the following organizations under its jurisdiction:

- The Federal Service of Natural Resources Management (RosPrirodNadzor), which performs supervisory functions, including overseeing the efficient use and protection of subsoil resources, forests, and water bodies. RosPrirodNadzor also organizes and conducts the State Environmental Expert Reviews (SEER).
- The Federal Agency of Water Resources (RosVodResoury), which provides government services and State property management of water resources use, including: State review of pre-design and design documentation for construction and upgrading of various facilities that impact the condition of water resources; ownership, use, and management of water resources on Federal property; management of the water fund, registration and issuing of water use licenses; State monitoring of water bodies; establishing water use limits (water consumption and disposal) for water bodies on Federal property; providing water users with agreed norms for Maximum Allowable Discharges (PDV) of hazardous substances to water bodies; and providing recommendations to the constituent entities of the Russian Federation authorities on the dimensions and boundaries for sanitary zones for water bodies, buffer coastal areas, and the use of water resources.
- The Federal Agency of Forestry (RosLesKhoz), which implements State policy, provides government services, and performs State property management in forestry.
- The Federal Agency of Subsoil Use (RosNedra), which provides government services and State property management in subsoil resources use, including the Federal Service for Environmental, Technological, and Nuclear Supervision (RosTekhNadzor). RosTekhNadzor is the State agency for mining supervision, a specially authorized government environmental expert agency, and a specially authorized agency for the protection of air quality including regulating the collection of fines for negative environmental impacts. RosTekhNadzor also performs functions pertaining to the adoption of regulatory acts, control and supervision in a variety of areas including: environmental protection via the limitation of negative environmental impact (including industrial and domestic waste management); monitoring compliance with the environmental protection laws of the Russian Federation (State environmental control), within the scope of its competence; and monitoring compliance with the requirements of Russian Federation laws regarding air quality protection and waste management, including the licensing of hazardous waste management. RosTekhNadzor issues permits for emissions of pollutants to the environment and harmful impacts on air quality, establishes limits for the disposal of wastes, and maintains a State inventory of wastes and a State waste management accounting system including the issuance of hazardous waste certificates. It also organizes and conducts the SEER reviews.

Table 2.47. Excise taxes in the Russian Federation.

	Tax rate	
Natural gas sold (transferred)		
within the territory of the Russian Federation	15%	
to member states of the CIS	15%	
outside the territory of the Russian Federation (to the far abroad)	30%	
Comparative analysis of excise rates for certain petroleum products in 2002 and 2003	2002	2003
automobile petrol with octane numbers up to and including 80	15.12%	21.9%
automobile petrol with other octane numbers	20.72%	30%
diesel fuel	6.16%	8.9%
directly distilled petrol	Not excisable	

Federal Hydrometeorology and Environmental Monitoring Service (RosGidromet)
RosGidromet performs functions related to the adoption of regulatory acts, management of State property and the provision of government services regarding hydrometeorology and other related fields, the monitoring of pollutants and the natural environment, and State supervision of work affecting meteorological, hydrological, and geophysical processes.

Ministry of Public Health and Social Development of the Russian Federation (MinZdravSotsRazvitiya)
MinZdravSotsRazvitiya develops government policy and legal regulations regarding health protection, social development, labor and consumer rights protection, health and epidemiological well-being, and social protection of the population. MinZdravSotsRazvitiya coordinates and supervises the activities of the Federal Consumer Rights Protection and Human Welfare Supervision Service, the Federal Public Health and Social Development Supervision Service, the Federal Labor and Employment Service, the Federal Public Health and Social Development Agency, and the Federal Physical Education, Sports and Tourism Agency.

RosPotrebNadzor is an authorized Federal executive authority that supervises and controls compliance with the mandatory requirements of the Russian Federation related to ensuring the health and epidemiological well-being of the population and, within the consumer market, consumer rights protection.

Ministry of Civil Defense, Emergency Situations, and Natural Disaster Response of the Russian Federation (Ministry of Emergencies of the Russian Federation)
The Ministry of Emergencies of the Russian Federation performs functions related to the development and implementation of government policy, legal regulations, and supervision and control in the fields of civil defense, protection of the population against natural and man-made emergencies, and ensuring fire safety. The Ministry of Emergencies acts both directly and through the following territorial agencies within its system: regional civil defense, emergency situation, and natural disaster response centers and specially authorized civil defense and emergency prevention and response agencies of the lower-level authorities of the Russian Federation; the State Firefighting Service of the Ministry of Emergencies; Civil Defense Forces; the State Small Vessels Inspectorate of the Ministry of Emergencies; and emergency rescue and search-and-rescue units, educational, research, medical, resort/sanatorium, and other establishments and organizations within the competence of the Ministry of Emergencies. The main tasks of the Ministry of Emergencies are: developing and implementing government policy for civil defense, protecting the population and the territories against emergencies, and ensuring fire safety; arranging the preparation and approval of draft regulatory acts within the competence of the Ministry of Emergencies; managing activities regarding civil defense, protection of the population and the territories in case of emergencies, ensuring fire safety and the safety of personnel, and managing the activities of Federal executive bodies within the framework of the unified State emergency prevention and response system; establishing legal regulations to prevent, forecast and mitigate the consequences of emergencies and fires; and performing special permitting, supervisory and control functions with regard to issues within the competence of the Ministry of Emergencies.

2.4.7.1.2. Regional level
Regional State authorities of the Russian Federation may form their own authorized agencies for environmental protection. The powers of State authorities of constituent entities of the Russian Federation in the area of environmental protection include:

- adoption of laws and other regulatory enactments in the field of environmental protection and monitoring of their implementation;
- participation in the implementation of State environmental monitoring;
- implementation of State environmental monitoring, including State environmental expert review for economic bodies located within a constituent body of the Russian Federation, except those engaged in economic and other activity that are subject to Federal State environment monitoring;
- setting of environmental-quality standards containing appropriate requirements and norms no worse than those in place at the Federal level;
- introduction of restrictions on vehicular traffic in inhabited areas, recreational sites, and tourist areas in specially protected territories in order to reduce emissions of harmful substances into the air; and
- monitoring the fee for a harmful environmental impact for entities engaged in economic and other activity, except those subject to State environmental monitoring.

Executive authorities of a constituent body of the Russian Federation have the right to maintain regional registries of waste, including data provided by local governmental authorities and by legal bodies involved in waste handling.

As an example, in Chelyabinsk Oblast, the system of environmental protection authorities is represented by administrations, agencies, and institutions accountable to the Governor of Chelyabinsk Oblast. These include the Ministry of Radiation and Environmental Safety of Chelyabinsk Oblast, the Ministry of Health of Chelyabinsk Oblast, and the Ministry of Industry and Natural Resources of Chelyabinsk Oblast. The main tasks of Chelyabinsk's Ministry of Radiation and Environmental Safety are: to perform State environmental monitoring of bodies engaged in economic activity, regardless of their form of ownership, that are located within Chelyabinsk Oblast (except those that are subject to Federal State environmental monitoring); to participate in establishing and implementing State air monitoring; and to provide a system of State regulatory measures aimed at satisfying the needs of Chelyabinsk Oblast for mineral resources, raw materials, and water, forest, and other natural resources on the basis of study, restoration, management, environmental protection, and environmental safety.

Territorial administrations are the representatives of Federal governmental authorities; their powers are fully consistent with the powers of Federal authorities. The territorial bodies of Federal ministries, services, and agencies are represented by the corresponding administrations, agencies, and institutions for Chelyabinsk Oblast: Rostekhnadzor Administration for Technological and Environmental Oversight for Chelyabinsk Oblast; the Administration of the Federal Service for Oversight of Natural-Resource Use (Rosprirodnadzor) for Chelyabinsk Oblast; the Territorial Agency for Subsoil-Resource Use for Chelyabinsk Oblast (Chelyabinsknedra); the Forestry Agency for Chelyabinsk Oblast; and the Chelyabinsk Administration for Hydrometeorology and Environmental Monitoring.

2.4.7.1.3. Local (Municipal) level

The powers of local governmental authorities for environmental protection include: the preservation of objects of cultural heritage (historical and cultural monuments) owned by a settlement, and protection of regional-level (municipal-level) objects of cultural heritage located within a settlement; the establishment of municipal environmental protection measures; and organization of the collection, hauling, disposal, and processing of domestic and industrial waste. Local governmental authorities have no powers in the field of public health, epidemiological well-being, or industrial safety.

2.4.7.1.4. Mechanisms for implementing environmental protection legislation

Reforming the system of environmental management in Russia appears difficult against the background of an extremely unstable institutional framework that is subject to many and contradictory changes. In recent years, environmental agencies have been repeatedly restructured; powers have been delegated from one to another; leadership and vertical subordination have been changed. The executive environmental authorities were radically reorganized in 1994, 1996, 2000, 2004 and 2008. The government's constant search for an optimal vertical and horizontal configuration of environmental authorities has often brought the system to the brink of paralysis. As a result, commitment to improve environmental policy and regulation has been low among managers at all levels.

The law-making segment is the most stable within the institutional framework. There is a wide range of actors involved in law making: the Federal Assembly (Russia's parliament, which is composed of two chambers - the State Duma and the Federation Council), Russia's President, the government and line ministries, as well as similar actors in sub-national and local governments. Also, the Constitutional Court, the Supreme Court, and the Supreme Court of Arbitration have the right to initiate laws. Other stakeholders include lawyers, researchers, and practitioners who act as experts or provide feedback on the quality of the draft laws, etc. This diversity of authorities and stakeholders generally plays a positive role in balancing competing interests, although it might have contributed to the fragmentation and inconsistency of the legal framework.

Unlike the law-making institutions, the executive branch of the government has gone through several major reorganizations since 1999. In 2000, most of the responsibility for environmental management was devolved to the oblast (sub-national) governments without strengthening the Federal-level capacity to coordinate environmental policy development and to ensure effective regulation. This change in responsibilities was accompanied by a decline in the overall number of staff, in particular those involved with inspection and enforcement. Relations between the centre and the regions remained unclear, particularly due to the fact that an additional administrative layer – the Federal Okrugs – was added between the centre and the sub-national level. While there was a need and justification for change on the grounds of an exaggerated jurisdiction of the Federal-level authorities, the process of reform was poorly implemented and increased the level of ambiguity in the distribution of functions between different administrative-territorial levels. Their mandates were later amended in 2004, in 2005, and again in 2006, with no clear understanding of how the environmental management system would evolve in the longer term.

In relation to the clarification of mandates at the Federal level, the administrative reform of 2004 pursued the goal of clearly separating the policy-making, regulatory and compliance monitoring, and service provision functions of government authorities in order to increase the effectiveness of government authorities while reducing the conflicts of interest that arise when these functions are combined. In this context, three types of executive bodies were instituted:

- Federal ministries, which are policy-making bodies. They conduct the problem analysis, development and evaluation of policies in their domains, as well as draft new legislation. They also coordinate and monitor the activities of Federal services and agencies within their jurisdiction. They are not authorized to perform enforcement functions, to manage state property or to provide services;
- Federal services, which are executive authorities vested with permitting, inspection and administrative enforcement functions, but are not authorized to develop primary legislation; and
- Federal agencies, which can provide public services and manage state property, maintain various types of registers, but are not authorized to engage in regulatory development or perform any compliance assurance functions.

Currently, the key authorities responsible for formulating and implementing environmental policy and law at the Federal level in Russia are the Ministry of Natural Resources and Ecology and the agencies and services under its umbrella, including the Federal Environmental, Industrial, and Nuclear Supervision Service (Rostekhnadzor) and the Federal Hydrometeorology and Environmental Monitoring Service (RosGidromet)[6].

Following the administrative reform of 2004, some institutional stability in the environmental authorities has been achieved and attempts to streamline their responsibilities and powers have been made. But there is little evidence that the reorganization has achieved its aims as functions are not totally separated and regulators continue to be exposed to political pressure. The overlaps of functions and adversarial relations among various executive authorities have persisted and the level of institutional fragmentation has increased.

6 These two services have been under the MNRE umbrella since May 2008.

Poor cooperation between ministries (and their subordinate bodies) has continued to affect the robustness of the institutional framework for environmental management. Currently, many line ministries have environmentally related functions, including the Ministry of Health and Social Development (including the Federal Agency for Health and Social Development and the Federal Health and Social Development Supervision Service); the Ministry of Economic Development (including the Federal State Statistics Service); the Ministry of Industry and Trade and its subordinate bodies; the Ministry of Agriculture and its subordinate bodies; the Ministry of Energy, the Ministry for Civil Defense, Emergencies, and Natural Disaster Mitigation; and the Ministry of Internal Affairs. To a certain degree, activities of all these Federal bodies are planned and coordinated based on the medium-term program of social and economic development of the Russian Federation and its implementation action plan, developed by of the Government of the Russian Federation.

2.4.7.1.5. Environmental health and safety legislation

In the Russian Federation, the laws and regulations that provide environmental, health, social, and safety (EHSS) protection are organized into a four-tier system. Near the top of the hierarchy is Federal legislation designed to protect the natural resources of the country and to ensure the rights of citizens to live in a good quality environment. Regional legislation involves constitutional and legislative acts set forth by the Okrugs and includes any decrees, orders, or regulations issued by their President or administrative agencies. At the local Oblast level, various orders and directives are designed to address specific situations and sensitivities that require special attention or protection. The last tier of the system involves sectoral legislation including regulations, directives, orders, and instructions by various Federal authorities plus industry standards, including Specific Industry Standards (OST), Construction Guides (SP), and SNiP.

There are three types of regulatory documents in the Russian Federation: *legislative acts,* such as Federal laws and codes; *regulations (legal)* that determine the interactions between Federal and regional regulatory authorities and their individual responsibilities; and *regulations (technical)* that establish specific requirements, parameters, limitations, and other factors related to EHSS protection. Most of the 'technical' regulations were created and adopted in the 1970s, the 'legal' regulations in the 1980s, and the legislative acts in the 1990s. A systematic revision of environmental legislation has been ongoing for the last five years. Nevertheless, a substantial number of regulations and legislative acts from the period of the former Soviet Union are still in force. A large number of these are outdated, impractical, or conflict with more recent legislation. In addition, most Russian legislation is predominantly declaratory in nature and lacks supporting regulations and guidelines to provide interpretive clarity. Moreover, the recent legislative and organizational changes have left issues of authority and responsibility poorly defined. These conditions make it extremely difficult for companies, especially Western companies, to operate within the Russian Federation.

Laws and regulations concerning environmental and natural resource protection, sanitation and epidemiological well-being of the population, and industrial safety form a multi-level hierarchical system (Appendix 2.1, Section A.4.7.).

Federal legislation

Russian Constitution

The December 12, 1993 Constitution of the Russian Federation is unusual in that it provides explicit guarantees of environmental quality. These include that:

1. Each citizen has a right for a good quality environment, reliable information on its status and compensation of damage inflicted upon people's health or property as a result of violating environmental legislation (Article 42).
2. Everyone shall have the right to a good quality environment, reliable information about its condition and to compensation for the damage caused to people's health or property by ecological violations (Article 58)
3. The land and other natural resources may be in private, state municipal and other forms of ownership (Article 9).
4. The possession, use, and management of the land and other natural resources shall be freely exercised by their owners provided this does not cause damage to the environment or infringe upon the rights and interests of other persons (Article 36).

Presidential Decrees and Orders

Presidential Decrees and Orders have a legal status equal to the Federal laws and are intended to regulate particular problems. They are issued in order to make changes in or additions to existing legislation. They may, for example, fill gaps in EHSS legislation or address particular environmental issues that require assistance from Federal funds.

Laws of the Russian Federation

Federal laws are the legal foundation for State policy in the field of environmental protection. These laws are designed to ensure a balanced solution for socio-economic activities, preserve biological diversity and natural resources to meet the needs of the present and future generations, and enhance law and order in the field of environmental protection and ecological safety. The laws also govern the interaction of society and nature that results from a variety of economic activities.

The basic law is the Law on Environmental Protection (2002), which is the basis for the entire system of environmental legislation. It covers general issues of resource use and environmental protection with a particular emphasis on sources of adverse impacts on the environment and human health. This law also regulates the distribution of roles and functions between the different levels of authority, in particular between the Federal, regional, and local authorities, and is more progressive than previous law.

Other Federal legislation is divided into three categories:

- Resource-directed laws regulate the use and protection of certain natural resources including codes on land, water, wildlife, forestry, the continental shelf, and mineral resources. They include rules for production, rules for allocation of the usage rights, responsibility for violation of the norms, requirements for users of resources, an enforcement system, procedures for permitting and licensing of usage of particular resources, and distribution of environmental responsibilities between Federal, regional, and local authorities.

- Laws on human health and safety. This category comprises Federal laws that consider resource use and environmental protection from the viewpoint of human health and safety. It includes laws covering sanitary and epidemiological welfare, health protection, emergencies, occupational health and safety, and radiation safety.
- The category 'indirect legislation' includes laws that have no direct relation to environmental protection, for example, Federal laws on investment, the administrative code, and excise taxes.

Federal decisions and resolutions

Federal decisions and resolutions usually define the responsibilities of the State government institutions regarding environmental issues, approval of Federal programs, norms, rules and regulations of a general nature.

Acts of specially designated State bodies of environmental protection

These are usually registered in the Ministry of Justice. Their legal status makes them obligatory for all natural resource users unless otherwise stated. The Acts may be rules, instructions, directives, or other instruments.

Departmental Acts constitute the basis of environmental legislation under the central planning system. General-purpose ministries and departments, such as the State Planning Committee, State Committee on Construction, State Committee on Science and Technology, and State Committee on Standards also develop norms, rules, and standards for general use. These rules are intended for use in planning, designing, and operating facilities and complexes, and in directing economic development of regions. Departmental Acts include departmental standards, norms for technology development, norms for construction, and directives. They govern the activities of enterprises subordinate to the corresponding department. This system was recently superseded and regulation of economic activities by this method no longer applies. The only components that are still in effect are State standards, construction norms and rules, and sanitary norms and rules. Departmental regulations still exist in those areas of the economy that have a substantial share of State-owned enterprises.

Acts of regional and local authorities

Lower-level authorities of the Russian Federation can form their own legislation within their competence provided their legislation does not conflict with Federal legislation. Development of legislation on environmental protection and use of natural resources is usually preceded by a special agreement on the distribution of responsibility between Federal, regional, and local authorities. Thus, some regions have their own laws on environmental protection, including subordinate acts and regulations that reflect specific regional or local issues. Acts at this level are valid in the territory whose authorities issued them.

Internal Acts issued by enterprises, institutions, and bodies

Internals Acts are increasingly used due to the proliferation of large joint publicly traded companies that have their own environmental and resource management policies. Internal rules cover, for example, worker's health and safety procedures, and actions in emergency situations. These rules are approved by the manager of the enterprise and are regularly updated.

Federal EHSS Legislation

The overall structure of the Russian legislation in the areas of environmental protection, sanitary and epidemiological welfare, and industrial safety is described in (Appendix 2.1, Section A.4.7.). The main Federal laws that determine environmental, natural resource, health/social, and industrial safety safeguards and protection measures are briefly described in this section. Regulatory directives promulgated by regional or local authorities are not covered here because they do not apply throughout the Russian Federation.

Environmental legislation

The key environmental law is the Law on Environmental Protection that was revised in 2002. Other important legislation provides protection of ambient air, wildlife, and specially protected natural territories.

The Law on Environmental Protection (2002) is the main legal document stipulating environmental procedures in the Russian Federation. This outlines the general principles of administrative and regulatory protection of components of nature and their systems. The law details the rights and obligations of all parties concerned, including State structures, users of the environment and the public, and defines the legal basis of State environmental policy. The main policies defined by this law include:

- payment for nature use and compensation for damage to the environment;
- independence of environmental enforcement activities;
- requirement to conduct an OVOS;
- consideration of natural and socio-economic regional particularities when planning or implementing economic activities;
- priority of conservation of natural ecological systems, natural landscapes and ecosystems;
- ensuring reduction of negative environmental impacts according to environmental standards which can be achieved using best available technologies;
- compulsory involvement of the public and other non-commercial associations, legal bodies and individuals in State activities;
- integrated and individual approach to the setting of environmental requirements applicable to economic or other activities;
- respect of the individual's right to receive reliable information on the state of the environment, as well as citizen's participation in decision-making related to their right to a favorable environment in accordance with the legislation;

- liability for infringement of environmental legislation; and
- public participation in the resolution of environmental issues.

The Law on Protection of Ambient Air (May 1999), as amended in December 2005, provides for the general air protection requirements while building and operating structures and facilities. The law establishes rules for setting air emission standards and limits for physical impacts; stipulates terms and conditions for issuing permits for air emissions and related physical impacts; specifies payments for air emissions; and provides guidelines for conducting environmental control and monitoring.

The Law on Protection of Wildlife (April 1995), as amended in December 2005, establishes general requirements for the protection of wildlife in the Russian Federation, including specific measures for protection of wildlife habitat while operating industrial structures and facilities. It specifies terms and conditions for the use of wildlife resources (licensing procedures, payments) and sanctions for violating the law and causing damage to wildlife or habitat.

The Law on Environmental Expert Review (November 1995), as revised in December 2005, defines the principles of environmental review; the authority of government authorities and various organizations in the review process; procedures of environmental review; and sanctions for violation of Federal laws involving environmental review.

The Law on Specially Protected Natural Territories (March 1995), as amended in September 2005, establishes a system of specially protected natural territories; defines the terms of use, protection, organization and management procedures for these designated territories; and outlines sanctions for violation of established rules.

Natural resource legislation

These Federal laws address the utilization and conservation/protection of natural resources within the Russian Federation. The primary legislation concerns subsurface resources, water, forests, and land use. The Law on Underground Resources (February 1992, revised April 2006) outlines the procedures for using subsurface natural resources and establishes requirements for the use and protection of mineral resources. The Law on Land Code (October 2005) establishes the legal basis for State and private land ownership; possession of land through inheritance or life-long ownership; limited use of another's land (servitude); leasing of land; and gratuitous temporary use of land. The Law on Forest Code (January 1997, as amended in December 2003) defines the legal principles for the use, conservation, protection, and regeneration of forests, and enhancement of their ecological and resource potential. The Law on Water Code (November 1995 and currently under revision) establishes procedures for the use and protection of inland water bodies including requirements for protection and use of water resources; licensing procedures; water quality standards; and specific sanctions for violating provisions of the code.

Health and social legislation

The system of legislative acts that defines requirements for health and labor protection consists of sectoral rules and instructions pertaining to sanitary norms and rules for construction, rules and instructions on labor protection, and State standards for the safety of workers. Some of the more important laws are outlined below.

The Law on Sanitary and Epidemiological Welfare of the Population (March 1999, as revised in December 2005) establishes general sanitary requirements for the protection of human health from natural and industrial impacts, including specific protection requirements for raw materials, human water supplies, wastes, and the atmosphere.

The Law on Territories of the Traditional Nature Use of Indigenous Peoples of the North, Siberia, and Far East of the RF (May 2001) establishes legal grounds for the formation, protection, and utilization of territories of traditional nature use of indigenous peoples of the North, Siberia, and Far East of the Russian Federation with the objective of sustaining their customary nature use and lifestyle. It establishes the order for the formation of such territories, and the legal regime and nature resource use regulations within the territories. If a company wishes to establish and operate a facility within an area of traditional nature use by indigenous people, the law includes stipulations for compensation of the affected individuals or communities for the withdrawal of the necessary land parcel(s) from their natural use.

The Law on Cultural Heritage Objects and Historical and Cultural Landmarks of the Peoples of the Russian Federation (June 2002, as amended in December 2005) establishes regulations regarding preservation, use, and protection of objects of cultural heritage and importance to the peoples of the Russian Federation.

Industrial safety legislation

The basic Federal policies pertaining to industrial safety include establishment of uniform safety requirements, establishing priorities for health and safety of all workers engaged in industrial activities, creating tax incentives for company-sponsored safety policies, investigating accidents and occupational diseases, and establishing economic sanctions to encourage compliance with safety regulations.

The Law on Industrial Safety of Potentially Hazardous Industrial Facilities (July 1997 and amended in September 2005) establishes the legal, economic, and social basis for ensuring safe operation of hazardous industrial facilities. The primary focus is on the prevention of emergencies at industrial facilities and assurance of the preparedness of companies operating hazardous facilities to localize and mitigate any such emergencies.

Other oil- and gas-related Federal legislation

The Federal laws and their scope described here pertain mostly to economic activity proposed or operated in the offshore territorial waters of the Russian Federation including all areas of the continental shelf.

The Law on the Continental Shelf of the Russian Federation concerns resource development on the offshore continental shelf; it also includes legislation pertaining to subsurface resource development. With respect to the Russian Federation continental shelf and in accordance with national laws and international agreements, this law implements:

- The sovereign rights to explore the continental shelf and develop its mineral resources.

- The exclusive right to permit and regulate drilling operations for any purpose.
- The exclusive right to build and to allow and regulate the building, operation, and use of artificial islands, installations, and structures.
- Jurisdiction over such artificial islands, installations, and structures, including jurisdiction with respect to customs, fiscal, sanitation, and immigration laws and rules, as well as safety-related laws and rules.
- Jurisdiction with respect to offshore scientific research; protection and conservation of the marine environment in connection with the development of mineral resources and the disposal of waste and other materials; and laying and operation of subsea cables and pipelines.

The rights of the Russian Federation to the continental shelf do not affect the legal status of the waters covering it or the airspace above them. The following, in particular, fall within the purview of Federal State authorities on the continental shelf in regard to subsoil-resource use:

- Determination of the strategy for studying, prospecting, exploring, and developing mineral resources, protecting and preserving the marine environment and mineral and biological resources on the basis of Federal strategy, programs, and plans with consideration for the findings of State environmental expert review, and with special consideration for the economic interests of the indigenous minority peoples of the North and Far East of the Russian Federation.
- Establishment of the procedure for developing mineral resources, including a licensing procedure, and drafting of appropriate standards (norms and rules).
- Establishment of the procedure for holding tenders (auctions) for the right to use areas of the continental shelf, and determination of the winning bidders.
- State geological control.
- State mine oversight.
- Registration of work on the study, exploration, and development of mineral resources, compilation of a Federal balance sheet of mineral reserves, and Federal accounting of tracts of the continental shelf that are used in the study, exploration, and development of mineral resources.
- Entering into production-sharing agreements.
- Introducing restrictions and special conditions for the use of the seafloor and the resources beneath it in individual tracts of the continental shelf in connection with the prospects for the development of mineral resources, and also at breeding sites of marine fauna.
- Regulation and conduct of resource surveys and offshore scientific research.
- Regulation and determination of the conditions for laying subsea cables and pipelines used for exploration and development of mineral resources or for the operation of artificial islands, installations, and structures, as well as those that run into the territory of the Russian Federation.
- Establishment of a system of payments, and determination of the amounts, conditions, and procedure for collecting the fee for use of areas of the continental shelf for purposes of prospecting, exploration, and development of mineral resources.
- Regulation of the creation, operation, and use of artificial islands, installations, and structures to study, prospect for, explore, and develop mineral resources.
- Performance of State environmental expert review, State environmental monitoring, and State monitoring of the environmental state of the continental shelf.
- Management of the Russian State Data Fund on the State of the Continental Shelf and Its Mineral Resources.
- Establishment of environmental norms or standards for pollutant content in waste and other materials intended for disposal on the continental shelf, and of lists of harmful substances, waste, and other materials banned for disposal on the continental shelf, and regulation and monitoring of the disposal of waste and other materials.
- Entry into and implementation of international treaties of the Russian Federation with respect to the continental shelf and activity thereon.

The Law on the Inland Sea Waters, Territorial Seas, and Continental Shelf establishes acceptable activities for the use of offshore natural resources together with environmental protection measures for marine waters and territorial seas. The law defines the main principles of economic relations during the use of natural resources of inner and territorial seas, including: payments for use; responsibility for violation of economic activity conditions; compensation for damage to inner marine waters and territorial seas, their natural resources, environment, historical and cultural monuments; and financial provision for activities for natural resources restoration and protection of the inner marine waters and territorial seas environment and historical and cultural monuments. The law also provides for the preservation of the marine environment by establishing regulations for maximum permissible concentrations of hazardous substances and maximum permissible adverse impacts on the marine environment and its natural resources.

The Merchant Shipping Code designates acceptable practices and requirements related to, among others:

- carrying of cargoes, passengers, and passenger baggage;
- production of aquatic biological resources;
- exploration and development of seabed or sub-seabed mineral resources or any other non-living resources;
- pilotage or icebreaker assistance;
- search, rescue, and tugging operations;
- hydraulic engineering, underwater engineering, or other similar operations;
- protection and preservation of the marine environment; and
- the conduct of marine scientific research.

The code provides provisions for monitoring compliance with international treaties and agreements of the Russian Federation related to merchant shipping, requirements related to the procedures for vessels entering and exiting the port, the issuance of permits for conduct of civil engineering, hydraulic engineering, or any other activities in the port, and investigation of any vessel accidents.

The Law on the Exclusive Economic Zone of the Russian Federation establishes standards, rules, and measures for preventing, reducing, and controlling pollution from artificial islands, installations, and structures operating within the territorial sea and interior waters of the Russian Federation. This applies exclusively to oil and gas production operations on the continental shelf of the Russian Federation. The law prohibits disposal of wastes and other materials, and discharging of dangerous substances into inner marine waters and the territorial seas. However, normal wastes and discharges that do not exceed maximum permissible concentrations or adverse impacts are exempt. In addition, the law does not apply to wastes and discharges generated during the course of exploratory activities. An additional provision stipulates that all foreign operators working offshore on the continental shelf are obliged to accommodate visits and inspections from all governing authorities including paying for all related expenses.

Regional legislation

Regional legislation is not applied uniformly throughout the Russian Federation and is therefore not covered here. Regional authorities can adopt regional laws and regulations pertaining only to environmental protection and commonly occurring natural resources use.

Environmental performance standards of the Russian Federation

System of environmental standards

The system of standards for environmental protection and improvement of natural-resource use was established in the Soviet Union in 1976 and included State, industry, and enterprise standards. The following nine standard complexes were established in accordance with the fundamental system of standards (GOST 17.0.0.01-76, CEMA Standard ST 1364-78) and remain in effect to this day:

- Organizational and methodological standards in the field of environmental protection.
- Standards for environmental protection and water management.
- Standards for air protection.
- Standards for soil conservation and management.
- Standards for improving land use.
- Standards for conservation of flora.
- Standards for conservation of fauna.
- Standards for landscape conservation and conversion.
- Standards for subsoil-resource conservation and management.

Types of standards

The general legal framework for environmental standards is established by the Law on Environmental Protection of 2002, Articles 19–29. All standards are divided into three principal groups: environmental quality standards, emission and discharge standards, and procedural standards.

Environmental quality standards, or maximum allowable concentrations of pollutants (PDK) in Russian terminology, are comparable to maximum allowable (or admissible) concentrations (MAC) in EU terminology.

Emission and discharge standards, or maximum allowable air emissions (PDV) and maximum allowable water discharges (PDS) in Russian terminology, are comparable to emission limit values (ELV) in EU terminology.

Procedural standards define mandatory requirements for organizing and conducting economic activity with a goal of preventing unregulated environmental impact. The basic standard is GOST 17.0.0.01-76, System of Standards for Environmental Protection and Improvement of the Use of Natural Resources, which defines the structure of the system of procedural environmental protection standards. These are technical, urban-development, recreational, organizational, administrative, and terminological standards.

These environmental quality and air emission standards are outlined in Article 1 of the framework Federal Law on Environmental Protection (2002), but unlike European ELVs, actual PDV and PDS are not established by this law nor are they based on BAT (Best Available Technology).

The establishment of standards occurred through numerous legislative acts, mostly adopted from 1977 to 1987. PDV and PDS calculations, according to the guidelines provided in those documents, are very complicated and require significant amounts of data. Such data are often not available for start-up projects, thus calculations are often based only on computer modeling.

Environmental quality standards

Environmental quality standards are based on established environmental indices that are judged to be safe for human health, protection of natural ecosystems, and protection of living organisms. The scientific concept of emission and quality regulation in the Russian Federation is based on Maximum Permissible Environmental Load. The assumption is that if concentrations of key pollutants in the environment do not exceed PDKs, then the load is not exceeded. The established concentrations are judged to be those causing no adverse effects on individuals for their whole lifetime and all subsequent generations (i.e., a 'zero risk' human health protection criterion).

PDKs are established for the following receiving media: air (ambient, residential, and in working areas), water (surface water for domestic use, fisheries, drinking water, and groundwater that is normally assessed as a potential source of drinking water), and soil (arable land). When setting PDK values, specific natural features of areas, including specially protected territories, should be taken into account. Therefore, the PDKs may be stricter for some selected areas, such as those in the vicinity of nature reserves. Background concentrations, however, are not taken into consideration.

PDKs are divided into single exposure and daily average limit standards. Single exposure PDKs reflect concentrations of substances that should not cause any harm to a human within 20 minutes of exposure. PDK daily average values are defined as the concentration that should not cause any adverse effects on the inhabitants of a settlement for the whole lifetime of each individual and all subsequent generations. These standards are aimed at the entire population, including children and elderly people. There are hundreds of chemicals for which standards have been set.

Emission and discharge standards

These standards determine the quality of water and the surrounding atmosphere which can be affected by operating facilities. PDS and PDV are set for these facilities based on the requirement that, after being released into the environment, these amounts will not result in concentrations exceeding respective PDKs in receiving media for water and at the edge of the Sanitary Protection Zone for air emissions.

Water quality standards. Two types of quality standards have been established for water bodies: maximum allowable concentrations of harmful substances (PDKs) and temporary water quality standards established for pollutants not regulated by PDKs (ODUs and OBUVs).

Regarding PDKs, the Water Code (1995) in Article 109 requires that the quality of water bodies and effluents conform to PDKs and be differentiated depending on the designation of the water bodies. Such standards are to be established for two types of water bodies separately, namely those designated for:

- fisheries, which are further subdivided into three categories:
- fisheries of the highest category (most valuable, such as spawning grounds);
- fisheries of the first category (with fish sensitive to the concentration of dissolved oxygen);
- fisheries of the second category (water bodies used for other fishing purposes); and
- domestic and drinking water supply.

PDKs for fisheries are to be established by the Fisheries Committee after coordination with the MNR of the Russian Federation, while PDKs for water bodies designed for domestic and drinking water supply are to be set by the Ministry of Healthcare. A provision has been made for the development of PDKs for water bodies designated for agricultural purposes.

ODUs and OBUVs are temporary water quality standards for pollutants without relevant PDKs. ODUs are developed for facilities that emit or discharge pollutants not covered by PDK standards. They usually remain valid for three years, as indicated in Hygienic Standard 2.1.5.1316-03 and further addendums: 'Approximate allowable levels of chemical substances in ambient water for drinking purposes and social and general use'. ODUs are subject to approval by the Ministry of Health and Social Development and may be assigned the status of PDK by decision of this Ministry. OBUVs apply to non-PDK pollutants that affect fishery water bodies, and are approved by fishery authorities.

Wastewater discharge standards. Two types of discharge standards have been established: maximum allowable discharges (PDSs) and temporarily approved discharges (VSSs).

PDSs are developed according to the source of discharge on the basis of PDK values for each pollutant by taking into account cumulative discharges from other sources, natural background concentrations of pollutants in water bodies, and natural dilution. PDS values are enforced after their approval by a licensing authority (territorial units of the MNR) and included as a condition in a license for water use, as granted by the MNR and its territorial units. Monitoring of compliance is conducted at the established control points, but in no case further than 500 m from the point of discharge into a water body. Should the PDS be exceeded at the point of discharge, the operator will be cited with a violation and monetary fines will be applied. This procedure is described in The Rules for the Protection of Surface Water Bodies, dated February 21, 1991.

VSSs are set for operating facilities that cannot achieve PDKs. VSSs are established for a period needed to meet the PDS levels, but never longer than five years. VSSs are inscribed in temporary permits issued by territorial units of Rosvodresursy. Facilities which apply for a VSS and a temporary permit are obliged to prepare a plan of water protective measures which will remain in effect during the permit period. Should a facility be in compliance with VSS and fulfill the requirements of the plan of water protective measures, no penalties will be imposed, although the company is obliged to pay for excessive discharges based on a much higher rate per unit of discharge.

Air quality standards. Articles 1 and 2 of the Law on Air Protection (1999) require that maximum allowable concentrations of pollutants in air be established to ensure protection of human health and the natural environment. This law provides that air quality standards should be of the following types: hygienic quality standards for human settlements (hygienic PDK); ecological quality standards for other areas (ecological PDK); approximate allowable levels of concentration of pollutants as temporary quality standards (OBUV); and maximum allowable air emissions (both in terms of human health and environmental protection), PDV.

General rules for limiting emissions of pollutants and setting quality standards are also established by the Law on Sanitary and Epidemiological Well-being of the Population (Article 20). This law and other governmental and ministerial acts establish procedures and requirements for designing of standards.

Hygienic and ecological PDKs. PDKs determine maximum allowable concentrations of pollutants − hygienic PDKs for human settlements and ecological PDKs for other areas within the Russian Federation. According to the Governmental Decree dated March 2, 2000 On the Procedure for Establishing and Review of Ecological and Hygienic PDK, and also Levels of Physical Impacts on Air, hygienic PDKs are to be established by the Ministry of Healthcare and the ecological PDKs are to be established by the MNR.

Hygienic PDKs for about 600 pollutants were established by the Ministry of Healthcare and approved by the Chief Sanitary Doctor on April 29, 1998 in the document Hygienic Quality Standards GN 2.1.6.695-98. This document also contains a list of 38 pollutants that are entirely banned. In addition, PDKs for about 2300 microorganisms were set by the Hygienic Rules 2.1.6.1003-00 on December 20, 2000. One particular provision states that PDKs shall be established for the same pollutants as PDK single exposure values and PDK daily average values. The single exposure PDK values may be higher than the daily average PDK values.

Russian law also stipulates that no company may design, construct, or put into operation air pollution emitting facilities in areas where the hygienic PDKs are already exceeded. Reconstruction and technical modernization of industrial facilities within these areas are allowed on condition that the emissions are in conformity with the PDV set individually for each source.

OBUVs are temporary air quality standards for pollutants not covered by relevant PDKs. OBUVs are generally valid for a period of three years; they are approved by the Ministry of Health and Social Development, and may be assigned the status of PDK by decision of the Ministry of Healthcare. OBUVs for 1495 substances were approved by decree on April 29, 1998. Additional lists have been established in the Hygienic Quality Standard GN 2.1.6.673-97 Approximately Safe Level of Impacts of Air Pollutants for Human Settlements and its amendments.

<u>Air emission limits.</u> According to the Governmental Decree dated March 2, 2000 On Approval of Rules for Maximum Allowable Emissions of Pollutants into Air and Harmful Physical Impacts, emission limits shall be of two types: technical quality standards for a harmful emission and PDVs. In addition, temporarily approved emissions limits (VSVs) are allowed for facilities when they are unable to comply with PDVs. These regulations/standards are similar to the regulations/standards for PDS.

- Technical quality standards are established by Rostekhnadzor for stationary air emission sources and technologies. These standards are applicable for the air emission sources that are included in the Cadastres kept by Rostekhnadzor. Technical quality standards for facilities and transportation can be found in various GOST documents, and for equipment, construction rules and norms in SNiP, and elsewhere.
- PDVs are set separately for each source of pollution, taking into account the type and toxicity of the emission, background pollution, technical quality standards, and PDKs. According to the Instructions for Determining Air Emissions and Water Discharges, companies operating affected facilities must develop draft PDVs and submit them to Rostekhnadzor for a compliance assessment. A positive assessment is then submitted to the MNR for final approval which is valid for a period of five years.
- VSVs are established for situations where a facility is unable to comply with a PDV. The operating company is responsible for preparing draft VSVs which are submitted to the Ministry of Healthcare for approval. Once approved, they are set for a specified period of time by Rostekhnadzor. An air emission reduction plan also needs to be developed by Rostekhnadzor. The reduction plan is part of the permit and should be in effect for the same time period. VSVs are generally valid for a period of construction, modernization, and/or any other modifications in the operation of a facility.

Procedural standards

The GOST 17.0.0.01-76, System of Standards for Environmental Protection and Improvement of the Use of Natural Resources is the primary basis for determining the structure of the system of environmental-protection procedural standards. These include the following types of standards: technical, urban development, recreational, organizational, administrative, and managerial.

- Technical standards define the general requirements for production processes and apply to both the design and operating stage of facilities. Some standards are directly classified as environmental-protection standards, such as GOST 17.1.3.05-82, Environmental Protection. Hydrosphere. General Requirements for Protection of Surface and Subsurface Water from Contamination by Oil and Petroleum Products. Other standards apply to the group of construction standards and rules (construction codes) that include environmental-protection requirements, such as SNiP 2.04.02-84, Water Supply. External Networks and Structures.
- Urban development standards define environmental-protection requirements for planning the development of cities and settlements – requirements aimed at creating favorable living conditions for the population with consideration for architectural and urban-development traditions and the natural, climatic, landscape, national, everyday, and other local specifics of territories.
- Recreational standards set the rules for using specially protected natural territories and other recreational facilities and complexes.
- Organizational standards are intended to support the creation of a unified system for management and monitoring in the field of environmental protection. These include GOST 17.2.3.01-77, Rules for Monitoring Air Quality in Inhabited Points, GOST 17.1.3.06-82, Environmental Protection. The Hydrosphere. General Requirements for Subsurface-Water Conservation, and others.
- Administrative standards include environmental protection requirements documented as legal enactments or ministry-approved rules. One example is the Russian Federation Government Decree No. 20 of January 19, 2006 which deals with Engineering Surveys for Preparation of Design Documentation, Construction, and Renovation of Capital Construction Projects, and is considered a state standard.
- Among the fundamental managerial standards in the field of environmental protection is GOST 24525.4-80, Management of Environmental Protection, which regulates the rules for the organization of environmental-protection activity at an industrial enterprise. The standard defines the requirements for: the activity of a user with respect to natural-resource use; the drafting of plans and product manufacture, and for all production stages in which materials that have a harmful environmental impact could appear; and environmental-protection equipment at an industrial enterprise. The purpose of introducing this standard was to create a unified mechanism for the management of environmental-protection activity at enterprises. All divisions or laboratories of an industrial enterprise, from the chief account's division to the packaging and shipping shop, are given a special environmental-protection function. For example, the planning and economics division is responsible for determining the

list of planned environmental-protection indices, the division of the chief power engineer and mechanic is responsible for environmental expert review of technical documentation of products. Management is implemented on the basis of the technical standards for each specific issue.

Waste management standards. Article 18 of the Law on Industrial and Communal Wastes (1998) establishes two types of waste management standards related to production, transportation, storage, treatment, and disposal of wastes: standards for waste management and limits for disposal of wastes.

- Waste management standards are established guidelines and standards for managing various types of oil industry-related wastes. These standards are established based on general environmental conditions in the area, maximum allowable impacts from waste disposal, and availability of waste treatment technologies listed in the state Cadastre of wastes. The company operating a facility is responsible for preparing draft waste management standards and limits, and submitting these plans to the Territorial Units of Rostekhnadzor for approval.
- With regard to waste disposal limits, a company is responsible for proposing volumetric limits for disposal of wastes generated by operating facilities. These limits are submitted to the Territorial Units of the MNR for approval. The approved limits for waste disposal are generally valid for a five-year period provided that the operator confirms annually that the production process has not changed. Otherwise, the approved waste disposal limits need to be revised accordingly and undergo the approval process again.

Performance standards. The benchmarks to which companies worldwide are encouraged to perform are typically referred to as performance standards. Through international efforts by many organizations (International Standards Organization – ISO, industry groups, etc.), voluntary standards of operation have been established for a wide range of industries, including the petroleum industry. Petroleum industry groups have also established operational standards for a wide range of discharges, emissions, and wastes commonly generated during the course of normal operations. These standards are usually referred to as International Best Practices and are considered by the industry as general guidelines for the conduct of their operations worldwide. In addition, most petroleum companies, especially major companies, have developed internal policies and procedures for the conduct of their operations. These individual operational standards, which include environmental, health, and safety directives, are often much more stringent than International Best Practices or the performance standards set by individual countries. Russian performance standards, at least on paper, are some of the most stringent in the world.

Special environmental and social issues. When designing, building, and operating facilities, a company may encounter certain situations governed by special laws. Such situations include:

- The use of lands or impact on specially protected natural lands, habitats of disappearing plant and animal species, water and swampy areas, sites of mass aggregations for reproduction, feeding, wintering, and migration of animals and birds, areas of reproduction of commercial or valuable species of fish and other aquatic life, and the grounds of historical and cultural monuments of the Russian Federation (termed 'especially valuable territories').
- The use of lands and effect on the preservation of traditional conditions of life and health of small aboriginal peoples of the north.
- The participation of non-governmental public organizations in the drafting and adoption of decisions on project facilities.

Especially valuable territories include: specially protected natural territories (SPNTs, in Russian OOPT); especially valuable lands; specially protected bodies of water (SPWs, in Russian OOVO); cultural heritage objects; and specially protected territories of international significance (SPTISs, in Russian OOPTMZ).

- Specially Protected Natural Territories are parcels of land, water surface, and the airspace above them containing natural systems and objects of special conservation, scientific, cultural, aesthetic, recreational, or recuperative significance that have been taken by decisions of government authorities in whole or in part out of commercial use, and for which special protective rules have been established (Federal Law 33-FZ of 3/14/95, On Specially Protected Natural Territories). SPNTs can be established at the Federal, regional, or local level and include national natural preserves, including biosphere preserves, national parks, nature parks, national natural reserves, natural monuments, forest parks and botanical gardens, and therapeutic and recuperative areas and spas.

  A company may obtain a permit to conduct certain work within the territory of an SPNT. However, the following activities are generally not allowed: water drainage; paving of roads or laying of pipelines, power transmission lines, or other utility structures and lines unrelated to the preserve's function; geological exploration and surveying, mineral development and production; drilling and blasting; and movement of mechanized vehicles other than utility vehicles off-road. The only exception to these restrictions is for activities ongoing prior to the establishment of the SPNT.

  In designing facilities that may impact SPNTs, a company must locate oil pipeline routes such that they do not enter the territory of SPNTs or the protection zones around them. Construction work must be completed in the shortest possible time. When calculating the area potentially affected by accidental oil spills, special measures must be designed to keep impacts from affecting an SPNT. The plans for environmental measures must include funding for work to create new SPNTs if impacts on existing SPNTs are unavoidable.

- Especially Valuable Lands are lands containing natural systems and objects of cultural heritage representing special scientific or historical-cultural value, and include atypical or rare landscapes; cultural landscapes; unusual plant or animal communities; rare geological formations; and land parcels set aside for the operations of scientific research organizations (*RF Land Code, Art. 100*). When designing facilities that may impact Especially Valuable Lands**,** a company must assess the consequences of possible accidents and develop adequate measures to eliminate or mitigate resulting impacts. Examples of such measures might be the funding of re-cultivation work, and the implementation of biological monitoring.
- Specially Protected Waters are natural aquatic ecosystems of special conservation, scientific, cultural, aesthetic, recreational, or recuperative significance that may, on the basis of decisions by executive authorities, be taken in whole or in part, permanently or temporarily out of commercial use. The following categories of specially protected waters may be established (RF Water Code, Federal Law 167-FZ of 11/16/1995): parcels of inland sea waters and territorial sea of the Russian Federation; water and swamp lands; streams and other bodies of water classified as unique natural landscapes; protection zones around sources or mouths of bodies of water; spawning grounds of valuable fish species; and other categories of waters considered to be in intimate contact with forests, wildlife and other natural resources subject to special protection.

  When designing facilities that may impact on SPWs, a company is required to develop an integrated system for localizing and eliminating accidental oil spills from oil pipeline systems that enter into or cross SPWs, and special measures to localize and eliminate accidental oil spills in wetlands, peat bogs, and seas, etc. They must also provide for environmental measures to clear river beds of sediment containing contaminants that exceed water quality requirements and apply measures to prevent marine pollution from drilling fluids. Maximum allowable concentrations or approximate safe exposure levels must be established for chemicals used in the preparation of drilling fluids. A suite of environmental measures for the environmentally safe performance of work that may impact on water bodies needs to be developed and the location of construction sites and roads should be planned giving consideration to surface and groundwater runoff. The possibility of erecting above-ground crossings to avoid impacts on water bodies to the greatest extent possible should be examined and, when water courses must be intersected, the category of piping (piping service factor) should be chosen with consideration of the significance to the fishery industry. Furthermore, when there are water resource restrictions in territories within which a pipeline is routed, it is necessary to resolve issues not only of water reuse, but also of creating a water recycling system.
- Cultural Heritage Objects are parcels or areas of land with associated works of painting, sculpture, decorative-applied art, scientific and technical facilities and other items of material culture created by historic events that represent value from the standpoint of history, archeology, architecture, city construction, art, science and technology, aesthetics, ethnology or anthropology, culture, and are evidence of epochs and civilizations or genuine sources of information on the origins and development of culture (Federal Law 73-FZ of 6/25/2002, On Cultural Heritage Objects and Historical and Cultural Landmarks of the Peoples of the Russian Federation, as amended 12/31/2005). Lands containing cultural heritage objects are classified as especially valuable lands and generally preclude any type of economic activity.
- Specially Protected Territories of International Significance are territories with special nature use rules established under international obligations of the Russian Federation. Examples are Key Ornithological Territories of Russia (KOTR), and specially protected waters of international significance such as cross-border or boundary waters, sections of inland sea waters and territorial seas of the Russian Federation, and swamp or wetlands. Nature use within SPTISs is not restricted. However, in the future, nature conservation rules may be established and they may be accorded the status of SPNTs.

  Federal and local government agencies may also establish other categories of SPTISs including: green zones, city forests, city parks, landmarks of garden and park art, protected shorelines, protected river systems, protected natural landscapes, biological stations, and micropreserves.

  If cultural heritage objects or associated territories are discovered on territory subject to commercial development, then land development, earthworks, construction, and other work may be conducted only if the plans for performance contain sections on preserving the integrity of cultural heritage objects that have received positive findings from State environmental expert review (SEER) and historical-cultural expert review. The conduct of land development, earthworks, construction, melioration, commercial, and other work *requires a finding of historical-cultural expert review* that the territory subject to commercial development is free of objects possessing the features of cultural heritage objects.

<u>Endangered species.</u> Rare and/or endangered wildlife species are recorded in the Red Book of the Russian Federation, and in the Red Books of the Russian Federation member regions. Plant and animal species classified under special laws include:

- rare and endangered species, as well as those listed in the Red Book of the Russian Federation
- species inhabiting SPNTs
- species populating the territorial seas, continental shelf, and exclusive economic zone of the Russian Federation
- species subject to international treaties of the Russian Federation
- species classified as specially protected or commercially valuable

- species that naturally migrate through the territories of two or more Russian Federation member regions (Federal Law 52-FZ of 4/24/1995, On Wildlife) (Federal Law, On Environmental Protection, Art. 60).

Restrictions and rules. Any operation entailing alteration of the habitat of wildlife or degrading its conditions of reproduction, feeding, recreation, or migration routes must be conducted in compliance with requirements ensuring the protection of wildlife.

When locating, designing, and building pipelines, and other transportation arteries, power transmission and communication lines, and canals, dams, and other hydraulic structures, a company must specify and conduct measures to preserve wildlife migration routes and areas of permanent concentration, including during their breeding and wintering seasons.

Regardless of the type of especially valuable territories, for purposes of protecting habitats of rare, endangered, and commercially and scientifically valuable wildlife, protective land and water areas needed to support their life cycles (reproduction, growth of young individuals, fattening, recreation, migration) must be set aside. In these protective land and water areas, certain types of commercial operations are prohibited or regulated if they disturb the life cycles of wildlife.

Actions that could cause the death, reduce the population, or disturb the habitat of wildlife listed in Red Books are not permitted. Legal entities and citizens conducting commercial operations in land and water areas inhabited by animals listed in Red Books are liable for their preservation and reproduction under the laws of the Russian Federation and its member regions.

Social sensitivity. There are two types of territories in the Russian Federation that merit special social considerations: territories inhabited by small aboriginal peoples (SAPs, in Russian KMN) and territories that contain objects of special historical or cultural significance.

Territories of traditional nature use by SAPs of northern Siberia and the Far East are specially protected areas formed to preserve the traditional lifestyle and nature use of the SAPs who inhabit these regions (Federal Law 49-FZ of 5/7/2001, On Territories of Traditional Nature Use by Small Aboriginal Peoples of the North, Siberia, and the Far East of the Russian Federation). These special territorial regions may be created at the Federal, regional, or local level. Within these regions, the SAPs may: locate residences, camping grounds, stopping areas for reindeer herders, hunters, and fishermen; and use certain parcels of land and water for the purpose of engaging in traditional nature and lifestyle activities including sea areas for taking of fish and marine mammals. These areas may include historical and cultural heritage objects, sites of ancient settlement and burial of ancestors and other sites of cultural, historic, or religious value.

The use of natural resources within special territories set aside for aboriginal peoples is permitted if it does not violate the legal status of those territories. On land parcels within these regions, easements may be established in accordance with Russian Federation law to support reindeer migration, animal watering, pedestrian and mounted travel, water supply, stringing and operation of power and communication lines and pipelines, and other needs, if that does not violate the legal status of the territories of traditional nature use. If a company plans operations that could impact SAPs, it must begin negotiations with representatives of the peoples living on the affected land.

Objects or sites of historical or cultural significance include ancient settlements, special landmarks, cult structures, and burial sites of forbearers. Such sites or objects are afforded special protection and preservation under the laws of the Russian Federation and may be used only in accordance with their purpose. A company's operations must not damage or disturb these historical or cultural sites nor affect any objects associated with them.

Non-governmental organizations. By law, non-governmental organizations (NGOs) in the Russian Federation are entitled to engage in certain monitoring or oversight activities. The most important include:

- to organize and conduct hearings regarding the design and location of facilities whose commercial and other operations could damage the environment or create a threat to the life, health, or property of citizens;
- to organize and conduct public environmental expert review, and to recommend their representatives for participation in state environmental expert review;
- to participate in the conduct of an OVOS with respect to planned commercial and other operations that could directly or indirectly impact the environment;
- to perform public environmental monitoring in the area of environmental protection;
- to file complaints with Federal and local government agencies and courts for repeal of decisions on the design, location, construction, reconstruction or operation of facilities whose operation they believe could have an adverse impact on the environment, or for restriction, suspension, or termination of such operations; and
- to bring actions in court for compensation for damage to the environment (Law, On Environmental Protection).

Recently, the Russian Federation government passed new legislation requiring that NGOs open their books for regular inspections to ensure that these organizations are not engaged in terrorist activities. Despite this increased scrutiny, Western companies operating within the Russian Federation would be well advised to communicate with these organizations, especially those that take an active interest in their intended operations.

Public environmental expert review. The rights of citizens and public organizations in the area of environmental expert review are defined by Federal Law 174-FZ of 11/23/1995, On Environmental Expert Review). This law grants the right to make proposals for public environmental expert review (PEER, in Russian OEE) of commercial and other operations affecting the interest of the public living in the territory; to send proposals to Rosprirodnadzor and Rostekhnadzor and their territorial agencies regarding environmental aspects of proposed commercial and other operations; and to receive information from Rosprirodnadzor and Rostekhnadzor and their territorial agencies on the results of SEER. Although State agencies must take PEER findings into account when preparing their own SEER findings, these public opinions seldom determine the approval outcome of economic proposals.

Public environmental monitoring. Non-governmental public organizations are entitled to perform public environmental monitoring so that citizens may exercise their right to a favorable environment and to prevent violations of conservation laws (Law, On Environmental Protection, Art. 68). The results of public environmental monitoring, submitted to Federal and local government agencies, are subject to mandatory review as provided by law. A company that impedes citizens, the public and other non-commercial associations in the performance of environmental activities is accountable under Russian Federation law.

2.4.7.2. Development of oil and gas activity in the Russian Federation

Russia has always attached great significance to the development of its northern territories. As a result of early and active trading, trade centers and small settlements developed in the north many years ago; these include Mangazeya, Arkhangelsk, and a number of other populated areas. Development of the northern seaway – the main navigable waterway of Russia in the Arctic – was accompanied by the construction of the large seaports: Igarka, Dudinka, Dixon, Tiksi, Pevek, Foresight, which facilitated the development of the rich natural resources of the north.

2.4.7.2.1. Classification of Russian oil and gas provinces

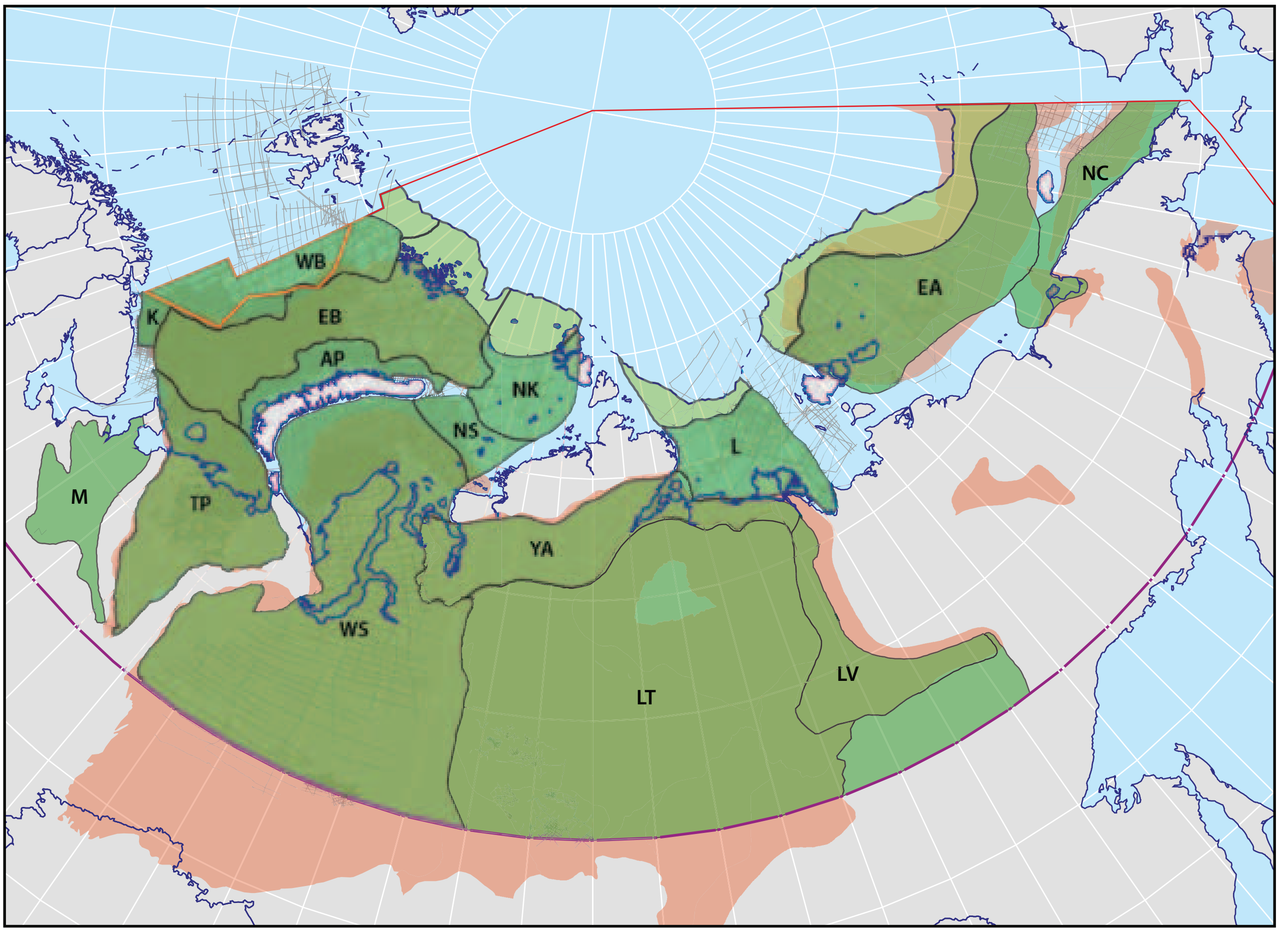
The current Russian classification of oil- and gas-bearing territories is based on the tectonic principle. Oil and gas deposits are allocated into oil- and gas-bearing belts classified as: mega-provinces, provinces, sub-provinces, regions, and areas of oil and gas concentration zones. Within the limits of platforms, fold belts, and transitive territories, 19 oil and gas prospective provinces and sub-provinces have been defined (Table 2.48). Each includes a few oil- and gas-bearing areas and regions.

Arctic Russia is divided into geological oil and gas provinces (OGP) and further subdivided into oil and gas geological regions (OGR). Some are considered as prospective provinces or regions (POGP and POGR), which are quantitatively or qualitatively assessed. The

Table 2.48. Oil and gas provinces in the Russian Federation; Arctic areas are shaded.

Oil and gas provinces	Discovery	Age of oil and gas deposits
Eastern European (Russian) OGMPs		
Volga-Ural OGP	1936	Permian, Carboniferous, Devonian
Timan-Pechora OGP	1930	Triassic, Permian, Carboniferous, Devonian, Silurian, Ordovician
Pre-Caspian OGP	1895	Cretaceous, Jurassic, Triassic, Permian, Carboniferous, Devonian
Baltic OGP	1962	Silurian, Ordovician, Cambrian
East Siberian OGMP		
Lena-Tungus OGP	1962	Cambrian, Vendian, Riphean
Lena-Vilyuskii OGP	1956	Jurassic, Triassic, Permian
Yenisey-Anabar OGP	1960	Cretaceous, Jurassic, Triassic, Permian
OGMPs of young platforms		
West Siberian OGMP	1953 gas 1961 oil	Cretaceous, Jurassic
Pre-Caucasian (Scythian) OGMP	1946	Neogenic, Paleogenic, Cretaceous, Jurassic, Triassic
OGSPs of transitive territories		
Pre-Caucasian OGSP	1864	Neogenic, Paleogenic, Cretaceous, Jurassic, Triassic
Pre-Ural OGSP	1929	Permian, Carboniferous, Devonian, Silurian, Ordovician
Pre-Verkhoyanskay GSP	-	Jurassic
OGPs of Arctic and Far Eastern Seas of Russia		
Barents Sea OGP	1982	Jurassic, Triassic
North Kara POGP	-	Cretaceous, Carboniferous, Devonian
Laptev POGP	-	Paleogenic, Cretaceous, Jurassic, Triassic, Permian, Carboniferous, Devonian, Silurian, Vendian, Riphean
East Arctic POGP	-	Paleogenic, Cretaceous, Jurassic, Triassic, Permian, Carboniferous, Devonian, Silurian, Vendian, Riphean
South Chukchi POGP	-	Cretaceous, Permian, Carboniferous
Pre-Pacific OGP	-	Miocene, Oligocene, Eocene
Oil and gas of fold belts		
Far East OGP	1923	Neogenic

OGMP: oil and gas mega-province; OGP: oil and gas province; OGSP: oil and gas sub-province; GSP: gas sub-province; POGP: prospective oil and gas province.



Oil and gas basins (see Figure 2.9)
Potential prospective regions lacking study
Prospective regions with quantitative or qualitative assessment
Disputed area boundaries
Shelf boundary
60° N latitude
Seismic surveys

Oil and gas provinces and prospective provinces and regions

WB West Barents OGP
EB East Barents OGP
TP Timan-Pechora OGP
WS West Siberian OGP
YA Yenisey-Anabar OGP
LT Lena-Tungus OGP
LV Lena-Vyluy OGP
EA East Arctic POGP
NC Novosibirsk-Chuckchi POGP
K Kolskaya POGR
M Mezenskaya POGR
AP Admiralteysko-Prinovozenelskaya POGR
NS Northern Siberia Rock Step POGR
NK Northern Kara POGR
L Laptevskaya POGR

Figure 2.80. Map of Russian oil and gas provinces.

distribution of OGPs and OGRs is shown in Figure 2.80. In spite of the paucity of geological and geophysical data coverage in the Russian Arctic, its general geological structure has been studied, the main oil and gas provinces have been discovered, and their boundaries have been defined.

The Russian Arctic region includes vast northern territories with large OGPs such as the Timan-Pechora OGP (within the limits of the Eastern European (Russian) mega-province, the northern part of which is in the Arctic), the large West Siberian OGMP with important oil and gas deposits, and the East Siberian OGMP, not yet adequately explored and currently almost undeveloped, which includes Yenisey-Anabar, and polar regions of Lena-Tungus and Lena-Vilyuj. In addition, there are the OGPs and OGRs of the large Arctic shelf containing both proven and potential reserves (POGPs and POGRs). Among those with proven reserves are submarine continuations of the Timan-Pechora OGP in the Barents and Pechora Seas and the West Siberian OGP (in the Pechora and Kara Seas). Among those with potential reserves are the Kola and Admiralteisko-Prinovozemelskaya POGR in the Barents Sea, North-Kara POGP, Laptev POGP, East Arctic POGP, and Novosibirsk-Chukotka POGP. In the Far East outside the Arctic, oil and gas production occurs in the Sakhalin OGP, which is a component of the Okhotskoye Sea or Far East OGP.

The economic value of the provinces varies. Currently, the major oil and gas production occurs in the fields of the West Siberian OGMP. A significant amount of oil is produced from the Timan-Pechora OGP. Although the Barents Sea and other Arctic marine shelf provinces also have good prospects for resources, these provinces are not yet being developed.

These Russian Arctic provinces and regions contain tens of billions of tons of oil and over 100 trillion m^3 of gas – a significant proportion of the total hydrocarbon resources of the Russian Federation. Some estimates show that about 240 billion tons of oil equivalents (o.e.) are contained in these OGPs and OGRs, which is approximately 40% of Russia's undiscovered oil, gas, and condensate resources.

These resources are relatively well-explored only in the coastal areas, where 34% of the oil and gas resources of the northern Timan-Pechora OGP and 46% of the gas resources of the northern West Siberian OGMP are known. The Taymir Autonomous Okrug and transpolar regions of the Republic of Sakha-Yakutia remain little explored. Despite its potentially enormous oil and gas resources, the Arctic shelf is also poorly explored, with some exploration only in the Pechora Sea, Barents Sea, and partially the Kara Sea of the West Arctic shelf. Although the uncertainty of oil and gas resource estimates is increased by the lack of exploration in these areas, it is evident that they contain the largest hydrocarbon resources in the country (and maybe in the world).

Over 90 oil and gas fields have been discovered in the northern Timan-Pechora OGP that are part of the Pechora-Kolva, Khoreiver and Varandey-Adzvin OGR, including the large *Vassilkovskoe*, *Korovinskoe* and *Kumzhinskoe* gas and condensate fields; *Vaneivisskoe*, *Yuzhno-Shapkinsoe*, *Layavozhskoe* oil, gas and condensate fields; *Yuzhno-Khylchuyuskoe*, *Vozeiskoe*, *Verkhnevozeiskoe*, *Usinskoe*, *A. Titov*, *R. Trebs* and *Toraveiskoe* oil and oil and gas fields. The majority of oil and gas reserves and resources in the northern Pechora-Kolva OGR are concentrated in the carboniferous Lower Permian complex, but terrigenous Upper Permian and Triassic sediments are also productive to the north of *Shapkinsko-Yuryakhinsky* gas and condensate fields.

In the Khoreiver OGR, many fields with high-yield deposits have been explored in the Silurian, Lower and Upper Devonian, and Permo-Carboniferous carbonate sediments. Single deposits have been discovered in Ordovician carbonates. The main high-yield deposit on one of the largest fields – the *Verkhnevozeiskoe* field – is related to Lower Silurian carbonate rocks (at 3300–4000 m depth), whereas the main deposits of *R. Trebs* and *A. Titov* fields located near the Pechora Sea coast are found in the Lower Devonian carbonate rocks (at 4000–4200 m depth).

Recently published estimates (Grigorenko, 2004) showed that the commercial reserves in the northern Timan-Pechora OGP amount to 480 million tons of oil and 515.6 billion m^3 of gas. Oil production is 5.2 million tons of oil and 0.3 billion m^3 of gas per year. However, growth in production is restricted by undeveloped infrastructure. Furthermore, the total initial resources are more than one billion tons of oil and condensate and 1850 billion m^3 of gas (Grigorenko, 2004). But, according to data from the All Russia Geological Research Institute (VNGRI), the volume of economically prospective and forecast oil resources in this part of the Timan-Pechora OGP is estimated at 1.34 billion tons, including 0.73 billion tons in the Nenets Autonomous Okrug (Belonin et al., 2003).

The northern areas of the West Siberian OGP possess the largest hydrocarbon resources in the Arctic. Extraordinary gas, gas and condensate, and oil, gas and condensate fields such as *Kharasaveiskoe*, *Bovanenkovskoe*, *Utrennee*, *Gydanskoe*, *Yamburgskoe*, *Severo-Urengoiskoe*, *Urengoiskoe*, *Medvezhie*, and other large fields have been discovered in the Yamal and Gydan OGR, the northern part of Nadym-Pur and Pur-Taz OGR. According to Gramberg and Laverov (2000) "There is no such concentration of the largest gas field elsewhere in the Russian and foreign Arctic as in the north of West Siberia. Discovered and explored gas reserves are over 30 trillion cubic meters; oil, over 2.5 billion tons; and condensate, over 900 million tons." A very important feature of these reserves is that they lie mainly at shallow depths in highly efficient Cretaceous Cenomanian reservoirs. Estimated reserves of gas in the Arctic regions of West Siberia are 34.5 trillion m^3 with 48% economically recoverable (Grigorenko, 2004). Oil resources are also significant, mainly as gas and condensate fringe deposits.

In the eastern Arctic areas, commercial oil and gas resources have been found in the Yenisey-Khatanga OGR and the Yenisey-Anabar OGP where 12 oil and gas fields have been discovered, amongst which the *Severo-Soleninskoe*, *Yuzhno-Soleninskoe*, *Mesoyakhskoe* and *Pelyakinskoe* fields are used to supply gas to the Norilsk Mining Region. Commercial oil and gas resources have been found in Jurassic and Cretaceous reservoirs. The main target of exploration is Cretaceous oil and gas play in which the largest fields such as the *Severo-Soleninskoe*, *Yuzhno-Soleninskoe*, *Pelyakinskoe* fields are found (All-Russia Petroleum Research Exploration Institute, 1997). The forecast resources of the Yenisey-Anabar OGP and polar regions Lena-Tungus OGP are over 17 billion tons o.e. including 3.2 billion tons of oil and condensate; the reserves of the above-mentioned ten gas and gas and condensate and two oil fields of the Yenisey-Khatanga OGR are 33.4 million tons of oil and condensate and almost 350 billion m^3 of gas (Gramberg and Laverov, 2000).

2.4.7.2.2. Reserves and resources

The Russian classification system of oil reserves and resources is different from that used in the Western oil and gas industry (see section 2.2) and is represented by the following categories:

- explored reserves: categories A, B, and C1;
- preliminary estimated reserves: category C2;
- potential resources: category C3; and
- forecasted resources: categories D1 and D2.

Western classifications, such as the widely used classification of the Society of Petroleum Engineers, result in the following recovery probabilities:

- proven: not less 90%;
- probable: not less 25%; and
- possible: not less 10%.

The Russian classification is mainly based on the extent, source, manner of acquisition, completeness, and quality of available geological and geophysical data and does not account for an assessment of economic profitability or such factors as technical recoverability, access to the field, available technology, and timing of production. Such an approach is a throw-back to the former USSR classification (approved by the USSR Council of Ministers in 1983). Later, the Russian classification of 2001 (approved by the Ministry of Natural Resources) was almost a literal adoption of the Soviet classification (see section 2.2 for a more thorough discussion of the Russian resource classification system).

Non-harmonized methodologies make it difficult to compare resource estimates made for different countries and basins and by different methodologies (such as by the Society of Petroleum Engineers, Security and Exchange Commission and/or the United Nations Framework Classification (UNFC) for Fossil Energy and Mineral Resources). In addition, estimates of these different classes for the same country but by different authors result in further complications for making comparisons. For example, reserves of major Russian companies assessed in the highest confidence classification ($A+B+C_1$) are now being reevaluated by independent audits and a significant reallocation of reserves between classes has been necessary,

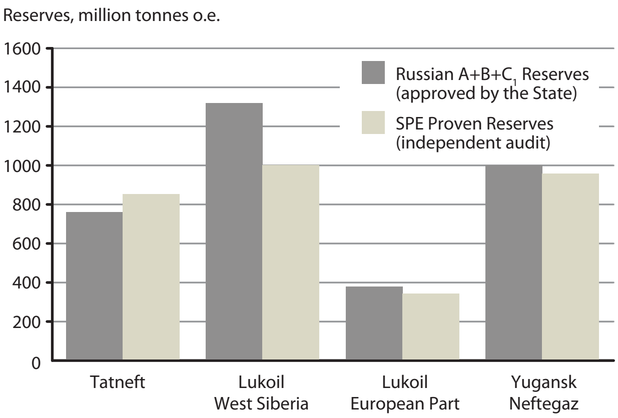


Figure 2.81. Russian reserves, according to State and independent classifications.

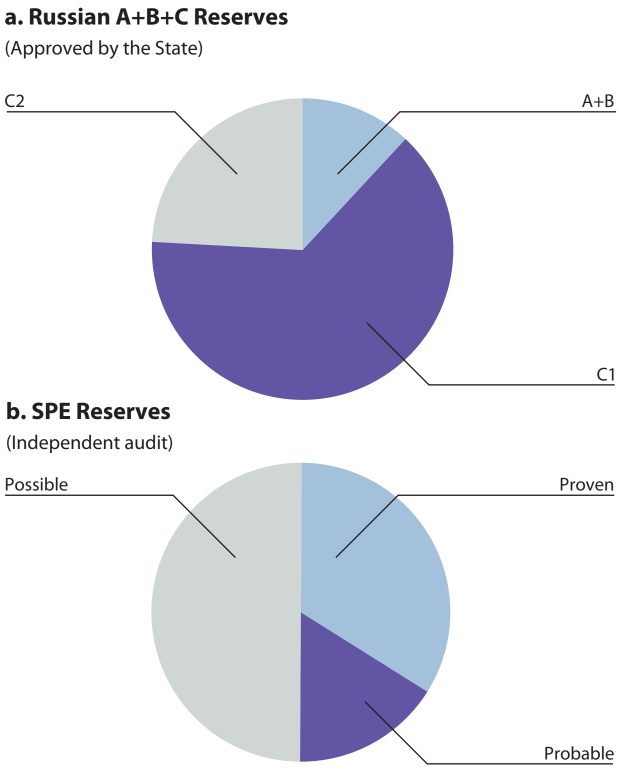


Figure 2.82. Proportion of different classes of Russian reserves, (a) approved by the state and (b) according to independent classifications.

resulting from both underestimating and overestimating resources (Figures 2.81 and 2.82).

The categories in most dispute are C_1 and C_2. The first, on an expert level, is considered in Russia to be 75% recoverable reserves, while Western experts argue that it would not exceed 30%. There are some discrepancies in the total Russian oil resource estimates: while such a recognized source as the BP Statistical Report 2005–2006 evaluates them at 86.7 billion m^3, Russian expert sources are insisting on figures above 116 billion m^3.

A notable step toward harmonization occurred in 2005 by the issue of revised Rules of Classification of Oil and Flammable Gases Reserves and Prognostic Resources, which document is more consistent with the UNFC classification for oil and flammable gases. The rules are required to be put into force in 2009.

Official data on Russian reserves and resources are now kept confidential. The latest data (end of 2006) from open sources in the Ministry of Industry and Energy (Minpromenergo) show that explored oil reserves in Russia are 19 billion m^3 as preliminary estimated reserves (category C_2), 9 billion m^3 as of the estimation at the beginning of 2005. Table 2.49 shows that total explored oil reserves (categories A+B+C_1) in onshore and offshore areas of Russia (excluding Khanti-Mansisk) comprise slightly more than 9.35 billion m^3, of which Arctic areas (Timan-Pechora, Yenisey-Anabar, and YaNAO) contain 5.24 billion m^3 or 56% of Russia's total explored oil reserves. The total estimated reserves (category C_2) in Russian onshore and offshore areas (excluding Khanti-Mansisk) comprise about 5.8 billion m^3, of which the Arctic areas (Timan-Pechora, Yenisey-Anabar, and YaNAO) contain 4.3 billion m^3, or about 74% of all estimated reserves. Total estimated undiscovered resources (categories C_3+D_1+D_2) in Russian onshore and offshore areas (excluding Khanti-Mansisk) total about 80 billion m^3, of which the Arctic areas (Timan-Pechora, Yenisey-Anabar, and YaNAO) contain 73.5 billion m^3; thus, over 90% of Russia's estimated undiscovered oil is found in the Arctic outside of Khanti-Mansi Autonomous Okrug.

Table 2.49. Oil production, explored reserves, and undiscovered resources in Russia (excluding the Khanty-Mansisk Autonomous Okrug). Initial resources and undiscovered resources estimates are from the latest official Ministry of Industry and Energy (Minpromenergo) estimate in 1993.

Region and its relation to Arctic	Initial resources[a], billion m^3	Accumulated production, billion m^3	Explored reserves[b], billion m^3		Estimated undiscovered resources, billion m^3	
			A+B+C_1	C_2	C_3	D_1+D_2
Russia onshore	100.23	17.53	8.99	5.05	13.79	54.86
Timan-Pechora	5.32	0.61	1.53	0.76	0.89	1.53
Yenisey-Anabar	13.94	0.28	0.88	1.06	2.28	9.43
YaNAO	N/A	7.25	2.83	2.46	8.96	37.72
Total for Arctic areas (TP+YA+YaNAO)	19.21	8.14	5.24	4.29	12.08	48.68
Russia offshore	13.83	0.01	0.35	0.73	1.25	11.48
Russia in total	114.05	17.5	9.35	5.77	15.04	66.34

[a] Produced A+B+C_1+C_2+C_3+D_1–D_2; [b] data as of 1 January 2005.

The indices presented here for the OGPs in the Russian Federation can be viewed in relation to the overall indices of oil and gas activity in the Arctic as a whole presented in section 2.3. With regard to the petroleum regions and oil and gas fields in Russia (Figure 2.9), the indices show the number of meters of exploratory, discovery, and production wells drilled in all regions of Arctic Russia (Figure 2.83), and oil production and gas production in the Timan-Pechora and West Siberian oil and gas basins of Arctic Russia (Figures 2.84 and 2.85).

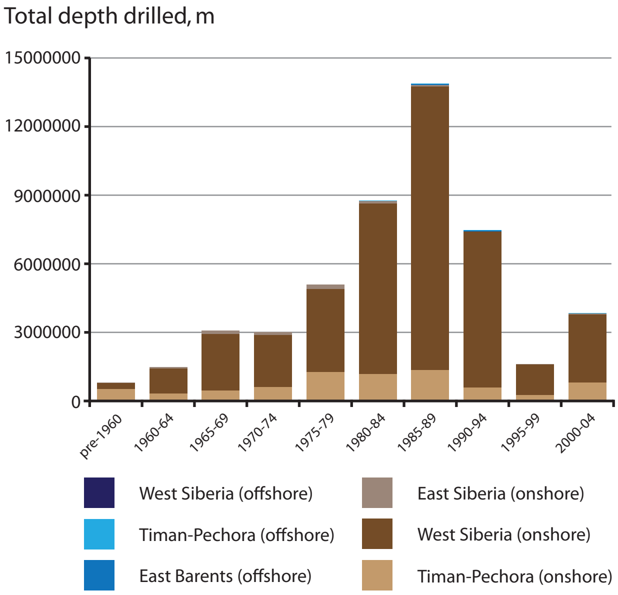


Figure 2.83. Arctic Russia metres wells drilled over time by region.

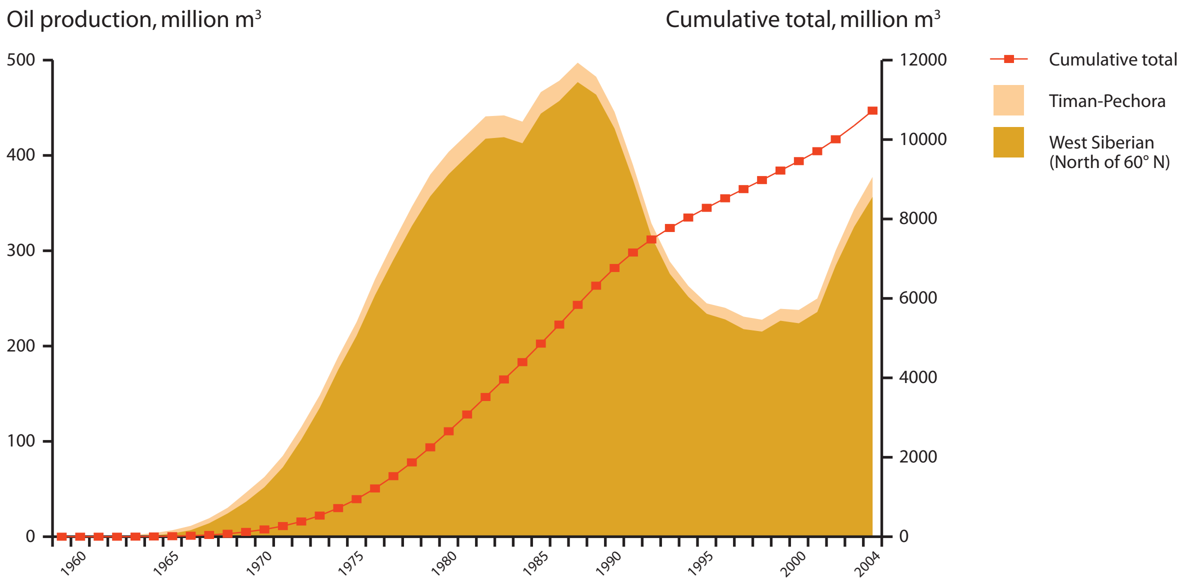


Figure 2.84. Arctic Russia oil production over time for all regions.

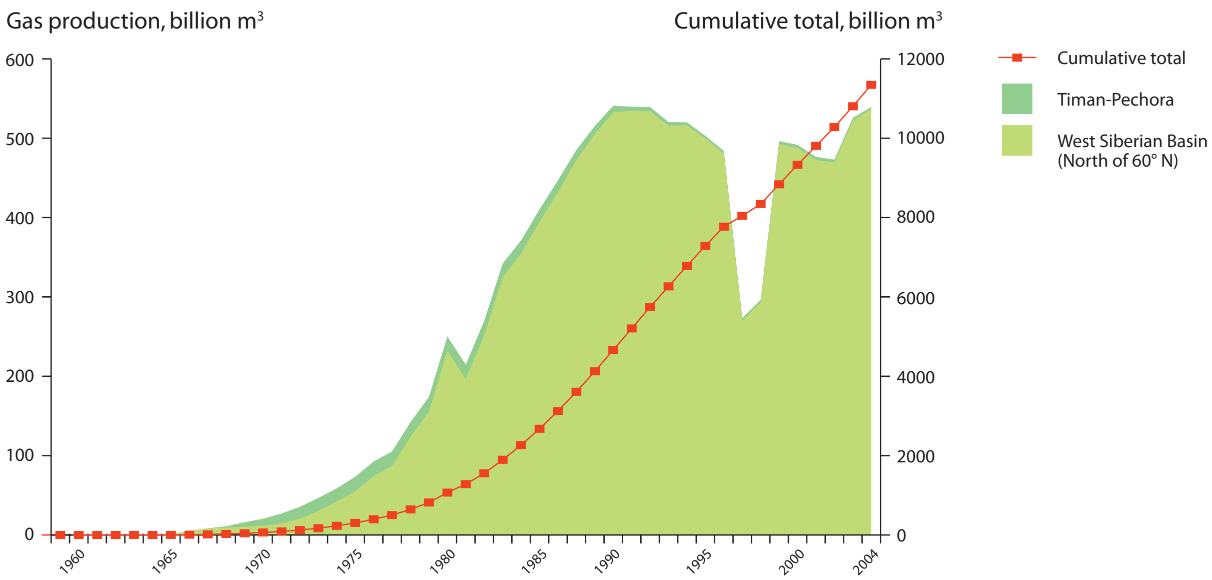


Figure 2.85. Arctic Russia gas production over time for all regions.

2.4.7.3. Timan-Pechora OGP

2.4.7.3.1. Historical to present

Pre-exploration

The first information on Arctic oil seeps came centuries ago from the Ukhta region of the Timan-Pechora OGP. Primitive production and processing began in 1745 from oil gathered from seeps along the bed of the Ukhta River. Some oil-based products from this area were delivered to Moscow and St Petersburg.

Exploration

In the history of the geological exploration of the Timan-Pechora OGP, there are several periods characterizing geological and geophysical studies of the territory, working procedures, changes in principles of formation and distribution of accumulations of hydrocarbons, as well as priorities in explorations associated with the macroeconomic situation (orientation on oil and gas, on certain promising fields and regions): the first period covered up to 1960; the second from 1961 to 1980; the third from 1981 to 1993; the fourth from 1994 to 1998; and the fifth began in 1999.

During the first period of studies, regional geological and geophysical data were acquired on basic geological structure and reconnaissance was made of oil and gas deposits in the southern territories. The first light-oil field, *Chibyu*, was discovered in 1930 in Upper Devonian reservoirs, while the *Yareg* heavy-oil field was discovered in 1932 in the rocks of the Middle Devonian. The first oil fields in the USSR were built and operated during the Second World War.

In the period between 1948 and 1957, seven oil, oil/gas, and gas fields were discovered and by 1959, four additional small oil fields were discovered to the south side of the Timan-Pechora OGP, in the Komi Republic. At this time, the first wells were drilled in the Nenets Autonomous Okrug (NAO).

Geological and geophysical exploration increased greatly in the period from 1959 to 1964, when the southern Komi Republic was the principal oil exploration target. The discovery of 12 fields (mainly oil) resulted in the creation of a resources base for the oil production industry. The most important factor during that period was the migration of exploration activities to the northern regions of the province. Regional airborne gravity surveys helped discover the large linear Kolva, Shapkino-Yutyakhisky and Sorokina structures. The large *Usinskoe* oil field discovery in 1963 created the second resource base for oil production in the Timan-Pechora OGP.

The second period of studies was fundamental for the further development of the oil and gas industry, primarily in the southern regions (the Komi Republic). This period is characterized by an increase in geological exploration, and an expansion of the areas under exploration, including the territory of the NAO. The highest efficiency of exploration in the province occurred from 1961 to 1975, when 22 oil fields were discovered, including sixteen in the Komi Republic and six in the NAO.

The period from 1966 to 1970 was marked by the first discoveries in the NAO. Using single stratigraphic test wells and parametric wells, the *Kharyaginskoe* oil field on the Kolva megaval and the *Yuzhno-Shapkinskoe* gas and oil field on the Shapkina-Yuryakhinskiy val were found. Discovery of those oil fields made possible further exploration work in the northern part of the Timan-Pechora OGP.

In the period 1965 to 1975, active exploration of the northern parts of the OGP including its Arctic regions continued. Over this period, average well depth increased from 1761 m in 1961 to 2829 m in 1974.

During 1971 to 1980, deep drilling continued to increase and reached 1371.3 thousand meters in the Timan-Pechora OGP, including 621.1 thousand meters in areas of the Komi Republic, and 750.2 thousand meters in the northern areas (Nenets Autonomous District).

The first oil field in the northern part of the OGP – *Shapkinskoe* – was discovered in 1966. Further efforts resulted in the discovery of several oil fields and dry and wet gas fields. Several oil fields currently produce oil in the NAO and more are under development.

The third period of oil resources development of the Timan-Pechora OGP began when only 21% of the area had been explored, when the main large oil fields of the Komi Republic had been revealed and, in contrast to the NAO, a gradual decrease in geological exploration was observed.

In 1981 to 1985, the main geological exploration was concentrated in the Khoreyverskaya depression, in the Pechora-Kolva avlakogene, and on Sorokin Val. The period 1981 to 1990 was characterized by maximum volumes of deep-drill footage in the province. Deep-drill footage continued to increase considerably. Parametric drill footage more than doubled. The third period of the resource development showed a considerable increase in exploration seismology in addition to deep-drill footage.

The fourth period of geological exploration is associated with the post-perestroika period, when the structure of the oil- and gas-producing industry changed dramatically. The change in the organizational system ended in almost full privatization of the oil industry. A number of oil companies with different patterns of ownership were formed. The financing of geological exploration work also changed abruptly. Instead of centralized budgetary financing, mixed financing appeared: both budgetary, as well as at the expense of the internal funds of the companies. These changes affected the results of exploration work and particularly the prospecting activity.

In 1991 to 1995, an abrupt decrease in drill footage and seismic works was observed. Deep-drill footage more than halved. There was an abrupt reduction in drilling in the period 1996 to 2000, while a small increase was observed in 2001 to 2002.

In the northern and north-eastern areas of the Timan-Pechora OGP, prospecting work was concentrated in the Khoreyverskaya depression.

The period 1996 to 2000 was characterized by moderate volumes of seismic works and drilling activity. Exploration seismology decreased more than five-fold in comparison with the previous five years. Deep prospect drilling was conducted mainly on the territory of the Komi Republic.

By the beginning of 1995, 178 fields had been discovered in the Timan-Pechora OGP, about 85% of which are oil and oil/gas fields, indicative of the quantitative predominance of oil over gas in the resource base of the province. 363 million tonnes of oil, 382 billion m^3 of gas, and about 50 million tonnes of condensate were extracted from fields in the province during its development lifetime. Maximum production was reached in the late 1970s to the early 1980s (20 million tonnes of oil and condensate and 20 billion m^3 of gas). Thereafter,

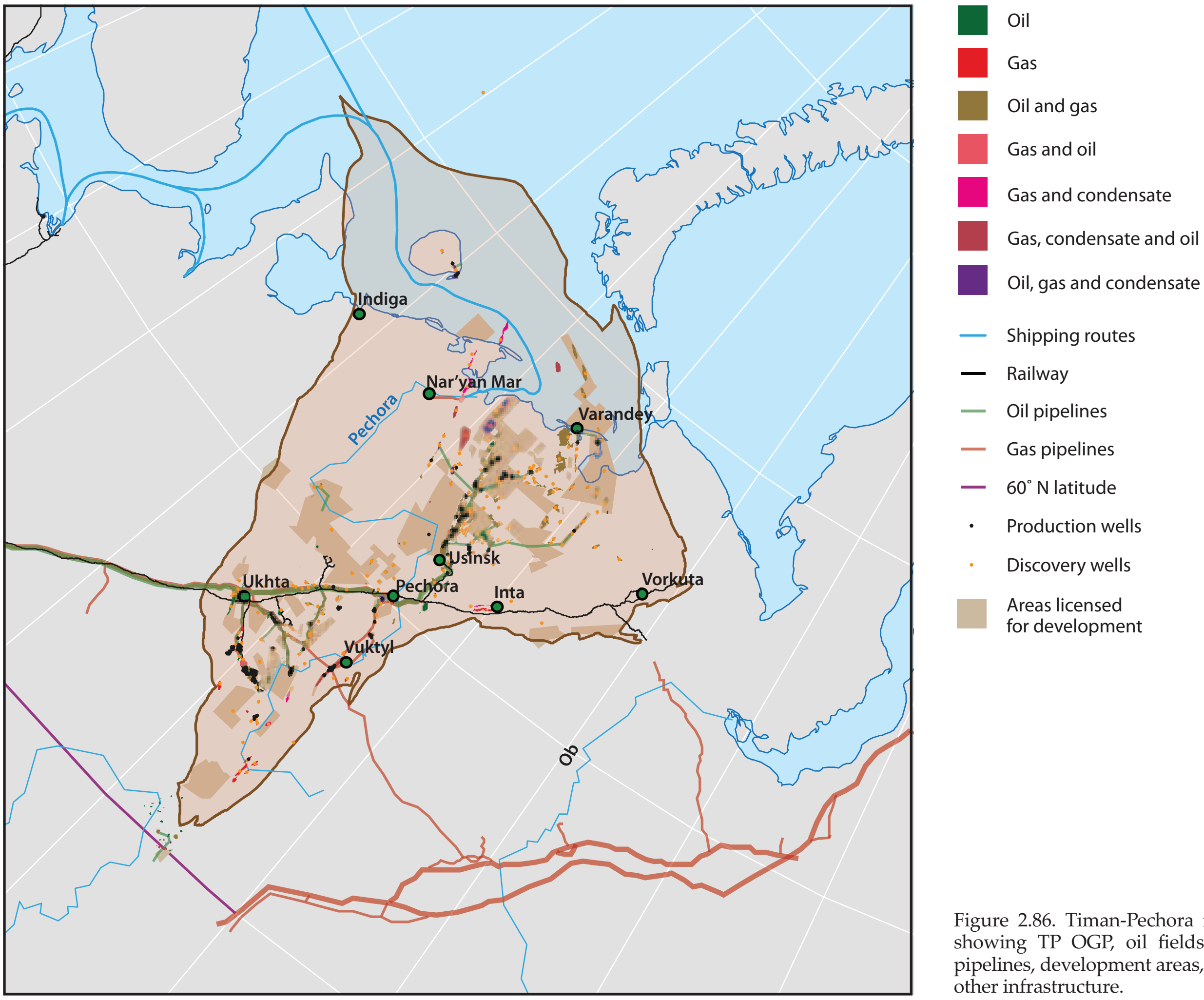


Figure 2.86. Timan-Pechora map showing TP OGP, oil fields, oil pipelines, development areas, and other infrastructure.

Table 2.50. Dynamics in the growth of hydrocarbon reserves and production from 1980 through 2004 in Timan-Pechora OGP.

Period	Growth of reserves, million tons	Production, million tons	Ratio of reserves growth to production
1980–1984	391.85	0.51	766.80
1985–1989	277.17	1.02	271.20
1990–1994	168.35	8.82	19.10
1995–1999	4.37	16.76	0.26
2000–2004	30.29	32.10	0.94

Table 2.51. Seismic data acquisition reported by Sibneft in northern oil fields of West Siberia and Timan-Pechora in 2005.

	1997	1998	1999	2000	2001	2002	2003	2004
2-D, km	1459	1672	1594	768	1726	3190	1149	166
3-D, km^2	150	326	160	205	260	939	2087	1918

production began to decline due to exhaustion of the main fields (*Usinskoe*, *Vozeiskoe*, and *Vuktylskoe*) and a delay in development and commissioning of new fields with large reserves.

Discoveries and development

The locations of development areas, oil fields, pipelines, and other infrastructure in the Timan-Pechora OGP are shown in Figure 2.86. From 1980 through 2004, there was variable growth in hydrocarbon reserves together with a steady increase in production in the Timan-Pechora OGP (Table 2.50). 2-D and 3-D Sibneft seismic data acquisition in the northern oil fields of West Siberia and Timan-Pechora was variable over the period 1997 to 2004, with a recent increase in the collection of 3-D data (Table 2.51).

The NAO contains 52.5% of initial hydrocarbon resources of the Timan-Pechora OGP. Initial hydrocarbon resources in NAO are 4.18 billion m^3 o.e., including accumulated production, extractable and probable reserves. Considering that only 81 million m^3 of oil had been produced through 2005, the degree of development maturity is less than 5% of the potential oil resources and less than 1% of the potential gas resources.

At present, 180 oil and oil/gas deposits have been discovered in the onshore Timan-Pechora OGP, with recoverable reserves (A+B+C$_1$ category) of over 1.5 billion

Table 2.52. Estimates of resources and reserves of the Timan-Pechora OGP, including its part in the Pechora Sea (resources as of 1993, reserves as of 2005).

	Initial resources, billion m^3	Accumulated production, billion m^3	Explored reserves ($A+B+C_1+C_2$), billion m^3	Resources (C_3+D), billion m^3
Oil				
Nenets AO	3.18	0.06	1.46	1.434
Komi	2.55	0.49	0.72	1.33
Pechora Sea	2.42	0	0.46	1.96
Total	8.15	0.55	2.64	4.72
Gas				
Nenets AO	1054	30	524	500
Komi	1677	410	198	1069
Pechora Sea	2476	0	74	2402
Total	5207	440	796	3971

Table 2.53. Status of wells for oil and associated gas in the Timan-Pechora OGP, 2002 to 2004.

	Number by years		
	2002	2003	2004
Wells with oil and associated gas production by the end of the year	90	103	143
Operating well stock	111	138	175
Total number of wells	456	394	351
New wells from development for the year	32	39	36
Water intake wells	8	14	24
Produced water injection wells	6	7	13
Control wells	1	1	1
Waste injection wells	1	1	1
Wells shut in (non-producing)	176	62	59
Wells waiting for abandonment	44	3	3
Wells abandoned after production	0	1	1
Wells abandoned after drilling	109	74	81

m^3 of oil. However, the degree of geological study is still low; experts estimate that these numbers are only 30% of available recoverable resources. Currently available estimates of oil and gas resources and reserves of the Timan-Pechora OGP, including its part in the Pechora Sea, as well as figures for accumulated production, are given in Table 2.52.

The NAO is currently a major focus of energy production and has become the new key petroleum and gas production region. A total of sixteen fields (thirteen oil, two oil/gas/condensate, one gas/condensate) were under development in the NAO in 2004. The most productive fields are *Khajyginckoje*, *Toraveyskoje*, *Varandeyskoje*, *Khasyreyskoje*, and *Tedinskoje*.

Annual oil production reached 5.1 million tons in 2002, 7.4 million tons in 2003, 10.5 million tons in 2004, 12.1 million tons in 2005, and exceeded 13.0 million tons in 2006. Maximum oil production of 25–30 million tons per year is projected for 2015–2020.

Currently there is an active phase of oil field development, as indicated by the dynamics of operating wells for oil and associated gas in the Timan-Pechora OGP during the 2002 to 2004 period (Table 2.53). However, the degree of industrial development of resources is low: only five of 74 oil deposits are developed, the largest of which are Khar'yaginskoye and Ardalinskoye. Among the undeveloped deposits there are large structures with the reserves of 50-70 million tons of oil (e.g., Yuzhno-Khyl'chuyuskoye, Trebsa, Titova). Significant oil reserves have been investigated and prepared for development in the northeast region of the Varandey-Adzhvinskaja structure (e.g., Varandeyskoye, Toraveyskoye, Labaganskoye). Furthermore, very little development of gas deposits has taken place; as of the end of 2004, there were only three producing gas wells in the Timan-Pechora OGP (Table 2.54).

According to the Nenets Regional Branch of the Russian Subsoil Resources Agency of the Ministry of Natural Resources, plans have been made to distribute 17 oil fields with total resources of 245 million tons of oil through auctions, but only five have been completed according to schedule.

Large gas deposits, such as Layavozhskoye with 140 billion m^3 of gas, have been investigated in the NAO but have not yet been developed. Gas is produced from two deposits and is targeted for domestic consumption (gas supply to the capital city Narjan-Mar and aligned settlements).

2.4.7.3.2. Future

Near-term (up to about 2015)

Over recent decades, the Timan-Pechora OGP has experienced a lack of reserves coming from exploration to development against extracted reserves. Future plans are aimed at achieving full recovery of extracted reserves, as shown in Table 2.55 and Figure 2.87.

Table 2.54. Status of gas wells in the Timan-Pechora OGP in 2002 to 2004.

	Number by years		
	2002	2003	2004
Producing gas wells	-	3	3
All gas wells	-	3	3
Gas wells shut in (non-producing)	-	-	-
Gas wells abandoned after production	-	-	-
Gas wells abandoned after drilling	-	-	-

Table 2.55. Planned exploration and development activities for oil and gas fields in the Timan-Pechora OGP.

	Drilling, 1000 m		2-D seismic surveys, km	3-D seismic surveys, km^2	Resources increment, million tons o.e.	
	70% recovery	100% recovery			70% recovery	100% recovery
2006–2010	57.1	66.9	3 900	2 100	17.5	22.0
2011–2015	267.2	381.9	11 600	1 500	73.6	105.1

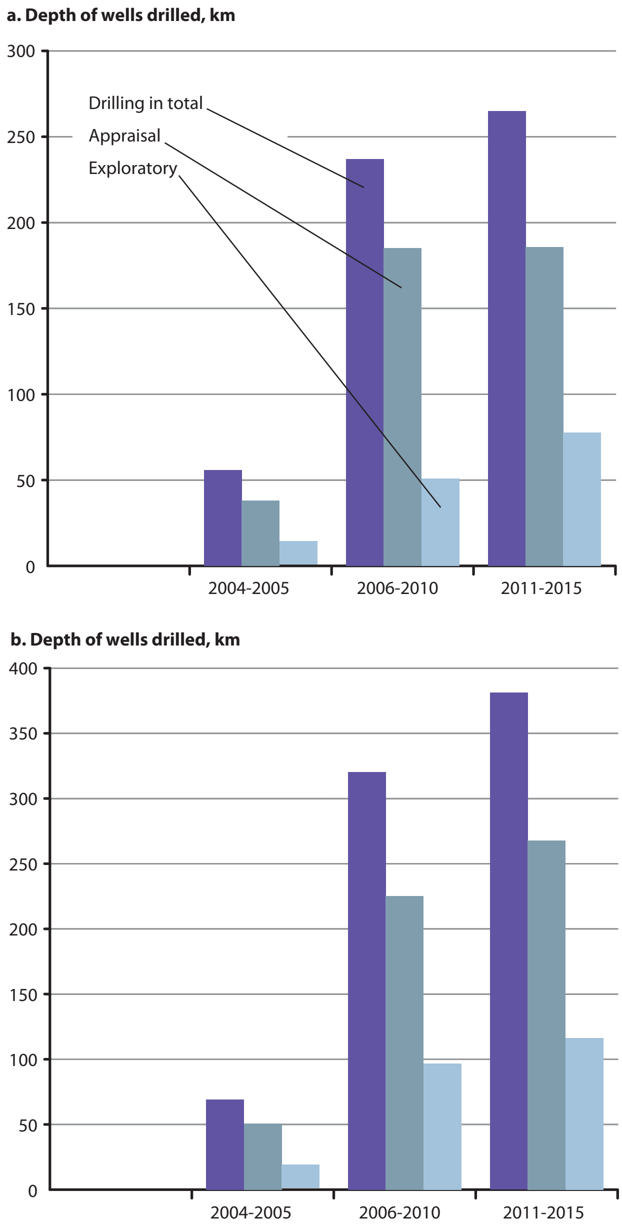


Figure 2.87. Past and anticipated drilling in Timan-Pechora OGP in relation to (a) 70% extraction recovery and (b) 100% extraction recovery.

2.4.7.4. West Siberian OGP

2.4.7.4.1. Historical to present

Pre-exploration

The West Siberian OGP is the largest hydrocarbon resource deposit in Russia if not the entire world. Almost all parts of the OGP are rich in resources, but the distribution of specific resources is irregular (Figure 2.88).

Exploration

Most oil resources are located in the southern and central parts of the OGP (Tyumen Region and the Khanty-Mansisk Autonomous Okrug – KhMAO) and, with the exception of some prospective oil fields on the coast and offshore of Ob-Taz Bay, are mainly located outside the Arctic.

Discoveries and development

Non-associated gas resources prevail in northern parts of the OGP (Yamal-Nenets Autonomous Okrug – YaNAO), where huge gas fields are located within the Arctic Circle. *Tazovskoje*, the first gas field within the Arctic Circle, was discovered in 1962 in the course of drilling the Taz appraisal well. Gas was encountered from Cenomanian sediments, which constituted a new productive oil and gas play. The first oil deposit was discovered in the YaNAO at *Novoportovskoe* field, where an exploratory well resulted in the production of over 200 tons per day from Neocomian deposits.

The giant *Urengoy* gas field was discovered in 1966, followed by the *Medvezhie* field in 1967 and the *Yamburg* field in 1969. Further exploration proved that reserves in each of these fields comprised trillions of cubic meters. The oil- and gas-bearing part of the *Yamburg* field section is 6–7 km thick and was only half-explored by drilling.

Commercial oil production in the YaNAO started in 1972. The period from 1971 through 1992 is sometimes called a heroic period of exploration of the northern part of the West Siberian OGP. In 1971, the unique *Bovanenkovo* oil, gas, and condensate field was discovered. In addition, it was found that the *Urengoy*, *Medvezhie*, and *Yamburg* fields outlined earlier were enormous. In this period, the annual volume of deep drilling reached 935–956 thousand meters. Also, the annual growth of oil and gas reserves in the

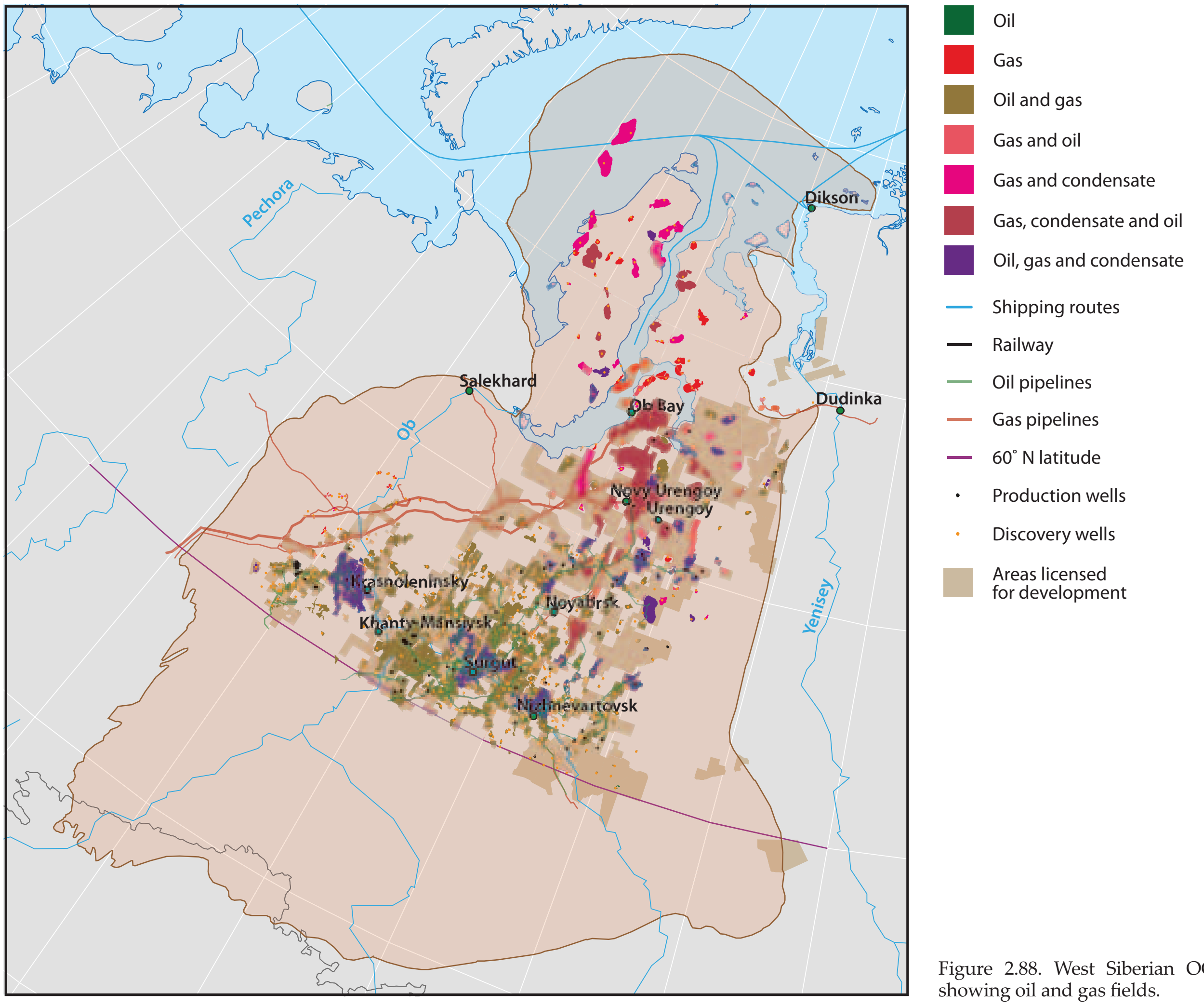


Figure 2.88. West Siberian OGP showing oil and gas fields.

YaNAO was the largest in the country, up to 538 million tonnes of oil and 2–3 trillion m^3 of gas (see Table 2.56 for data from 1963–1997).

The deepest West Siberian wells (more than 5000 m in depth) and the Tyumen super-deep well (7502 m) were drilled in this period. Deep horizons of Lower Cretaceous and Jurassic strata containing highly condensed gas were explored and delineated.

Seismic operations increased to their maximum between 1988 and 1991, with up to 25 000 to 28 000 km of survey lines collected per year. Exploration seismic surveying equipment was improved by utilizing CMP (common midpoint) data, and by increasing the fold from 6 to 12, and then up to 24 and 48. In addition to structural traps, lithological and stratigraphic traps were mapped, thus increasing the efficiency of exploration drilling. During this period, in addition to the above-mentioned fields, the multi-layer oil and gas fields of *Komsomolskoe*, *Tarasovskoe*, *Aivasedopurovskoe*, *Russkoe*, *Arkticheskoe*, and others were discovered. A total of 184 fields with 1520 economically-recoverable deposits had been discovered in the YaNAO by the end of 1992.

In 2002, seismic surveys by OAO Gazprom in the West Siberian OGP amounted to 3887.6 line-km for 2-D data acquisition and 505.1 km^2 for 3-D data (Gazprom, 2003).

The number of meters drilled in exploration and production wells in the YaNAO also increased steadily from 1963 to a maximum between 1988 and 1991, dropping off rapidly until 1995 (Figure 2.89).

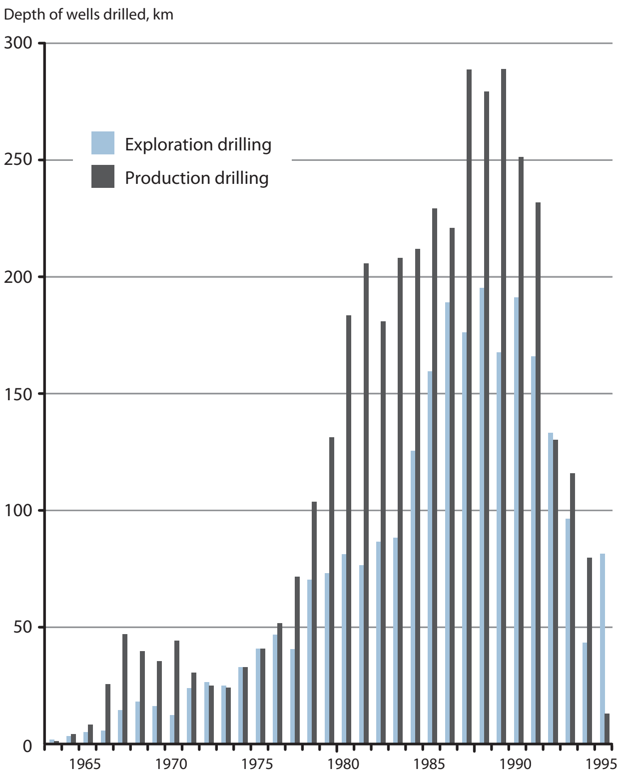


Figure 2.89. Depth of meters drilled in exploration and production wells in the Yamal-Nenets Autonomous Okrug from 1963 to 1995.

Table 2.56. Commercial oil production in the YaNAO, 1963 to 1997 (Brekhuntsov and Levinzon, 2000).

	Drilling, 1000 m			Growth of reserves			Oil+ Condensate		Hydrocarbons
	Appraisal	Exploratory	Total	Oil, million tonnes	Gas, billion m^3	Condensate, million tonnes	Efficiency, tonnes o.e. per meter drilled	Growth, million tonnes o.e.	Efficiency, tonnes o.e. per meter drilled
1963	4.7	3.4	8.1		27			27	3 340
1964	7.2	9.4	16.6		83			83	4 995
1965	10.6	17.3	27.9		99			99	3 549
1966	12.6	52.8	65.4		208.6			208.6	3 191
1967	29.3	94.3	123.6		3 136.3			3 136.3	25 381
1968	37.2	79.9	117.1	10	865.2		85	875.2	7 471
1969	32.6	70.5	103.1	79.1	1 227.2		767	1 306.4	12 666
1970	25.2	89.1	114.3	17	2 333.7		149	2 350.7	20 566
1971	48.2	60.9	109.1	94.1	1 506.1	0.9	871	1601	14 681
1972	53.7	49.6	103.4	4	1 339.2	8	116	1 351.2	13 072
1973	50.8	48.5	99.3	15.3	1 678.6	42	577	1 735.8	17 485
1974	65.8	66.3	132.1	23	1278	35.4	442	1 336.4	10 117
1975	82.8	82.5	165.2	93.4	1 609.9	80.7	1 053	1 783.9	10 796
1976	95.2	104.2	199.4	96.5	1 568.6	41.9	694	1 706.9	8 561
1977	81.7	144.1	225.7	107.8	1 650.5	70.4	789	1 828.8	8 101
1978	140.4	207.3	347.7	293.1	2 017.6	52.3	993	2363	6 796
1979	148.1	263.3	411.4	538.2	3 105.3	90	1 527	3 733.6	9 075
1980	163.2	369	532.2	384.6	2 091.4	104.3	919	2 580.3	4 848
1981	153.4	414.8	568.2	162.2	1 304.6	62.2	395	1 528.9	2 691
1982	174.6	364.8	539.3	94.1	1 704.4	72.1	308	1 870.5	3 468
1983	177.3	418.7	596	36.4	1 902.8	22.6	99	1 961.7	3 291
1984	251.9	427.3	679.2	254	851.4	22.5	407	1 127.9	1 661
1985	322.2	461.8	784	327.1	1 193.2	29.9	455	1550.2	1 977
1986	380.4	445.0	825.3	207.8	1 463.9	45.6	307	1 717.4	2 081
1987	355.3	580.5	935.8	142.8	1 984.1	80.7	239	2 207.5	2 359
1988	393.7	562.7	956.4	179.6	1 186.8	-39.5	146	1 326.9	1 387
1989	338.7	581.1	919.8	87.2	1 616.9	48.2	147	1 752.3	1 905
1990	385.7	506.6	892.3	270.4	1 389.8	84.5	398	1 744.7	1 955
1991	334.4	466.8	801.2	180.3	1 027.2	82.6	355	1 290.2	1 741
1992	268.5	261.9	530.4	72.9	587.3	69.1	268	729.2	1 375
1993	192.7	232.9	425.6	-17.1	518	38.8	51	539.7	1 268
1994	86.8	160.4	247.2	7.8	137.7	3	40	148.5	547
1995[a]	162.7	26.5	189.2	23.5	77.2	4.6	149	105.3	557
1996[b]			169.3	25.5	146.5	0.6	152.4	172.6	1 019.5
1997[b]			210.8	32.3	527.6	32.5	307.4	592.4	2 810.2
Total			13 171.6	3 842.9	43 444.6	1185.9			

[a] Data for 1995 are from the Program of the YaNAO Oil and Gas Resources Development until 2010; [b] data for 1996-1997 are from the Siberian Scientific Analytical Center.

Current activity in the YaNAO is very high. In the last few years, the YaNAO has become one of the most attractive investment regions in Russia. The basic volume of investments is directed to exploring, equipping, and developing petroleum and gas fields. The average per capita volume of investments exceeds by more than 2.5-fold the average level in the Russian Federation. Oil and gas activities are characterized by increasing extraction of gas and declining oil production.

In 2007, the YaNAO was projected to produce 624 billion m^3 of gas, which is an increase of 54 billion m^3 relative to 2006. The planned growth is for production of up to 635 billion m^3 in 2008 and up to 658 billion m^3 in 2009. The main contribution is expected from Gazprom,

Table 2.57. Comparison of the number of wells involved in operations in the West Siberian OGP, 2002 to 2004.

	Wells by year		
	2002	2003	2004
Wells with gas only	3046	3280	3624
Wells with gas and condensate	585	656	746
Operating gas wells	3650	3974	4393
Wells under testing and completion	106	84	151
Total number of gas wells	5110	5381	5938
Wells decommissioned from drilling	176	272	441
Wells shut-in	316	200	840

Table 2.58. Operational indicators for West Siberian wells, 2002 to 2004.

Operational indicator	Reported by year		
	2002	2003	2004
Gas production, billion m^3	507.1	528.5	533.3
Number of producing wells by the end of the year	3616	3936	4325
Accounted wells/ month	42908	45713	50071
Actual wells/month	41337	44189	47855
Actual to accounted ratio, %	96.3	96.7	95.6
Average debit on actual operations, 1000 m^3 per well per month	133.8	150.2	166.6

for which the current production accounts for 82.2% of the total gas extraction.

During the period 2002 to 2004, operational data indicate a growing number of wells in operation and an increasing number of wells in transition from drilling to production (Table 2.57). This increase in activity is accompanied by highly efficient production and assets use (Table 2.58). Over this period efficient use of well stock was supported and working wells were operating with increasing productivity.

According to the regional Subsoil Resources Agency, 188 500 m were drilled in 2006 with a 60% increase planned in 2007. The announced drilling program for fields licensed for geological survey, exploration, and production calls for 89 800 m to be drilled (38% increase), and for fields under survey and exploration, 212 200 m (2.6 times growth) are planned to be drilled.

Oil production in the YaNAO in 2007 is expected to be 34.0 million tons and will continue a production decline profile that started in 2004 (42.0 million tons in 2004, 39.0 million tons in 2005, and 37.0 million tons in 2006).

2.4.7.4.2. Future

Near-term (up to 2015)

The main oil resources and reserves of the West Siberian OGP are located to the south of the Arctic in the KhMAO. This area is projected to remain the main oil-producing region in the Russian Federation at least until 2015.

Long-term (on the horizon)

The West Siberian OGP, in which the YaNAO includes the Arctic districts and regions and contains the largest gas reserves, will remain the main gas supplier for national and foreign consumers in the Russian Federation at least until 2030 (Figure 2.90).

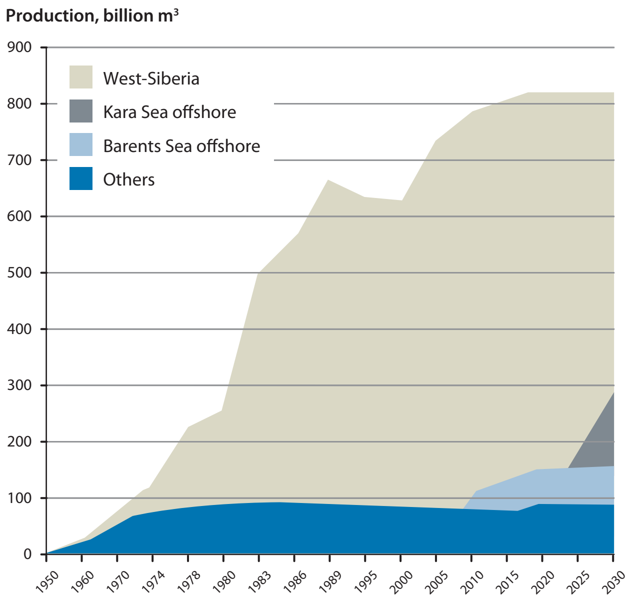


Figure 2.90. Gas production forecast up to 2030 in the West Siberian OGP and other areas of the Russian Federation.

2.4.7.5. Yenisey-Anabar OGP

2.4.7.5.1. Historical to present

Exploration

The study of oil and gas reserves in the Yenisey-Anabar OGP began in order to supply gas to the Norilsk Mining Region, where rich copper-nickel deposits had been discovered at Talnakh. To supply this need, the Krasnoyarsk Geological Survey expedition started oil and gas exploration in the Norilsk (northwest) and Ust-Yenisey regions in the early 1960s. Comparative assessment of these regions' prospects showed that the Ust-Yenisey region was more promising. Gas exploration in the region was successful and the large *Messoyakhskoe* gas field, with production from Late Cretaceous Cenomanian reservoirs, was discovered in 1967. This discovery solved the problem of gas supply to Norilsk.

Discoveries and development

Development of the *Messoyakhskoe* gas field with gas supply to Norilsk via the Messoyakha–Dudinka–Norilsk gas pipeline started in 1969. After the discovery of the *Messoyakhskoe* gas field, the *Yuzhno-Soleninskoe*, *Pelyakinskoe* and *Kazantsevskoe* fields were discovered in 1969, followed by the *Severo-Soleninskoe* field in 1972 and the *Deryabinskoe* field in 1976, containing large reserves of gas and condensate in Lower Cretaceous sediments. The fields' reserves are enough to meet the Norilsk Mining Region's demand for gas in the long term. Overall estimates of initial resources in this area amount to 13.94 billion m^3 (see Table 2.49).

With the exception of seismic surveys, there is no reported oil and gas activity in the Arctic part of this Province.

2.4.7.6. Arctic Shelf

2.4.7.6.1. Historical to present

Exploration

Systematic geophysical studies of the Russian Arctic shelf were started in the 1960s and significantly increased in the 1970s. From 1976 to 1980, a series of appraisal wells were drilled in the Spitsbergen and Frantz Josef Land archipelagos, and the Kolguev and Svedrup islands. The drilling data provided a reliable basis for geological interpretation of geophysical data on the West Arctic Shelf. Intensive regional geological investigations, along with exploration activities, have provided the data to interpret the structural, tectonic, stratigraphic, and petroleum geological framework of the shelf and the basis for calculating hydrocarbon resources. The main result of these studies was the determination of the largest oil and gas accumulations on the Arctic shelf, inside which were discovered basins with multiple columns of oil and gas deposits and widely distributed local producible structures.

The estimate of potential oil and gas resources of the Arctic shelf showed that the largest portion of resources is in the Barents and Kara seas of the West Arctic Shelf. Favorable geological prerequisites were associated with oil and gas manifestations on the islands and evident structural integrity with the Timan-Pechora and West Siberian OGPs on the adjacent land (Figure 2.91).

Most acquisition efforts and integrated analyses of geological and geophysical data have focused on the deep structure of the Barents and Kara seas. Arctic marine seismic exploration started in 1979, followed by exploratory drilling on the Barents Sea in 1981 and on the Kara Sea in 1987. Seismic profiling, aeromagnetic surveys, ship-borne gravity-magnetic and gravity-meter surveys, bottom samples and geological surveys were acquired on and around the Arctic islands during the 1980s and 1990s. By 1992, the volume of regional and exploration seismic profiles on the Barents and Kara seas exceeded 400 line km (Figure 2.91).

The main features of the geological structure of the Barents and Kara seas (stratigraphy, structure, offshore seismic sequences, and isopachs) have been studied and the local structures (such as Murmanskaya, Severo-Kildinskaya and Prirazlomnaya on the Barents and Pechora seas, and Rusanovskaya and Leningrdskaya on the Kara Sea) have been discovered.

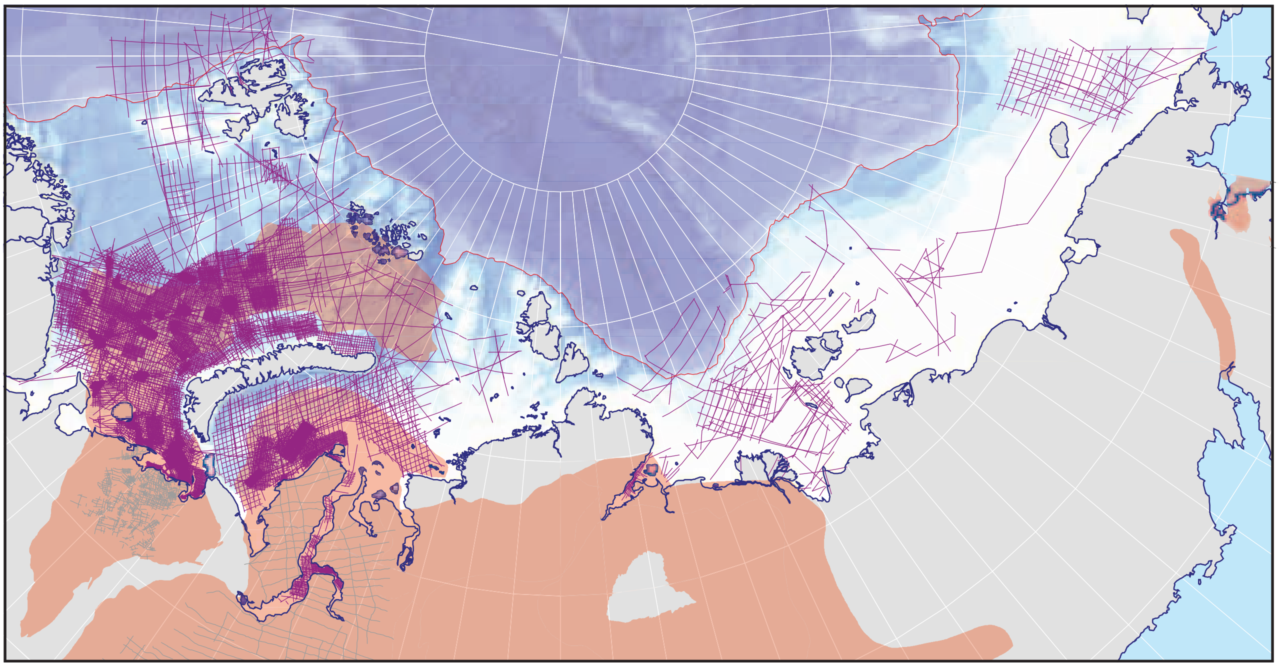


Figure 2.91. Seismic coverage for the Barents and Kara seas.

Drilling

Thirty-four exploratory wells were drilled at eighteen of 34 prepared structures. This resulted in the discovery of new large oil and gas fields on the Barents Sea beginning with the *Peschanoozerskoe* oil and gas field on Kolguev Island in 1982 and the *Murmansk* gas field in 1984. The *Severo-Kildinskoje* gas and *Pomorskoje* gas and condensate fields were discovered in 1985, followed by the *Severo-Razgulyaevskoje* oil and condensate field in 1986 and the huge *Stokman* gas and condensate field in 1988. The *Prirazlomnoje* oil and *Rusanovskoje* gas and condensate fields were discovered in 1989, and the *Ludlovskoe* gas and *Leningradrskoje* gas and condensate fields in 1990.

The 1990s were marked by a dramatic decrease (due to termination) in exploration on the Arctic shelf. However, Gazprom continued exploratory drilling on the Pechora Sea, which resulted in discovery of the *Varandeya Sea* (1995), *Medynskoe Sea* (1997), and *Dolginskoe* (1999) oil fields. The licensing round (Barents-1) took place in 1999, during which licenses for developing the Medyn-Varandeya, Pomor and Kolokolmor blocks were issued. The Barents-2 licensing auction was scheduled for 2006 but has not occurred.

Currently, all areas of the Kara Sea shelf offshore of Yamal, except the narrow circumlittoral margin, are covered by surveys with a 20 × 20 km regular seismic grid, with the most promising areas by regular 4 × 4 km grids with a total length of 11 000 km (Figure 2.91). As a result, more than 20 prospective structures have been discovered. The enormous gas and condensate fields *Rusanovskaya* and *Leningradskaya* on the Kara Sea (Figure 2.92) were discovered by targeted exploratory drilling of two appraisal wells on each. Gas and condensate fields have also been discovered in Ob-Taz Bay (Figure 2.92).

Discoveries and development

The Russian continental shelf occupies an area of 6.2 million km^2 (more than 20% of the total area of the World Ocean shelf) and contains Russian's main petroleum resource base for the 21st century. Original recoverable oil and gas reserves of the Russian continental shelf are from 90 to 100 billion tons o.e., i.e. 20–25% of the world hydrocarbon reserves. The share of the total initial hydrocarbon resources of the Russian shelf in relation to the total overall Russian initial hydrocarbon resources is as follows: 33% of the gas, 22% of the condensate, and 12% of the oil. Almost 80% of the total initial resources of the Russian shelf are thought to occur in the Arctic seas.

An important achievement of early oil and gas exploration was the discovery on the West Arctic shelf of the largest oil and gas mega-province. In the course of the past few years, the West Barents and East Barents OGP and the North Kara autonomous POGR have been identified.

In general, geological and geophysical coverage of the Russian Arctic shelf is very low. Coverage of seismic data does not usually exceed 1 line km per 1 km^2, even for the best-investigated area (the southern part of the Barents Sea shelf) (Figure 2.91). Only 55 wells had been drilled by 2005 on the entire area of the Russian Arctic shelf and these were all located in the West Arctic seas only (the Barents, Pechora, and Kara seas). The northern parts of the Barents and Kara seas and the entire East Arctic shelf are covered

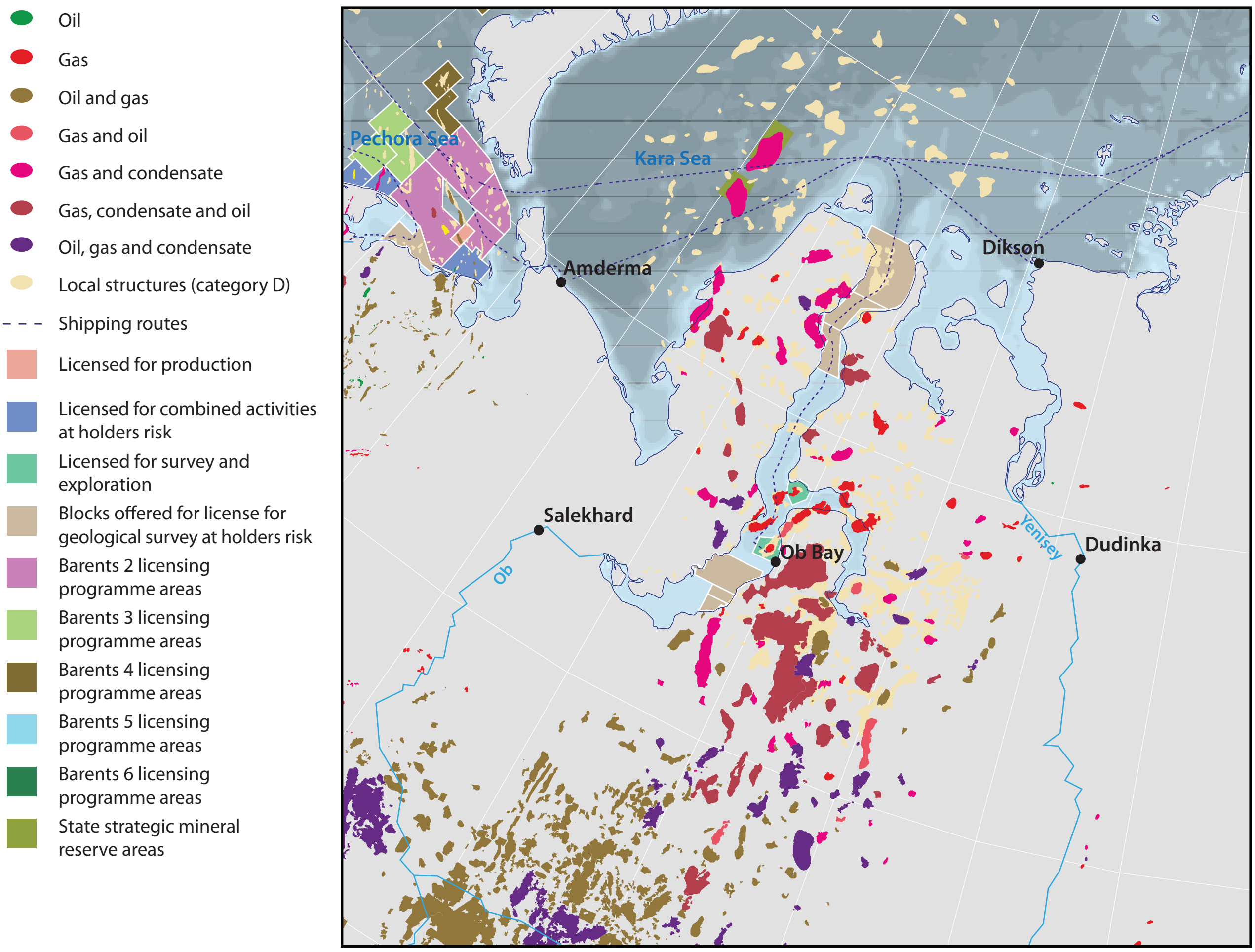


Figure 2.92. Reserves and resources in the Kara Sea and Ob-Taz Bay.

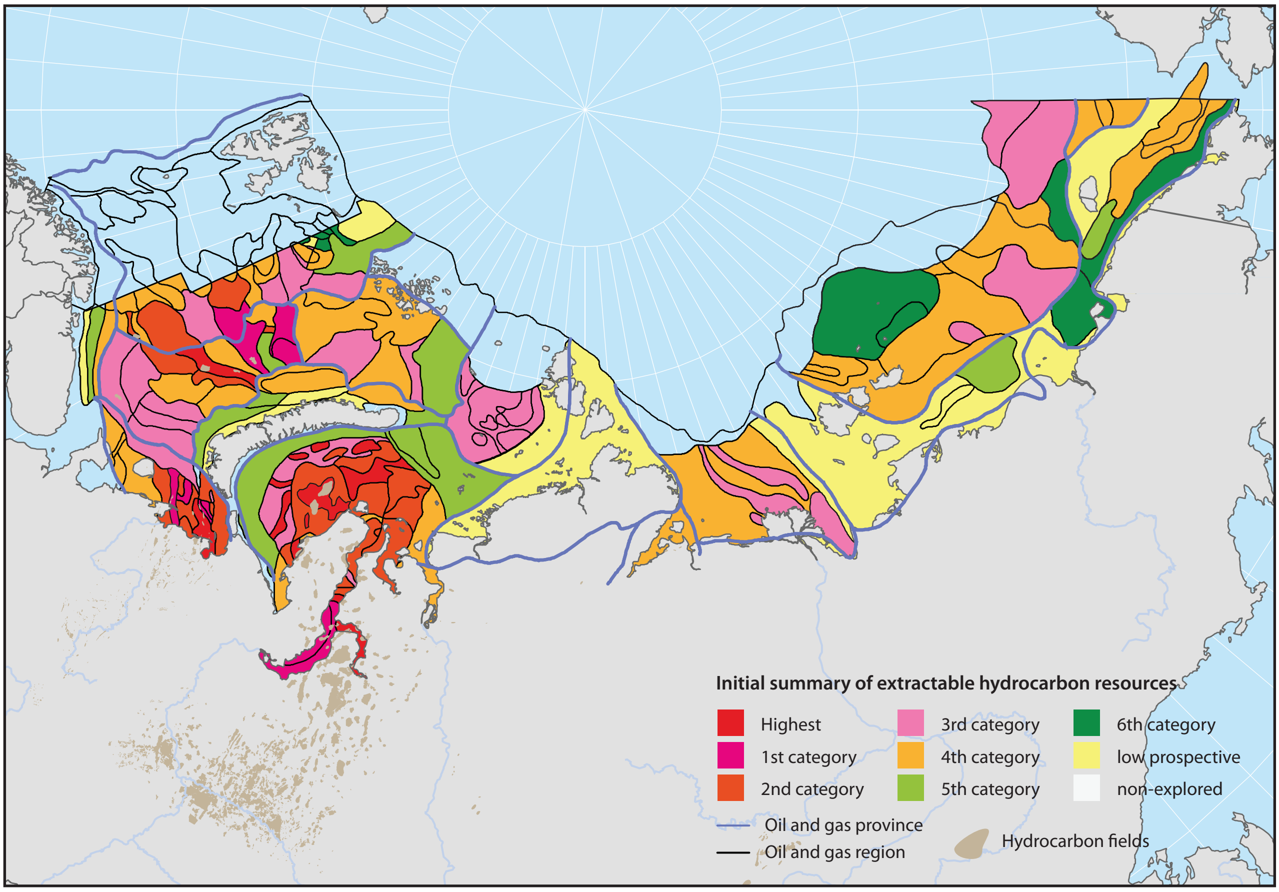


Figure 2.93. Hydrocarbon resources on the Russian Federation continental shelf in the Arctic.

by a sparse seismic grid (Figure 2.91). No wells have been drilled on the Russian Arctic shelf east of the Taymir Peninsula.

The entire thickness of the sedimentary cover has been defined and original recoverable hydrocarbon resources have been estimated (Figure 2.93). The average density of the original recoverable resources was found to be 20 000 to 25 000 tons per km^2.

The West Arctic shelf reserves are far from depleted. It is evident that the Barents Sea region, as well as the southern part of the Kara Sea (offshore continuation of the West Siberian OGP), contain enormous oil and gas reserves. To date, 11 oil and gas fields have been discovered on the Barents Sea, among which are a giant field (*Shtokman*), seven large fields (*Ledovoe, Ludlovskoe, Murmanskoe, Dolginskoe, Prirazlomnoe, Medynskoe-sea, Severo-Gulyaevskoe*), two medium fields (*Pomorskoe, Severno-Kildinskoe*), and one small field (*Varandey Sea*) (Table 2.59). Four of these fields are gas, two are gas/condensate, four are oil, and one is a gas/oil field. Two gas and condensate fields (*Rusanovskoe, Leningradskoe*) have been discovered in the Kara Sea shelf. Both are huge.

Despite these discoveries, the degree of exploration of the enormous hydrocarbon reserves in the Russian Arctic shelf (i.e., the ratio of the total initial resources and reserves of ABC$_1$ categories) is very low: 1% of oil and 5% of gas (Figure 2.94). Furthermore, no fields have been discovered in the East Arctic shelves.

The discovery of new fields in recent years has not changed the overall distribution of the Russian sea shelf reserves. The discovery of the large *Dolginskoe* field emphasized the key role of the Barents Sea region (Figure 2.95 and Table 2.60). Unique in its reserves, *Shtokman*,

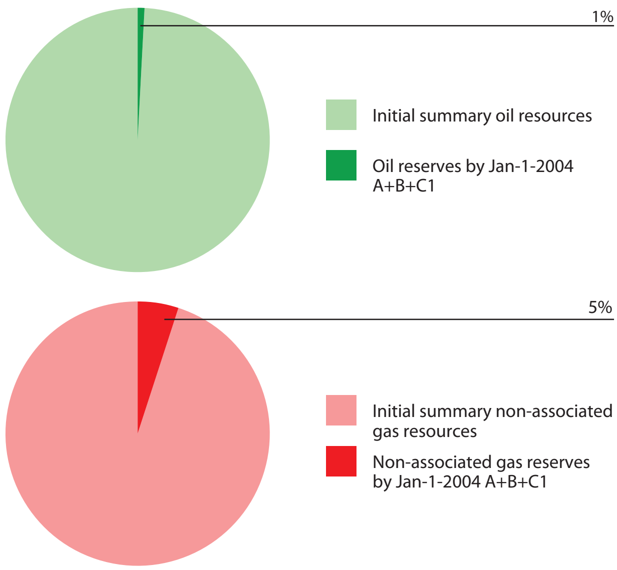


Figure 2.94. Proportion of discovered resources to reserves of oil and gas on the Russian Arctic Shelf.

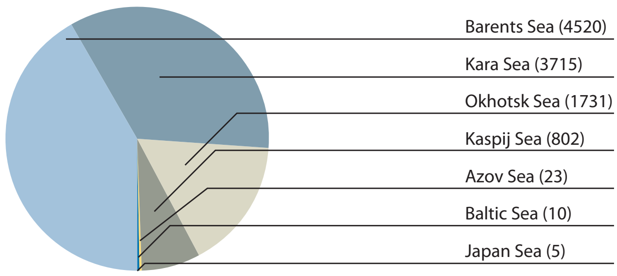


Figure 2.95. Distribution of hydrocarbon reserves (million tonnes o.e.) in Russian sea areas.

Table 2.59. Marine oil and gas deposits on the Russian West Arctic Shelf and in all Russian sea areas (data supplied by VNIGRI).

Oil/gas field	Discovery	Type of fluids	Deposits, million tons			Resources	Status of natural resources user
			S	A+B+C_1	C_2	C_3	
Barents Sea							
Shtokman	1988	free gas	3205.4	2536.4	669.0	-	ZAO Sevmorneftegas
		condensate	26.9	21.5	5.4	-	
		ΣHC	3232.3	2557.9	674.4		
Ledovoe	1992	free gas	422.1	91.7	330.4		NDF[a]
		condensate	4.2	0.9	3.3		
		ΣHC	426.3	92.6	333.7		
Ludlovskoe	1990	free gas	211.2	80.1	131.1		NDF
Murmanskoe	1983	free gas	120.6	59.1	61.5		NDF
Severno-Kildinskoe	1985	free gas	15.5	5.0	10.5	26.2	NDF
Total		free gas	3974.8	2772.4	1202.4	26.2	
		condensate	31.1	22.3	8.8		
		ΣHC	4005.9	2794.7	1211.2	26.2	
Pechora Sea							
Dolginskoe	1999	oil	235.8	0.9	234.9		OAO Gazprom
		dissolved gas	16.0	0.2	15.8		
		ΣHC	251.8	1.1	250.7		
Medynskoe Sea	1997	oil	91.4	9.0	82.4		ZAO Arcticshelfneftegas
		dissolved gas	1.8	0.2	1.6		
		ΣHC	93.2	9.2	84.0		
Prirazlomnoe	1989	oil	72.0	46.5	25.5	42.3	ZAO Sevmorneftegas
		dissolved gas	3.2	2.1	1.1		
		ΣHC	75.2	48.6	26.6	42.3	
North-Gulyaevskoe	1986	oil	11.4	0.8	10.6		NDF
		dissolved gas	0.3	0.1	0.2		
		free gas	51.8	10.4	41.4		
		condensate	1.5	0.3	1.2		
		ΣHC	65.0	11.6	53.4		
Pomorskoe	1985	oil				36.0	ZAO Arcticshelfneftegas
		free gas	22.0	6.0	16.0	5.3	
		condensate	0.6	0.2	0.4		
		ΣHC	22.6	6.2	16.4	41.3	
Varandey Sea	1995	oil	5.8	1.8	4.0	14.7	ZAO Arcticshelfneftegas
Total		oil	416.4	59.0	357.4	93.0	
		dissolved gas	21.3	2.5	18.8		
		free gas	73.8	16.4	57.4	5.3	
		condensate	2.1	0.5	1.6		
		ΣHC	513.6	78.4	435.2	98.3	
Kara Sea							
Leningradskoe	1990	oil	-	-	-	110.1	NDF
		free gas	1051.6	71.0	980.6	3065.7	
		condensate	3.0	0.2	2.8	62.7	
		ΣHC	1054.6	71.2	983.4	3238.5	
Rusanovskoe	1989	oil	-	-	-	119.5	NDF
		free gas	779.0	240.4	538.6	3248.3	
		condensate	7.8	2.4	5.4	84.7	
		ΣHC	786.8	242.8	544.0	3452.5	

Table 2.59. Cont.

Oil/gas field	Discovery	Type of fluids	Deposits, million tons			Resources	Status of natural resources user
			S	A+B+C_1	C_2	C_3	
Yurkharovskoe[b]	1987	oil	4.3	0.2	4.1		OAO Yurkharovneftegas
		dissolved gas	0.4	0.02	0.4		
	1970	free gas	652.2	213.1	439.1		
		condensate	31.5	9.4	22.1		
		ΣHC	688.4	222.7	465.7		
Kamennomysskoe Sea	2000, 2003	free gas	491.4	425.7	65.7		OAO Gazprom
North- Kamennomysskoe	2000	free gas	300.4	185.7	114.7		OAO Gazprom
Semakovskoe[b]	1971	free gas	186.3	25.6	160.7		NDF
Antipayutinsloe[b]	1978	free gas	100.0	20.9	79.1		NDF
Totayakhinskoe[b]	1984	free gas	63.0	18.8	44.2		NDF
Salekaptskoe[b]	1995	oil	16.2	-	16.2		NDF
		dissolved gas	2.9	-	2.9		
	1986	free gas	16.6	-	16.6		
		condensate	2.3	-	2.3		
		ΣHC	38.0	-	38.0		
Obskoe	2003	free gas	4.8	4.8	-		OAO Gazprom
Chugor'yakhinskoe[b]	2002	free gas	1.7	1.7	-		OAO Gazprom
Kharasavey		free gas	-	-	-	40.3	NDF
		condensate	-	-	-	2.1	
		ΣHC	-	-	-	42.4	
Total		oil	20.5	0.2	20.3	229.6	
		dissolved gas	3.3	0.02	3.3	-	
		free gas	3647.0	1207.7	2439.3	6354.3	
		condensate	44.6	12.0	32.6	149.5	
		ΣHC	3715.4	1219.9	2495.5	6733.4	
Total for Russian seas (including Okhotsk, Caspian and Baltic seas)		oil	1023.2	304.9	718.3	645.2	
		dissolved gas	99.0	37.7	61.3	-	
		free gas	9577.5	5149.9	4427.6	6389	
		condensate	200.2	114.0	86.2	149.5	
		ΣHC	10899.9	5606.5	5293.4	7183.7	

[a] NDF: non-distributed fund; [b] sea continuation of onshore deposits.

Table 2.60. Distribution of hydrocarbon reserves and resources on the continental shelf of the Russian Federation as of 1 January 2004 according the Ministry of Natural Resources of Russia.

Area	Initial resources	Reserves	Resources	
		A+B+C_1+C_2	C_2	C_3
Shelves in total	15400	302.300	625.793	1073.238
Arctic seas		59.157	377.663	346.694
Barents Sea	2900	58.919	357.417	117.090
Kara Sea	3662	0.238	20.246	229.604
Laptev Sea	940	-	-	-
East Siberian Sea	2064	-	-	-
Chukchi Sea	1438	-	-	-

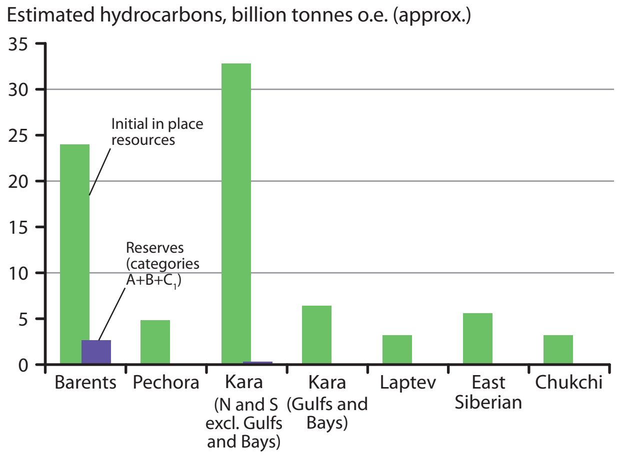


Figure 2.96. Reserves and initial resources in place in Russian Federation continental shelf areas in the Arctic.

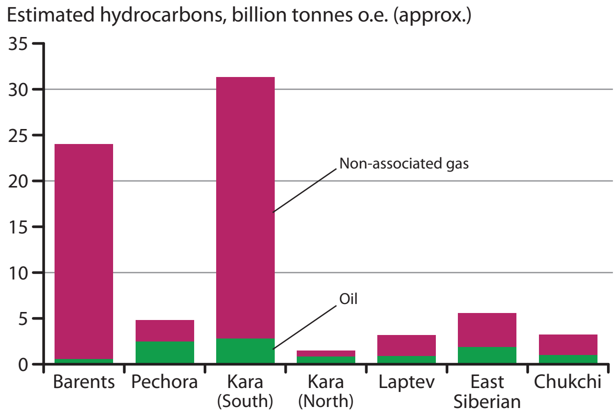


Figure 2.97. Ratio of oil to non-associated gas in Russian Arctic shelf sea resources.

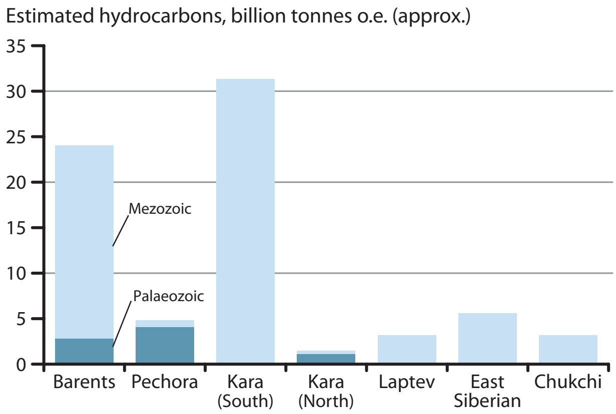


Figure 2.98. Division of resources between Mesozoic and Paleozoic strata in Russian Arctic shelf sea resources.

the large *Ledovoe*, *Murmanskoe*, *Ludlovskoe*, *Prirazlomnoe*, *Medynskoe Sea* and *Severo-Gulyaevskoe* fields, as well as medium and small fields, account for 50% of the entire reserves (categories ABC_1C_2) of hydrocarbons on the Russian shelves.

Initial hydrocarbon resources of the Pechora Sea are estimated to be 10–12 billion tons o.e., of which 6–8 billion tons are oil resources.

In the marine areas of the Russian Arctic, 22 oil and gas fields including four fields in the Kara Sea bays and gulfs and underwater continuations of five coastal fields in the same bays and gulfs have been discovered to date. There is currently no production of oil and gas from these fields.

The exploration maturity of the Timan-Pechora OGP amounts to 9.7% for categories C_1+C_2, while the exploration maturity of the Barents Sea and the southern Kara Sea is 15.9% and 5.4%, respectively. Resources of the East Arctic seas remain completely unexplored (Figure 2.96).

In 2004, VNIIokeangeologia completed studies aimed at determining the oil and gas potential of the West Arctic shelf (the Pechora, Barents, and Kara seas). Gas resources are significantly greater than those of oil (Figure 2.97). The southern Kara Sea is the richest in resources (both oil and gas). Available geological and geophysical data make it possible to estimate the resources of both oil and gas of West Arctic provinces and to determine the most prospective sectors (i.e., with the highest density of resources) of the shelf for further exploration.

Gas and oil plays are a part of the sedimentary cover potentially bearing oil and gas that lie within large units of oil and gas zones that include reservoir rocks sealed by regional caps. Oil and gas plays for the eastern seas and the northern Kara Sea can only be estimated according to the conventional division of the sedimentary cover into Mesozoic and Paleozoic strata. A large part of the total initial resources of the Russian Arctic seas is found in Mesozoic sediments (Figure 2.98).

In terms of current activity (2006), exploratory well No.7 was drilled by Gazprom on the *Shtokman* gas-condensate field by the Norwegian company Deepsea Delta semi-submergible. Exploratory drilling on the *Pakhtusovsky* field in the Barents Sea near Novaya Zemlya that had been planned for 2006 was delayed. Drilling of exploration well No.2 was expected in 2007 on the *Dolginskoje* field in the Pechora Sea by the Seadrill-7 jack-up from Norway.

There is no offshore oil and gas production currently operating in the Russian Arctic. The *Prirazlomnoje* oil field development with 7 million tons per year of production is close to commission with the setting up of a gravity-based ice-resistant platform of Russian construction in the Pechora Sea and oil export by tanker.

Licensing

Russia's experience in licensing offshore oil and gas exploration and production is relatively limited. Since 1991, four tenders for offshore hydrocarbon exploration and production have been conducted: Sakhalin-1 (1991–1996), Sakhalin-2 (1991–1996), North Caspian (1997), and Barents-1 (1999). Some productive areas have been transferred to subsurface users without auctions based on particular decisions of the country's top authorities. In addition, a series of tenders were conducted for geological study and evaluation of deposits and geological study for waste drilling fluid and other processing waste disposal in the West Arctic shelf and shelves of the Far East and southern seas. These efforts resulted in the establishment of a very small (in terms of area occupied and total resources) allocated mineral resources fund.

Fifty-six licenses for hydrocarbon exploration and production and drilling waste disposal in the Russian shelf, awarded to thirty subsurface users, had been issued as of 12 January 2005; including fifteen licenses for the West Arctic shelves awarded to five subsurface users (Table 2.61).

By the beginning of 2005, the allocated mineral resources fund included the following Barents Sea shelf fields: *Shtokman*, *Prirazlomnoe* (license holder is ZAO

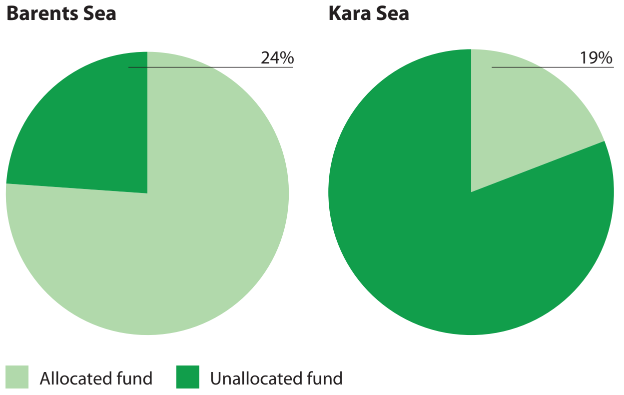


Figure 2.99. Allocated and unallocated mineral resources fund of the Barents and Kara Seas.

Sevmorneftegas); *Pomorskoe*, *Medynskoe Sea* and *Varandey Sea* (license holder is ZAO Arktikshelfneftegas). License data are provided in Table 2.62.

The allocated mineral resources fund of the Kara Sea shelf includes the deposits of Ob and Taz Bays, including offshore continuations of onshore deposits in the bays. The ratio of recoverable hydrocarbon reserves of $A+B+C_1+C_2$ categories and the allocated and unallocated mineral resources fund of the West Arctic Seas is depicted in Figure 2.99.

Despite a significant proportion of the reserves including the large and very large deposits, particularly in the Barents Sea, having already been divided among subsurface users, actually putting them on stream can take ten or more years from the date the license was issued. At present, no West Arctic deposit has been put on stream. The process of Arctic shelf development is restrained for several reasons, including the absence of a stable regulatory and legal framework for subsurface management, and technological problems related to the development and operation of some heavy equipment.

At present, the East Arctic shelves are not covered by the licensing process; the first step in this direction is a State review of requests from subsurface users for exploration in the Chukchi and East Siberian Seas and preparation of lists of the areas put up for bidding to conduct geological studies at the expense of subsurface users. The first licenses to explore in the East Arctic Seas were scheduled to be issued in 2006. The area of the allocated fund does not exceed 2.5% of the entire Arctic shelf and the total resources of the allocated fund do not exceed 13% of the total resources.

Table 2.61. Licenses awarded for the Barents and Kara seas.

Offshore and license holder	Type of license	Quantity
Barents Sea		
ZAO Arktikshelfneftegas	Geological study and evaluation of deposits (valid for up to 5 years)	3
ZAO Sevmorneftegas	Production of hydrocarbons (valid for up to 25 years)	2
OAO Severneftegas	Geological study and evaluation of deposits (valid for up to 5 years)	3
ZAO Sintezneftegas	Geological study and evaluation of deposits (valid for up to 5 years)	5
Kara Sea		
OAO Gazprom	Geological study and evaluation of deposits (valid for up to 5 years)	2
Total		15

Table 2.62. Licenses awarded for the Barents Sea and the Kara Sea.

Deposit	License holder	License reference	End date
Barents Sea			
Stokman	ZAO Sevmorneftegas	ШБЦ 11322 НЭ	March 2018
Kolokolmorsky	ZAO Arktikshelfneftegas	ШБМ 11358 НР	2025
Pomorsky	ZAO Arktikshelfneftegas	ШБМ 11357 НР	2025
Prirazlomnoje	ZAO Sevmorneftegas	ШПЧ 11323 НЭ	March 2018
Medynsky-Varandejsky	ZAO Arktikshelfneftegas	ШБМ 11356 НП	2025
Kolsky-3	OAO Severneftegas	ШБМ 11649 НП	February 2008
Kolsky-2	OAO Severneftegas	ШБМ 11648 НП	February 2008
Kolsky-1	OAO Severneftegas	ШБМ 11647 НП	February 2008
Central-Kolsky	ZAO Sintezneftegas	ШБМ 12527 НП	June 2009
Mid-Kolsky	ZAO Sintezneftegas	ШБМ 12528 НП	June 2009
West-Kolsky	ZAO Sintezneftegas	ШБМ 12529 НП	June 2009
Pakhtusovsky	ZAO Sintezneftegas	ШБМ 12644 НП	August 2009
Admiraltejsky	ZAO Sintezneftegas	ШБМ 12645 НП	August 2009
Kara Sea			
Obsky	OAO Gazprom	ШКМ 11229 НП	September 2006
Chugorjakhinsky	OAO Gazprom	ШКМ 11230 НП	September 2006

The locations and status of current licenses and those planned to be issued up to 2010 for hydrocarbons resource sites on the Barents and Kara Sea shelves and in the Pechora Sea as of 12 January 2005 are shown in Figure 2.100.

2.4.7.6.2. Future

Near-term (up to 2020)

According to the Government strategy for exploration and development of the oil and gas potential of the Russian Federation continental shelf, the continental shelf will play an important role in accomplishing the tasks assigned by Russia's Energy Strategy until 2020. Scientific developments in recent years have shown that a significant mineral resource potential can be accumulated on the basis of the discovered and predicted offshore fields, which makes it possible to reach 95 million tons of oil and 320 billion m^3 of gas by 2020. Up to 0.6 to 0.7 billion tons of oil and 1.6 trillion m^3 of gas can be extracted from the Russian offshore fields during the period 2006 to 2020.

By 2020, production should reach 30 million tons of oil and 130 billion m^3 of gas per year on the basis of the discovered and predicted fields in the Pechora and Barents Sea shelves, as well as up to 14 million tons of oil and 37 billion m^3 of gas per year in the shelf and gulfs of the Kara Sea.

Consequently, the development of the Russian continental shelf mineral and energy potential and, primarily, its Arctic sector will play a stabilizing role in oil and gas production dynamics to compensate for a possible decrease in production owing to depletion of the continental fields in the period 2010 to 2020. The West Arctic shelf is among the priorities for the development and expanded production of the mineral resource base in the Russian Federation and has the clear potential to become a region of oil and gas production in the period 2015 to 2020, with the development of large production centers in the region and adjacent coastal areas.

The main concepts of the State policy in geological exploration and the development of mineral resources of both the Arctic shelf and the Russian Federation continental shelf as a whole is based on a three-level strategy for subsurface use:

- Level 1 includes regional geophysical surveys and orientation drilling in unexplored and/or poorly explored sites based on an exploration program developed and funded from the Federal budget according to current legislation. The aim of this stage is to acquire primary geological information for a correct assessment of the hydrocarbon potential of large offshore zones of oil and gas accumulation, and selection of prospective areas and subsurface sites for future mineral resource development.
- Level 2 includes work at the regional and exploration scale at the sites which are planned to be put up for auction for the purposes of geological surveys, prospecting, exploration, and production of hydrocarbons.
- Level 3 is directed at prospecting, exploration, and development of hydrocarbons at local sites within

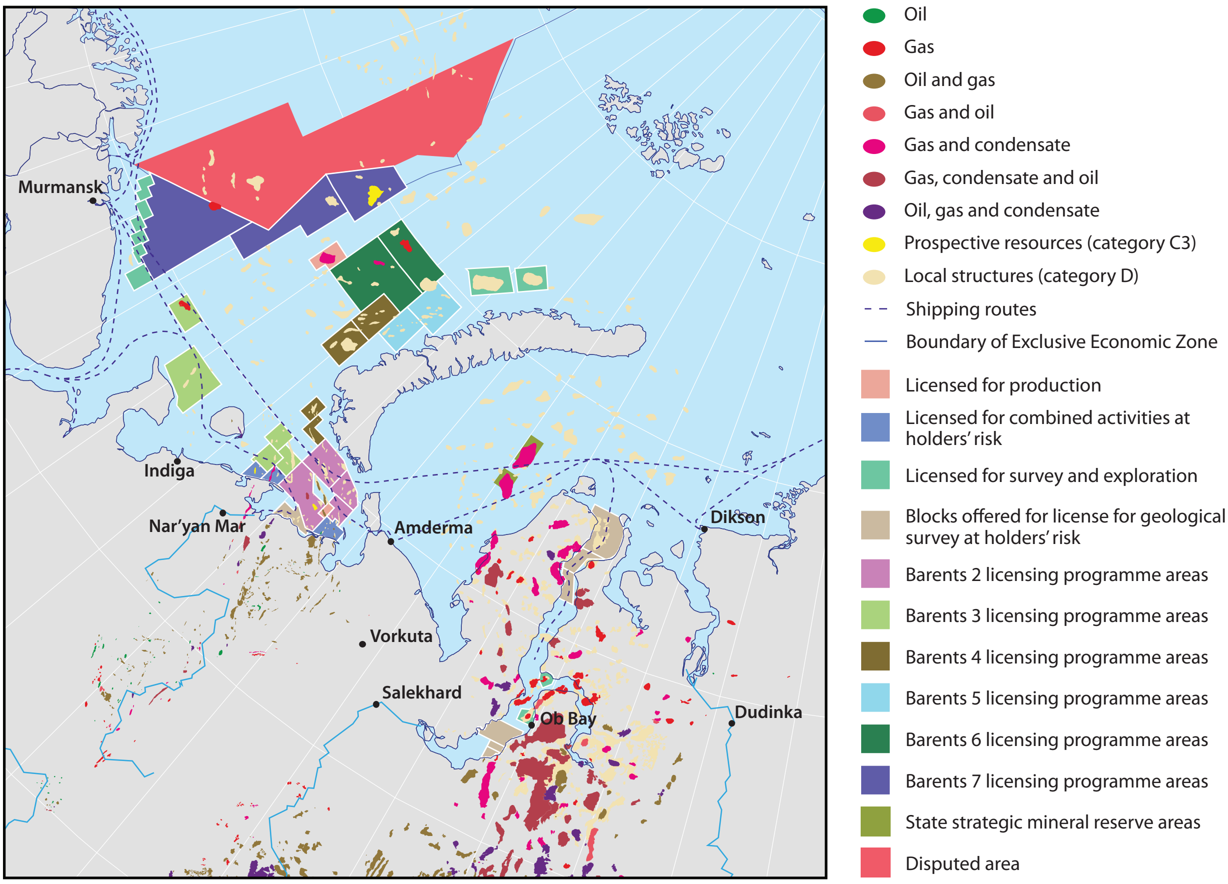


Figure 2.100. Locations and status of current and planned licenses up to 2010 for hydrocarbons resource sites on the Barents and Kara Sea shelves (as of 12 January 2005).

Table 2.63. Seismic surveys planned for Arctic offshore areas, 2006 to 2020.

	Barents and Pechora seas	Kara Sea	Laptev Sea	East Siberian Sea	Chukchi Sea	Total
Regional and exploration geological and geophysical work						
Funded at Federal level (observation interval 50×50 -5×10 km), 1000 km	70	78	90	75	50	363
Funded by subsurface user (observation interval 5×5 - 2×4 km), 1000 km	457	528	534	1050	250	2819
Total, 1000 km	527	606	624	1125	300	3182
Stratigraphic and parametric drilling						
1000 m	16	9.4	0.9	12.0	3.0	41.3
Number of wells	4	3	2	3	1	13

which resources are predicted with a high degree of probability or in fields with previously evaluated or explored hydrocarbon reserves. A license to use these subsurface sites will be granted through auctions for the right to use the subsurface site, followed by further signing of an agreement between the subsurface user and the authorized Federal executive body.

The mineral resources use in the Russian Arctic shelf is aimed at expanded production of mineral/hydrocarbon reserves both by investment of funds from the Federal budget and by seeking of private (including foreign) investment.

From 2006 to 2020, about 360 000 line-km of geophysical surveys are planned to be completed and thirteen orientation wells, with a total length of 41 300 line-m, are planned to be drilled on the Russian Arctic shelf funded by the Federal budget (Table 2.63). Geological and geophysical work will be divided into two stages. Stage 1, comprising reconnaissance, will involve special operations on an irregular observation network or separate section lines, aimed at accomplishing the tasks related to the delimitation of the water areas, determination and substantiation of the outer limit of the continental shelf, and initial assessment of the geological situation and hydrocarbon potential in unexplored offshore areas. The scope of stage 1 in the period 2006 to 2020 is estimated to comprise 10% of all regional efforts mainly concentrated in the high-latitude Arctic (Figure 2.101). Stage 2, comprising 325 000 km of regional and regional/exploration work, will cover large offshore areas. The two stages can be

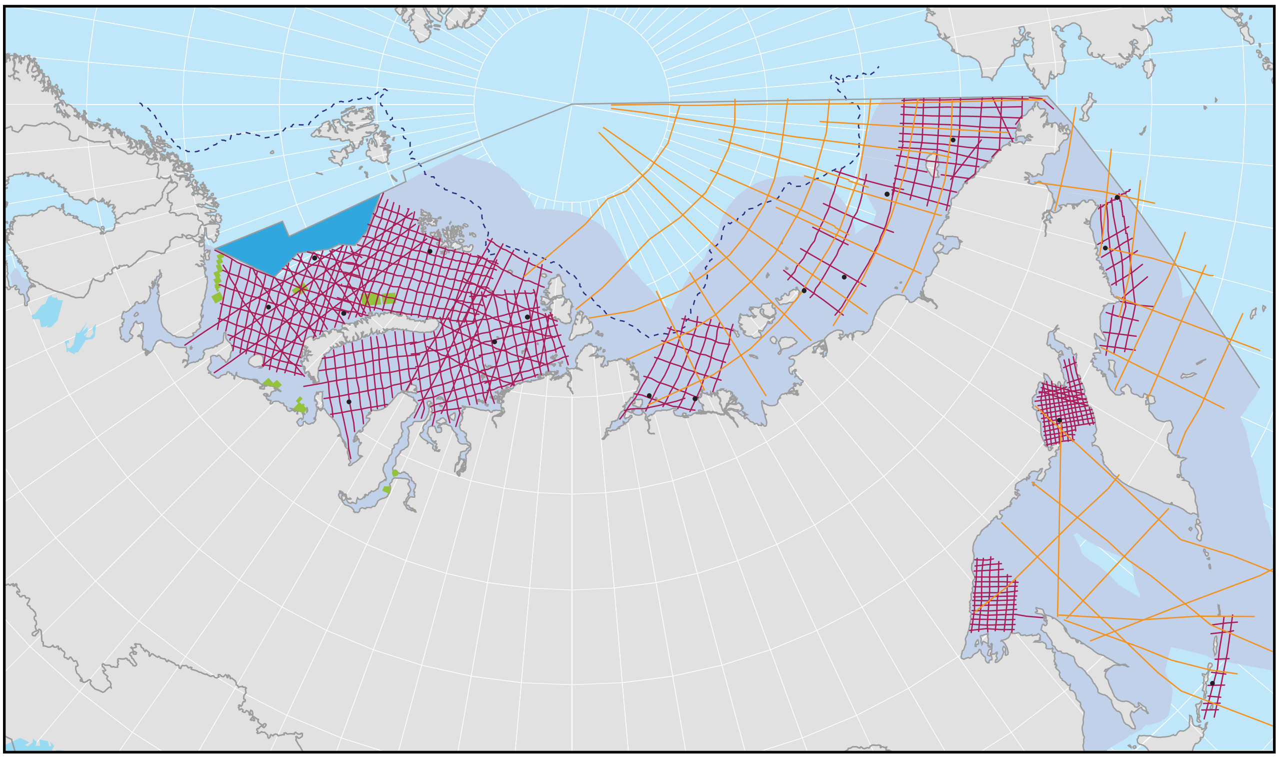


Figure 2.101. Scheme of reconnaissance, special operations, and orientation drilling during 2006-2020 in Russian Sea areas.

performed either in series, one by one, in the same region or in parallel in different regions.

The planned scope of regional exploration in the Arctic shelf for the period 2006 to 2010 is 85 000 line-km of integrated geological and geophysical studies and 3500 line-m of orientation drilling (Table 2.64). The Federal budget expenses in 2006 to 2010 will amount to 2790 million rubles for integrated geological and geophysical studies along the planned transects and 980 million rubles for drilling the orientation wells. At this time, the greatest expenses are planned for the Barents–Kara Sea region (2134 million rubles), with 100% of the orientation drilling expenses in the same region. However, the greatest amount of work in hard-to-reach Arctic areas is targeted for the period 2011 to 2020. The total volume of integrated geological and geophysical studies at this stage will be 278 000 line-km and 45 900 line-m for orientation drilling; the total amount of the Federal budget funds allocated for preparing the areas selected for the auction will reach 21.98 billion rubles.

An estimate of the amount of exploration needed for geological surveying of offshore areas, prospecting, and localization of hydrocarbon reserves on the Russian Arctic shelf from 2006 to 2020 (up to the stage of exploration drilling) is shown in Tables 2.61 and 2.62. The main areas and sites of the geophysical studies to be carried out up to 2020 are shown in Figure 2.101. During stage 1 (2006–2010), the main amount of regional and regional/exploration work at Federal level will be focused in the strategic regions, namely, the Barents and Kara Seas (Figure 2.101). The coastal areas of these two seas are considered to be the base areas and centers for offshore oil and gas development.

The objective of the regional geophysical studies in these basins is to prepare as soon as possible the new regions and sites for the licensing of subsurface use and to include them in the auction plan. 76.5% of all exploration work is planned for this region. Exploration of the East Arctic seas will be limited (23.5%) and mainly related to determination of the outer limit of the shelf, delimitation lines, and geological investigations.

The work in each offshore area may be grouped into one general or two to four regional production areas (or projects), which may be awarded to contractors on a competitive basis. The conditions for such contracts are: 1) use of state-of-the-art facilities and technologies; 2) a requirement to study the offshore sedimentary sections to the bottom depth of potential deposits; 3) independent classification and scientific analysis of new data together with previously acquired data performed both at the end of each work phase and at the end of the complete cycle in each offshore area and group of offshore areas.

Barents Sea

During 2006 to 2010, 35 000 line-km of integrated geophysical surveys are planned including 2-D seismic surveys with a regional observation network resolution from 100 × 100 km to 50 × 50 km. This work is aimed at the regional geological study of high-latitude offshore regions situated between the northwest of Novaya Zemlya and the Frantz Josef Land archipelago and a specification of the geological structure and petroleum potential of the lower horizon of the section in the central and southern regions of the Barents Sea. This work will ensure the growth of new prospective areas for oil and gas exploration by up to 500 000 km^2 and provide a basis for further growth of mineral resources by 5.4 to 6.6 billion tons o.e.

Future discoveries of medium and large oil and gas accumulations are expected in the unexplored structural traps along the entire sedimentary section of the Pechora Sea and also in poorly explored traps of different types in the Barents Sea deep horizons (3.0–6.5 km).

Kara Sea

In the period 2006 to 2010, up to 30 000 line-km of integrated regional geophysical surveys are planned for the North Kara and South Kara Basins and the North Siberian Sill that divides them. A 3.5 km deep orientation well will be drilled in the North Kara Basin. The overall aim is to attain a regional geological study of the North Kara offshore bottom and North Siberian Sill region with a specification of the geological structure and petroleum potential of the lower horizon of the section in the South Kara depression. This work is intended to ensure the growth of new prospective areas for oil and gas exploration by up to 300 000 km^2 and to provide a basis for further growth of forecasted and prospective resources by 8.0 to 12.0 billion tons o.e.

The largest oil and condensate fields are anticipated to occur in the unexplored areas south of the *Rusanovskoje* and *Leningradskoje* fields. The discovery of medium-size oil deposits is expected in the deeper horizons of the South Kara Basin section. The large and huge accumulations of liquid hydrocarbons are predicted in an almost unexplored section of the North Kara Basin which, according to the reconnaissance geological survey, may be an analogue of the Timan-Pechora OGP in terms of oil and gas potential.

Laptev Sea

Approximately 5000 line-km of integrated geophysical surveys are planned during 2006 to 2010 for the Laptev Sea, concentrated in the southwestern area. This is aimed

Table 2.64. Schedule of Federal activities planned for Arctic offshore areas.

	Integrated geological and geophysical studies, including 2-D seismic survey, 1000 km		Orientation drilling, 1000 m (number of wells)	
	2006-2010	2011-2020	2006-2010	2011-2020
Barents and Pechora seas	35	35	-	16.0 (4)
Kara Sea	30	48	3.5 (1)	5.9 (2)
Laptev Sea	5	85	-	9.0 (2)
East Siberian Sea	5	70	-	12.0 (3)
Chukchi Sea	10	40	-	3.0 (1)
Total	85	278	3.5 (1)	45.9 (12)

at the regional geological study of the offshore bottom in the central and southern region and an evaluation of its hydrocarbon potential. It is anticipated that this work will increase new prospective areas for oil and gas exploration by at least 80 000 km^2 and provide a basis for the start of large-scale prospecting and exploration and growth of hydrocarbon resources by 5.5 to 6.0 billion tons o.e.

Discovery of offshore oil deposits is mainly expected in the central and southern parts of the Laptev Sea, which, according to the reconnaissance geological survey data, are similar to the geology of the North Sea oil and gas regions.

East Siberian Sea

In 2006 to 2010, approximately 5000 line-km of integrated geophysical surveys are planned for the East Siberian Sea, with the aim of developing a network of reconnaissance observations and confirming primary information on high oil and gas potential as well as gathering information to substantiate the outer limit of the continental shelf. When completed, it is expected that this will increase new prospective areas for oil and gas exploration by up to 180 000 km^2, providing a basis for further growth of forecasted resources by 8.0 to 11.0 billion tons o.e.

Chukchi Sea

During 2006 to 2010, around 10 000 line-km of integrated geophysical surveys are planned in the Chukchi Sea. Along with the regional geological study of the offshore area and evaluation of its potential, this work aims to gather data to substantiate the offshore delimitation with an adjacent state. It is anticipated that this work will provide an increase in new prospective areas for oil and gas exploration by up to 330 000 km^2 and will serve as a basis for further growth of forecasted resources by 1.2 to 1.8 billion tons o.e. Geological and geophysical data show that this region is a direct continuation of Alaska's Arctic Slope Basin and its largest *Prudhoe Bay* field as well as some other deposits.

A viable alternative to seismic prospecting in the East Siberian and Chukchi Seas in 2006 to 2010, is the use of modern airborne geophysical surveys in the offshore areas of the East Arctic shelf including the Laptev Sea, with an average scale of 1:500 000 (in practice, from 1:200 000 in the most prospective and accessible areas to 1:1 000 000 in areas where a larger scale cannot be provided due to the impossibility of the necessary positioning).

Licensing program

The Program of Subsurface Management on the Russian Federation Continental Shelf until 2020 is aimed at providing an accelerated plan to expand production and development of the hydrocarbon potential of the continental shelf by the continuous and regular holding of license rounds on terms favorable for both the State and potential investors. This program is intended to result in the discovery of eight to seventeen large and huge hydrocarbon fields: at least two to four such areas can be anticipated in the Barents Sea; the same number in the northern and southern depressions of the Kara Sea; and one to three areas in the Laptev Sea.

The anticipated growth of commercial reserves at these new fields will be 5000 to 8000 million tons o.e. Exploration in the offshore area, together with known reserves, will enable the growth of the total production potential to 15 000 to 17 000 million tons o.e., including 2900 to 4000 million tons of oil and condensate. New discoveries will be able to maintain an annual production on the shelf of not less than 95 million tons of oil and 320 billion m^3 of gas by 2020.

By 2010, it is planned to have put up twenty promising blocks for tender, divided into six tenders, in the Barents Sea and Pechora Sea located in the best-studied areas where commercial oil and gas reserves have already been discovered or resources evaluated as at least C_3–D_1 category are available. Among them are the eastern part of the Pechora Sea with four blocks and total recoverable resources of 640 to 680 million tons o.e. (Barents-2 tender), the Barents-Pechora area with reserves of 354 to 382 million tons o.e. (Barents-3 tender), the South-Prinovozemelsky region with four blocks containing from 1200 to 1300 million tons o.e. (Barents-4 tender), the Prinovozemelsky area with two blocks containing up to 1300 million tons o.e. (Barents-5 tender), and the central and western part of the Russian Barents Sea offshore with total resources and reserves of about 2500 million tons o.e. (Barents-5 and 7 tenders) (Table 2.65 and Figure 2.100).

The Barents-2 tender, in 2006, includes four blocks with commercial reserves of oil, gas and condensate and resources estimated as $A+B+C_1+C_2$ and C_3–D_2, respectively. The blocks are offered for hydrocarbon prospecting, exploration, and production on an auction or tender basis. The tender includes the following blocks:

- West-Matveyevsky with an area of 2600 km^2 (Polyarnaya, West-Polyarnaya and West-Matveevskaya structures) with recoverable resources of 180 to 200 million tone o.e.;
- Mezhdusharsky East with an area of 6300 km^2 (Sakhaninskaya and Mertsayucsaya structures and Rakhmanovskaya group) with recoverable resources of about 100 million tons o.e.;
- South-Prinovozemelsky with an area of 3400 km^2 (Piritovaya, Mikhailovskaia, Morzhovaya and Reinikskaya structures) with recoverable resources of 80 million tons o.e.;
- South-Russky with an area of 9100 km^2 (*North-Gulyaevskoe* oil, gas and condensate field, South-Russkaya, Bolshegulyevskaya, West-Gulyevskaya, Alekseevskaya, Pakhancheskaya, Magdagachskaya and other structures) with recoverable reserves and resources of about 300 million tons o.e..

The Barents-3 tender, also in 2006, includes five blocks in the Barents-Pechora area with commercial reserves of gas and resources of hydrocarbons estimated as $A+B+C_1+C_2$ and C_3–D_1, respectively. The blocks are offered for geological study, hydrocarbon prospecting, exploration, and production on an auction or tender basis. The tender includes the following blocks:

- Murmansk with an area of 4400 km^2 (*Murmansk* gas field, non-structural traps) with recoverable reserves and resources of more than 120 million tons o.e.;
- Korginsky with an area of 10 100 km^2 (Korginskaya 1 and 2 and Seduyakhinskaya structures) with recoverable resources of up to 70 million tons o.e.;
- Russky with an area of 2700 km^2 (Russkaya structure) with recoverable resources of 107 to 115 million tons o.e.;

Table 2.65. Oil and gas tenders for the Barents Sea from 2006 to 2010.

Name of structure	Tender	Year	Area, 1000 km^2	Resources in place; million tons o.e.
South-Russky	Barents-2	2006	9.1	300
West-Matveevsky		2006	2.6	180-200
South-Prinovozemelcky		2006	3.4	70-80
Mezhdusharsky East		2006	6.3	90-100
Russky	Barents-3	2006	2.7	107-115
North-Pomorsky-1		2006	2.5	30-35
North-Pomorsky-2		2006	2.8	37-42
Korginsky		2006	10.1	60-70
Murmansk		2006	4.4	120
Papaninsky	Barents-4	2007	2.1	50-60
Mezhdusharsky		2007	2.0	50-60
West-Mitjushikhinsky		2007	6.5	170-180
Dmirievsky		2007	6.6	200-210
Mitjushikhinsky	Barents-5	2008	6.1	190-200
Krestovy		2008	8.6	170-180
Ledovy	Barents-6	2009	23.6	430
Ludlovsky		2009	12.2	210
Demidovsky	Barents-7	2010	18.2	800
Kildinsky		2010	35.6	120
Fersman		2010	16.8	950

- North-Pomorsky-1 with an area of 2500 km^2 (East-Kolguyevskaya and Razlomnaya structures) with recoverable resources of 30 to 35 million tons o.e.;
- North-Pomorsky-2 with an area of 2800 km^2 (North-Pomorskaya and North-Kolokolmorskaya) with recoverable resources of 37 to 42 million tons o.e..

The Barents-4 tender, in 2007, includes four blocks adjacent to Novaya Zemlya with resources estimated as D_1–D_2, respectively. The blocks are offered for geological study, hydrocarbon prospecting, exploration, and production on an auction or tender basis. The tender includes the following blocks:

- Papaninsky with an area of 2100 km^2 (Papaninskaya structure) with recoverable resources of up to 60 million tons o.e.;
- Mezhdusharsky with an area of 2000 km^2 (Mezhdusharskaya structure) with recoverable resources of up to 60 million tons o.e.;
- Dmitrievsky (Dmitrievskaya structure and a group of non-structural traps) with recoverable resources of up to 210 million tons o.e.;
- West-Mityushikhinsky (non-structural traps including the largest ones No. 3, 4, and 7) with recoverable resources of up to 180 million tons o.e..

The Barents-5 tender, in 2008, includes two blocks with resources estimated as D_1–D_2. The blocks are offered for geological study and hydrocarbon prospecting and exploration on an auction or tender basis. The tender includes the following blocks:

- Mityushikhinsky with an area of 6100 km^2 (Mityushikhinskaya structure and a group of non-structural traps) with recoverable resources of up to 200 million tons o.e.;
- Krestovy with an area of 6100 km^2 (East-Krestovaya and North-Sulmenevskaya structures and non-structural traps) with recoverable resources of up to 180 million tons o.e..

The Barents-6 tender, scheduled for 2009, includes two blocks in the central part of the Barents Sea with commercial reserves of gas and condensate and resources estimated as $A+B+C_1+C_2$ and C_3–D_2, respectively. The blocks are offered for offshore hydrocarbon prospecting, exploration, and production on an auction or tender basis and are open for speculative surveys in the period prior to the auction. The tender includes the following blocks:

- Ludlovsky with an area of 12 200 km^2 (*Ludlovskoe* gas field and Luninskaya structure) with recoverable reserves and resources of about 210 million tons o.e.;
- Ledovy with an area of 23 600 km^2 (*Ledovoe* gas field and a group of structural and non-structural traps) with recoverable reserves and resources of about 430 million tons o.e.

The Barents-7 tender, scheduled for 2010, includes three blocks in the western part of the Russian Barents Sea offshore with commercial reserves of gas and resources estimated as $A+B+C_1+C_2$ and C_3–D_1, respectively. The blocks are offered for hydrocarbon prospecting, exploration, and production on an auction or tender basis and are open for speculative surveys in the period prior to the auction. The tender includes the following blocks:

- Fersman with an area of 16 800 km^2 (Fersman high and nameless structures and non-structural traps) with recoverable reserves and resources of up to 950 million tons o.e.;
- Demidovsky with an area of 18 200 km^2 (Demidovskaya structure and non-structural traps) with recoverable reserves and resources of up to 800 million tons o.e.;

- Kildinsky with an area of 35 600 km² (*North-Kildinskoe* gas field and a group of non-structural traps) with recoverable reserves and resources of about 120 million tons o.e.

The blocks and types of licenses, as well as the procedure and schedule for holding tenders, are determined by the current degree of the resource base exploration maturity, the market value of hydrocarbon products, the market demand for hydrocarbons, and other factors and is monitored regularly and corrected in accordance with changes in these factors. In general, procedures for holding auctions are determined by the interest expressed by potential investors regarding the offshore subsurface zones. This interest provides the competitive environment in the course of the auction and ultimately determines success or failure of the activity. Broad publication of lists of areas offered for different forms of mineral resources management, and receipt of preliminary applications for participation in the events and their classification are provided to specify the programs and develop detailed plans for auctions. As an example, one additional resource block was prepared in the Barents Sea for offer – Konstantinovsky with 2875 km² with resources in place of 237 million tons o.e.

The Federal Agency for Mineral Resources Management offered six sites in the Gulf of Ob in the Kara Sea for geological study at the expense of subsurface users in 2006 to 2007 (Table 2.66 and Figure 2.102). Two sites were previously granted licenses for geological exploration.

One site in the Chukchi Sea was to be offered for geological survey.

Concepts for resource management from 2011 to 2020

Significant expansion of mineral resources management areas is planned for the period 2011 to 2020. By this time, exploration areas will include the Barents Sea, the Kara Sea, and the Laptev Sea. In particular, promising areas in the Barents Sea will be covered by 0.4 to 0.7 km/km² regional and exploratory seismic surveys. In the Kara and Laptev Seas, the expected density of geophysical exploration of these basins will be lower (0.25 to 0.5 km/km²). Consequently, it is anticipated that the number of licenses for hydrocarbon prospecting, exploration, and production in the Barents Sea offshore will be greater than the number for the Kara and Laptev Seas, where the licenses for geological study and prospecting are likely to be awarded.

Owing to a low exploration maturity of prospective mineral resources sites, it is currently impossible to delineate the future blocks and accurately estimate their physical parameters (area and resource potential) or the economic prospects of their exploration. However, the geological data available show the general characteristics regarding implications for the development of these areas.

In 2011 to 2020, the prospective mineral resources sites in the Barents Sea will comprise: the central part of the South Barents depression; the northern zone of the Timan-Pechora platform; and the South-East Prinovozemelie adjacent to the Gusinaya Zemlya Peninsula.

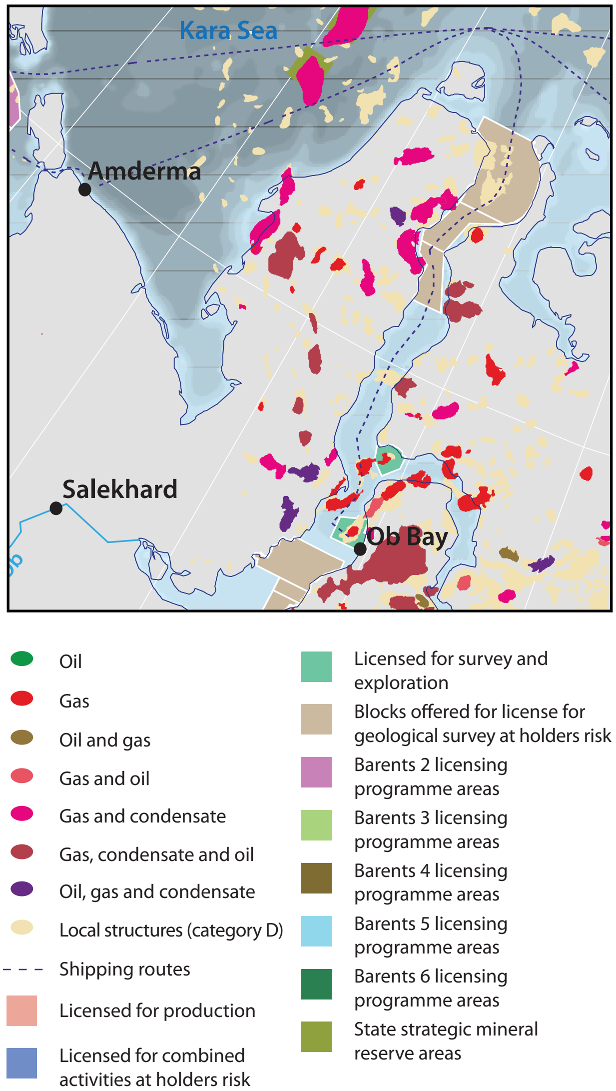


Figure 2.102. Areas in the Gulf of Ob, Kara Sea, offered for geological exploration in 2006-2007.

Table 2.66. Areas made available for licensing for geological exploration in the Gulf of Ob (Kara Sea), 2006 to 2007.

Block	Area, km²	Resources in place	
		Category	Million tonnes o.e.
North-Obsky	8875	C_3+D_1	1597
Tambey-Obsky	2603	D_1+D_2	900–1200
Sabetta-Obsky	2340	D_1+D_2	750–850
South-Obsky	4481	D_1	254
North-Sandibinsky-1	754	D_1+D_2	148
North-Sandibinsky-2	782	D_1+D_2	189

Large traps which may not have been discovered during previous surveys may be found in the Jurassic, Triassic, and the Upper Paleozoic sediments.

In the Kara Sea, the priority mineral resources management regions in 2011 to 2020 will comprise the western part of the South Kara depression including the systems of the Sharapov, Obruchev, and East Novaya Zemlya highs. Analysis of regional seismic materials indicates possible prospective exploration targets in the Jurassic-Cretaceous and deeper parts of the section.

In the Laptev Sea, the southern part including the South Laptev depression and adjacent water area is the most promising for mineral resources management.

Specification of the prospective mineral resources sites in these offshore basins by dividing them into blocks with specific geographical coordinates and division of these blocks into local exploration targets, as well as quantitative assessment of the resources and economic estimates of mineral resources management efficiency in these regions, will be possible after regional exploration and analysis of the results. Based on these results, a quantitative and geological/economic assessment of hydrocarbon resources can be made.

Implementation of the activities under this program will create the necessary prerequisites for further development of Russia's infrastructure and strengthening of its presence in outlying regions, as well as protection of Russia's geopolitical interests.

2.4.7.7. Infrastructure and transportation

2.4.7.7.1. Onshore transport

Data from the Russian Federal State Statistics Service on the ton-km of freight moved by public transport in Russia during 2005 show for oil that 55.1% is transported by pipeline, 41.4 % by rail, 1.6% by inland waterways, 1% by marine tankers, and 0.8% by motorway (Bambulyak and Frantzen, 2007).

Oil pipelines

Russia's oil pipeline transport system comprises some 50 000 km of trunk pipelines (Figure 2.103), all but a small amount of which are owned by the state company Transneft. Even though there are no trunk pipelines in Arctic Russia, a review of the history and current status of trunk pipelines in Russia is useful for undertanding possible future pipeline systems for the Arctic region.

The safety of the trunk pipeline system, which was subject to criticism and government hearings in the 1990s, was subsequently improved, resulting in fewer pipeline accidents (Table 2.67).

In 2004 to 2005, the officially reported rate of spills was 0.04 per 1000 km. However, there may be under-reporting of the number of oil spills since 2002 owing to the established reporting criteria (for example, a spill from a pipeline of less than 7 tons of crude oil is not required to be reported as an emergency situation, unless people and/or water bodies are affected). Nevertheless, there are about 135 000 km of oil field and collection pipelines throughout Russia for which safety remains very questionable: according to various sources, the annual number of oil

Table 2.67. Oil pipeline accidents in Russia, 1985 to 2002.

Year	Length, km	Number of accidents		Reasons for accident				
		Total	Per 1000 km	Corrosion	Manufacturing defect	Construction defect	Mechanical damage	Other, including illegal intrusion
1985	62249	27	0.43	6	2	7	10	2
1986	64189	24	0.37	4	6	8	4	2
1987	64069	16	0.25	3	3	3	6	1
1988	65866	25	0.38	3	5	10	5	2
1989	66291	17	0.26	2	4	5	4	2
1990	66700	14	0.21	5	2	3	4	0
1991	65350	9	0.14	1	2	4	2	0
1985-1991		*132*	*0.29*	*24*	*24*	*40*	*35*	*9*
1992	48100	10	0.21	0	4	2	4	0
1993	48100	12	0.25	2	1	4	4	1
1994	49600	6	0.12	1	2	1	2	0
1995	47200	7	0.15	2	2	3	0	0
1996	47200	9	0.19	2	1	4	2	0
1997	47200	6	0.13	0	0	3	2	1
1998	47200	3	0.06	0	0	3	0	0
1999	47200	3	0.06	1	0	0	1	1
2000	47200	6	0.12	Data missing, added to others				6 (cond.)
2001	48500	5	0.10	0	1	1	0	1+2
2002	48500	3	0.06	1	1	0	0	1
1992-2002		*70*	*0.13*	*9*	*12*	*21*	*15*	*13*

Figure 2.103. System of oil pipelines in Russia.

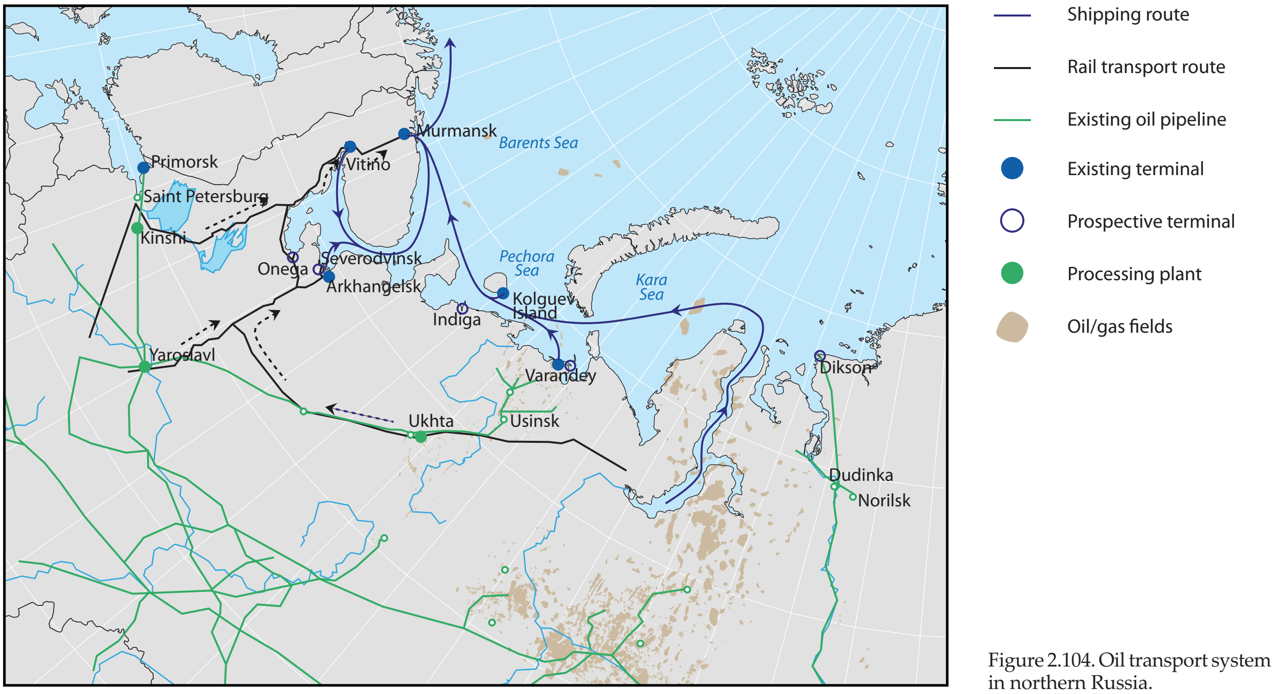


Figure 2.104. Oil transport system in northern Russia.

leaks and spills from such pipelines amounts to several tens of thousands.

Transportation of hydrocarbons for export, including crude oil and mineral oil, has increased during recent years owing to the development of transportation routes through the Arctic seas and particularly in the Barents, White, and Kara Seas.

The main oil transport flows coming to the Arctic are for domestic consumption and export via railroad routes (to Murmansk on the Barents Sea, Vitino and Arkhangelsk on the White Sea, etc.). In addition to the oil produced in northern regions, there are large oil flows coming from other OGPs (mainly Volga-Ural) to sea terminals for export. The existing oil transportation routes to the ports of the White and Barents Seas are shown in Figure 2.104.

At present, the transportation of oil from Nenets AO occurs onshore. About 95% of the oil produced in the southern oil fields is transferred to the trunk Baltic Pipeline System, and only 5% is delivered through the Varandeya transfer terminal, which is working on a temporary basis and has a limited transfer capacity of not more than 1.5 million tons per year. Under-development of the onshore transportation systems is one of the factors restricting an increase in oil production in the north of the Timan-Pechora OGP.

To overcome this situation, two projects related to onshore transportation infrastructure are planned:

- development of a collection pipeline system for fields in order to extend the stationary year-round working capacity of the Varandeya terminal to 12 million tons/y in 2010 and 20 million tons/y in 2015;
- construction of a trunk oil pipeline with a capacity of up to 24 million tons/y from the West Siberian OGP with input from the northern territories of the Timan-Pechora OGP to Indiga harbor with the establishment of a new transfer terminal there.

The Varandeya terminal project is planned to be put into operation in 2008 to 2009. The Indiga terminal is at the stage of investment planning.

In East Siberia, the onshore oil pipeline is planned to be extended to Dikson for further oil transportation by tankers via the Northern Sea Route.

As of late 2005, the capacity of Transneft Company to deliver oil to the 'far abroad' countries was 221 million tons. New directions of transport that are anticipated to begin soon are east (30 to 80 million tons) and north (12 million tons).

Oil pipeline projects

Eastern Siberia-Pacific Ocean pipeline system

The construction of the Eastern Siberia-Pacific Ocean (ESPO) pipeline system is being implemented to deliver West- and East-Siberian oil to the Pacific oil terminal. The pipeline is 4670 km long (2764 km at the first stage, with a diameter of 1067/1220 mm) and a design capacity of 30 million tons during the first stage and 80 million tons when completed. In April 2006, construction of the first start-up complex of the ESPO system began. Pursuant to decisions taken at the meeting in Tomsk in April 2006, chaired by the President of the Russian Federation, the company Transneft started implementing the project and exploration work on the route of the ESPO system beyond the water drainage basin of Lake Baikal. The ESPO is to be expanded and pass along the following route: Ust-Kut–Kirensk–Lensk–Olekminsk–Aldan–Tynda. The route of ESPO expansion over a stretch of 2050 km has been divided into three sections: Ust-Kut–*Talakansk* field, Aldan-Tynda, and *Talakansk* field–Aldan.

Kharyaga-Indiga pipeline

The proposed Kharyaga-Indiga pipeline is intended to deliver oil produced in Timano-Pechora to the oil terminal near the Indiga settlement on the Barents Sea coast. The design capacity of the pipeline is 12 million tons and its length is 460 km.

Transport of oil by rail

The length of railways in Russia is 86 600 km, with about 85% in the European area. The amount of oil transported by rail in Russia during 2006 was 228 million tons (Bambulyak and Frantzen, 2007).

About 50 million tons of crude oil and oil products can be delivered by railway to the Murmansk ports in the Barents Sea, and Kandalaksha and Arkhangelsk in the White Sea (Bambulyak and Frantzen, 2007). Railways in the northern part of the country include the October railway that runs from Moscow through Tver, Pskov, Novgorod, Leningrad, Vologda and Murmansk regions and the Republic of Karelia, and the Northern railway from Moscow to Arkhangelsk.

The October railway is over 10 000 km long and carries more than 100 million tons of cargo per year (123.6 million tons in 2005). Oil for export has been delivered to the Vitino port since 1995 and in 2003 reached almost 6 million tons (about 100 000 railway tank cars). Since 2004, oil has been transported to the port of Murmansk and in 2006 more than 7 million tons were sent to the Murmansk region terminals. The increase in northern freight traffic is mainly due to the shipment of crude oil and fuel oil cargoes to Vitino and Murmansk for export. In 2005, the October railway was electrified over the entire distance to Murmansk, which has the possibility of increasing its carrying capacity 1.5-fold.

The modernization of the railway's northern line (both tracks and service facilities) is being carried out by the October railway department together with customers and carriers and by 2015 it is planned that new lines to Kola and Murmansk are built on the eastern side of Kola Bay; and to Lavna and Kulonga on the western side.

The October railway joins the Northern railway on the borders of the Republic of Karelia and Arkhangelsk region, Tver and Yaroslavl regions, and in Vologda region. The Northern railway is 140 years old and follows an old wagon trail through northern and northeastern Russia, where it crosses the territory of the YaNAO region, Republic of Komi, Arkhangelsk, Vologda, Kostroma, Ivanovo and Yaroslavl regions. It passes through the location of the major pipeline junction where the Ukhta–Yaroslavl–Kirishi pipeline joins the pipeline that runs through Surgut–Yaroslavl–Polotsk. The operational length of the railroad is 8508 km and in 2006 it carried 19 million tons of crude oil and oil products.

In 2005, the Northern railway delivered 4.7 million tons of oil and oil products to the terminal in Talagi near Arkhangelsk. The company Rosneft-Arkhangelsknefteprodukt plans to increase Talagi oil terminal deliveries to 10.2 million tons per year by 2008. In October 2006, Gazprom decided to resume construction of the 500-km Polar rail line Obskaya–Bovanenkovo that in 2010 is planned to connect the Northern railway with one of the giant *Bovanenkovskoye* oil and gas condensate fields on the Yamal Peninsula.

The Strategy of Transport Development in the Russian Federation for the Period to 2010 describes a number of large onshore infrastructure projects, including:

- the railway Berkakit–Tommot–Yakutsk that could increase mineral resources development in the Republic of Sakha;
- modernization of existing roads and construction of new roads in the North and new developed regions;
- completion of the railways Noviy Urengoy–Nadym and Noviy Urengoy–Yamburg for efficient development of the YaNAO region and its natural resources;
- creation of a transportation corridor by the eastern Ural mountains towards Polunochnaya–Labytnangi for developing the Yamal Peninsula, the Kara Sea shelf and the Northern Sea Route; and
- complex system modernization of the Far East ports with railway connections for developing economic relations with Pacific Asia countries.

Inland water transport of oil

In the Russian part of the Barents Region, the main navigable river is the Northern Dvina that carries cargo to Arkhangelsk and Kotlas. The Pechora River carries goods

Table 2.68. Pipelines within the United Gas Pipeline System by diameter and year.

Year	Length, 1000 km	Pipe diameter, mm						
		1420	1220	1020	820	720	530	<530
1991	132.14	44.85	23.52	14.74	4.79	10.79	11.94	22.51
1992	135.11	43.85	23.34	14.88	4.77	11.67	11.59	22.30
1993	138.08	42.85	23.16	15.02	4.76	12.56	12.23	22.09
1994	139.30	48.20	24.10	15.27	4.78	11.70	11.98	23.28
1995	140.80	48.30	24.20	15.57	4.75	10.35	11.95	25.68
1996	145.16	48.86	24.94	15.88	4.73	10.76	11.93	28.07
1997	146.72	48.96	25.60	15.67	4.59	11.34	11.72	28.85
1998	148.23	49.68	25.02	16.51	4.54	11.31	12.20	28.98
1999	148.80	49.61	25.06	16.50	4.53	11.41	11.83	29.86
2000	148.90	49.88	25.47	16.32	4.44	11.28	11.74	30.87
2001	148.90	49.9	25.21	16.07	3.85	10.86	11.42	31.47
2002	151.60	50.73	25.28	16.77	4.05	11.06	12.23	31.49

Table 2.69. Accidents and incidents reported for the United Gas Pipeline System.

Year	Total length, 1000 km	Accidents		Incidents	
		Reported number	Frequency, 1/1000 km/y	Reported number	Frequency, 1/1000 km/y
1991	132.14	36	0.27	470	3.56
1992	135.11	25	0.19	405	3.00
1993	138.08	30	0.22	322	2.33
1994	139.30	28	0.20	588	4.22
1995	140.80	30	0.21	509	3.61
1996	145.16	35	0.24	411	2.83
1997	146.72	39	0.27	520	3.54
1998	148.23	35	0.24	595	4.01
1999	148.80	23	0.18	1096	7.37
2000	148.90	33	0.22	1006	6.71
2001	148.90	31	0.21	2090	14.07
2002	151.60	32	0.21	1453	5.58

Table 2.70. Accident rates for the United Gas Pipeline System in relation to pipe diameter size, 1991 to 2002.

Pipe diameter, mm	Number of accidents, 1991–2002	Pipeline length, 1000 km	Frequency, 1/1000 km/y
1420	85	47.97	0.148
1220	104	24.58	0.353
1020	46	15.77	0.243
820	18	4.55	0.330
720	30	11.26	0.222
530	30	11.90	0.212
<530	64	27.12	0.197

to Naryan-Mar and the NAO. The Ladoga and Onego lakes also have significant economic value.

The White Sea–Baltic canal was opened for navigation in 1933 with the first delivery of oil in 1970 by river-sea tanker to the Murmansk Region. In the 1990s, the White Sea canal was essentially shut down. In 2003, 220 000 tons of fuel oil shipped in the canal were loaded onto sea tankers in the Onega Bay of the White Sea for export. However, transportation of export oil through the White Sea canal was halted due to a fuel oil spill accident that occurred during trans-shipment in Onega Bay in September 2003.

Gas transport

The United Gas Pipeline System (UGPS) comprises 151 600 km of trunk gas pipelines, 254 compressor stations with a total capacity of 42.4 million kWt, and 23 underground gas

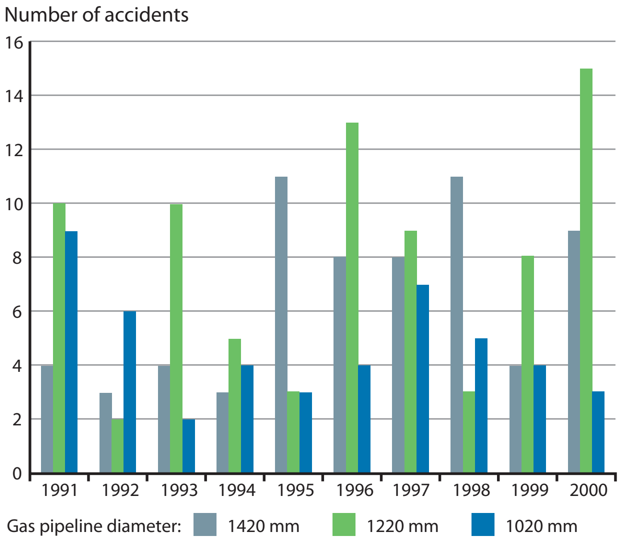


Figure 2.105. Gas pipeline accidents from 1991-2000 for large diameter pipes.

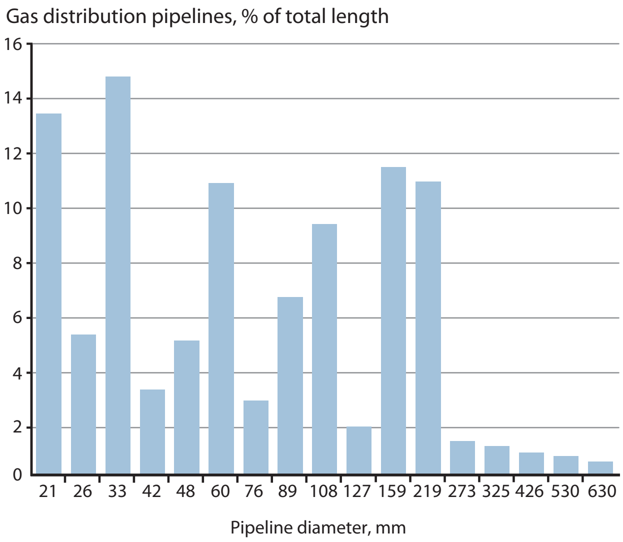


Figure 2.106. Proportion of gas distribution pipelines according to diameter.

storage tanks with a capacity of 58 billion m^3. The system is made up of pipelines of various diameters (Table 2.68).

The operation of the UGPS is fairly stable, with accident statistics given in Tables 2.69 and 2.70 for the period 1991 to 2002 and Figure 2.105 for large-diameter pipelines for the period 1991 to 2000. Similar statistics were collected after 2002, with some improvements reported in 2005 to 2006.

In the Arctic region, the main gas flow is from the YaNAO, where more than 90% of Russia's gas is produced, to the central region and, after distribution, to export lines via Ukraine and Belarus.

There are no publicly available statistics concerning gas collection pipelines in the region (an expert estimate is tens of thousands of kilometers), but given the involvement of new remote fields, some of which are relatively poor but numerous, that will need to be connected to the same collection and processing units, a growth of such pipelines is anticipated.

Despite very large gas production and export, there are wide and populated regions in the Arctic and sub-Arctic with no access to gas supplies: the Murmansk region, Karel Republic, and the Arkhangelsk region (only 9% before 2006, when a new gas pipeline from the trunk Yamal–Europa gas pipeline was commissioned). Some prospects of improving energy supply to such regions are arising with the development of new pipelines, such as the gas pipeline from Stokman to Vyborg with promised gas distribution to the Murmansk region, Karelia and north of the Leningrad region.

Local gas distribution networks comprise in total about 785 000 km, based on a variety of pipeline diameters (Figure 2.106). Of all distribution pipelines, 93.9% are made of steel, with the rest of different types of plastic.

The UGPS is owned and managed by Gazprom, including the regulation of access by other (so-called 'independent') producers to the gas transportation system, comprising also those that are able to deliver associated gas from oil-producing fields. Starting from six companies with 28.2 billion m^3 supply, the annual supply of gas from independent producers has been reported as: 2001: 24 companies (92.4 billion m^3); 2002: 33 companies (103.6 billion m^3); 2003: 30 companies (95.4 billion m^3); 2004: 33 companies (99.9 billion m^3); and 2005: 31 companies (114.9 billion m^3). Currently, independent gas production constitutes about 15% of the total amount.

2.4.7.7.2. Offshore transport

The only example of oil and gas transport by underwater pipelines in the Russian Arctic is oil transport to the tanker terminal at Varandey in the Pechora Sea.

Crude oil and oil products are exported by sea to Europe and North America and to Russian consumers in Arctic regions. The existing terminals load around 12 million tons of oil products and crude oil; the oil is then transported by sea to delivery sites farther away. A large proportion of the oil and liquid fuel is delivered to the ports from internal regions of Russia.

Sea terminals

In the Barents Sea region, small volumes of oil are extracted from onshore deposits only, such as on Kolguev Island (Peschnoozerskoye deposit) and at four coastal deposits of Timanskii (Varandey, Toraveiskii, Toboiskii, Myadseyskii). The prospective raw material resources in the European part of the Arctic region are mainly associated with the Timan-Pechora OGP. Over the next one to two years, oil extraction is planned to begin on the Arctic shelf with the development of the Prirazlmnoye deposit. By 2013, oil production on the shelf of the Pechora Sea (*Prirazlomnyi*, *Medynsko-Varandeyskii*, *Kolokomorskii*, *Pomorskii* oil fields) may reach 12.7 million tons per year. The volumes of oil extracted from land deposits of the Timan-Pechora OGP and transported by sea are also expected to increase. This increase in oil and gas extraction can lead to shortages in transportation capacity. In 2010, the volume of oil sent to markets by sea in the Arctic regions may increase up to 40 million tons.

Barents Sea terminals

<u>The Peschano–Ozerskii terminal (on Kolguev Island):</u> This began operations in 1986. The extracted oil is pumped through the pipeline from the deposit to a coastal oil storage tank, then to the underwater oil-loading terminal and, finally, into the oil tanker. Oil is shipped by tankers of 20 000 tons dwt straight to export or to the port loading terminal in Kola Bay. In 2004, the terminal's annual oil

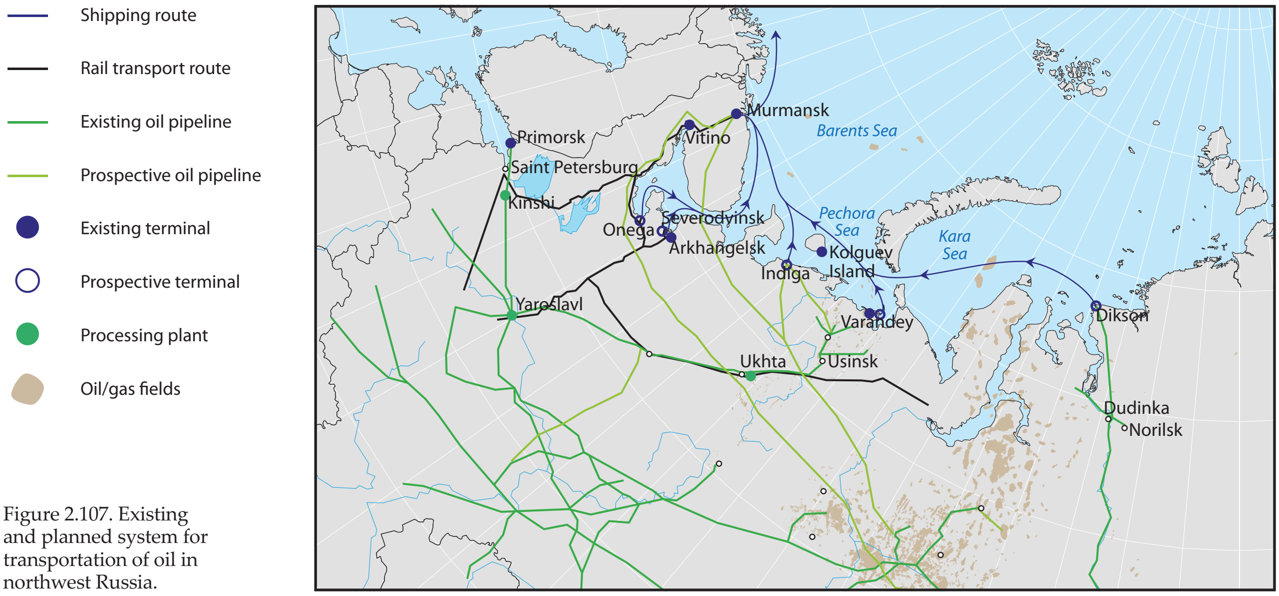


Figure 2.107. Existing and planned system for transportation of oil in northwest Russia.

shipments amounted to 80 million tons. The quality of oil extracted at the deposit is the highest in the Timan-Pechora OGP.

The oil terminal in Varandey: This was built on the premises of the Varandey port in the Pechora Sea and was intended for loading oil extracted from coastal deposits in the Timan-Pechora OGP. The Arctic underwater reloading complex pumps oil through the underwater pipeline from the coastal storage area. The oil is then transported by 20 000 tons dwt tankers to the oil-loading terminal in Kola Bay for reloading into supertankers (100 000 tons dwt and more) for shipment to consumers abroad (Azarov, 2001a). The terminal ships oil from the four deposits in the Timan-Pechora OGP. Winter shipments are possible owing to the ice support of the diesel-electric icebreaker *Captain Nikolaev*, which is considered the best icebreaker in the world. Oil pipelines connect the terminal to the Varandey, Toraveisskii, Toboiskii and Myadseyskii oil deposits. In 2004, the oil shipment volume reached 609 000 tons. Further growth of the shipment volume at the terminal can be anticipated as soon as oil production starts at the Southern Khychulskii deposit, which is expected to allow extraction of more than 4 million tons of oil per year, and construction of a new pipeline to the terminal begins. It is planned to expand the coastal storage tank park, to lay a 12-km underwater pipeline from the coastline, and to install a new underwater loading terminal at a depth of 21 m that will make it possible to load tankers of up to 100 000 tons dwt.

The Prirazlomnoe Deposit Terminal (planned): The *Prirazlomnoe* oil field is one of the largest on the shelf of the Pechora Sea, whose stocks are more than 231 million tons. Drilling of the first well was scheduled for December 2005, the start of industrial oil extraction for 2006, and the expected capacity is about 6.5 million tons per year. The maximum annual volume of extraction of 7.55 million tons will be reached in the fifth year of operation. For the next 25 years, the deposit is expected to produce about 75 million tons of oil. Transportation of the extracted oil will be carried out year-round by shuttle tankers of 70 000 tons and 20 000 tons dwt to Offshore Terminal 3 in Kola Bay. Icebreakers and ice-reinforced shuttle tankers will provide ice-breaking support in winter. With the help of Offshore Terminal 3 *Belokamenka* (refurnished 300 000 ton dwt storage tanker), the oil from Prirazlomnoye will be transported to Rotterdam, the only port in northwest Europe accepting sulphurous oil.

Indiga Terminal (planned): This trans-shipment terminal is planned to be built in the area of Indiga city on the Pechora Sea coast simultaneously with the construction of an oil pipeline along the Barents Sea coast from the Titov deposit (in the area of Varandey). Depths there reach 25 to 30 m even within 3 km of the coast, so it is possible to serve tankers of 100 000 tons dwt and over. The 400-km oil pipeline (820 mm diameter) will cross the NAO from east to west. The initial loading complex of Indiga is expected to process 11 million tons of oil per year. A decision on construction has not yet been taken (Azarov, 2001b).

A map of the planned oil transportation system in this region is provided in Figure 2.107.

Kola Bay terminals

The Murmansk port and Kola Bay have become a powerful center of oil trans-shipment, integrating both coastal and offshore terminals. This was not accidental. In the European part of Russia, Murmansk is the largest deep-water port able to serve supertankers. Murmansk is the closest port to the United States across the Atlantic. In view of this, the general scheme of development of the Murmansk transport unit envisages that the turnover of goods will increase by up to 57 million tons by 2010, including an increase in oil and mineral oil of up to 27 million tons.

RPK 1 offshore reloading complex to the south of Cape Mishukov (owned by Murmansk Sea Shipping Company): The offshore terminals are intended for loading oil from shuttle tankers (20 000 to 60 000 tons dwt) onto seagoing tankers of 150 000 tons dwt. The complex comprises one offshore mooring point in the area of Kola Bay to the south of Cape Mishukov for mooring seagoing tankers of 150 000 tons dwt. Loading is performed on a ship-to-ship basis. In August 2004, a storage tanker (127 500 tons) was anchored at the loading terminal. Oil is shipped to the offshore terminal by shuttle tankers from the terminals in Varandey and Vitino.

Ice-reinforced shuttle tankers (20 000 to 30 000 tons dwt) can operate at the site on a year-round basis, while heavier shuttle tankers (40 000 or 60 000 tons dwt) can operate there only during the navigation season. The capacity of the offshore reloading complex at Mishukov is 4.5 million tons per year.

RPK 2 offshore complex in the area of Mishukov settlement: The construction of RPK 2 has been completed, but it is not yet in operation. Year-round operation of the offshore mooring will permit the reloading of 2.5 to 3 million tons of oil per year when operating continuously.

RPK 3 Belokamenka: Owned by NK Rosneft, RPK 3 is intended for loading oil from shuttle-tankers (20 000 to 80 000 tons dwt) into seagoing tankers (100 000 to 150 000 tons dwt) via the *Belokamenka* storage tanker of 300 000 tons dwt (Figure 2.108). Oil shipped from RPK 3 comes from deposits in the Timan-Pechora OGP (and in future also from Prirazlomnoye deposits) as well as from Vankorskii deposits.

The coastal terminal of Murmansk fishing port was constructed at the site of the port tank farm in 2003 for reloading oil from railway tanks into 15 000-ton dwt shuttle tankers for further reloading at RPK 1. In 2004, the terminal processed nearly 2 million tons of oil. After completion of the planned reconstruction, the capacity of the terminal is expected to reach 2.5 million tons per year.

The coastal reloading complex of the 35th Shipyard is located on the Kola Bay coast in the area of Rost settlement (a suburb of Murmansk) on the location of the Federal State Unitary Company of the 35th Shipyard. The complex is owned by Tangra Oil. The complex is intended for loading oil and fuel oil, including fuel oils such as F-5, F-12, M-40, and M100. The complex has been in operation since 2004.

The unique feature of the complex is the combination of a mooring point for reloading oil via a storage tanker from feeder tankers into seagoing tankers (50 000 to 100 000 tons dwt) on a ship-to-ship basis and an oil-loading rack connected to the storage tanker by pipeline. The projected capacity of the complex is up to 4 million tons of fuel oil per year, comprising 2 million tons shipped by rail and 2 million tons transported by sea. The outgoing volume is 4 million tons per year. The average total storage volume in the storage tanker is around 130 000 m^3. Oil exports by supertankers are now carried out at RPK 1 and RPK 3.

RPK 4 in Mohnatkina Pakhta Bay (planned): There are plans to build another offshore reloading complex in Kola Bay on Cape Mohnatkina Pakhta with a projected capacity of 2.5 million tons of oil per year. Oil is planned to be loaded from railway tanks into a storage tanker and then reloaded onto a seagoing tanker. The projected capacity of the new terminal is 2 million tons of oil per year (Bambulyak and Frantzen, 2005).

Lavna Coastal Terminal (planned): There are several more projects planned to increase the volume of oil shipments in Kola Bay. The main emphasis is currently on permanent oil reloading complexes with the use of the railway line in the area of Lavna settlement. There are plans to construct a technological mooring to service tankers of 300 000 tons dwt. The projected capacity of the terminal is 2 million tons per year. Operations are planned to begin in 2008. With further growth of Russian oil shipments by the Arctic seaway, it is possible to imagine new offshore oil loading terminals constructed in the ports of eastern Norway.

White Sea terminals

The seaport of Vitino (Kandalaksha Bay): This is the oldest and, until recently, the largest oil terminal in northwest Russia. The port serves as a storage and reloading terminal for oil, fuel oil, and stabilized gas condensate. The port is capable of simultaneously serving three tankers (one sea tanker of up to 70 000 tons dwt and two oil-and-ore tankers). The enterprise transfuses oil and liquid oil products from nearly all deposits in the Russian Federation. The most important suppliers are: Yaroslavlnefteorgsintez, Yaroslavl; NORSI, Nizhni Novgorod; Nizhnekamsk Oil Refinery, Nizhnekamsk; Permnefteorgsintez, Perm; Bashnefkhimzavody, Ufa; Samara Oil Refinery Unit, Samara, Syzran. Special attention is given to reloading of crude oil extracted in the Timan-Pechora OGP.

Figure 2.108. Offshore Terminal 3 *Belokamenka* (refurnished 300 000 ton dwt anchored tanker).

Oil is carried along river waterways by oil-and-ore bulk-tankers of mixed navigation type and also by railway tanks (www.vitino.ru). Around 5.7 million tons of oil were transported in this way in 2003. The port of Vitino is capable of handling 100 000 tons of fuel oil, 120 000 tons of gas condensate, and up to 380 000 tons of crude oil.

Since 2002, the Vitino seaport has operated on a year-round basis. In 2004, the port authorities started work to deepen the port to serve heavier tankers of 100 000 tons dwt and on reconstruction of the railway tank track.

The Arkhangelsk tank farm: The port of Arkhangelsk reloads crude oil, fuel oil, diesel oil, and gas condensate. To carry the flow of oil from Timan-Pechora deposits to the storage tanker *Belokamenka* in the port of Murmansk, Arkhangelsk began to build the first section of a new oil terminal capable of handling 2.2 to 2.5 million tons per year for 20 000-ton tankers. The railway station in Privodino, the central link between the major oil pipelines and the railway in oil shipments, was also reconstructed. The Arkhangelsk tank farm is now solely directed toward reloading heavy oil from Timan-Pechora deposits; the oil from this area solidifies at +10 °C.

The volumes of gas condensate transported from West Siberian deposits reach 20 000 tons per month; in the next few years the volume should increase to 1.2 to 1.5 million tons per year. In 2004, the Arkhangelsk tank farm uploaded 3.45 million tons of export oil and oil products. By 2010, the volume is planned to increase to 7.2 million tons by adding diesel fuel and gas condensate.

The Severodvinsk terminal (planned): This terminal has been in the negotiation stage since 2003. OAO Tatneft plans to use the terminal for oil exports of around 2.5 million tons per year. The transportation chain will be from railway to a tanker. The projected capacity of the tankers used is 40 000 tons dwt.

The Onega (White Sea and Baltic) terminal: This terminal was planned to start operating in 2003 as an offshore terminal for reloading bulk-oil cargoes arriving from the White Sea–Baltic canal: oil would arrive by a river- and sea-going tanker, would then be stored in the storage tanker (80 000 tons dwt) and later shipped to the consumer by a 68 000-ton tanker. The project has been halted and the operation suspended owing to a technical failure that resulted in severe ecological damage. It is planned to continue with the project after resolving the difficulties.

Kara Sea and the Laptev Sea terminals

The reloading complex of Dudinka–Dikson (planned): This terminal is intended to handle the export of oil from Vankorskii deposits and, in the future, to serve a cluster of new deposits in the Krasnoyarsk region. To achieve this, the construction of the Vankorsky–Dudinka–Dikson 720-mm oil pipeline is planned to run for 730 km. The projected capacity of the new oil pipeline is 30 million tons per year.

At the terminal in the port of Dikson, the oil will be reloaded onto tankers for export through an intermediate terminal in the Barents Sea (probably an RPK in Murmansk). It is intended that the first oil will flow through the pipeline by 2008. Before the Vankorskii–Dudinka link of the pipeline begins operation, oil is planned to be transported via the Taymir port of Dudinka on the Yenisey River. The pipeline construction will entail development and oil production at other deposits and further exploration of the known potential sites of the region.

RPK in the Gulf of Ob: This offshore loading terminal in the area of Cape Kamennyi (Gulf of Ob) has been in operation since 1999. The oil is carried from Sredne-Khylymskii and Sandibinskoye deposits by river and sea tankers of 3000 tons dwt. Thereafter, the oil is transported by ice-strengthened sea tankers (the Astrakhan type) to the RPK *Belokamenka* in Kola Bay. In 2004, the offshore terminal in the Gulf of Ob uploaded 240 000 tons of oil.

The oil loading complex in the port of Tiksi: This was organized in 2001 under OAO NNGK Sakhaneftegas and Murmansk Sea Shipping. Oil is shipped to the complex from the Talakanskii deposit via the terminal in the river port of Vitim for further export. The river part of the transportation is conducted by Lenaneft tankers. The oil is then loaded onto seagoing tankers at the oil terminal in Tiksi. The oil transported along the Lena is meant to be used for consumers in the Republic of Sakha. The volumes for export are very small and in 2002 reached a modest 58 000 tons. In the future, the increasing level of oil production may result in export growth in the eastern direction.

2.4.7.7.3. Oil characterization

Oil shipments from the Timan-Pechora, Volga-Ural, West Siberian, and East Siberian (Eniseysko-Anabarskii) OGPs are currently carried out via the ports of the Barents, White, and Kara seas. Oil arrives at the loading ports directly from deposits (Kolguev Island, Varandey settlement), as well via rail, oil pipelines, and river transport. With rare exception, the arriving oil, although different in chemical and physical properties even within the limits of one deposit (Table 2.71), is mixed during transportation as prescribed by export standard requirements:

The largest proportion of the oil transported through the northern ports originates from the deposits of the Timan-Pechora OGP. This province is generally referred to as the area of the greatest hydrocarbons resources gain for the entire period until 2020. The known recoverable stocks of oil total 0.9 billion tons and are concentrated mainly in the NAO (47%) and on the Pechora Sea shelf (38%). According to the means of transportation, the oil fields are incorporated into thirteen centers of oil production (oil production centers, OPC). An OPC represents a set of operating deposits, which are connected by a major oil pipeline and have a common connection to the main oil pipeline. The oil from Kolguyev and Varandey OPCs is transported by sea. Oil from other OPCs is mixed and transported to the consumers by rail (Oil Refinery OAO Lukoil-Ukhtaneftepererabotka) and by the main pipeline.

A large volume of oil and oil products comes from the Volga-Ural OGP. It is one of the most developed provinces and is characterized by well-developed infrastructure of the oil and gas industry. Oil from Volga-Ural OPC is sent from the storage farms along the main oil pipelines and many oil refineries via river and rail to the ports of the Barents Sea and the White Sea for export through the Arctic seas. Direct communication between the deposits and the Arctic ports within this transportation chain does not exist.

Table 2.71. Characteristics of Russian oil.

	Urals oil type				
	0	1	2	3	4
Specific gravity at 20 °C, kg/m^3	<830	830–850	850–870	870–895	>895
Fractions output, %, not less					
at 200 °C	30	27	21	21	19
at 300 °C	52	47	42	41	35
at 350 °C	62	57	53	50	48
Sulphur content, %	n/a	≤0.6	≤1.8	≤2.5	≤3.5
Paraffin content, %	6	6	6	n/a	n/a
Water content, %,	n/a	0.5	0.5	1	n/a
Chlorides, %	n/a	100	300	900	n/a
Particulates, %	n/a	0.05	0.05	0.05	n/a

2.4.7.8. Unconventional resources

2.4.7.8.1. Arctic gas hydrates

Natural gas hydrate studies have expanded rapidly in recent years in association with natural gas resources investigations aimed at evaluating potential gas reserves in hydrate form and identifying the mechanisms of their formation and distribution. In terms of geological engineering, permafrost and gas-hydrate bearing sediments are rocks of special composition, state, and properties and require a special approach to the development of the Arctic offshore.

The Arctic Ocean is unique among the world's oceans in that submarine permafrost and, in particular, a frozen zone is present within the Arctic water areas only. Unlike other oceans, the Arctic Ocean conditions are favorable for the formation of natural gas hydrates not only in relatively deep depressions but also in the shallow shelf subsurface, particularly in the areas where relict submarine permafrost is developed. Both submarine permafrost and gas hydrate accumulations have formed under the conditions of Arctic area deep freezing in the past. Only the Arctic shelf conditions are suitable for formation of submarine gas hydrate accumulations.

The results of scientific investigations carried out in Russia (VNIIOkeangeologia) from the early 1980s explain important practical problems regarding assessment of the scale and nature of the gas hydrate stability field distribution in the sediments over the Arctic offshore. As gas hydrate accumulations are associated with submarine permafrost, the basis of the assessment is the permafrost/geothermal conditions on shelf areas. Temperature stability conditions and distribution of geothermal gradient with depth in permafrost zones are illustrated in Figure 2.109.

There have been no direct visual observations of natural gas hydrates in the Russian Arctic. Potential gas hydrate occurrence in the Russian Arctic is associated with the *Messoyakhskoe* gas field. This gas field, with Cenomanian terrigenous deposits at a depth of about 850 m, is located in northwest West Siberia (Figure 2.110). It is characterized by natural reservoir conditions, at least in the upper part of the deposit, which correspond to the methane gas hydrate stability field: temperature -8.4 to -12.5 °C with a pressure of 7.35 to 7.65 mPa; gas is 99% methane; low salinity of reservoir water (down to 13) may decrease the equilibrium temperature of gas hydrate formation by not more than 0.5 °C. These characteristics are the basis for considering the *Messoyakhskoe* gas field as a possible gas hydrate field (Figure 2.110).

In addition to its thermobaric conditions, there are some other indirect indicators of gas hydrate occurrence in this deposit: 1) according to geophysical surveys of wells, the probability of gas-bearing reservoirs was indicated by caverns and low differentiation of the spontaneous potential curve (as is usual in a frozen zone); 2) according to micro-acoustic data, there is low permeability; 3) low values of gamma activity on neutron-gamma logs characteristic of water reservoirs were obtained when

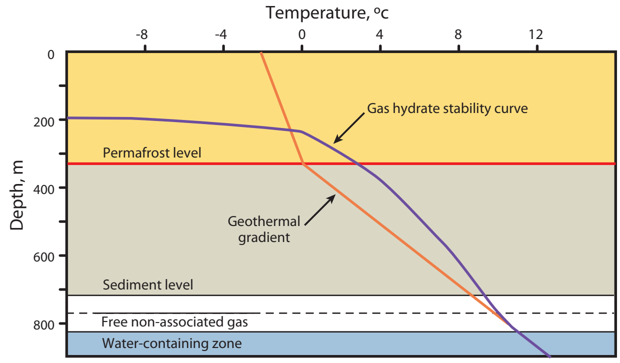
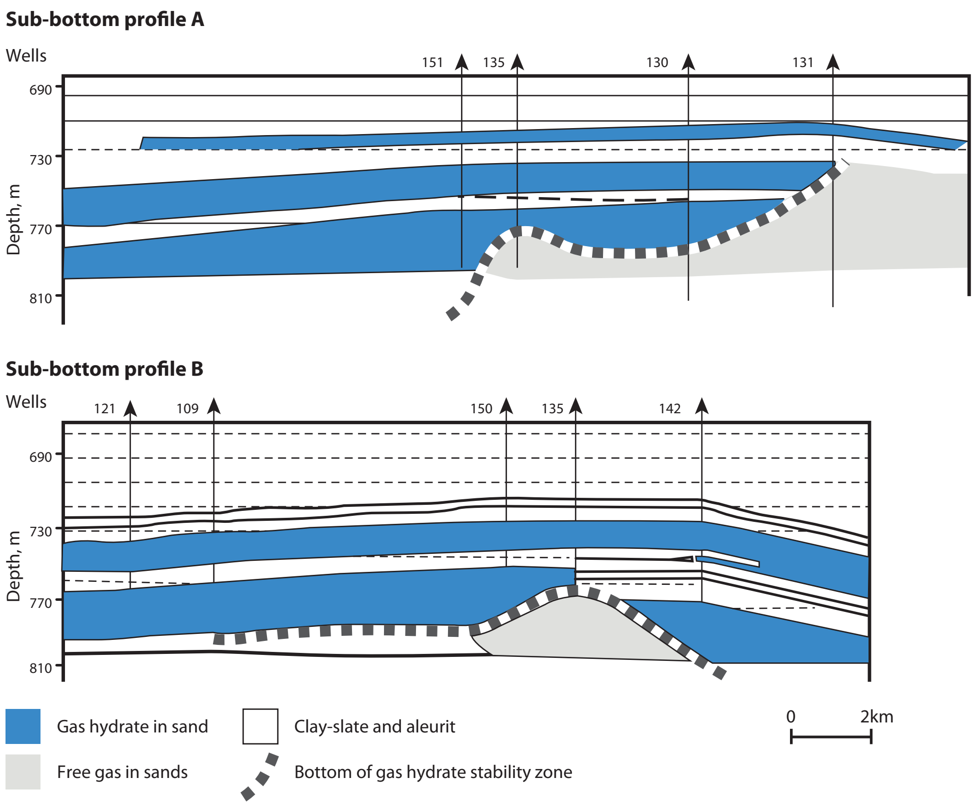


Figure 2.109. Temperature stability conditions and distribution of geothermal gradient with depth in permafrost zones, associated with formation of gas hydrates.



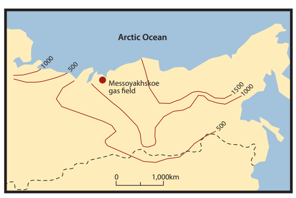


Figure 2.110. Diagrammatic geological sections through *Messoyakhskoe* gas field (A-A' and B-B').

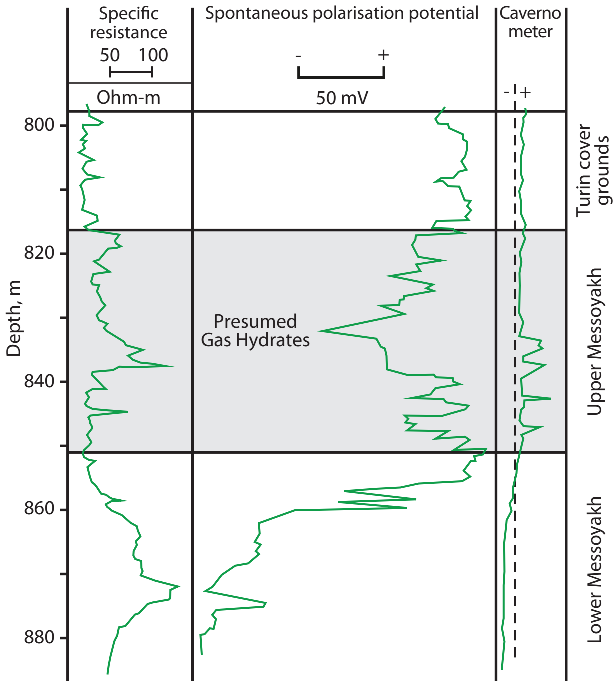


Figure 2.111. Test results for the Messoyakh reservoir in relation to the occurrence of gas hydrates.

testing these horizons; 4) gas was produced, but flow rates were very low; in some cases commercial gas flows have not been obtained at all. These factors could indicate the presence of gas hydrates (Figure 2.111) (Sapir et al., 1973).

During field exploitation, water was sometimes blown along with gas from many wells. Negative temperature anomalies, potentially related to endothermic reaction of gas hydrate dissociation, were observed in some shut-in wells within potential gas hydrate-bearing reservoirs. Field observations thus appear to indicate that gas hydrate is dissociated. Another indication is an increase in the components which easily form hydrates (ethane and carbon dioxide) in the produced gas (Sapir et al., 1973). Results of produced gas geochemical analysis indicated the presence of gases with a high (over 0.6%) and low (about 0.0002%) content of helium. Gas hydrate formation in bottom-hole formation zones is normally associated with gases with a high helium content, while gases with a low helium content are produced during gas hydrate dissociation.

Types of gas hydrate accumulations

Gas hydrates on the subsurface can be formed by sedimentation, diagenesis, or cooling of the existing free gas accumulations (deposits) and gas-containing waters; co-existence of gas hydrates of different origin is also possible (Ginsburg and Soloviev, 1994). As noted, the existence of conditions favorable for gas hydrate formation (pressure and temperature) is associated with the continuous permafrost. In the deep-water parts of the Arctic offshore areas, a significant role in gas hydrate accumulations belongs to gas-containing fluid filtration. Thus, in the Arctic region, on the basis of morphostructural division and geological and tectonic conditions, the following types of gas hydrate accumulations can be distinguished (similar to other mineral deposits): cryogenic accumulations and filtrogenic accumulations.

- Cryogenic accumulations of gas hydrate can be formed during exogenous cooling of the sediments which accompanies the formation of permafrost. On land, these hydrate accumulations are formed only due to transformation of previously existing pools of gas, part of which is transformed into hydrate form. On the Arctic shelves, accumulations of this type are restricted by the area of the relict submarine permafrost zone.
- Filtrogenic accumulations of gas hydrate are formed by upward filtration of water or gas. It is likely that some of the Laptev and East Siberian Seas shelves can be considered as potential gas hydrate-bearing areas for filtrogenic gas hydrate formation.

The most promising area for formation of gas hydrate accumulations is the Arctic shelf area owing to its morphostructural and thermobaric conditions, i.e. negative bottom temperatures and shallow water depths. It is the submarine permafrost zone along with low (negative) bottom temperatures that determines the presence of a thermobaric stability field within which previously formed hydrates are stable at relatively shallow shelf depths. The upper edge of the zone may be near the bottom or at a depth below the bottom.

Submarine permafrost is undoubtedly one of the most important geological and geophysical features of the Arctic shelf seas. It can be considered as a part of the submarine lithosphere within the freezing temperature zone. In terms of its physical state, permafrost may be either frozen (ice-containing) or non-frozen represented by negative temperature mineralized waters (cryopegs). The existence of submarine permafrost is mainly determined by two factors: negative temperature of the bottom water layer (present conditions) and deep freezing at the subaerial stages of the shelf development (paleoenvironment) (Soloviev et al., 1987).

Documentary data on the distribution of frozen rocks (particularly relict rocks) on the Russian Arctic shelf are relatively few; they are clearly not sufficient for relevant mapping. The forecast map of permafrost distribution on the Russian Arctic shelf (Figure 2.112) is based on the general permafrost/geothermal relationships, the features of geological conditions and paleogeographic conditions of the late Cenozoic, as well as cryogenic/geothermal estimates of the possible distribution of the relict frozen zone.

The basis of the estimate is relatively simple: calculation of thickness having been formed in subaerial conditions over a period of time; estimation of thawing rate after the transition of permafrost from subaerial to subaqueous

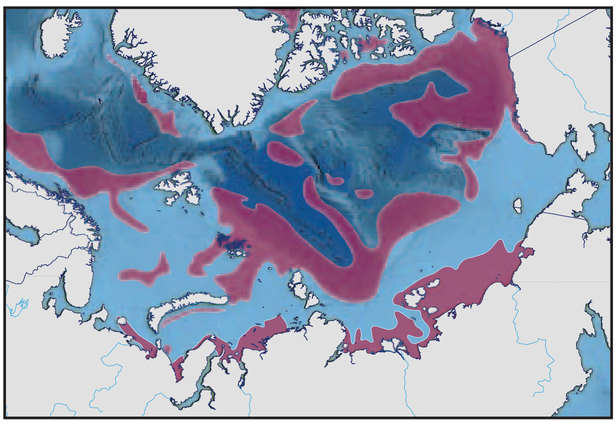


Figure 2.112. Relict permafrost distribution within the Russian Arctic seas (highlighted by purple color).

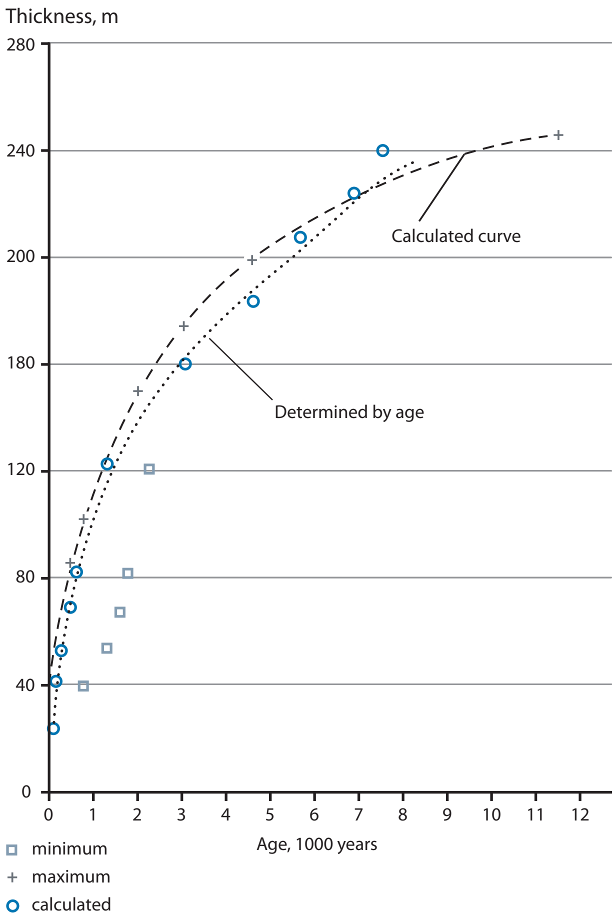


Figure 2.113. Age of permafrost of various thicknesses determined by absolute dating of terraces and theoretical freezing curve determined by an established calculation model.

conditions; and estimation of the possibility of permafrost conservation in sub-bottom conditions and its probable thickness and sub-bottom depth by difference between the two values. The preparation of such an estimate is complicated by both the large number and uncertainty of the parameters needed for the calculation and selection of the best-suited calculation method.

Figure 2.113 shows the ages of specific permafrost thicknesses determined according to absolute terrace dating (^{14}C) on the western Arctic Islands. Permafrost thickness was estimated by the electrical conductivity exploration method (vertical electric sounding). Since the terraces' age reflects the time of their subaerial development, it also features their duration of freezing. The calculated freezing curve is also given, the asymptote of which, with established initial parameters corresponding to actual geological/geothermal conditions, is a value of 280 m, the maximum possible freezing depth regardless of the duration. A good convergence of the curves confirms the relevance of this method for forecasting the relict submarine permafrost distribution.

A low enough level of maturity of the Arctic provides for considering the potential gas hydrate presence in the Arctic Ocean as a whole based on thermobaric conditions criteria. Even such limited data together with available information about the World Ocean make it possible to define some general principles of gas hydrate occurrence in the Arctic offshore:

- An essential difference exists between gas hydrate accumulations on the shelf and in the deeper parts of the Arctic Ocean.
- Gas hydrates on the shelf are mainly associated with relict permafrost and related to normal reservoirs.
- Evidence of gas hydrate presence in the Arctic Ocean should be related to the continental slope and its foot; gas hydrates are formed in relatively fine-grained sediments.
- Gravitational processes on the continental slope (density currents, landslides, and mudflows) may play a significant role in formation of gas hydrate-containing sediments.
- The source of hydrocarbon gases is mainly organic matter imported from the continent and accumulated on the continental slope near river deltas and offshore areas with very narrow shelf widths.
- Identification of gas hydrate fields and evaluation of their stability zone thickness by thermobaric parameters requires reviewing the principles of the formation and distribution of the following characteristics:
  - bottom pressure depending on the water column height; more or less detailed bathymetric data are required to measure it;
  - general paleogeographic characteristics of the regions;
  - bottom temperature determined by water mass dynamics and temperature conditions, sea depth, bottom shape, etc., is a very important characteristic;
  - analysis of geothermal maturity of the water areas; and
  - study of the distribution of submarine permafrost and its parameters (thickness, depth of occurrence, morphology, and temperature conditions).

Consequently, with a rigorous approach, a rather simple problem to estimate the fields of possible hydrate occurrences by thermobaric parameters becomes a complex multivariable problem.

An estimate of gas hydrate presence in the Arctic Ocean is mainly based on an analysis of thermobaric conditions of the bottom and sub-bottom. The following criteria form the basis for identifying potential gas hydrate-bearing offshore areas: on the Arctic shelf, potential gas hydrate-bearing offshore areas (except for deep-water trenches) are surrounded by relict permafrost zones (continuous and sporadic), within which the permafrost bottom (about 0 °C) lies at a depth of more than 260 m regardless of the depth of the sea itself. For the rest of the Arctic Ocean, the geothermal gradient is about 3 °C per 100 m of depth.

The distribution of the bottom and submarine permafrost temperature provides not only a general indication of favorable thermobaric conditions for natural gas hydrate stability, but also allows gas hydrates to be located by area and commonly in section. In general, the procedure to identify the areas and zones of gas hydrate stability reduces to the convergence of temperature (and/or geothermal gradient) and pressure in a specific place (sea bottom or sub-bottom section), according to an equilibrium gas hydrate formation curve in P-T coordinates (Figure 2.114). This means that methane is prevalent in natural

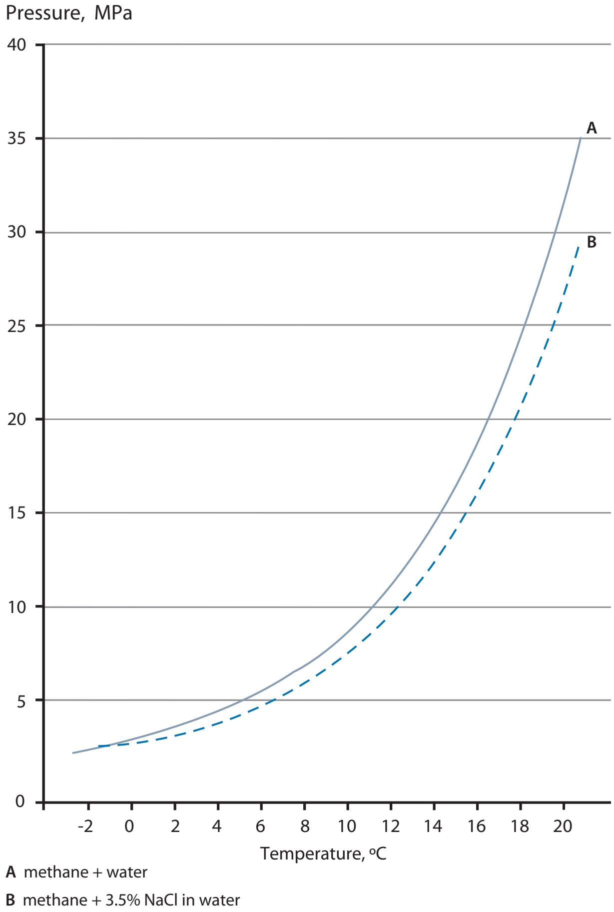


Figure 2.114. Methane hydrate stability as a function of pressure and temperature.

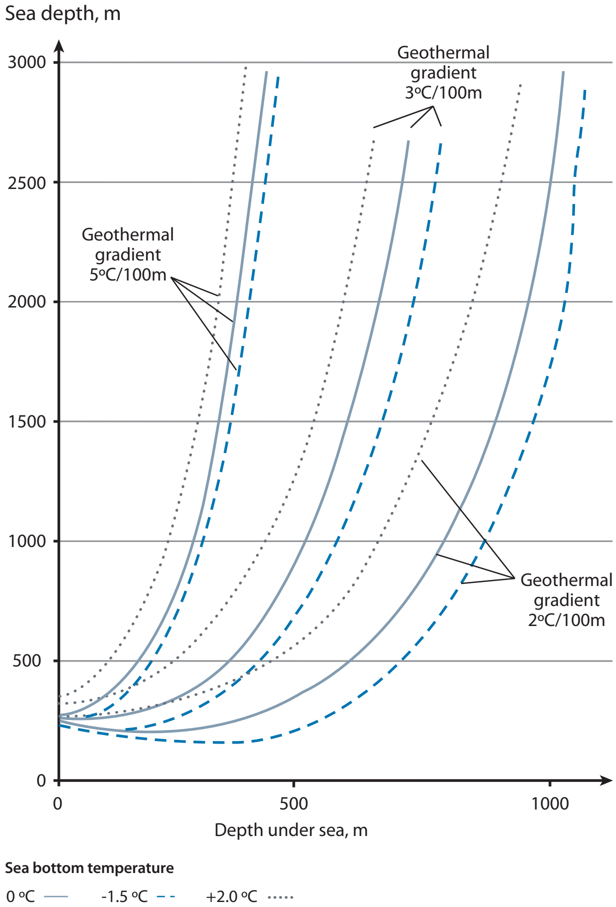


Figure 2.115. Nomogram to determine the stability zone of methane hydrate in relation to sea depth, geothermal gradient, and bottom temperature.

gases which form hydrates, while pore water salinity does not usually exceed 35. The indication of the bottom pressure value and its distribution in the section is based on the assumption of hydrostatic pressure variation.

The gas hydrate stability zone depending on specific thermobaric conditions and composition of the hydrate formation system can be distributed down to a certain sub-bottom depth beginning either from near the bottom or at some nominal depth. A nomogram to determine the zone of gas hydrate stability for a gas/water system (methane and 3.5% NaCl solution) in relation to sea depth, bottom temperature, and geothermal gradient value is given in Figure 2.115.

Variations in the thickness of the thermobaric methane hydrate stability zone under the current conditions of the Arctic Ocean mainly occur from 0 to 1000 m. In a review of the factors affecting gas hydrate presence thermobaric conditions, the possibility of the existence of several types of gas hydrate stability zones was found. In terms of the sea bottom, the thermobaric gas hydrate stability zone may be either near-bottom or not near-bottom, i.e. separated from the bottom by an interval ranging from several meters to over 200 m. The near-bottom stability zone is characteristic for the sea floor, continental slope, and those shelf regions where the relict permafrost is absent but the sea is deep. The hydrate stability zone that is not near-bottom may either be controlled by the fields of different thickness of submarine relict permafrost distribution or related to those shelf water areas where permafrost is absent but the bottom temperature is sufficiently low and the sea is deep but not enough to provide the needed pressure for gas hydrate formation at the very bottom. In general, for shelf seas with the bottom temperature close to -1.5 °C, the minimum sea depth at which a thermobaric hydrate stability zone may exist that is not near-bottom (out of the offshore areas with the relict permafrost zone) is from 180 m (average geothermal gradient of 2 °C per 100 m) to 220 m (average geothermal gradient of 3 °C per 100 m).

It is also anticipated that the conditions for gas hydrate accumulation on other parts of the continental slope and in some trenches and closed depressions of the shelf were more favorable due to the late Pleistocene sea level fall. Favorable conditions for the formation of gas hydrate accumulations are associated with the polar basin regression, the source area expansion, and the possibility of transportation of organic matter to the edge of the modern continental shelf by paleorivers. Enrichment of sediments by diagenetic gases due to accumulation of organic matter is an important condition for gas hydrate formation, increasing its probability.

The shelf areas, where higher methane content is observed in sub-bottom sediments along with the thermobaric conditions of gas hydrate stability, are of some interest. Such areas are usually associated with the upward migration of gas through faults and are observed on the Barents Sea shelf.

A lack of data on the level of rock saturation with hydrates in the gas hydrate stability zone excludes the possibility of traditional accounting for gas reserves in this zone. Only the volume of the gas hydrate stability zones

Table 2.72. Size of various types of gas hydrate stability zones in the Russian Arctic sea areas.

	Area, 1000 km^2	Layer thickness, m	Volume, billion m^3
Near-bottom	977	0–600	1.95 × 105
Not near-bottom, controlled by submarine relict permafrost of more than 100 m thickness	250	0–400	2.5 × 104
Not near-bottom, controlled by submarine relict permafrost of less than 100 m thickness	606	0–400	2.4 × 104
Not near-bottom, out of the offshore relict permafrost zone	24	0–200	2.4 × 103

on the Russian Arctic shelf can be calculated (Table 2.72), which essentially coincides with the potential hydrate presence area on the offshore shelf.

The only possibility to estimate the accuracy of mapped thickness is to compare its value with the results of drilling and seismic surveys.

The practical importance of the Arctic gas hydrate study is based on the fact that specific quantities of gas in hydrates are distributed according to the same law as for natural gas reserves densities and that cryogenic hydrates are not additional gas reserves in comparison with the expected reserves in conventional deposits. However, the proportion of gas converted into hydrates reduces the recoverable reserves which will inevitably decrease the productivity of the fields to be developed. For determining the importance of Arctic gas hydrates as an energy resource, it is necessary to obtain data on gas concentration and potential reserves in hydrate accumulations. Without solving these problems, it is impossible to develop the gas hydrate deposits. Further studies of Arctic gas hydrates may need to cover the conduct of special surveys including geophysical, geological, and geothermal investigation methods to substantiate theoretical insights and to develop methods and equipment for extracting gas hydrate reserves.

2.5. Past practices, BAT, and new technology

The assessment of oil- and gas-related effects on the Arctic environment is in part an examination of the evolution of engineering methods and associated technology used in the region by oil and gas operators. Initial efforts in the Arctic employed logistical and drilling methods that had been reasonably effective in other settings but quickly proved unsuitable in the Arctic, thus beginning a continuing process of engineering adaptation to Arctic conditions. The goal of this engineering optimization has been to limit environmental impacts of oil and gas operations, including physical disturbances and pathways to the environment for toxic substances, while improving efficiency and cost effectiveness. The history of the process of industrial adaptation to onshore Arctic conditions is a necessary element in evaluating cumulative impacts associated with activity levels. Initially modest levels of activity were associated with large impacts; however, due to advances in technology, an improved understanding of the Arctic environment, and greatly increased regulation and public oversight, operators and regulators have now been able to greatly reduce associated environmental impacts. The modern worldwide oil and gas industry is interconnected across national boundaries and effective methods and equipment designs frequently spread quickly from one place to another.

A broad range of terrestrial surface conditions exist within the Arctic. The onshore areas are vegetated primarily by boreal forests and tundra. The tundra areas are generally underlain by continuous permafrost. Areas of continuous permafrost are underlain 90–100% by material that has been below freezing for at least two years. Frequently, this material is water-saturated and contains ice; the ice can occur as frozen interstitial water or as distinct and sometimes massive lenses. Near-surface soil, overlain by undisturbed tundra, typically comprises the active layer of the permafrost. The active layer is an interval that seasonally thaws during the summer months and insulates the underlying permafrost, allowing it to remain frozen on a multi-year basis. A breach in the active layer will cause melting of the underlying water-saturated permafrost. Once initiated, this melting can be widespread, causing a water-filled depression to form; this process is called themokarsting and generally causes areas underlain by continuous permafrost to be poorly drained. In areas with very low surface elevation gradients, for example, the Coastal Plain of the Beaufort Sea on the Alaskan North Slope, a large number of relatively shallow lakes, uniformly oriented by the prevailing wind direction, can form in areas of continuous permafrost. Continuous permafrost is one of the most difficult Arctic working environments and comprises almost 100% of the Alaskan onshore Arctic area.

Early exploration efforts in the Arctic in the 1940s to 1960s used primitive technology and methods and were characterized by an initial lack of understanding of the environmental consequences of these activities. Offshore exploration began in the 1970s and early 1980s in all Arctic countries with petroleum provinces. As new techniques were developed, exploration activities both onshore and offshore picked up pace in the 1980s and in some areas into the early 1990s.

Modern technology and improved practices have raised expectations for dramatic improvements in Arctic land-based and offshore discharges and emissions. These expectations are principally based on all Arctic countries having now abandoned discharges of oil-based drilling mud. Most countries now use water-based drilling fluids and synthetic-based muds have replaced oil-based muds in most cases where it is necessary to use such fluids. The practice of re-injection of produced water has been established. The use of 'environmentally friendly' chemicals is being encouraged. There is continuous improvement in waste handling procedures. Improvements in technology, more stringent standards, and heightened awareness of the benefit of reducing emissions have resulted in significant environmental benefits.

Potential impacts on the environment and on biological resources can be mitigated or reduced by Arctic-specific technology. Use of low-impact seismic techniques has demonstrated this success in boreal forest, tundra, and wetland areas. A reduction in environmental impacts results from the increased use of vibrator vehicles, development and use of light-weight vehicles to reduce ground pressures, and reduced breadth and necessity of cut lines. Remote sensing and GPS technology have allowed for greater flexibility in the operational aspects of the program. Precise positioning has allowed for seismic surveys to be shot on ice roads or along frozen water bodies, thereby negating the need to cross the landscape. Offshore, new airgun technology and improved operating procedures have reduced impacts on the marine environment. Significant research has been conducted and will continue to be conducted in this area to continue to lower impacts. New survey methods include the use of 3-D seismic techniques that are more focused and less regional in extent. Because 3-D seismic surveying is able to image the sub-surface environment more accurately, its use has reduced the number of wells that need to be drilled to define a possible deposit and has resulted in a lower overall impact on the environment.

Well drilling technology and well design have undergone significant changes in the past 20 years. New exploration wells are drilled in winter, and technology using ice roads or roadless access, and drill pads made of ice leave virtually no footprint. Changes to rig design and well-drilling methods have reduced the size of development drill pads by 60 to 70% relative to the size of earlier designs.

Deep well injection of waste drill cuttings and muds, other drilling wastes, and produced water from oil fields plays an important role in reducing surface impacts. The disposal of millions of cubic meters of solid waste from the onshore Alaskan oil fields by this method has been undertaken in response to environmental concerns and technological advances.

This section examines some of the practices that were used in the early phases of oil and gas exploration and production in the Arctic (with examples mainly from Alaska) and outlines developments that have led to current Best Available Technology. The section concludes with examples of new technologies just coming into use or still under development.

2.5.1. Past practices

2.5.1.1. Tundra travel

The first attempts to mobilize oil and gas exploration drilling and geophysical equipment in the Alaskan Arctic were by the U.S. Navy in 1944 during the Second World War. With little experience in continuous permafrost areas, the Navy tried using cat trains or numbers of sleds or wagons pulled by a single bulldozer during the summer thaw. This method makes use of the path of the towed vehicles being lubricated by mud, but causes serious damage to the surface.

With operational experience, the Navy found that land travel and geophysical data acquisition in the Arctic were most efficiently conducted from February to July. The pervasive darkness and cold associated with the October to January period was operationally difficult and economically challenging for these kinds of activities and during August to September, the tundra was thawed too deeply to support motorized vehicles. Engineers studying the tundra at a dedicated cold regions research facility were able to delineate a specific set of conditions under which surface activities, including heavy vehicle motorized transport, could be conducted most efficiently and with no appreciable damage to the tundra throughout the North Slope regardless of the local topography or hydrographic conditions. The standard consisted of 30.5 cm (12 inches) of frozen ground and 15.2 cm (6 inches) of snow. These conditions were found to adequately protect the tundra and to provide land access through a substantial part of the year. In practice, the depth of frost and snow was rarely measured prior to 1985. From 1970 to 1985, there was increasing petroleum-related activity on the North Slope, particularly on State lands in the central part of the region adjacent to Prudhoe Bay. The Alaska Department of Natural Resources (ADNR) land managers controlled surface access and estimated, through a number of ad hoc methods, when the tundra was open for surface access. Summer inspections of areas traversed were used to collect fines related to surface damage; observation of actual effects related to tundra travel continues to be one of the most effective tools available to Arctic land managers.

From 1985 to 1995, the ADNR began to augment measurements of snowfall with frost measurements in order to determine tundra opening dates. Frost was measured by driving a steel spike into the ground. These measurements were refined and standardized until in 1995 a slide hammer was employed and the amount of force required to penetrate the frost layer could be reasonably well judged. The techniques and equipment used to make these measurements continue to be refined.

With more quantitative measurements of frost and snow conditions, the use of conservative access criteria, and generally warmer winters, the exploration season on the North Slope has became much shorter (Figure 2.116). Thus, the use of access criteria derived from early work at the cold regions facility was reassessed. The controlled use of typical heavy machinery in a number of tundra sub-environments through a range of surface conditions, combined with long-term monitoring of the test plots, has yielded new information on the tundra's ability to support mechanized vehicles. The results of the study indicate to land managers at the ADNR that access to the North Slope's surface can be significantly lengthened (Bradwell et al., 2004).

2.5.1.2. Seismic operations and noise-generating activities

2.5.1.2.1. Onshore activities

Although few or no data exist for noise generated from the earliest activities in the Arctic, the types and levels of activities and associated noise sources that took place previously are illustrated below using examples from the northwestern part of Arctic Alaska (see also section 2.7).

The first 'modern' petroleum exploration program started in NPR-4, later to become known as the National Petroleum Reserve-Alaska (NPR-A). This program involved drilling and geological and geophysical surveys. Generally, noise sources were from vessel traffic in offloading equipment and supplies, aircraft noise from cargo planes landing and taking off and from smaller planes supporting remote operations, the construction of camps, the running of generators and heaters, vehicle traffic including snow ploughs and bulldozers, tractor trains for moving personnel and supplies across the land, well-drilling operations, shot-hole drilling, and seismic operations that predominantly used dynamite until the early 1980s.

Seismic operations began in 1945 and were performed for the Navy by United Geophysical Co. (Reed, 1958) until 1952. During the first year of activities, seismic crews began operations from the Barrow base camp and made their way across the vast territory of Pet-4 (see section 2.4.1.3.1) in tractors pulling sleds – called 'Cat Trains'. In later years they operated out of other newly constructed base camps such as Umiat. These trains included Caterpillar tractors, housing, seismic, and kitchen units mounted on sleds, drill rigs for drilling shot holes, and smaller tracked vehicles. A Cessna on floats provided air support from Barrow.

These operations required the transport of drilling rigs for boring the seismic shot holes to depths of around 16 to 19 m (50 to 60 ft) and around 12.7 cm (5 in) in diameter. Dynamite was used as the sound source. During these early years, most operations took place in summer (Figure 2.117).

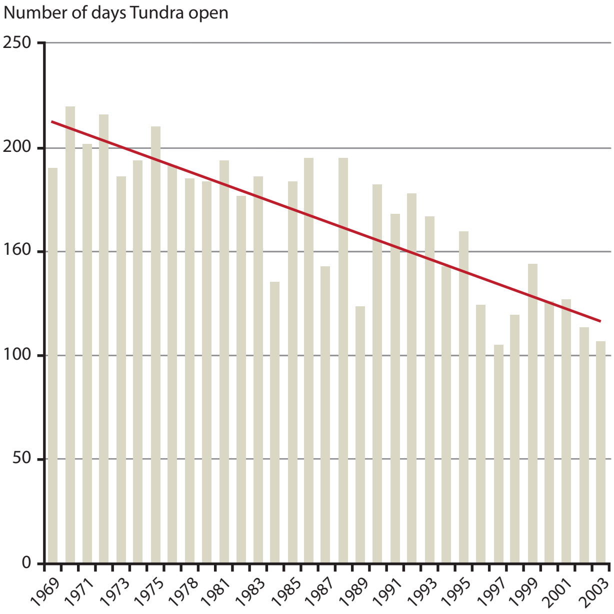


Figure 2.116. Length of the winter tundra travel season, as determined by the Alaska Department of Natural Resources Division of Lands, Northern Regional Office (Bradwell et al, 2004).

Figure 2.117. Use of Weasel in geological field work. *Upper:* Weasel on tundra in the Nuka River area. *Lower:* Weasel at a Geologic Survey camp on a gravel bar in the Caribou Creek area (Reed 1958).

Reed (1958) described a typical operation in 1947 as follows:

> *Party 43 was assigned the task and departed Barrow by tractor train on 24 April. The camp consisted of 10 wanigans in addition to water and instrument wanigans, 4 tractors, and 8 weasels [Figure 2.117]. The 2 Failing drills left from the year before were used by the party. Shotholes had an average depth of 75 feet [23 m]. Two drilling crews and two recording crews were used on different shifts. One lake deep enough to contain water below the ice was used for water for drilling before the thaw. After that, surface water, available almost everywhere, was used. Geophones were placed in contact with the frozen ground which in the summer required digging holes to place them.*

In total, 5280 line-km of seismic data were collected between 1945 and 1953.

The summer seismic program initiated shortly after the Prudhoe Bay discovery was, by all accounts, very damaging to the tundra and summer seismic activity was not attempted again. Since then, the seismic surveys on the Arctic North Slope have been conducted during the winter months to avoid damage to the fragile Arctic tundra. Seismic surveys are still conducted in the remote Arctic using self-contained camps made up of trailers, generally on skids, pulled along the frozen, snow-covered ground by tracked vehicles (BLM, 2000).

The second phase of exploration in the NPR-A began in 1972. Reconnaissance surveys covered all of the NPR-A with a regional seismic grid. The energy sources used were dynamite, 'mud gun', and Vibroseis; some data acquired in the Barrow area were higher resolution data (Schindler, 1983). Table 2.73 provides an overview of seismic field activity in the National Petroleum Reserve for the period 1944 to 1981.

When seismic exploration was conducted with explosives (see Box 2.13), there was potential for harming fish that were exposed to large, rapid changes in ambient pressure. The advent of vibrating equipment has reduced this concern, because the energy it generates is much less than the energy generated by explosives. The Alaska Department of Fish and Game blasting standards require that the instantaneous change in pressure resulting from any explosion must remain below 0.02 megapascals (Mpa; 2.7 psi). Results of a recent field test involving vibrators on ice over water indicate that peak pressure changes below a vibrator can be as low as 0.01 Mpa (1.57 psi). In addition, the energy velocity appears to be many times slower than velocities known to harm fish. When converted to energy, the Vibroseis machines transfer many times less energy to the water than airgun arrays. It is unlikely that impacts on fish populations have accumulated from Vibroseis seismic surveys. Mechanical devices (vibrators) are the preferred seismic source onshore.

During the winters of 1983/1984 and 1984/1985, one company representing a consortium to minimize potential effects collected a total of 2092 km of seismic data in the Arctic National Wildlife Refuge (see Figure 2.37). These activities were strictly overseen by the Fish and Wildlife Service to avoid any sensitive areas or habitats (U.S. Department of the Interior, 1987).

Although the winter operating period can be as long as five and a half months (early December to mid-May), typical seismic operations for an individual survey last about 100 days (BLM, 2000).

'Cat trains' for both 2-D and 3-D seismic operations consist of survey vehicles and support camp modular units. A train would consist of the approximately ten (2-D) to fifteen (3-D) vehicles that would run the seismic testing and one or more fuel trucks and strings of trailers comprising the camp modular units pulled by bulldozers. A train typically would include two or three strings of trailers. Each would be pulled by a single bulldozer, and each string would have four to eight trailers. These bulldozers and modular units generally exert greater ground pressure than the vehicles that run the seismic lines (BLM, 2000).

Once in the area of operation, camps are typically moved every few days to once a week. The fuel truck or trucks will make runs back to fuel-supply depots throughout the course of the seismic operation. These fuel

Table 2.73. Seismic field activity in the National Petroleum Reserve 1944-1981 (Schindler, 1983).

Year	Line km
1944-1953	5 280
1972	51
1973	99
1974	1 699
1975	3 904
1976	2 304
1977	4 222
1978	3 066
1979	3 042
1980	1 753
1981	946
Total	26 366

Box 2.13. Explosives as a sound source

The State of Alaska does not have a statute or regulation that specifically prohibits the use of chemical explosives as a sound source when gathering seismic data. However, the State permitting authority is very careful not to permit the use of explosives near any water body that might contain fish. This can be very restrictive in an area like the coastal plain of the North Slope where there are many lakes and streams. It is much easier to permit, and considered more environmentally friendly, to use vibrators (see Box 2.9) in these areas. In both State and Federal offshore waters it would be very unlikely that chemical explosives would be permitted for seismic work unless it could be proven conclusively that the method used would not cause harm to fish and other living resources.

In other parts of Alaska, south of the Brooks Range, the use of chemical explosives is permitted quite frequently. The explosives are attached to lathe above ground or more commonly in shallow shot holes. There is still the emphasis on avoiding water bodies. However, the heavier vegetative cover and often rougher terrain necessitates the consideration and frequent approval of the use of chemical explosives. The advantage of using explosives over the very heavy vibrator vehicles is that the survey can be supported by helicopters and light vehicles that create little or no disturbance to terrain or vegetation. In addition, chemical explosives may prove to be a superior sound source under certain circumstances.

The shot holes where the explosives are placed are drilled and prepared and the explosives are of a size and type to expend all of the energy below the surface. Typically the shot holes are 5 m to 8 m deep. There should be no surface disturbance except the small amount of material remaining from drilling the shallow hole for the charge. Occasionally a charge fails. The charges have a water soluble casing or patch so they will degrade quickly into an inert material if left in the ground.

Since 1991, there have been several attempts at using chemical explosives as a sound source for seismic work north of the Brooks Range. There was a test using explosives on lathe over the sea ice for seismic work. It was not considered completely successful. Another permit application on the Colville River delta was withdrawn because of restrictions imposed owing to the proximity to many lakes and streams. More recently, work in the foothills of the Brooks Range has rekindled interest in the use of explosives. This interest is driven by the realization that the rougher terrain would present a significant obstacle to the heavy source vehicles used in the seismic industry and could result in unsightly disturbance of the vegetation and soil cover that may be slow to recover. A permit was issued in 2004 to shoot a test survey consisting of 88 km of seismic data using explosives. This work was never performed, but plans still exist to shoot 16 km of seismic data using explosives.

runs may occur daily or every few days, depending on a variety of factors, including the size of the operation and weather conditions (BLM, 2000).

A typical 2-D operation will cover about 402 line-km (250 line-miles). The survey lines are in the form of a grid, with a typical line spacing of 8 x 16 km (5 x 10 mi). Each line of 2-D seismic is run by about ten vehicles. The vehicles run parallel to each other through an area about 61 m (200 ft) wide. The exterior dimensions of each survey area are variable, but the survey example described above could cover a total of about 1554 km^2 (600 mi^2) (BLM, 2000).

A typical 3-D seismic operation will collect 389 km^2 (150 mi^2) of data in a single winter season and typically would involve about fifteen vehicles. Each line-kilometer consists of a pair of linear areas, each about 33 m (100 ft) wide, through which the vehicles drive. The grid patterns for 3-D seismic surveys are considerably closer-spaced, with a typical line spacing of 165 x 610 m (500 x 2000 ft). Although the exterior dimensions of 3-D survey grids are variable, a typical 16 x 24 km (10 x 15 mi) survey area could contain about 3018 line-km (1875 line-miles) of data. The techniques of setting up geophone arrays and shot points is very different (and far more efficient) than those for 2-D survey methods.

2.5.1.2.2. Offshore activities

The U.S. Government issued industry 28 marine geophysical permits in 1969 and 36 permits in 1970 for seismic surveys on the Alaska Outer Continental Shelf (OCS). Between 1971 and 1975, the number of permits for geophysical data acquisition rose to 193. In subsequent years, permit applications increased to a maximum in the early 1980s. The corresponding number of line-kilometers of data shot (see Figure 2.44) is a better indicator of activity level and has more bearing on the noise levels released into the marine environment (Table 2.74). In the years since 1969, over 730 000 line-km of 2-D and 770 km^2 of 3-D survey data have been collected in offshore Alaska Arctic marine areas. During this period, the U.S. Geological Survey (USGS) and academic institutions collected approximately 20 613 line-km of data.

Between 1970 and 1975, twelve permits were issued for Chukchi Sea 2-D marine seismic surveys, while no permits were issued between 1976 and 1982. Seismic-survey activity increased between 1982 and 1991, when 30 permits were issued. To date, no 3-D seismic surveys have been conducted in the Chukchi Sea. The most permits issued in any one year in the Chukchi Sea was seven (six marine and one over ice) in 1986. Around 130 000 line-km of 2-D seismic surveys have been collected to date in the U.S. Chukchi Sea, with most between 1985 and 1989.

More seismic activity has occurred in the Beaufort Sea OCS than in the Chukchi Sea. The 2-D marine seismic surveys in the Beaufort Sea began with two permits issued in 1968 and four in 1969. Both over-ice in very shallow water (29 permits) and marine (43 permits) 2-D seismic surveys were conducted in the 1970s. With one exception, the 80 marine and 43 over-ice surveys permitted in the Beaufort Sea in the 1980s were 2-D surveys. In the 1990s, both 2-D (two over-ice and 21 marine) and 3-D (11 over-ice and seven marine ocean-bottom-cable [OBC]) seismic surveys were conducted. The first 3-D over-ice survey occurred in the Beaufort Sea in 1983 and the first marine (OBC) 3-D seismic survey occurred in 1996. The most active years for seismic data acquisition in the Beaufort Sea were 1982 when 23 permits were issued (11 marine and

12 over-ice 2-D surveys) and 1983 when 24 permits were issued (one 3-D over-ice survey; 14 2-D over-ice surveys; and nine 2-D marine surveys). Nearly 150 000 line-km of 2-D and 3-D seismic surveys have been collected to date in the U.S. Beaufort Sea.

Seismic surveys for exploration purposes in State of Alaska waters (mean high tide line to 5 km offshore) are authorized under Miscellaneous Land Use Permits; however, seismic surveys conducted for other purposes, such as shallow hazard assessments, do not require permits unless they are not conducted from the ice and/or involve contact with the seafloor (MMS, 2006a). Since 1969, the State has issued 42 permits for seismic-survey activities in the Beaufort Sea. The number and types of airgun-type seismic permits issued are as follows:

- 1969: 1 survey (2-D);
- 1970s: 23 surveys (20 2-D marine streamer and 3 2-D OBC);
- 1980s: 13 surveys (2-D marine streamer);
- 1990s: 3 surveys (2 3-D OBC and 1 2-D marine streamer);
- 2000-2002: 3 surveys (3-D OBC); and
- 2002 to date: none.

To date, the State has not issued any seismic survey permits for the Chukchi Sea (Matt Rader, ADNR, pers. comm., 2007).

The sound sources used in marine seismic surveys have changed over the decades. In the mid-1960s to the early 1970s, large airguns and dynamite were frequently used. Later, other sources were tried and refined including water guns, sparkers, and various styles of sleeve exploders.

In most marine areas of Alaska in the mid-1970s, seismic reflection surveys generally employed airguns as the source of choice. These were typically configured in arrays towed at a depth of 10 to 12 m with total capacities of about 16387 to 26219 cm^3 (U.S. Geological Survey, 1975a,b). They also typically towed a receiving cable of up to 2400 m in length and at a depth of up to 10 m (U.S. Geological Survey, 1975c).

In the late 1970s surveys in the shallow water of the Beaufort Sea, airgun arrays with capacities of about 2458 cm^3 of air were towed about 2 m below the water surface and operated at pressures generally less than 344 bar (5000 psi). The guns were fired about every 100 m. The geophone cables used in shallow water were typically bottom drag cables with lengths of about 1.5 km.

A typical late 1970s over-ice survey in the Beaufort Sea used 9504 cm^3 airgun arrays deployed through holes in the ice to water depths of about 6 m. The compressor, airguns, and small drill rig were transported on a wheeled trailer. Typically, the guns were fired on a 100-m interval (U.S. Geological Survey, 1975c).

2.5.1.3. Exploration practices

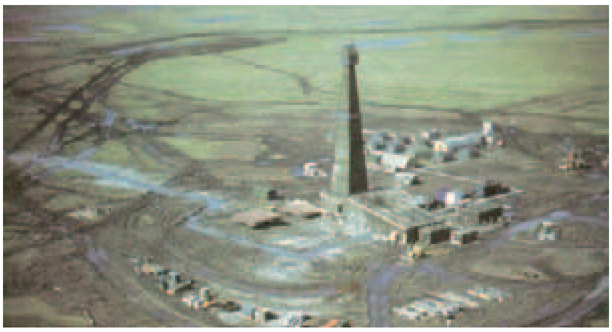
2.5.1.3.1. Early exploration in Alaska. Phase I: 1945–1953

When exploration for oil first started on Alaska's Arctic North Slope, it was in the area that is known today as the NPR-A. Little was known about working in Arctic conditions and conventional oil and gas exploration technology employed in the continental United States was used. To access proposed drill sites, early operators bladed the tundra in front of the equipment sleds as they moved forward, finding that temporarily the sleds moved extremely well on the slippery surface created by the meltwater on frozen ground. Early drill sites were also bladed-off areas that tended to be up to 0.16 to 0.20 km^2 (40 or 50 acres) per well. The rig and ancillary facilities were then set in place. It did not take long before it was realized that these facilities would have to be placed on elevated platforms or other means to keep the frozen ground from melting. Drilling rigs settled differentially on these first-generation drill pads, causing the drillstring to be out of vertical alignment with the well bore. In the very early stages, rigs were set on top of large timbers which sometimes involved scraping away the vegetation to obtain an even surface.

An example of an advanced early exploration well was the U.S. Navy Fish Creek No. 1 well, drilled in summer 1949. The drill rig for this well was actually mounted on a piling-supported cement platform. When the site was abandoned, the platform was left in place and is still visible almost sixty years later (Figure 2.118). The platform has collapsed but the wellhead is still intact.

Table 2.74. 2-D and 3-D seismic survey data collected in Alaska Arctic offshore basins since 1969.

Survey type	Line-km or km^2
2-D line-km	
North Aleutian	116 181
St. George Basin	116 200
Aleutian Basin	3 458
Bowers Basin	99
St. Matthew-Hall	35 019
Norton Basin	61 229
Navarin Basin	107 044
Hope Basin	16 742
Chukchi Sea	128 014
Beaufort Sea	147 761
Total	731 747
3-D km^2	
Beaufort Sea	770



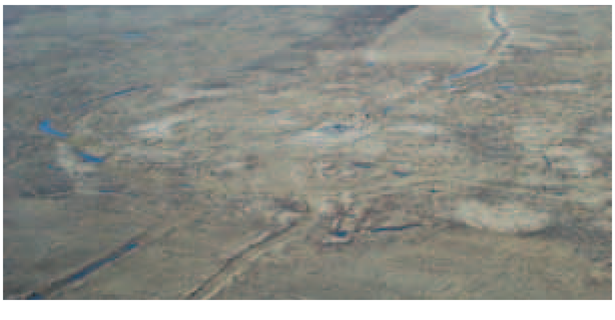


Figure 2.118. Above: Fish Creek No. I well site in 1949. Bottom: Tundra scarred by tracked vehicles and the concrete cellar for Fish Creek No. 1 well today.

The heavily disturbed surface at the site has re-vegetated fairly well, but depressions from some of the scraped-off tundra still exist. Drilling fluids used in these early wells were composed primarily of local clays where obtainable. Typical additives used consisted of Aquagel, tetra-sodium pyrophosphate (for pH control), calcium chloride, Baroid, and water. These fluids were typically discarded on the tundra or dumped into local streams.

Umiat is the first instance where exploration drilling led to potential production. Umiat was developed as a drilling and production camp. It would be the staging area for a number of wells to be drilled in the immediate area. It contained storage, housing, and a support airstrip. The wells that Umiat supported were all spudded on individual sites; no indications of gravel pads are found at Umiat. The drill sites contained not only the drilling platform, but also the mud/reserve pit for drilling fluid and waste. The main facility at Umiat covered nearly 0.16 km^2 (40 acres) and each well site was approximately 0.02 km^2 (5 acres). Umiat was the first reported site where the tracer Aloclor was used. Unfortunately, this introduced PCBs (polychlorinated biphenyls) into the formation and left contamination onsite which has only recently been remediated. Umiat was marginal in recoverable resources, but was put into limited production and even supported a small onsite refinery. Had there been more oil discovered, the total disturbed area would have been quite large, as one vertical well was drilled per site and each site would have had gravel road access to the main facility at Umiat. During this period, these sites were not reclaimed. The mud/reserve pits were left to the elements. The Umiat site was eventually transferred to the State of Alaska and although it does not have producing wells, it is still used as a support base for other oil and gas operations in the area. Some of these abandoned second- and third-generation sites have remained valuable because of their well-constructed gravel airstrips. Well spacing was for the most part non-existent. Even at Umiat, no record of planned well spacing can be found.

2.5.1.3.2. Exploration in Alaska. Phase II: Prudhoe Bay discovery 1974–1976

Second-generation technology on the slope is that of early Prudhoe Bay. Wells were in most cases drilled one to a pad and each had its own drill cuttings storage area, making the gravel pads relatively large. Low-departure deviated wells were the norm, so many well pads were needed to penetrate the reservoirs. Average drill pad spacing is of the order of 5 km at Prudhoe Bay. These pads were all connected by gravel roads and the oil and gas were sent to a central facility for processing, then down the Trans-Alaska Pipeline (TAPS) or compressed and re-injected. Prudhoe Bay is supported by two airstrips, the Dalton Highway to Fairbanks, and in the summer barge traffic. The latter part of this drilling period introduced the now-mandated central disposal of all drill cuttings in which the cuttings are hauled to a central grinding facility and re-injected below producing formations. Drilling fluids are also self-contained on the drill sites and, when the well is completed, the fluids are hauled to a central treatment and disposal area.

Using some of these numbers for early Phase I and Phase II activities in the NPR-A, some rudimentary estimates can be made of the amount of area affected. Seismic operations were carried out mainly in the summer during the first ten years of so of exploration activities. These surveys used tracked vehicles and sleds. Assuming that the width of the seismic trails was about 15 m, which is probably wider than the actual operations, then that can be multiplied by the number of kilometers of seismic lines collected – 5280 line-km. This results in 79.2 km^2 of land potentially affected by summer seismic survey activities. Some of the trails over tundra resulted in the thawing of permafrost and scarring of the tundra. But these areas are very few. There were 81 exploration wells drilled in the NPR-A during the early phases. These wells had an effect on land area estimated in the range of 0.16 to 0.20 km^2. The data for Umiat are more specific, showing that the facility affected 0.16 km^2 and the 11 wells affected an area of 0.02 km^2 each. This results in a potential affected area of 14.38 km^2 for the 81 wells drilled between 1944 and 1981. Measurements of the affected areas during remediation efforts in the late 1980s and early 1990s show a total disturbance of 2.19 km^2.

Figure 2.119. Old exploration drill site with gravel pad and road.

2.5.1.4. Drilling practices

Early exploration activities in the Arctic areas of the North Slope of Alaska were conducted using gravel roads, pads, and airstrips. The required footprint was dictated by the design of the drilling rigs utilized in the 1960s and 1970s. A relatively large area was required to support the drilling rig, airstrip, and associated support equipment. The pads were designed with surface storage areas to contain drilling muds/cuttings and flare areas. Some of the early exploration roads and pads can still be seen today (Figure 2.119); however, many of the early exploration pads have been re-vegetated, reclaimed as wildlife habitat, or removed.

Technological advancements have led to significant reductions in the surface area required to support an exploration drilling project. Drilling rigs have gone through many design modifications which have ultimately led to the design and construction of smaller gravel pads. Drilling muds and cuttings are no longer stored in surface storage areas. These drilling wastes are injected deep into the earth, into formations that provide safe and environmentally sound containment (Figure 2.120) (AOGCC, 2004).

2.5.1.5. Remediation activities

2.5.1.5.1. United States

Remediation of abandoned well sites is exemplified here by the USN/USGS/Husky well site remediation activities. The U.S. Navy 36-well (and 45 shallow core tests) exploration program in the Petroleum Reserve in Alaska (Pet 4/NPR-A) ended in 1953. The Navy resumed exploration activities in 1975. This second phase of activities included a seismic program and drilling technologies developed with exploration around Prudhoe Bay. The Navy with Husky as the operator drilled seven wells in northeast NPR-A. The entire program was transferred to the USGS in 1977 (Public Law 94-258; NPR-A Production Act), with Husky remaining as operator. A total of 28 exploration wells comprised this program.

The Husky program used comparatively modern rotary table rigs similar to those used at Prudhoe Bay. Almost all exploration and support activities were carried out during the winter. CAT and Rolligon trains hauled materials to the drilling sites on ice roads and across frozen streams and lakes.

Wells drilled before 1978 used thick pads, approximately 1.5 m (5 ft) thick, composed of sand, silt, and gravel. After 1978, construction was mostly thin pads (about 0.6 m [2 ft] thick), with the heavier rig components supported on wooden pilings (between 50 and 210) which were augured into the tundra. The 12 thin pads proved to be easier and faster to build. Most of the pad materials were typically dug onsite from the excavation of the mud pits. Additional materials came from nearby stream beds or local surface features such as dunes and ridge tops. In contrast, almost all the building material for the Inigok well pad and airstrip was transported more than 48 km from borrow pits.

Five gravel airstrips were constructed across the NPR-A. Most wells had airstrips on lakes or man-made ice. Layers of styrofoam were interbedded in some of the airstrips and pads to provide insulation and to lessen the amount of gravel required for construction. This proved successful. Drilling pads across the NPR-A varied in size from about 2 to 10 acres. Thick pads used around 23 000 to 38 000 m^3 of material. Thin pads used around 7500 to 11 500 m^3 of material. Reserve and flare pits were between about 1.3 acres and 6 acres in size. The total surface disturbance for the entire NPR-A is about 540 acres. It consists of around 250 acres in drill pads and reserve pits, 168 acres in borrow pits, 105 acres in airstrips, and 15 acres used in burial sites for waste.

Initially, drilling cuttings were put directly onto the tundra, as was the practice at the Barrow gas fields. Later, cuttings were boxed and hauled to disposal sites, as is the practice at *Prudhoe Bay* oil field. After well abandonment, thick pads were typically dozed into their respective mud pits and re-contoured. This was done to encapsulate the mud and cuttings and minimize the likelihood that they would react with the surrounding environment. Thin pads were left to disintegrate back into the tundra. Reclamation at some locations also included cutting off the pilings at ground level. These sites were seeded with an Arctic mix and nitrogen fertilizer. The Husky program also devoted considerable effort to removing old fuel barrels and assorted debris, much of which originated with the U.S. Navy's initial exploration program. Over 25 000 barrels were hauled and crushed, and over 10 000 tons of debris were burned or stockpiled.

Between 1989 and 1992, a joint USGS/BLM monitoring program compiled site information. It included aerial photos, site descriptions, and chemical constituent analyses of sediments on and peripheral to pads and water in and peripheral to pits. The data were assessed with respect to the State of Alaska (extant) Interim Guidance for inactive reserve pits.

Air photos from this program show the 1992 state of the drill pads and pits. Re-vegetation has succeeded at some of the sites. However, the high salt content in some of the silty soils used for pad construction has retarded plant re-growth in others. Sites such as Inigok are retained for ongoing scientific and industry support purposes. They remain similar in appearance to when they were initially active. Drill pads along the coast have been routinely flooded by seasonal storms. Comparatively small and shallow thaw ponds have developed around the

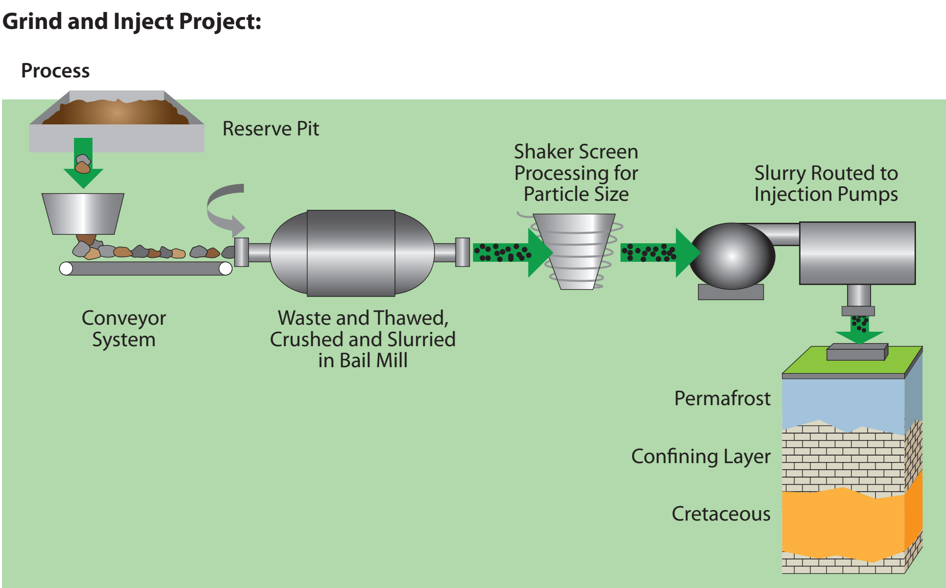


Figure 2.120. Diagram of a deep well injection process.

edges of some pads. The irregular shapes indicate that the pads appear to be disintegrating into the tundra at various rates. The JW Dalton site remained re-vegetated and stable until about 2002; however, recent coastal erosion has overtaken the entire site and it is now awash. The dozed and reclaimed WT Foran site was later used for a subsequent well (Livehorse) when the site was transferred to a regional Native Corporation. It is not remediated.

Many pits were not completely filled in during the recontouring of the pads. Other pits were left open. Seasonal precipitation accumulates in the pits. A combination of additional water and the salt content of the muds in the pits has caused the pits to subside. Water depths were measured at between slightly less than 1 m (2 ft) and 3 m (9 ft) when they were sampled. Seasonal storms have caused some pit walls to breach, allowing both the influx and discharge of surface waters. Some seepage also occurs.

Chemical analyses of the sites and surrounding areas showed that seven (25%) of the sites have no contaminants in excess of background levels or Maximum Clean drinking water Levels (MCLs). These sites were determined to be no threat to the environment. At the other sites, detectable organic contaminants included petroleum hydrocarbons. These were described as TPH (total petroleum hydrocarbons) and BTEX (benzene, toluene, ethyl benzene, and xylene). Some of these hydrocarbons are from local seeps and background levels of hydrocarbons are elevated in parts of the petroleum province. However, their occurrence on the 21 other pads and in pits indicates residue from well testing and spills of refined products. Although levels at some sites were above background, they were determined to have negligible potential as toxic hazards.

Inorganic contaminants detected include chromium, barium, and fluoride. These ions were predominantly found in the pits, particularly in the sediments at the bottom of the pits. At some pits, both barium and chromium can exceed MCLs. At some sites, detectable levels were found to decrease between 1989 and 1991. However, analyses of the down-gradient areas are clear. They suggest that the chromium and barium are complexed within the lignosulphonate drilling muds. These muds at the bottoms of the pits are much denser than the surrounding sediments and water. Consequently, they remain immobile and in the pits. Also, the pit waters are typically alkaline, which keeps the barium and chromium cations in a comparatively immobile state. Across the NPR-A there are areas which have high background barium, and the mixed oxidation states of the chromium ions suggest that some of it may be from natural sources rather than it all being from drilling mud additives. However, despite the detection of chromium and barium at 21 of the Husky sites, they were determined to have negligible potential as toxic hazards.

The 28 Husky drill sites, pads, and pits are located in comparatively remote areas of the North Slope. The physical appearances of the Husky sites vary from the construction materials being completely intact to sites entirely reclaimed with vegetation. Existing mud pits have subsided and contain water. Seven of the sites have no hydrocarbon or inorganic contaminants in excess of background levels or MCLs. Depending on the drilling mud additives, which are now in the bottoms of the mud pits, and sites which utilized lignosulphonate drilling muds, there are detectable chromium and barium concentrations which exceed the MCLs. However, these are contained within the dense drilling mud which lines the pits and does not appear to leave them.

2.5.1.5.2. Russian Federation

The State enterprise VNIIOkeangeologia (Russian State Institute for Research of the World's Oceans) in cooperation with the Research and Development Center (RDC) Technology XXI and VNIGRI (Russian State Institute for Geology and Resources Investigation) develops and implements environmental protection technologies in relation to exploration for oil and gas and for oil production in the Russian Federation (including in the Far North) (Kaminsky et al., 2005). (RDC Technology XXI unites the efforts of several Saint Petersburg enterprises which specialize in developing scientific and technological production and designing and implementing equipment to solve tasks on a turnkey basis for creating processing facilities for environmental protection and energy-efficient technologies, as follows: AO NP Sinteks, OOO Ekologicheskie Tekhnologii Na Trransporte [ETT], OOO SBNE -2, OOO Ekopolis, ZAO NPF Ekotekhnoserivs [ETS], OAO Tekhnoprom-K, GUP OGRN EKOINZH.)

Since 1994, in the Nenets Autonomous Okrug, RDC Technology XXI in cooperation with VNIGRI and VNIIOkeangeologia has been implementing a program aimed at increasing the ecological safety of drilling for oil and gas and also remediation of the areas impacted by those activities (Box 2.14).

In addition, the RDC Technology XXI enterprises have implemented a number of projects for environmentally sound support of oil and gas drilling and oil production in the Nenets Autonomous Okrug, Kaliningrad Region, Khanty-Mansi Autonomous Okrug, Yamal-Nenets Autonomous Okrug and other regions. Major RDC Technology XXI activities include the development of regulations regarding oil contamination levels in soils and sediments at the regional and departmental levels and techniques and procedures for oil contamination monitoring and assessment, also at the regional and departmental levels (Box 2.15).

According to calculations made for one of the exploration drilling sites (30 S-Khaseda), implementation of the regulations on the oil content of soils reduces the scope of mechanical cleanup of the area to 25% of that which would be required without such regulations (Kaminsky et al., 2005).

Pilot projects were implemented for the processing of drilling muds and oil-contaminated soils from OAO Arkhangelskgeoldobycha, ZAO Severgeoldobycha, OOO BOVEL, OAO LUKOIL-Kaliningradmorneft, OAO NK Rosneft-Purneftegas, and OOO LUKOIL-Nizhnevolzhskneft. The products obtained have been certified as construction materials – technogenic consolidated ground with a catalogue number assigned and a hygiene certificate issued (Kaminsky et al., 2005).

In 2005, on request from OOO PermNIPIneft, the engineering part of the project was developed to equip the drilling waste disposal area and to explore and exploit deposits (drilling and oil waste, mineral sediments from wastewater treatment, construction and domestic [including food] wastes) for the Nenets Autonomous Okrug.

From 2001 to 2003, in the Yamal-Nenets Autonomous Okrug, OOO ETT conducted environmental decontamination of OAO NK Rosneft-Purneftegas

Box 2.14. Program for ecological safety and remediation of areas impacted by oil and gas activities in the Nenets Autonomous Okrug

The program to increase the ecological safety of drilling for oil and gas and remediation of the areas impacted by those activities in the NAO, conducted by RDC Technology XXI in cooperation with VNIGRI and VNIIOkeangeologia, includes the following activities.

- Development of the regional normative base for an ecological/geochemical audit of the licensed areas; state and departmental monitoring and land and water contamination control.
- Development and implementation of regionally adapted techniques and procedures for quantitative assessment of damage caused by pollution and littering due to oil and gas complex activities, taking into consideration climate and landscape.
- Development and implementation of express methods for environmental monitoring of pollution at drilling and oil production sites.
- Sanitary and chemical analyses of drilling and oil production wastes including determination of their hazard class and toxicity.
- Development and implementation of economic technologies for the prevention, containment and removal of pollution, including:
  - modular technologies for decontamination and processing of solid and liquid wastes from drilling to use in mud-circulating systems: deep treatment of drilling wastewater (down to the Maximum Permissible Concentration, MPC); drilling mud and waste drilling fluid decontamination and processing into certified construction materials;
  - modular technologies for environmental decontamination and processing of oil fluids, oil sludges, and oil-contaminated soils into certified construction materials and high-energy briquetted solid fuel;
  - electro-osmotic technology for the cleaning of grounds in-situ, ground grouting, strengthening of foundations, improvement of corrosion resistance properties of product pipeline coatings without stripping operations;
  - technologies for containment and environmental decontamination of accidental spills of oil, oil products and chemical agents; and
  - economic sorbents including those containing bioadditives for remediation of contaminated areas.
- Development and implementation of accompanying technologies effectively implemented not only in gas and oil enterprises but also in other industry branches, including technology of freshwater preparation, industrial and rain effluent treatment, decontamination and processing of solid wastes and muds from different plants, activated sludges from waste plants, remediation of sludge pits, and reconstruction of aeration systems at biological treatment facilities (Kaminsky et al., 2005).

Box 2.15. Regulations regarding oil contamination levels in soils and sediments in the Russian Federation

RDC Technology XXI enterprises have implemented projects for environmentally sound support of oil and gas drilling and oil production in the NAO, Kaliningrad Region, KhAO, YaNAO and other regions, including the development of monitoring and assessment procedures (Box 2.22) and regulations regarding oil contamination levels in soils and sediments at the regional and departmental levels, as follows:

- Regional level: Relevant methodology has been developed in cooperation with the Sanitary and Epidemiological Station, GIDUV, SBNE and others. A range of regional regulations, including the first Russian temporary regional regulation 'Oil Products Content in Soils of Saint-Petersburg', have been developed, approved at the republic and district levels, and implemented. Since 1993, these regulations have been used by the State environmental control bodies in the region.
- Departmental level: At the request of OAO Arkhangelskgeoldobycha, the temporary regulation 'Oil Products Content in Soils, Grounds and Bottom Sediments at Oil and Gas Drilling Sites' was developed in cooperation with SBNE and is being implemented in the Nenets Autonomous Okrug for in-process monitoring of oil contamination at drilling sites and environmental optimization of remediation work.

In 2004, the regional regulations for OOO Naryanmarneftegas 'Norms for the Permissible Residual Content of Oil and Products of its Transformation in Soil after a Recultivation of the Oil-Polluted Soil and Other Remediation Works' were developed by OOO SBNE-2 experts and approved by the supervisory body. In 2005, similar regulations were developed and approved for LUKOIL-Komi and OAO Pechoraneft.

drilling wastes and remediation of contaminated areas. In 2001, this comprised the implementation of a project for environmental decontamination and processing of drilling muds and oil-contaminated soils into technogenic consolidated ground at the *Barsukovskoe* field test site. In 2002, an oil spill was contained and decontaminated in the area adjacent to the east of well cluster 13 of the OAO NK Rosneft-Purneftegas *Komsomolskoe* oil, gas and condensate field. The work included assessment of the effectiveness of a highly reactive hydrocarbon mixture application and its application in combination with other sorbents and materials. A 0.7-ha area of natural containment of the oil spill included natural (water body, boggy forested and forested) landscapes and anthropogenic (soil road) constructions. The analytical chemical control of the results of this work indicated a considerable decrease in the leachability of oil from processed soils and drilling muds. The results of this work were approved by the Yamal-Nenets Autonomous Okrug State environmental expert bodies. In 2003, a project for the containment and removal of soil and ground areas contaminated by oil, based on the results of the work conducted in 2002, was developed and approved by the Yamal-Nenets Autonomous Okrug State Environmental Expert Board (Kaminsky et al., 2005).

Figure 2.121. The drilling mud treatment facility at the OAO Yuganskneftegas test site for storing drilling mud and oil-contaminated soils.

In 2001 to 2002, an easily de-mountable facility for the processing of drilling mud, with a throughput of 30 tons per hour, was developed and put into operation for OAO Yugansneftegas (Figure 2.121). The annual processing volume exceeds 20000 tons of mud.

The enterprise standards for the processing of drilling mud and oil-contaminated soils were developed and approved for OAO AGD; OAO AGD and later OOO Naryanmarneftegas applied for a modernization of the drilling machine (Kaminsky et al., 2005).

2.5.2. Best Available Practices and Technology

The concept of Best Available Technology (or Techniques) (BAT) has been used in government regulations for a number of decades as a means of decreasing emissions and discharges of pollutants from industry. This is achieved by requiring industries to employ the best technologies available for the activities or production concerned. For example, the OSPAR Commission's strategy for the offshore oil and gas industry promotes the progressive development and adoption by Contracting Parties to the OSPAR Convention of Best Available Techniques for offshore activities in relation to: a) the use and discharge of hazardous substances; b) discharges of oil and other chemicals in water from well operations; c) emissions of substances likely to pollute the air (to the extent that they are not regulated by other international agreements); d) flaring (to the extent that emissions from flaring are not regulated by other international agreements); and e) the disposal of naturally-occurring radioactive material in the form of low specific activity radioactive scales and sludges. In addition to those Arctic countries with oil and gas activities that are signatories to the OSPAR Convention (Denmark [including the Faroe Islands and Greenland], Iceland, and Norway), the concept of BAT is also applied in relation to oil and gas activities in the Arctic by the State of Alaska. The example described below covers one specific application of BAT – for oil spill prevention and response. In principle, however, BAT can be applied at all stages of exploration, production, transportation of the oil or gas, and decommissioning. While BAT for some types of operations is mandated by State or national laws or regulations, there are also ISO standards and industry standards that apply to various other operations.

After the 1989 oil spill from the tanker *Exxon Valdez* in Alaska, the State of Alaska and the Federal government passed a number of laws to emphasize the need for oil spill prevention. Alaska adopted a new institutional approach with the aim of minimizing environmental impacts from oil spills on aquatic species, commercial fisheries, and recreational uses. This approach emphasized a process of Best Available Technology to ensure that operators enhanced their spill prevention technologies. Principles were taken from the established approaches in the national clean air and clean water laws (Box 2.16) to provide management concepts that would be useful as building blocks to better manage oil spill risk through appropriate pollution prevention technologies (Burden and Chapple, 2001).

Following input from a stakeholder panel comprising environmental, shipping, and other public interests, BAT concepts for a state-of-the-art response and prevention program were incorporated into an Alaska State law that became effective in 1997. The law requires that facility operators prepare contingency plans that provide for the use of the best technology that was available at the time that the contingency plan was submitted or renewed; this contingency plan is both an oil spill prevention plan and an oil spill response plan. Under this law, the BAT for each regulated facility must be re-assessed every three years in association with the renewal of the contingency plan (Burden and Chapple, 2001).

The Alaska BAT response and contingency plan is based on three components:

1. The Alaska BAT Response Planning Standards, which define how the State verifies the contingency plan holder's ability to meet the statutory clean-up standards, that is, the operator's planned ability to contain, control, and clean up a certain volume of spilled oil during a period of time. The standards vary for different types and sizes of operations.
2. Specific Performance Standards for spill prevention, as codified into State regulations; these include many industry trade standards.
3. Case-by-Case BAT Evaluations for prevention activities and equipment that are not covered by the Specific Performance Standards or other topics within the spill response area. Under this BAT review, technologies are analyzed in relation to alternative equipment on the basis of eight criteria: (i) availability of the technology; (ii) transferability of a technology used in other operations; (iii) effectiveness in providing increased spill prevention or other environmental benefits; (iv) cost; (v) age and condition of the existing technology in use; (vi) compatibility of the alternative technology with existing operations; (vii) engineering feasibility of the technology; and

Box 2.16. Best Available Technology

Examples of principles regarding Best Available Technology can be found in several U.S. pollution control laws. In the U.S. Water Pollution Control Act Amendments of 1972, levels of effluent limitations for existing industrial facilities to be achieved by 1983 were to be based on 'best available technology economically achievable' (BAT). Under this part of the Act, the U.S. EPA Administrator is required to consider the following for BAT: 1) the cost of achieving such effluent reduction; 2) the age of equipment and facilities involved; 3) the processes employed; 4) the engineering aspects of application of various types of control techniques; 5) process changes; and 6) non-water quality environmental impact (including energy requirements) (FWPCA Sec. 301(b)(2)(A), 33 U.S.C. Sec. 1311(b)(2)(A)).

The 1977 and 1980 Amendments to the U.S. Clean Air Act required certain facilities to employ 'best available control technology' (BACT), defined as the maximum degree of control, taking into account environmental, energy, and economic impacts determined to be achievable (42 USC 7475(a)(4) and 7479(3)). A new major stationary source of air pollution or a major increase of air pollution from an existing facility requires a permit setting emission limitations for the facility. As part of that permit, limitations are established based on levels achievable by the use of technology determined to represent BACT for each pollutant. The decision of what technology constitutes BACT is made by the regulatory agency based on a rigorous review by the permit applicant of all available technologies according to three main criteria: 1) the environmental benefits achievable; 2) the economic impacts associated with attaining those benefits; and 3) the energy considerations of the technology. The BACT decision uses the three criteria to arrive at a balance to provide for local site-specific considerations while invoking the use of field-proven advanced technologies.

These laws do not mandate the research and development of new technologies, but require the application of technologies that have already been proved effective and reasonable from a cost perspective.

(viii) associated environmental impacts.

Topics that are covered by case-by-case review include: fuel/oil transfer requirements; leak detection on laden oil tank vessels and laden oil barges; provision of escort vessels for laden oil tank vessels; recovery of an oil barge that breaks free of a towing vessel; leak detection and monitoring for crude oil pipelines; corrosion control for oil storage tanks; leak detection for oil storage tanks; corrosion control for facility piping for oil terminals, crude oil transmission pipelines, oil exploration and production facilities; and oil spill response systems (Burden and Chapple, 2001).

Best practices and technology for oil and gas exploration and production have evolved greatly over the years for the industry as a whole in response to technological advances and regulatory requirements. While many of these advances are also applicable in Arctic areas, there are additional requirements for best practice when working in the fragile environments of the Arctic. Some of these developments in relation to best practice and technology for Arctic operations are described below.

For example, in Alaska both vehicles and operating procedures used in the winter on the North Slope have evolved over the many years that oil and gas exploration has been conducted. The goal has been to minimize the immediate impact on the environment and ensure that, when the ice and snow melt in the spring and summer, all evidence of the operation would disappear. All solid and liquid waste is hauled away to approved disposal sites. Pans have been installed under the frame of the vehicles to capture any fuel spillage or fluid leaks. Fuel and fluids for the equipment are colored for ease of detection and clean-up if a spill occurs. Perhaps the most dramatic changes have been in the vehicles. Nearly all vehicles used in early exploration used steel tracks. Very large rubber tires were found to have less impact or ground load and their flexibility allowed them to conform more to the terrain; thus, they were phased into the equipment fleet. Now with new materials that can withstand the cold, there has been a move back to rubber-tracked vehicles that create even less ground load and the least risk of disturbing the delicate tundra (BLM, 2000).

In Canada, the Arctic exploration regions are very extensive and sparsely explored; petroleum operations have moved from exploration to development only locally, and over vast regions the industry is at an early stage of basin exploration. Consequently, the nature of operations is still geared more to techniques of reconnaissance geological, geochemical, and seismic exploration, leading to investment in few high-cost wild cat wells, often in areas where surface geology is still poorly known. For example, only fairly recently have 3-D seismic programs been employed in the North, and only in the Mackenzie Delta and Beaufort Sea have they been used (since 2000) as an exploration (as opposed to development) tool.

In spite of this early exploration/development scenario (or perhaps because of it), the Canadian petroleum industry has embraced the concept of 'footprint reduction' of oil and gas activities in Arctic and forested regions in Canada (CAPP, 2004a). Industry has undertaken to incorporate new and evolving innovative practices using advanced technologies and enlightened management and development practices. Some of these practices with respect to seismic acquisition and exploration/development drilling are described below.

2.5.2.1. Seismic operations

Examples of the technological development of seismic operations are mainly taken from Canada. The technology of acquisition, operational practices, and planning of seismic operations have evolved rapidly over the past decade in northern Canada. The Canadian Association of Petroleum Producers has published a position paper (CAPP, 2004b) on these recent changes in geophysical exploration practices.

Onshore operations have increased the use of low-impact seismic techniques. The term 'low-impact seismic' spans a variety of innovations in equipment, operating methods, and operation planning. In northern Canada, various low-impact seismic techniques have been tried in boreal forests, tundra, and delta wetlands. These have involved new seismic sources such as increased use of Vibroseis, development and use of light-weight vehicles to

Photograph: Gerald Shearer

Figure 2.122. Fueling vehicle on rubber tracks pulled by a rubber tracked tractor.

Photograph: Gerald Shearer

Figure 2.123. Dozer pulling a camp train. The steel tracked dozers are being phased out and replaced by the rubber-tracked tractors.

Photograph: Gerald Shearer

Figure 2.124. Personnel and light equipment are transported on lighter tracked vehicles.

Photograph: Gerald Shearer

Figure 2.125. Geophone placement has not changed much over the years. It is still labor intensive.

reduce ground pressures, reduced breadth and necessity of cut lines, and use of heli-portable operations. The use of remote sensing and GPS combined with vastly increased computer power has enabled greater flexibility in operations and in the design of acquisition programs to allow for variation of shot hole intervals to avoid water bodies. GPS can reduce unnecessary surface exploration and minimize surface travel. Precise location also allows geophysical companies to shoot seismic along all-weather or ice roads, or along water courses, thereby avoiding driving new seismic lines across the landscape.

In terms of equipment, new narrow-wheel-base shot-hole drilling units have been developed which can avoid the need to cut trees along the route of planned seismic lines. The breadth of disturbance of a seismic operation can be limited to 5 m compared with 15 m for more traditional methods. Sub-snow compaction of vegetation on tundra has been reduced by the use of equipment with tyres or tracks exerting low pressures on the underlying surface (Figures 2.122 to 2.125).

Lighter equipment has permitted the increased use of heli-portable seismic operations, especially on more rugged terrain. Such operations have minimal effect on vegetation and land beyond the immediate vicinity of shot holes, although additional helicopter traffic causes transient disturbance.

Since 1995, heli-portable seismic programs have been run in the central and southern Mackenzie Valley and in northern Yukon. These are significantly more costly than conventional programs, especially on flatter terrain where land operations remain prevalent, albeit using low-impact techniques.

Operations in the boreal forest are governed by regulatory requirements to minimize brush cutting, and disturbance of snow pack. Seismic operations north of 60° N on tundra and in the boreal forest are almost exclusively undertaken in winter when travel on the land is easiest and the impact on wetland tundra and wildlife migration is minimal.

Offshore operations have changed as seismic sources have evolved. The design of source and streamer arrays has improved acquisition efficiencies thereby reducing ship time and steaming programs; operational practices have evolved rapidly as a consequence. In northern waters where native populations of marine mammals are relatively undisturbed and a traditional harvest exists, offshore operations have needed to be particularly attuned to such concerns. Offshore operations in the past five years have focused on the Beaufort Sea off the Mackenzie Delta. Techniques to mitigate impact include gradual ramping up of the seismic power source (thereby alerting species to the intrusion with less alarm), use of standing orders to suspend operation on sighting of marine mammals, and retaining the use of observers, especially observers with traditional knowledge.

Seismic programs are also a concern on freshwater bodies, especially where they may not be fully frozen to the bottom. The prevalence of such bodies in the Canadian tundra, the prevalence of streams in the Mackenzie River watershed, and the complex wetlands of the Mackenzie Delta and shallow marine margins have made understanding and mitigating impacts of seismic activities on fish a major preoccupation of regulators. The impact of seismic activities on land on over-wintering fish in deep channels beneath ice is a case in point where pressure effects of seismic sources are potentially damaging.

In these habitats, the over-wintering populations of androgenous fish in the waters of the Mackenzie Delta distributaries may require special adaptation of seismic operations.

Where fish or marine mammals in ocean, brackish, or freshwater habitats may be affected by seismic operations, either on ice or in open water, new scientific research is assisting regulators and operators to collaborate in developing new guidelines for operations. This research is helping guide the development of thresholds for the pressure effects of seismic sources such as chemical explosives and airguns. Alternative operating practices are also being developed where specific environmental sensitivities are recognized.

In the Canadian Arctic, the modern seismic operator will be expected: a) to consult with regulatory authorities in the planning of programs; b) to develop contingency plans to allow for adaptive approaches to operational surprises; c) to use proven technologies and demonstrated mitigation techniques that work for Arctic conditions; d) to monitor continuously during operations and over the longer term; and e) to avoid specific habitats. Better planning of operations both onshore and offshore and mitigation of impact includes improved awareness of local and seasonal sensitivities through enhanced consultation particularly with sources of traditional knowledge. Many of these initiatives are complemented by evolving regulatory frameworks which can accommodate innovation. A trend in Canada to increase performance-based regulation should actively encourage innovation which will further minimize adverse impacts.

In Alaska, significant changes in marine seismic activities have taken place in the second half of the 1990s in both geophysical industry data acquisition technology and in public perceptions about environmental conservation. A typical survey is now more focused, employs techniques such as ramping up the airgun arrays to avoid a sudden burst of energy that could disturb marine mammals and fish, and often engages marine mammal observers to avoid contact or close encounters with marine mammals. The industry has seen a dramatic shift in operations from traditional 2-D data acquisition to 3-D and now to 4-D data acquisition.

2.5.2.2. Drilling

Onshore drilling operations are strongly constrained by operating windows governed by freeze-up. In the north, movement across tundra is only practical when the ground is frozen; this is a consideration for the mobilization of drilling rigs, logistical supply, and concerns over emergency response.

Access to drilling sites usually involves mobilization from staging areas. Rigs may be stacked at these locations after being offloaded from barges, usually toward the end of the barging season on the major waterways. In Arctic Canada, ice road construction to the drilling location may involve tens or hundreds of kilometers of road construction. New innovative proposals for moving heavy equipment by balloon airlift may prove to be a commercial proposition. Formerly impassable and remote areas could now be accessible with such technology, thus extending the drilling season in areas not normally accessible except in winter.

Well drilling has seen major technological advances over the past twenty years. The development of downhole steering tools, navigation, borehole telemetry, coiled tubing, and other new techniques has greatly expanded the use of extended-reach drilling. The depth/horizontal distance envelope for extended-reach operations is constantly being expanded (up to 10 km). Use of these techniques for exploratory wells is increasing in Arctic Canada, especially where surface environmental hazards or sensitivities are an issue. The positioning of surface well locations to avoid major lakes and waterways or to access prospects just offshore in the Beaufort Sea is likely for new exploratory wells, although companies will prefer to drill less costly vertical wells where possible. For example, drilling on the outer fringe of the Mackenzie Delta in 2003 took advantage of directional drilling to reach an offshore target from an onshore location, although the horizontal offset was small.

Use of directional drilling for field development allows the co-location of many wellheads at a single drilling pad. The proposal for development of Mackenzie Delta fields takes full advantage of this technology. For example, the development plan for the major *Taglu* gas field envisages ten to 15 production wells drilled directionally in a spider pattern from a single pad. Together with surface facilities, the development area is estimated to cover a total of 30 ha.

Disposal of drilling wastes in the Arctic environment is a matter of public and regulatory concern. In particular, earlier phases of exploration have disposed of wastes in sumps adjacent to drilling sites. With time, the methods of construction and abandonment of these sumps have been shown to be inadequate in certain cases where stream erosion, sapping, and permafrost degradation have raised questions as to the long-term integrity of the sumps. In the dynamic geo-morphological setting of the Mackenzie Delta, this is a particular concern. Recent work in Canada on sump stability has shown that careful positioning and adequate insulation can greatly reduce the risk of failure. Advances in drilling fluid technology to reduce harmful residues minimize the hazards if a sump fails. Where development is concerned, the drilling of multiple wells may permit downhole disposal of drilling wastes and remove the need for a permanent sump. This may be impractical for single exploratory wells where the characteristics of candidate formations for injection are unknown prior to drilling.

Drilling offshore of the Canadian Arctic Islands and in the Beaufort Sea has adopted the technological safeguards and advances developed and used by the industry elsewhere in the world, particularly in the North Sea, the Gulf of Mexico, and offshore Atlantic Canada. However, the extreme environments have forced offshore operators in parts of the Canadian Arctic to accept more rigorous requirements than those in other operating regions in order to mitigate the consequences of a blowout. For example, in the Beaufort Sea, there is a requirement for operators to plan for a same-season relief well in such an eventuality. This requirement limits the operating window for both summer and winter operations. The exigencies of Arctic operation in Canada have stimulated many custom drilling solutions: innovative approaches to more effective well control technology may allow the same-season relief well requirement to be relaxed in due course.

Many of the requirements and safeguards for drilling in Canadian waters became regulations prior to the 1970s drilling activity. The Canadian Centre for Energy (Bott, 2004) outlined Canada's regulations for mitigating 'footprints' offshore in eastern Canada, and these also apply to Canada's North.

In the Beaufort Sea, the building of artificial islands in the shallow nearshore areas was preceded by a myriad of seabed stability, water quality, pack ice, and biota investigations prior to the authorization of such drilling platform construction. These studies are ongoing (see the Natural Resources Canada, Environment Canada, and Northern Oil and Gas Directorate websites).

In Alaska, exploration drilling took a large leap in Phase III (2000 to present; Phases I and II are described in section 2.5.1.3). Well sites were now accessed by ice roads and the actual wells were drilled from ice pads. This technology required the building of drill rigs and camps in modular form for easier transport and set up. It drastically reduced the impact of drilling and in summer the wellheads are the only visible reminders of the activities there.

If a discovery is made and put into development, an example of current technology on the Alaska North Slope is best reflected by the Alpine discovery, located approximately 120 km west of Prudhoe Bay. Multiple production wells are now drilled with the wellheads closely spaced and processing facilities are designed to be as compact as possible, thereby reducing the surface impacts of development operations. At present, the development is nearly complete with 102 wells drilled in Alpine. All the production and injection wells at Alpine are high-departure deviated wells with extensive horizontal sections within the reservoir. The production wells typically have 1000 to 2000 m of horizontal section within the reservoir. Currently, one well at Alpine has a lateral reach of 6455 m and a vertical depth of 2134 m. Alpine drilling has surpassed 457 000 m drilled with over 118 000 m within the reservoir. Alpine is producing at around 120 000 bpd. One advantage of horizontal wells is that more of the reservoir is exposed to the production string, reducing the number of wells required to develop a reservoir. Well spacing for horizontal wells within the reservoir is 0.95 km^2 (275 acres) with approximately 97 km of reservoir developed. The significance of this is that the total surface disturbance for the Alpine site is two pads (one pad also contains the production facilities) and the airstrip, a total of 0.39 km^2 (96 acres). The Alpine site is self-contained. People and supplies are flown in and large equipment is brought to the site on winter ice roads. Oil, diesel, and water pipelines are roadless and connect the site to the Kuparuk facility. Sale oil is shipped to Kuparuk for sale. Diesel (for fuel) and seawater for reservoir pressure maintenance are sent to Alpine from Kuparuk. As more oil and gas is discovered near the *Alpine* field, development plans call for satellite drill sites to be built. Two satellite sites are currently under construction: CD3, which will not have road access, and CD4, which is connected to Alpine by a 6.5-km road.

Although production development has not begun in the NPR-A, it would be similar to that existing for Alpine.

Exploration seismic and drilling activities are currently conducted in the winter when frozen conditions provide protection to the Arctic tundra. Seismic activities are conducted on the tundra using rolligons, which are motorized vehicles with large, low-pressure rubber tires that exert very low pressure on the tundra thereby preventing any damage. Rolligons are versatile vehicles that can haul many different types of equipment. Access roads and drill sites for current remote exploration areas are constructed with a mixture of freshwater, ice chips and snow, commonly known as ice roads and pads. These ice roads and pads successfully support drilling activities and leave no permanent footprint following the completion of drilling activities. Technological advancements have progressed to the point where exploration seismic and drilling activities can be conducted in the winter months with virtually no permanent footprint on the Arctic tundra (Figures 2.126 and 2.127).

Technology advancements have been applied to oil development activities in Alaska Arctic regions. These advancements have resulted in a significant reduction in the footprint required to support development activities. For example, a development drill site today is around 60 to 70% smaller than early development pads. Drilling rig design modifications were instrumental in the construction of smaller gravel pads. Drilling rigs today have slimmer designs, efficient moving systems, and a smaller base. The rigs actually have self-contained moving systems where they can move without the need of large external equipment.

Drilling techniques have also contributed to the design and construction of smaller gravel pads (Figures 2.128 to 2.131). Directional drilling technology has allowed for many wells to be drilled from a single pad, minimizing the need for many drill sites. Currently, a directionally drilled well can achieve a bottom-hole location up to several kilometers from the surface location. This extended-reach drilling technology is rapidly advancing around the world, with bottom-hole locations being considered in the range of 12 km laterally distant from the surface location.

In development areas with a support infrastructure in place, it is possible to operate drilling rigs with electric power as opposed to fossil fuels. This option is utilized in Arctic Alaska in areas with sufficient available electric

Figure 2.126. Rolligons making an ice pad.

Figure 2.127. Rolligon making an ice road.

Figure 2.128. Early Development Gravel Pad with 80-100 foot well spacing.

Figure 2.130. Exploration well with ice road and ice pad.

Figure 2.129. Recent Development Gravel Pad with 10-15 foot well spacing.

Figure 2.131. Same exploration well during the following summer.

power. Electric power meets the needs of the drilling rigs and significantly reduces air emissions.

2.5.2.3. Contamination prevention technologies

Since 1995 in the Russian Federation, VNIGRI in cooperation with SBNE has been developing drafts of guidance documents on environmental contamination prevention technologies used at drilling and production sites (enterprise standards) for oil production enterprises (OAO AGD and OAO RN-PNG) (Kaminsky et al., 2005).

SBNE and SINTEKS have developed a modular technology for the decontamination and processing of drilling mud returns into useful products (construction materials) to use in mud-circulating systems for offshore and onshore drilling for oil and gas. The use of the national modular modifications of the integrated mineral matrix technology (SINTEKS) and deep (down to the Maximum Permissible Concentration, MPC) treatment of drilling wastewater (SBNE), non-standard technical solutions, and orientation to the national production base caused a very great decrease in cost (from 1.5- to 2-fold) of the processing facility compared to the foreign competitors.

SBNE has developed, manufactured and implemented technology for deep (down to MPC) treatment of drilling wastewater for closed-water treatment systems based on the modular facility ECHO-B. The facility ECHO-B with a throughput of 5 m^3 per hour is successfully operated at ZAO Severgeoldobycha drilling sites (Naryan-Mar). SBNE has filled an order for delivery of the ECHO-B for OOO LUKOIL-Kaliningradmorneft (LUKOIL-KMN) (Figure 2.132) and OAO AGD regional enterprises (Kaminsky et al., 2005).

With regard to technologies for pollution containment and removal, industrial effluent treatment, and waste processing, a range of guidance documents on drilling waste decontamination and disposal are being developed in the Russian Federation in cooperation with ETT, as part of the implementation of the program of contamination prevention at oil drilling and production sites for OAO AGD. In 2001, the enterprise standard Technology for Drilling Solid Waste Decontamination and Disposal was developed and approved by the Russian Federation Ministry of Natural Resources supervisory bodies. In 2003-2004, the enterprise standard Technology for Containment and Decontamination of Chemical (including Oil) Environment Pollution Areas at Oil Drilling and Production Sites in the Nenets Autonomous Okrug was developed.

Figure 2.132. Installation of ECHO-B-3 to treat drilling wastewater from regional LUKOIL enterprises.

In 1998, ETT conducted a test for processing of drilling mud returns from OAO AGD, LUKOIL-KMN, and AO ARKTIKMORNEFTEGEOFIZIKA and developed recommendations for modular facilities for the processing of drilling mud returns and the conversion of oil-contaminated muds into construction materials and high-energy briquetted solid fuel. Also in 1998, ETT constructed a trial ground in Gatchina, Leningrad District, and in 1999, a plant to convert oil-containing wastes into economic high-energy briquetted solid fuel with a throughput of up to 60 000 tons per year was put into operation (Kaminsky et al., 2005).

From 1999 to 2005, ETT and ETS successfully conducted experimental testing and implementation of the following technological applications:

- pilot projects on processing oil-contaminated soils from OAO AGD sub-base Sinkin Nos;
- processing of a test batch of drilling mud returns from OOO LUKOIL-KMN which was the basis for the development and approval of the drilling mud processing plant design with a throughput of 5000 tons per hour;
- processing of drilling mud returns in the course of well 112 Tedinskaya drilling; and
- removal of an oil spill at one of the ZAO Severgeoldobycha Toraveiskoe oil field wells; removal of a large oil/gas/water liquid mixture spill at well cluster K-1 of OOO BOVEL *Tedinskoe* oil field, as well as an accidental oil/drilling fluid spill at other Kumzha gas and condensate field wells (Figure 2.133). In the last case, a modification was used that allowed the underwater conservation of oil-contaminated soils and muds (in a man-made lake) without soil removal.

A positive opinion was given by ROSPRIRODNADZOR regional bodies on this work. The technology was recommended for the processing of drilling muds, oil-contaminated wastes, and the removal of catch basins and sump and cutting pits in the Nenets Autonomous Okrug (Kaminsky et al., 2005).

Evaluation of the economic efficiency of one of the 1000-m^3 catch basins showed that the cost of processing 1 ton of drilling muds is 490 to 1800 rubles depending on the contamination level and required properties of the materials. These results served as a basis for developing production procedures and working designs for mud and waste processing lines.

In addition to drilling and oil production waste processing, the integrated mineral matrix technology is used for the processing of solid and viscous wastes from various plants. Decontamination efficiency was monitored by certified laboratories of the Russian Federation Ministry of Health Institute of Toxicology and Department for State Sanitary and Epidemiological Supervision.

The developments already implemented make it possible to substantially increase the ecological safety of the activities of the enterprises NGK and other branches of production and infrastructure in the petroleum- and gas-extracting and other regions of Russia.

2.5.2.4. Deep well injection

Deep well injection of oilfield wastes has been a demonstrated and safe disposal option in Alaska for more than 25 years. Alaskan oilfield wastes that have been safely

Figure 2.133. Remediation of contaminated coastal pollution zone No. 2 at Kumzhinskaya Well 9, after two weeks (above) and after two years (below). Processed oil-contaminated soil disposal sites are characterized by active growth of indigenous species (flowering chamomile on the picture).

injected below permafrost through deep industrial Class I and oil- and gas-related Class II wells include solids (drill cuttings/muds/other drilling-related wastes) as well as liquids (produced oilfield brines, grey-water, snowmelt). Application and regulation of Class I, III, and V wells via underground injection in Alaska is the responsibility of the U.S. Environmental Protection Agency (EPA), while the Alaska Oil and Gas Conservation Commission (AOGCC) has jurisdiction for Class II wells.

At present, there are eight EPA-permitted Class I wells in the North Slope of Alaska. These include three wells at the Pad 3 facility in *Prudhoe Bay*, two wells at *Northstar*, one well each at *Milne Point* and *Badami*, and one well at *Alpine/Colville River* field. In addition, three wells at the Grind & Inject (GNI) facility are permitted both as Class II (by AOGCC) and Class V (by EPA) to enable disposal of both oilfield-related wastes and other materials from former reserve pits and oil waste pits. The *Prudhoe Bay* GNI operation (see Figure 2.120) is the world's largest drill cuttings injection project in terms of drilling volume. Slurry fracture injection at *Badami*, *Northstar*, and *Alpine* are utilized at a smaller scale to manage wastes at the individual field site, which reduces transport, handling, and roads offsite.

Federal and State environmental regulations require the operators to assure that the injected fluids remain confined within the permitted injection interval and prevent migration to overlying groundwater aquifers and/or to the surface. Strict regulatory and engineering requirements relating to well design, construction, operations, and monitoring (of all deep injection wells including slurry fracture injection wells) must be complied with by operators in order to ensure that the injected wastes are contained within the permitted injection interval and that the injection streams do not escape into overlying groundwater resources or to the surface. Additional Class I wells are projected to be permitted for the additional development of new fields in the North Slope of Alaska (Nikaitchuq and Ooogurak prospects). The emerging issue of geologic capture and storage of carbon dioxide (CO_2) to limit greenhouse gas emissions will also potentially affect the permitting of such wells.

2.5.3. New technology

Industry is continually developing new technologies to support the challenges of reaching and recovering as much oil and gas as possible from discovered reserves as well as discovering new reserves in an efficient and cost-effective manner. These challenges are particularly great in the Arctic, with its fragile environment, harsh conditions, and remote location. Offshore operations, particularly in deep-water locations and in ice-infested Arctic waters, also pose technological challenges that require sophisticated technology. Furthermore, costs associated with exploration, development, and production provide a strong impetus for the development of technological innovations that will result in greater effectiveness. Several new and emerging technologies are discussed in this section.

2.5.3.1. New technology for both onshore and offshore application

2.5.3.1.1. Coiled tubing drilling

Coiled tubing drilling is a relatively new operation where a coiled tubing unit is combined with a drilling rig (Figures 2.134 and 2.135). This combination allows for the drilling of new well bores from an existing well. Down-hole steerable motors allow geologists and engineers to steer the drill bit to selected targets in the reservoir. These new well bores are referred to as 'sidetracks' or 'redrills' (Figure 2.136). Several redrills result in a 'multilateral' completion. It is not uncommon to design and construct three to four lateral extensions from a single well bore. This technique optimizes contact with the producing reservoir, thus maximizing the production potential.

Coiled tubing technology has been shown to provide significant benefits to an oil and gas development operation. Coiled tubing is a small, continuous tube that is wrapped around a large drum. An injector assembly pushes and pulls the coiled tubing into and out of a well. Many operations can be achieved with the use of coiled tubing such as circulating, cementing, and drilling new wells from old or existing well bores. The major benefit of coiled tubing is that intervention work can be achieved in a well bore without having to pull the production tubing string from the well. The coiled tubing is small enough to fit inside existing production tubing.

2.5.3.1.2. Extended-reach drilling

The future holds promise for additional technological advancements in the exploration and development of oil and gas. Extended-reach drilling techniques could allow for wells to be drilled beyond 12 km laterally from a surface location. This will, for example, allow wells to be drilled from an onshore surface location to a distant offshore bottom-hole location. This may eliminate the need to construct offshore islands or platforms to access offshore reservoirs within the range of an extended-reach well drilled from shore. Coiled tubing drilling advancements are being formulated and tested that will improve the horizontal penetration into a productive reservoir (Figures 2.134 to 2.136).

The new horizontal drilling technology has been used, for example, in the Norwegian field *Troll Oil* – thin oil-bearing formations that underlie the huge Troll gas reservoir in the North Sea, with the oil spread over an area of roughly 450 km^2. New drilling technology has been taken further with the first five-branch oil well set in production in 2004.

Figure 2.134. Typical coil tubing unit.

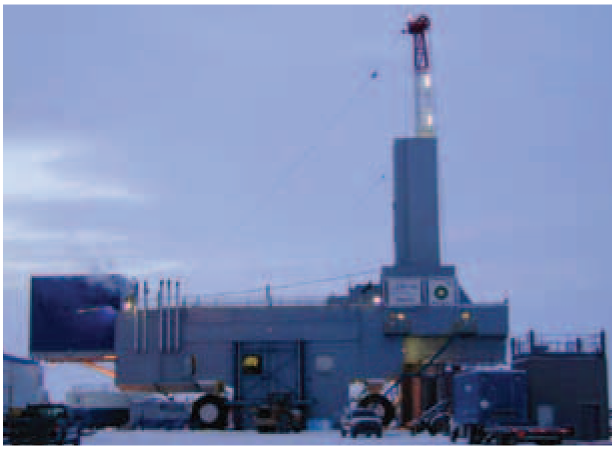


Figure 2.135. Typical coiled tubing drilling rig.

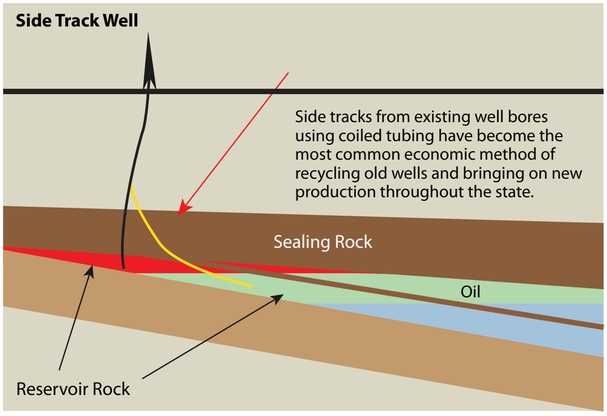


Figure 2.136. Side track well bore from an old well.

Software for dynamic simulation models has also been developed to support drilling operations by making it possible to anticipate pressure levels during drilling and to simulate potential well control situations (NTVA, 2005). The models can be used to identify potential well problems, perform procedural verifications and make required improvements as well as giving rig personnel greater understanding of the drilling process. They can also be used in the planning and review of complex wells (i.e., high pressures and temperatures, deep water, and under-balanced drilling). The models have been shown to provide a realistic description of the drilling process and should contribute to making drilling operations safer and more cost-effective along with providing greater understanding of the dynamics involved in actual operations.

As the degree of difficulty of reservoir drilling has increased, tolerances for the placement of horizontal sections have become smaller. At the Norwegian Troll West OGP, drilling was performed in an oil layer with a thickness of approximately 23 m, so there was need for the development of a PDM (Positive Displacement Motor) featuring instrumentation near the drill bit. This major improvement in the drilling system was used for the second well in the area. It is now possible to maintain tolerances within ±1 m vertical depth when drilling along horizontal lengths of up to 2000 m, which was a requirement for drilling on the Troll West OGP at that point in time.

Subsequently, a 3-D rotary-steerable drilling system was developed to enable drilling with tolerances down to ±0.5 m vertical depth over horizontal lengths of up to 4700 m (NTVA, 2005). This is an intelligent drilling system with a two-way communication link that enables execution of commands during drilling operations, in order to correct direction and angle as well as receiving data at the surface in real-time as the drilling progresses.

2.5.3.2. New technology for offshore application

The examples of new technology in this section are from Norway, which conducts all of its exploration and production for oil and gas offshore. The offshore technology is international in nature. To allow Norway to combine its role as a major energy producer with that of a pioneer in environmental issues, a comprehensive set of policy instruments has been developed to safeguard consideration of the environment in all phases of the activity. As a result of this strong emphasis on the environment, the Norwegian petroleum sector maintains very high environmental technology standards. Emissions and discharges from offshore petroleum activities in Norway are to a great extent regulated by the Petroleum Act, the CO_2 Tax Act, and the Pollution Control Act (see section 2.4.6.1 and Appendix 2.1). Emission permits entail a requirement whereby oil must be stored and loaded using BAT. Technologies designed to meet this requirement will be implemented according to a specified timetable extending to the end of 2008.

Technology has been fundamental to the progress seen in reservoir management and enhanced recovery factors. The average recovery factor on the Norwegian Continental Shelf is about 45% and the focus is now on increasing this to more than 50%. In some maturing fields, up to 70% of oil-in-place will be produced. Every percentage point growth in recovery adds 30 billion dollars of value to the industry and society.

Currently, the industry is focusing on cost reduction and on improved safety standards. The result is innovative design and construction methods. Simultaneously, the industry faces new challenges in the form of increasingly deep waters, uneven seabed, new materials, and higher temperatures and pressure that have an impact on, among others, the design of pipelines.

Technology has also allowed companies to meet ever more stringent environmental requirements, including no harmful discharges to sea and CO_2 storage in sub-sea reservoirs, such as on the *Sleipner* field in the Norwegian North Sea. Floating production and extensive use of sub-sea technology have revolutionized the way projects are developed and made new development solutions far more cost-effective. 3-D seismic and horizontal wells are regarded by industry experts as two of the most important innovations in the history of oil operations.

2.5.3.2.1. New technology for surveying and resource mapping

A battery-operated, remote-controlled, free-swimming deep-water vehicle that lacks a cable connecting it to the mother vessel is a new type of surveying device that can perform detailed mapping surveys of the seabed at depths of up to 3000 m (NTVA, 2005). Autonomous Underwater Vehicle (AUV) technology of this type reduces the high costs of using the alternative, cable-controlled technology (Remotely Operated Vehicles, ROVs) for surveys for sub-sea construction operations at great depths, as the 'umbilical' cables used by the latter put severe limits on the critical top speed of the submerged survey vehicle. The actual mapping systems and operations are more or less identical for ROVs and AUVs; nonetheless, removing the ROV cable introduces extremely complex technological challenges, particularly in relation to supplying the vehicle with the necessary energy, communication, and control.

An understanding of the basin and its petroleum system is important for efforts to find oil and gas. Basin modeling software has been under development for two decades with the aim of being able to develop quantitative estimates of oil and gas volumes in undrilled prospects and to predict the most likely hydrocarbon phases and compositions to be expected. A thorough understanding of the geological development of a basin is essential to carry out a rational process of exploration with the lowest possible risk of making poor decisions. This produces a large number of challenges.

Basin modeling, which aims to understand and quantify geological processes, is a research field in rapid development. One type of basin modeling software employs a raytracing methodology to model the movement of oil and gas in three dimensions along permeable layers (Figure 2.137) (NTVA, 2005). One of the challenges lies in following the hydrocarbons from their source past faults and other barriers until they are caught in a trap, or leak vertically upwards to the next porous layer or all the way to the surface. The results are calibrated against existing fields and dry wells by systematically varying individual parameters and assumptions of the model. This is done to test the sensitivity of the modeled processes to uncertainties in the geological model and thus improve the predictability of finding oil and gas. This has become a recognized method which is used by the petroleum industry to assist in quantifying the likelihood of making discoveries in undrilled exploration targets. The software

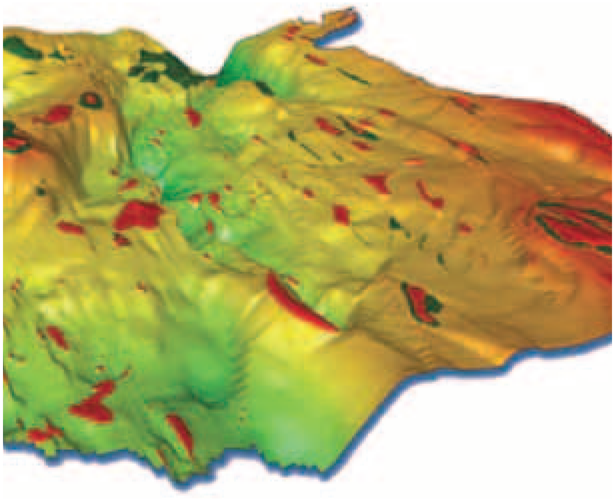


Figure 2.137. Illustration of a product from a 3-D basin simulator.

Figure 2.138. The Melkøya LNG plant and terminal.

deals with extremely large geological models of high complexity and it is also possible to perform stochastic simulations to reduce the uncertainty of exploration drilling even further.

The development of 3-D seismic technology was a very important innovation for oil operations. This technology has been greatly improved, and the latest innovation involves the introduction of 'production time' as the fourth seismic dimension. So-called 4-D seismic or 'time-lapse seismic' surveying is being used to monitor the movement of oil as it is produced in a reservoir, similar to the mapping of cloud system movements on a weather map using time-lapse satellite measurements (NTVA, 2005). Time-lapse measurements require exactly the same conditions during each recording of seismic data. The seismic sources must be steered to the same position, navigating each recording line in the same direction and steering the 3-km-long receiver cables to exactly the same positions. In order to obtain such accuracy, the vessels must tow seismic sources and seismic receiver cables equipped with GPS satellite navigation and an acoustic network. The receiver cables are made steerable with the help of small wings, which function similar to airplane wings. Time-lapse seismic surveys provide oil companies with such accurate data that oil production can be increased considerably.

Three-dimensional and 4-D seismic surveys generate data on the terabyte scale. Advanced computing systems are therefore required to analyze the data. Results from the analyses are presented in virtual 3-D reservoir models, which can be manipulated with advanced computer graphics. These advanced computing systems are now being expanded to enable remote onshore control when drilling complex horizontal wells offshore. The trend is towards further development of these systems in order to allow remote control of oil production itself from onshore control rooms.

2.5.3.2.2. Floating production platforms, sub-sea production systems, and multiphase technology

In their different variants, the fixed platforms represent the first generation of solutions on the Norwegian shelf. These were followed by the production vessels on *Norne* and *Åsgard*, before technology development pointed to the depths on *Snøhvit*. Floating production facilities offer a much higher degree of flexibility, not least in terms of their potential for re-use. The development of flexible risers from the fixed installations and to the production vessels and floating production platforms was a decisive factor in the ability to use floating installations.

Multiphase technology made its breakthrough in the development of the *Troll* gas field. The original plans for the development of this field were based on the concept of an integrated platform for drilling, production, process systems, and living quarters. However, the planning process showed that such a platform would be too heavy and would have too great a draught, which would make it impossible to tow from the shipyard in Norway out to the field. It was therefore proposed that the process plant for the platform be moved onshore. The result was the gas treatment terminal at Kollsnes in Øygarden. However, this required that multiphase technology be developed and proved for industrial use. The successful introduction of multiphase technology on *Troll* was of decisive importance for the development of *Snøhvit*. While the multiphase pipeline from *Troll* to Kollsnes is 63 km long, the distance from the sub-sea installations on *Snøhvit* to the LNG terminal at Melkøya outside Hammerfest is 143.3 km (see Figure 2.138).

The *Ormen Lange* gas field was proven by drilling in 1997. After an intensive period of studies, the operator decided in 2003 to develop the field without any platforms. The project's sub-sea production systems, with no sea-surface installations, are at the vanguard of ultradeep-water production solutions. The first two remotely controlled sub-sea production stations will be located 120 km from shore at 850 m water depth. From these stations, two 76.2-cm (30-in) pipelines will transport the well stream to the onshore plant at Nyhamna at the coast of mid-Norway for processing. The pipelines are laid across extremely irregular seabed with boulders and slide blocks up to 60 m high in the Storegga slide; the pipelines are crossing the slide with an inclination of up to 40 degrees (NTVA, 2005).

The special water current conditions give water temperatures as low as –1° C. Such extreme temperature conditions combined with high pressure can cause gas and water to form hydrates and ice, which can form plugs in the pipelines. The sub-sea system has been designed to avoid hydrates, and production simulators will be built to control the entire system to avoid hydrate problems (NTVA, 2005).

The installation of the Troll Pilot, a sub-sea separator, may represent the beginning of a platform-free future. The separator is installed on the seafloor to remove water from the well stream before taking it to the platform (Figure 2.139). This is the first sub-sea processing plant and this project represents a large advance in transferring platform functions to the seabed.

Sub-sea solutions depend critically on the transport of the untreated well stream, for example, oil, gas, and water in the same pipeline, known as multiphase transport. The active use of multiphase transport represents a paradigm shift in the way offshore oil and gas fields are developed on the Norwegian continental shelf as well as internationally. Multiphase transport has facilitated the development of smaller satellite fields close to existing platforms. This provided a simplified solution for the *Troll* gas field, in which the main part of the process plant was moved onshore, made possible by multiphase transport through the twin pipeline.

A computer program is used in the design and operation of offshore fields with multiphase transport. The development of this program relied partly on the building of the SINTEF multiphase laboratory, which provided realistic data for how oil and gas flow in a single pipeline. This multiphase flow laboratory, located in Trondheim, has a 1-km 20.3-cm (8-in) pipe with a capacity of 9539 m^3 (60 000 barrels) per day and is the largest test facility for multiphase flow. This program has made it possible to develop offshore fields as sub-sea solutions based on multiphase transport. The well stream (oil, water, and gas) is transported unprocessed, in a single pipeline, to an existing platform with available capacity, or directly ashore. The development of *Snøhvit* (see Figures 2.140 and 2.141) and *Ormen Lange* are examples of this application. *Troll* is an early example of the use of multiphase transport, which allowed the gas processing facilities to be moved ashore, at great savings in investments and operating costs (NTVA, 2005).

The development of technology for multiphase oil/water/gas flow measurements based on electrical impedance provides production engineers with important information about the quantity and distribution of oil, water, and gas in a multiphase flow. This allows the optimization of production and improves the exploitation of production capacity. Current multiphase flow meters are large and very expensive, but smaller and less expensive flow meters are under development. The goal is to have one meter per well, whereas today it is normal to have one meter per manifold which serves between five and ten wells. There is a need for high-technology, reliable well-monitoring tools. This is particularly true for sub-sea wells, for which it is extremely difficult and expensive to obtain up-to-date reliable information about the well, except by using multiphase flow measurement technology. Multiphase flow meters are used in wells at depths of up to 3000 m, for which a focus on reliability and well-designed functional solutions is extremely important.

Pumping, separation, re-injection of produced water, gas compression, and gas drying are new sub-sea functions that contribute to increasing recovery rates in sub-sea-based field developments (NTVA, 2005). An important challenge has been to gain control of the technical risks. Even though the functions that are to be transferred from an installation on the surface to the bottom of the sea are well-known in their original form, there are other issues and priorities that must be considered sub-sea. One consequence of equipment failure is longer down times and more expensive repairs. This means that development, testing, and qualification are essential.

The future will need increasingly advanced sub-sea technology. In a few years, it will be possible to send the well-flow directly from remote fields over much longer distances than today, to onshore terminals or to an existing infrastructure. This will be particularly useful in northern regions where ice conditions necessitate development on the seabed and ultra-long multiphase transport ashore. A possible solution is a system in which gas hydrates and other solids at the wellhead are formed and follow the flow. These are very complex transport systems to design.

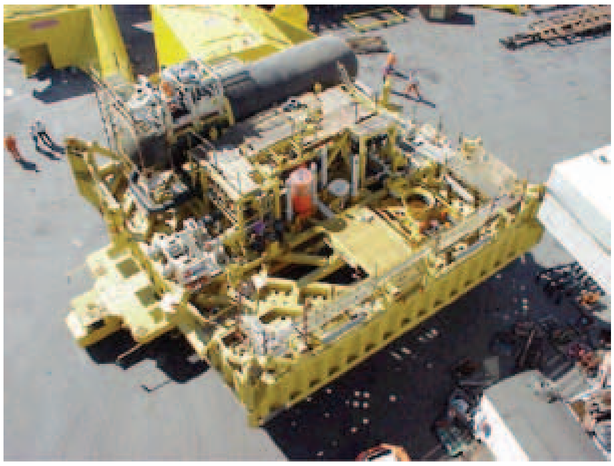


Figure 2.139. A sub-sea separator.

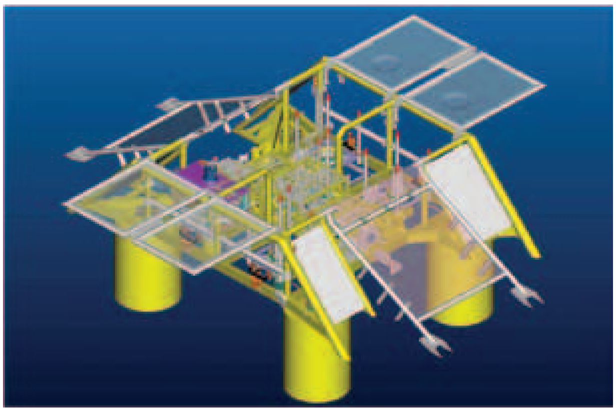


Figure 2.140. *Snøhvit* sub-sea templates (courtesy of Statoil ASA).

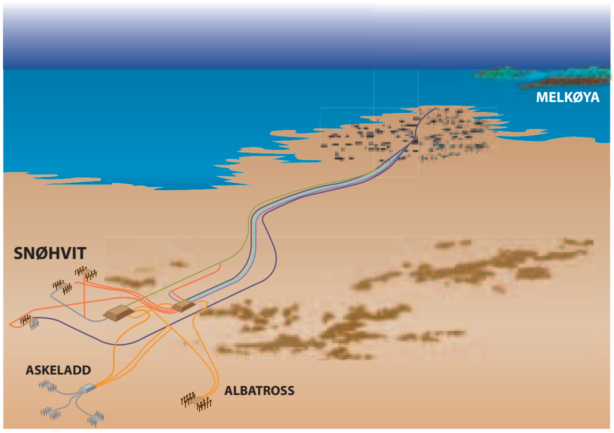


Figure 2.141. Schematic of sub-sea installations and pipelines of the *Snøhvit* field (courtesy of Statoil ASA).

2.5.3.2.3. Pipeline design

The design of pipelines is an important multidisciplinary task. It involves structural analysis, testing, fracture mechanics, material and corrosion technology, geotechnical assessments, and hydrodynamics. The costs of constructing a pipeline to new offshore fields are often one of the main cost elements of the development. Thus, it may be decisive for the economic analysis of the possibilities for developing the field. Many research projects have assessed a number of scenarios, including ultra-deep waters, in order to develop reliable codes with consistent safety levels; this is facilitating better designs and installation of more cost-effective pipelines offshore. Today, deep-water pipelines are laid with free spans of up to 200 m, whereas previously there was a maximum length of 30 m irrespective of environment and pipe-laying conditions.

The service life of pipelines is often determined by corrosion. This is particularly true for fields with high temperatures and fields in which corrosive elements are present in the oil. Current Norwegian projects include the development of a calculation method for the residual capacity of corroded pipelines (NTVA, 2005). This will facilitate the re-qualification of the pipelines, which will make it possible for the operator to determine that a pipeline may be in operation within a defined safety margin for an extra number of years, even after changes in the operational conditions or observation of damage.

An integral part of the production of oil and gas is that water and CO_2 accompany the well flow. In oil and gas pipelines with a high CO_2 content, internal corrosion attacks may occur at rates of up to 10 mm/y and there are cases of this having caused leaks from pipelines. *Snøhvit* is a gas field with a particularly high CO_2 content and, in the assessment of the field in the early 1990s, it was regarded as impossible to transport the gas ashore without separation. At that time, there were no methods capable of limiting the high corrosion rate that was expected. Before the development of the *Lille-Frigg* field, it was decided to try out a new method to limit corrosion in wet gas pipelines. Adding a base would reduce the acidity of the well flow and corrosion would be reduced through the formation of a protective corrosion product film. The method was first employed in the North Sea on *Lille-Frigg* in 1994, and it was demonstrated that the method was extremely efficient. The method is now known as pH stabilization. When pH stabilization in gas pipelines is achieved by the addition of sodium hydroxide, internal corrosion can be reduced by more than 95%. This is an inexpensive and environmentally friendly solution. Sodium hydroxide is a well-known chemical which does not cause harm to water or fish. The sodium hydroxide is regenerated continuously and only a limited refill is necessary every two to three years. The method is now undergoing further development for use in pipelines in which hydrogen sulphide (H_2S) is present in addition to CO_2 (NTVA, 2005). Corrosion control in wet gas pipelines by means of pH stabilization has been employed both on *Åsgard* and *Huldra*. The method has also been introduced in older fields such as *Heimdal* and there are plans to use it on *Snøhvit* and *Ormen Lange*. Work is on-going to optimize the method for these two major new developments in the Norwegian Sea and the Barents Sea.

2.5.3.2.4. Liquefied Natural Gas

One of the greatest challenges in the design and construction of vessels for the transportation of LNG is the low temperature required by the cargo, -163 °C. This makes most materials that are normally used in ship building unsuitable for LNG containment. The low temperature also requires a special design to ensure the safety of such vessels (see Figure 2.142).

At present, there are plans for gas tankers of up to 250 000 m^3. These tankers will probably be wider than conventional vessels and will need new designs for the hull and maneuvering. Sloshing and fatigue of the tanks will become increasingly important design parameters owing to the larger tanks and more demanding maritime conditions. Offshore terminals are receiving preference because of improved safety and security performance. The gas may be unloaded in liquefied and in gas form. This implies that the ships must be able to lie by the unloading buoys for up to a week with varying levels of liquid filling without damaging the interior of the tanks.

The *Snøhvit* field was discovered in 1984 and it was realized that if the gas was to be sold, it would have to be by means of a LNG facility and transport by sea owing to the great distance to the market; it was regarded as unprofitable to lay a pipeline all the way to Europe. To develop the LNG technology further and find less expensive solutions that would make it more attractive to develop *Snøhvit*, Norwegian companies began a cooperative effort that included extensive experimental work that aimed to develop thorough competence in the properties and behavior of natural gas during refrigeration to the liquefied state. A thermodynamic package and a database containing the properties of natural gas at low temperatures were developed (NTVA, 2005). In addition, a large simulator was produced that was capable of simulating the whole LNG process. With this tool, it was possible to find energy- and cost-optimal solutions that also resulted in a new LNG facility which was less expensive. One of the greatest challenges was to develop main heat exchangers that would be much less expensive than those that were standard at the time. The main heat exchangers that are used to cool down the natural gas to such low temperatures are among the largest and most expensive components in an LNG facility. Ultimately, cost-effective heat exchanger equipment was developed, tested, and built for LNG purposes; the first became operational at a large facility in 2004 (NTVA, 2005).

Traditionally, import terminals for LNG have been built on land. However, there is growing skepticism among

Figure 2.142. LNG carrier

local people about locating these facilities on land owing to the fear of gas leaks and explosions as a consequence of terrorist attacks or sabotage, environmental pollution of the coastal areas, and increased shipping activity. This has resulted in the planning of offshore terminals. The design of offshore solutions will often be a compromise between employing standard LNG vessels and a safe and reliable cargo transfer system. All known solutions have weaknesses in one or both of these areas. LNG is a cold fluid (-163 °C) that makes severe demands of materials and equipment.

2.5.3.2.5. Operations

Increasing use is being made of simulators. A simulator of a processing facility can be used in all phases of the service life of the facility: for planning purposes, for construction, and for operational purposes. Potential problems in a process can be detected and the control system verified and modified before it is brought into use. Accurate simulation models are also used to calculate important, non-measurable, conditions. A simulator that is directly connected to the measuring system is able to warn about abnormal conditions in the process by comparing the measurements against simulated values.

The production system on the continental shelf is becoming increasingly complex and operations require steadily better coordination. Simulation models of the total systems help operators to maintain an overview of everything that is going on and to optimize the production process. A simulator is also an efficient tool for teaching operators to control the process better. As well as gaining insight into the normal running of the process, the operator has the opportunity to train especially on more demanding situations such as start-up, shut-down, and malfunctions, as well as accidents.

The reliability of exploration and production equipment has an important influence on safety, production availability, and maintenance costs. Safe, reliable production in the petroleum industry, particularly offshore, is essential in order to provide a high degree of technical integrity. The joint industry project OREDA® (Offshore Reliability Data) has collected experience data in order to determine the frequency and cause of equipment malfunction on offshore oil and gas installations (NTVA, 2005). Failure and maintenance data for equipment on platforms and sub-sea has been collected since 1981. OREDA is currently being sponsored by eight international oil companies, and the project has established an important source of reliability data in the offshore area for use in design and maintenance planning. OREDA's main objective is to collect and exchange reliability data among the participating companies, as well as exchanging data and reliability experience with the equipment suppliers. It acts as a forum for the coordination and management of reliability data collection in the petroleum industry.

SINTEF has been the project manager for this project since 1992 and has, on behalf of the project, published several reliability data handbooks. Experience and knowledge developed in this project have been collated into an ISO standard, ISO 14224 'Petroleum and Natural Gas Industries – Collection and Exchange of Reliability and Maintenance Data for Equipment'; initially issued in 1999, this standard was revised and re-issued in 2006.

A reliability study for well-completion equipment was launched in 1990. As many as 16 oil companies have participated in the project and submitted daily reports containing data on any malfunction of the well equipment from more than 2200 wells. This project includes a comprehensive database which describes all the components in each well, with a complete history of how they have worked and malfunctioned. On the basis of this database, it is possible to calculate and predict the service life and the reliability of each separate well and equipment item, enabling the selection of well components based on documented reliability. The documented improvement in reliability has led to a considerable increase in safety levels on offshore installations and provided savings owing to reduced intervention costs. The technology has also led to higher production regularity in a number of installations.

2.5.3.2.6. Purifying produced water

The platforms in the North Sea discharge produced water in large volumes. In a major project, scientists have developed a process in which the oil and other substances are removed from the produced water before it is discharged. Between 1990 and 2000, it is estimated that discharges of produced water rose nearly ten-fold to 120 million tonnes. The requirement of the authorities is that there should be a maximum of 40 ppm oil in the produced water when it is discharged. New technology reduces emissions of harmful components (benzene, toluene, xylene, and PAHs) by 70 to 95%, that is, below the acceptable limit set by the authorities for the oil and gas fields in 2005 (NTVA, 2005).

2.5.4. Assessment of past practices, BAT, and new technology

Early oil exploration activities in the Arctic used conventional techniques and were characterized by a lack of understanding of the effects of human activities on the fragile Arctic ecosystems and the long-term nature of impacts on Arctic vegetation and tundra. These impacts were particularly obvious in the damage to the tundra from heavy vehicles, the fairly wide swaths of boreal forest cut for seismic survey lines, the large size and number of drilling pads for exploration wells, and the sumps of drilling wastes and other wastes from the human activities near the drill sites. Remediation efforts have been successful in some, but not all, of the impacted areas.

Based on experience gained in the early years, the progressive development of technology, and the establishment of regulatory requirements, the footprint of exploration and production activities has considerably decreased in recent years. Currently, best practice for onshore activities includes: a) use of low-impact seismic survey techniques, including the use of GPS, remote sensing, and computer power; b) use of light-weight vehicles with large, low-pressure rubber tires; c) construction of ice roads and ice drilling pads so that only the wellheads are visible during summer; and d) good environmental practices including deep-well injection of both solid and liquid oilfield wastes. Best practice for offshore seismic activity includes the use of better source and streamer arrays and better techniques, including gradual ramping up of the seismic source to reduce impacts on marine mammals and fish.

A new technology in the early stages of application both onshore and offshore is the use of directional drilling, which allows many wells to be drilled from a single pad. The relatively new operation of coiled tubing drilling may be used for this purpose. Extended-reach drilling technology is advancing rapidly, with longer lateral distances being reached as well as the ability to access narrower horizontal sections using an 'intelligent' drilling system with a two-way communication link. Use of this technology will reduce the number of wells required to develop a reservoir, thus considerably decreasing the area of surface disturbance, which is particularly important in the fragile Arctic environment.

A major new technology under development for offshore application is the use of remotely controlled sub-sea production systems, with no sea-surface installations. Utilizing multiphase technology to transport oil, gas, and water in the same pipeline, means that the process plant for the platform can be moved onshore. Elimination of the need for surface installations provided by this technology will be particularly useful in Arctic areas, where impacts from ice and heavy storms create serious structural demands on offshore surface installations.

2.6. Physical impacts and disturbance

Oil and gas exploration and development activities on land cause a wide range of physical impacts and disturbance. These include changes to the physical landscape, disturbance to plants and animals near exploration and development activities, and fragmentation of the habitat near roads and pipelines. Early exploration and development activities were conducted without an understanding of the fragility of the Arctic environment and the very long time needed to recover from damage; thus, the 'footprint' left by these early activities was often large and scars are still evident in some areas today (Figure 2.143). Although the use of new procedures developed specifically for use in Arctic conditions and more modern technologies have resulted in a significant reduction in the 'footprint' created by oil and gas activities, it is not possible to avoid completely physical disturbances and impacts on the habitat and biota in areas where petroleum activities are conducted. Thus, the cumulative effects from past and current activities may continue to increase, although at a slower rate than was previously the case.

Figure 2.143. Tracks on the tundra left by oil and gas exploration activities, Mackenzie Valley, Canada.

This section presents an overview of physical impacts from oil and gas activities on land and in coastal areas. Additional information is given in section 2.7 (disturbances from noise on land and at sea) and Chapters 5 and 6 (ecosystem impacts from physical disturbances and terrestrial and marine oil spills). The general descriptions of habitat damage and loss presented in this section are also supplemented by the more detailed information concerning specific habitats and biota that may be impacted by oil and gas activities in the various oil and gas provinces and Large Marine Ecosystems in the Arctic presented in Chapter 6.

Some physical disturbances from oil and gas exploration and development activities are temporary, such as noise from the overflight of aircraft or the passage of supply ships, noise from seismic exploration, and noise and the presence of humans in road traffic. Impacts from such disturbances vary with the time of year (e.g., fewer animal species are present in winter) and the life cycle of the affected species. Key reproductive stages, such as nesting (birds), spawning (fish), migration (marine mammals), denning (bears), and calving (caribou/reindeer), are generally the most sensitive to physical disturbances and the consequences of disturbance during these periods are more critical than at other periods of the year.

Many disturbances from oil and gas activities are long term or even permanent, affecting soils, vegetation, and drainage patterns, creating impoundments of water, and developing barriers to the movement of animals via the construction of roads, pipelines, and other structures. These long-term disturbances affect the quality and availability of habitats. Fragmentation or loss of parts of a species' habitat may affect the distribution of the species, while loss of high value habitats can have immediate adverse consequences for the populations of animals and plants that they support. Although remediation of damaged habitats is possible, this is usually a very long-term process in the Arctic owing to the low temperatures and low-nutrient soils.

2.6.1. Types of disturbances and impacts on habitats

2.6.1.1. Impacts on soil

A number of activities associated with oil and gas exploration, development, and production may impact on soils. Where such activities do not alter the vegetative cover, there is generally only a small impact on the soil. However, where activities are concentrated so as to create surface disturbance, the soils may become damaged. Soil stability depends on vegetative cover. If the vegetative cover or surface organic mat is removed or disturbed, soil erosion can occur. In permafrost areas, surface soils thaw naturally during the warmest months, resulting in an 'active layer' depth of around 25 to 45 cm, depending on the location, aspect, vegetation type, soil composition, and water content. Generally, a loss of vegetation cover would cause the greatest change in the thermal balance of the soil. Soils containing ice may lose volume when thawing, resulting in subsidence, thermokarsting, and gullying (BLM, 2005).

Oil and gas exploration and development activities on land result in a number of changes to the physical landscape. Work and camp pads, roads, and pump stations are usually constructed from sand, gravel, or rock fragments and completely cover the natural soils. Landscape scarring resulting from working material sites, conventional pipeline construction, and digging, excavation, and placement of fill is particularly damaging in the Arctic owing to the slow rate of soil formation. Soils in many areas of the Arctic are subjected to cold and anoxic conditions that retard soil formation, allowing exposed mineral soil layers to persist for decades (BLM, 2005).

Seismic surveys and exploration drilling activities occur in most, if not all, Arctic areas during winter months when the ground is frozen. Nonetheless, traffic from camp move vehicles (camp trains with several strings of trailers) and heavy survey equipment may result in soil compaction. Although modern seismic equipment and vehicles employ low-ground-pressure equipment and designs, which have much less impact on the tundra than older equipment, camp moves can still impact on the tundra and cause thermokarst. Removal of the organic mat exposes soils to erosion by wind and water, which can enhance sediment deposition into water bodies. Limiting land seismic surveys to snow-covered areas greatly reduces the potential for thermokarst and long-term impacts on the tundra. In general, 3-D surveys have the potential to cause greater impacts on the soil than 2-D surveys because tighter turns by heavy equipment are required (BLM, 2005). Soil compaction resulting from on-road vehicle traffic could increase localized ponding and permafrost degradation. Seismic surveys and overland moves can also alter the thermal balance of the soil as well as increase the risk of thermokarsting.

Exploration activities conducted during colder months are able to employ ice pads for drilling exploratory or delineation wells and ice roads to access these pads. These provide a viable alternative to the use of gravel pads and roads and generally cause only localized impacts on soils, usually limited to compression of the tundra immediately under the ice roads and ice pads. Development of a field, however, will entail the construction of central production facilities and associated satellite pads, roads, a pump station, and airstrips, all of which will result in the loss of soil productivity in areas where gravel is placed. The construction of gravel pads, roads, and airstrips can also alter the moisture regime of tundra near the structure by changing natural drainage patterns and areas where snow accumulates. Snowdrifts caused by gravel structures increase the wintertime soil surface temperature and increase thaw depth in the soil near the structures. These impacts are exacerbated by dust deposition and by the formation of impoundments. These factors may combine to warm the soil, deepen thaw, and cause thermokarst adjacent to roads and other gravel structures.

Mining for gravel required for the development of pads and other facilities for oil and gas production will affect soil productivity at the gravel extraction sites. Also, removal of gravel from areas near streams and lakes can cause changes to stream or lake configurations, stream-flow hydraulics, and lake shoreline flow patterns, erosion and sedimentation, and ice damming (NRC 2003 in BLM, 2005).

Permafrost contains a substantial amount of ice, and this contributes to the support for buildings, roads, and pipelines placed on these surfaces. Accordingly, structures for oil and gas development constructed on permafrost must be designed to avoid thawing of the foundations. To avoid thawing, roads and buildings must be elevated on thick gravel berms or pads or on pilings. Gravel berms for roads may need to be as high as 2 m above the tundra surface to ensure that the underlying substrate remains frozen. These roads can therefore block natural drainage and create ponds that thicken the active layer and initiate thermokarst. Heated buildings can also thaw the permafrost leading to thaw settlement, if they are not elevated on pilings or they lack insulated and refrigerated foundations. On pads with closely spaced wells, extensive refrigeration with passive heat pipes and insulation is needed to ensure that the heat from the fluids does not melt the permafrost (BLM, 2005).

Pipelines built on vertical support members should have a minimum height of 1.5 m above the ground to ensure that the heat from the transmission of warm fluids does not thaw the surrounding permafrost, causing differential settlement and potential damage to the pipeline; this height is also needed to minimize disturbance to caribou/reindeer herd movements. Vertical support members for pipelines displace vegetation and disturb a zone with a radius of around 0.5 m resulting from the overburden deposited around the structure as well as from thermokarst (BLM, 2005).

The duration of the impacts on soils associated with oil and gas development range from the short term (one to five years) if the soil is disturbed, up to several decades if the soil is removed. Even if the soil is restored as sites are abandoned and reclaimed, the harsh Arctic climate means it can take several hundred years for soil productivity to reach pre-disturbance levels.

2.6.1.2. Impacts on vegetation

Seismic operations, exploration drilling, the construction of ice roads and ice pads, the construction of gravel roads, pads, and airstrips, and pipeline construction can all impact on vegetation.

In general, low ground-pressure wheeled vehicles have less impact on vegetation than tracked vehicles or sleds on skids. In wetter tundra areas, impacts are usually limited to trails caused by the compression of snow and dead plant material; such trails are often visible for one to several growing seasons. In general, wet areas are less affected than dry areas, and snow acts as a buffer against these impacts. Tracked vehicles can disrupt the vegetation surface when making tight turns. In wet tundra this disruption can result in water accumulation and thermokarst, while in drier tundra, travel over low shrubs can cause breakage and tussocks may be broken or crushed.

Winter seismic surveys impact on vegetation along the survey track. Similar impacts result from camp move vehicles traversing about the same distance as that surveyed. Trails are also made by camp move vehicles while travelling to and from the survey areas, which increases the area affected.

The construction of ice pads for drilling exploratory or delineation wells and ice roads used to access the pads may also impact on vegetation. In general, the construction of ice roads and ice pads will have only localized impacts on vegetation, usually limited to compression of the tundra under the roads and pads and a shortened growing season for the plants due to delayed melting of the ice in the spring. However, ice roads may also cause localized areas of plant death. The construction and use of ice roads and ice pads in drier habitats may result in the breakage of shrubs and the breakage and crushing of tussocks. Recovery from impacts on vegetation may take a few years. In contrast, if the exploration activities employ gravel pads and roads, the vegetation under the gravel will be destroyed and the impact will be the same as that from development and production activities.

Oil development and production activities that affect vegetation include the construction of gravel pads, roads, airstrips, and pipelines, the excavation of material sites, and the construction of ice roads. The construction of central processing facilities and associated pads, roads, and airstrips causes the destruction of vegetation where the gravel is placed. Also, the passage of vehicle traffic over the gravel pads and roads results in dust and gravel being sprayed over vegetation within about 1 m of the pad or road and a dust shadow out to at least 50 m. This dust and gravel may smother vegetation within 10 m of gravel structures. The dust may also result in early snowmelt, reduced soil nutrient concentrations, lower moisture, an altered soil organic horizon, and higher bulk density and depth of thaw, such effects may result in reduced plant species richness and altered species composition near gravel structures, particularly in naturally acidic soils. In areas of heavy dust fallout, native plant communities could be killed and replaced by early-successional colonizers and species more tolerant of the altered conditions. The magnitude of these effects depends on the duration of dust exposure and distance from the source (BLM, 2005).

Impoundments, which are generally confined to areas of wet and aquatic vegetation, can alter both the hydrology and species composition of wetlands. Plant productivity could increase the biomass of a few species; or productivity may decrease as a result of the loss of plant communities to the development of deep, open water areas. In most cases, impoundments will lead to a decrease in plant species richness.

Although vegetation is a renewable resource and impacts on vegetation are often reversible, owing to the harsh climate and short growing season in the Arctic, it may take plants decades to centuries to recover from a disturbance. The greatest impacts occur where vegetation is removed or buried under gravel or other material that destroys the vegetation.

2.6.1.3. Impacts on water resources, lakes, and streams

Natural drainage patterns can be disrupted when activities or structures divert, impede, or block flow in stream channels, lake currents, or shallow-water tracks. Blockages in areas with low flow capacity, especially culverts blocked by snow and ice, can result in seasonal and sometimes permanent impoundments. Diverting stream or lake flows can also lead to increased bank or shoreline erosion and sedimentation. Any surface activities that disturb streambeds and stream banks can lead to channel erosion, the formation of meltwater gullies, and the formation of alluvial fans in streams and lakes.

Construction may result in short-term subsidence of the ice-rich permafrost along stream banks and lakeshores. Fine-grained sediments melting out of the ice-rich permafrost increase sediment erosion and the associated changes to stream channel morphology.

Roads pose the single most critical impact on water resources owing to the diversions, impoundments, and increased sediment runoff that they create.

2.6.1.4. Disturbance to fish and fish habitat

The potential impacts of oil exploration and development activities on freshwater, anadromous, and amphidromous fish include vibrations from winter seismic activities near sensitive overwintering habitats; loss of overwintering habitat from water withdrawals from freshwater lakes; degradation or blockage of water bodies used as fish migratory corridors or feeding grounds resulting from the construction and placement of pipelines, pads, ice and gravel roadways, airstrips, and causeways; loss or degradation of habitat from gravel extraction, or crude and refined-oil spills; and loss or degradation of habitat from gravel structure erosion.

The life cycles of freshwater and diadromous fish species in the Arctic are adapted to the long winters and low productivity. After spring ice break-up, fish move quickly during the brief summer into many habitats, often at great distances from the wintering area. Locating a suitable wintering area at the end of the summer is critical to survival. In many Arctic areas, less than 5% of stream habitat remains available to fish by late winter owing to freeze-over. These widespread movements, and the greatly restricted area of habitat available to fish in winter, make many species highly vulnerable to the effects of oil and gas exploration and development.

Unavoidable adverse effects include short-term avoidance behavior and stress related to seismic vibration activity; loss of habitat and reduced productivity created by gravel excavation in spawning, rearing, and overwintering areas; degradation and loss of habitat and mortality of fish eggs and larvae from erosion and sedimentation in streams and lakes; and lethal and/or sub-lethal effects on fish from oil spills.

Peat and gravel roads and pads, and gravel mines cause the direct loss of fish habitat, and the indirect loss of fish habitat due to erosion and sedimentation along streams and rivers, and alteration of natural drainage patterns. In addition to causing the loss of fish habitat, gravel fill may occur in wetlands where cross-pad drainage has been blocked by road construction. During spring ice break-up, there is substantial flow across expansive wetlands into lakes and streams. When long stretches of gravel road or pad interrupt the flow, the difference in water surface elevation from one side of the pad or road to the other can produce high-velocity water flow in the cross-pad/road drainage structures, usually culverts, which can inhibit upstream fish movements and delay migration to summer habitats. The delays are a particular issue for species that spawn shortly after ice break-up and that undertake long, rapid migrations from wintering areas to spawning sites.

The opposite effect can occur in mid- to late summer when stream flow is low. Fish that disperse during or after spring ice break-up must leave small drainage areas and shallow lakes by late summer to reach wintering areas before the waters freeze because there are often limited or no opportunities for overwintering within the habitats used for summer feeding. Fish that cannot leave would freeze. Too few or improper placing of culverts or modifications to the stream bed can cause flow to go below the surface or to become too shallow to allow downstream movement when flow levels are reduced in late summer.

Fish habitat is also affected if culverts are not properly installed or sized, thus changing water flows or causing the formation of ice jams. If incorrectly sized, engineered, or constructed, impacts on fish associated with bridges, pipes, and culverts will persist and accumulate.

In coastal areas, developments that pose the greatest risk of causing effects include facilities that change physical conditions that are important to nearshore biota, for example causeways. Coastal fish species may be affected by the construction of solid gravel causeways that may extend several kilometers from the coast. These are used for offshore drilling, year-round seawater extraction, and as docking facilities for sea-based supply. Their solid construction enables them to withstand the immense pressures of shifting coastal ice in late winter and spring. However, they also have the potential to physically block fish moving along the coast and/or to alter coastal circulation and mixing patterns so that hydrographic conditions become inhospitable for anadromous and amphidromous species, for which the nearshore coastal zone is a prime summer feeding ground.

2.6.1.5. Disturbance to birds and bird habitat

Activities related to oil and gas development and production, such as vehicle, aircraft, pedestrian, and boat traffic, routine maintenance activities, heavy equipment use, and oil-spill clean-up activities can cause disturbances that would affect tundra-nesting birds. These disturbances can result in temporary or permanent displacement from preferred foraging, nesting, and brood-rearing habitats, decreased nest attendance, nest abandonment, and increased energy expenditures that could affect the physiological condition of birds and avian survival or reproduction. The likelihood for impacts on tundra-nesting birds will depend on the location of the disturbance, the species and number of individuals in the area, and the time of year. Impacts are most likely to occur when facilities are located in habitats with high bird concentrations, or if species with low population numbers or declining populations are disturbed.

During the summer, birds may be subjected to disturbances caused by vehicular and pedestrian traffic, and by noise from equipment on roads or at facilities, including large trucks hauling cranes and other equipment and road maintenance equipment on access roads and pads. Disturbances would be most prevalent during the pre-nesting period when birds gather to feed in open areas near roads, and during brood-rearing and autumn staging when some species such as geese exhibit higher rates of alertness in areas near roads than do birds in undisturbed areas. Disturbance to birds occurs most often within about 50 m of roads, but may extend out as far as 220 m from roads. Disturbance from vehicular traffic may affect activity and energy budgets and have negative impacts on nest density and success for some birds. Higher shorebird densities may occur in areas near the coast compared to inland areas and disturbance that occurs in coastal areas may have a greater impact on shorebirds than inland disturbances.

The use of fixed-wing aircraft and helicopters to transport personnel, supplies, and equipment to airstrips or staging areas during development and production activities creates the potential for disturbance to waterfowl and other birds. Responses of birds to overflights of aircraft include alert postures, interruption of foraging behavior, and flight. Disturbances from aircraft may displace birds from feeding habitats and negatively impact their energy budgets.

Responses of birds to routine aircraft flights into airstrips range from avoidance of certain areas to the abandonment of nesting attempts or lowered survival of young, with the greatest negative impact of aircraft noise probably occurring during the nesting period, when the movements of incubating birds are restricted.

Construction activities result in a permanent loss of some bird habitat. Gravel mining and placement for the construction of oil field infrastructure causes loss of habitat for tundra-nesting birds. During construction of oil field roads and pads, tundra covered by gravel, as well as tundra associated with gravel mine sites, is lost as nesting, brood-rearing, and foraging habitat. This loss of habitat continues throughout the operation of the oil or gas field, and will be permanent unless habitat restoration measures are successfully implemented after abandonment of the oil/gas field. In addition, a functional loss of habitat may occur in areas near roads and pads if development-related disturbances preclude birds from using these habitats. Impacts related to habitat loss may be more severe for species that have specific habitat requirements or are species of special concern due to low population numbers.

In addition to permanent habitat loss, temporary loss of habitat associated with gravel placement may occur on tundra adjacent to gravel structures, where accumulated snow from snow-plowing activities or snowdrifts would become compacted and lead to a delayed snowmelt. Delayed snowmelt persisting into the nesting season could prevent tundra-nesting birds from nesting in these areas. Delayed snowmelt resulting from the construction and use of ice roads during winter activities can also cause temporary habitat loss. Ice roads can also reduce the availability of cover for nesting birds in the ice-road footprint by compacting vegetation.

Water withdrawal from lakes during ice-road construction can lower the water level and affect waterfowl and shorebirds that use adjacent habitats, particularly small islands and shoreline areas used for nesting. Changes in water levels depend on the amount of water withdrawn, the volume of the lake, and the recharge rate.

Dust deposition can affect bird habitat by causing early green-up on tundra adjacent to roads and pads, which could attract waterfowl and shorebirds early in the season, when other areas are not yet snow free.

Impoundments created by gravel structures can cause temporary or permanent flooding on adjacent tundra. Impoundments may be ephemeral, drying up early during the summer, or could become permanent water bodies that persist from year to year. Tundra covered by impounded water could result in a loss of nesting habitat, but could also create new feeding and brood-rearing habitat.

Some predators, such as ravens, gulls, Arctic fox, wolverines, and bears, may be attracted to areas of human activity where anthropogenic sources of food and denning or nesting sites occur. Availability of anthropogenic food sources, particularly during winter, could increase winter survival of Arctic foxes and contribute to increases in their population. Increased levels of predation due to elevated numbers of predators could in turn affect nesting and brood-rearing birds. Predators attracted to areas of human activity could also affect tundra-nesting birds by depredation of eggs and young.

Bird mortality may occur from collisions with buildings, vehicles, aircraft, vessels, towers, pipelines, platforms, or other structures associated with onshore and offshore oil and gas development. However, such mortality is generally small.

2.6.1.6. Disturbance to terrestrial mammals and their habitat

The primary effects of oil and gas exploration and development on terrestrial mammals include habitat loss and disturbances that displace them from preferred habitat areas or cause changes in their behavior. Impacts on terrestrial mammals can occur from motor vehicle, foot, and aircraft traffic; seismic operations; oil spills; gravel mining; and construction.

Potential causes of disturbance from seismic activities and overland moves include helicopter and fixed-wing aircraft traffic, surface-vehicle traffic on ice roads, and people on foot. Exploration activities, particularly seismic testing, and human presence pose potentially serious disturbances to denning bears.

Caribou and reindeer may be disturbed by traffic, people on foot, and low-flying aircraft, particularly when they circle over an area. The response of caribou to disturbance is highly variable, ranging from no reaction to violent escape reactions depending on the distance from human activity; the speed of the approaching disturbance source; the frequency of disturbance; the sex, age, and physiological condition of the animals; the size of the caribou group; and the season, terrain, and weather.

Road traffic causes a delay in the successful crossing of pipelines and roads by caribou/reindeer, and could have adverse energetic effects on some animals. Caribou cow and calf groups appear to be the most sensitive to traffic, especially in early summer during and immediately after calving, while bulls appear to be least sensitive all year. Grizzly bears, wolves, Arctic foxes, and other mammals generally seem to be less affected by roads than caribou.

Caribou, however, are generally insensitive to disturbance when under extreme insect harassment. When insect harassment abates, caribou drift inland to better foraging areas. At this time, they are more sensitive to disturbance, and infrastructure and activities in oil fields or roads between oil fields can delay or alter movements of caribou from coastal insect-relief areas to foraging habitat further inland. Impaired movements between insect-relief habitat and inland foraging areas may reduce food intake and slow rates of weight gain. The probability of producing a calf is directly related to the body weight and fat content of females during the previous autumn (Cameron et al. 2000 in BLM, 2005). Because the reproductive success of caribou is highly correlated with nutritional status (Cameron et al. 2002 in BLM, 2005), there could be reproductive consequences from extensive disruption of caribou during the insect-relief season.

For caribou in the Alaskan *Prudhoe Bay* and *Kuparuk* oil fields and pipeline-road corridors, the greatest anthropogenic influence on behavior and movement is vehicle traffic within the pipeline-road corridors. Caribou generally hesitate before crossing under an elevated pipeline, and may be delayed in crossing a pipeline and road for several minutes or hours during periods of heavy road traffic; however, successful crossings do occur. Furthermore, roads and gravel pads may provide some relief for caribou from insect harassment. Studies have shown that the presence of the *Kuparuk River* oil field does not seem to have adversely affected the population size of the Kuparuk caribou herd, which calves within the oil field.

Unlike caribou, muskox are not able to travel and dig through snow easily. In winter, they search out sites with shallow snow, and greatly reduce movements and activity to conserve energy. Muskox survive the winter by using stored body fat and reducing movement to compensate for low forage intake. For this reason, muskox may be more susceptible to disturbances during winter; repeated disturbances of the same animals during winter could result in increased energetic costs that could increase mortality rates.

2.6.1.7. Disturbance to marine mammals and their habitat

Potential noise disturbance to marine mammals can result from support travelling to and from exploration and production facilities, and from seismic activities. Effects should be localized and short term, and include displacement from preferred resting and feeding locations.

During summer, some of the air traffic to and from exploration and production facilities may disturb ringed, bearded, and spotted seals hauled out on nearshore ice or beaches. Such disturbance may cause the displacement of seals into the water. Aircraft disturbance to seals hauled out along the coast or on nearshore ice is not likely to result in the death of any seals, although increased physiological stress from frequent disturbance could reduce the fitness of individual seals.

For most of the year, polar bears are not very sensitive to noise or other human disturbances. However, exploratory drilling near the coast in winter (December to mid-April) will potentially disturb, displace, or attract polar bears. Female polar bears denning within 2 km of the construction activity could be disturbed by vehicle traffic or construction noise. Disturbance of females in maternity dens could result in abandonment of the cubs or premature exposure of cubs. In general, pregnant females and those with newborn cubs in maternity dens both on land and on sea ice are sensitive to noise and vehicle traffic.

Gravel placement for the construction of drilling and production islands, offshore platforms, drilling ships, and the installation of buried pipelines alter habitats for marine mammals. Gravel placement for island construction generally covers relatively small areas of benthic habitat, but these habitats will be permanently lost. Installation of sub-sea pipelines may cause short-term effects on benthic habitats that are likely to persist for less than a year. Marine mammals usually have large territories and are not dependent on local food sources; thus, the effects of habitat loss on marine mammals due to offshore oil and gas production is unlikely to be cumulative.

2.6.2. Estimates of habitat area impacted by oil and gas activities

Very few estimates have been made of the amount of land in the Arctic that has been affected by oil and gas activities; however, some estimates have been made for the area affected by exploration in the National Petroleum Reserve-Alaska (NPR) during the period 1974 to 1976, when second-generation technology was in use (see section 2.5.2.3). This technology generally involved the construction of one well per pad and the gravel pads were initially relatively large as they each included a storage area for drill cuttings. As low-departure deviated wells were normally used, there was a need for many pads, which were constructed at an average spacing of around 5 km. All pads were connected by gravel roads to a central processing facility, from which oil was transported down the Trans-Alaska Pipeline. During the early phases, 81 exploration wells were drilled in the NPR. Each well affected an area of around 0.16–0.20 km^2. Measurements of the affected areas during remediation efforts in the late 1980s and early 1990s showed a total surface disturbance for the entire NPR of about 2.2 km^2, comprising around 1 km^2 in drill pads and reserve pits, 0.7 km^2 in borrow pits, 0.42 km^2 in airstrips, and 0.06 km^2 in burial sites for waste (Banet, 2006).

For the North Slope of Alaska as a whole, it has been estimated that infrastructure and gravel mines occupy an area of around 100 km^2 (slightly less than 0.1% of the area of the coastal plain tundra), and that tundra travel may have impacted an area of similar extent.

Although oil and gas activities Arctic Alaska have to date generally created only small but locally intense terrestrial disturbances, the impacts of these small-scale disturbances on wildlife may be disproportionate to their spatial extent by creating micro-scale heterogeneity with patches that can either attract or repel animals. Networks of roads and pipelines, together with human settlements, contribute to habitat fragmentation that also affects wildlife.

In parts of northwest Siberia, the actual and potential impacts of oil and gas activities are greater than those in Arctic Alaska by an order of magnitude, due to little or no adherence to, or enforcement of, regulations aimed at mitigation. For example, in the Yamal-Nenets Autonomous Okrug, disturbance of soil and vegetation cover and associated shifts in the tundra landscape (bogging, littering, and chemical contamination) are clearly evident in the Pur, Nadym, Taz, and Yamal areas where oil and gas sites are still being developed without due attention being given to environmental regulations and policies. The State environmental control determined that, as of 1 January 2004, the total area of disturbed land amounted to over 1500 km^2 or somewhat more than 0.13% of the okrug area; nearby land areas are on the verge of changes in their natural state. Soils in some areas have accumulated large amounts of oil, up to 10 g per 100 g of soil; taking into account remediation rates (25 years in the medium taiga zone and over 50 years in forest tundra and northern taiga), this will lead to significant ecosystem disturbance and long-term withdrawal of contaminated lands from traditional economic activities. On the Taz Peninsula, 6000 to 7000 km^2 of tundra land have been disturbed, which is around 1.5% of the total land area.

2.7. Noise from oil and gas activities

Noise in the environment occurs at differing levels, frequencies, and durations and from many sources, some of which are natural. Noise varies geographically, seasonally, and diurnally. The perceived loudness of any given noise or sound is influenced by many factors, including both the frequency and pressure of the sound (Gausland, 1998), levels of background noise, the distance and physical environment through which the sound travels before reaching the recipient, and the sensitivity of the recipient to sound (Box 2.17).

Noise arising from oil and gas activities can contribute disturbance above background levels. Noise may be generated in all phases of oil and gas activities: exploration, development, production, and decommissioning. The sources and effects may be in offshore or onshore areas or in a combination of both. More information on the effects of noise associated with oil and gas activities can be found in Chapter 5, section 5.3.8.

2.7.1. Noise in the marine environment

To evaluate potential effects of noise from oil and gas activities, the noise levels need to be viewed in relation to background or ambient noise in the Arctic.

The Arctic marine environment receives many natural and anthropogenic sounds that can vary in level and source within and between seasons, regions, and sites. The level of ambient noise is dependent on: a) physical conditions (i.e., water depth, current speed, temperature, salinity, density layering; sea ice thickness and distribution; wind; precipitation; seafloor bathymetry, substrate, and sediments; and proximity and configuration of the coast); b) the presence of marine mammals; c) the presence of marine activities such as industrial shipping and land-based industrial, research, community, and subsistence activities; and d) other miscellaneous factors. In general, ambient noise in the Arctic marine environment is in the range 63 to 133 dB (Burgess and Greene, 1999) and varies seasonally (Table 2.75). For information on the characteristics of sound transmission in the marine environment, see Box 2.17.

The measurement of underwater sound levels has historically been complicated by a system of inconsistent and confusing units (MMS, 2006a). Sound pressures in underwater sound studies are reported in terms of peak-peak, 0-peak, peak-equivalent rms, and rms (root-mean-square) (Madsen, 2005). Root-mean-square is linked to the derivation of power measurements from oscillating signals. The magnitude of sound pressure levels in water is normally described by sound pressure on a decibel scale relative to a reference rms pressure of 1 μPa (dB re 1 μPa) (Madsen, 2005) (see Box 2.18 for a glossary of acoustic terms). Results from underwater-noise studies can be difficult to evaluate and compare, as decibel levels may vary by 10 dB or more between the different units of measurement. Sound pressure of continuous sound sources is normally parameterized by an rms measure, while transient sound is normally given in peak pressure measures (MMS, 2006a).

Natural and background sound sources in Arctic marine areas include the wind stirring the surface of the ocean, lightning strikes, animal vocalizations and noises,

Table 2.75. Levels of common sounds in the marine environment (modified from MMS, 2006a).

Source/activity	dB at source or re 1 μPa at 1 m
Vessel activity	
Tug pulling barge	171
Fishing boats	151 – 158
Zodiac (outboard)	156
Supply ship	181
Tankers	169 – 180
Supertankers	185 – 190
Freighter	172
Ambient noise	
General[a]	65 – 133
Bearded seal song	168
Ringed seal calls	95 – 130
Bowhead whales	128 – 189

[a] Wind on the ocean, lightning strikes, animal noise, earthquakes, and ice movements.

Box 2.17. Characteristics of sound

Sound is the transmission of energy through a medium by compression and expansion of particles of that medium (i.e., air or seawater). Unbounded sound radiates from its source in an expanding spherical shell at approximately 330 m/s in dry air at 0 °C and 1500 m/s in seawater. As the spherical pulse of pressure spreads outward, the original energy it contained is dispersed across an ever-increasing surface area, and the energy per unit area decreases in proportion to the square of the distance traveled from the source.

Sound transmission is affected by the speed it travels through different media; it travels faster in water than in air, and faster in seawater than in fresh water. It is also affected by acoustic interfaces and barriers. Sound striking an interface will divide its energy (and dissipate) by being reflected, by traveling along the interface, or by crossing the interface and changing direction in the new medium. The surface of the sea is an important natural interface affecting sound propagated both in air and in water. Other common interfaces are temperature inversions in the atmosphere and marine thermoclines and haloclines, which are boundaries of water layers with different temperatures or salinities.

The transmission of sound in air is highly dependent on many factors: attenuation by air molecules, receiver's height above the ground, humidity, temperature, air pressure, wind speed and direction, topography and vegetation, and the presence of water bodies. In addition, reflection and refraction of energy and interference of incident and reflected wave trains also cause differences in transmission (Malme et al., 1989).

The characteristics of sound transmission in the marine environment can be summarized as follows (MMS, 2006a):

- sound travels faster and attenuates less in water than it does in air;
- the fate of sound in water can vary greatly, depending on characteristics of the sound itself, characteristics of the location where it is released, characteristics of the environment through which it travels (Richardson et al., 1995a; McCauley et al., 2000), and the characteristics (i.e., depth, orientation) of the receiver (Richardson et al., 1995a; Gausland, 1998);
- sound propagation can vary seasonally in the same environment;
- extrapolation of data on the sources and properties of sound from outside the Arctic is speculative because many characteristics of the particular marine environment such as bathymetry, salinity, sound-source depth, and seabed properties affect the propagation of sound horizontally from the source (McCauley et al., 2000); and
- because the air-water interface acts as a good reflector, sound generated underwater generally will not pass to the air (Gausland, 1998).

Sound, or noise, is a waveform and like all waveforms is measured by frequency, wavelength, and amplitude. The frequency of sound is usually measured in Hertz (Hz), the pressure level in microPascals (µPa) (Gausland, 1998), and intensity or sound pressure levels on the logarithmic decibel (dB) scale (Richardson et al., 1995a; McCauley et al., 2000) (see also Box 2.18 for a glossary of acoustic terms). The logarithmic Sound Pressure Level scale is used owing to the very wide range of sound pressures possible; for example, underwater sound pressures may range from 1×10^{-7} Pa in a quiet sea to around 1×10^{7} for an explosive blast. Underwater sound is usually expressed in decibels referenced to a pressure of 1 µPa and the sound level in this example ranges from 0 to 260 dB re 1 µPa (ICES, 2005).

1 Leq is the equivalent steady sound level that, if continuous during a specific time period, would represent the same total acoustic energy as the actual time-varying sound.

For sound levels in relation to human hearing, the 'A-weighted decibel' (dBA) scale has been devised, correcting sound levels to levels as heard by the human ear, which is most sensitive to middle- and high-frequency sounds (1000 to 4000 Hz octave band centre frequencies). U.S. EPA guidelines recommend that a day-night sound level (Ldn) of 55 dBA be used as a community noise standard. The level has been determined by the U.S. EPA to be sufficient to protect the public from the effects of broadband environmental noise in typically quiet outdoor and residential areas. A second standard, Leq1 of 70 dBA or less over a 40-year period, is recommended by the U.S. EPA for protection against hearing loss in the general population from non-impulsive noise.

sub-sea earthquakes, ice movements, and distant shipping (Figure 2.144) (MMS, 2006a). These sources typically create an ambient noise in the range 63 to 133 dB; certain sea-ice noises (e.g., ice fracture) can increase ambient levels to 137 dB (Buck and Greene, 1979).

2.7.1.1. Wind and waves

In the Arctic, during the open-water season, wind and waves are important sources of ambient noise in the marine environment, with noise levels tending to increase with increased wind and sea state (MMS, 2006a). The curves for wind-related ambient noise shown in Figure 2.144 are representative averages. The median levels in the U.S. Beaufort Sea, as indicated by the curves for tidal

Box 2.18. Glossary of terms for sound

1/3 Octave Band Filter: A bandpass filter having a bandwidth equal to 23% of the centre frequency.

Equivalent Sound Level, L_{eq}: The constant sound level which produces the same acoustic exposure dose as the actual time-varying sound field.

Sound Level or Received Level, L_r: The sound pressure at an observation position expressed in logarithmic terms, where the reference pressure, P_r = 1 microPascal (µPa).

Source Level, L_s: The sound pressure at an observation position 1 m from an acoustic source (dB re 1 µPa at 1 m).

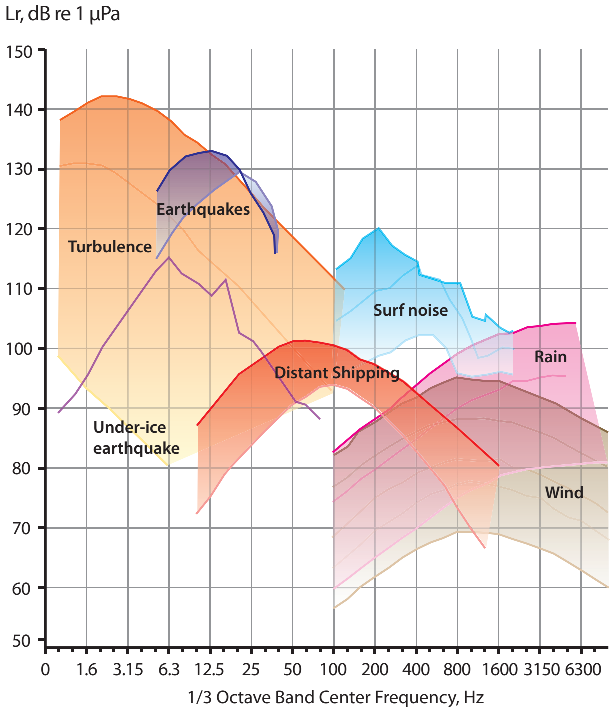


Figure 2.144. Underwater noise spectra from natural background sources: distant shipping, wind and rain in shallow open-water; tidal turbulence, earthquakes and surf in shallow (depth < 180m) Alaskan waters (after Malme et al., 1989).

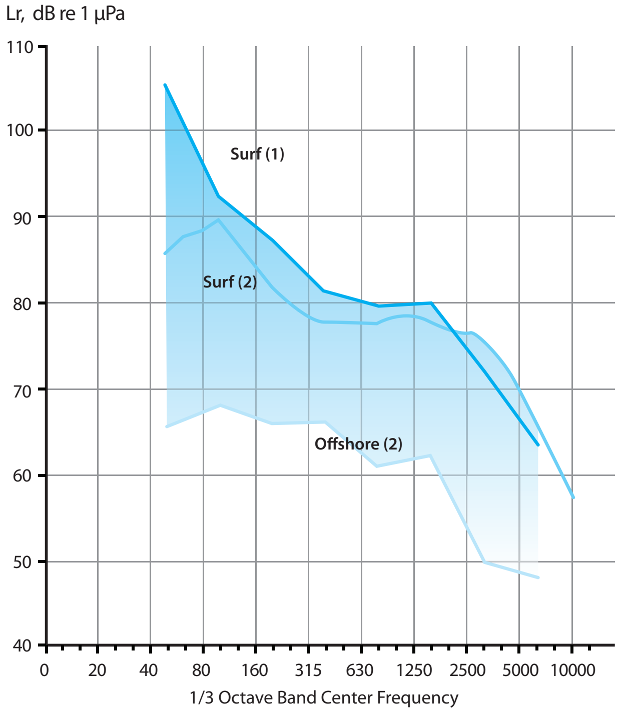


Figure 2.145. Equivalent underwater ambient noise spectra from surf, measured at two shoreline locations and one location 200 m offshore of the beach, under conditions of 'choppy seas with some breaking crests' (after Malme et al., 1989).

turbulence, earthquakes, and surf noise in Figure 2.144 and by Greene (1987), are close to a Beaufort Scale Sea State 2.

Studies have shown that wind and surf are also the main sources of airborne ambient noise in the Arctic (Malme et al., 1989). In a coastal area near the shoreline, surf noise is the dominant contributor to the airborne ambient noise. The overall airborne noise level and spectrum shape are related not only to the local wind speed but also to the height of the swell, which may be influenced by distant storms at sea. Beyond 100 to 200 m offshore, the airborne noise level is influenced primarily by local breaking wave crests and may become quite low during calm sea conditions. Some surf noise data reported for moderate wind speed conditions (about 10 kn) are shown in Figure 2.145. The band levels shown for the offshore spectrum correspond to those measured on land in rural areas and thus represent relatively quiet airborne noise conditions (Malme et al., 1989).

A 2001 study (Shepard et al., 2001) measured various noises from areas around the Northstar and Endicott island production facilities near Prudhoe Bay in the Beaufort Sea, and Liberty Island, which was planned for development but then canceled (see section 2.4.1.3.2). The measurements were taken during daylight in April 2000. Measurements at site LA2 near Liberty Island were taken 5 km north-northwest of the island in 6 m of water with ice 1.6 m thick. These measurements essentially represent ambient levels.

2.7.1.2. Rain

Depending on the rate of precipitation, rain drops hitting the sea surface can be a dominant source of noise in the ocean. Malme et al. (1989) reported that one-third octave band ambient noise levels approaching 105 dB at 10 kHz can be expected for a rainfall rate of 10 cm/hr. Noise levels from moderate to heavy rain dominate the wind-related ambient noise levels above 1 kHz, even for the most severe wind condition (Figure 2.144). Generally, rain as well as hail is an important component of total noise at frequencies above 500 Hz (Richardson et al., 1995).

2.7.1.3. Ice noise

Several properties of sea ice determine its contribution to background noise levels in Arctic seas. As reported by Malme et al. (1989), under-ice noise studies (e.g., Milne and Ganton, 1964; Greene and Buck, 1964; Urick, 1983) show large variability in ambient noise levels due to wind speed, changes in temperature, and pressure ridge activity. Environmental changes such as ice cracking or increased wind speed can cause background noise levels to increase by as much as 40 dB.

Under solid ice cover, wind effects are minimal but when there are leads, open water at the edge of the ice pack or ice floes, the wind plays an important role in ice-generated noise. Fluctuations of 5 to 10 dB at the 50 Hz noise level were detected under ice and were correlated with changes in wind speed over the range 2 to 28 kn (Greene and Buck, 1964 in Malme et al., 1989). As pointed out by Urick (1983), for a given wind condition, ambient noise levels are 12 dB or more higher near a sharp ice edge than in open water, and 20 dB higher than levels measured under an ice sheet well away from the ice edge.

Buck and Wilson (1986) reported on ice breakup and pressure ridge formation from the Eurasian Basin of the Arctic Ocean. They collected data from two hydrophones deployed approximately 100 m from the ridge zone at a depth of 30 m and by 61 m apart to provide a two-element array. They measured noise spectra data from a 'lead pressure ridge' that formed when l-m thick re-frozen lead ice fractured and began to build up due to horizontal forces. A 'floe pressure ridge' was formed after the lead ice was forced onto the 4-m thick floe ice causing ice loading and fracturing of the floe ice. A pressure ridge and fractured keel were formed at the impact zone.

Noise spectra acquired during the two stages of the pressure ridge formation are given in Figure 2.146. Early in the pressure ridge formation (lead pressure ridge), 1/3 octave band sound pressure levels in the 100 to 400 Hz range were 93 to 94 dB. During the more forceful part of the ridge formation (floe pressure ridge), sound levels increased by about 19 to 111–113 dB (Malme et al., 1989). A pressure ridge active over a 3-day period produced tones at frequencies of 4 to 200 Hz, with source levels for 4-Hz and 8-Hz tones ranging from 124 to 137 dB.

A decrease in temperature causes ice fracturing and an increase in under-ice noise levels. Milne and Ganton (1964) obtained data from the Canadian Archipelago while temperature dropped from -12 to -38 °F in February 1963 during under-ice experiments. Their data converted to 1/3 octave band levels are shown in Figure 2.146. Land-fast ice produces significant thermal cracking noise (Milne and Ganton, 1964). In areas of continuous fast-ice cover, the dominant source of ambient noise is ice cracking under thermal stresses (Milne and Ganton, 1964). The spectrum of cracking noise typically displays a broad range from 100 Hz to 1 kHz. As icebergs melt, they produce additional background noise as the icebergs tumble and collide. Rising temperatures tend to stabilize the ice and background noise levels drop (MMS, 2006a).

The diurnal air temperature flux can result in received sound levels varying by 30 dB between 300 and 500 Hz (Urick, 1984).

Sea ice can also dampen ambient noise. Marine areas with 100% ice cover may have reduced or no noise from waves or surf (Richardson et al., 1995). In shallow water, ice effectively decreases water depth and may impair the propagation of low frequency industrial sounds (Blackwell and Greene, 2002). The marginal ice zone, the area near the edge of large sheets of ice, is usually characterized by high levels of ambient noise compared to other areas, in large part due to the impact of waves against the ice edge and the breaking up and rafting of ice floes (Milne and Ganton, 1964).

2.7.1.4. Background

Since the mid-20th century, shipping noise, often at source levels of 150 to 190 dB, has contributed a worldwide 10- to 20-dB increase in the background noise level of the sea (Acoustic Ecology Institute, 2005). In shallow water, vessels more than 10 km from a receiver generally contribute only to background noise (Richardson et al., 1995). However, in deep water, traffic noise up to 4000 km away may contribute to background-noise levels (Richardson et al., 1995). Shipping traffic is most significant at frequencies of 20 to 300 Hz (Richardson et al., 1995).

2.7.1.5. Animals

Marine mammals can contribute significantly to the background noise in the Arctic marine acoustic environment; however, frequencies and levels depend on the species and season. For example, source levels of bearded seal songs have been estimated to be up to 168 dB re 1 μPa at 1 m (Cummings et al., 1983). Ringed seal calls have a source level of 95 to 130 dB re 1 μPa at 1 m, with the dominant frequency under 5 kHz (Richardson et al., 1995). Bowhead whales, which are present in the Arctic from early spring to mid- to late autumn, produce sounds with source levels ranging from 128 to 189 dB re 1 μPa at 1 m in frequency ranges from 20 to 3500 Hz. Richardson et al. (1995) concluded that most bowhead whale calls are 'tonal frequency-modulated (FM)' sounds at 50 to 400 Hz. Beluga and other toothed whales produce higher frequency sounds (generally >1 kHz) than baleen whales (generally <1 kHz), which are associated with echo-location and various pulsed sounds (Richardson et al., 1995). Beluga produce sounds in the frequency range 0.26 to 20 kHz, with the dominant frequencies between 1 and 8.3 kHz (Richardson et al., 1995). There are many other species of marine mammals in the Arctic marine environment whose vocalizations contribute to ambient noise including, but not limited to, the walrus, spotted seal, ribbon seal, harbor porpoise, killer whale, grey whale, minke whale, fin whale (in the southwestern areas) and, potentially but less likely, the humpback whale. In air, sources of sound include seabirds (especially near colonies), walrus, and seals.

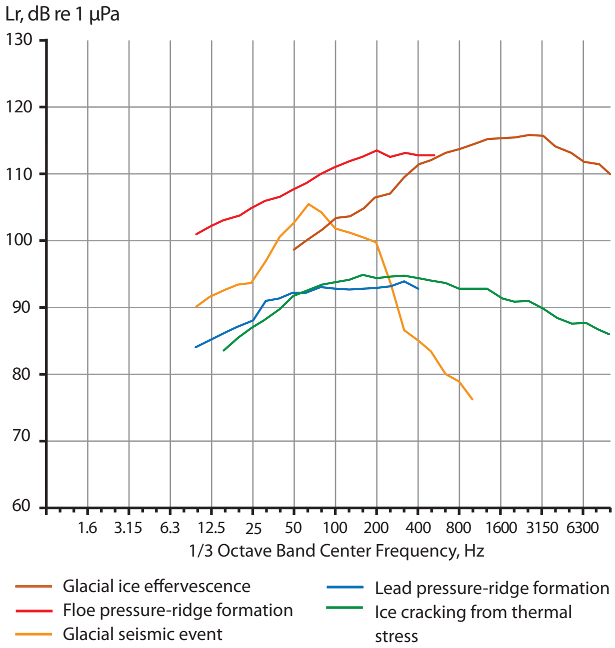


Figure 2.146. Underwater noise spectra from ice-related sources (Malme et al., 1989).

2.7.2. Anthropogenic sources of noise

A number of human activities generate noise, which adds to the ambient noise levels from natural sources. Human sources include noise from vessels (e.g., motor boats used for subsistence and local transportation, commercial shipping, research vessels, see Table 2.75); navigation and scientific research equipment; airplanes and helicopters; human settlements; military activities; and marine development. Anthropogenic noise associated with oil and gas activities is discussed in section 2.7.3.

2.7.2.1. Cultural and recreational sources

In the Arctic, this category includes vehicles and tools used for cultural and recreational fishing, hunting, camping, and other activities for non-industrial or non-commercial purposes. Spectra for several of the more popular airborne sound sources are shown in Figure 2.147; these show radiated noise spectra for a range of 150 m, not source level spectra. The snowmobile spectrum is representative of older models and was obtained during acceleration of the machine while running at about 40 km/hr. The spectrum for the 10-gauge shotgun shows peak 1/3 octave band levels. Since this is a highly sporadic and impulsive source, it is difficult to estimate a representative time

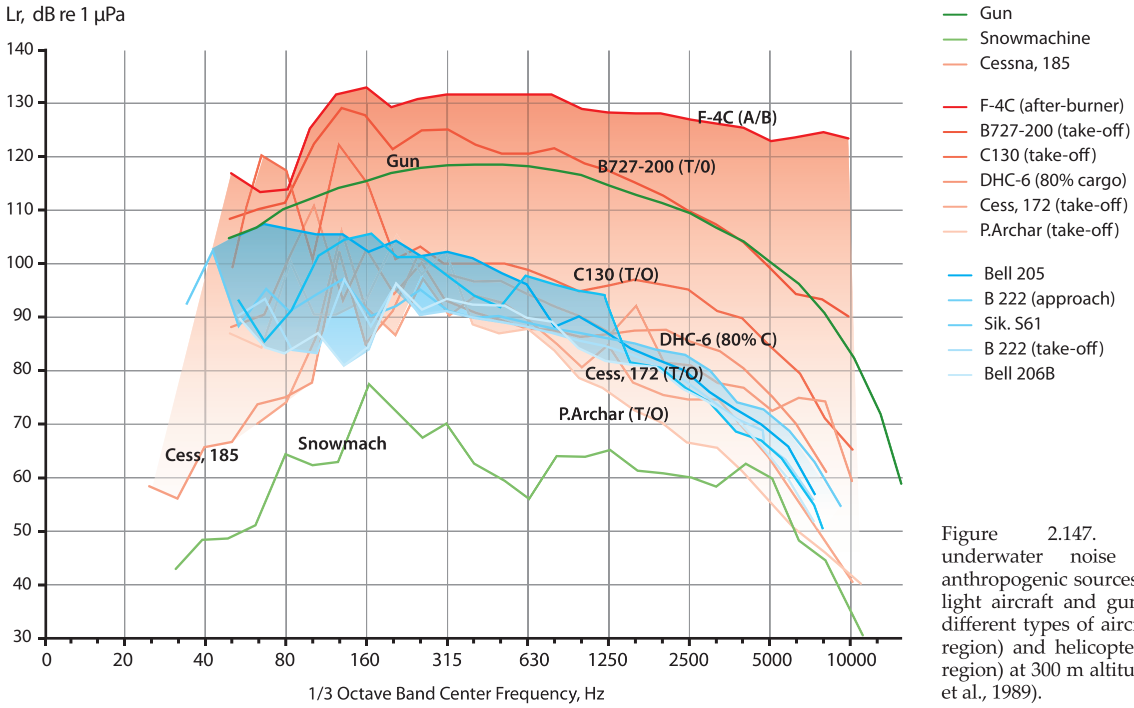


Figure 2.147. Representative underwater noise spectra from anthropogenic sources: snowmachine, light aircraft and gunshot at 150 m; different types of aircraft (red shaded region) and helicopters (blue shaded region) at 300 m altitude (after Malme et al., 1989).

fraction to obtain an equivalent level. If a pressure pulse time constant of 2 msec and a shot repetition rate of l/hr is assumed, the Leq (see Box 2.17 for an explanation of Leq) for the shotgun is estimated to be about 60 dB less than the spectrum levels in Figure 2.147. The longer duration signal from the aircraft flyover is thus one of loudest recreational source signals.

2.7.2.2. Aircraft

The loudest non-explosive airborne noise sources are aircraft (Figure 2.147). Aircraft are used in Arctic areas for transporting supplies and personnel to local communities and industrial complexes (e.g., villages, oil fields, mines); conducting research (e.g., marine mammal and seabird surveys); recreation and tourism; monitoring weather and oceanographic conditions; and military exercises and surveillance. Much of the air traffic occurs over land. Underwater sounds from aircraft are transient. The primary sources of aircraft noise are the engine(s) (either reciprocating or turbine) and rotating rotors or propellers. Sound levels from both helicopters and fixed-wing aircraft are at relatively low frequencies.

2.7.2.2.1. Airplanes

The F-4C military fighter with twin turbojet engines under afterburner power produces an effective bandwidth source level of 192 dB re 1 µPa at 1 m. This is comparable to the output source level of an icebreaker operating in ice, causing propeller cavitation. For a takeoff under normal power, the F-4C is similar to the Boeing 727 (three turbofan engines) in source level output. The two-engine Learjet, while considerably smaller than the 727, produces a source level within 5 dB of the larger aircraft on takeoff. The older design four-engine propeller and turboprop aircraft such as the DC-6, Electra (P-3), and C-130 have takeoff source levels which are about 175 dB, 10 dB lower than those of the 727 and F-4C. The 737-300 two-engine high by-pass turbofan and the smaller two-engine turboprop aircraft have takeoff source levels of about 165 dB, 20 dB less than those of the 727 and F4-C. The light two-engine and one-engine propeller aircraft such as the Piper Navajo and Cessna 185 have takeoff source levels which are another 5 to 10 dB lower than those of the two-engine turboprop, averaging about 155 to 160 dB. Cruise and approach power settings produce considerably lower source levels, ranging from 5 to 15 dB less than those measured for takeoff power. The takeoff power acoustic source level data is thus the most relevant for estimating the potential noise impact of aircraft operations.

2.7.2.2.2. Helicopters

The Bell 205 helicopter, used for transporting cargo and personnel, produces a source level of 165 dB for the loaded cruise condition. This is comparable to the takeoff source level of the Boeing 727-200. The Bell 222, a newer and smaller helicopter, produces an approach source level of 161 dB. The Sikorsky S61, a larger model often used for search and rescue as well as oil industry operations, produces a cruise source level of 156 dB which is comparable to the takeoff source level of the Cessna 172 single-engine propeller aircraft. This relatively low source level may be aided by the five-bladed main and tail rotors used on the S61 helicopter. The Bell 206B, a five-passenger light helicopter, produces a cruise source level of 151 dB which is similar to that of a Cessna 185 at cruise power.

The helicopter spectra are all similar with the exception of the Bell 205 and Bell 222 helicopters having band levels below 1.25 kHz which are 5 to 10 dB higher than those of the Bell 206B and the Sikorsky S61. Comparison of the general range of the helicopter spectra with the examples of fixed wing aircraft spectra in Figure 2.147 shows that the group of helicopters selected produces source levels which are comparable to the lowest range of fixed-wing aircraft spectra. With the probable exception of noise from the large two-bladed helicopters such as the Bell 205 and 212, the potential noise impact of helicopter operations is thus not expected to be much different from that for fixed-wing aircraft operations for comparable aircraft sizes. However, because helicopters are typically operated at lower altitudes, there may be an increase in noise exposure at ground level for helicopters as a result of usual operating procedures.

2.7.2.3. Vessel activities and traffic

Vessels are the greatest contributors to overall noise in the sea. Sound levels and frequency characteristics of vessel noises underwater are generally related to vessel size and speed. Larger vessels generally emit more sound than smaller vessels (see Figure 2.148), and those underway with a full load, or those pushing or towing a load, are noisier than unladen vessels. The primary sources of sound are engines, bearings, and other incidental mechanical parts. The sound from these sources reaches the water through the vessel hull. The loudest sounds are made by the spinning propellers. Navigation and other vessel-operation equipment also generate subsurface sounds.

The types of vessels that produce noise in most Arctic sea areas include barges, skiffs with outboard motors, icebreakers, scientific research vessels, and vessels associated with geological and geophysical exploration and oil and gas development and production. In many Arctic sea areas, vessel traffic and associated noise is mostly limited to late spring, summer, and early autumn.

During ice-free months, barges are used to supply the local communities, Native villages, and, for example, in Alaska the North Slope oil-industry complex at Prudhoe Bay, with larger items that cannot be flown in on regular commercial air carriers. In Alaska, a large fuel barge and a supply barge generally visit the villages once a year and one barge crosses the Arctic Ocean each year to the Canadian Beaufort Sea. Along the northern Russian coast and inland waterways, barges and supply vessels are similarly used to offload fuel and supplies for settlements and to transport minerals and oil products.

Icebreaking vessels used in the Arctic for activities such as keeping navigation routes open, scientific research, and oil and gas activities, produce stronger, but more variable, sounds than those associated with other vessels of similar power and size (Richardson et al., 1995; see also Figure 2.149). The alternating periods of ramming and backing ice produce sounds that are stronger than when underway in open water or light ice, due to strong propeller cavitations. There are tones at frequencies related to the propeller blade rate below 200 Hz, including some strong tones below 20 Hz, and lesser components extending beyond 5 kHz (Richardson et al. 1995). Even with rapid attenuation of sound in heavy ice conditions, the elevation in noise levels attributed to icebreaking can be substantial to at least 5 km away (Richardson et al., 1991). In some instances, icebreaking sounds are detectable from more than 50 km away. However, the underwater noise levels rapidly decline with distance, as seen for the icebreaker *Robert Lemeu*, where sound levels declined from 140 to around 120 dB at 3 km and to 100 dB at around 10 km (Greene, 1987). In general, the spectra of icebreaker noise are wide and highly variable over time (Richardson et al., 1995).

There were 99 vessel transits (62 eastbound and 37 westbound) through the Northwest Passage (which links the Beaufort and Chukchi Sea areas) from its opening to the end of 2004, mostly by icebreakers (Brigham and Ellis, 2004). Arctic marine transport in the area is likely to increase given that between 1977 and 2005 there were 61 North Pole transits (17 in 2005 alone) and seven trans-Arctic voyages (Brigham, 2005). Global warming is predicted to reduce annual sea-ice coverage and to open the Northwest Passage and the Northern Sea Route to increased cargo traffic. Cargo transport in the Arctic is also expected to increase as a result of increased petroleum and mining activities and the need to support these industries (PAME, 2000).

2.7.2.4. Acoustic system sources

The term 'acoustic surveys' refers to a broad class of activities including the use of active acoustic sensors such

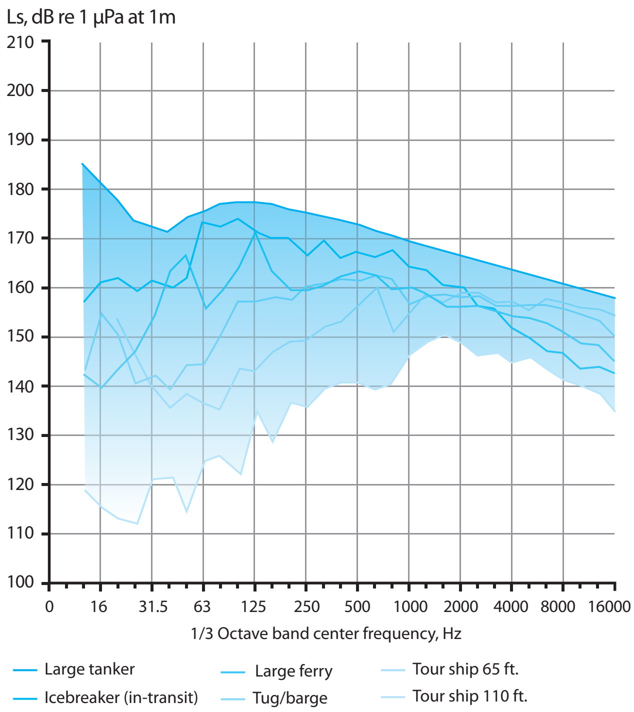


Figure 2.148. Representative underwater noise spectra for ships and boats (after Malme et al., 1989). Note: The peak level for the tanker spectrum occurs below 2 Hz at a level greater than 204 dB.

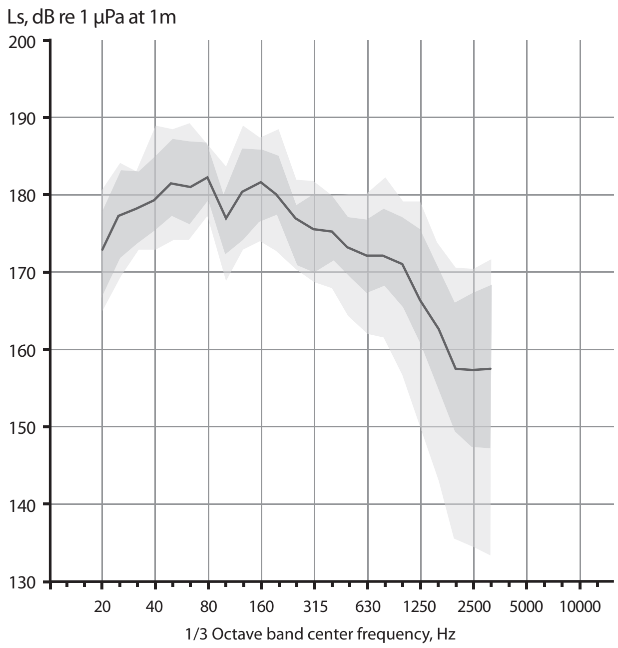


Figure 2.149. Statistical analysis of icebreaker underwater noise spectra (from the top: maximum, 95%, 50% (dark line), 5%, and minimum limits) (after Malme et al., 1989).

as side-scan sonar, search-light and other sonars, sub-bottom profilers, and single and multi-beam bathymetry, but excluding seismic sources. Table 2.76 compares the noise levels for some of these activities. While many acoustic surveys are conducted in relation to oil and gas activity, acoustic systems such as multi-beam sonar, sub-bottom profilers, and acoustic Doppler current profilers are also used for other purposes, such as military activities, navigation, hydrographic surveys, scientific research, and construction. Active sonar is used for the detection of objects underwater; ranging from depth-finding sonar, found on most ships and boats, to powerful and sophisticated units used by the military. Sonar emits transient, and often intense, sounds that vary widely in intensity and frequency. Acoustic pingers used for locating and positioning oceanographic and geophysical equipment also generate noise at high frequencies.

Sounds from the multi-beam sonar are very short pulses, depending on water depth. Most of the energy in the sound pulses emitted by the multi-beam sonar is at moderately high frequencies, centered at 12 kHz. The beam is narrow (~2°) in fore-aft extent and wide (~130°) in the cross-track extent and short in duration (fractions of a second). Sub-bottom profilers and acoustic Doppler current profilers emit similarly short pulses. Conversely, military (Navy) sonar that have been linked to avoidance reactions and stranding of cetaceans are generally more powerful than the multi-beam sonar, have a longer pulse duration, and are directed close to horizontal vs. downward for the multi-beam sonar. Marine mammals that encounter the bathymetric sonar at close range are unlikely to be subjected to repeated pulses because of the narrow fore-aft width of the beam, and will receive only small amounts of pulse energy because of the short pulses.

Sounds from acoustic pingers are very short pulses, occurring for 0.5, 2 or 10 ms once every second, with a source level of ~192 dB re 1 μPa at 1 m at a rate of one pulse per second. Most of the energy in the sound pulses emitted by the pinger is at mid-frequencies, centered at 12 kHz. The signal is omni-directional. The pinger produces sounds that are within the range of frequencies used by small odontocetes (toothed whales) and pinnipeds. However, the pinger signals are unlikely to interfere much with their communications because of the relatively low power output, low duty cycle, and brief period when an individual mammal is likely to be within the area of potential effects. In the case of mysticetes (baleen whales), there is no overlap between the pulses and the predominant frequencies in the calls.

2.7.2.5. Other sources

Table 2.76 reviews sound levels characteristic of activities in the Arctic including icebreaking, dredging, drilling, and several types of seismic and other acoustic survey equipment. A comparison of spectra for some of these sources shows seismic air guns and icebreakers to be among the loudest (Figure 2.150). The icebreaker spectrum has a large amount of energy at high frequencies which is typical of cavitation noise. The dredge noise output level is higher than that of the drillship, particularly above 63 Hz. The trawler spectrum is representative of large trawlers (30 to 50 m) operating at 5 kn.

Table 2.76. Levels of sound from industrial noise sources (modified from MMS, 2006a).

Source	Noise level, dB
Ice breaking	
Ice-management	171 – 191
Ice breaking	193
Dredging	
Clamshell dredge	150 – 162
Aquarius (cutter suction dredge)	185
Beaver Mackenzie dredge	172
Drilling	
Kulluk (conical drillship)	185
Explorer II (drillship)	174
Artificial island	125
Ice island (in shallow water)	86
Seismic sources and acoustics	
Airgun arrays	235 – 259
Single airguns	216 – 232
Vibroseis	187 – 210
Water guns	217 – 245
Sparker	221
Boomer	212
Depth sounder	180
Sub-bottom profiler	200 – 230
Side-scan sonar	220 – 230
Military	200 – 230

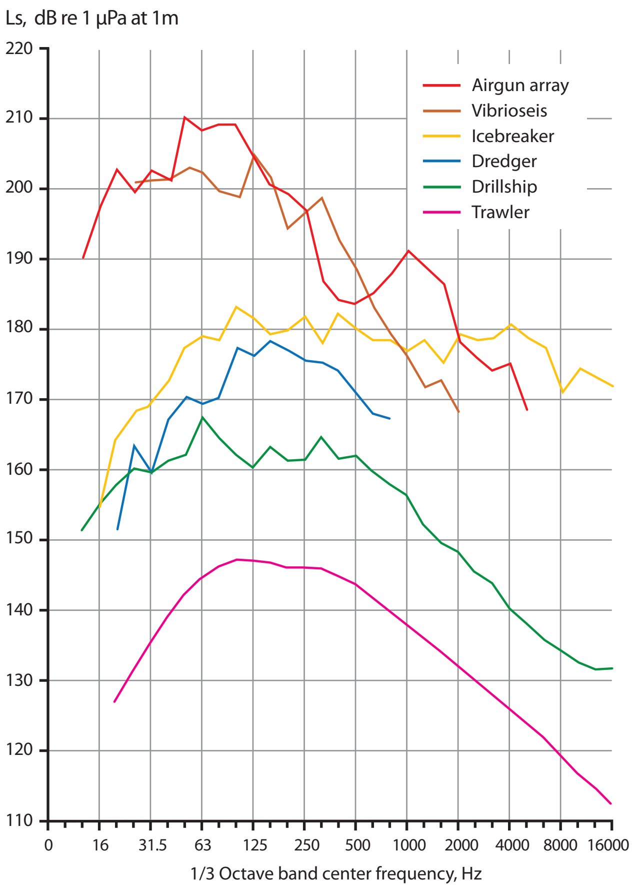


Figure 2.150. Underwater sound spectra of representative marine industrial noise sources (after Malme et al., 1989).

The U.S. EPA has published guidelines for noise emissions from certain types of construction equipment including equipment transporters, portable air-compressors, and medium- and heavy-duty trucks. The Federal Aviation Administration has established noise standards for overflight and airport noise, although no standards have been established for civilian helicopters.

2.7.3. Sources of noise from oil and gas activities

2.7.3.1. Noise associated with onshore oil and gas activities

Onshore, the operation of equipment during exploration, drilling, facility construction, and oil and gas production, and the use of aircraft for the transportation of personnel and materials contribute noise to the environment. Several studies have been undertaken to measure noise associated with onshore oil and gas activities. Levels of sound from typical oil field noise sources are shown in Table 2.77.

2.7.3.1.1. Onshore seismic activities

The scope of disturbance and noise associated with terrestrial seismic surveys is given here using operations in Alaska as an example. Typically, three to four seismic crews are active on the North Slope each winter, and one to two crews could be expected to collect seismic data in the northern NPR-A in future winter seasons. A 2-D seismic party typically consists of 40 to 60 persons and can collect 5 to 10 line-miles of seismic data per day. A more closely spaced 3-D seismic program typically requires 60 to 100 persons and can collect 2 to 4 square miles of data per day. However, winter weather is a constant factor affecting visibility and crew safety, and time is lost in mobilization, camp moves, and downtime during storms. Considering these logistical problems, one 2-D seismic crew typically could collect 250 line-miles of data in one winter season, while a 3-D seismic crew typically could collect 150 square miles of data in one winter season. Although the winter operating period can be as long as five and a half months (early December to mid-May), typical seismic operations for an individual survey last about 100 days.

Seismic crews are housed in mobile camps consisting of a 'cat train' of trailer sleds pulled by tractors. Seismic data-collection operations are conducted by all-terrain, low ground-pressure vehicles (both wheel and articulated-track designs). Camp supplies (food, fuel) are transported to the survey area by both ground vehicles and light fixed-wing aircraft. Each cat train would consist of survey vehicles and support camp modular units.

Table 2.77. Typical oil field noise sources and sound levels measured at the *Kuparuk River* oil field (BLM, 2004; Table 3.2.3-8).

Source	Noise level, dBA	Distance from source, m
HPE-1 (operating)	88 – 105	0
HPE-1 (flare)	78 – 82	50
HPE-2 (construction)	95 – 105	0
Drill rig	82 – 92	25
Production module	88 – 105	0
Pickup truck	67 – 75	0
Semi-truck	73 – 85	0
Gravel truck	93 – 102	0
Helicopter (206 Bell)	115	10

Cummings et al. (1981) reported levels of sound from winter use of Vibroseis seismic profiling during solid ice cover in a permitted period from about 15 October to about 15 March. The Vibroseis method begins with energizing the ice by vibrating it with powerful, hydraulically operated pads. One pad is situated below each of the trucks, which are driven in phase. Typical operations space four trucks 6.9 m (22.5 ft) apart. The four pads are about 15.2 m (50 ft) apart. After vibrating for 16 seconds, using a linear fundamental frequency sweep of 10 to 70 Hz, the convoy moves 6.9 m and repeats the sequence. After ten such repetitions, the convoy moves 67 m (220 ft) and begins ten more repetitions. While vibrating, each truck is jacked up in order to put the vehicle's weight on the vibrating pad. The program can operate 24 hours a day but because the entire procedure entails more than vibrating and recording, the activities are not continuous. In addition, calibrations, geophone positioning, troubleshooting, and repairs occupy significant periods of time.

The truck convoy proceeds along a snow-ploughed road on the ice. Alongside the road a very long array of geophones are planted on the snow and ice. These sensors receive the reflected sound, and the recordings are made in a special recording truck ahead of the convoy.

2.7.3.1.2. Onshore drilling

A study (BLM, 2004) was conducted to address the issue of whether noise from the HPE-2 facility, located in the Kuparuk River Unit, had a significant impact on waterfowl in the designated wetlands adjacent to the facility. From 1985 to 1986, the ambient noise level was measured at 32 dBA. During 1985 construction activities, noise levels averaged 74 dBA at the planned site for HPE-2. During 1986, the noise level ranged from 95 to 105 dBA with the installation of one large and twelve portable generators at the pad. Heavy equipment and pipefitting increased the noise level to a range of 107 to 128 dBA.

A study by Shepard et al. (2001) near Northstar Island measured sounds related to operations (Figure 2.151). Conditions at all Northstar sites were: 1.5 to 2.5 m thick shorefast ice, water depths of 11 to 18 m, light snow, and snow cover of about 5 to 15 cm. Northstar Island was built but activity during measurements included vibrahammer sheet-pile driving, truck traffic, and snowplowing. Operations also included backfilling of the trench that was dug through the ice into the seafloor after the pipeline had been laid. The in-air noise level at a site (NA2) approximately 4 km northeast of Northstar was very low. Winds were light and ice cracking noise could not be heard by ear. In-air noise levels were also measured at a site (NT1) near an ice road about 1 km from Northstar. Trench backfilling operations were occurring during the recording. The dominant feature is the broadband low frequency noise. Compared to measurements made near the Liberty site (near ambient levels), the airborne noise level is 10 to 25 dB higher at frequencies below 200 Hz. At another site (NA3), 150 m from Northstar in a water depth of 11.5 m, recordings were taken while several activities were occurring, including vibrahammer sheet pile driving, trucks moving, and snowplowing activities.

Onshore drilling activities also generate some aircraft traffic, as helicopters may be used to transport personnel and supplies to and from the seismic survey vessels and platforms.

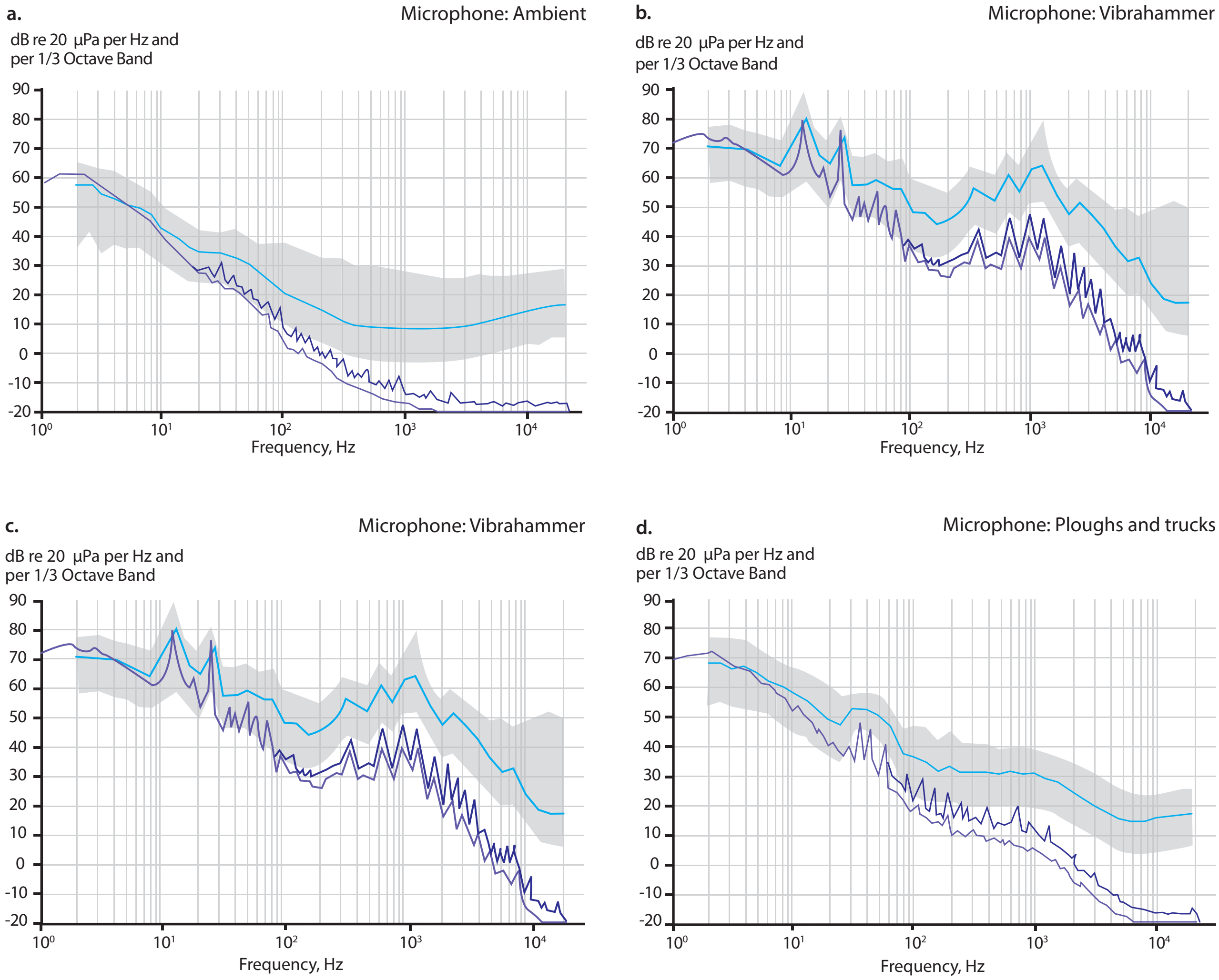


Figure 2.151. Airborne noise levels measured in air at a site: (a) about 4 km northeast of Northstar; (b) near an ice-road about 1 km from Northstar and close to trench backfill operations; (c) 150 m from Northstar with a water depth of 11.5 m showing vibrahammer noise spectra during pile-driving operations; and (d) at the same site as figure 'c' showing noise from snowploughing and truck traffic (after Shepard et al., 2001).

2.7.3.2. Noise associated with offshore oil and gas activities

Oil and gas activity generates noise that is propagated into the marine environment.

Existing offshore oil-field developments are serviced by land, air, and sea. For example, major sealifts into the industrial complex at Prudhoe Bay occur frequently. Between 1968 and 1990, approximately 480 sealifts (averaging 22 per year) were made to Prudhoe Bay, which corresponds to the period when the complex was constructed and subsequently expanded; considerably fewer sealifts have occurred since then. Oil and gas exploration and development in the Norwegian, Barents, and Kara Seas are dependent on marine operations in open-sea areas, as are oil and gas exploration in the marine areas around Greenland, Iceland, the Faroe Islands, and in the Russian eastern-Arctic seas.

Service vessels that support offshore oil and gas activities are categorized into supply, crew, and utility vessels. Each type of vessel produces noise above and under water and generates discharges and air emissions. Service-vessel trips are usually most frequent during the exploration, drilling, and construction phases and are fewer in number during the production phase.

Tug and barge traffic associated with onshore oil development travel mainly in nearshore waters along the coast. Barging associated with onshore and limited offshore oil and gas activities, and fuel and supply shipments, contributes to overall ambient noise levels in some regions of the Beaufort Sea and off the Arctic coast of Russia. The use of aluminum skiffs with outboard motors during autumn subsistence whaling in, for example, the Alaska Beaufort Sea also contributes noise. Fishing boats in coastal regions also contribute to the overall ambient noise. Sound produced by these smaller boats is typically at a higher frequency, around 300 Hz (Richardson et al., 1995).

2.7.3.2.1. Offshore seismic activities

Seismic surveys measure the structure of the seafloor or sub-surface by generating elastic energy waves (acoustic shock waves with a frequency less than 100 Hz, typically around 50 Hz) and measuring the reflected signals (Box 2.19). Recent studies in the Gulf of Mexico using acoustic tags attached to sperm whales suggest that frequencies can range from 0.3 to 2 kHz along multiple paths varying with range and depth from the source (Madsen et al., 2006). Seismic surveys differ from other forms of acoustic survey by the frequency range of the acoustic

Box 2.19. Seismic surveys

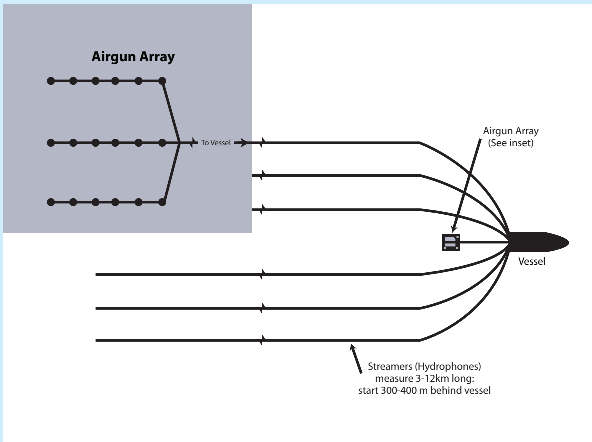
Seismic surveys use sound waves to gather information about geological structures lying beneath the surface of the earth, both on land and in the marine environment. A common purpose for conducting seismic surveys is to locate rock formations and sediments that could potentially contain hydrocarbons. Seismic surveys are also conducted by government and academic researchers for general scientific purposes to understand the composition, structure, and movement of the earth's crust.

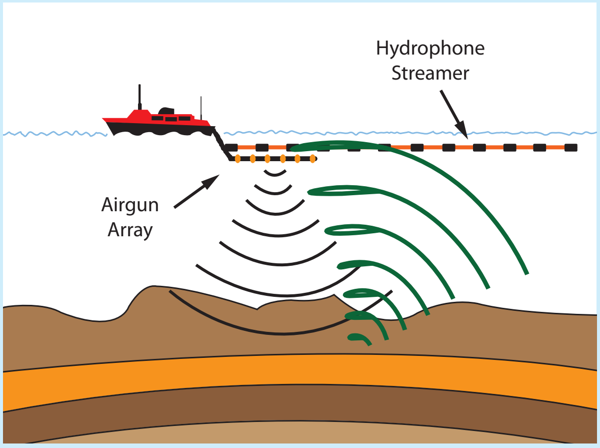
During marine seismic surveys, compressed air is released into the water column, creating a sound energy pulse. The pulse is focused to concentrate the sound energy toward the ocean bottom rather than horizontally. These surveys are undertaken from a ship that tows a sound source or sources, referred to as 'air source arrays', and one or more cables ('streamers') that contain sound receivers and other instruments (see figures).

The sea floor and the structures beneath it are mapped by measuring the time it takes for a sound energy pulse to leave the source, penetrate the earth, reflect off a subsurface layer, and return to a sound receiver. Reflections occur at each layer where there is a measurable change in the speed at which sound is transmitted. The data retrieved from these surveys provides information on the depth, position, and shape of underground geological formations.

Most seismic surveys conducted in Arctic marine waters are either 2-D surveys or 3-D surveys. The objective of a 2-D survey is to provide a high-level picture of the geological characteristics of an area, including the type and size of structures present. In conducting a 2-D survey, a seismic vessel typically tows a single air-source array and a single set of receivers along a set of parallel and transverse lines, spaced up to 5 km apart, to create a grid pattern. A 3-D seismic survey is conducted over a smaller area to obtain more detailed geological information and to identify potential targets for hydrocarbon drilling. 3-D surveys also create a grid pattern, but generally use two or more air-source arrays and multiple sets of receivers trailed more closely together.

Marine seismic survey operation using streamers and typical 3-D marine seismic array configuration (source: MMS).





source and consequently the depth of penetration of the seafloor. Higher frequency sources are typically used for bathymetric mapping and for surveys where the object is to provide a high level of detail about the seafloor and shallow sub-surface sediments.

Seismic and acoustic surveys are conducted on behalf of the oil industry for several purposes (MMS, 2002b).

- Common Depth Point (CDP) or 3-D surveys are conducted to explore and delineate potential hydrocarbon reserves and identify or assess drilling prospects. Such surveys always use seismic methods and sometimes conduct additional work using acoustic methods.
- Geohazard (or site clearance) surveys are conducted with the objective of locating and identifying hazards such as shallow gas, hydrates, unstable seafloors, active geologic features and potential shallow water flow-zones to enable exploration drilling, facilities installation (such as island construction), and production operations to be performed safely. Geohazard surveys do not often use seismic survey methods.
- Surveys with specific objectives such as delineation of potential pipeline routes, bathymetric charting of the seafloor, locating and identifying man-made artifacts including debris, shipwrecks and sub-sea structures, profiling shallow geologic features to assist with engineering studies and facilities design. Such surveys typically do not use seismic methods.

Examples of the history of Arctic marine seismic surveys on the Alaska Outer Continental Shelf are provided in section 2.5.1.2.2. Since 1969, over 560 000 line-km of 2-D and 770 line-km of 3-D survey data have been collected in offshore Alaska Arctic marine areas. Over this period, the USGS and academic institutions collected approximately 20 613 line-km of data. Around 130 000 line-km of 2-D seismic surveys have been collected to date in the U.S. Chukchi Sea, most between 1985 and 1989, and more than 160 000 line-km of 2-D and 3-D seismic surveys have been collected to date in the U.S. Beaufort Sea (see Figure 2.44). Examples of noise spectra from such surveys in the Chukchi Sea in winter and summer are shown in Figure 2.152.

Seismic surveys are occasionally conducted in the Arctic Ocean for scientific research purposes. These

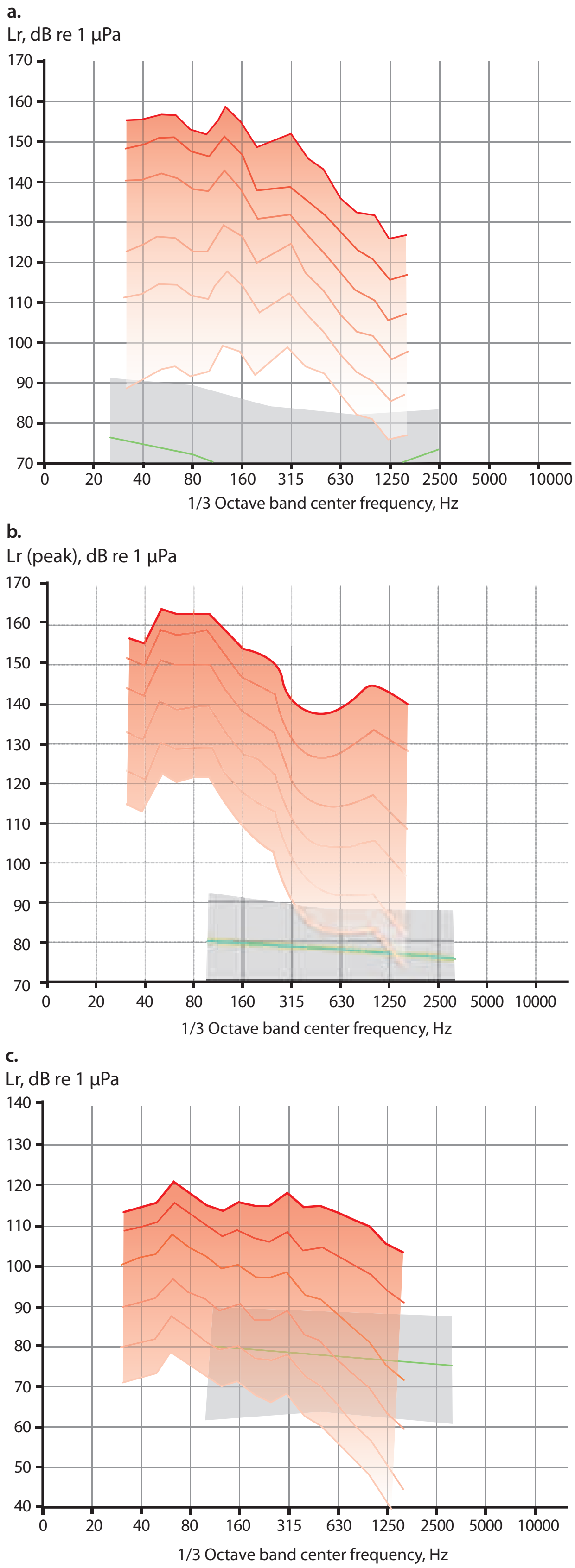


Figure 2.152. Underwater noise spectra at various distances from source for: a Vibroseis array in the Chukchi Sea, in winter with 100% ice cover (a); an airgun array operating in the Chukchi Sea in summer with 50% ice coverage (b); and a drillship operating in the Chukchi Sea in summer with 50% ice cover (c) (after Malme et al., 1989). Red lines: noise spectra at different distances from the source. Figure 'a', from top: 300 m, 1.5 km, 3.2 km, 5.5 km, 11.7 km, and 18.5 km; 'b' and 'c' figures, from top: 300 m, 1.1 km, 3.3 km, 8.5 km. 18.0 km, and 31.0 km. Grey shading: 95%, median, and 5% limits for ambient noise levels.

surveys often use seismic-research vessels that employ a variety of air-gun configurations, as well as multi-beam bathymetric sonar, a sub-bottom profiler, and other standard acoustic-research instrumentation. The U.S. Department of Interior Minerals Management Service issues geophysical scientific research permits for any oil- and gas-related investigation conducted in the Outer Continental Shelf for scientific and/or research purposes.

2.7.3.2.2. Offshore drilling

Arctic marine drilling in Alaska has involved conventional drillships, SSDC (single steel drilling caisson), or artificial islands. Power generation is considered the primary contributor of sound to the water. Drillships tend to generate more noise than bottom-founded structures, even though both are well-coupled to the water, because the noise-emitting equipment is generally on decks well above the water, so less vibration is manifest in the water. Artificial and natural islands do not conduct sound and vibration into the water very well. There are also other sources of noise from drilling operations depending on the type of activity, such as power generation, the top drive, pumps, and drawworks.

Measurements have been made of the composite signal from a site which was a representative mix of drillship sounds, supply vessel sounds, and icebreaker sounds. A series of 170 hourly measurements were taken over a period of nine days. A statistical analysis of the data (see Figure 2.153) showed the 95th percentile spectrum may be dominated by the short contributions from icebreaker operation whereas the 50th percentile spectrum levels were controlled by drillship and supply vessel activity. The estimated source levels for the 95th, 50th, and 5th percentile dominant bandwidths are 191, 180, and 171 dB, respectively (Malme et al., 1989). Figure 2.152 shows representative spectra from drillship operations in the Arctic at various distances from the source.

The marine acoustic environment of the Arctic varies among seasons and between areas. During much of the year, in many Arctic marine areas there are few near-field marine noise sources of human origin and limited, but increasing, land-based sources of noise.

2.7.3.2.3. Oil and gas development and production activities

There are a few oil production facilities on artificial islands in the Beaufort Sea. Typically, noise propagates poorly from artificial islands, as it must pass through gravel into the water (Richardson et al., 1995). Much of the production noise from oil and gas operations on gravel islands is substantially attenuated within 4 km and often not detectable at 9.3 km.

Richardson and Williams (2004) summarized results from acoustic monitoring of the offshore Northstar production facility from 1999 to 2003. Northstar is located on an artificial gravel island in the central Alaskan Beaufort Sea. In the open-water season, in-air broadband measurements reached background levels at 1 to 4 km and were not affected by vessel presence. Based on measurements of noise from Northstar during March 2001 and February to March 2002 (during the ice-covered season), Blackwell et al. (2004) found that background levels were reached underwater by 9.4 km when drilling was occurring and by 3 to 4 km when it was not. However, irrespective of drilling, in-air background levels were

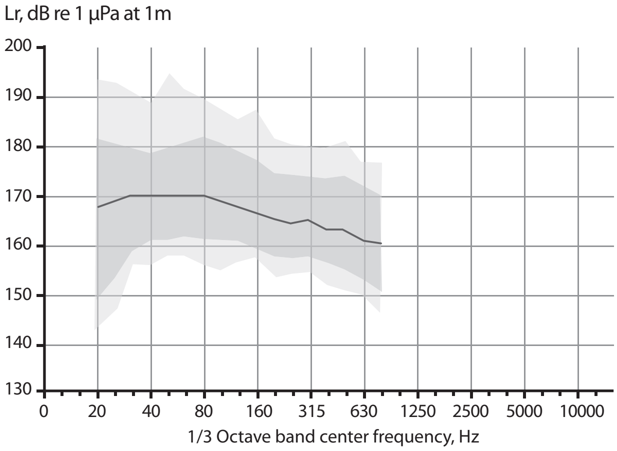


Figure 2.153. Statistical analysis of Corona Well underwater noise spectra (maximum, 95%, median, 5%, and minimum interval and range), 15 km from a drillship (*Explorer II*) operating with ice breaker and supply ship support in the Beaufort Sea in water depth of 35 m (after Malme et al., 1989).

reached by 5 to 10 km from Northstar during quiet ambient conditions (little to no wind) and by 2 to 5 km during noisier ambient conditions (Blackwell and Greene 2006).

Richardson et al. (1995) reported that during unusually quiet periods, drilling noise from ice-bound artificial islands would be audible at a range of about 10 km, when the usual audible range would be ~2 km. Richardson et al. (1995) also reported that broadband noise decayed to ambient levels within ~1.5 km, and low-frequency tones were measurable to ~9.5 km under low ambient-noise conditions, but were essentially undetectable beyond ~1.5 km with high ambient noise. Wind speed significantly affected the detection distances of production noises by reducing sounds to below ambient levels at much closer distances to the source for both underwater and airborne conditions (Blackwell and Greene, 2006). Moderate to high winds are common in the Arctic year-round.

During the open-water season, vessels such as tugs, self-propelled barges, and crew boats were the main contributors to Northstar-associated underwater sound levels, with broadband sounds from such vessels often detectable around 30 km offshore. In 2002, sound levels were up to 128 dB re 1 µPa at 1 m, at 3.7 km when crew boats or other operating vessels were present (Richardson and Williams, 2003). In the absence of vessel noise, averaged underwater broadband sounds generally reached background levels 2 to 4 km from Northstar. Underwater sound levels from a hovercraft, which BPXA began using in 2003, were quieter than similarly sized conventional vessels.

Although these findings are for the U.S. Beaufort Sea they are generally applicable throughout all of the Arctic shelves but may vary according to ice, sea temperature, chemistry, water depth and other factors.

Underwater noise spectra measured at a site along an ice road about 1 km from the Northstar Island production facility during offshore pipeline trench backfill operations are shown in Figure 2.154 for a hydrophone at mid-water depth and one near the bottom. At another site about 150 m from the Northstar Island production facility, underwater noise spectra were measured during vibrahammer sheet pile-driving operations, as shown in Figure 2.154 for a hydrophone near the bottom and at mid-water depth.

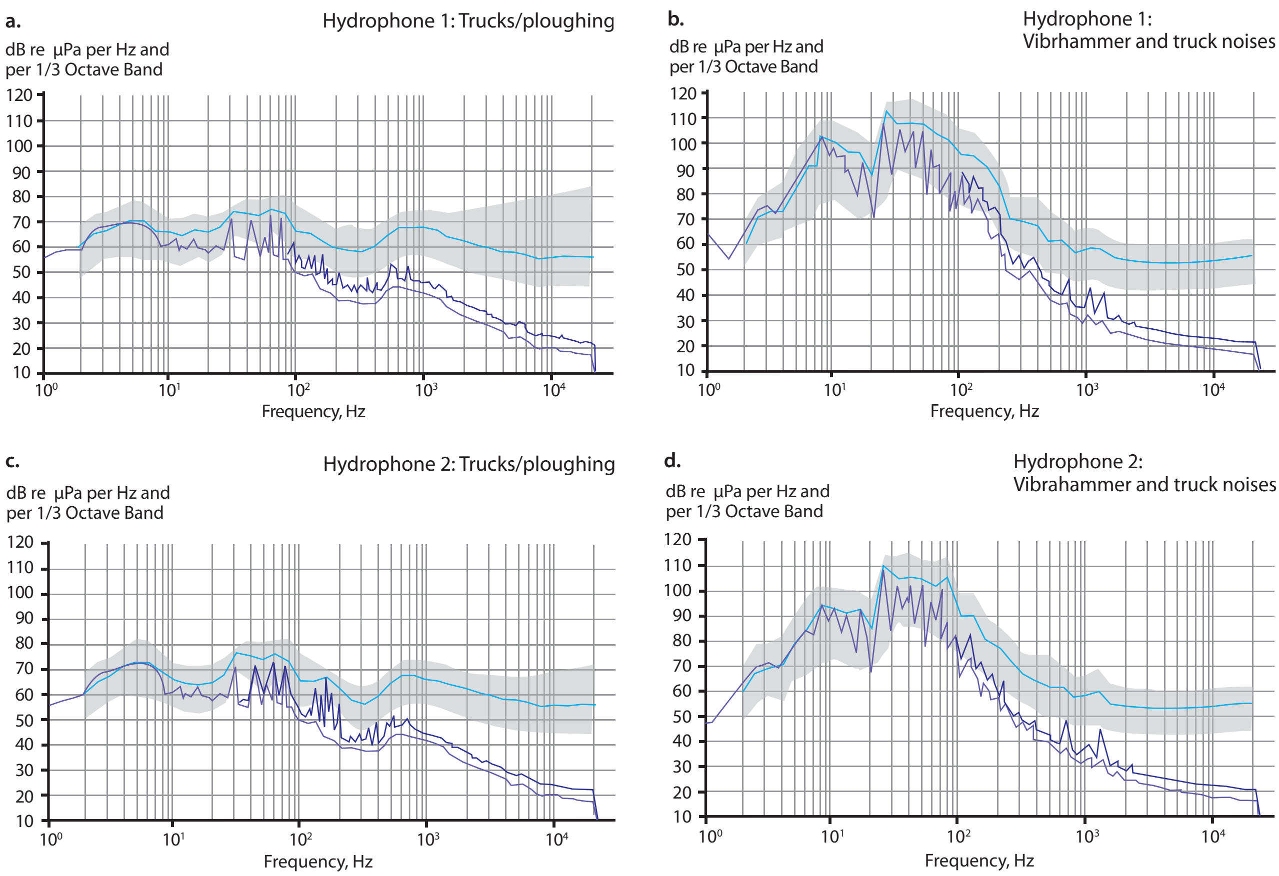


Figure 2.154. Underwater noise spectra at a site along an ice road about 1 km from the Northstar Island production facility, Beaufort Sea, during offshore pipeline trench backfill operations (a: mid-depth hydrophone; b: near-bottom hydrophone); and at a site about 150 m from Northstar Island production facility during vibrahammer sheet pile-driving operations (c: near-bottom hydrophone; d: mid-depth hydrophone) (after Shepard et al., 2001).

2.8. Oil spill preparedness and response in the Arctic

2.8.1. Introduction

Activities associated with petroleum industry exploration and development operations and the transport of petroleum and petroleum products via pipelines or tankers will result in a risk of accidental spills of oil and oil products. While experience shows that most oil spills are small, there is a risk of larger spills particularly from pipelines or tanker accidents (see Chapter 6). This section describes the regimes adopted by Arctic countries for preparedness and response to oil spills occurring in the Arctic. Neither Finland nor Sweden have oil or gas activities in the Arctic. Their oil spill preparedness and response programs are directed towards the Baltic Sea and so are not considered here, although there is the possibility that a pipeline may be constructed from Russian gas fields in the Arctic across the Baltic Sea, in which case these countries would then require the appropriate response programs.

In each Arctic country, oil spill preparedness and response programs are usually based on regulations adopted under national legislation and, where relevant, legislation adopted at the state or provincial level. These regulations are prescribed by national (and state or provincial) agencies, which also check on compliance by the industry to ensure their implementation. Some national laws and regulations have been adopted as a result of international conventions, particularly those regarding safe vessel transport at sea, procedures for response to accidental oil spills from tankers and other vessels, and compensation for the resulting pollution damage, and the safety of workers (see Appendix 2.1).

In anticipating spills, government regulators and the petroleum industry focus on three areas.

1. Prevention: safety requirements and planning to prevent spills.
2. Preparedness: ensuring that personnel are trained and prepared and that appropriate equipment is available.
3. Response: ensuring an immediate and coordinated response.

With regard to prevention, national laws and associated regulations (see, for example, Canada and the United States in Appendix 2.2, section A2) specify safety requirements under which the operator is required to design the facilities and plan the work to prevent emergency situations from developing as well as to have a clear plan to handle emergency situations that may arise. In Canada, for onshore operations, the operator must declare that its equipment is fit for purpose, while offshore operations require a certificate of fitness issued by an approved international certifying authority. Recently revised regulations in the State of Alaska specify new standards for pipeline and tank integrity, including corrosion control and inspection requirements. U.S. government-established prevention standards include the requirement of double hulls for tanker vessels, enhanced equipment and construction standards, and additional conditions for pilotage and escort vessels for tankers.

Preparedness includes the requirement, for example in Canada and Norway, for operators to develop emergency response plans to handle any safety or environmental emergency. Operators are required to demonstrate their preparedness for spills including the availability of emergency response equipment and materials on site or nearby for immediate deployment. Preparedness also covers the appropriate training of personnel to respond to accidents and emergencies as well as agreements with other organizations or contractors that can provide access to and use of additional equipment and personnel in oil spill clean-up operations. Preparedness is also required at the local level for small spills and at the state or national level for larger spills or spills from vessels including tankers. Government response structures usually involve response teams composed of trained personnel from various agencies (see example on the United States in Appendix 2.2, section A2.3).

Response covers the procedures and actions taken to control the accidental release of oil or oil products, to track spilled oil, and to clean it up to the extent possible. To enhance response capabilities, there is usually a requirement for the conduct of regular safety and emergency response drills during which trained workers and emergency responders carry out regular exercises. Drills include desk-top exercises and actual equipment and operational deployment exercises. Such drills should be conducted by private operators as well as by relevant government authorities in their areas of responsibility, such as coast guards for marine spills and environmental agencies for terrestrial spills. For effective response, there should be rapid notification procedures to the appropriate government authority (see Appendix 2.2, section A1), an evaluation of the hazards posed to public health and the environment, decisions on what response action should be taken, and implementation of the response.

The Arctic is one of the most challenging areas for oil spill response. Drifting ice, ice-covered waters, heavy winds, and poor light conditions during winter impose severe limitations on responses to oil spills. In addition to the large variations in weather and light conditions, mist and low clouds prevail, reducing infrared sensor performance and hampering the use of sensors for locating and tracking spilled oil. Enhancing the ability to recover oil during darkness and low visibility is vital to oil spill contingency in the Arctic.

New challenges in pollution control also arise from new frontiers in deep-water exploration and coastal production. Furthermore, petroleum activities in northwestern Russia may lead to increased tanker traffic along the Russian and Norwegian coasts, resulting in an increased risk of oil spills.

The oil spill regimes of the Arctic countries reflect the varying concerns associated with unique marine and terrestrial ecosystems, the development of national authorities and policies on the direction of oil spill response, and the relative levels of oil spill response system development in both highly populated and unpopulated areas as well as in very remote regions subject to extreme wind, sea, and temperature conditions. Given these factors, there are several aspects which are central to a consideration of the various oil spill regimes: spill response authorities; regional response organization structures for notification and response; spill response technologies applied; and equipment distribution and depots.

2.8.2. Spill response authorities

The summary descriptions in this section highlight key similarities and differences in national perspectives among Arctic countries (see also Table 2.78 and Appendix 2.2, section A2 for more detailed discussions of the oil spill regimes in Canada, Norway, and the United States).

2.8.2.1. Alaska, United States

Under the Oil Pollution Act of 1990, oil handling facilities must have a facility response plan and tankers within U.S. waters must have a vessel response plan which identifies pre-contracted resources sufficient to deal with a number of spill scenarios, including loss of the entire cargo. In addition, these entities may possess quantities of spill response equipment and supplies. The facility and vessel response plans must identify a Qualified Individual with full authority to implement the plan together with a spill management team. Vessel response plans are also required for non-tank vessels over 400 gross tonnage (GT).

The party responsible for the oil spill must respond to the spill. The responsible party is expected to implement the appropriate vessel or facility response plan, providing pre-contracted personnel and resources or engaging appropriate contractors. This is carried out under the review of a designated Federal On-Scene Commander who is a U.S. Coast Guard officer if the spill is in the marine environment or navigable waters of the United States or an Environmental Protection Agency officer if the spill is terrestrial. If the work is not performed in a satisfactory manner, the Federal On-Scene Commander is empowered to take over the clean-up and appoint contractors at the owner's expense. There are limits on the responsible party's liability for removal costs and pollution damage which are based on the size of the vessel. These limits may be breached if the polluter fails or refuses to adequately report the incident or fails to cooperate with the authorities.

Oil spill response is organized under a standard process known as the Incident Command System (see Appendix 2.2 for further details). The Incident Command System has Planning, Operations, Logistics, and Finance sections under the direction of a Unified Command. The Unified Command comprises the Federal On-Scene Commander, the State Incident Commander, and the responsible party. For a major spill of significant national concern, a National Incident Command is headed by a National Incident Commander.

A National Response Team comprises members of 16 Federal agencies with the Environmental Protection Agency as chairman and the U.S. Coast Guard as vice-chairman. When a spill occurs in the marine environment or navigable waters, the U.S. Coast Guard will chair the National Response Team. Under the auspices of the National Response Team, Regional Response Teams have been established for the various regions, including one in Alaska; these teams comprise regional Federal and State staff. The two groups have a planning, policy, and support role. The National Response Team is responsible for the National Contingency Plan, while the Regional Response Teams are responsible for developing regional contingency plans and providing guidance for subordinate area contingency plans. Area Committees comprising Federal, State, and local agencies have been established for local

Table 2.78. Oil spill response regimes for spills occurring in the Arctic.

	United States	Canada	Greenland	Iceland	Faroe Islands	Norway	Russian Federation
Main legislation	Oil Pollution Act of 1990	Canadian Shipping Act; Arctic Waters Pollution Prevention Act			Act on Protection of the Sea No. 59 from 17 May 2005	Pollution Control Act; Svalbard Environmental Protection Act (Svalbard only)	Federal law On Protection of Population and Territories from Natural and Man-Made Emergency Situations of 21 December 1994 #68-FZ (as amended by Federal laws of 28.10.2002 #129-FZ, of 22.08.2004 #122-FZ)
Responsibility for clean-up	Party responsible for the spill	Party responsible for the spill		Office of Marine Environmental Protection and municipalities	Party responsible for the spill	Party responsible for the spill	State Marine Pollution Control, Salvage and Rescue Administration of the Ministry of Transport
Overall lead agency	U.S. Coast Guard (marine and navigable waters) or U.S. Environmental Protection Agency (terrestrial)	Canadian Coast Guard (in Arctic) (marine) or Environment Canada (terrestrial)	Danish Environmental Protection Agency	Environmental and Food Agency of the Ministry of the Environment	Faroese Food, Veterinary and Environmental Agency and Faroese Fisheries Inspection	Norwegian Coastal Administration	State Marine Pollution Control, Salvage and Rescue Administration of the Ministry of Transport
Financial responsibility	Party responsible for the spill				Party responsible for the spill	Party responsible for the spill	
Port and harbour clean-up		Port authority	Local Greenland communes	Municipality	Municipality		Port or terminal authority
Coastline clean-up			Local Greenland communes	Local community	Government/ Municipality	Party responsible for spill or municipality	Local administration

preparedness and planning including maintenance of the area contingency plan. Area contingency plans include local sensitivity maps (see Chapter 6) and spill response strategies. Oil facility and vessel response plans must relate to the larger area contingency plan.

In addition to these structures, there are a number of specialized teams resident within specific Federal agencies which can be activated to support an oil spill response. Primary among these are the U.S. Coast Guard National Strike Teams which can mobilize both administrative and operational support, the Scientific Support Coordinators from the National Oceanic and Atmospheric Administration, and the Emergency Response Teams from the Environmental Protection Agency.

Pollution equipment, both public and private, is inventoried in the Regional Response Inventory. U.S. Coast Guard equipment is dispersed in a variety of depots and additional small amounts of equipment are available to the local Captains of the Port for initial response until more substantial resources arrive. A number of communities in Alaska hold caches of pre-staged spill response equipment and have made formal agreements to provide spill response support.

The State of Alaska has oil spill prevention and contingency plan regulations (18 AAC 75), which were updated at the end of 2006. These relate to terminals and tank farms, marine vessels, and pipelines, and specify new standards for pipeline and tank integrity. To obtain a license for exploration or production of oil or operation of an oil refinery, an Oil Discharge Prevention and Contingency Plan (C-plan) must be prepared by the operator and approved by the Alaska Department of Environmental Conservation (ADEC). The operator must also meet other requirements including appropriate training of personnel in relation to company and State spill prevention measures. Maintenance of a register of Primary Response Action Contractors is also covered by these regulations.

Preparing and gaining approval for a C-plan can be a time-consuming component of permitting a project in the Alaskan Arctic. Operators of oil and gas facilities must provide ADEC with proof of financial responsibility for the cost of responding to the maximum likely oil spill at each facility. The State of Alaska has developed an Alaska Incident Management System, known as AIMS, for managing oil spill response. AIMS is an Alaskan version of the Incident Command System (ICS) that is widely used for crisis response in the United States. The State maintains a register of oil-spill response contractors that can supply resources for spill response work. These contractors generally operate as industry co-ops, in which co-op members pay membership and other fees for access to the use of the co-op's resources. The high cost of these fees, especially on the North Slope, has been a major obstacle for small companies wishing to enter the Alaska oil and gas industry. Restructuring of the fees in recent years has made the co-ops more accessible for small operators.

2.8.2.2. Canada

The Canadian oil spill regime is established under the Canada Shipping Act and the Arctic Waters Pollution Prevention Act. Under the Canada Shipping Act, tankers of more than 150 GT and all other vessels of more than 400 GT must carry an approved shipboard oil pollution emergency plan for operation in Canadian waters. In the event of a spill, and for non-Federal-government vessels, the polluter is required to implement measures to respond to the incident. Transport Canada has responsibility for shipping matters, with the Rescue Safety and Environmental Response Directorate, Canadian Coast Guard, and a part of the Department of Fisheries and Oceans, generally being the lead agency in preparation for and response to spills of oil and noxious substances from ships. The Canadian Coast Guard is organized into five Regions, each with a Regional Director and a Director of Marine Programs responsible for the maintenance of regional contingency plans, stocks of oil spill response equipment, and the provision of trained personnel. Within port limits, responsibility falls to the appropriate port authority. Specific ports have developed spill contingency plans. In military port areas, primary responsibility is held by the Department of National Defence, which responds to all spills from its own vessels and facilities.

Canadian Coast Guard spill response equipment is cached in ten northern communities; including Rankin Inlet, Arctic Bay, and Coral Harbour, Iqaluit, Tuktoyaktuk, Churchill, and Hay River. The equipment includes booms, skimmers, and pumping systems. In the event of a considerable spill, The Canadian Coast Guard also has a transportable system that can be airlifted to communities within 48 hours.

Privately-funded certified Response Organizations have the responsibility to maintain an oil spill response capability under contract to vessels. Ship owners are required to have an arrangement with one or more Response Organizations for the areas travelled; however, there is no legal obligation to implement the arrangement and engage the services of the Response Organization. Alternative arrangements can be made using other resources. In Arctic waters, north of 60° N, the Canadian Coast Guard is the prime responder. Each Response Organization has a Response Plan establishing the resources and strategies needed to respond to a range of oil spill scenarios. The polluter is expected to appoint an On-Scene Commander responsible for providing the Canadian Coast Guard with an acceptable plan of action, agreed by the Response Organization. The polluter directs the response accordingly. However, the Canadian Coast Guard retains the right to intervene and take control of the spill response for mystery spills and spills where the polluter is unwilling or unable to mount an effective response.

Various agencies have responsibilities as the lead, under memorandums of agreement for environmental matters relating to spills of oil on land or on water, based on the source of the spill. These agencies include the National Energy Board (oil spills on land or water from exploration or production facilities), Indian and Northern Affairs Canada (spills on Crown Land and water not covered by other agencies), the territorial governments (spills on territorial-controlled lands), Environment Canada (spills at Federal facilities), Canadian Coast Guard (ship-based spills), and Inuvialuit Land Administration (spills on Inuvialuit-owned lands) (see also Appendix 2.2, section A2.1). Shoreline clean-up is the responsibility of the polluter and is monitored by Environment Canada.

Regional Environmental Emergencies Teams (REETs), led by Environment Canada, exist for each region including the Arctic (A-REET) and comprise representatives from Federal, provincial, territorial, Native, and local government and regulatory bodies and from private sector groups, industry specialists, academics, environmental organizations, and local individuals. REETs provide environmental advice to other lead agencies on oil spill response including weather and hydrological conditions, spill trajectory modeling, surveillance/monitoring, environmental sensitivities, protection strategies, clean-up priorities, clean-up evaluation, fate and effects, wildlife, and fisheries protection, environmental restoration, and waste storage and disposal options.

The A-REET is led by Environment Canada in Yellowknife, NT. In addition to members shared with the Northwest Territories – Nunavut Spills Working Group, the A-REET can provide expertise from other agencies and organizations in the territories or Federal government.

2.8.2.3. Greenland

Greenland, as part of Denmark, relies for response to oil spills on the support of the Danish Ministry of the Environment, which has delegated planning and operational responsibility to the Danish Environmental Protection Agency. The Danish Environmental Protection Agency has developed an oil spill contingency plan for Greenland. Upon notification from the Maritime Rescue Coordination Centre, the Danish Environmental Protection officer will decide the manner of oil spill response. The Danish Environmental Protection Agency as the principal authority, may request support in the form of other agency expertise in dealing with wildlife, fisheries, and general marine environmental protection. Assistance can also be requested from the Danish Armed Forces, both the Navy for on-water oil recovery and the Air Force for surveillance, as well as a number of civilian authorities including disaster management forces. The local Greenland communes are responsible for beach clean-up and harbor clean-up. The Civil Defense Corps can be called upon to provide equipment and personnel.

2.8.2.4. Iceland

The Environmental and Food Agency of the Ministry of the Environment, is the lead government agency overseeing maritime oil spill response in Iceland. Responsibility for oil spills is divided between the Office of Marine Environmental Protection, a division of the Agency, and the municipalities. Municipalities are the main responders to spills in ports and harbors. The Icelandic Coast Guard provides surveillance and communications for spill response. Within port areas that role is fulfilled by the port authorities. The ports are either government owned and operated (Keflavik, Helguvik) or run by the municipal authorities (Reykjavik). Upon notification of a major spill from the Icelandic Coast Guard, the responsible officer of the Environmental and Food Agency of Iceland will determine necessary response operations. A member of the Agency will assume the role of On-Scene Commander. The Agency is assisted by an expert advisory committee regarding the environment, wildlife, and sensitive areas. The local communities are responsible for shoreline clean-up. In practice, this may be delegated to the local fire brigades.

A national training course in pollution response is held each year for the benefit of personnel from government agencies, local authorities, oil companies, and operators of industrial facilities.

2.8.2.5. Faroe Islands

In the Faroe Islands, oil spill response is governed by the Act on Protection of the Sea No. 59 from 17 May 2005. The governmental lead agencies are the Faroese Food, Veterinary and Environmental Agency and the Faroese Fisheries Inspection. A person or vessel responsible for an oil spill pollution incident is required to carry out preventative measures to reduce the pollution.

The local council (municipality) is responsible for combating oil and chemical pollution in and alongside quays and harbors, while the national government is responsible for combating oil and chemical pollution at sea and in coastal areas outside harbors and quays.

The polluter is required to cover the cost of combating pollution at sea and along the coasts; but if the polluter is unknown, the government or the local council, respectively, will cover the expense of clean up.

The Faroese local and national governmental authorities are required to prepare contingency plans for combating pollution in their respective areas of responsibility.

Oil companies must maintain approved contingency plans for combating oil spills that may occur in association with exploration drilling operations in Faroese waters. As part of the application for approval to drill, the operator must provide and document such contingency plans. These contingency plans must thereafter be approved by the Faroese authorities.

2.8.2.6. Norway

Contingency planning requirements are addressed by the Norwegian Pollution Control Authority. Spill response in Norway is based on private, municipal, and governmental contingency plans, all of which are coordinated under a national emergency response plan prepared by the Norwegian Coastal Administration, which is also responsible for coordinating private, municipal, and governmental preparedness into a national emergency response system (see Appendix 2.2, section A2.2). Private and municipal plans are approved by the Norwegian Pollution Control Authority. For nearshore spills, the first level of response is by the port or terminal, with larger incidents supported by the inter-community response group in whose area the spill occurs. The oil industry must provide contingency plans addressing equipment, personnel, and oil spill response strategies. If a spill were to pass beyond the capability of the local industry, resources from the inter-community group would be enlisted for support. Contingency planning requires all parties to provide assistance to other parties in need.

The Norwegian Coastal Administration maintains copies of inter-community contingency plans, which contain data on local coastal sensitivities. The Administration maintains a Marine Resource Database including coastline sensitivity maps. A mutual agreement policy exists, whereby the Coastal Administration notifies any organization potentially at risk of a spill. These plans therefore run in parallel and are complementary to the government response measures. Municipalities are mandated to respond to those spills within the confines of the municipalities that are not otherwise covered by private contingency plans. This responsibility extends to 12 nautical miles from shore. Each municipality has an oil spill group with members drawn from local interested parties and chaired by the harbor master, fire, or police chief. Manpower for this response may be drawn from local authorities, the Civil Defense Force or the Army.

The Norwegian oil industry must establish an oil spill preparedness capability able to handle spills according to defined hazard and accident situations. The industry is legally responsible for any acute spill from its activities. Based on an environmental risk assessment and emergency preparedness analysis, emergency response requirements are established by the Norwegian Pollution Control Authority in association with each drilling permit granted to an operator. Oil companies are required to prove their ability to achieve rapid response times for oil spill recovery.

The government provides for major incidents not covered by, or beyond the capabilities of, the municipal and private contingency plans. In the event of a major spill, the government may call on industry to aid in the response. In such cases, equipment may be supplied from industry stockpiles, including the Norwegian Clean Seas Association for Operating Companies (NOFO), which was originally established to support Norwegian North Sea offshore exploration and production rigs and platform operations.

The Coastal Administration is also responsible for the National Training Centre for Oil Pollution Control and the National Test Centre for Oil Spill Response Technology.

2.8.2.7. Russian Federation

The State Marine Pollution Control, Salvage and Rescue Administration of the Ministry of Transport is the national authority responsible for responding to marine pollution incidents. A national contingency plan is in place which reflects Russian authority for oil spill response. The national contingency plan requires three levels of planning: local, regional, and Federal. Ports, oil terminals, and harbors have local contingency plans and capabilities which, if exceeded, can be supplemented by regional plans and resources. Regional plans are coordinated by the State Marine Pollution Control, Salvage and Rescue Administration which has established eight regional salvage and spill response bases; two located in the Arctic (Murmansk and Arkhangelsk) with a third (Petropavlovsk Kamchatskiy) located on the east coast of the Kamchatka Peninsula just south of the Bering Sea. These bases specialize in spill response, salvage, and towing operations. Shoreline clean-up is the responsibility of the appropriate local administrations.

The Regional Plan of Oil Spill Response in the West Arctic, approved in 2003 and covering the region of the Barents Sea, has a number of disadvantages (Jouravel et al., 2005): incompleteness of accounting for possible oil spill sources; insufficient resources, for example, to respond to oil spills from the tankers of up to 100 000 tonnes deadweight that enter Kola Bay; the decrepit state of shipboard facilities and equipment that began operation in the 1980s; the remoteness of accident response resources from the sites of possible spills (approach time is up to two days); the absence of modern accidental oil spill detection, monitoring, and behavior forecast devices; the absence of floating craft and equipment for work in ice conditions; the near impossibility of working in shallow coastal water with the resources available; and a significant, if not complete, lack of resources to protect and clean up shorelines.

The causes of such disadvantages include: the traditional inclination toward the use of government resources (the only operator of the Plan is the Murmansk Basin Emergency Administration); the extreme complexity of developing and agreeing on the Plan (the development and concurrence of the final version of the Plan by Russia's State Sea Rescue Service took almost two years); and the absence of organizational, economic and, to a certain extent, regulatory mechanisms for multi-level coordination of the accident response system with involvement of all interested parties.

2.8.3. Regional response organizations

Principal oil spill response organizations provide both a notification system for reporting oil spills and a central organization for directing governmental spill response (see also Appendix 2.2).

Some countries, such as Norway and Sweden, combine both the notification call center and the central authority for directing spill response in a single organization, while other countries such as Iceland establish their oil spill notification center as organizationally separate from the principal oil spill response organization. Other countries establish national notification call centers separately from, but co-resident with, the government's national spill response organizations; this is the case in Canada and the United States. For Greenland, the notification call center is located in Greenland but the principal spill response authority is in Denmark.

Some countries including the United States strictly centralize their notification process, while others such as Canada provide for regional notification call centers in addition to a central center. Several countries have joint notification call centers for both oil spill notification and search and rescue notification; this is the case for the Russian Federation, Iceland, Sweden, Denmark, and Greenland. In some countries, such as the Russian Federation, these regional notification call centers are co-located with regional equipment and personnel depots. Some regional notification call centers also have further sub-centers depending on notification contingencies, as is the case in the Russian Federation.

Other countries, for example Denmark, require that under certain conditions, such as while in port, notification must be made to the local port authority.

2.8.4. Spill response technologies

The member countries of the Arctic Council vary widely in the response technologies that are accepted by governmental policy. While all rely principally on mechanical recovery techniques involving booming of oil and retrieval with a wide variety of skimmers ranging from rope mops to disk and brush skimmers, only a few apply in situ burning and fewer still consider the use of dispersants. The concern with dispersants is often underscored by international conventions. For example, in certain areas such as the Baltic Sea, it has been internationally agreed in the Helsinki Commission that oil spill response will be based on mechanical recovery. The Helsinki Commission allows the use of chemicals only within very strict limitations. Elsewhere, significant concerns for unique marine environments and substantial fishing concerns militate against the use of dispersants, as is seen in Iceland and Greenland. This section describes the relevant policies of the individual countries on spill response technologies (see also Table 2.79).

2.8.4.1. Alaska, United States

Spill response in U.S. waters is primarily that of mechanical containment and recovery. In Alaska, a new tactic (designated R-31) has been developed to recover oil that is present among broken ice and large floes; instead of

Table 2.79. Oil spill clean-up methods used in the Arctic.

	United States	Canada	Greenland	Iceland	Faroe Islands	Norway	Russian Federation
Mechanical containment and recovery of oil from surface	1	1	1[a]	1	1	1	1
Use of pre-approved dispersants	2[b]	2	X	2[c]	2	2	2
In situ burning	2[d]	2[d]					3[c]
Bioremediation	3[a]	3[a]					

1: primary method; 2: secondary method; 3: used occasionally or in specific circumstances; X: prohibited.
[a] useful in certain circumstances only; [b] use in cold-water applications requires specific authorization by regional spill response authority; [c] approval is required prior to use; [d] pre-approved in certain conditions.

deploying containment booms, this tactic relies upon the ice's ability to contain and concentrate oil into a sufficient thickness for recovery using a skimmer deployed from a tank barge or smaller vessel. Shoreline response is based on protective booming and the use of mechanical recovery, manual removal, water flushing/washing, and the use of sorbent materials. In-situ burning and dispersant use have been pre-approved in certain conditions. Dispersants have been pre-approved for application in the national response regime; however, the actual use of dispersants in cold-water applications continues to require the specific authorization of the regional spill response authorities. Bioremediation is considered to be a further option, depending on the circumstances involved, but has seen very limited application. Disposal of oily debris is usually through landfill or incineration.

2.8.4.2. Canada

Spill response focuses primarily on containment and recovery of oil from the water surface. The application of dispersants is considered to be of secondary importance. In-situ burning techniques may be used in certain circumstances where there is an imminent threat to a sensitive environment. Shoreline response is based on protective booming and the use of mechanical recovery, manual removal, water flushing and washing, and the use of sorbent materials. Dispersants must be pre-tested and evaluated, and their use approved, by Environment Canada or, for spills from well drilling, by the National Energy Board. Several chemical dispersants for shoreline clean up have been pre-approved; however, the use of dispersants is precluded in areas where drinking water is obtained. Bioremediation is considered to be a further option depending on the circumstances involved, but has seen very limited application. Recovered oil is recycled, incinerated or used in commercial applications. Disposal of oily debris is usually through landfill or incineration.

2.8.4.3. Greenland

Sea conditions, particularly in the winter months, prevent most clean-up methods. However, in view of the unique marine biota, spill response focuses primarily on containment and recovery of oil from the water surface. The use of dispersants is prohibited.

2.8.4.4. Iceland

Spill response focuses primarily on containment and recovery by mechanical means. Chemical dispersion is used in limited circumstances when mechanical removal is not viable. Significant concern related to the use of dispersants focuses on the need to avoid tainting of commercial fish, particularly in salmon farms scattered along the coast. However, the low population density, harsh climate, and poor access to many coastal areas make mechanical recovery more difficult. In contrast, weather and sea conditions may support the application of dispersants. Prior to use, dispersants must be approved by the Environmental and Food Agency of Iceland. Oil companies operating in Iceland are expected to accept any recovered oil. Processed waste oil may be used as a fuel in certain commercial enterprises (e.g., cement factories). Oil sludge may be incinerated and solid wastes can be disposed of in inland landfills.

2.8.4.5. Faroe Islands

The response to oil spills primarily focuses on mechanical containment and recovery. Any use of dispersants or other chemicals for combating pollution requires permission from the Faroese Food, Veterinary and Environmental Agency (Heilsufrøðiliga Starvsstovan). Permission for the use of dispersants will be granted only under special circumstances and for a specified period of time. The Minister of Interior (Environmental) may establish rules for the use of chemicals for combating oil pollution.

2.8.4.6. Norway

Spill response focuses primarily on the containment and recovery of oil from the water surface. The use of dispersants, considered ancillary to mechanical removal, is required to be considered as part of the larger spill response strategy. Organizations that are required to have an oil spill contingency plan are expected to consider dispersant use as part of their larger spill response strategy. Dispersant use not already specified in a contingency plan according to the dispersant regulation must be approved by the Norwegian Pollution Control Authority. The disposal of oily waste in local domestic waste sites is dependent upon local authority regulations. If local authorities do not accept the recovered oil and oil debris, the waste may be dealt with through a nationally coordinated waste disposal plan in which all the major waste disposal companies in Norway participate. Cement plants are sometimes used for incineration. Landfill and land farming have also been used for disposal.

2.8.4.7. Russian Federation

The Russian Federation predicates its spill response largely on spill size and environmental conditions which may encourage or discourage the use of non-mechanical spill response technologies. Generally, Tier 1 oil spills are treated by mechanical means if weather conditions allow. Tier 2 and Tier 3 oil spills will rely on mechanical recovery but may also consider dispersant use and in-situ burning, depending on the circumstances. Dispersants must be pre-approved by the Ministry of Natural Resources, the Ministry of Health, and the Fisheries Committee. In-situ burning is employed on rare occasions and is subject to a similar approval process. Recovered oil and oily debris may be incinerated, recycled where possible through commercial interests or deposited in landfills under specific conditions.

2.8.5. Equipment distribution

Response resources which include air and sea platforms, spill response equipment, lightering equipment, disposal supplies such as sorbents, and chemical response supplies such as dispersants and herding agents, as well as the resources necessary for in-situ burning are generally maintained in both governmental and private sector contexts. However, there is wide variability in the type and amount of such response resources that are held by either governmental or private sector sources. The continuum ranges from resources that are predominantly held in the private sector to resources predominantly owned by governments.

2.8.5.1. Alaska, United States

The United States government holds large amounts of equipment placed at strategic sites around the coast and on associated islands. U.S. Coast Guard cutters and other vessels have been adapted to deploy this equipment. U.S. Coast Guard Strike Teams as part of larger integrated Deployable Operations Groups (DOGs), Environmental Protection Agency Emergency Response Teams, the Department of Energy Radiological Response Teams, and the National Oceanic and Atmospheric Administration Scientific Support Coordinators all provide specialized equipment, laboratory support, and technical personnel. The U.S. Coast Guard and the Department of Defense both have aircraft and helicopters for equipment deployment and surveillance. In addition, the U.S. Navy has large amounts of equipment at three major stockpiles established by the Navy salvage division.

The U.S. Coast Guard has pre-positioned oil spill response equipment in Alaska including one Vessel of Opportunity Skimming System (VOSS) in Anchorage, four Spilled Oil Recovery Systems (SORS) in Kodiak, Homer, Cordova, and Sitka and connex boxes of oil spill response equipment pre-positioned in several areas throughout the State. Additionally, the Navy's Supply and Salvage Division also has a large inventory of oil spill response equipment located on Fort Richardson Army Post in Anchorage.

In addition, pre-position stocks of equipment are cached for use with vessels of opportunity and each U.S. Coast Guard Captain of the Port has access to limited response equipment for small spills and for immediate application until back-up equipment is available. These resources are intended as a back-up to those from the private sector, as hundreds of private Oil Spill Removal Organizations (OSROs) and supporting contractors have been classified by the U.S. Coast Guard to operate in designated environments within U.S. waters depending on their capability. Large OSROs have dedicated vessels deployed at a number of ports around the country, in addition to non-dedicated multipurpose vessels. In addition, major regional as well as national oil producers and transporters have formed spill response cooperatives. One significant Tier III organization, funded by member oil companies, operates a large amount of equipment from Alaska. Equipment is packaged for immediate air transport. Each marine transportation-related oil facility is also required to retain equipment on the facility or to have contracted a spill response organization for those services.

2.8.5.2. Canada

The Canadian Coast Guard operates a fleet of ships, hovercraft, helicopters, and fixed-wing aircraft. In addition, spill response equipment is located at sites throughout Canada with dedicated, experienced personnel in major centers (see section 2.8.2.2 for specific locations).

2.8.5.3. Greenland

Greenland, with no specialized clean-up resources stockpiled in the local area, must respond to a spill through air transport of equipment and trained personnel from Denmark or Canada. The Danish Environmental Protection Agency has two main stockpiles of air transportable equipment in Denmark; one in Copenhagen and one in Korsør. This equipment would be deployed by the Danish Navy via air transport. Spill response vessels would require time to travel to Greenland. It is anticipated that any significant spill response, therefore, would require air transport of Danish spill response resources and invocation of the Canadian agreements for response support in Baffin Bay, Davis Strait, and other joint sea areas. Spills on land would require Danish government support.

2.8.5.4. Iceland

The Icelandic Coast Guard provides vessels that have been prepared for response to a major pollution incident. Oil spill removal equipment and supplies are stockpiled at five sites around the coast. The smaller stockpiles are maintained and operated by regional cooperatives formed by the municipalities and harbor and port authorities. In addition, several port tugs have the facility for dispersant spraying. Icelandic Coast Guard aircraft and helicopters are equipped for aerial surveillance and equipment transport. There is limited private sector spill response capability.

2.8.5.5. Faroe Islands

The Faroe Islands Fisheries Inspection (Fiskiveiðieftirlitið) maintains equipment and vessels for combating oil spills at sea and in coastal areas around the islands. In the larger municipalities, the local authorities hold equipment for combating oil spills in harbors. In addition, a private company has some equipment and manpower available to combat oil spills in harbors and coastal areas. This company also cooperates with companies from Norway and the UK in case additional equipment and resources are needed.

2.8.5.6. Norway

Norway's Coastal Administration Department of Emergency Response is located in Horten, with stations in Tromsø and Bergen. The Coastal Administration operates a number of vessels for at-sea operations, which are either permanently equipped or capable of having and deploying oil spill response equipment. In addition, a number of naval defense vessels are on contract, capable of oil recovery, transportation or acting as lead offshore command vessels. Eight Coast Guard vessels are permanently equipped with oil recovery equipment. Vessels from the civilian coastal patrol, as well as vessels of opportunity such as fishing boats are also available. The Coastal Administration maintains fifteen equipment stockpiles with oil spill control equipment, trained personnel, and small boats; these are located along the coast and on the Svalbard Islands (Figure 2.155). In addition, the various coastal communes have inshore booms and skimmers available. The Coastal Administration also operates aircraft equipped with Side-Looking Airborne Radar capable of tracking spills and attempts to make use of radar satellites to provide information on substantial oil spills. A cooperative oil spill enterprise, the Norwegian Clean Seas Association for Operating Companies (NOFO), operates large supply ships with the capability for conversion to oil recovery operations. In addition, it maintains five depots with equipment consisting of large, heavy-duty containment and recovery systems. NOFO has contracted helicopters to enable surveillance and tracking of oil movement monitoring and recovery, as well as dispersant applications. In addition, the oil industry also maintains three large stockpiles of equipment, including vessels, at major oil refinery and crude oil terminals. Several bunker stations have small amounts of equipment.

2.8.5.7. Russian Federation

The Russian Federation maintains stocks of spill response equipment in amounts varying according to estimates of oil spill amounts and the likelihood of spills in local operations at ports, harbors, and oil terminals. Spill response equipment consisting of supplies and equipment for larger spills are contained in one of a series of eight salvage and spill response bases co-located with key ports. The largest and most significant equipment depots on the west and northern coasts are at the ports of Murmansk and St Petersburg which have specialized pollution response vessels, tug access, and suitably equipped supply vessels. On the east coast, the ports of Vladivostok and Sakhalin also have pollution response vessels, tug access, and offshore response vessels. Other specific pollution equipment includes offshore booms and skimmers, oil trawls, and portable pumps located at various ports.

2.8.6. Challenges of oil spill response in Arctic conditions

The Arctic is one of the most challenging areas for oil spill response in the world owing to the severe limitations imposed by drifting ice, ice-covered waters, heavy winds, and poor light conditions during winter. Spill response operations in ice-infested and open water are fundamentally different. These differences must be recognized when determining the most appropriate strategy for dealing with oil in specific ice conditions and seasons, including freeze-up, winter, and break-up. Owing to the vastly different ice environments and oil-in-ice situations, over-reliance on a single type of response in different ice environments and oil-in-ice situations is likely to result in inefficient, ineffective clean-up after an oil spill.

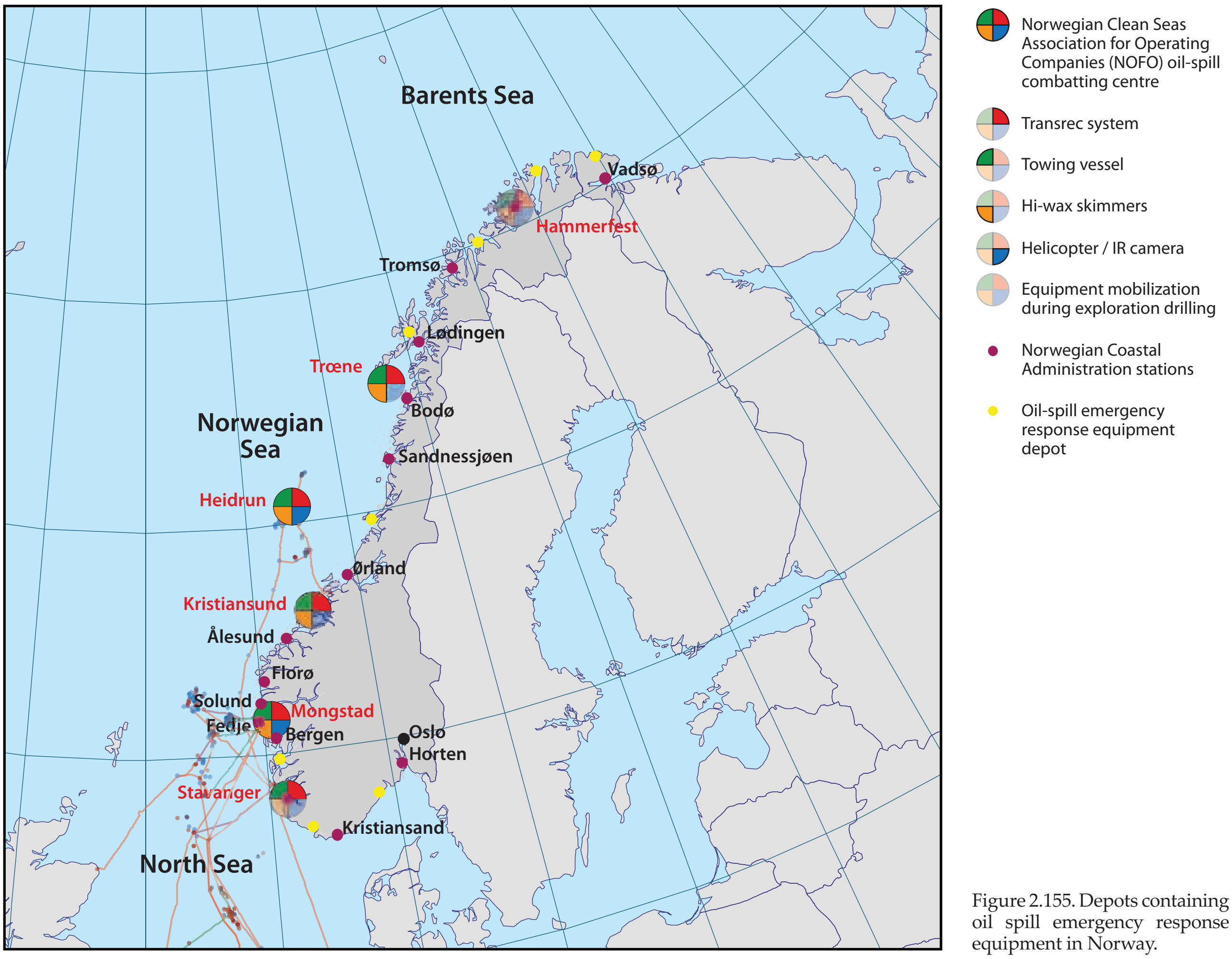


Figure 2.155. Depots containing oil spill emergency response equipment in Norway.

The oil spill contingency for ice-infested waters will never reach the same level as for open waters owing to the natural restrictions associated with the presence of ice, low temperatures, and darkness during the winter months, as well as the problems associated with remoteness and poor infrastructure. Nevertheless, research on oil spill response technology and techniques has progressed over the past few years resulting in many refinements to existing practices and the introduction of promising new technology and techniques that respond to the varying conditions likely to be encountered in marine areas of seasonal ice cover.

When deciding on tactics to respond to an oil spill, the fate and behavior of the oil are crucial factors and serve as important input to oil spill response modeling. An important issue on which research is needed to improve the response to oil spills in the Arctic is a better understanding of the weathering processes for oil in ice. There is limited knowledge about the influence of freezing temperatures and sea ice on oil weathering rates and changes in oil properties, and such information is needed to improve oil weathering models for the Arctic. An understanding of oil-ice interactions during freezing and thawing is also important.

Despite being the primary means of oil spill clean-up in the Arctic (Table 2.79), most mechanical methods for the recovery of spilled oil were developed for open-water conditions and do not operate efficiently in ice-infested waters or under low temperatures; this is particularly a problem for large oil spills. Tests of booms and skimmers in broken ice conditions have shown the severe limitations of conventional containment and recovery equipment in even trace concentrations of broken ice (Bronson et al., 2002). The effective operation of skimming systems designed for use in ice-infested waters is severely impacted by even very small pieces of brash ice concentrated by the containment booms. Among the main challenges for mechanical recovery of oil in icy waters are: the icing or freezing of equipment; limited or difficult access to the oil owing to the deflection of oil together with ice; limited flow of oil to the skimmer; problems of separation of oil from ice and water; strength considerations regarding pressure and impact in the ice field; increased oil viscosity at low temperatures; and detection and surveillance of the oil slick, potentially over a long period of time (SINTEF, 2006).

Accordingly, clean-up technology and techniques have been a major focus of studies and tests. Recent basin and field testing shows promising results for the efficiency of some designs of brush drum and brush helix skimmers (Singsaas, 2007). Field testing of rope mop and brush drum skimmers is being conducted in 2008 and further concept designs will be completed and tested in field trials in 2009 as part of the SINTEF Joint Industry Program. Other research has shown good rates of recovery of various oils in different temperature and ice conditions by configuring the surface of the drum in different geometries and materials (Keller, 2007). These surface or geometric configurations may be retrofitted to existing equipment.

The largest potential for improving mechanical oil-recovery equipment in ice-infested waters will probably occur via further improvement and adaptation of existing methods, although such developments are unlikely to produce substantial gains in response effectiveness. New or improved concepts for the pumping of oils and emulsions are needed as existing pumping equipment may fail to operate effectively for oils or emulsions at the increased viscosities of oil at low temperatures or owing to the solidification of waxy oils on the sea surface at low temperatures (SINTEF, 2006). Also, new techniques to deflect and separate oil and ice – such as prop wash or pneumatic bubblers – may enable mechanical systems to encounter and recover oil at higher rates in the presence of drifting ice. Given the probability that future developments in the Arctic will include sub-sea production, equipment should also be developed to handle oil spills under ice as there are currently no concepts or equipment for the recovery of oil under ice.

The use of dispersants is a secondary clean-up method available for consideration in most Arctic countries (Table 2.79 and Box 2.20); however, the use of dispersants in cold-water environments where there is also ice is viewed as having the potential for limited success. Concerns include the lack of natural mixing energy owing to the damping effects of the ice and the tendency for oils to become viscous at low temperatures. With regard to the potential use of dispersants, critical parameters for the operational use of dispersants under Arctic conditions include: contact between the dispersant and oil; sufficient energy for the dispersion process; properties of the oil at low temperatures including weathering; and the properties and performance of the dispersant under relevant conditions, such as oil type, salinity, and temperature (SINTEF, 2006). Weathering models are needed to be able to predict more reliably the effectiveness of dispersants as a function of oil type, degree of weathering, and ice concentration. The technology for application of the dispersants is also critical with regard to the platform for application (helicopter or vessel) and adaptation of the equipment such as spraying arms and nozzles for use at low temperatures.

Nonetheless, recent promising results from industry-sponsored tank tests have spurred a re-examination of dispersants as a possible clean-up strategy for certain oil-in-ice situations. Studies and tests on dispersants include experiments in 2006 and 2007 at the Ohmsett test facility using dispersants currently deployed in Alaska, which demonstrated that they are more than 90% and up to 99% effective in dispersing fresh and weathered North Slope crude oils tested in very cold water (Mullin, 2007). Large-scale tests in 2006 on the use of natural dispersants consisting of micron-size fine mineral particles show that Oil Mineral Aggregate (OMA) is solids-stable and shows great promise as an oil spill countermeasure for oil spills in ice-infested waters (Lee, 2007). These OMAs decrease the adhesion of oil enhancing mechanical recovery and make the oil more easily biodegraded. Winter tests took place in 2007 and field tests in 2008.

Using icebreakers or other vessels to introduce the required mixing energy, in combination with a dispersant formulated for longer retention by viscous oils, could lead to dispersants becoming a practical response option for oil spills in ice. Research is still at an early stage, and more research and development is needed before a definitive recommendation can be made.

One of the response techniques with the greatest potential for use in Arctic conditions, especially in dense ice and in snow, appears to be in-situ burning (Box 2.21). A series of successful Arctic field experiments in the 1970s and early 1980s was largely responsible for helping in-situ burning become accepted as the most effective oil recovery strategy in situations involving spills in ice-covered waters. There is an extensive body of knowledge on the fundamentals of burning in different ice types. The suitability of in-situ burning depends on the initial oil characteristics and the weathering state of the oil. Factors important to successful burning include heat transfer and flame temperature, oil slick thickness, type of oil and weathering characteristics, and the wind speed and general weather conditions (SINTEF, 2006). The potential and limitations with regard to oil types and weathering degree need to be better defined so that in-situ burning can be developed into an operational tool. New research and development need to concentrate on measures and techniques for expanding the operating window for burning in ice, such as when spills result in thin films occurring among ice floes. The successful development of chemical herders could enhance burning in these marginal situations. The use of surfactants to herd and thicken oil slicks in pack ice for in-situ burning has resulted in burn rates and efficiencies close to those for contained slicks (Buist, 2007). This technique will be explored for enhancing mechanical recovery. Field testing is planned for Svalbard in 2008/2009 as part of the SINTEF Joint Industry Program.

Research is also needed on the potential value of using fire-resistant booms in areas with low concentrations of pack ice to concentrate spilled oil enough to permit in-situ burning. Also, more sophisticated but easy-to-use ignition technologies are needed for in-situ burning to be a viable operational response option (SINTEF, 2006). However, the technique of in-situ burning must be used with great caution owing to the risk of fire spreading and the potential danger to personnel from the fire, heat, and smoke; inhalation of the smoke can be very dangerous owing to the particulate matter that may contain high concentrations of bioavailable contaminants and is easily retained in the lungs (see Chapter 5).

The present inability to reliably detect and map oil trapped in, under, on, or among ice is a critical deficiency, affecting all aspects of response to spills in ice. Although there is still no practical operational system to remotely detect or map oil-in-ice, there are several technology areas where further research into ground-based remote sensing could yield major benefits. Examples include recent tests with optical beams for river spills, and consideration of vapor detection (sniffer systems) for oil trapped in ice. Aerial remote sensing for detecting oil in ice remains an elusive goal. Promising technologies for detecting oil in and under thick ice covers include the use of Ground-

Box 2.20. Use of dispersants for oil spill clean-up in the Arctic

An adequate response to oil spills in the Arctic can be difficult owing to the great distances involved, poorly developed transportation networks, an inadequate labor force, limited mechanical spill clean-up technology appropriate for Arctic conditions, and severe weather. In some countries, the use of oil-dispersing chemicals may provide a supplemental response method to existing conventional clean-up techniques. Oil-spill dispersants are complex chemical formulations comprising a blend of surfactants, or detergents, in a mixture of solvents. When applied to a floating oil slick, dispersants reduce the interfacial tension between the oil and the water, allowing the oil to be broken into small droplets by the action of the wind, waves, and currents. This process disperses the oil into the water column and reduces the concentration of hydrocarbons on the surface.

In deciding whether to use dispersants to supplement mechanical clean-up, the short-term impacts of introducing dispersed oil into the upper water column need to be evaluated against the long-term impacts of allowing the oil to continue to float on the water surface and/or to strand on the shore. In many cases, adverse effects from chemically dispersed oil are much less than those that result from oil stranded in biologically sensitive areas or effects on seabirds or marine organisms that float at the water surface, such as some fish eggs. For example, the risk of untreated oil threatening highly aggregated populations of surface-utilizing organisms (such as migrating or staging seabirds, breeding sites of birds or marine mammals) may need to be weighed against the risk of dispersed oil threatening aggregated populations of water-column organisms (such as migrating salmon, or crab eggs or larvae). Surface oil slicks may cause oiling of seabirds and fur-bearing marine mammals, while stranded oil has a very long residence time and a high probability of chronic impact on subtidal benthos and the water column. On the other hand, the effects of chemically dispersing the oil into the water column are transient, but may be severe. Nevertheless, it is usually anticipated that mortalities would be low owing to the rapid decline in hydrocarbon concentrations in the water column after the chemical dispersion of an oil slick (ARRT, 1999).

As an example, in Alaska criteria for the use of dispersants classify coastal waters into three dispersant use zones, defined by: physical parameters such as bathymetry and currents, biological parameters such as sensitive habitats or fish and wildlife concentration areas, nearshore human use areas, and the amount of time required to respond (ARRT, 1999). In all cases, the use of dispersants must be based on a determination that the impact of dispersants or dispersed oil would be less harmful than that of non-dispersed oil. Stockpiles of pre-approved, low-toxicity dispersants are available in Alaska. Prior approval from the U.S. Environmental Protection Agency and the State of Alaska is required for the use of dispersants in two of these three zones. Subsequent notification only is required in the third zone (Zone 1), where water conditions will allow dispersed oil to be diluted rapidly to low concentrations and the spill is far enough from sensitive resources that dispersant operations would not cause disturbance, but where spilled oil would be likely to affect sensitive resources thus necessitating an immediate response to mitigate consequences. Sensitive resources include endangered or threatened species; nesting, spawning, breeding, and nursery areas for mammals, birds, fish, and shellfish; fish and wildlife concentration areas for feeding, resting, or migrating; and sensitive marine habitats (e.g., seagrass and kelp beds, tidal flats, marshes, and shallow subtidal areas).

To be effective, dispersants must be applied in a timely manner; oil allowed to weather on the surface of the sea becomes difficult, if not impossible, to disperse chemically. Also, there are many difficulties associated with the application and effectiveness of dispersants in cold, ice-infested waters in the Arctic that must be taken into account when considering this option.

Box 2.21. In situ burning of spilled oil

In Canada, Russia, and the United States, in situ burning may be considered as a countermeasure against spilled oil. In situ burning involves the use of an ignition source to initiate the combustion of spilled oil that will burn on its own, without the addition of a burning agent. This response technique should only be considered as an option in worst-case situations, when mechanical containment and recovery response methods are not capable of controlling the spill, and when it may be used in a proper way under the correct conditions. Specific guidelines are required for its use and a considerable amount of planning, practice, and competence is necessary for successful and safe use of this method.

To be effective, burning must be employed early in the spill before the spilled oil weathers and loses its highly flammable constituents. The efficiency of in situ burning is dependent on a number of physical factors, but it can be very effective in removing large quantities of oil from the water. It is more effective for crude oil than for lighter oils (owing to difficulties in maintaining the necessary slick thickness) or heavier oils (difficulties in ignition) (ARRT, 1999). A number of conditions are required for effective burning, with oil thickness and degree of emulsification among the most important. A minimum thickness of oil is required to light the slick, with the efficiency of a burn increasing with slick thickness and the size of the oil pool. Increased water content through emulsification greatly increases the difficulty and time required for ignition. Weathering has considerably less effect on ignition times (ARRT, 1999).

Owing to incomplete combustion, in situ burning produces a number of by-products. These include airborne components, as burning results in a large plume of smoke containing carbon dioxide and particulate matter, together with small amounts of carbon monoxide, nitrogen oxides, and polycyclic aromatic hydrocarbons. In addition, although a large proportion of the oil is burned, a residue of unburned oil will remain that will need to be cleaned up by other means. A solid combustion residue is also formed, with a composition similar to that of the original oil but depleted in volatile hydrocarbons with low boiling points; it is important that this residue is collected promptly to prevent it from sinking to the bottom and affecting the benthos.

Human health issues associated with this method mainly relate to the inhalation of the fine particulate matter (both elemental carbon and unburned oil particulates) that is a major constituent of the smoke produced. Inhalation of the smoke can be very dangerous because the particulate matter is easily retained in the lungs and can contain high concentrations of bioavailable contaminants (e.g., polycyclic aromatic hydrocarbons, sulfurous compounds, dioxins, furans, and metals) (see Chapter 5). This is a particular problem for the personnel applying in situ burning, but nearby communities may also be affected if downwind of the burning. Further studies are required to provide more data based on test burns of various types of oil.

In addition, both the ignition and burn phases of large amounts of oil on the water surface pose unique safety concerns for response personnel. Appropriate safety distances must be kept at all times during ignition and great care must be taken to control the fire and to prevent the ignition of secondary fires. In situ burning in broken ice is not easily extinguished once started. Personnel and equipment involved in the process must be protected at all times. As in situ burning at sea will involve several vessels working closely together, possibly at night or in poor visibility, vessel safety must be a priority requiring a great amount of practice, competence, and coordination.

Few studies have been conducted on the potential ecological impacts of in situ burning. The high temperatures at the interface between the oil and water could adversely affect organisms near this area. The surface microlayer is an important ecological niche that serves as a habitat for many sensitive life stages of marine organisms, including egg and larval stages of fish and crustaceans and reproductive stages of other animals and plants. There may also be questions in relation to the ecotoxicological properties of the by-products and burn residues, although these would need to be seen in relation to those of an uncontained oil spill.

In situ burning has the potential for removing large quantities of oil from the surface of the water with a relatively small investment of equipment and manpower, and may be particularly useful in remote areas. If properly planned and implemented, it may prevent or significantly reduce the extent of shoreline impacts, including exposure of sensitive birds and mammals and the oiling of beaches. However, in situ burning generates large quantities of black smoke that may adversely affect human and other exposed populations downwind. Burn residues may sink and expose benthic populations and it is not known whether these residues would have long-term effects on exposed populations of marine organisms.

As an example of the use of this method in the Arctic, in Alaska the use of in situ burning is regulated under provisions of the National Contingency Plan and State of Alaska law and its application must be authorized according to a specified procedure established under guidelines (ARRT, 1999). Burning may be used as a response method in both the coastal and inland zones of Alaska.

Penetrating Radar (GPR) and ethane gas sensors, with both requiring further development (SINTEF, 2006); recent studies using GPR to detect oil under ice resulted in up to 80% of the oil outlined (Bradford, 2007). Improved modeling is helping to understand GPR response to conditions that may increase the accuracy of this method, such as ice and oil thicknesses, ice salinity, and temperature. Remote sensing using Nuclear Magnetic Resonance is also showing potential as a means of detecting oil under ice (Nedwed, 2007).

Use of multi-sensor systems in aerial remote sensing combined with satellite data for maritime surveillance has shown promise for the detection and delimitation of surface spills on ice (Baschek, 2007). Integrated Satellite Tracking of Pollution (ISTOP) using SAR satellite imagery coupled with aerial surveillance as an aid in marine oil spill detection and response has been successful in detecting and responding to marine spills in Arctic Canada (Weir, 2007).

An airborne laser fluorosensor system has been identified as a promising technology for detecting and possibly quantifying oil on the surface of solid ice and snow or on the surface of brash and slush in pack ice (SINTEF 2006). This system has the advantage that it operates independently of light conditions.

Modeling tools also need to be developed for ice-infested waters for use in risk assessment and oil spill response analyses. Advances in the modeling of oil-ice interactions are also extremely important.

Although there are oil spill contingency plans and guidelines for some Arctic areas, there is great potential to improve these by providing response options and more dedicated analyses for different types of ice regime (based on ice cover, ice thickness, and ice type or category).

It is crucial for oil spill personnel to become familiar with conditions in the Arctic and to undertake training exercises and to test the various types of response equipment. Regular field exercises should be performed, with careful regard to health and safety considerations in Arctic waters.

2.8.7. Assessment of oil spill preparedness and response in the Arctic

With the current and increasing levels of oil exploration and exploitation in the Arctic, together with the increase in the transport of oil and oil products particularly via tankers in Arctic waters, there is a clear and growing need for rapid and effective oil spill response systems. Each country in the Arctic has developed requirements and regulations for the prevention of, preparedness for, and response to oil pollution incidents both on land and particularly at sea. Some of these systems, such as those in Iceland and Norway, appear to be able to provide an effective response in relation to the current limitations of technology under Arctic conditions, and this is probably also the case for the United States. However, for vast offshore and coastal areas of Arctic Canada and Arctic Russia, there may be a need to transport equipment and personnel over long distances to respond to an oil spill from a tanker or other vessel and possibly also for major incidents at oil-producing installations.

The first line of action must always be prevention. To minimize the risk of oil spill incidents at oil facilities, current regulations should be reviewed to ensure that there are appropriately stringent standards for equipment design and construction, corrosion control, leak detection, and other technical issues. Equipment used in the Arctic should meet the highest engineering and environmental standards. The schedules for inspections, maintenance, and repair of equipment and pipelines should be reviewed to ensure that they provide adequate possibilities for detecting incipient corrosion or other potential failure. Outdated or worn equipment should be replaced with new equipment; where needed, better designs or more modern materials should be used. Furthermore, it is vital that personnel at oil facilities are fully and appropriately trained both in the use and handling of the equipment and in procedures for emergency response in relation to the various types of accident that could occur. Health and safety issues should have high priority, including a focus on avoiding fatigue in personnel as fatigue can be an important factor in accidents.

In terms of preparedness, the development of contingency plans for oil spill response and periodic updates of these plans are very important. Equally important are the full training of responders, both in desk-top exercises and under actual conditions in the Arctic, and the maintenance of a supply of suitable combating equipment in well-placed depots. However, most oil combating equipment currently stored in Arctic depots is not adequate for use in typical Arctic conditions of low temperatures and icy waters. It is vital that appropriate equipment be developed for oil combating in Arctic waters. Vessels or aircraft for the rapid transport of such equipment from the depots to the site of the oil spill are also needed. From the information supplied for this section, it appears that there may be a need for the placement of additional response equipment depots in Arctic areas, especially on the Arctic coasts of Canada and Russia, to provide better readiness in the event of oil spills, particularly from vessel traffic, in Arctic waters. It is also vital to have networks in place so that additional assistance in terms of equipment and/or response personnel can be obtained quickly in cases when they are needed.

To provide a satisfactory response to oil pollution incidents in the Arctic, it is necessary to develop equipment and techniques for oil spill detection and combating that are adapted to the low temperatures, poor light conditions, and severe weather conditions of the Arctic. This will require investment in programs of research, development, and testing under Arctic conditions, such as the SINTEF Joint Industry Program (SINTEF, 2006).

Nonetheless, new research on techniques of remote response to spills including the use of chemical dispersants and surfactants to facilitate in-situ burning for spills in dynamic ice has shown good results (Nedwed, 2007). Dispersants are able to work when enough mixing energy is applied, for example, as aided by ice breaker prop-wash. In-situ burning is effective when the ice cover is sufficient and this may be extended to lower concentrations of ice if surfactants are applied.

2.9. Monitoring and research

2.9.1. Purposes of monitoring

Within the context of assessing and regulating the environmental and human health and welfare impacts of anthropogenic activities, monitoring can be defined as the repeated measurement of an activity or of a contaminant or of its effects, whether direct or indirect, in the environment. Generally, three categories of environmental monitoring are recognized: monitoring status and trends, monitoring for compliance purposes, and monitoring for research purposes.

Monitoring must have clearly defined objectives. A monitoring program should contain a clear statement of its objectives and be designed with methodology to ensure the fulfillment of these objectives together with methods to assure quality control for all aspects of the monitoring process. The results of monitoring should be reviewed at regular intervals in relation to the objectives. This review may indicate a need to amend the monitoring scheme. Key components of an environmental monitoring and assessment program are outlined in Box 2.22.

In relation to oil and gas activities, monitoring status and trends includes (a) the initial pre-operational baseline studies of environmental conditions, as well as social (including cultural) and economic conditions, in the geographical area that may be influenced by proposed oil and/or gas exploration and development activities, and (b) regular, repeat measurements or observations of the trends in these conditions over the course of the petroleum activities, including decommissioning and reclamation.

Box 2.22. Key components of an environmental monitoring and assessment program

An effective environmental monitoring program should preferably include the following components (U.S. EPA, 2003): a monitoring program strategy, monitoring objectives, monitoring design, core and supplemental environmental quality indicators, quality assurance, data management, data analysis and assessment, reporting and program evaluation.

- A monitoring program strategy is a long-term implementation plan that serves all of the relevant environmental quality management needs in relation to a specific medium or purpose, such as water quality. The strategy should be comprehensive in scope and identify the technical issues and resource needs central to the implementation of the program. The manager of the monitoring program should collaborate with other environmental managers and interested parties to maximize the use of relevant data from other programs.
- Monitoring objectives should be identified to enable the design of a program that is efficient and effective in generating data that serve the decision needs of management. The monitoring program should be able to determine the current quality status of the environmental medium under investigation, to assess the extent to which this quality status is changing over time (when possible, also using models or other tools), to determine problem areas requiring restoration or areas requiring protection, and to determine the success of management measures.
- There should be a clear approach and rationale for the selection of a monitoring design and sampling sites that best serve the objectives of the monitoring program. The monitoring design should be developed with the aid of statistical methods to identify a sampling protocol that will provide an appropriate level of statistical power and to enable scientifically and statistically valid results. The design should also provide for a cost-effective program to address the monitoring objectives. The levels of precision and confidence should be appropriate to the monitoring objectives and to the types of data collected. The monitoring design should also incorporate appropriate methods to control decision errors.
- Owing to the limited resources available for most monitoring programs, a tiered approach to monitoring can be used that includes a core set of baseline indicators for use on a broad basis, with the use of supplemental indicators in special situations or areas.
- Quality Management Plans and Quality Assurance Plans should be developed, maintained, and peer-reviewed to ensure the scientific validity of monitoring and laboratory activities. A Quality Management Plan addresses the overall planning and implementation of quality assurance activities, while a Quality Assurance Plan documents the specific quality assurance and quality control activities. These plans should reflect the level of data quality that is appropriate for the specific uses of the data in relation to the types of decisions that will need to be made.
- An appropriate and accessible electronic data system is required to handle the monitoring data, and timely data entry. The use of GIS (Geographic Information System) tools is also recommended.
- A methodology is required for the assessment of environmental quality based on the analysis of various types of data (chemical, physical, biological) from the monitoring program and other sources. This methodology should describe how relevant data will be compiled and analyzed to serve as a basis for decision-making. The methodology should also contain procedures for evaluating the quality of data with regard to analytical precision and representativeness and provide appropriate data reduction procedures such as statistical analyses to aid in preparing an assessment.
- A procedure for the production of timely and complete reports on the results of monitoring and assessment is necessary.
- Periodic reviews of all aspects of the monitoring program should be conducted to determine the effectiveness of the program in serving the needs of the decision-makers in relation to the quality of the environmental medium under consideration.

Depending on the country, this monitoring is usually conducted by government agencies or their contractors, although in some countries industry may be required to conduct some or much of this work.

In most countries with offshore oil and gas activities, baseline investigations are carried out before development starts. These studies are designed to map the distribution of seabed, water column and sea surface resources, and representative samples are analyzed for all parameters used in the later compliance monitoring. The station net should be designed to exclude areas that have been affected by previous activities, such as exploration drilling. Sampling stations to be used in compliance monitoring are chosen from among the stations investigated during the baseline study.

Monitoring for compliance purposes includes monitoring in relation to the various project-specific lease stipulations and other requirements, local and national discharge and emission standards, health and safety regulations, oil spill emergency response requirements, and any other requirements specified for the activity by government authorities. Most of the monitoring is conducted by the operator of the petroleum facility or their contractors, with the results reported to the appropriate local and national regulatory agencies for review.

The general scheme for monitoring in relation to offshore oil and gas activities given in Table 2.80 applies to the monitoring associated with each installation; monitoring should be coordinated among the installations in a field and, more broadly, on a regional level.

Monitoring for research purposes in an oil and gas activity context could cover such issues as obtaining better knowledge of the chronic effects of oil contamination on specific types of biota, accumulating more and better data on currents and sediment transport in areas of the Arctic with offshore installations, or observing the impact of petroleum-related activities on the behavior and migration of particular types of biota such as caribou or birds. This type of monitoring is usually conducted by universities, with funding often provided by government agencies, as

Table 2.80. Examples of generalized monitoring plans for offshore activities (adapted from PAME, 2002).

Investigation	Environmental compartment / activity or facility	Frequency	Parameters to be included
Phase: Planning for development			
Baseline study	Seabed, water column, shoreline, etc.	Once, before activities are started	Inventory of biota/ ecosystems; levels of all relevant contaminants; identification of particularly sensitive resources
Phase: Development			
Trend monitoring[a]	Seabed	Every year and as frequently as necessary, depending on the type of activity	Contaminants[b], biota[c]
	Other	Every year and as frequently as necessary, depending on the type of activity	Physical disturbance[d]
Compliance monitoring[e]	Construction of roads, facilities, platforms; traffic; drilling		Waste discharges: According to permit or standards
			Air emissions: According to permit or standards
			Worker health and safety: According to standards
Phase: Production			
Trend monitoring[a]	Seabed	Every year first three years, thereafter every three years	Contaminants[b], biota[c]
	Water column	Every three years and/or periodically, as necessary	Relevant contaminants in environment and biota[c], effects on biota[f]
	Seashore and other as relevant	As relevant	As relevant
Compliance monitoring[e]	Platforms, associated facilities		Waste discharges, production water: According to permit or standards
			Air emissions: According to permit or standards
			Worker health and safety: According to standards
Phase: Decommissioning			
Trend monitoring[a]	Seabed and water column, as relevant	During operations and once at reclamation phase	Levels of contaminants and effects on biota, as relevant
Compliance monitoring[e]			

[a]Terminology varies among countries. Trend monitoring covers such terms as 'status monitoring', 'condition monitoring', or 'regional impact monitoring' conducted over a period of time; [b]see Table 2.81; [c]see Table 2.82; [d]includes seismic (impact on marine mammals), noise and other disturbance (impact on marine mammals, birds), turbidity (impact on benthos); [e]compliance monitoring also covers 'field-specific monitoring'; [f]see Box 2.25 OSPAR biological effects monitoring in relation to offshore oil and gas installations.

well as by non-governmental organizations. Industry may also conduct research monitoring, for example, in relation to the stability of artificial islands or structural materials to currents, ice movements, and other forces. In Norway, research for monitoring purposes is a requirement from the authorities, for example, concerning the development and testing of new methods for monitoring biological effects in the water column. The research is funded by the operator and carried out by relevant research institutions and contractors.

Guidelines with respect to monitoring offshore oil and gas activities in the Arctic have been developed under the Arctic Council (Box 2.23). The OSPAR Commission has also adopted guidelines for monitoring the environmental impact of offshore oil and gas installations (OSPAR, 2004), which are applicable to installations in the Northeast Atlantic and the Arctic waters north thereof (Box 2.24).

Box 2.23. Purpose and targets of monitoring oil and gas activities in the Arctic

According to the Arctic Council's Arctic Offshore Oil and Gas Guidelines (PAME, 2002), monitoring is an analytical tool used to assist in conserving and protecting ecological and socio-economic resources and human health. The purpose of monitoring with respect to petroleum activities is as follows:

- to ensure that regulatory and licensing requirements are satisfied;
- to establish a basis for identifying environmental responses and trends;
- to assess whether the observed environmental impacts are in line with the forecasted and accepted environmental impacts identified in the EIA or license;
- to detect the first signs of environmental changes, contamination or pollution;
- to help assess whether the operator is meeting the goals of its environmental management plan;
- to facilitate early detection of possible unforeseen effects; and
- to aid future decisions about where, when, how and whether oil and gas activities should be allowed to occur.

Examples of targets for priority monitoring during all phases of oil and gas activities to assess and minimize or mitigate adverse effects include:

- environmental accounting of emissions to air, discharges to land, water and the seafloor, and emissions of noise;
- physical disturbance to the seafloor, pelagic biota, ice-edge communities, and the seashore, and effects on species populations, distribution, and migration routes;
- levels of contaminants in bottom sediments and the water column;
- levels of contaminants and effects in living marine resources, seabirds and other wildlife, with particular attention given to vulnerable life stages and areas of critical habitat;
- effects of petroleum activities on local human populations, subsistence access and harvest, workers safety, and other human activities; and
- environmental effects on the integrity of the infrastructure.

Box 2.24. OSPAR guidelines for monitoring the environmental impact of offshore oil and gas activities

The aim of the OSPAR Guidelines for Monitoring the Environmental Impact of Offshore Oil and Gas Activities (OSPAR, 2004) is to harmonize the monitoring of environmental impacts of discharges from offshore installations, and to harmonize reporting and assessment of the data. The main purposes are:

- to provide the necessary information for assessing the effectiveness of reduction measures;
- to establish the spatial distribution and extent (with respect to a reference) of substances released from installations;
- to establish the spatial distribution and extent of biological effects;
- to establish temporal trends in order to estimate the magnitude of changes over time;
- to identify unforeseen impacts and new areas of concern;
- to create the background to develop prediction of expected effects and the verification thereof (hindcasting).

In general, impact concerns should be addressed during all phases of petroleum activities and might cover aspects such as:

- spatial and temporal changes in seabed contamination and biological community structure;
- effects on pelagic organisms and water column systems;
- contamination mediated through the food chain; and
- effects on specific natural resources.

The focus of the OSPAR guidelines is on monitoring spatial and temporal changes in seabed contamination and benthic animal community structure (see Table 2.81) and on impacts on pelagic organisms and water column systems (see Box 2.25), with further developments foreseen regarding pelagic impacts as new biological effects techniques are developed.

2.9.2. Monitoring status and trends

Monitoring should measure the physical, chemical, biological, and socio-economic conditions that may be impacted by the activities being conducted. For offshore developments, however, while socio-economic aspects are often addressed in the environmental impact assessment (EIA), they are usually not part of the regular monitoring. Before petroleum activities commence, monitoring should begin with a comprehensive baseline investigation (in some cases, in association with an EIA (see Chapter 6)), which should incorporate existing information, and comprise as a minimum all monitoring sites and variables planned to be used in the long-term monitoring program. A baseline investigation will often, however, also cover

Box 2.25. OSPAR biological effects monitoring in relation to offshore oil and gas installations

The OSPAR guidelines for monitoring the environmental impact of offshore oil and gas activities (OSPAR, 2004) provide recommended procedures for point sampling monitoring of offshore discharges and impacts on pelagic organisms and water column systems, acknowledging that there is still limited knowledge of appropriate methods for water column monitoring. This monitoring is conducted according to two main strategies: biological and chemical analyses of near-zone collected and caged fish; and biological and chemical analyses of caged mussels.

For monitoring using caged fish, 50 individuals from one population of a selected fish species should be deployed at each location. The table lists the minimum range of analyses (core methods) for caged fish. Analyses of each determinand are to be performed on 25 of these individuals at the time of deployment (time-zero conditions), while analyses on the remaining 25 individuals should be conducted after cage deployment in the near-zone area for at least five to six weeks. Wider area monitoring may also be conducted, by which 25 individuals of the selected species should be collected by trawling in the region to be surveyed. In addition to contaminant-specific methods, the general health of the fish should be assessed (e.g. condition, liver somatic index) and gonad weight should always be determined. Markers of PAH exposure (bile metabolites) and early effects, i.e. EROD and GST, should be determined alongside markers of damage (DNA adducts) and tissue change (histopathology). These methods have been recommended to enable an assessment of the severity of effects as well as to increase the ability to separate PAH-related effects from those caused by other factors. The methods should not be used in isolation.

For monitoring using caged mussels, 120 blue mussels (*Mytilus edulis*) should be deployed at each location, with cages or nets designed to ensure that the deployment provides equal exposure of all individual mussels to the surrounding water. Twenty individual mussels at each location should be analyzed for each biological effects method. For PAH and metal analyses, three pools of 20 mussels each should be sampled. Samples should be taken from blue mussels from the same batch at the time of deployment for zero-time analysis. In addition to contaminant-specific methods (see the table for analyses required), the general health of the mussels should be assessed (condition).

Core methods for caged fish.

Method	Tissue/matrix
EROD induction	Liver
GST expression	Liver
DNA damage	Liver
Vitellogenin	Blood plasma[a]
Histopathology	Liver
ALA-D inhibition	Red blood cells[b]
AChE inhibition	Muscle
PAH-metabolites	Bile
Metals (Cd, Hg, Pb)	Liver

EROD: ethoxyresorufin-*O*-deethylase; GST: glutathione-*S*-transferase; ALA-D: ẟ-aminolevulinic acid dehydratase; AChE: acetylcholinesterase. [a] blood sampled prior to and after deployment; [b] if Pb exposure is expected.

Core methods for caged blue mussels.

Method	Tissue/matrix
BaPH	Hepatopancreas
AChE	Hepatopancreas
Lysosomal stability	Hematocytes
Histopathology	Hepatopancreas
PAH concentration[a]	Whole mussel
Lipid content	Whole mussel
Metals (Cd, Hg, Pb)	Whole mussel

BaPH: benzo[a]pyrene hydroxylase; AChE: acetylcholinesterase; [a] the PAH-compounds to be analysed should be those on the U.S. EPA 'list of 16 compounds'. PAHs should be quantified by GC/MS according to OSPAR (1993). In some instances, total 2-6-ring parent and branched PAH analysis might be desirable.

additional monitoring sites and a broader geographical area, as well as a larger number of parameters, to provide a more detailed overview of the environmental status of the region of potential impact prior to the start of petroleum activities.

An important emphasis of the baseline survey (and EIA) is the preparation of an inventory of environmental resources that may be affected by the planned petroleum activity and the identification of resources, areas or uses that may be particularly sensitive to the various phases of the petroleum activities. Some resources may be more sensitive to acute disturbances, discharges, or emissions, while others may be more sensitive to chronic disturbances, discharges, or emissions even at sub-lethal concentrations. Programs for the identification of biota that may be particularly sensitive to pollution from petroleum activities usually not only include adult stages and established communities, but also early stages in the life cycle of plants and animals including larval stages, which are more vulnerable to oil and chemicals than adult stages. Thus, not only should vulnerable species be identified prior to setting up a monitoring program, but also particularly sensitive life stages.

A baseline survey serves as the basis for further monitoring by establishing the pre-activity population structure, size, and distribution of the key groups of biota; habitat status; and existing levels of contaminants in the environment and biota. This information is essential if previous introductions of the contaminants in question have already taken place either naturally or from other human activities. Baseline monitoring usually involves chemical measurement of the levels of the contaminants in air, soil, water, ice/snow, sediments, or biological tissue. The concentrations are then compared to criteria such as background data or appropriate standards.

Once petroleum activities have begun, periodic monitoring must start in order to determine potential trends in environmental conditions and potential effects on biota. Monitoring should be conducted so as to distinguish impacts due to the relevant activities and impacts from other sources, also taking into account natural variability. More focus has been directed recently at monitoring the combined environmental impact of all types of pollutants and other influences on the affected area, i.e., taking an ecosystem approach. The monitoring conducted depends on the type of activity anticipated and the nature of the environment that could be affected. The main emphasis of the monitoring will vary depending on the phase of the petroleum activity. Exploratory drilling and production activities will each require a different monitoring emphasis. Similarly, monitoring will have a different emphasis in the early rather than latter stages of the life of a field/facility (PAME, 2002).

Monitoring of trends in levels of contaminants in air, soil, sediment, water, ice/snow, and biota has been the traditional means of monitoring impacts of pollutants on the environment. This approach still forms the backbone of most monitoring programs, as reliable trend data are needed both to document changes in the environment resulting from the activities and as a basis for the prediction of future changes (PAME, 2002). The OSPAR recommendations for analyses of sediment samples near offshore oil and gas installations, as well as in reference areas, are an example of such a program (Table 2.81).

In addition to measuring the concentrations of contaminants in the environment or biota, monitoring programs should also address the effects that these contaminants on species, ecosystems, and human health. Effects may be monitored by recording changes in biodiversity over time, including changes in the population or reproductive capacity of individual species or by measuring effects on single specimens. Such methods, which include the use of biological indicators, could give early warning of negative changes in the environment. Effects monitoring is often an integral part of monitoring programs. For example, the OSPAR monitoring program on environmental impacts of offshore oil and gas activities includes biological effects measurements in the water column based on caged fish and mussels ( ).

Monitoring of contamination related to petroleum activities should take into account sources of contaminants, potential transport routes (e.g., aqueous, particulate, or airborne), and potential pathways for bioaccumulation. Other considerations may include wind strength and gustiness; terrain, vegetation, ocean currents; relevant river flow; precipitation; air temperature; ocean temperature; sea ice conditions and movement; water depth; sea surface state; subsurface geology; and other resources affected (PAME, 2002).

Monitoring surveys are usually more frequent during the first years of investigation until the main impacts and trends have been determined and are then undertaken as frequently as required. Environmental accounting and budgeting usually form part of the monitoring process, showing the types and quantities of substances being used and discharged, environmental impacts that have been observed, and what might be expected to occur in the future.

The best results will be obtained if monitoring programs are coordinated regionally so that interactions between multiple activities are more easily detected.

Monitoring programs are generally reviewed on a regular basis to determine whether the results they are yielding indicate a need for changes in operational practices (for example, as a result of failing to achieve the initial hypotheses set out in the EIA or because of unforeseen impacts). Programs should be reviewed to determine whether they should continue, be modified or be terminated. Ultimately, the length and extent of a monitoring program is determined by the scale and duration of offshore oil and gas activities and the immediate or longer-term impacts.

Table 2.81. OSPAR recommendations for sediment monitoring in the vicinity of offshore oil and gas installations (OSPAR, 2004).

	Baseline survey		Monitoring survey		
Analytical parameter	Field station	Reference station	Field station	Reference station	Preservation / sample quantity
Total organic carbon[a]	3 samples 0–1 cm	3 samples 0–1 cm	3 samples 0–1 cm	3 samples 0–1 cm	-20 °C
Grain size[b]	1 sample 0–5 cm	1 sample 0–5 cm	1 sample 0–5 cm	1 sample 0–5 cm	-20 °C, 100 g
Total hydrocarbon content, PAHs, NPDs, decalines[c]	3 samples 0–1 cm 1 sample[d] 1–3 cm 1 sample[d] 3–6 cm	5 samples 0–1 cm 1 sample 1–3 cm 1 sample 3–6 cm	3 samples 0–1 cm 1 sample[d] 1–3 cm 1 sample[d] 3–6 cm	5 samples 0–1 cm 1 sample 1–3 cm 1 sample 3–6 cm	-20 °C, 300 g
Synthetic drilling fluids	3 samples 0–1 cm	5 samples 0–1 cm	3 samples 0–1 cm	5 samples 0–1 cm	-20 °C, 300 g
Metals: Ba, Cd, Cr, Cu, Pb, Zn, Al[e], Li[e]; Hg[c]	3 samples 0–1 cm	5 samples 0–1 cm	3 samples 0–1 cm	5 samples 0–1 cm	-20 °C, 50 g
Benthic fauna	5 samples	10 samples	5 samples	10 samples	10% formalin, Rose Bengal / Eosin

PAHs: polycyclic aromatic hydrocarbons; NPDs: sum of naphthalene, phenanthrene/anthracene, dibenzothiophene and their C_1-C_3 alkyl-homologues; decalines: C_5–C_8 alkyl decalines, which should be analysed if low-aromatic drilling fluids have been used in a field; Ba: barium, Cd: cadmium; Cr: chromium, Cu: copper; Pb: lead; Zn: zinc, Al: aluminum; Lithium; Hg: mercury.

[a] material is to be taken from samples collected for hydrocarbon or metal analysis (i.e., separate samples are not taken); [b] mixed sample from three grab samples collected at each station; [c] conducted at reference stations and two other stations, 250 m and 2000 m downstream of the installation; [d] conducted at two stations, 250 m and 2000 m downstream of the installation; [e] Al or Li for normalization purposes (selection depending on mineral composition of the sediments monitored).

2.9.3. Monitoring for compliance purposes

Monitoring standards and practices are generally established for all phases of petroleum activities, including seismic operations and marine transportation. Compliance monitoring is a process of oversight designed to determine conformity with environmental legal mandates, regulations, lease stipulations, and conditions of approval. Principal monitoring activities occur during drilling, development, production, decommissioning, and reclamation, as well as during transportation of oil, gas, supplies, and personnel. Compliance monitoring covers both monitoring in relation to requirements regarding the external environment as well as for health, safety, and environment (HSE) standards for workers; the latter usually undertaken by industry and with the requirement to maintain appropriate records and often to report the outcome to the appropriate government agency (see Table 2.80 for examples of compliance monitoring in relation to offshore installations).

Monitoring results are also utilized by regulators in compliance audits and on-site regulatory supervision as the basis for requiring modification, postponement, or shut-down of operations or specific components of an operation and to change laws. Monitoring activities can be conducted in conjunction with environmental audits to assure the operator that equipment and procedures are functioning within design parameters and will not lead to significant impact on the environment. Authorities use environmental audits to verify that monitoring results are used by the petroleum companies and reflected in their environmental strategy.

2.9.4. Monitoring for research purposes

As well as field monitoring, monitoring programs also include laboratory experiments and combinations of laboratory experiments and field studies. Monitoring for research purposes often seeks to determine the underlying causes of conditions or events observed in environmental monitoring, and so is very close to ordinary research (see section 2.9.2). Monitoring may also form part of research projects to develop and test new monitoring methods.

2.9.5. Examples of monitoring in Arctic countries

2.9.5.1. Alaska, United States

A number of agencies and organizations are responsible for monitoring in relation to oil and gas activities in the U.S. Arctic: Federal, State of Alaska and regional agencies, as well as academic institutes, industry and non-governmental organizations.

2.9.5.1.1. Compliance monitoring

Several agencies require monitoring as part of the process of obtaining a lease or permit for particular activities. Agencies that require monitoring include: the U.S. Environmental Protection Agency (EPA) for water and air discharges and emissions, the National Marine Fisheries Service (NMFS) for harassment and impact on marine mammals, the U.S. Fish and Wildlife Service for endangered or threatened species, the U.S. Bureau of Land Management (BLM) for onshore oil and gas activities, the U.S. Minerals Management Service (MMS) for offshore oil and gas activities, the State of Alaska Department of Natural Resources for essential and critical habitats, the Alaska Oil and Gas Conservation Commission for drilling wells, and The Joint Pipeline Office for pipeline integrity and flow, as well as others.

The U.S. EPA has monitoring requirements in its National Pollutant Discharge Elimination System (NPDES) permits for the discharge of waste into the marine environment in order to determine compliance with effluent limits. NPDES permits require monitoring of discharges, collecting and analyzing of samples, record-keeping and reporting to the EPA. Flow monitoring, the location, frequency, and type of sampling, and the requirement for reporting are mandated by law and specified in the Permit as an annual submission of a Discharge Monitoring Report. The permits also cover effluent limits for the control of pollutants in dewatering of gravel pits used as sources of gravel for oil and gas operations. To ensure that the standards are met, the government requires the monitoring of settleable solids, pH and oil sheen. Storm Water Pollution Prevention Plans also contain monitoring requirements, mainly in relation to inspections of facilities at specific times of the year.

For activities on Federal lands in the National Petroleum Reserve–Alaska (NPRA), as many as 79 stipulations and many required operating procedures (ROPs) are attached to a permit or lease in the northeast part, with similar requirements in the rest of the area. Most of the stipulations and ROPs contain requirements for environmental research and monitoring, some starting as early as three years before the permitted activity and most lasting through the life of the project. Monitoring of natural and cultural resources is required. Monitoring activities include:

- monitoring the movements, distribution, and range use of caribou (*Rangifer tarandus*) in areas proposed for development;
- monitoring caribou movements in areas with permanent roads;
- monitoring fish-bearing waters when projects affect fish-bearing and non fish-bearing water bodies to ensure free passage of fish and water quality;
- monitoring oil and gas exploration, development, and production effects on subsistence activities;
- conducting cultural and paleontological surveys in areas where ground-disturbing activities will take place; and
- monitoring bear activity near development and production sites; and conducting aerial surveys of Steller's (*Polysticta stelleri*) and spectacled eiders (*Somateria fisheri*), and yellow-billed loons (*Gavia adamsii*) in areas of facility construction before construction begins.

In addition, funding has been provided by the State of Alaska to fund the NPRA Impact Mitigation Program. During fiscal years 2000 through 2004, USD 56.3 million was awarded to North Slope communities under the program. These funds have been used, among others, to upgrade equipment; conduct fish, waterfowl, gull, fox, and caribou surveys; monitor subsistence harvest; assess the impacts on fish from hydrocarbons; and to provide health care training and education. Ongoing and proposed monitoring activities under State of Alaska funding include:

- an inventory of fish resources in the lakes and streams of the eastern NPRA;
- monitoring subsistence harvests;
- surveying waterfowl use on the North Slope;
- tracking of Teshekpuk Lake Herd caribou and determining their habitat use;
- monitoring habitat use and movements of Arctic fox (*Alopex lagopus*);
- determining caribou movements and distribution;
- monitoring effects of hydrocarbons on fish; and
- monitoring movements, behavior and distribution of glaucous gulls (*Larus hyperboreus*) by satellite telemetry.

The MMS offshore Environmental Compliance Monitoring is a process of oversight designed to determine conformity with environmental legal mandates, regulations, lease stipulations, and conditions of approval. Conditions of approval include mitigation measures and other requirements imposed on applicants. This process addresses the Federal Government's commitment to assuring environmentally sound operations through improving the effectiveness of mitigation and establishing a link between pre- and post-lease analyses and project effects. The Alaska Outer Continental Shelf Region Oil and Gas Compliance Monitoring program for oversight and adaptive management also involves an ongoing assessment of new and updated environmental information from government-sponsored studies and integration of this assessment with ongoing activities. This combination of management review of active oil and gas projects, updated environmental studies, and site-specific monitoring are part of the approach to adaptive management, which provides credible information for the modification of activities based on experience and new information.

The Federal Government conducts on-site inspections for compliance with various environmental protection measures, including lease sale terms (stipulations and Information to Lessees), project mitigation adopted by the operator and described in an Outer Continental Shelf (OCS) plan, conditions of approval of an OCS plan adopted by the MMS following reviews and consultations, and permits issued by other regulatory authorities such as the EPA. In addition to a national standards compliance checklist, the government develops a project-specific compliance checklist that highlights the unique environmental protection measures required for that project. The checklist is developed based on mitigation adopted by the operator as described in their plan and the conditions of approval imposed by the government.

With regard to the Marine Mammal Protection Act, the National Marine Fisheries Service has established a mechanism to review monitoring and mitigation plans, as well as results from monitoring efforts, to evaluate the impact of activities on the availability of marine mammals for take by Alaska Native subsistence uses.

Air emissions from OCS sources in the Alaska Region are regulated by EPA Region 10. The EPA's air permits require monitoring, record-keeping, and reporting to the EPA. The EPA includes provisions in its permits for OCS facilities that require records and logs to be maintained on-site and made available to MMS inspectors. In the Alaska Region, an inspector reviews the records for compliance with permit terms and may conduct additional inspections for compliance. If a potential non-compliance issue is identified, the Alaska Region will notify the EPA.

The Alaska Department of Environmental Conservation, Division of Water has developed a long-term Water Quality Monitoring and Assessment Strategy to guide its stewardship of Alaska's marine and freshwater resources. The strategy is intended to meet Federal expectations for State water quality stewardship activities enumerated in the Clean Water Act in a manner influenced by Alaska's unique needs and challenges.

2.9.5.1.2. Research monitoring

The Environmental Assessment Program (EAP) is an integral part of the MMS Offshore Research Monitoring. The MMS has an extensive Environmental Studies Program that supplies scientific and technical information needed to manage OCS activities. To date, the Environmental Studies Program has funded studies on topics including physical, chemical, biological oceanography, atmospheric studies, whales and other marine mammals, seabirds, and sociological and economic factors.

The U.S. MMS operates five meteorological stations along the Beaufort Sea coast of Alaska. Each station collects data on wind speed, wind direction, barometric pressure, relative humidity, solar radiation, and air temperature. Other MMS monitoring and studies in the Arctic include:

- demographics and behavior of polar bears (*Ursus maritimus*) feeding on bowhead whale (*Balaena mysticetus*) carcasses at Barter and Cross Islands, Alaska, 2002 – 2004;
- annual assessment of subsistence bowhead whaling near Cross Island, 2003;
- monitoring Beaufort Sea waterfowl and seabirds, 2003;
- bowhead whale feeding in the eastern Alaskan Beaufort Sea: update of scientific and traditional information, 2002;
- monitoring distribution and abundance of ringed seals (*Phoca hispida*) in northern Alaska, 2002;
- aerial surveys of endangered whales in the Beaufort Sea, autumn 2000, 2002; and
- the role of copepods in the distribution of hydrocarbons: An experimental approach.

As funded by the U.S. Geological Survey, researchers with the Alaska Science Center Biological Science Office are conducting a variety of projects to increase understanding of terrestrial ecosystems in Alaska. These typically address how vegetation is affected by factors such as climate change or disturbances and how changes in the vegetation affect wildlife populations. Specific projects with a terrestrial focus also include development of a long-term research program on wildlife and habitats of the coastal plain of the Arctic National Wildlife Refuge, as well as a project on plant ecology in relation to ecological restoration, wildlife habitat, and inventory.

Research monitoring under the North Slope Science Initiative includes environmental policy and planning studies to characterize the environmental, economic, and social implications of proposed policies and regulations applicable to energy systems and Federal facilities. Under the Site Environmental Restoration and Stewardship program, environmental evaluation and planning projects address soil, surface water, sediment, and groundwater contamination at Federal sites. Assessments are also conducted of approaches for long-term stewardship of remediated sites with residual contamination.

Under the State of Alaska, the North Slope Borough Department of Wildlife Management facilitates sustainable harvests and monitors populations of fish and wildlife species through research, leadership, and advocacy from local to international levels, concentrating on subsistence species of the greatest interest to North Slope residents.

2.9.5.2. Canada

The Federal Department of Fisheries and Oceans (DFO) is charged with the implementation of Canada's Oceans Act including the establishment and enforcement by regulation of Marine Environmental Quality (MEQ) guidelines, criteria, and standards designed to conserve and protect ecosystem health. In this context, ecosystem health includes both the environmental aspects of ecosystems (i.e., the biophysical aspects) as well as the social and economic aspects. To assess MEQ, ecological monitoring or marine science-based monitoring is required. Owing to the importance of the integrity and strength of cultural variables in northern regions, this must explicitly include culture under the social aspects of ecosystem health (DFO, 2000).

The inclusion of community-based and socio-economic programs is of two-fold importance to implementing MEQ and ecosystem health guidelines and objectives in the north. First, the principles of environmental quality and ecosystem health are intrinsically based on humans as a part of the environment. In addition, the quality of the marine environment is a significant determinant of the social and economic health of northern communities; as such, any program to establish and monitor ecosystem health must include assessment of socio-economic variables impacted by the quality of the marine environment. Second, setting environmental quality guidelines and objectives for northern marine environments and the ecosystems based thereon can best be accomplished through cooperative ventures with local residents. This is a factor of the new northern political environment and the intimate environmental knowledge possessed by local people; in addition, effective program delivery and enforcement requires acceptance and support by local populations (DFO, 2000).

Based on a summary of Canadian government-initiated scientific research and monitoring programs relevant to ecosystem health in the northern regions (DFO, 2000), it would be possible to compile a catalogue of indicators or other approaches used in monitoring ecosystem health. Such a list would include indicators of three types: those that are based on purely scientific observations and assessments of the biophysical environment; those that involve community participation and traditional environmental knowledge (TEK) in observing and assessing the biophysical environment; and those which assess and monitor socio-economic variables. Use to date of these three types of indicator is heavily skewed towards the former, with relatively few initiatives using community involvement, and very few socio-economic indices included whatsoever.

An example of a relevant monitoring program is the Beaufort Environmental Monitoring Program, which was established in 1983 to prepare for hydrocarbon developments in the Beaufort Sea. A key feature of this program was to determine research and monitoring needs by balancing the concerns of the people who live in that particular ecosystem with scientific criteria. Through a series of workshops, key resources or ecological parameters – Valued Ecosystem Components (VEC) – were identified. Research and monitoring were then established to answer questions about how the VECs could be affected by potential stresses from development (see Chapter 6).

2.9.5.3. Greenland

A number of monitoring studies have been conducted in connection with oil exploration activities in Greenland. Some are listed below and can be downloaded from the websites of the Bureau of Minerals and Petroleum (www.bmp.gl) or the National Environmental Research Institute (www.dmu.dk):

- Preliminary strategic environmental impact assessment of hydrocarbon activities in southeastern Baffin Bay west of Disko Island
- Ice studies of West Greenland 2006
- Weather, sea and ice conditions in eastern Baffin Bay, offshore northwest Greenland: A review
- Physical environment of eastern Davis Strait and northeastern Labrador Sea: An overview
- NERI report 132: Preliminary environmental impact assessment of regional offshore seismic surveys in Greenland
- Distribution and variability of icebergs in eastern Davis Strait 63° N to 68° N
- Environmental assessment of the four license areas of the West Greenland licensing round 2004
- Weather, sea and ice conditions offshore West Greenland – focusing on new license areas 2004
- Environmental oil spill sensitivity atlas of West Greenland

Additionally, the Department of Arctic Environment at the National Environmental Institute maintains a database on the breeding colonies of seabirds in Greenland, and the National Environmental Research Institute has surveyed molting sea ducks in West Greenland, in relation to the mapping of oil spill sensitive areas.

2.9.5.4. Faroe Islands

The regulatory requirements for environmental monitoring in the Faroe Islands derive from Section 23 of the 1998 Parliamentary Act on Hydrocarbon Activities. Based on this provision, the Faroese Earth and Energy Directorate, in preparation for opening up an area for possible hydrocarbon exploration activities, decides whether the planned exploration activities require that an EIA should be conducted in advance. Before taking this decision, the Faroese Earth and Energy Directorate may request advice from the Food, Veterinary and Environmental Agency and Fisheries Laboratory. The procedure thus far has been that seismic activities offshore require no EIA prior to the survey, but that during the surveys a whale sighting is done to avoid shooting when marine mammals are in the close vicinity of the vessel. However, if drilling is to take place, an EIA is required (see also Chapter 6). The EIA may require the acquisition of new data on the general environment where the drilling is to take place, i.e., a type of baseline survey. Required new data may include descriptions of abiotic parameters such as meteorology, ocean currents, bottom topography and sediment type, and biological and chemical information about populations of bottom dwellers, fish, seabirds and marine mammals and how and when they use the area, as well as information about commercial uses of the area, for example, fisheries and ship traffic.

The EIA prepared prior to drilling in License Round 1 (Alpha Environmental, 2001) assessed both the impact of the planned activity if conducted according to schedule without accident, as well as the impact of non-planned events, i.e., accidents that have an impact on the environment (rig workers' health is exempt from this assessment). Accidents were treated in the risk assessment part (see also Chapter 6) of the EIA, which also considered possible impacts of oil spills on both the in-situ biological life and commercial interests, as well as negative impacts in the far reaches of the area of influence with regard to ambient environmental health and commercial loss. In connection with the drilling licenses in License Round 1, the oil industry prepared a regional EIA, which included a regional environmental monitoring survey. License Round 2, which covered seismic licenses only, drew on the knowledge of the area that had been acquired in association with the EIA for License Round 1.

Environmental monitoring, in the sense of obtaining data on environmental pollutants in the general vicinity of drilling activities, is conducted offshore of the Faroe Islands in association with exploration drilling. The environmental monitoring is conducted at two levels: as a regional baseline study, where the status of environmental pollutants in the general area identified for exploration drilling is described, and as site-specific monitoring around the single drilling sites.

Regional environmental monitoring is conducted on the basis of the Hydrocarbon Act if the Faroese Earth and Energy Directorate considers this a necessary step in the EIA. It is assumed that environmental monitoring in a region will be regularly repeated if the area is used regularly for hydrocarbon exploration or possible production activities. Site-specific monitoring is conducted at the request of the Food, Veterinary and Environmental Agency to satisfy section 19 of the 2005 Parliamentary Act no. 59 on Environmental Protection of the Marine Environment. The site-specific surveys are carried out to ensure the likelihood that degradation of the environmental status by oil exploration activities is kept to a minimum. The regional environmental monitoring survey was conducted using the guidelines of the State Pollution Control Authority in Norway for environmental monitoring around offshore deep-water installations (Nilssen, 1999), and the site-specific monitoring generally considered the same parameters that had been analyzed in the regional survey. In contrast to the regional survey, the site-specific survey sampling sites were laid out in a cross around the drilling site, whereas the regional survey sampling was based on a grid. The site-specific survey monitoring was conducted both before and after the drilling operation, whereas the regional survey was conducted as a one-off event in order to establish a baseline of knowledge about the status and levels of environmental pollutants. The results of the regional environmental monitoring surveys as well as the other environmental data acquired in connection with the EIA are publicly available. On the other hand, the results of the site-specific surveys are presented to the Food, Veterinary and Environmental Agency; their availability to the public is at the discretion of the operator who commissioned the survey.

Among the environmental studies undertaken in order to gather the data necessary for an EIA, the studies that collected and reviewed data on the natural resources in the general area of the License Round 1 exploration drilling licenses included the following:

- Expert review of seabed fauna and chemistry (Bett et al., 2001)
- Marine benthic algae and invertebrate communities from the shallow waters of the Faroe Islands: A baseline study (Bruntse et al., 1999)
- Marine biological investigations and assemblages of benthic invertebrates from the Faroe Islands (Bruntse and Tendal, 2001)
- Macrozooplankton in the Faroe-Shetland Channel (Debes, 2003)
- Marine mammals in Faroese waters (Bloch et al., 2000)
- The distribution of seabirds and cetaceans around the Faroe Islands (Taylor and Reid, 2001)
- Dispersion and vulnerability of marine birds and cetaceans in Faroese waters (Skov et al., 2001)
- Populations of guillemots, razorbills, and puffins in Faroese waters as documented by ringed birds (Olsen et al., 2000)

A number of reports summarized the findings of projects involving analyses of ambient concentrations of chemical pollutants and biomarkers of pollutants both in the general area where the drilling licenses were granted, and in coastal areas of the Faroe Islands:

- Field report: Benthic baseline survey of the Faroes offshore license areas 001–004 April–June 2001 (Larsen, 2001)
- Environmental baseline survey of the Faroe offshore license areas 001–004 in the Faroe-Shetland Channel, 2001 (Mannvik et al., 2002)
- A baseline study of Greenland halibut off the Faroe Islands (Grøsvik et al., 2000)
- Background levels of oil-derived pollution in fish and invertebrates from the coastal zone around the Faroe Islands – Biomarker analyses in fish and analyses of PAH and metals in invertebrates (Hoydal, 2004)

In 2005, the industry group FOIB, in cooperation with the Faroese government and the Food, Veterinary and Environmental Agency, produced a report for the public that summarized the environmental issues associated with hydrocarbon exploration drilling activities, in particular those relating to License Round 1 (Petersen et al., 2005). The booklet described the requirements of Faroese legislation for operators of drilling campaigns and the environmental investigations that had been performed prior to drilling; short descriptions of the issues of concern in drilling and drilling-related activities were also included. The booklet summarized the findings of the site-specific monitoring to show the impact of the drilling on the immediate surroundings.

2.9.5.5. Norway

Monitoring of oil and gas activities on the Norwegian shelf is regulated by the Norwegian Pollution Control Authority (SFT). Monitoring was previously a requirement in field-specific discharge permits, but is currently included as part of a common set of offshore regulations from the Norwegian Board of Health, the Norwegian Petroleum Safety Authority, and the Norwegian Pollution Control Authority. The Norwegian monitoring system has also served as the basis for the OSPAR guidelines on monitoring the environmental impact of offshore oil and gas activities in the Northeast Atlantic (Box 2.24), and the principles and methods currently used in Norway follow the OSPAR guidelines. All field-specific baseline studies and regular monitoring on the Norwegian shelf are funded by the operators and conducted by certified consultants. Norwegian regulations also require that operators cooperate and coordinate regional surveys so that the impacts of all activities and discharges are seen in combination.

2.9.5.5.1. Cooperation

On the initiative of the SFT, authorities, operators, and consultants have established several fora for cooperation and information exchange related to environmental monitoring.

- In the 'Forum for Offshore Environmental Monitoring', operators and consultants present results from the latest environmental surveys and plans for future surveys. Representatives from universities and research institutions are invited to comment on the plans and present new results from research that may be relevant to monitoring. Non-governmental organizations are also invited to comment on plans and results.
- The 'Coordination Group' convenes in early spring for a discussion of the results from the previous year's surveys and the plans for the current year's monitoring. A similar meeting is also held in the autumn, after the surveys have taken place. This makes it possible to utilize experience gained to update regulatory requirements and monitoring plans.
- The Norwegian Oil Industry Association's 'Coordination Group Team for Offshore Environmental Monitoring' coordinates the cooperation related to the planning, implementation, and reporting of environmental surveys on behalf of the operators.

2.9.5.5.2. Monitoring principles

Offshore environmental monitoring includes monitoring of both the seafloor and the water column. The main purpose is to obtain a thorough overview of pollution from offshore activities and its environmental impact and an overview of trends in the environment around the fields and in the expanse between the areas of influence of separate fields in defined regions. The results from the monitoring are used:

- to obtain an early warning of potential impacts in the environment;
- to develop prognoses for trends in the environment;
- to verify models for calculating environmental risk; and
- to verify laboratory-based research to evaluate the risk of environmental harm and to conduct such evaluations.

As the oil and gas activities move nearer to shore, areas in the littoral zone and onshore may also need to be monitored.

The environmental monitoring is audited by the SFT, covering all stages of the activities, from the planning of the surveys through to the various operators' internal use of the results. In addition, SFT has appointed an independent group of experts, with representatives from universities and research institutions, which reviews all monitoring reports, including the work conducted, methods used, and conclusions drawn. An important task of the group is to suggest improvements to the monitoring and the use of the results.

In the first years of offshore oil and gas activity, discharges of oil-based drilling mud and cuttings were the main environmental problem. Monitoring was introduced with legal requirements for seabed surveys from 1980. Increasingly greater restrictions were placed on discharges of oil-based mud until they were ultimately banned and discharges ceased on the Norwegian shelf in 1992. As the first fields grew older, discharges of produced water to sea increased and more focus was placed on monitoring of the water column. At the same time, the number of fields grew rapidly and the authorities foresaw that the areas of influence of many fields would start to overlap. This led to a revision of the monitoring guidelines, and a change in focus from seabed and sediments around single installations to an inclusion of both the seabed and the water column in larger regions.

In 1996, SFT also accepted more flexible monitoring, allowing the operator to use professional judgment in choosing a station network. Any deviation from the standard station network established in the requirements must be thoroughly justified, and the programs for the monitoring surveys should be submitted to SFT well in advance of their commencement.

No standard for water column monitoring of offshore discharges currently exists. SFT therefore requires operators to participate actively in the testing and development of methods for monitoring pollution and environmental effects in the water column.

2.9.5.5.3. Purpose of the monitoring requirements

The main purpose of the monitoring requirements is to ensure a standardized performance of the surveys to promote comparable results over time and between regions. This is essential to meet the requirements of section 49 of the Pollution Control Act, under which anyone who causes pollution has a duty to control the environmental impacts of their operations. The standard requirements represent only the minimum with which all operators must comply. Operators are further obliged to assess whether additional investigations are needed on an individual field or in the region. SFT may also, at any time, impose additional investigations whenever considered necessary.

2.9.5.5.4. Monitoring strategies

In order to obtain an optimal description of the conditions around individual installations and in the region, monitoring programs must be designed in relation to pre-existing pollution and current and planned discharges. Ideally, the influence from all other activities in the region should also be taken into account. Operators thus must conduct an evaluation based on the collective results from EIAs, environmental monitoring (Figure 2.156), and discharge monitoring in the planning stage for new monitoring surveys.

Monitoring of the seafloor

The Norwegian continental shelf is divided into eleven regions for seabed monitoring. Monitoring in each region should be conducted every third year, alternating among the regions. The scope of the monitoring is related to the offshore activity in the individual regions, and the scope of the surveys should be comparable to allow for comparison among years. Monitoring of new developments should be added and adapted to the existing monitoring scheme in the region. Since 1997 the concepts of 'reference stations' and 'regional stations' have been employed; both types of station are used to establish the background level of selected components in the area, and the stations may be used interchangeably in given cases. Samples from regional and field-specific stations must be taken during the same field survey in the region. The regional stations should describe general background levels in the area for the components studied, while the field-specific stations give information about pollution levels and effects around individual installations in the region.

Baseline surveys

For all types of installations, baseline surveys should be performed prior to exploration drilling in deep waters; prior to exploration drilling in areas where particularly vulnerable environmental resources have been detected, or where there is reason to assume that such exist; and prior to the start up of production drilling and development in other areas.

Because the monitoring focus is on regional impacts in addition to the conditions around the individual field or installation, the station network must be adjusted accordingly. In selecting stations within one region, coordination among field-specific and regional stations should be ensured. When selecting the position of stations, weight should be given to the following factors:

- the stations should cover the different major seabed types (sand, clay, etc.), emphasizing those most suitable for sediment sampling;
- if water depths in the region vary, the stations should be positioned in such a way that the various depth intervals can be described; and
- the stations should cover all parts of the region with existing or anticipated future field developments.

The field-specific stations should be placed in a cross, covering the entire geographical area that is anticipated to be included later in the monitoring program. The stations must thus cover the area where the installation(s) are to be placed and the areas where local environmental effects from future discharges can be expected according to experience, as well as the area relevant as a reference station. The positioning and area of the cross should be decided on the basis of the expected area of influence based on discharge quantities and dispersion modeling. The operator should document the reasons for the selection of station locations in relation to factors such as currents and depth intervals. The station network for baseline surveys in deep waters (600 m) should be established on the basis of calculations of dispersion from surface discharges.

For the regional baseline survey, more than ten regional stations should be established. The ten most representative stations should be included in subsequent monitoring surveys. The stations are to be distributed so that at least three regions/reference stations are included at each depth interval and each sediment type. The regional stations and the field-specific reference stations should be considered together as the group of reference stations for the region. The regional stations should be placed in areas that are not expected to be affected by discharges from the offshore industry. Thus, they must be placed outside the areas of influence of the various existing and planned installations. As new fields are developed in the region, the need for establishing additional regional stations should be considered.

Monitoring surveys

Monitoring surveys comprise field-specific surveys and regional surveys; Table 2.82 lists parameters to be monitored. For field-specific surveys, the frequency is the same for all types of fields and development concepts. Monitoring surveys on the field must coincide with the first regional survey in the region. After the initial survey, monitoring surveys are to be performed every three years, as part of the regional monitoring surveys. After production has ceased, two monitoring surveys are to be performed at three-year intervals. SFT will then decide whether further monitoring of the field is needed. In waters near the coast or close to areas with particularly vulnerable environmental resources, or where such resources can be assumed to exist, shorter intervals between the monitoring surveys may be relevant. Requirements for this may be included in the discharge permit for the individual field. For regional surveys, seabed monitoring on the Norwegian continental shelf is divided into eleven regions. The positions of the regions and a summary of the timing of the regional surveys are given in Table 2.83. Investigations of the sediments in each region are to be made every three years. A standard regional monitoring survey includes both the regional and field-specific stations in the region.

Depending on the monitoring survey in a particular region, some of the stations may be excluded and new ones included, as appropriate, in consultation with SFT. The position of individual stations should not be changed from year to year, as a comparison of results from different years for the same installation requires sampling station continuity. New stations may need to be established for transitional zones between fields where required.

For field-specific monitoring stations, the station network should be established on the basis of the baseline survey once the locations of the installation(s) and the discharge points, if any, have been decided. As many of the stations from the baseline survey as possible should be included in the final station network. The general station network for the individual stations is presented in

Table 2.82. Parameters included in the Norwegian monitoring program in relation to offshore oil and gas installations (for details see OSPAR, 2004).

Seabed monitoring	
Sediment characterization	Description of sediment surface composition, colour, smell, grain size distribution
Organic material	Total organic material (TOM)
Hydrocarbons and synthetic drilling fluids	Total hydrocarbons (THC) Aromatic hydrocarbons (NPD): naphthalene, phenanthrene/anthracene, dibenzothiophene and their C_1-C_3 homologues PAH: U.S. EPA list of 16 compounds Decalines (C_5-C_8) Main components of the drilling fluids used
Metals	Ba, Cd, Cr, Cu, Pd, Zn, all stations Hg, same stations as NPD and PAH Al, Li, selected stations
Biology	Number of species and individuals per 0.5 m^2 sediment Complete species lists (number of species and individuals) Tables of most common species on every station Diversity (Shannon Wiener index, log_2) Pielous index Hulberts ES_{100}
Additional investigations	As considered necessary by SFT.
Water column monitoring	
Status monitoring	Cod (*Gadus morhua*) Aromatic hydrocarbons C_5-C_8 alkyl decalines
Effects monitoring	Methods are currently under development (see Box 2.25 for biological effects methods agreed by OSPAR) and testing and may vary from one investigation to the next, but they all include shellfish and fish in cages at defined distances from discharges offshore. The aim is to obtain early warning, monitor gradual changes, verify models for calculation of environmental risk; and to verify results from laboratory experiments.
Additional investigations	As considered necessary by SFT.

Table 2.83. Norwegian regions for offshore sediment monitoring, with positions and years of the first regional surveys. The surveys are to be performed every third year from the starting year listed in the table.

	The years of the regional monitoring
The North Sea	
I The Ekofisk area (56–58° N)	1999
II The Sleipner area (58–60° N)	2000
III The Oseberg area (60–61° N)	2001
IV The Statfjord area (61–62° N)	1999
The Norwegian Sea	
V The Møre area (62–64° N)	
VI The Trøndelag area (64–66° N)	2000
VII The Nordland area (66–68° N)	
VIII Troms (68–70° N)	
The Barents Sea	
IX Finnmark (70–72° N)	2001
X The Barents Sea, south (72–75° N)	
XI The Barents Sea, north (north of 75° N)	

Photograph: Geir W. Gabrielsen

Figure 2.156. Environmental monitoring in Arctic waters.

Figure 2.157 and Table 2.84. The station network should preferably be organized as a radiate transect with one axis along the main current direction at the sea bottom and one axis perpendicular to this. The bulk of the stations should be placed downstream in the predominant current direction. If no clear predominant current direction can be established, the system of coordinates should be placed with one axis in a north-south direction.

When using both a grid and a system of coordinates, the station network should always include at least one station in each of the four main directions out from the field that are not chemically contaminated or biologically affected. If the chemical contamination or the biological impact on a field spreads beyond the outermost stations but one, new stations should be established during the next monitoring survey if earlier surveys have indicated a tendency toward increased impact on the field. The new stations should be placed along the axes at geometrically increasing distances. The outer stations in the cross should always be uncontaminated.

Each field-specific station network must have a minimum of one reference station. The station(s) must remain the same from year to year. The reference station(s) for a field should ideally reflect stations that are unaffected physically, chemically, and biologically. The reference stations should have both a certain geographical affinity to the field and approximately the same type of sediment and the same depths as the areas around the installations, but must be located outside the area of influence. In some cases, neighboring regional stations may function as reference stations for a field (or reference stations function as regional stations), but this should not be a criterion for the location of the regional stations.

In calculating background values for chemical parameters in each region, a sliding average should be determined based on all reference stations and regional stations in that region over the preceding six years.

The fauna at reference stations, regional stations, and field-specific stations should be evaluated by experts using biological analyses, with an emphasis on multivariate techniques.

If the direction of the dominant currents is known, the reference station must be placed countercurrent (on the 180° axis) at least 10 000 m from the installation (Table 2.84). If the regional stations in the area are not comparable with the field-specific stations for a specific installation, three reference stations should be established for that installation. Any other reference stations that are selected should to the extent possible be located in areas that are assumed to be unaffected by discharges in the region at present or in the foreseeable future. If a reference station is no longer suitable owing to new field developments, new reference stations will need to be established.

Water column monitoring

Water column monitoring comprises two components: monitoring of environmental status and regional impact monitoring. Monitoring is carried out both in the form of direct measurements of the levels of selected components, and by documenting the probability of sub-lethal and long-term effects in the pelagic environment. Monitoring of environmental status includes measurement of the levels

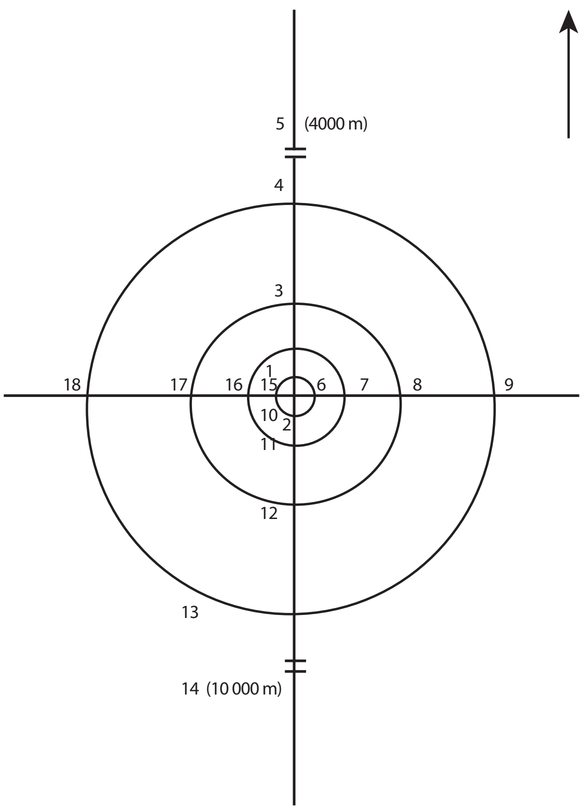


Figure 2.157. Standard field-specific station network for seabed surveys around the installations. The stations are numbered, and the individual station's distance from the installation is stated in Table 2.84. The predominant current direction is shown in the figure.

Table 2.84. Standard field-specific station network for seabed monitoring.

Direction	Station	Distance from zero, m
0°	1	250
	2	500
	3	1000
	4	2000
	5	4000
		(min. 10 000)
90°	6	250
	7	500
	8	1000
	9	2000
		(min. 10 000)
180°	10	250
	11	500
	12	1000
	13	2000
	14	(min. 10 000)
270°	15	250
	16	500
	17	1000
	18	2000

The reference stations in brackets on the 0° axis are to be used if the regional stations in the area are not comparable with the field-specific stations. There should always be a total of three reference and regional stations, with sediments and depths comparable with each field station. The 0° axis is downstream of the main current direction, or alternatively to the north.

of selected parameters in fish from ten regions, including two reference areas, every three years. These regions cover the entire Norwegian continental shelf. The chemical measurements document whether fish have elevated concentrations of chemicals that have been discharged by the petroleum industry. Few internationally accepted standardized methods currently exist for regional impact monitoring of the water column. A number of methods are under development, some of which have been tested in the field. Biomarkers for exposure and impacts are the methods that currently appear to provide the most reliable information about the status of the environment, and that can best detect changes. Thus, measurements of concentration levels in selected organisms will remain a key component of environmental monitoring until standardized methods for regional impact monitoring have been established. The monitoring of biological impacts has therefore focused initially on measuring concentration fields of selected components in the various regions. This forms the basis for a description of exposure and for risk evaluations of damage to organisms in the water column. Use of environmental monitoring and environmental impact analysis together seems at present to represent the most reliable method for assessing the impacts of discharges from oil and gas activities on the environment.

Environmental status monitoring
The first monitoring of environmental conditions started with investigations of oil in fish in 1993. Environmental status monitoring is performed every three years. The first surveys after new regulations took effect were carried out in 2002 (see Table 2.82 for parameters to be measured for status monitoring in the water column).

Regional impact monitoring
Regional impact monitoring is to be performed in one region per year. At present, regional impact monitoring covers four regions (see Table 2.85); this number will increase as the activities in new areas increase.

In waters near the coast or close to areas where particularly vulnerable environmental resources are detected, or where there is reason to assume that they exist, a special program may be needed for the monitoring surveys. Operators are responsible for identifying the need for such surveys. The SFT may also order that surveys be conducted in each individual case. Plans for these surveys should be developed in consultation with SFT, SFT's expert team, and OLF's Taskforce for Discharges to the Sea.

Table 2.85. Positions of status monitoring areas and regions for impact monitoring of the water column.

Monitoring of environmental status	Regional impact monitoring
North Sea	
Ekofisk area (56–58° N)	Ekofisk area (56–58° N)
Sleipner area (58–60° N)	Sleipner area (58–60° N)
Tampen (60–62° N)	Tampen (60–62° N)
Norwegian Sea	
Møre area (62–64° N)	
Trøndelag area (64–66° N)	Trøndelag area (64–66° N)
Nordland area (66–68° N)	
Troms area (68–70° N)	
Barents Sea	
Finnmark area (70–72° N)	
Reference stations	
Barents Sea (71–72° N, 20–22° E)	
North Sea (57–58° N, 05–07° E)	

Sampling area and station network
The sampling area for monitoring environmental status should be chosen on the basis of knowledge of fishery biology and the distribution and migration pattern of the fish stocks in the area. For regional impact monitoring, the station network should be based on knowledge of the physical conditions in the area and calculations (modeling) of the concentration fields of the relevant types of pollution. Samples should be taken from a minimum of fifteen stations in each region.

Depending on the results of ongoing monitoring surveys, certain stations or activities may be excluded or new ones included in consultation with the SFT. The station network should be increased as required, for example, in association with major changes in discharges or the development of new fields (regional impact monitoring) and areas (condition monitoring). The sampling protocol for status monitoring should provide a representative view of the fish species in the region. Knowledge of the composition of the fish stocks and migration patterns in the region is particularly important. Table 2.85 shows the locations and geographical positions of the sampling areas for condition monitoring of fish. For regional impact monitoring the station networks should be positioned with a view to securing an optimal representation of environmental conditions in the region. The need for change or expansion of the station networks should be addressed in the survey report. Regional impact monitoring is divided according to four regions: the Ekofisk area, the Sleipner area, Tampen, and the Trøndelag area.

2.9.5.5.5. Quality control requirements
Prior to awarding environmental monitoring contracts, the operator must document that the contractors are accredited according to relevant national and/or international quality control standards.

2.9.5.5.6. Reporting
To be able to compare monitoring results from different stations and between years, it is essential that comparable analytical methods are used. The operators should use several analytical methods for chemical analyses at the regional stations in order to maintain continuity in relation to determining temporal trends at specific stations and to meet OSPAR reporting requirements. To obtain an overview of the monitoring activities, the SFT requests operators to submit a brief summary and status of R&D work related to monitoring.

2.9.5.6. Russian Federation
Monitoring activities at the regional level in association with oil and gas development in the Arctic areas of the Russian Federation (Kaminsky et al., 2005) include the following.

- From 1989 to 2000, techniques for multiscale mapping, and zonal and local monitoring of soil and water were developed in cooperation with SBNE (School of

Built and Natural Environment, University of Central Lancashire, UK) and implemented at the regional level (Nenets Autonomous Okrug, NAO; St-Petersburg and Leningrad District; Severouralsk of Sverdlovsk District and Samara District).

- Techniques, express analysis complex and technology for the monitoring of oil pollution in soil and water with quantitative assessment of the pollution scale were developed and implemented in 1989 to 2002. In 1990, in cooperation with SBNE-2, an expert survey was conducted at 365 exploration drilling, oil production, and infrastructure sites in the NAO under the State Pollution Monitoring Program.
- In 2000, SBNE in cooperation with experts from the Russian Federation Ministry of Natural Resources (RF MNR) developed techniques and procedures for quantitative assessment of damage caused by area pollution and waste in the NAO. The report was recommended by the RF MNR for approval at the regional level and has been submitted to the process of legislative adoption in the region.
- In 2000, SBNE implemented programs of environmental status assessment for the northern part of the Kumzha area (Pechora River delta) and 3400 km^2 licensing areas of Khoreiver depression (Bolshezemelskaya tundra). In 2001, SBNE started work on a program of containment and removal of the pollution zone in the Kumzha area including areas polluted by the accidental oil spill at well 9 Kumzhinskaya.

Activities at the Departmental level (Kaminsky et al., 2005) include the following.

- Within a mission-oriented research program funded initially by OAO AGD, funded then by OOO Naryanmarneftegas and funded since 2006 by OOO LUKOIL-Sever in the NAO, and by OAO Rosneft-Purneftegas (OAO RN-PNG) in the Yamal-Nenets AO (YNAO), guidance documents (enterprise standards), techniques and technologies of in-process contamination monitoring and monitoring of the contamination of oil drilling and production sites are being developed and implemented. Based on these, VNIGRI (Russian State Institute for Geology and Resources Investigation) and recently SBNE performed mapping, assessment of the degree of contamination, and zonal and local monitoring of more than 7500 km^2 of the okrug lands and waters including environmentally vulnerable ecosystems in the delta of the Pechora River in the NAO (*Kumzha* gas and condensate field).
- Operational monitoring of contamination levels at production facilities is being performed to develop recommendations and implement programs of pollution prevention and elimination. Programs of survey, containment, and partial removal of the pollution zone at the site of the accidental oil spill at well 9 (*Kumzha* gas and condensate field), sub-base Sinkin Nos, oil drilling and production sites belonging to the subsidiaries of NK LUKOIL in the NAO and NK ROSNEFT in the YNAO and these regions' infrastructure sites, were implemented in cooperation with SBNE-2.
- SBNE-2 has developed and is implementing in a stepwise manner a program of sanitary and chemical analyses of drilling and oil production wastes including the issuance of sanitary epidemiological certificates for oil and gas complex enterprises (OAO AGD, OOO LUKOIL-Komi, and OAO RN-PNG).

2.9.5.6.1. Compliance monitoring

Enforcement of environmental, health, social, and safety requirements

Onsite monitoring by government representatives is the standard method by which a company's compliance with project environmental, health, social, and safety requirements is confirmed. Any facility that has the potential to affect the surrounding environment or poses safety and health risks is subject to monitoring. The extent and frequency of monitoring activities are related to the type of facility and the associated level of risk, but are largely determined by the inspection agencies within whose jurisdiction the operation resides. Warnings and fines are the usual results of non-compliance, but suspension of operations and administrative proceedings against violators are possible.

All levels of government in the Russian Federation conduct monitoring of environmental, health, social, and safety activities. State environmental monitoring or control is conducted at the Federal and Regional levels as well as State oversight of safety, health, land, and geological issues. Municipal and public environmental monitoring is also conducted in Russia.

Federal level

There are three Federal-level government agencies that undertake environmental monitoring activities: the Federal Service for Environmental, Technological and Nuclear Supervision (Rostekhnadzor); the Federal Service for Natural Resource Management Supervision (Rosprirodnadzor); and the Federal Veterinary and Phytosanitary Supervision Service (Rosselkhoznadzor).

Rostekhnadzor and its territorial agencies conduct monitoring and oversight in the areas of waste handling, subsoil-resource conservation, air protection, and limiting adverse technogenic environmental impacts. Rostekhnadzor also undertakes environmental monitoring in association with authorized officials from the environmental safety service of the Ministry of Defense.

Rosprirodnadzor and its territorial agencies conduct monitoring in the areas of:

- protection, use, and replacement of wildlife and their habitat (except game animals and animals harvested by the fishing industry);
- organization and functioning of specially protected natural territories of Federal importance;
- geological study, management, and conservation of subsoil resources;
- use, conservation, and protection of State forestland and replacement of forests;
- use and protection of water bodies;
- observance of Federal law and international norms and standards regarding the marine environment and natural resources of interior seawaters, the territorial sea, and the EEZ;

- management of mineral and living resources on the continental shelf; and
- monitoring of land in State water holdings, State forestland, forestlands that are not part of State forestland, and land of specially protected natural territories.

Rosselkhoznadzor and its territorial agencies conduct monitoring and provide oversight for the protection of water bodies of importance to the fishing industry.

Federal monitoring of industrial safety is performed to check that companies fulfill industrial safety requirements during the construction, placement into operation, and operation of hazardous production facilities. Most oil industry operations/facilities are classified as hazardous in Russia. Production control is also an integral part of industrial safety management during field producing activities and is also monitored by Federal authorities. Federal monitoring of industrial safety is performed primarily by Rostekhnadzor and its territorial authorities. However, other Federal executive authorities may also engage in safety oversight within their purview; these include the Ministry of Emergencies, the Ministry of Health, the Ministry of Agriculture, and the Russian Federation Federal Service for Hydrometeorology and Environmental Control (Rosgidromet).

The Federal Consumer Rights Protection and Human Welfare Supervision Service (RosPotrebNadzor) and its territorial agencies is a Federal executive authority that supervises compliance with laws and regulations developed to ensure public health and epidemiological well being within the Russian Federation. The monitoring of project operations to identify, stop and/or prevent violations of these public health laws is performed by Rospotrebnadzor.

Monitoring of land use is conducted to observe and enforce the requirements of the laws concerning land conservation and use. State land control is handled by Rosnedvizhimost′ and its territorial divisions, together with the Ministry of Natural Resources and its territorial agencies with regard to land in State water holdings, State forestland, forestland that is not part of State forestland, and specially protected natural territories.

State geological oversight is performed to ensure that all subsoil-resource users observe the prescribed procedure for using subsoil resources, the requirements of Federal law, and duly approved standards (norms, rules) for the geological study, use, and conservation of subsoil resources. State geological oversight is performed by: Rosprirodnadzor, which is the State geological oversight authority; Rostekhnadzor, which is the State mining oversight authority, and their territorial agencies interacting with other oversight authorities; State authorities of constituent entities of the Russian Federation.

Regional level

At the regional level, special agencies created in the administrations of the constituent entities of the Russian Federation conduct environmental, health, and safety monitoring activities. The targets of their control include all facilities that are engaged in economic activity and that are located within a constituent entity of the Federation. The rights and obligations of the regional State environmental inspector are similar to those of the Federal state inspector. However, most facilities that are classified as hazardous, including the majority of oil industry operations, remain the subject of Federal control. In this instance, a State environmental control department (or group) is created within the environmental department of the Federation constituent entity.

The Shtokman LNG facilities at their proposed location will almost certainly be classified as hazardous. Thus, they will be subject to Federal control, and will be inspected and monitored by Rostekhnadzor and its territorial agencies in Murmansk. Regional representatives may participate in the activities of the Federal environmental control commission.

Municipal level

Municipal environmental monitoring and control is handled by local government agencies within their purview at facilities that are engaged in economic activity and that are located within the territory of a municipal entity. For the Shtokman LNG facilities, local government agencies may participate in State environmental monitoring as members of the control commission.

Municipal control of land management in the territory of municipal entities is also handled by local governmental agencies.

Public control

Public environmental control is handled by public organizations in accordance with their individual charters. Typically, if individual citizens or public organizations discover that a company is failing to comply with rules for the safe operation of facilities, or is causing harm to the environment or public health, they contact environmental protection agencies (Ministry of Natural Resources, Rosprirodnadzor, or Rosprirodnadzor) requesting an audit of the company's operations. In extreme cases, the citizen or public organization may file a lawsuit for damages. Once contacted, the State environmental monitoring agencies will conduct inspections and determine whether damage has occurred. The principal public organizations actively participating in organizing public environmental control in Russia are listed in Box 2.26.

In addition to monitoring activities by public organizations, any citizen of the Russian Federation has the following rights: to ask companies about environmental impacts at their places of residence and about environmental protection measures that have been undertaken; to participate in public environmental control of the public environmental expert review; and to sue for damage to the environment.

2.9.5.6.2. Monitoring activities

Monitoring by Federal and Regional authorities is carried out in the form of checks performed according to duly approved plans by the agency responsible for State oversight. There are no established guidelines that determine or limit the frequency of these types of inspections.

State environmental inspectors have the right to conduct the following activities:

- to visit facilities engaged in economic activity regardless of their form of ownership, and examine documents and other necessary materials;
- to check the fulfillment of the requirements specified

Box 2.26. Key organizations in public environmental control in the Russian Federation

The principal public organizations actively participating in organizing public environmental control in Russia are as follows.

- Russian Regional Ecology Centre (RREC, Russian RRETs)
- Ecojuris Institute
- Ecological Policy Centre of Russia (EPCR, Russian TsEPR)
- All-Russian Nature Conservation Society (ARNCS, Russian VOOP)
- Ecological Research and Design Centre (ERDC, Russian TsEIP)
- Ecoline public organization
- Greens, Russian ecological party
- Alliance of Russian Greens, political party ('Green Russia')
- Vladimir I. Vernadsky Non-governmental Ecology Fund
- World Wildlife Fund (WWF) in Russia
- International Union for the Conservation of Nature (IUCN) in Russia
- Greenpeace of Russia
- EcoDefense international ecological group
- Russian Green Cross (RGC)
- Bellona-Murmansk regional nongovernmental organization, Murmansk

in a Environmental Expertise Review finding, and standard allowances, State standards, and other regulations with regard to environmental protection for the location, construction, placement into operation, operation, and decommissioning of facilities;

- to check the operation of treatment facilities and other decontamination units and instruments, and to monitor the implementation of environmental protection plans and associated measures;
- to issue orders to legal entities and persons to eliminate any violations found;
- to suspend company operations; and
- to institute administrative proceedings against individuals who have committed a violation.

A company's operations are routinely checked by State inspectors for the following environmentally-related issues:

- to check observance of the standards and limits for maximum permissible emissions/discharges of pollutants and for waste disposal;
- to determine whether permits have been obtained and water-use (water-allocation) limits are being observed;
- to determine whether permits have been obtained for pollutant emissions into the atmosphere, for wastewater discharges, and for the disposal of domestic and industrial waste;
- to inspect the results of an inventory of sources of environmental pollution and the status of these sources;
- to identify the existence and implementation of an environmental protection plan;
- to determine the environmental state of land, water bodies, and other natural resources in close proximity to the operating facility;
- to determine whether the operation of treatment facilities, domestic and consumer-service facilities, and special-purpose facilities (boiler houses, fuel stores, motor pools, etc.) comply with environmental protection requirements, and how solid-waste storage facilities are maintained;
- to check on the implementation of measures under previously issued orders to eliminate identified violations of environmental protection laws;
- to check on the regularity of submission of State statistical reporting materials; and
- to determine whether there is a measures plan and an action plan in the case of emergencies with environmental consequences.

The following are verified during production control of industrial safety:

- the organizational structure; administrative and operating procedures; human and material resources; and equipment intended to fulfill industrial safety requirements;
- work areas, operations, and industrial processes; manufactured product (for the purpose of determining its conformance to established industrial safety requirements);
- documentation, reports, and registration and storage of data in accordance with permits and the Declaration of Industrial Safety; and
- the number of hazardous production facilities in operation, including:
  - those insured in accordance with article 15 of the law 'On industrial safety at hazardous production facilities' and
  - the number of units of operated equipment subject to mandatory certification for conformance to industrial safety requirements, including: the number of units of operated equipment certified as conforming to industrial safety requirements; the number of workers at operating organizations that have undergone industrial safety training and certification during the reporting year; the number of workers engaged in the operation of hazardous production facilities; the number of accidents that have occurred in the reporting period; the number of incidents that have occurred in the reporting period; and the number of operational shutdowns resulting from hazardous conditions (according to the results of production control).

An industrial-safety inspector has the following rights:

- to visit organizations that operate hazardous production facilities;
- to familiarize themselves with required documents;
- to check the performance of technical investigations of incidents at hazardous production facilities, as well as to check the adequacy of the measures taken;
- to issue orders to correct any violations found;
- to issue industrial safety instructions regarding the need to conduct an expert review of industrial safety;
- to issue instructions to remove people from their workplaces in the case of a threat to the life or health of the workers;
- to institute administrative proceedings against people guilty of violating industrial safety requirements; and
- to send law enforcement authorities materials for the institution of criminal proceedings against the above-mentioned individuals.

The most frequently monitored requirements in relation to human health include:

- assurance of atmospheric air quality in populated areas;
- protection of surface water;
- protection of subsurface water from pollution;
- protection of coastal marine waters from pollution at water use locations;
- water quality in centralized potable water supply systems;
- water quality in non-centralized water supply systems;
- establishment of a sanitary protection zone for water supply sources and potable water pipelines;
- observance of maximum allowable concentrations of chemicals in water bodies providing water for domestic (potable and cultural) utility use;
- observance of maximum allowable concentrations of chemicals in the soil;
- disposal and decontamination of production and consumer waste; and
- observance of noise levels at workplaces, in living accommodations, in public buildings, and within the territory of residential developments.

A State sanitation inspector has the following rights:

- to visit unfettered the grounds and enclosed spaces of facilities;
- to perform inspections of vehicles and the freight that they are hauling;
- to sample the air, water, and soil;
- to make measurements of environmental factors;
- to draw up a report of a violation of a sanitation law; and
- to issue legal orders to correct, within the prescribed time periods, identified violations of mandatory sanitation rules.

The sanitation inspector may ask for proceedings to be initiated for administrative (or criminal) violations if a company permits infractions of sanitary and hygienic rules.

State inspectors for land conservation have the following rights:

- to visit organizations and facilities and inspect land parcels;
- to issue mandatory orders regarding observance of the requirements of land law and the correction of any violations found;
- to draw up inspection reports, with mandatory familiarization required by the company;
- to draw up, through the procedure prescribed by the law on administrative infractions, reports on violations of land law and send them to the proper officials for review, in order to institute proceedings against the guilty parties;
- to obtain, free of charge, information and materials on the condition, use, and conservation of land; and
- to request that internal affairs authorities provide assistance in preventing or halting actions that interfere with the performance of lawful activity by inspectors, and in establishing the identity of the offending persons or citizens.

The following conditions are checked in the course of State land control:

- observance of the prescribed procedure for land use and conservation;
- use of land for the designated purpose;
- fulfillment of environmental protection requirements during land allocation;
- observance of the procedure for occupying land parcels;
- performance of land re-cultivation after the completion of development of mineral deposits (including common minerals), after construction, land reclamation, logging, survey, and other work, including work carried out for farm or internal needs; and
- the procedure for alienating and transferring forestland to non-forestland status.

In relation to oil and gas injection wells, water abstraction wells, groundwater monitoring wells, groundwater protection, and permafrost protection, a State geological inspector has the following rights:

- to visit organizations that conduct the geological study and use of subsoil resources, without advance notification and upon presentation of a warrant, regardless of their organizational legal form and departmental affiliation;
- to check, through the prescribed procedure, observance of the requirements of Federal laws during work on the geological study and use of subsoil resources; and
- to issue orders to subsoil-resource users to correct any violations found during work on the geological study, use, and conservation of subsoil resources, and

to observe the conditions of use licenses for tracts of subsoil resources.

In the course of State geological monitoring, Rosprirodnadzor checks the following:

- fulfillment of the conditions of subsoil resource use contained in use licenses for tracts of subsoil resources;
- the existence of detailed designs (process flow diagrams), plans, and schematics for the development of mining operations, and the conformance of the present state of work on the geological study and management of mineral reserves to the indices set forth in the design documentation;
- the accuracy of the data needed to calculate payments for the use of subsoil resources during prospecting for and evaluation, exploration, and extraction of minerals;
- the state of preservation of exploratory mine workings and boreholes, geological and technical documentation, ore and rock samples, cores, and backup mineral samples that could be used in further study of subsoil resources or in the exploration and working of mineral deposits; and
- fulfillment of the conditions specified in the applicable permits for building, operating, and using artificial islands, structures, and installations, carrying out drilling operations related to the geological study of, prospecting for, and exploration and development of mineral resources, and laying of subsea cables and pipelines in the interior seawaters, territorial sea, and continental shelf of the Russian Federation.

Rostekhnadzor checks the following in the course of State geological monitoring:

- the accuracy and substantiation of materials submitted by subsoil-resource users for placement or removal of mineral reserves on the State balance sheet;
- prevention of unauthorized use of subsoil resources and of unsubstantiated and unauthorized development of areas where minerals occur; and
- abandonment, through the prescribed procedure, of exploratory mine workings and boreholes that will not be used.

State governmental authorities of constituent entities of the Russian Federation check the fulfillment of the conditions of use licenses for tracts of subsoil resources that contain deposits of common minerals, and for tracts containing subsoil resources of local importance.

2.9.5.6.3. Research monitoring

Russia has many research initiatives for environmental and geochemical monitoring. One example is the State Monitoring Program of the Offshore North-West Russia. The Environmental Offshore Monitoring Centre for Baltic and Arctic Seas of the State Scientific and Production Company for Marine Geological Prospecting, SEVMORGEO SC, of the Russian Ministry for Natural Resources conducts marine environmental monitoring in the Arctic (Sevmorgeo, 2006).

SEVMORGEO assesses and monitors the external and internal geological processes in offshore sediments for total hydrocarbon concentration, heavy metals, ^{137}Cs, and grain size, and near-bottom waters and sediment pore waters for heavy metals, oxides of nitrogen and phosphorus, phenols, SCAS (semi-continuous activated sludge), and total hydrocarbon concentration. The parameters measured, particularly those in sediments, are similar those monitored in OSPAR programs (Tables 2.86 to 2.88). These data allow the definition of the associated Permission Level Concentration (PLC) for water and Target Value (TV) for sediments.

2.9.6. Research in the Arctic countries

Research activities in Arctic countries relevant to oil and gas activities and their environmental, socio-economic, cultural, and potential human health impacts span a very wide range of topics. These range from broad scientific investigations of the sensitivity of habitats or species to oil and gas development to technology-based applied research related to, for example, production challenges in ice-infested waters. Some is essentially local or regional, relating to the resident or migratory species of an area, their population status, and potential impacts of oil and gas activities. On the other hand, much of the technology-based and engineering research relevant to pollution prevention, enhanced recovery, oil spill response techniques, or sub-sea pipeline construction may be applicable on a broad basis. Research is also being conducted in relation to socio-economic and cultural effects on local communities affected by oil and gas operations.

The types of research funded and conducted by the Arctic countries reflect the types of oil and gas activities under their jurisdiction, the location of these activities (terrestrial or offshore), and the presence of local communities and/or subsistence activities that may be affected by activities associated with oil and gas development and production. The following sections provide an overview of some of these research activities.

2.9.6.1. Alaska, United States

2.9.6.1.1. The North Slope Science Initiative

The North Slope Science Initiative was established to enhance the quality and quantity of scientific information available for aquatic, terrestrial, and marine environments on the North Slope and to make this information available to decision-makers, governmental agencies, industry, and the public. Established by Congress in the Energy Policy Act of 2005, the North Slope Science Initiative (NSSI) focuses on prioritization of pressing natural resource management and ecosystem information needs, coordination and cooperation among agencies and organizations, competitive selection of approved projects, enhanced information availability and public involvement.

The Alaska leadership of ten local, State, and Federal land and resource agencies, including the Arctic Slope Regional Corporation as the largest private landowner on the North Slope, signed a charter establishing the Oversight Group for the NSSI. Resource management agencies administering the resources of the North Slope of Alaska include those at the local, state, and Federal level. Members comprise: the Mayor of the North Slope Borough; the President of the Arctic Slope Regional Corporation; the Commissioners of the Alaska Department of Fish and Game, and the Alaska Department of Natural Resources; the Regional Directors of the U.S. Geological Survey, the U.S. Fish and Wildlife Service, the Minerals Management

Table 2.86. Comparison of analytical parameters for sediment monitoring by Russia and in accordance with the OSPAR guidelines for monitoring the environmental impact of offshore oil and gas activities (OSPAR, 2004).

Parameters	Russia	OSPAR
Sediment description: visual, presence of fauna, colour and smell	+	+
Physical characterisation of sediments: total organic matter and grain size distribution	+	+
Hydrocarbons:		
total hydrocarbon content	+	+
aromatic hydrocarbons, naphthalene, phenanthrene/anthracene, dibenzothiophene	–	+
Metals:		
cadmium, chromium, copper, lead, mercury, zinc	+	+
barium, aluminum, lithium	–	+
Benthic fauna: taxonomic name and numbers of individuals of all species	–	+
Radoinuclides	+	–
Synthetic elements	+	–
Phenols	+	–

Table 2.87. Comparison of analytical parameters for monitoring of water by Russia and in accordance with the OSPAR guidelines for monitoring the environmental impact of offshore oil and gas activities (OSPAR, 2004).

Parameters	Russia	OSPAR
Total chemical analysis	+	+
Hydrocarbons:		
total hydrocarbon content	+	+[a]
aromatic hydrocarbons, naphthalene, phenanthrene/ anthracene, dibenzothiophene	–	+[a]
Heavy metals: cadmium, copper, lead, mercury, zinc	+	+[b]
Temperature, pH, Eh, O_2, salinity	+	+
Biogenic compounds: PO_4, NO_3, NO_2	+	+
Synthetic elements	+	+
Phenols	+	+

[a]Measured in whole mussels deployed in cages or nets at sampling locations; [b]cadmium, mercury and lead measured in whole mussels or the liver of fish deployed in cages at sampling locations.

Table 2.88. Comparison of sampling methods by Russia and in accordance with the OSPAR guidelines for monitoring the environmental impact of offshore oil and gas activities (OSPAR, 2004).

Parameters	Russia[a]	OSPAR
Sampling square	0.1 m^2	0.1 m^2
	0.25 m^2	0.25 m^2
Sampling depth of sediments	20–25 cm	0–6 cm
Depth of analytical studying	0–1 cm	0–6 cm
Frequency of sampling	1 year	3 years
Sediment sampling equipment	Van Veen Box-Corer	Box corer
Near-bottom water sampling equipment	Box corer and bathometer (+1m)	–

[a] www.sevmorgeo.com/Направления/ Мониторинг

Service, the National Marine Fisheries Service, and the National Park Service; and the State Director of the Bureau of Land Management. The U.S. Arctic Research Commission and the Department of Energy serve as advisors to the NSSI Oversight Group.

Objectives incorporated in the Oversight Group charter include the following:

- to identify and prioritize information needs for inventory, monitoring, and research activities to address the individual and cumulative effects of past, ongoing, and anticipated development activities and environmental change on the North Slope;
- to develop an understanding of information needs for regulatory and land management agencies, local governments, and the public;
- to focus on prioritization of pressing natural resource management and ecosystem information needs, coordination, and cooperation among agencies and organizations;
- to coordinate ongoing and future inventory, monitoring, and research activities to minimize duplication of effort, share financial resources and expertise, and assure the collection of quality information;
- to identify priority needs not addressed by agency science programs in effect on the date of enactment of this Act and develop a funding strategy to meet those needs;
- to provide a consistent approach to high caliber science, including inventory, monitoring, and research;
- to maintain and improve public and agency access to:
    - accumulated and ongoing research; and
    - contemporary and traditional local knowledge; and
- to ensure through appropriate peer review that the science conducted by participating agencies and organizations is of the highest technical quality.

While the Energy Policy Act authorized that sums be appropriated to carry out this initiative, no appropriations have yet passed Congress. Contributions from the member agencies have been pooled to fund the administration of this initiative. A dedicated long-term funding source to meet the objectives of the NSSI is being pursued.

The Oversight Group has met to receive briefings on current North Slope research, inventory, and monitoring activities conducted by each agency, oil industry companies, and the various institutes within the University of Alaska. A database of all activities is being compiled and currently contains over 500 projects. This database will provide project leaders with a tool to determine potential opportunities for collaboration and increased communication.

The charter for the Science Technical Group was drafted by the Oversight Group and approved by the Secretary of the Interior. As required by the Energy Policy Act, the Science Technical Group shall consist of a representative group of not more than fifteen scientists and technical experts from diverse professions and interests, including the oil and gas industry, subsistence users, Native Alaskan entities, conservation organizations, wildlife management organizations, and academia. Members provide advice on proposed inventory, monitoring, and research functions. The Secretary of the Interior appointed fifteen members to the Science Technical Group in January 2006.

A data gap assessment completed in 2004 identified a need to develop infrastructure and communication pathways to support the continued exchange of information relevant to the North Slope. Major data gaps on the North Slope include incomplete baseline data for the region both at spatial and temporal scales, insufficiently organized data management, and the lack of coordination to maximize and leverage data use. The NSSI draft Science Strategy provides a broad strategy for identifying priorities and addressing development issues. An Implementation Plan is under development, incorporating a monitoring plan to implement studies assessing the impacts of oil and gas exploration and development on various surface resources and to determine the effectiveness of current mitigation measures and management policies. The following areas within the biological, physical, and social systems sensitive to development on the North Slope have been identified as priorities for the NSSI.

- Regional long-term hydrologic gauging stations in areas of potential development.
- Caribou populations and harvest: effects of ice roads and facilities on habitat use and migration, disturbance effects from vehicle and aircraft traffic, seismic exploration, and drilling activities, and potential displacement from areas of high forage quality, potentially affecting rates of reproduction and survival.
- Molting geese: disturbance effects of aircraft, vehicles, pedestrians, and facility noise potentially affecting survival.
- Potential impacts on fish due to changes in hydrology from infrastructure and roadways (including ice roads), and changes in water quality due to water withdrawals or sedimentation and scouring during spring floods.
- Change in access to subsistence resources: altered distribution or abundance of subsistence resources and physical or perceptual barriers to subsistence users.
- Alteration of predator/prey relationships: increased predator populations resulting from human developments and activities, and any resulting adverse impacts on prey species.
- Impacts on local cultural systems: any changes to the sharing network which may result from altered subsistence activities.
- Populations of cliff-nesting raptor species: effects of disturbance and habitat loss.
- Effects on migrating bowhead whales in autumn: deflection of migrations from noise associated with barging, seismic exploration, and drilling in marine waters.
- Populations of threatened eider species: effects of collision and oil spill-related mortality, increased predator density, habitat loss, and disturbance.
- Environmental contaminants: oil or hazardous chemical spills, water effluent and air emissions, resulting in contaminants in water, sediments, invertebrates, plants, fish, birds, and mammals.

The NSSI has begun to address some of the priorities listed above, such as dedicating additional funding to establish four long-term hydrologic gauging stations in the National Petroleum Reserve-Alaska, appropriating additional funding to ongoing research of the Central Arctic caribou herd, and dedicating funding to assess effects of disturbance on molting geese north of Teshekpuk Lake. Further development of the NSSI is dependent on continued support and interest from the U.S. Federal government and relies on participation from Federal, State, and local stakeholders, research institutes, and the oil and gas industry.

2.9.6.1.2. Other Federal research programs

Research programs under the Department of Energy cover, for example, enhanced recovery, carbon dioxide sequestration, coiled tubing, and small bore drilling.

Minerals Management Service

MMS decisions and rules are based on high-quality science and sound scientific and technical information. In addition, the MMS prepares Environmental Impact Statements (EISs) and must also evaluate or permit every offshore oil- and gas-related activity. To obtain this information, the MMS sponsors or conducts scientific and technical research. Much of this research is in pioneering areas, both topically and geographically. Two of several MMS divisions that conduct research are the Technology Assessment and Research (TA&R) Program, which is involved in offshore safety, pollution, and oil spill research and response, and the Environmental Studies Program (ESP), which funds (over USD 250 million) and directs a wide variety of environmental, oil spill, and socio-economic research. Support is also provided for the University of Alaska Coastal Marine Institute (USD 1 million per year in matching funds) for environmental research (a five-year agreement with them has been renewed) and the Marine Minerals Research Centre, as well as for scientific studies conducted in partnership with other interested parties.

Environmental Studies Program

In addition to MMS's work on improving the U.S. regulatory regime, the United States has invested over half a billion U.S. dollars to increase scientific understanding of the oceans and coastal environments, including the socio-economic environments in coastal communities. This knowledge base increases the ability of current and future generations to understand the effects of oil and gas activity, to mitigate the effects, and in some cases improve coastal ecosystems.

The ESP funds outside research applied towards resolving specific problems. This research will ultimately help in the development of the offshore resources in an environmentally safe way. The purpose of the ESP is to define information needs and implement studies to assist in predicting, assessing, and managing potential effects on the human, marine, and coastal environments of the OCS and coastal areas that may be affected by gas and oil development. Lease-management decisions are enhanced when current, pertinent, and timely information is available. To attain MMS program goals, data on specific environmental, social, and economic concerns arising from offshore leasing are required. The ESP then monitors any effects during and after oil exploration and development. It is the largest, single-agency, mission-oriented, marine studies program in the Federal government. Since the ESP began in 1973, more than USD 620 million has been spent nationally and more than USD 285 million has funded Alaskan studies in 15 planning areas in the Arctic, Bering Sea, and Gulf of Alaska sub-regions.

The Alaska OCS Region encompasses 600 million acres of U.S. waters and more than 9600 km of coastline including the Arctic Ocean, the Bering Sea, and the northern Pacific Ocean. The Alaska Region is working on first-in-the-world projects that could lead to the first Federal offshore oil production in the region. BP's Northstar Project has provided the first OCS production offshore in Alaska. The MMS has sponsored several workshops to have the best international experts give their insights into the issues faced, such as sub-seabed pipelines and Arctic oil spill response.

The Alaska Environmental Studies Program was initiated by the U.S. Department of the Interior in 1974 in response to the Federal government's decision to propose areas of Alaska for offshore gas and oil development. The Outer Continental Shelf Lands Act requires the Secretary of the Interior to conduct environmental studies to obtain information pertinent to sound leasing decisions as well as to monitor the human, marine, and coastal environments.

Public input and partnerships with other agencies are important aspects of the Alaska ESP. Local government leaders, sources of traditional knowledge, environmental groups, oil and fishing industry personnel, studies contractors and other scientists, and specialists from Federal, State, and local agencies help the MMS to identify environmental issues and information needs. They help by commenting at scoping meetings in local towns and villages before the preparation of EISs, and by attending periodic regional Information Transfer Meetings and workshops held in major population centers to bring together information from all possible sources. The overlap of knowledge among participants in focused workshops results in a synthesis of information that supports EIS analyses and also identifies needed studies. In addition, a draft of the Alaska Region Environmental Studies Strategic Plan is distributed for review each year to approximately 150 Native, environmental, industry, international, and other organizations; Federal, State, and local governments; and the MMS Advisory Board, Scientific Committee. Comments received from these stakeholders as well as the general public are taken into consideration in identifying needed studies.

The Alaska Annual Studies Plan FY 2006–2007 covers a number of studies on physical oceanography, the fate and effects of oil, studies of some fish populations, and a large number of studies on protected species: bowhead whales, polar bears, ringed and harbor seal, and various birds, particularly eiders. The plan also encompasses a number of socio-economic studies including:

- a synthesis on the socio-economic effects of oil and gas industry activity on the Alaska OCS;
- a quantitative description of potential impacts of OCS activities on bowhead whale hunting and subsistence activities in the Beaufort Sea;
- subsistence mapping at Nuiqsut, Kaktovik, Barrow, and Wainwright: past and present comparison;
- researching technical dialogue with Alaskan coastal communities: analysis of the social, cultural, linguistic, and institutional parameters of public/agency communication patterns;
- dynamics of distribution and consumption of subsistence resources in coastal Alaska; and
- social and economic assessment of major oil spill litigation settlement for the Alaska OCS Region.

Future studies will assess the cumulative extent of offshore human activities in the Alaskan Arctic and establish environmental mitigation monitoring of oil industry operations on subsistence activities in the vicinity of Nuiqsut.

Scientific studies are conducted in partnership with other interested parties. The Beaufort Sea is an area of primary concern to both the MMS and the State of Alaska.

Technology Assessment and Research Program

The TA&R program:

- covers oil spill response and research on engineering and safety;
- provides a technology base to support MMS regulatory decisions and to ensure safe and pollution-free offshore operations;
- assesses and analyzes applicable technologies and sponsors applied research:
  - operational safety (blowout prevention, fire safety);
  - verification of offshore structures and pipelines; and
  - technologies to prevent and mitigate pollution;
- operates through contracts with universities, private firms, and government laboratories; and
- maintains the National Oil Spill Response Test Facility, which tests response equipment and procedures.

The MMS is the principal U.S. government agency funding offshore oil spill response research. Through the TA&R Program, the MMS annually selects and funds research projects to improve the capabilities to detect and respond to an oil spill in the marine environment. The MMS issues an annual Request for Proposals that is open to anyone to submit proposals for oil spill research that will advance oil spill response. Projects are solicited for the following topics: behavior of oil, chemical treating agents, deepwater response, mechanical containment, remote sensing, in situ burning (details at: www.mms.gov/taroilspills.

- *Behavior of oil:* this category includes determining the properties and behavior of oil from MMS producing areas once it is released into the environment. This aids in identifying or designing appropriate equipment to respond to the spill. It gives responders an idea about, for example, how long chemical or in situ burning tactics would be effective, how rapidly the oil will weather, how emulsified it will become.
- *Chemical treating agents:* this category includes oil dispersants which, when applied, cause the oil slick to disperse into smaller pieces and become part of the water column. This category also includes emulsion breakers that cause the oil to release the water it has picked up.
- *Deep water response:* this category is more applicable to the Gulf of Mexico and studies what happens to oil when a spill occurs in deep water and how best to mitigate those effects and respond to the spill.
- *Mechanical containment:* this category addresses oil containment mechanisms such boom and skimmers that collect the oil from the surface of the water.
- *Remote sensing:* this category addresses means to locate spills using satellite imagery or other technologies.
- *In situ burning:* this category addresses the burning of oil on the surface of the water or in the shallows instead of its collection with skimmers.

MMS funded research projects of interest in the Arctic (www.mms.gov/tarprojects**)** include:

- Comprehensive Spill Response Tactics for the Alaska North Slope-Oil in Broken Ice Spill Response Scenarios
- Detection and Tracking of Oil Under Ice
- Water Jet Barrier Containment of Oil in the Presence of Broken Ice
- Alaska Arctic Workshop
- International Oil and Ice Workshop
- Evaluation of Skimmers for Offshore and Ice-Infested Waters
- Mechanical Oil Recovery in Ice Infested Waters (MORICE) - Phase III
- The Use of Ice Booms for the Recovery of Oil Spills from Ice Infested Waters
- New and Innovative Equipment and Technologies for the Remote Sensing and Surveillance of Oil in and Under Ice
- Outdoor Wave Tank and Program of Mid-Scale In Situ Burn Testing in Alaska
- Understanding Oil Spill Dispersants: Efficacy and Effects
- Ohmsett 2003 Cold Water Dispersant Effectiveness Experiments
- Mid-Scale Tests to Determine the Limits to In-Situ-Burning in Broken Ice
- Using Dispersants to Test and Evaluate the Effectiveness of Dispersants in Cold Water and Broken Ice

The MMS has funded a number of TA&R research projects and workshops to advance oil spill responses in the cold water and ice environment and has conducted extensive research on in situ burning, mechanical recovery of oil in and under ice, tracking of oil in and under ice and dispersant effectiveness and efficiency in cold water. In situ burning is one response tactic that has the potential to remove a large quantity of oil from the ocean surface in difficult to reach, fragile or dangerous areas such as tidal areas, or broken ice environments.

In addition to funding spill response research, the MMS funds and operates the OHMSETT (Oil and Hazardous Material Simulated Environmental Test Tank) facility. The OHMSETT facility is a 2.6 million gallon salt-water test tank used for evaluating everything from equipment to how oil reacts in the marine environment. The tank is 203 m x 20 m x 3.4 m deep. It has a wave generator that can produce waves up to 1 m in height and can simulate a beach environment at the opposite end. It has two tow bridges which can pull boom and skimmers up to speeds of 6.5 knots to test boom and skimmer efficiency in wave conditions. The tank is available for testing all year round.

The OHMSETT facility allows responders to train with actual oil, and can be chilled to allow for testing at near freezing temperatures and with ice. The OHMSETT is routinely used by the Coast Guard, oil spill response organizations and others to train personnel on the equipment they would use in a spill situation and with the oils they would normally recover (www.ohmsett.com).

Coastal Marine Institute

In 1993, the MMS developed the Coastal Marine Institute (CMI) to take advantage of environmental scientific expertise at local levels. The CMI is managed by the University of Alaska Fairbanks School of Fisheries and Ocean Sciences, which is nationally renowned for its coastal/marine expertise. Under a five-year Cooperative Agreement, the MMS committed USD 1 million per year for studies to be conducted by the CMI, if it can obtain matching funds. Twelve multi-disciplinary studies are currently under way.

In addition to funding CMI scientific research, 9% of the MMS's USD 1 million contribution supports education in Alaska by funding tuition and travel for University of Alaska Fairbanks graduate-student research related to CMI projects.

2.9.6.2. Canada

Research (environmental, technological, and social) related to oil and gas exploration, development, production, and transportation in Canada's circumpolar region is funded through various government and industry initiatives. Typically projects will receive funding from several research programs with additional support from specific companies, individual government departments, research councils, or universities who are either conducting or sponsoring the research. The Program of Energy Research and Development (PERD) is administered by the Office of

Energy Research and Development of Natural Resources Canada. It has an annual budget of USD 56 million. PERD funds research and development projects to ensure sustainable energy development. The Environmental Studies Research Funds (ESRF) were established under the Canadian Petroleum Resources Act. ESRF is administered by a twelve-member industry, government, and public board and obtains funds from annual levies on exploration licenses held by individual companies in the Northwest Territories, Nunavut, Beaufort Sea, and the East Coast offshore. ESRF funds environmental and social studies pertaining to the manner in which, and the terms and conditions under which, exploration, development, and production activities on frontier lands should be conducted.

In addition to the longer, established programs, there are shorter-term, specifically focused programs which provide funds for specific oil and gas research. The Department of Indian Affairs and Northern Development in cooperation with Environment Canada, Fisheries and Oceans Canada and Natural Resources Canada obtained funding of USD 63 million over the period 2004–2009 to undertake science projects in support of the environmental assessment and regulatory process in preparation for the Mackenzie Gas Project (1300-km natural gas pipeline) and associated exploration and development activities in the Northwest Territories and the Beaufort Sea.

The Climate Change and Initiative and Technology Transfer program administered by Natural Resources Canada funds research in frontier areas. The research programs and the research funding mechanisms listed in the following sections are representative of the types of work being done under these funding mechanisms with respect to northern oil and gas activity.

2.9.6.2.1. Ice structure interaction

There was considerable oil and gas exploration in the Beaufort Sea during the 1970s and 1980s and over eighty wells were drilled in the offshore region. During this exploration phase, there were a large number of uncertainties, especially with respect to the level of the ice loads on a large offshore structure. Industry spent considerable resources diligently measuring the loads and behavior of the ice as it interacted with the offshore structures. Although industry activity ceased in the Beaufort Sea in the early 1990s, the data collected have continued to be analyzed. The Canadian Hydraulics Centre of the National Research Council (CHC/NRC) in Ottawa has managed an ice-structure interaction program for the Program of Energy Research and Development and has made use of this data to increase understanding of several ice engineering issues.

The CHC/NRC has analyzed the ice loads on the four caisson structures that were used in the Canadian Beaufort Sea. They have provided details on the level of the ice loads for a wide range of ice conditions (first-year and multi-year ice) and different ice macrostructures (level ice sheets, ridges, large floes, hummock fields). They found that for all ice conditions, the global pressure on the caissons was a function of the failure process of the ice but was always less than 1.5 MN/m^2, even for multi-year ice floes that were 8 m thick (Timco and Johnston, 2003, 2004). This has important implications for designing a structure to withstand all anticipated ice loading situations. The CHC/NRC has also analyzed the instrumentation to gain insight into the local pressures on the structure (Sudom and Frederking, 2005). This information is essential for the design of local framing of a structure to withstand ice loads. Observations of Beaufort structures showed that large rubble fields often formed around them. These rubble fields, if grounded on the seafloor, protected the structure from advancing ice. The CHC/NRC is currently investigating the potential of using 'ice rubble generators' to generate and hold the rubble at the site (Barker and Timco, 2005). This would reduce ice loads considerably and lead to significant savings for a production structure in certain regions of the Beaufort Sea. Analysis of the behavior of ice as it interacts with an offshore structure has important implications with respect to the types of systems that could be used for emergency evacuation of personnel from a structure in ice-covered waters. The CHC/NRC have analyzed ice observations reports and videos and have provided guidance in this area (Timco and Dickins, 2005; Timco et al., 2006).

Although there has been significant progress in the knowledge of ice loads and ice interaction with offshore structures, there remain a number of key ice engineering issues. Research needs include better estimates of ice loads due to extreme multi-year ice features, cost-effective methods for generating and stabilizing ice rubble, vessel station-keeping in ice (e.g., tanker loading) and related ice management aspects, ice scour and its influence on the design of seafloor facilities, the engineering implications of climate change on Beaufort Sea ice conditions, improved oil spill countermeasures and clean-up methods in ice, and improved emergency evacuation methods for platforms operating in ice-covered waters.

2.9.6.2.2. Coastal and marine geo-environmental and engineering research

Based on the recent resurgence in oil and gas activity in the Canadian Arctic since 2001, an environmental assessment process and a regulatory process are underway for the proposed construction of the Mackenzie Valley Pipeline. With a prospective natural gas pipeline, the potential for offshore gathering lines to carry proven reserves onshore to the Mackenzie Delta could be a future development scenario. In addition, new exploration licenses have been awarded in the Canadian Beaufort Sea indicating that there is a need for research to ensure sustainable development.

Consultations with government regulators, the Inuvialuit, government departments, and the oil industry have resulted in an active seabed geo-environmental and engineering research program for the Canadian Beaufort Shelf, which has been underway since 2001. The research is focused on specific coastal and offshore constraints to anticipated hydrocarbon development scenarios over the next 20 years. This research is on the key geohazards of coastal and nearshore stability, extreme ice scour events, modeling ice-sea sediment-pipe interactions, sub-sea and coastal permafrost, marine clay performance under load, artificial island stability, and habitat sensitivity. This information will enable informed decisions as to whether this development should proceed, by ensuring that mitigating measures are in place, minimizing environmental disturbance. It will also provide information to allow decision-makers to address risk factors and to comply with the necessary safety considerations prior to development.

The project is structured so that the scientific information derived from the various project components will be able to influence decision-making processes in the Federal government and within industry, through project design considerations. The scientific results will be used to ensure that future hydrocarbon exploration and development in the Beaufort Sea, and potential sub-sea pipeline development in the nearshore or coastal environment, can adopt a sustainable development approach ensuring that mitigating measures are taken to minimize negative impacts on the environment. This information will allow mitigating measures to be taken in support of environmental protection and will enable an assessment of various factors and their implications for engineering design, location and routing for pipelines, design and safety of offshore drilling platforms, and will allow a precautionary approach to prevail prior to development.

The CCGS Nahidik is the essential platform for conducting coastal and Mackenzie Delta aquatic research. Work will include the deployment of multi-beam technology to capture the seabed in 3-D imagery, providing detailed data on ice scour, seabed granular materials, seabed disturbance, navigation hazards, and artificial islands. This information will be tied to the biological data to provide an ecosystem level assessment of impacts of coastal dredging and other coastal development activities. The data from this project will be critical for informing the environmental assessment and regulatory processes. It is also critical in the induced exploration phase and contributes not only to significant partnerships with other departments and organizations, but also to ongoing legal obligations under co-management in the Inuvialuit Settlement Region.

Areas of interest include: coastal stability, ice scouring/gouging, artificial islands, benthic ecosystem mapping, subsea permafrost, and geohazards.

Coastal stability

Erosion rates of 1 to 20 m/y are exacerbated by climate change, rising sea level, a subsiding Beaufort-Mackenzie Sedimentary Basin, and coastal permafrost degradation. Applications of new technologies including LIDAR, interferometric sonar coupled with satellite imagery, and traditional sampling programs are providing the baseline information required to determine the processes responsible for coastal instability. Integrated databases provide a more quantitative understanding of the coastal environment in terms of the impact on hydrocarbon infrastructure such as pipeline crossings. The information on coastal and nearshore instability, coastal processes, coastal permafrost, and coastal erosion rates will be critical for the engineering and design of any offshore pipeline coming onshore into the Mackenzie Delta. The information will enable appropriate design and technical considerations for sensitive coastlines and nearshore environments with permafrost and sub-sea permafrost, so that they are not altered or disturbed by activity resulting in irreversible negative environmental impacts.

Ice scouring/gouging

Sea-ice pressure ridge ice keels continuously scour/gouge the seabed in water depths ranging from 2 to 60 m. For example, 97% of the seabed is rescoured in less than 100 years in water depths less than 24 m (Figure 2.158).

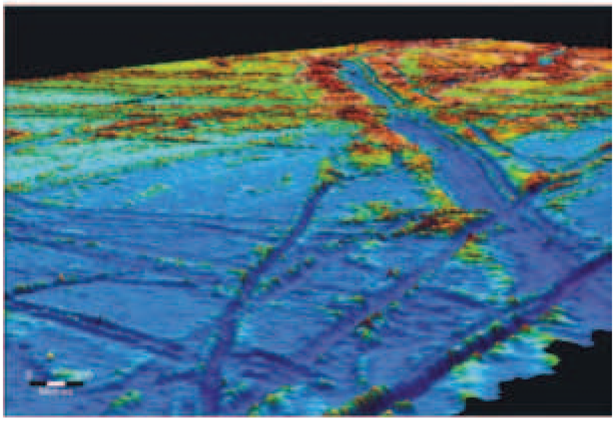


Figure 2.158. Simrad EM3000 3-D multi-beam image of the seabed of the Canadian Beaufort Shelf in water depths of 13 m. The seabed is saturated with cross-cutting ice scours ranging in age from one year to several hundred years. Ice scours caused by the drifting keels of sea-ice pressure ridges can incise the seabed to depths of 5 m. Continuous reworking of the seabed by ice keels has both engineering and environmental implications. Ice scour morphology impacts sub-sea pipeline trench depths, and the ongoing disturbance of the seabed adversely affects the benthic ecosystem (Steve Blasco, Geological Survey of Canada).

Extreme ice-scour events with observed scour depths of 2 to 5 m have been mapped across the central shelf. The return period of these extreme events is required to set regulations and guidelines for pipeline trench depths as well as for the glory hole depths for Blow Out Preventors installed on the exposed seabed. Repetitive mapping techniques using new multi-beam technologies and traditional sidescan sonar are being employed to conduct annual repetitive surveys of the seabed to identify new extreme ice scour events and to map the morphology of new extreme scours along axis. Information on extreme ice scour events and modeling of ice-sediment pipe interactions is important for identifying the depth and frequency of the extreme scours so that in pipeline design, routing and in the projections of pipeline trench depths, ice scour impact can be avoided and the route altered.

Artificial islands

During the first phase of Beaufort Sea hydrocarbon exploration in the 1970s and 1980s, 37 artificial islands were constructed as exploration drilling platforms in 2 to 44 m of water. Sand and gravel dredged from the seabed were piled up on the seafloor until the 'islands' were several meters above sea level. Since abandonment over 20 years ago, these islands have eroded below sea surface. These submerged islands are now being investigated as navigation hazards, potential future sources of granular resources, and as possible habitats for benthic ecosystems. The digitally mapped information on artificial islands will facilitate sustainable development decisions by industry, as to whether this aggregate material could be reused for future drilling platforms thereby eliminating the need for dredging the seabed for new granular material. This is particularly relevant as granular resources are limited and dredging of the seabed would be a disturbance to the benthic ecology. Government will use the information to identify whether or not these islands pose a navigational hazard to marine traffic.

Benthic ecosystem mapping

Under Canada's new Ocean's Act, ecologically and biologically sensitive areas of the Beaufort Shelf are to be identified and assessed. Benthic ecosystem mapping is focused on assessing the abundance and diversity of flora and fauna across the shelf. Research involves assessing key environmental factors controlling benthic ecosystem biodiversity. Environmental disturbance processes including seabed scouring by sea-ice pressure ridge keels and the turbidity generated by the Mackenzie River plume limit the biodiversity and primary productivity of the inner shelf seabed. Information on the benthic ecosystem sensitivity to hydrocarbon development enables offshore exploration companies to avoid sensitive habitats when planning their seismic activities and eventual drilling sites. The seabed habitat mapping information will enable sustainable development decisions to protect ecologically sensitive seabed habitat.

Subsea permafrost

Ice-bearing sediments exist to depths of 700 m below the central Beaufort Shelf. Sediments contain pore ice, vein ice, lenses, and massive ice. Heat generated by the production of hot hydrocarbons from depth over the lifetime of a field could lead to permafrost melting and differential thaw settlement of the seabed over time. Research on the extent and distribution of ice-bearing sediments is providing the knowledge base for both regulations and engineering design for production wells.

Geohazards

Knowledge of the regional occurrence and distribution of geohazards across the shelf provides the framework for identifying and mitigating potential exploration and production well problems. Geohazards on the Beaufort Shelf include high pressure shallow gas deposits, faults, and hydrates. Foundation conditions for gravity-based exploration and production structures are also of concern. Soft marine clays on the seabed offer reduced resistance to ice loading on structures. Submarine slumps, mud volcanoes, mud diapirs and pockmarks (gas vents) are seabed features indicating instability conditions to be avoided by exploration and production structures.

2.9.6.3. Greenland

As part of the 2006 licensing round, the Bureau of Minerals and Petroleum and the National Environmental Research Institute are cooperating on the development of a Strategic Environmental Impact Assessment for the areas offshore of the Disko-Nuussuaq region in West Greenland (see map in Figure 2.65). To support this assessment, a number of background studies have been initiated in collaboration with the Greenland Institute of Natural Resources and others. The studies are being conducted over the period 2005 to 2007. Further studies are expected to be initiated to strengthen the knowledge base for planning, mitigation, and regulation of oil activities in the assessment area. At the same time, the National Environmental Research Institute is developing a spatial database with relevant environmental data from these background studies as well as other sources. Data include the spatial and temporal distribution of key animal species and fishing areas. The data will be made available on DVDs in a Geographic Information System in ArcGIS format in support of the companies' environmental analyses. Ongoing projects include:

- Development of a hydrodynamic model and oil spill trajectories.
- Identification of productive zones and key areas for fish and shrimp larvae.
- A baseline study of oil concentrations and potential biological responses to an anticipated natural oil seep at the coast of Nuussuaq.
- A study of the ecology in the marginal ice-edge zone during spring. Large numbers of birds and marine mammals pass through the area during spring migration and the spring bloom is an important event in the Arctic, often determining the production capacity of Arctic marine food webs. The study will improve the identification of key areas and linkages with the lower levels in the food web including areas important for plankton, seabirds, and marine mammals.
- Thick-billed murre swimming migration and colony development at the only murre colony in the area, Ritenbenk. The murre chicks leave the colony before they can fly and embark on a long swimming migration to the winter quarters. The routes for this swimming migration have previously been unknown, but murres are now tracked by satellite transmitter during their swimming migration.
- Bowhead whale distribution. Based on satellite tracking data and aerial survey data, a detailed analysis will be conducted describing temporal and spatial distribution, the bowheads' behaviour in the area, and the importance of the area for the population.
- A study of walrus migration and population delineation. Based on satellite tracking, the habitat use of walrus wintering at the banks in the area is studied and the population delineation between Greenland and Canada supported by genetic analysis.
- An analysis of polar bears' habitat use and movements in Baffin Bay is being conducted based on satellite tracking.

The ongoing analysis will identify the areas where further studies are most needed to minimize potential impacts by careful planning and mitigation. A preliminary assessment of the need for further studies includes the following aspects.

1. A study of bottom fauna and its linkages to higher trophic levels at the west coast of Disko Island and the shallow areas at Store Hellefiskebanke and the adjacent coasts. Important concentrations of walrus, king eider, and common eider feed on this bottom fauna, and along the coast there are spawning grounds for lumpsucker and capelin. If oil from an oil spill settles in the intertidal zone or in shallow water, the impact can be substantial and it is also at the coasts that there is a risk of embedding of oil which slowly leaks causing a more chronic pollution situation, which can also affect higher trophic levels.
2. A study of thick-billed murres' autumn migration routes through southern Baffin Bay by satellite tracking. Millions of thick-billed murre migrate through southern Baffin Bay in autumn from the large, important colonies in northern Baffin Bay and adjacent waters. Migration routes and offshore key foraging areas during the autumn migration are still unknown. A large part of this migration is a swimming migration while the birds' molt their flight

feathers and the birds are extremely vulnerable to oil pollution in this season.

3. A ship-based study of the ecology of the marginal ice zone in the central southern Baffin Bay including the feeding ecology of thick-billed murres and little auks during the autumn migration. More than 100 million birds migrate through Baffin Bay in early autumn, presumably to a large extent feeding on the ice-associated fauna in the Labrador Current. An oil spill could be driven to this ice edge by the wind and could impact the ecosystem associated with the ice, as well as the large number of swimming birds. More knowledge of seabird distribution and ecological importance and linkages to ice-associated fauna is needed. A study has been proposed, including cooperation with Canada, on satellite tracking of thick-billed murres, aerial surveys and a biological oceanographic cruise using a research vessel.

2.9.6.4. Faroe Islands

Some of the more research-orientated projects regarding environmental vulnerability conducted in association with preparations for oil and gas exploration offshore of the Faroe Islands include:

- effects of seismic activity on the fisheries at the Faroe Islands (Jákupsstovu et al., 2001);
- fisheries in Faroese waters (Jákupsstovu et al., 1999);
- an experiment on how seismic shooting affects caged fish (Thomsen, 2002); and
- fishing data and seismic activity for the Faroe Islands (electronic GIS maps) (DNV, 2005).

In addition, several studies were aimed primarily at environmental protection and emergency planning in the case of oil spills:

- environmental risk assessments (Jødestøl, 2001);
- oil drift simulations at the Faroe Islands (GEM License 003) (Skognes, 2001);
- coastal protection plans for the Faroe Islands (Perry et al., 2001);
- oil spill sensitivity maps and coastal protection plans for the Faroe Islands (Cordah, 2001); and
- Faroe Islands coastal resources and prioritization maps (Dam and Danielsen, 2003).

2.9.6.5. Norway

In Norway, the development of new technology and increased expertise in the oil and gas industry is important to ensure that the sector will continue to contribute to economic growth and general welfare. Several of the solutions currently used by the oil and gas industry are the result of significant investments in research and technology development over the past three decades. In the years to come, however, value creation on the Norwegian continental shelf will be more technologically demanding and knowledge-intensive than is the case today. For this reason, continuing efforts in research and technology development are important to ensure a competitive Norwegian oil and gas industry.

In order to meet the challenges associated with efficient and prudent petroleum activities, OG21 – Oil and Gas in the 21st century – was established on the initiative of the Ministry of Petroleum and Energy in 2001. The objective was to unite the oil and gas industry in a common national technology strategy. OG21 is organized as a board, whose composition is determined by the Ministry of Petroleum and Energy, and a secretariat. The link to the petroleum industry is through the OG21 Forum, which is a meeting place where all parties with an interest in petroleum research can participate in the OG21 strategy process. OG21 has enabled oil companies, universities, research institutes, the supplier industry, and the authorities to join forces and support a common national technology strategy for oil and gas. In the International Energy Agency's evaluation of Norwegian energy policy in 2005, the OG21 collaboration was recognized as being unique in a global perspective.

The goals of OG21 are to increase the value creation on the Norwegian continental shelf and to increase the export of Norwegian technology. OG21's work on strategy has identified eight core areas for research and technology development:

1. Environmental technology for the future
2. Exploration and reservoir characterization
3. Enhanced recovery
4. Cost-effective drilling and intervention
5. Integrated operations and real-time reservoir management
6. Subsea processing and transport
7. Deep-water and subsea production technology
8. Gas technologies

An important objective for OG21 is to increase state funding of research and development in the petroleum-related area to NOK 600 million per year. OG21 believes that such a public research effort would be commensurate with the main technological challenges in the sector.

The authorities' contribution to petroleum research is largely organized in the PETROMAKS and the DEMO 2000 research programs. These programs are intended to contribute to attaining the goals set in the national technology strategy for the petroleum industry, OG21. The funds from the authorities are channeled through the Research Council of Norway, which coordinates the programs.

2.9.6.5.1. PETROMAKS

PETROMAKS is the umbrella for most of the petroleum-orientated research supported by the Research Council of Norway. PETROMAKS encompasses both long-term basic research and applied research, resulting in the development of expertise, technological development, and research as a basis for the formulation of policy. The program's target groups are Norwegian companies and groups that wish to promote the accumulation of knowledge and expertise in Norway, productivity, innovation and exports in the petroleum sector.

The objective of PETROMAKS is to contribute to better exploitation of fields in production and increased access to new reserves. The activities in the program are largely aimed at discovering more oil and gas reserves, improving recovery from existing fields, streamlining the transport of well streams over large distances, and efficient transport of gas to the markets. The program also seeks to prepare a basis for development in HSE and the external environment, reducing the cost level on the Norwegian continental shelf and strengthening petroleum-related industrial development in Norway. Current projects include the development of systems to clean produced water from oil platforms and technology to collect drilling fluids and cuttings from the seabed and pump them back to the platform.

The social science research program Petropol was incorporated into PETROMAKS in 2004. Establishment of a new social science program targeting the challenges faced by the authorities and the petroleum industry is also under consideration.

2.9.6.5.2. DEMO 2000

An important initiative for the promotion of new technological solutions within the petroleum industry is the DEMO 2000 partnership. This program targets projects where new technology can be demonstrated through pilot projects and field tests, and relates particularly to challenges associated with getting research-based innovations in the Norwegian petroleum sector out into the market. The pilot projects entail close cooperation with supplier firms, research institutions, and oil companies; a collaboration which, in itself, helps to develop a progressive, market-orientated expertise network.

In total, the State has contributed more than NOK 340 million to DEMO 2000 projects in the period 1999 to 2005. These efforts have triggered a total commitment, together with the industry, of NOK 1.5 billion.

DEMO 2000's main goals are to develop new fields on the Norwegian continental shelf through new and cost-effective technologies and new implementation models, and to develop new Norwegian industrial products for sale in a global marketplace.

The DEMO 2000 program has supported demonstration of new petroleum technology since 1999. Some of the technologies developed through the program are now available on a commercial basis, and have resulted in significant cost savings for the industry. DEMO 2000 aims to ensure that a greater number of new solutions can be put to commercial use within the coming years, both in Norway and abroad, including in technical disciplines such as seabed processing, gas compression on the seabed, efficient drilling, and integrated operations. Enormous value could be created by innovations within these areas.

2.9.6.5.3. PROOF

Budget funds from the Ministry of Petroleum and Energy are also allocated to important research and development activities relating to the environment. The research program PROOF examines the long-term effects of discharges to the sea from petroleum activities, and constitutes a part of the larger program, 'The Sea and the Coast' (2006–2015), which aims to encourage high-quality research to obtain a broad understanding of the marine environment that will form a basis for long-term management in relation to marine ecosystems and their resources.

2.9.6.5.4. CLIMIT

CLIMIT is a cooperative program between Gassnova and the Research Council of Norway, and concerns research, development and demonstration of technology associated with gas-fired power production with carbon capture and storage. This relates to knowledge and solutions for: CO_2 capture before, during, and after power production; compression of CO_2; transport of CO_2; and long-term storage of CO_2, disposal, or alternative uses.

The CLIMIT program encompasses all phases of development and commercialization of new solutions and administered approximately 145 million NOK for support activities in 2006.

2.9.6.5.5. Industry joint venture on nmVOC-reducing technology

Emission permits entail a requirement whereby oil must be stored and loaded using the best available technology (BAT). Technologies designed to meet this requirement will be implemented according to a specified timetable extending to the end of 2008. Operators of Norwegian continental shelf fields with buoy loading have established a joint venture to coordinate the phase-in of nmVOC-reducing technology and to fulfill the requirement in an expedient and cost-effective manner. The joint venture paves the way for the exchange of experience with regard to the operation of the facility.

The joint venture agreement was signed in 2002, and 26 companies take part in this collaboration which covers buoy loading of oil from *Varg*, *Glitne*, *Jotun*, *Balder*, *Gullfaks*, *Statfjord*, *Draugen*, *Njord*, *Åsgard*, and *Norne*. At the end of 2005, nmVOC-reducing technology had been installed on 13 buoy loaders, as well as on two ships transporting oil from *Heidrun*. The estimated nmVOC reduction in 2004 was 38 762 tonnes. The focus in the future will be on measures to achieve high operational regularity on existing facilities.

2.9.6.6. Russian Federation

No information was available on research activities in the Russian Federation.

2.10. Summary and conclusions

2.10.1. Arctic oil and gas activities are variable and change phase

Levels of oil and gas activity in the Arctic, representing different phases and types of operation, vary over time and across regions. These fluctuations in the type and levels of activity reflect discoveries of large resources, operational cycles, world events, changes in technology, the political climate, depletion of known Arctic reserves, and rising demand for energy. In some Arctic areas, activities have peaked and in others they are increasing or changing phase from exploration to development or from production decline to shut down.

In the North American and Russian Arctic regions, periods of exploration activity began in the 1940s and early 1950s, peaked in the 1970s and early 1980s, and now appear to be entering new phases and new areas (see Figures 2.2a to 2.3b). Most of the large producing areas and many of the smaller fields now being developed or prepared for development in the Arctic were discovered in the early phases of exploration in the 1940s to 1970s.

Oil and gas activities are cyclical and comprise the following phases: reconnaissance, licensing/leasing, exploration, delineation, development, production, and decommissioning. Licensing and leasing for exploration may occur many times in the same areas including those in which more advanced phases of development are already underway. For some areas, this cycle can start at different times depending on the size and availability of the resources, or the activities can happen essentially simultaneously under the influence of world events (such as the Second World War, the Oil Embargo of 1973, and the Iraq war). They may continue uninterrupted through all phases, although few producing Arctic fields have been completely depleted and decommissioned. They can stop at different phases: in the reconnaissance or exploration phase because no resource was found; in the exploration/delineation phase because the potential resource was too small, too remote, or too difficult to develop; in the production phase when the cost of producing an economically marginal field is too high (e.g., *Bent Horn*, Canadian Arctic Islands in 1997 and *Pointed Mountain*, Mackenzie Valley in 2001); and exploration may recommence in areas that were less attractive decades before. Exploration phases may peak in more than one decade, while explorers seek to define smaller, more remote, or more complex fields to develop.

When a field is discovered, depending on its economic viability, activity associated with delineating the field may or may not begin. If the activity does not take place soon, it often happens years later. This phase also includes wells that are drilled from mobile drilling units and seismic crews acquiring data in the field. However, this phase of activity is more geographically focused and typically involves more wells, well testing, and more seismic surveys, including denser 3-D seismic grids. Fields discovered and delineated may or may not enter the next phase of activity.

The recurring exploration phases as well as later-generation development and production phases of activity are accompanied by, and are in part as a result of, deployment of increasingly new technology and techniques learned from and replacing primitive earlier methods.

Exploration begins with geological field party reconnaissance expeditions and geophysical surveys onshore, and seismic reconnaissance in offshore areas in early phases (early 1900s, 1940s to early 1950s in the Russian, American, and Canadian Arctic, again in the 1960s to 1970s along with marine exploration activities), accompanied by exploratory wells (1940 to 1950s, 1970s to mid-1980s in the Russian, American, and Canadian Arctic and the 1970s to 1980s in marine areas). If minor discoveries are made, the area may be abandoned (U.S. Bering Sea, 1985) or may only produce oil or gas for local use (Ikhil, Canada 1960; Barrow, Alaska 1967), but may experience peaks of exploration activities decades later. If a major discovery is made in the early exploration efforts, intense seismic and exploratory drilling activities follow both in onshore and offshore prospective areas (Vozeiskoe, Usinskoe, Yaregskoe, Urengoi, 1965 Western Siberia; Yamberg, 1967 Western Siberia; Prudhoe Bay 1969, United States; Aasgaard 1981, Norwegian Sea; Snøhvit 1982, Stockmann 1988, and Prirazlomnoe 1989, Barents Sea). After discoveries are made and delineated, they are evaluated for economic viability. This critical step looks at the oil in place, against the oil and gas pool size, depth, reservoir quality, oil-to-gas ratio, oil weight, distance to infrastructure, transportation costs, environmental assessment, social and political issues, and the price of oil and gas. Discoveries that are large enough, or relatively easy to produce, are developed first (Urengoi, 1977; Prudhoe Bay, 1977; Snøvhit, 2007) and the smaller or otherwise difficult-to-produce discovered fields are left undeveloped (Pt. Thompson, United States 1977; Mackenzie Delta and Valley, East Siberia, Arctic Shelves) or are developed many years or decades after their discovery (Northstar, U.S. Beaufort Sea), when small or more difficult-to-develop fields are sought to replace production from older fields where production is declining.

2.10.2. The Arctic is a challenging operational environment

The Arctic presents harsh and complex working conditions that combine remoteness, average yearly temperatures of below 0 °C, wintertime darkness, fragile ecosystems, changing climate, and impacts on local indigenous human populations. The combination of these conditions makes the Arctic very different from other regions and requires different approaches to oil and gas exploration and development.

Increased awareness of, and protection against, potential effects on the environment and people living and working in the Arctic remain important considerations in whether deposits are developed. The Arctic surface environment is one of the most easily impacted on Earth. With marine and coastal areas forming some highly critical habitats, oil and gas activities in the Arctic must conform to highly rigorous environmental standards that have been developed, in addition to other operational challenges.

2.10.3. Economic factors are important determinants for Arctic oil and gas projects and operations

The difficulties of operating in the Arctic generally combine to make it the most expensive operational theatre in the world. Although many estimates exist, they all indicate that large volumes of discovered reserves and undiscovered resources (Table 2.89) lie within the Arctic (see Figure 2.17 and 2.19). Ultimately, the price of oil will control the degree of Arctic activity except in places where the high operating cost or social cost shapes events. The establishment and activity level of national petroleum companies may also have an effect on oil and gas activities beyond simple price considerations.

Financial controls on operating strategies affect companies that compete for financing from international institutions such as the World Bank and in large equity markets. Increasingly, Arctic operations are conducted either by publicly traded international companies and/or are financed at least in part by international financial organizations. Operators must conform to a number of common standards in order to fully participate in the worldwide petroleum market; these include common reporting requirements for reserves, petroleum quantity and quality measurement, safety procedures, and environmental protection. Operational requirements related to financial considerations have stimulated the application of common operating standards for Arctic projects.

2.10.4. Petroleum activities have taken place in the Arctic for over one hundred years

Oil seeps were discovered thousands of years ago by Arctic indigenous people whose oral traditions from across the Arctic contain references to a variety of uses for tar and other forms of residual crude oil found at surface seeps. The earliest rudimentary oil refinery was constructed in the Russian Arctic in the mid-1700s. Surface seeps have

Table 2.89. Estimates of reserves, undiscovered resources, and initial total resources in the Arctic.

	Alaska, USA	Canada	Norway	Russia	Total
Oil in Place (discovered/proven-probable) – million m^3	6385 (40157 million bbl) (80 billion bbl USGS, 2006)	265 (1664 million bbl)	1619 (10186 million bbl)	25911 (162976 million bbl)	34180 (214983 million bbl)
Oil Cumulative Production – million m^3	2278 (14330 million bbl)	36.5 (230 million bbl)	336 (2116 million bbl)	10786 (67839 million bbl)	13437 (84515 million bbl)
Remaining Reserves (discovered/proven-probable) – million m^3	4106 (25827 million bbl)	228 (1434 million bbl)	1283 (8070 million bbl)	15126 (95136 million bbl)	20743 (130468 million bbl)
Gas in Place (discovered/proven-probable) – billion m^3	1376 (3332 USGS, 2006)	1000	1554	51647	55577
Gas Cumulative Production – billion m^3	0	19.6	46.0	12177	12242
Remaining Reserves (discovered/proven-probable) – million m^3	1376	980	1508	39470	43335

attracted the attention of oil and gas explorers to the Arctic since the beginning of the industrial age. Many of the areas most prospective for hydrocarbons in the onshore Arctic had been recognized by the late 1800s.

The first generation of sustained Arctic production occurred in Russia in the first half of the 1900s and has continued there in a robust and systematic manner to the present. Russia is one of the world's major hydrocarbon-producing and exporting countries. While many different assessments have been made and many different values are published, using estimates from production values reported here, Arctic Russian fields have produced 10.7 m^3 or 67.8 billion bbl (51.2% of total Russian oil production) and 12.2 trillion m^3 of natural gas (78.8% of total Russian gas production). Over 80% of all Arctic oil and over 99% of all Arctic gas have been produced from Arctic Russia. Russia has over 75% of known Arctic oil and over 90% of known Arctic gas reserves. In addition, Arctic Russia, including its Arctic shelves, is estimated to have vast undiscovered conventional recoverable oil and gas resources. Russia will continue to be the dominant Arctic producer of oil and gas. To transport this resource, Russia has 150 000 km of gas and 50 000 km of oil product lines and a significant number of kilometers of oil and gas collection and gas distribution lines. Current projections indicate that in the near future greatly increased volumes of oil and gas will be transported by tankers from the Russian Arctic, from 93 million m^3/y by 2010 and up to 175 million m^3/y (1.1 billion bbl/y) in the next ten years (Bambulyak and Frantzen, 2007).

Exploratory efforts and economic realities in other parts of the Arctic were initially less conducive to establishing long-term production than in Russia. Sustained commercial production did not occur elsewhere in the Arctic until 1942, when a pipeline was constructed to the 1920 Norman Wells discovery in Canada during the Second World War. Exploratory drilling activity in the Canadian Arctic has proceeded cyclically, driven by world oil prices in conjunction with intermittent government-sponsored incentives. Many of these exploratory wells were successful; however, development projects have generally not been forthcoming. The Canadian Arctic's oil production is still limited to the *Norman Wells* field at 4770 m^3/d (30 000 bbl/d); Arctic gas production has been restricted to several fields for local markets. A major gas pipeline to the Mackenzie Delta in the Western Canadian Arctic is currently under consideration and may enable gas production in the range of 56 000 to 84 000 m^3/d (2 to 3 billion cu. ft/d) from the area within the next ten years.

The U.S. government undertook a large-scale exploratory effort in the western part of Arctic Alaska during the Second World War in an effort to mitigate potential war-related petroleum shortages. Cooperation with the Canadian government in building the Norman Wells pipeline was part of this effort. Importantly, these were the first attempts at heavy industrial oil and gas exploratory activity on terrain underlain by continuous permafrost in the U.S. and a need to develop specialized techniques to operate in this environment was recognized. A program to study engineering techniques appropriate to the Arctic, the precursor to what is now the Barrow Permafrost Observatory, was established at this time. These war-time exploratory efforts also established the prospective nature of Arctic Alaska. Commercial production from the U.S. Arctic did not occur until the 1977 start-up of the 1300-km (800-mile) Trans-Alaska Pipeline connecting the 1969 Prudhoe Bay discovery to the southern Alaska port at Valdez. Between the start of leasing and 2006, over 140 000 km^2 of lands were leased (Table 2.8). Exploration has proceeded throughout the Alaskan Arctic with the discovery of significant resources; however, as in the case of Canada, a lack of processing and transportation infrastructure has prevented development in areas inaccessible to existing transportation and processing infrastructure.

Development operations and production from the areas adjacent to Prudhoe Bay continue, but only 3% of the total land leased is unitized for oil production (ADNR, 2006b) and the vast majority of leases have been relinquished to the government. Produced volumes of oil from the Prudhoe Bay region are in decline, averaging 143 100 m^3/d (900 000 bbl/d). A gas pipeline capable of transporting 112 000 to 140 000 m^3/d (4 to 5 billion cu. ft/d) from the *Prudhoe Bay* field is currently in the planning stage.

One field has been approved for development in the Norwegian part of the Barents Sea: the *Snøhvit* gas/condensate field. The field includes several nearby discoveries that will be developed entirely through sub-sea installations. Gas and condensate will be transported in a pipeline to Melkøya, near Hammerfest, where the gas will be processed to LNG (liquefied natural gas) and shipped to market on LNG tankers. Arctic Norwegian operations will be entirely offshore and are a result of extensive experience gained by the Norwegian operating community from offshore operations in the North Sea and the Norwegian Sea. Norwegian Arctic exploratory activities including leasing, seismic acquisition, and drilling continue. Additional development projects are under consideration. The Norwegian Arctic will continue to be a major locus of petroleum activity and, according to Russian near-term future projections, a heavily travelled petroleum tanker route.

Greenland and the Faroe Islands are offering offshore exploration concessions and exploratory activities are ongoing. Drilling has indicated prospective areas in each of these territories. While neither of these areas has ever been a major center for petroleum exploratory activity, significant efforts have been undertaken and early drilling results have been favorable in many respects. A major discovery capable of transforming each of these areas remains a possibility.

Even though commercial oil and gas exploration in the Arctic has been carried out for over a hundred years in some areas of North America and Russia, production has not proceeded from most of these past efforts – only on Alaska's North Slope, in the Beaufort Sea, Canada, in Norway, and in areas of Russia's north have oil deposits been commercially produced. Current production is likely soon to be joined by gas production in the offshore areas of the Russian and Norwegian Barents Sea and in the Mackenzie Delta and Northwest Territories areas of Canada. In the less-explored areas of the Arctic, a significant proportion of the world's remaining undiscovered producible hydrocarbon resources remain to be found (Table 2.89, 2005; EIA, 2003). Regardless of sizable discovered reserves and very large potential undiscovered resources, additional Arctic development will proceed only when the costs of production, including environmental, cultural and economic costs, are viable.

2.10.5. Legal and regulatory control

Regulatory and economic factors unique to each sovereign country have had significant influences on the range of techniques employed in oil and gas activities and the subsequent associated impacts. Five of the eight Arctic countries have had significant oil and gas activities and have associated active regulatory regimes: Canada, Russia, Norway, Denmark (Greenland and Faroe Islands), and the United States. Denmark has a mature national regime, but Greenland and the Faroe Islands have young systems that have not yet encountered activities that follow discoveries. Canada, the United States, and Norway have older, more mature systems of legislation and regulatory control. Since 1991, Russia has been building a modern legislative base and regulatory regime for the oil and gas sector.

The impacts associated with oil and gas exploration, production, transportation, and refining are controlled in large part by the regulatory framework of a country, through which environmental and social impacts are weighed against the economic and security benefits of producing oil and gas. The balance of values enforced by each government is constantly being revised and is partially responsible for a reduction over time in the amount of impacts associated with petroleum industry activity. Key among the political influences driving modern industry regulatory control is the increasing voice of indigenous peoples.

Russia is the country with the largest amount of Arctic territory and is also the country with both the greatest scale of oil and gas operations and the longest history of activities. Soviet Arctic oil and gas operations were conducted by the government in a centrally controlled economy. Since 1992, Russia has been developing a system for allowing private development of oil and gas production governed by a market economy. This has been accompanied by the development of a modern legal and regulatory regime for oil and gas activities.

2.10.6. Technological adaptation

An important aspect of oil and gas development in the Arctic has been the adaptation of the industry to operating in the easily impacted environment. The process of operating efficiently from both an environmental and an economic perspective in the Arctic is an ongoing process with a long history. The impacts associated with an activity are, therefore, to a not inconsequential degree, a function of when the activity occurred.

In many of the basins with known resource potential, most of the initial prospecting and resource delineation were conducted using operational methods that have unacceptable levels of environmental impact under modern standards. In the 1940s, U.S. exploration activities in northern Alaska were initially conducted using techniques not adapted to the Arctic such as blading of tundra down to the permafrost for road and drill pad construction, using tracked vehicles for summer overland transport and seismic operations on tundra, dumping of drilling and camp waste, abandonment of equipment and material, gravel mining in non-renewable areas, and siting of wells in unstable coastal and stream areas. These techniques and practices were found to be economically, logistically, and environmentally unacceptable, resulting in tundra scars, melt ponds, open gravel borrow pits, contaminated dumps, abandoned equipment, chemicals, and barrels, and erosion. Drill sites were bladed off and tended to be up to 0.16 to 0.20 km^2 (40 or 50 acres) per well. These or similar methods were also practiced in early exploration efforts in northern areas of Canada and Russia.

Early development activities in Russia in the 1940s through 1960s employed techniques and technology that impacted large areas for production wells, roads, pipelines, processing and refining, often resulting in the establishment of new towns such as Novy Urengoi in 1974. Summer tundra travel was still practiced in some areas until the 1970s.

The *Prudhoe Bay* field in Alaska, which began production in 1977, has gravel covering over 19 km^2 of tundra for 322 km of roads, 38 pads, and two airstrips that was extracted from six gravel mines affecting almost 3 m^2 of land, and it has almost 350 km of in-field pipelines (Table 2.13). In contrast, a recent oil field in Arctic Alaska, the *Alpine* field, has gravel covering only 0.39 km^2 of tundra for 5 km of roads, two pads, and one airstrip and 55 km of pipelines – it has no reserve pits or gravel mines. Although much smaller in oil pool size, *Alpine* still illustrates the effect of new technology on the physical footprint of modern operations.

Technological changes reflecting the use of specialized equipment and procedures and the use of improved fabrication techniques as well as a growing understanding of Arctic sensitivities have influenced the management of impacts associated with the Arctic petroleum industry. Very few modern Arctic oil and gas operations are conducted as was done twenty years ago; furthermore, many large, capital-intensive developments such as the *Snøhvit* field were not possible twenty years ago. In addition to adopting project designs capable of minimizing environmental impacts, large-scale environmental remediation projects in existing fields, such as the disposal of millions of cubic meters of solid waste from the onshore Alaskan oil fields, are being undertaken in response to technological advances.

Arctic projects have expensive operations requirements and compete with other, lower-cost operating environments for investment. Technological enhancements enabling continued reduction of the environmental impacts associated with oil and gas activities are ongoing and generate efficiencies in design that result in operating cost reductions. Such advances as winter seismic and 3-D seismic acquisition allow more efficient exploration operations. For production, advances include improved recovery efficiencies from enhanced recovery techniques, drilling of multilateral wells, re-injection of produced water, reduced surface footprint for facilities, and exploratory drilling from ice pads. In addition, winter operations using ice roads and ice pads have reduced the impacts on tundra and wetlands.

Long-term containment and mitigation of environmental impacts associated with these operations has increasingly become an accepted and necessary part of Arctic development. The increase in large multinational companies' exploration and production activities in these regions has contributed to modernized operating procedures that reflect affirmative acceptance of responsibility for environmental protection. Future operations in these areas will be more focused and efficient, and result in lower impact.

2.10.7. The future of Arctic oil and gas activities

As producing Arctic fields are depleted, other known reserves will be brought on-line, and the search to prove undiscovered resources will continue. Old and mature fields in the Timan-Pechora and Western Siberia regions of Arctic Russia and the Prudhoe Bay-Kuparuk fields in Alaska are declining in production, and satellite fields in nearby areas are being developed; for example, the *Fedorovskoe, Samotlorskoe,* and *Mamontovskoe* fields in Western Siberia and new oil fields – *Yuzhno-Kyrtaelski, Lekkerski, Kyrtaelski,* and *Verkhne-Vozeiski* have real potential. Activities are likely to occur in new frontier or poorly explored areas of interest including the NPRA in northwest Alaska, northern Timan-Pechora, and areas in Eastern Siberia and the Russian Far East. The Taymir Autonomous Okrug and transpolar regions of the Republic of Sakha-Yakutia remain little explored and it is believed that they contain the largest hydrocarbon reserves in Russia.

Offshore Arctic development has started at Alaska's *Northstar* oil field in the Beaufort Sea (1999), and will be joined very soon by the Norwegian *Snøhvit* field and soon by the Russian *Stockmann* gas field and the *Prirazlomnoe* oil field in the Barents Sea. New reserves will be actively sought, with leasing and exploration programs planned for all oil- and gas-endowed Arctic nations. Russia has a 2006–2020 exploration and development program that includes exploration activities in the Kara and Barents Seas, the State of Alaska has annual plans for leasing of offshore and onshore Arctic lands, and the United States has leasing programs offshore in the Beaufort and Chukchi Seas and possibly the North Aleutian basin for 2007–2012.

In Russia, oil and gas tenders and exploration licenses are planned in several onshore areas including East Siberia, northwest Russia, and Timan-Pechora, and in offshore areas in the Barents, Pechora, Kara, Laptev, East-Siberian, and Chukchi Seas.

In Alaska, leasing is planned throughout the onshore North Slope except for a large protected area (ANWR) adjacent to the Canadian border, and in the Beaufort and Chukchi Seas and Bristol Bay regions offshore. In Canada, areas will be made available for oil and gas concessions in the Mackenzie Delta area onshore and offshore. In Norway, licensing rounds are scheduled for the Norwegian and Barents Seas.

According to the Russian Federal Program Subsoil Use 2006–2020, 85 000 km of 2-D seismic data are likely to be acquired in Russian Arctic seas by 2010, and an additional 278 000 km of seismic data are anticipated to be acquired by 2020. Thirteen orientation wells with a total length of 41 300 line-meters are expected to be drilled on the Russian Arctic shelf. In the period 2011–2020, licensing and exploration for resources in the Barents Sea will concentrate on the central part of the South Barents depression, the northern zone of the Timan-Pechora platform and the South-East Prinovozemelie area, and in regions of the Kara Sea in the western part of the South Kara depression including the systems of the Sharapov, Obruchev, and East Novaya Zemlya highs. In the Laptev Sea, the southern part including the South Laptev depression and adjacent water area is the most promising for mineral resources management.

Plans are in place for near-term (<10 years) and mid-term (10–15 years) future development and further exploration for oil and gas in the Arctic. In Russia, oil and gas production activities will increase in the Timan-Pechora, West Siberia, and East Siberia provinces and in the Barents Sea. This development is likely to include the planned construction of major oil pipelines from the West Siberian Basin and Timan-Pechora to a western Arctic port, a Far East pipeline for Arctic oil transport to the Pacific Rim, and several new marine terminals. In Alaska, oil production will continue on the North Slope State lands and will probably include natural gas production. Production of oil and gas will probably start in federally owned lands in the western North Slope and in new fields in the Beaufort Sea. A major pipeline may be constructed to transport gas to the mainland United States. In Canada, oil and gas production is likely to occur in onshore and offshore areas including the Mackenzie Delta and may include the construction of the major Mackenzie Valley gas pipeline. Norway is planning continued exploration and development activities in the Norwegian and Barents Seas. Greenland and the Faroe Islands continue to issue exploration seismic permits and have plans in place for licensing rounds and subsequent exploration drilling programs.

In the mid-term and far-term (15–25 years), exploration is likely to continue and extend into new offshore Arctic areas, and new onshore exploration activities are likely to take place in Canada, Greenland, East Siberia, and Far East Russia. Development as a result of these activities is, however, unlikely to occur within the mid- to far-term due to the typically long lead-time between exploration and development.

On the horizon (>25 years), it is possible that unconventional resources may be developed in Arctic areas. These deposits include viscous or 'heavy' oil, coal-bed methane, and potentially vast methane hydrate deposits both onshore and offshore. High viscosity oil occurrences in Alaska include as much as 5.7 billion m^3 (36 billion bbl) of original-oil-in-place within the Ugnu, West Sak, and Schrader Bluff formations on the North Slope of Alaska. In Alaska, hydrates are thought to make up a total of 4733 trillion m^3 (Collett and Kuuskraa, 1998). A potentially large natural gas resource has been estimated to occur in Mackenzie Delta hydrates, with a minimum in-place volume of 240 billion m^3 as estimated by Majorowicz and Osadetz (2001). Estimates of volumes of gas hydrate stability zones for the entire Russian Arctic are at 318 trillion m^3.

2.10.8. Transportation by pipelines and tankers is likely to increase

Existing transportation infrastructure for oil and gas in the Arctic includes pipelines, tankers, vehicles, and railcars. In the United States, oil is transported from the North Slope of Alaska by the 1300-km Trans-Alaska Pipeline (see Figure 2.41) to southern Alaska and transferred to tankers for export. In Canada, oil from the *Norman Wells* field is transported by pipeline 900 km south to Alberta and then on to southern markets. In Arctic offshore Norway, oil is transported to shore by tankers and gas is transported by sub-sea pipelines to the mainland (Figure 2.71). In Russia, transportation of oil and gas is accomplished by a combination of pipelines, coastal barges, shuttle tankers, large tankers, supertankers, railcars, and trucks which carry oil and gas to refineries and users. Over 50% of oil is transported by pipelines and a significant amount is transported by rail (41.4%), with lesser amounts transported on inland waterways (1.6%), by marine tankers (1%), and by motorway (0.8%) (Bambulyak and Frantzen, 2007). Russia's pipeline system comprises approximately 150 000 km of gas and 50 000 km of oil product lines and a significant number of kilometers of oil and gas collection and gas distribution lines (Figure 2.103). There has been an increase in the volume of oil transported by tankers along the Norwegian coast from Russia (Figures 2.104 and 2.159). In 2002, the volume was 4.66 million m^3, while in 2006 it was over 12 million m^3. By 2015, Russia may have the capacity to ship more than 175 million m^3 of oil (Bambulyak and Frantzen, 2005).

Several major pipeline projects are planned in the near- to mid-term in the Arctic. If Canada approves the 1200-km Mackenzie Valley gas pipeline, this will allow the first production from gas fields of the Mackenzie Delta, Central Mackenzie, and Beaufort Sea and it will connect to existing pipeline systems in southern Canada. The Alaska natural gas pipeline is likely to be built connecting the Alaska North Slope with pipeline transport to Canada and the United States mainland, allowing gas to be commercially produced for the first time in northern Alaska. Depending on the final route, this pipeline could be 2600 to 3400 km long. In Russia, many new pipelines are being built to augment an aging system. Two major projects being planned are the Angarsk-Nakhodka oil pipeline from the West Siberian and possibly East Siberian oil fields over 4000 km to the Pacific coast of Russia for regional export. The other major project is an oil pipeline from the fields in Timan-Pechora and West Siberia thousands of kilometers to an Arctic port, either Indiga or Murmansk, where oil will be shipped by tanker to Europe and the United States. There are new projects underway to expand port capacities or to construct new ports for loading of tankers in the Russian north.

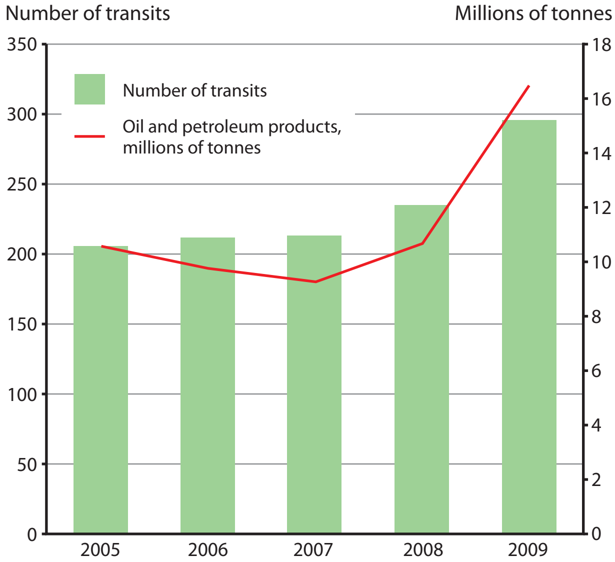


Figure 2.159. Number of fully-laden oil tankers transiting along the Norwegian coast from northwestern Russia, and associated amount of oil and petroleum products carried (millions of tonnes) (IMR, 2010).

In areas of new discoveries where infrastructure does not exist, such as the Chukchi Sea or East Siberia, new transportation infrastructure will need to be built.

2.10.9. Oil spill prevention and preparedness

In alignment with the generally difficult overall operational environment, responding to Arctic oil spills is also more difficult. The Arctic remoteness and extreme environments such as permafrost and sub-sea ice gouging require engineering practices not used in other regions. Engineering solutions developed over many years and new technologies developed recently have decreased the risk of spills from operational activities. However, pipelines are getting old and many in Russia were reportedly being undermined by erosion almost ten years ago (Zlotnikova et al., 1999). Tankering of oil is also projected to increase significantly, which increases the risk of oil spills at sea.

2.10.9.1. Pipelines

Many transport and inter-field pipelines servicing production areas in North America and Russia are at or near their general design lifetimes. In Alaska, many inter-field pipelines at the *Kuparuk* and *Prudhoe Bay* fields are nearly 30 years old and even some low-pressure oil transit pipelines, thought to be least susceptible to corrosion, have recently failed due to severe corrosion.

In Russia, pipelines carry about 55% of oil and gas (Bambulyak and Frantzen, 2007), but there are no major trunk oil pipelines in the Russian Arctic. In 1999, a government review showed that 30% of gas pipelines and 46% of oil pipelines had been in operation for more than 30 years, and 5% of gas, 25% of oil, and 34% of petroleum product pipelines had been constructed more than 40 years ago (Zlotnikova et al., 1999). It was the same situation for about a third of pumping units and compressor stations (Zlotnikova et al., 1999; Gozgortechnadzor, 2003). However, rates of accidents between 1991 and 2000 decreased by more than half compared to the period 1985 to 1990 (see also section 2.4.7.7) owing to the upgrading of systems, better materials, new pipelines replacing old, higher standards of design and construction, and better monitoring.

Oil spills from Russian and U.S. Arctic pipelines are likely to increase with the age of the pipes. Monitoring and repair or replacement of substandard segments will need to be undertaken more frequently as they age. These pipelines need modern, systematic, and comprehensive monitoring programs. Rigorous inspections using frequencies and technology commensurate with the age or condition of the pipe are required. Preventative measures must be instituted such as engineering design specifically suited to Arctic conditions, application of anticorrosive coating, and use of corrosion inhibitors (Gozgortechnadzor, 2003). Employment of the best technology and practices for flaw detection and diagnostics allows defective or corroded pipeline segments to be replaced before an accident happens. Detection of oil or gas leaks is vital in reducing the likelihood of environmental damage or health and safety situations. It is important that operators implement up-to-date systems for the detection of small-volume leaks.

2.10.9.2. Drilling operations

Blowouts are not common, but represent a possible source of an oil spill. They occur when drilling programs do not anticipate high pressure shallow gas or if operations are conducted in a risky or careless manner. A shallow gas kick is a danger both in the shallow part of the well before a blowout preventer can be installed when the 'open' bore hole is not yet cased and also during operations deeper in the well when gas or fluid pressure exceeds the weight of the mud column. In the first case, oil is almost never spilled and only gas escapes, possibly creating toxic and hazardous conditions. In the second case, involving blowouts during deeper well drilling, oil is often ejected along with gas and water. Prevention measures for these emergency conditions are accounted for in standard operating practices and regulations, such as the use of blowout preventers, well casing design, mud program, and training, but emergency conditions still occur when procedures are not followed, work or maintenance is careless, training is inadequate, designs are flawed, or downhole geological conditions are not anticipated correctly.

Statistics from the entire U.S. Outer Continental Shelf (OCS) indicate a rate of about 4.1 blowouts per 1000 wells drilled for the period 1971 to 1998. From 1998 to 2003 the rates were above 6 then fell back to about 4.5 per 1000 wells until 2005 and continued to just 1 in 1000 wells in 2006. In 2007 the rate was 7 blowouts per 1000 wells (MMS, 2007b). There have been no blowouts in the Alaskan OCS. Russian onshore production areas have a reported average rate of one blowout for every 1000 wells drilled annually (Zlotnikova et al., 1999). Typically gas blowouts cease due to collapse or clogging of the hole and last less than a day. In the case of offshore wells, U.S. OCS statistics show that 60% of gas well blowouts cease within one day or less and only 10% lasted more than a week. For offshore catastrophic oil blowouts, in-situ burning may be the only effective technique for spill control.

2.10.9.3. Tanker transport

Tanker transport of oil along the Norwegian coast is projected to increase due to new production from Arctic Russian fields and offshore fields in the Barents Sea. The Russian Regional Plan of Oil Spill Response in the West Arctic, approved in 2003 and covering the region of the Barents Sea, has a number of disadvantages (Jouravel et al., 2005):

- incompleteness of accounting for possible oil spill sources;
- insufficient resources, for example, to respond to oil spills from the up to 100 000-tonne deadweight tankers which enter Kola Bay;
- remoteness of accident response resources from the locations of possible spills (approach time is up to two days);
- absence of modern accidental oil spill detection, monitoring, and behavior forecast devices;
- absence of floating craft and equipment for work in ice conditions;
- impossibility to work in shallow coastal water with the resources available; and
- significant, if not complete, lack of resources to protect and clean up shorelines.

The causes of such disadvantages are:

- the traditional inclination to use government resources (the only operator of the Plan is the Murmansk Basin Emergency Administration);
- the extreme complexity of developing and agreeing on the Plan (the development and concurrence of the final version of the Plan by Russia's State Sea Rescue Service took almost two years); and
- the absence of organizational and economic and, to a certain extent, regulatory mechanisms of multi-level coordination of the accident response system with involvement of all interested parties.

A significant modernization of the response system for possible accidental oil spills in the Barents Sea will require the following actions (Bambulyak and Frantzen, 2005):

- conducting an inventory and regular update of the list of potential accidental pollution sources, with a periodic risk assessment;
- updating the legal framework for planning and controlling oil spill response operations in the Arctic;
- taking acceptable measures to regulate marine oil transportation in this region;
- improvement of the Regional Plan for the west sector of the Arctic taking into account the priorities of marine environmental protection from pollution; and
- development and implementation of methods of effective mutually advantageous interaction between the State rescue teams and rescue teams of private companies.

Owing to the export orientation of the oil transport system, the problems mentioned above have a transboundary context both in terms of potential threats to the ecological well-being of the region and in terms of joint efforts aimed at preventing and mitigating the threats. For this purpose, bilateral and multilateral cooperation can be used (for example, within the framework of the Russian-Norwegian Intergovernmental Agreement, conventions on a transboundary context, large industrial accidents and assessments of environmental impacts, etc.).

2.10.10. Technological advances will mitigate environmental impacts

An understanding of the level of environmental impacts associated with activity indices is not possible simply from assessing the frequency or scope of an operation, such as meters of wells drilled or line-kilometers of seismic data acquired. Technological advances driven by cost considerations and compliance with evolving regulatory constraints are continually modifying field operations and mitigating associated impacts. Legal constraints driven by objective impact assessments and research, combined with perceived public attitudes, have consistently imposed increasingly rigorous operational constraints on oil and gas operators across the Arctic during the past 100 years. Technological advances that allow more cost-effective means of regulatory compliance dominate the marketplace and are fungible across regulatory boundaries. As cost-effective technological solutions emerge and are shown through experience to be effective, these techniques are frequently employed in areas with less rigorous compliance standards because of cost advantage. A contemporary element of an operator's cost structure that is of increasing importance is the cost of long-term containment or mitigation of environmental impacts and the necessity to reduce cumulative impacts. Limiting or removing long-term liabilities, particularly those requiring continuous monitoring, can in many cases drive acceptance of operational techniques not considered necessary in the recent past. In conjunction with these changes, large multinational companies have increasingly dominated the petroleum industry in recent years. These companies tend to operate in a consistent manner across national boundaries and their operating procedures are driven by the strictest regulatory regimes. International financial institutions are important participants in most large-scale projects. Lending procedures adopted by most of the important sources for project financing include adherence to some of the most rigorous environmental and safety standards and practices, serving as an important impetus for change.

Appendix 2.1. Legal and Regulatory Systems of the Arctic countries

A.1. Introduction

All Arctic countries with oil and gas activities have a legislative and regulatory base within which these activities are allowed. There are many similarities among these regimes – they allow for access to the resource, they regulate the activities associated with exploration, development, production, transportation, and decommissioning, and they protect national interests including security, financial, environmental, social, and cultural interests. All of these legislative and regulatory regimes have undergone some degree of change over time and are still evolving. There are, however, some differences in approach to these issues from country to country, such as in the division of responsibility between the operator and the regulator.

There are two main approaches for the regulation of industrial or other activities: a ‘prescriptive’ approach, and a ‘performance-based’ or ‘goal-setting’ approach. In an extremely prescriptive regime, all aspects of control are spelled out in detail and those conducting the regulated activity must ‘follow the rules’. In this system, the regulator assumes the responsibility for safe and environmentally sound operations by writing and enforcing detailed regulations and standards covering all aspects of the operation with the expectation that, if the operator follows the rules, the operation will be safe. In a performance-based or goal-setting system, the regulator sets out goals and it is up to the company, with oversight from the regulator, to achieve those goals with the best available or appropriate technology or techniques. In this system, the operator assumes a majority of the responsibility for safety and environmental protection by developing a plan to satisfy the goals set by the regulator or by law. No country has a purely prescriptive or a purely performance-based system; instead they all have some combination of the two.

Among the Arctic countries with oil and gas activities, the United States (including the State of Alaska), Canada, and Russia have more or less prescriptive systems for regulating oil and gas activities, while Norway, Greenland, and the Faroe Islands have more of a performance-based system. The United States and Canada have a long history of regulating oil and gas activities in the Arctic, starting in the late 19th Century. Their systems have adapted to changes in science, technology, politics, and social needs to evolve into what they are today – basically founded on prescription but increasingly incorporating performance-based measures and goals into laws and regulations. Norway has conducted oil and gas activities since the early 1960s and, as with the United States and Canada, has undergone change from a more prescriptive regime. However, unlike the United States and Canada, Norway went much farther, much faster toward a performance-based system in a major restructuring of the legal regime in the late 1970s. Russia, while having a long history of oil and gas activities also dating to the late 19th Century, did not have a true regulatory regime because the State was the explorer, developer, operator, and transporter. Therefore, the Russian Federation system is very new, starting in the early 1990s. The Russian regime, while still undergoing great changes, is similar to the approach of the United States and Canada in its mix of prescriptive and performance-based components.

In addition, there are several international conventions and agreements that relate to marine environmental protection, the transport of oil and hazardous substances, and oil spill response, liability, and compensation to which one or more Arctic countries is a party. These are described below, with an emphasis on the provisions of the conventions and agreements that are relevant to oil- and gas-related activities.

A.2. International Conventions and Agreements

Table A2.1 provides a brief overview of international conventions and protocols relevant to oil and gas activities, along with a list of the Arctic countries that are Contracting Parties or Signatories to these international instruments. Under the rules prescribed by the 1969 Vienna Convention on the Law of Treaties and applicable to written treaties concluded after its entry into force in 1980, a ‘Party’ is a State which has consented to be bound by the treaty and for which the treaty is in force. The consent to be bound by a treaty is expressed by ‘ratification’, ‘accession’, ‘acceptance’, or ‘approval’ of the treaty by the State, usually by the national parliament or other internal process. It is not until the instruments of ratification have been deposited and any other requirements for entry into force (such as a specified number of ratifications) have been met, that the convention or protocol enters into force and becomes binding on its parties, requiring implementation by them in good faith. States which are signatories to a convention or protocol are expected, pending ratification, not to do anything that would defeat the purposes of the convention or protocol, if it came into force. However, this does not mean that they must comply with its terms in the interim; moreover, they are not bound by this provision if they subsequently make a clear declaration of intent not to become a party to the treaty. It should be noted that, on issues of foreign policy including international conventions and agreements, the accession, ratification, or acceptance of an instrument by Denmark will indicate whether it is also in respect of the Faroe Islands and/or Greenland, based on the respective decisions of their local governments; where information on these decisions was available for specific conventions, it is indicated below and in Table A2.1.

A.2.1. Conventions relating to marine issues: shipping, oil pollution, marine environmental protection

A.2.1.1. UN Convention on the Law of the Sea, 1982

The 1982 United Nations Convention on the Law of the Sea (UNCLOS) was developed as a comprehensive legal order for the seas and oceans to facilitate, among others, the equitable and efficient utilization of marine resources and the protection and preservation of the marine environment. The provisions of the Convention address navigational

Table A2.1. International Conventions and Agreements relevant to Arctic oil and gas activities. Denmark is signatory on behalf of the Faroe Islands and Greenland; information on their accession is provided where available.

Convention or Agreement	Purpose	Arctic Contracting Parties
Conventions relating to marine issues: shipping, oil pollution, marine environmental protection		
UN Convention on the Law of the Sea, 1982	Comprehensive legal order for the seas and oceans, addressing navigational rights, territorial sea limits, economic jurisdiction, the legal status of resources on the seabed beyond the limits of national jurisdiction, passage of ships through narrow straits, conservation and management of living marine resources, protection of the marine environment, marine research regimes, and a binding procedure for settlement of disputes between States.	Canada, Denmark, Finland, Iceland, Norway, Russia , Sweden
Conventions relating to marine pollution		
International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto	The main international convention covering prevention of pollution of the marine environment by ships from operational or accidental causes; includes regulations aimed at preventing and minimizing pollution from ships, both accidental pollution and that from routine operations, including by oil (Annex I) and by noxious liquid substances (Annex II) (the two mandatory annexes).	Canada, Denmark (+ Faroe Islands, Greenland), Finland, Iceland, Norway, Russia, Sweden, USA
Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972, and the 1996 Protocol	1972 LDC prohibits the dumping of certain hazardous materials, requires a prior special permit for the dumping of a number of other identified materials and a prior general permit for other wastes or matter. 1996 Protocol provides for strong restrictions on dumping according to the Precautionary Approach and establishes the 'polluter pays' principle.	1972 LDC: Canada, Denmark (+Faroe Islands), Finland, Iceland, Norway, Russia, Sweden, USA. 1996 Protocol: Canada, Denmark (+ Greenland), Finland, Iceland, Norway, Sweden. Signatory: USA
Conventions relating to response to pollution incidents		
International Convention on Oil Pollution Preparedness, Response and Cooperation, 1990	Designed to facilitate international cooperation and mutual assistance in preparing for and responding to a major oil pollution incident and to encourage States to develop and maintain an adequate capability to deal with oil pollution emergencies; covers both ships and offshore units.	Canada, Denmark (+Greenland), Finland, Iceland, Norway, Sweden, USA
Protocol on Preparedness, Response and Co-operation to Pollution Incidents by Hazardous and Noxious Substances, 2000	Global framework for international cooperation in combating major incidents or threats of marine pollution from ships carrying hazardous and noxious substances, such as chemicals, following the principles of OPRC.	Sweden Signatories: Denmark, Finland
International Convention Relating to Intervention on the High Seas in Cases of Oil Pollution Casualties, 1969	Affirms the right of a coastal State to take such measures on the high seas as may be necessary to prevent, mitigate or eliminate danger to its coastline or related interests from pollution by oil or the threat thereof owing to a maritime casualty.	Denmark, Finland, Iceland, Norway, Russia, Sweden, USA
Conventions regarding liability and compensation for damage from pollution incidents		
International Convention on Civil Liability for Oil Pollution Damage, 1969, and the Protocol of 1992 to amend the International Convention on Civil Liability for Oil Pollution Damage, 1969	Adopted to ensure that adequate compensation would be available to persons who suffer oil pollution damage resulting from maritime casualties involving oil-carrying ships; liability for such damage is placed on the owner of the ship from which the polluting oil escaped or was discharged. The 1969 Convention covers pollution damage resulting from spills of persistent oils suffered in the territory (including the territorial sea) of a State Party; applicable to ships which actually carry oil in bulk as cargo. Protocol of 1992 expands the limits of liability and widens the scope of the Convention to cover unladen tankers as well as pollution damage caused in the EEZ or equivalent area of a State Party.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden
International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage, 1971, and the Protocol of 1992	1971 Convention provided for the establishment of an international fund, to be subscribed to by the cargo interests, available to relieve ship owners of some compensation burden and also to provide additional compensation to the victims of pollution damage in cases where compensation under the 1969 Civil Liability Convention was either inadequate or unobtainable. The 1992 Protocol established a separate 1992 International Oil Pollution Compensation Fund, which functions along with the 1971 Fund until all 1971 Convention Parties have ratified the 1992 Protocol.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden
International Convention on Civil Liability for Bunker Oil Pollution Damage, 2001	Adopted to ensure that adequate and effective compensation is available to persons who suffer damage caused by spills of oil when carried as fuel in ships' bunkers. Modeled on the 1969 CLC; applies to pollution damage caused to the territory, including the territorial sea, and in exclusive economic zones of States Parties. Convention not yet in force.	Signatories: Canada, Denmark, Finland, Norway, Sweden
International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea, 1996	Provides for a compensation and liability regime for incidents involving hazardous and noxious substances; is complementary to the CLC and Fund Conventions for oil pollution damage, but in addition to pollution damage also covers the risks of fire and explosion, including loss of life or personal injury as well as loss of or damage to property. Convention not yet in force.	Russia Signatories: Canada, Denmark, Finland, Norway, Sweden

Table A2.1. Cont.

Convention or Agreement	Purpose	Arctic Contracting Parties
Conventions regarding maritime safety		
International Convention for the Safety of Life at Sea, 1974, as amended; Protocol of 1978	Most important international treaty concerning the safety of merchant ships. Objective is to specify minimum standards for the construction, equipment, and operation of ships, compatible with their safety. Flag States are responsible for ensuring that ships under their flag comply with the requirements; certificates are prescribed in the Convention as proof of compliance. Port State control procedure allows Parties to inspect ships of other Parties if clear grounds exist to believe non-compliance. Protocol of 1978 contains measures for the design and operation of tankers.	1974 Convention: Canada, Denmark, Finland, Iceland, Norway, SWE, RUS, USA. 1978 Protocol: Denmark, Finland, Iceland, Norway, Russia, Sweden, USA.
International Convention on Load Lines, 1966, as amended; 1988 Protocol	Provides for regulations limiting the draught to which a ship may be loaded; additional safety measures concern doors, hatchways and other items, to ensure the watertight integrity of ships' hulls below the freeboard deck. 1988 Protocol harmonized survey and certification requirements with SOLAS and MARPOL 73/78 requirements.	1966 Convention: Canada, Denmark, Finland, Iceland, Norway, SWE, RUS, USA. 1988 Protocol: Denmark, Finland, Iceland, Norway, Russia, Sweden, USA
International Convention on Standards of Training, Certification and Watchkeeping for Seafarers, 1978, and the 1995 amendments	Establishes basic requirements and minimum standards for training, certification, and watchkeeping for seafarers on an international level. 1995 amendments completely revised the Convention, providing more precise language of the requirements, imposing clearer obligations for their uniform application and implementation, and transferring many of the technical regulations to a new STCW Code.	Canada, Denmark (+ Greenland), Finland, Iceland, Norway, Russia, Sweden, USA
Convention on the International Regulations for Preventing Collisions at Sea, 1972	Establishes international rules to prevent collisions at sea, including traffic separation schemes, guidance for determining safe speed, the risk of collision, steering and sailing; technical requirements including for lights and shapes; sound and light signals. Rules apply to all vessels on the high seas and all associated waters.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden, USA
Convention for the Suppression of Unlawful Acts Against the Safety of Maritime Navigation, 1988, and the Protocol for the Suppression of Unlawful Acts against the Safety of Fixed Platforms Located on the Continental Shelf, 1988	Relates to unlawful acts that threaten the safety of ships and the security of their passengers and crew, including the seizure of ships by force; acts of violence against persons on board ships; and placing devices on board a ship which are likely to damage or destroy it. The Protocol extends the coverage of the Convention to fixed offshore structures such as oil and gas platforms.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden, USA
Conventions relating to nature conservation and environmental protection		
Convention on Biological Diversity, 1992	Establishes three main goals: conservation of biological diversity, sustainable use of its components, and fair and equitable sharing of the benefits from the use of genetic resources; covers all ecosystems, species, and genetic resources; links traditional conservation efforts with the sustainable use of biological resources and sets principles for the equitable sharing of the benefits from the use of genetic resources.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden Signatory: USA
United Nations Framework Convention on Climate Change, 1992, and 1997 Kyoto Protocol	Provides an international treaty addressing global warming; sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change, including gathering and sharing information on greenhouse gas emissions, national policies, and best practices; launching national strategies for addressing greenhouse gas emissions and adapting to expected impacts; and cooperating in preparing for adaptation to the impacts of climate change. The 1997 Kyoto Protocol significantly strengthens the Convention by committing Annex I Parties to individual, legally-binding targets to limit or reduce their greenhouse gas emissions.	1992 Convention: Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden, USA. Kyoto Protocol: Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden Signatory: USA
Convention on Environmental Impact Assessment in a Transboundary Context, 1991	Stipulates the obligations of Parties to assess the environmental impact of certain activities at an early stage of planning; provides a general obligation of States to notify and consult each other on all major projects under consideration that are likely to have a significant adverse environmental impact across boundaries.	Canada, Denmark (+Faroe Islands, Greenland), Finland, Norway, Sweden Signatories: Iceland, Russia, USA
Protocol on Strategic Environmental Assessment, 2003	Requires Parties to evaluate the environmental consequences of official draft plans and programs; provides for extensive public participation in government decision-making. The Protocol is not yet in force.	Finland, Sweden Signatories: Denmark, Norway
Convention on Wetlands of International Importance especially as Waterfowl Habitat, 1971, as amended	Provides the framework for national action and international cooperation for the conservation and wise use of all wetlands and their resources through local, regional and national actions and international cooperation, as a contribution towards achieving sustainable development.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden, USA
Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal, 1989	Provides for development of controls on the movement of hazardous wastes across international frontiers and the development of criteria for environmentally sound management of the wastes. Emphasis recently on minimization of hazardous waste generation through an integrated life-cycle approach. Covers hazardous wastes that are explosive, flammable, poisonous, infectious, corrosive, toxic, or ecotoxic.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden Signatory: USA

Table A2.1. Cont.

Convention or Agreement	Purpose	Arctic Contracting Parties
Rotterdam Convention on the Prior Informed Consent Procedure for Certain Hazardous Chemicals and Pesticides in International Trade, 1998	Designed to promote shared responsibility and cooperative efforts in the international trade of certain hazardous chemicals, and to protect human health and the environment from potential harm by facilitating information exchange about their characteristics. Enables monitoring and control of the trade in certain hazardous chemicals and also places requirements for labeling and information on potential health and environmental effects.	Canada, Denmark (not including Faroe Islands or Greenland), Finland, Norway, Sweden Signatory: USA
Convention Concerning the Protection of the World Cultural and Natural Heritage, 1972	Parties have a duty to ensure the identification, protection, and conservation, of cultural and natural heritage covered by the Convention. In terms of natural heritage, this includes natural features that are of outstanding universal value from the aesthetic or scientific point of view, and areas that constitute the habitat of threatened species of animals and plants of outstanding value from the point of view of science or conservation	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden, USA
Conventions concerning the rights of indigenous peoples		
Convention concerning Indigenous and Tribal Peoples in Independent Countries, 1989	Establishes a comprehensive set of minimum standards on indigenous rights. The Convention establishes a duty for States to respect the special importance for the cultures and spiritual values of indigenous peoples of their relationship with the lands and territories which they occupy. It establishes an obligation for States to recognize indigenous ownership and possession over lands they traditionally occupy, and also establishes a duty for States to specially safeguard indigenous peoples' right to the natural resources pertaining to their lands, including their right to participate in the use, management, and conservation of such resources.	Denmark, Norway
International Covenant on Civil and Political Rights, 1966	Reaffirms the political dimension of the right of self-determination, through which 'all peoples' have the right to freely determine their political status, and freely pursue their economic, social and cultural development. The right of self-determination also includes an economic or resource dimension, such that the people concerned may, for their own ends, freely dispose of their natural wealth and resources.	Canada, Denmark, Finland, Iceland, Norway, Russia, Sweden, USA
International conventions regarding the working environment		
Convention concerning the Protection of Workers against Occupational Hazards in the Working Environment Due to Air Pollution, Noise, and Vibration, 1977	Concerns the development and implementation of national laws or regulations prescribing measures to be taken for the prevention and control of, and protection against, occupational hazards in the working environment due to air pollution, noise, and vibration.	Denmark, Finland, Norway, Russia, Sweden
Convention concerning Labour Administration: Role, Functions, and Organisation, 1978	Intended to ensure the organization and effective operation of a system of labour administration in the Contracting Parties.	Denmark, Finland, Norway, Russia, Sweden, USA
Convention concerning Occupational Safety and Health in Dock Work, 1979	Requires the development of national laws or regulations prescribing measures that, among others, provide for safe workplaces, equipment and methods of work; provide for training and supervision to ensure the protection of workers against risks of accident; provide workers with personal protective equipment and clothing; and establish proper procedures to deal with any emergency situations which may arise.	Denmark, Finland, Norway, Russia, Sweden
Convention concerning Occupational Safety and Health in the Working Environment, 1981	Requires the formulation and implementation of a coherent national policy on occupational safety and health and the working environment, with the aim of preventing accidents and injury to health arising in relation to the working environment.	Denmark, Finland, Iceland, Norway, Russia, Sweden
Prevention of Major Industrial Accidents Convention, 1993	Requires the formulation and implementation of a coherent national policy concerning the protection of workers, the public, and the environment against the risk of major accidents.	Sweden

rights, territorial sea limits, economic jurisdiction, the legal status of resources on the seabed beyond the limits of national jurisdiction, the passage of ships through narrow straits, the conservation and management of living marine resources, the protection of the marine environment, marine research regimes, and a binding procedure for the settlement of disputes between States.

One of the most far-reaching features of the Convention is the creation of the exclusive economic zone (EEZ), which recognizes the right of coastal states to jurisdiction over the resources in the waters, on the seabed, and in the subsoil of an area extending 200 nautical miles from its coastline. As a result, about 87% of all known and estimated hydrocarbon reserves under the sea fall under some national jurisdiction.

The Convention also establishes the fundamental obligation of all States to protect and preserve the marine environment. The Convention addresses six main sources of ocean pollution: land-based and coastal activities; continental-shelf drilling; potential seabed mining; ocean dumping; vessel-source pollution; and pollution from or through the atmosphere. Every coastal State is granted jurisdiction for the protection and preservation of the marine environment of its EEZ. Such jurisdiction allows coastal states to control, prevent and reduce marine pollution from dumping, land-based sources or seabed activities subject to national jurisdiction, or from or through the atmosphere.

All member countries of the Arctic Council, with the exception of the United States, are Parties to UNCLOS. Further details are at http://www.un.org/Depts/los/convention_agreements/convention_overview_convention.htm.

A.2.1.2. Conventions relating to marine pollution

A.2.1.2.1. MARPOL 73/78

The International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto (MARPOL 73/78), is the main international convention covering prevention of pollution of the marine environment by ships from operational or accidental causes. It is a combination of two treaties adopted in 1973 and 1978, respectively, and updated by amendments through the years.

The International Convention for the Prevention of Pollution from Ships (MARPOL) was adopted in November 1973 and covered pollution by oil, chemicals, harmful substances in packaged form, sewage, and garbage. The Protocol of 1978 relating to the 1973 International Convention for the Prevention of Pollution from Ships (1978 MARPOL Protocol) was adopted at a Conference on Tanker Safety and Pollution Prevention in February 1978 held in response to a number of tanker accidents in 1976-1977. Measures relating to tanker design and operation were also incorporated into a Protocol of 1978 relating to the 1974 Convention on the Safety of Life at Sea (1978 SOLAS Protocol). As the 1973 MARPOL Convention had not yet entered into force, the 1978 MARPOL Protocol absorbed the parent Convention. The combined instrument is referred to as the International Convention for the Prevention of Marine Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto (MARPOL 73/78).

The Convention includes regulations aimed at preventing and minimizing pollution from ships – both accidental pollution and that from routine operations – and currently includes six technical Annexes. Contracting States must accept Annexes I and II, but the other Annexes are voluntary. The Annexes are:

- Annex I – Regulations for the Prevention of Pollution by Oil
- Annex II – Regulations for the Control of Pollution by Noxious Liquid Substances Carried in Bulk
- Annex III – Prevention of Pollution by Harmful Substances Carried by Sea in Packaged Form
- Annex IV – Prevention of Pollution by Sewage from Ships
- Annex V – Prevention of Pollution by Garbage from Ships
- Annex VI – Prevention of Air Pollution from Ships

All Arctic countries have ratified or acceded to MARPOL 73/78 and the required Annexes I and II, concerned with the prevention of pollution from oil and the control of pollution by noxious liquid substances carried in bulk, respectively. In addition to Annexes I and II, Denmark (also in respect of the Faroe Islands and, with the exception of Annex IV, Greenland), Finland, Norway, and Sweden are Parties to Annexes III, IV, V, and VI; the Russian Federation is a Party to Annexes III, IV, and V; the United States and Iceland are Parties to Annexes III and V; and Canada is a Party to Annex III. Further details are at http://www.imo.org/Conventions/contents.asp?doc_id=678&topic_id=258.

A.2.1.2.2. Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972, and the 1996 Protocol

The Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972, generally known as the London Dumping Convention, is global in character and has contributed to the international control and prevention of marine pollution. It prohibits the dumping of certain hazardous materials, requires a prior special permit for the dumping of a number of other identified materials and a prior general permit for other wastes or matter. 'Dumping' is defined as the deliberate disposal at sea of wastes or other matter from vessels, aircraft, platforms or other man-made structures, as well as the deliberate disposal of these vessels or platforms themselves. Wastes derived from the exploration and exploitation of seabed mineral resources are, however, excluded from the definition. Among other requirements, Contracting Parties undertake to designate an authority to deal with permits, keep records, and monitor the condition of the sea.

Under the 1972 Convention, annexes list wastes which cannot be dumped and others for which a special dumping permit is required. The criteria governing the issuing of these permits are specified in a third Annex which deals with the nature of the waste material, the characteristics of the dumping site, and the method of disposal. Subsequent amendments restricted and ultimately banned the dumping into the sea of low-level radioactive wastes, as well as phased out the dumping of industrial wastes and banned the incineration at sea of industrial wastes.

The 1996 Protocol is designed to replace the 1972 Convention and represents a major change of approach to the question of how to regulate the use of the sea as a depository for waste materials. An important development is the introduction of the precautionary approach, which requires that 'appropriate preventative measures are taken when there is reason to believe that wastes or other matter introduced into the marine environment are likely to cause harm even when there is no conclusive evidence to prove a causal relation between inputs and their effects.' The article also establishes the 'polluter pays' principle, and emphasizes that Contracting Parties should ensure that the Protocol will not simply result in pollution being transferred from one part of the environment to another.

In contrast to the 1972 Convention, which permits dumping to be carried out provided that certain conditions are met unless a substance is on the 'black list', the 1996 Protocol is much more restrictive and provides that Contracting Parties should prohibit the dumping of any wastes or other matter with the exception of dredged material; sewage sludge; fish waste, or material resulting from industrial fish processing operations; vessels and platforms or other man-made structures at sea; inert, inorganic geological material; and organic material of natural origin. Incineration of wastes at sea, permitted under the 1972 Convention but later prohibited under amendments adopted in 1993, is specifically prohibited by Article 5 of the 1996 Protocol.

All Arctic countries are Contracting Parties to the 1972 Convention, with Denmark also including the Faroe Islands. For the 1996 Protocol, Canada, Denmark (including Greenland), Iceland, Norway, and Sweden are Parties; the United States is a signatory but has not yet ratified the Protocol. Further details are at www.imo.org/Conventions/mainframe.asp?topic_id=258&doc_id=681.

A.2.1.3. Conventions relating to response to pollution incidents

A.2.1.3.1. International Convention on Oil Pollution Preparedness, Response and Cooperation, 1990

The Convention on Oil Pollution Preparedness, Response and Cooperation (OPRC) is designed to facilitate international cooperation and mutual assistance in preparing for and responding to a major oil pollution incident and to encourage States to develop and maintain an adequate capability to deal with oil pollution emergencies. The Convention stipulates that ships are required to carry a shipboard oil pollution emergency plan, to report incidents of pollution to coastal authorities, and to take appropriate action. Operators of offshore units under the jurisdiction of Parties to the Convention are also required to have oil pollution emergency plans or similar arrangements, which must be coordinated with national systems for responding promptly and effectively to oil pollution incidents. In addition, the Convention calls for the establishment of stockpiles of oil-spill combating equipment, holding oil-spill combating exercises, and the development of detailed plans for dealing with pollution incidents. Parties to the Convention are required to provide assistance to others in the event of an oil spill.

With the exception of the Russian Federation, all Arctic Council countries (for Denmark, including Greenland but not the Faroe Islands) are Parties to this Convention. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=258&doc_id=682.

A.2.1.3.2. Protocol on Preparedness, Response and Co-operation to Pollution Incidents by Hazardous and Noxious Substances, 2000

The Protocol on Preparedness, Response and Co-operation to Pollution Incidents by Hazardous and Noxious Substances, 2000 (OPRC-HNS Protocol) provides a global framework for international cooperation in combating major incidents or threats of marine pollution from ships carrying hazardous and noxious substances, such as chemicals. The Protocol follows the principles of the International Convention on Oil Pollution Preparedness, Response and Co-operation, 1990 (OPRC), requiring the establishment of measures for dealing with pollution incidents, either nationally or in cooperation with other countries, involving hazardous or noxious substances (HNS). For the purposes of this Protocol, a hazardous and noxious substance is defined as any substance other than oil which, if introduced into the marine environment, is likely to create hazards to human health, harm living resources and marine life, damage amenities or to interfere with other legitimate uses of the sea. Ships carrying hazardous and noxious liquid substances will be required to carry a shipboard pollution emergency plan to deal specifically with incidents involving HNS.

The HNS Protocol was formally adopted by States already Party to the OPRC Convention and entered into force on 14 June 2007. The HNS Protocol will ensure that ships carrying hazardous and noxious liquid substances are covered, or will be covered, by regimes similar to those already in existence for oil incidents.

Of the Arctic Council countries, Sweden has acceded to this Protocol, while Denmark and Finland are signatories. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=258&doc_id=683.

A.2.1.3.3. International Convention Relating to Intervention on the High Seas in Cases of Oil Pollution Casualties, 1969

The International Convention Relating to Intervention on the High Seas in Cases of Oil Pollution Casualties, 1969, affirms the right of a coastal State to take such measures on the high seas as may be necessary to prevent, mitigate or eliminate danger to its coastline or related interests from pollution by oil or the threat thereof, following upon a maritime casualty. However, the coastal State is empowered to take only such action as is necessary, and after due consultations with appropriate interests including, in particular, the flag State or States of the ship or ships involved, the owners of the ships or cargoes in question and, where circumstances permit, independent experts appointed for this purpose. Provision is made for the settlement of disputes arising in connection with the application of the Convention. The Convention applies to all seagoing vessels except warships or other vessels owned or operated by a State and used on government non-commercial service.

The 1973 Protocol extended the Convention to cover substances other than oil, while subsequent amendments have revised the list of substances attached to the 1973 Protocol following the adoption of new criteria for their selection.

All Arctic countries except Canada are Parties to this Convention. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=258&doc_id=680.

A.2.1.4. Conventions regarding liability and compensation for damage from pollution incidents

With the exception of the United States, all Arctic Council countries are Parties to one or more of the compensation and liability conventions and protocols regarding damage from oil pollution. In addition, there are several significant conventions under consideration which no Arctic Council member state has yet adopted.

The United States is unique in its reliance on domestic legislation under the Oil Pollution Act of 1990 to support the Oil Spill Liability Trust Fund (OSLTF), which provides a compensation and liability regime. In addition to the international compensation and liability convention protocols, Canada under authority of its Canadian Shipping Act established a Ship Source Oil Pollution fund to pay claims for which no other compensation was available, based on a levy on oil passing though Canadian ports. However, contributions to this fund were discontinued in 1976.

A.2.1.4.1. International Convention on Civil Liability for Oil Pollution Damage, 1969, and the Protocol of 1992 to amend the International Convention on Civil Liability for Oil Pollution Damage, 1969

The International Convention on Civil Liability for Oil Pollution Damage (CLC), 1969, was adopted to ensure that adequate compensation would be available to persons who suffer oil pollution damage resulting from maritime casualties involving oil-carrying ships. The Convention places the liability for such damage on the owner of the ship from which the polluting oil escaped or was discharged. Subject to a number of specific exceptions, this liability is strict; it is the duty of the owner to prove in each case that any of the exceptions should in fact operate. However, except where the owner has been guilty of actual fault, there may be a limit to the liability. The Convention requires ships covered by it to maintain insurance or other financial security in sums equivalent to the owner's total liability for one incident. The 1969 Convention applies to all seagoing vessels actually carrying oil in bulk as cargo, but only ships carrying more than 2000 tons of oil are required to maintain insurance in respect of oil pollution damage. However, warships or other vessels owned or operated by a State and used for government non-commercial service are not covered.

The 1969 Convention covers pollution damage resulting from spills of persistent oils suffered in the territory (including the territorial sea) of a State Party to the Convention. It is applicable to ships which actually carry oil in bulk as cargo, i.e., generally laden tankers. Spills from tankers in ballast or bunker spills from ships other than tankers are not covered, nor is it possible to recover costs when preventive measures are so successful that no actual spill occurs.

The Protocol of 1992 expands the limits of liability and widens the scope of the Convention to cover pollution damage caused in the EEZ or equivalent area of a State Party. The Protocol covers pollution damage as before but environmental damage compensation is limited to costs incurred for reasonable measures to reinstate the contaminated environment. It also allows expenses incurred for preventive measures to be recovered even when no spill of oil occurs, provided that there was grave and imminent threat of pollution damage. The Protocol also extended the Convention to cover spills from sea-going vessels constructed or adapted to carry oil in bulk as cargo so that it applies to both laden and unladen tankers, including spills of bunker oil from such ships. Under the 1992 Protocol, a ship owner cannot limit liability if it is proved that the pollution damage resulted from the ship owner's personal act or omission, committed with the intent to cause such damage, or recklessly and with knowledge that such damage would probably result.

Parties to the 1992 Protocol ceased to be Parties to the 1969 CLC due to a mechanism for compulsory denunciation of the 'old' regime established in the 1992 Protocol. However, currently the two regimes co-exist, since there are still a few States which are Party to the 1969 CLC but have not yet ratified the 1992 regime, which is intended eventually to replace the 1969 CLC. Further amendments in 2000 raised the limits of liability.

With the exception of the United States, all Arctic countries are Parties to the 1992 Protocol. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=256&doc_id=660.

A.2.1.4.2. International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage, 1971, and the Protocol of 1992

The International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage (FUND), 1971, was adopted because the 1969 Civil Liability Convention, although providing a useful mechanism for ensuring the payment of compensation for oil pollution damage, did not deal satisfactorily with all legal, financial and other issues, such as the strict liability of the ship owner for damage which they could not foresee and the limitations on compensation that were likely to be inadequate in cases of oil pollution damage involving large tankers.

In the light of these issues, the International Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage, 1971, was adopted. This provided for the establishment of an international fund, to be subscribed to by the cargo interests, which would be available for the dual purpose of, on the one hand, relieving the ship owner of the burden by the requirements of the new convention and, on the other hand, providing additional compensation to the victims of pollution damage in cases where compensation under the 1969 Civil Liability Convention was either inadequate or unobtainable.

Under this Convention, the Fund is under an obligation to pay compensation to States and persons who suffer pollution damage, if such persons are unable to obtain compensation from the owner of the ship from which the oil escaped or if the compensation due from such an owner is not sufficient to cover the damage suffered. The Fund's obligation to pay compensation is confined to pollution damage suffered in the territories including the territorial sea of Contracting States. However, the Fund is also obliged to pay compensation in respect of measures taken by a Contracting State outside its territory. In addition, the Fund is obliged to indemnify the ship owner or his insurer for a portion of the ship owner's liability under the CLC. Contributions to the Fund are made by all persons who receive oil by sea in Contracting States.

As with the 1992 Protocol to the CLC Convention, the main purpose of the 1992 Protocol to the Fund Convention was to modify the entry into force requirements and to increase compensation amounts. The scope of coverage was extended in line with the 1992 CLC Protocol. The 1992 Fund Protocol established a separate, 1992 International Oil Pollution Compensation Fund, known as the 1992 Fund, which is managed in London by a Secretariat, as with the 1971 Fund.

From 16 May 1998, Parties to the 1992 Protocol to the Fund Convention ceased to be Parties to the 1971 Fund Convention due to a mechanism for compulsory denunciation of the 'old' regime established in the 1992 Protocol. However, the two Funds are currently in operation, because there are still a few States that have not yet acceded to the 1992 Protocol, which is intended to completely replace the 1971 regime.

A 2003 Protocol established an International Oil Pollution Compensation Supplementary Fund to supplement the compensation available under the 1992 Civil Liability and Fund Conventions with an additional, third tier of compensation. The Protocol is optional and participation is open to all States party to the 1992 Fund Convention. The supplementary fund will apply to damage in the territory, including the territorial sea, and in the EEZ of a Contracting State.

All Arctic countries except the United States are Parties to the 1992 Fund Protocol, while Denmark (also including Greenland), Finland, Norway, and Sweden are Parties to the 2003 Supplemental Fund. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=256&doc_id=661.

A.2.1.4.3. International Convention on Civil Liability for Bunker Oil Pollution Damage, 2001

The International Convention on Civil Liability for Bunker Oil Pollution Damage, 2001, was adopted to ensure that adequate, prompt, and effective compensation is available to persons who suffer damage caused by spills of oil when carried as fuel in ships' bunkers. Modeled on the 1969 CLC, the Convention applies to pollution damage caused to the territory, including the territorial sea, and in EEZs of States Parties. This convention has currently not entered into force. Signatories include Canada, Denmark, Finland, Norway, and Sweden, none of which have yet ratified the Convention. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=256&doc_id=666.

A.2.1.4.4. International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea, 1996

The International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea (HNS), 1996, provides for a compensation and liability regime for incidents involving these substances. HNS are defined by reference to the lists of substances included in various IMO Conventions and Codes. These include oils; other liquid substances defined as noxious or dangerous; liquefied gases; liquid substances with a flashpoint not exceeding 60 °C; dangerous, hazardous, and harmful materials and substances carried in packaged form; and solid bulk materials defined as possessing chemical hazards. The HNS Convention is complementary to the CLC and Fund Conventions for oil pollution damage. However, it goes further in that it covers not only pollution damage but also the risks of fire and explosion, including loss of life or personal injury as well as loss of or damage to property. The Convention also covers residues left by the previous carriage of HNS, other than those carried in packaged form. The Convention defines damage as including loss of life or personal injury; loss of or damage to property outside the ship; loss or damage by contamination of the environment; the costs of preventative measures and further loss or damage caused by them. The Convention introduces strict liability for the ship owner and a system of compulsory insurance and insurance certificates. The Convention is not yet in force. Of the Arctic countries, the Russian Federation has acceded to the Convention, while Canada, Denmark, Finland, Norway, and Sweden are signatories but have not yet ratified the Convention. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=256&doc_id=665.

A.2.1.5. Conventions regarding maritime safety

A.2.1.5.1. International Convention for the Safety of Life at Sea, 1974, as amended

The International Convention for the Safety of Life at Sea (SOLAS), in its successive forms, is generally considered the most important international treaty concerning the safety of merchant ships. With a history dating back to 1914 in response to the Titanic disaster, the current 1974 Convention contains a provision that permits easy updating by virtue of a 'tacit acceptance procedure' for new amendments, providing that a new amendment will enter into force on a specified date unless objections are received from an agreed number of Parties before that date. This has resulted in the Convention being updated and amended on numerous occasions. The objective of the Convention is to specify minimum standards for the construction, equipment, and operation of ships, compatible with their safety. Flag States are responsible for ensuring that ships under their flag comply with the requirements, and a number of certificates are prescribed in the Convention as proof that this has been done. There is also a procedure – known as port state control – that allows contracting governments to inspect the ships of other Contracting States if there are clear grounds for believing that the ship and its equipment do not comply with the requirements of the Convention. All Arctic countries are Parties to the 1974 Convention.

Based on a large number of tanker accidents in 1976 to 1977, the Protocol of 1978 was adopted which contains measures concerning the design and operation of tankers, including requirements regarding inert gas systems, radar, and steering gear. All Arctic countries except Canada are Parties to this Protocol. Further details are at www.imo.org/Conventions/mainframe.asp?topic_id=257&doc_id=647.

A.2.1.5.2. International Convention on Load Lines, 1966, as amended

The International Convention on Load Lines, 1966, provides for regulations limiting the draught to which a ship may be loaded, making a significant contribution to safety. These limits are given in the form of freeboards, which constitute, in addition to external weather-tight and watertight integrity, the main objective of the Convention. Concern regarding load lines derived from the fact that the stability of ships can be seriously affected by overloading, especially if the cargo shifts during the course of the voyage. The Convention contains detailed regulations on the assignment of the freeboard – the vertical distance between the top of the hull and the waterline – and the specific limitations to which different types of ships may be loaded, as well as the associated marking of the ships. The technical annex contains several additional safety measures concerning doors, freeing ports, hatchways and other items, intended to ensure the watertight integrity of ships' hulls below the freeboard deck. All Arctic countries are Parties to the 1966 Convention.

The 1988 Protocol harmonized the Convention's survey and certification requirements with those contained in SOLAS and MARPOL 73/78 and adopted a similar 'tacit amendment procedure'. 2003 Amendments to this Protocol provided a comprehensive revision of the technical guidelines of the original Convention and only applied to the ships flying the flags of States Party to the 1988 Load Lines Protocol.

All Arctic countries except Canada are Parties to this Protocol. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=254.

A.2.1.5.3. International Convention on Standards of Training, Certification and Watchkeeping for Seafarers, 1978, and the 1995 amendments

The 1978 International Convention on Standards of Training, Certification and Watchkeeping for Seafarers (STCW) was the first to establish basic requirements and minimum standards for training, certification, and watchkeeping for seafarers on an international level. Previously, these types of standards had been established by individual governments, usually without reference to practices in other countries, thus resulting in widely varying standards and procedures.

The articles of the Convention include requirements relating to issues surrounding certification and port State control. One important feature is that it applies to ships of non-party States when visiting ports of States which are Parties to the Convention. Article X requires Parties to apply the control measures to ships of all flags to the extent necessary to ensure that no more favorable treatment is given to ships entitled to fly the flag of a State which is not a Party than is given to ships entitled to fly the flag of a State that is a Party.

1995 amendments completely revised the Convention. These amendments provided more precise language of the requirements and imposed clearer obligations for uniform application and implementation of the requirements. Many of the technical regulations were transferred to a new STCW Code, of which Part A is mandatory and Part B is recommended. Parties to the Convention are also required to provide detailed information to the International Maritime Organization concerning administrative measures, including education and training courses and certification procedures, taken to ensure compliance with the Convention.

All Arctic countries are Parties to this Convention, although Denmark's ratification does not include the Faroe Islands. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=257&doc_id=651.

A.2.1.5.4. Convention on the International Regulations for Preventing Collisions at Sea, 1972

The 1972 Convention on International Regulations for Preventing Collisions at Sea (COLREGs) updated and replaced the Collision Regulations of 1960, which had been adopted at the same time as the 1960 SOLAS Convention. One of the most important innovations in the 1972 COLREGs was the recognition given to traffic separation schemes: Rule 10 provides guidance in determining safe speed, the risk of collision, and the conduct of vessels operating in or near traffic separation schemes. The COLREGs include 38 rules divided into five sections: general; steering and sailing; lights and shapes; sound and light signals; and exemptions. There are also four Annexes containing additional technical requirements. The rules apply to all vessels upon the high seas and all waters connected to the high seas and navigable by seagoing vessels and address the responsibility of the master, owner, and crew to comply with the rules. There have been a number of amendments to update the regulations. All Arctic countries are Parties to this Convention. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=257&doc_id=649.

A.2.1.5.5. Convention for the Suppression of Unlawful Acts Against the Safety of Maritime Navigation, 1988, and the Protocol for the Suppression of Unlawful Acts Against the Safety of Fixed Platforms Located on the Continental Shelf, 1988

The Convention for the Suppression of Unlawful Acts Against the Safety of Maritime Navigation, 1988, was adopted owing to concern about unlawful acts that threaten the safety of ships and the security of their passengers and crew. Unlawful acts include the seizure of ships by force; acts of violence against persons on board ships; and placing devices on board a ship which are likely to damage or destroy it. The Convention obliges Contracting governments to extradite or prosecute the alleged offenders. The Protocol extends the coverage of the Convention to fixed offshore structures such as oil and gas platforms. All Arctic countries are Parties to the Convention as well as to the Protocol. Further details are at http://www.imo.org/Conventions/mainframe.asp?topic_id=259&doc_id=686.

A.2.2. Conventions relating to nature conservation and environmental protection

A.2.2.1. Convention on Biological Diversity, 1992

At the 1992 Earth Summit in Rio de Janeiro, world leaders agreed on a comprehensive strategy for sustainable development, defined as meeting current human needs while ensuring that a healthy and viable world is left for future generations. One of the key agreements adopted at the Earth Summit was the Convention on Biological Diversity (CBD). This pact among most of the world's governments sets out commitments for maintaining the Earth's ecological underpinnings while still providing for economic development. The Convention established three main goals: the conservation of biological diversity, the sustainable use of its components, and the fair and equitable sharing of the benefits from the use of genetic resources.

The Convention recognizes that the conservation of biological diversity is 'a common concern of humankind' and is an integral part of the development process. It covers all ecosystems, species, and genetic resources. It links traditional conservation efforts with the sustainable use of biological resources and sets principles for the equitable sharing of the benefits from the use of genetic resources. The Convention is legally binding, and countries that join it are obliged to implement its provisions.

States have, in accordance with the Charter of the United Nations and the principles of international law, the sovereign right to exploit their own resources pursuant to their own environmental policies, and the responsibility to ensure that activities within their jurisdiction or control do not cause damage to the environment of other States or of areas beyond the limits of national jurisdiction. The Convention requires that each Contracting Party, in accordance with its particular conditions and capabilities: develop national strategies, plans or programs for the conservation and sustainable use of biological diversity or adapt for this purpose existing strategies, plans or programs which shall reflect the measures set out in this Convention relevant to the Contracting Party concerned; and integrate, as far as possible and as appropriate, the conservation and sustainable use of biological diversity into relevant sectoral or cross-sectoral plans, programs and policies.

The provisions of the Convention do not affect the rights and obligations of any Contracting Party deriving from any existing international agreement, except where the exercise of those rights and obligations would cause a serious damage or threat to biological diversity. The

Contracting Parties are to implement this Convention with respect to the marine environment consistently with the rights and obligations of States under the Law of the Sea.

All Arctic countries except the United States are Parties to the CBD. The United States is a signatory, but has not yet ratified the Convention. Further details are at http://www.biodiv.org/default.shtml.

A.2.2.2. United Nations Framework Convention on Climate Change, 1992, and 1997 Kyoto Protocol

The United Nations Framework Convention on Climate Change (UNFCCC), the other major outcome of the Earth Summit in Rio de Janeiro, provides an international treaty addressing global warming. The Convention sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. It recognizes that the climate system is a shared resource whose stability can be affected by industrial and other emissions of carbon dioxide and other greenhouse gases. Under the Convention, governments gather and share information on greenhouse gas emissions, national policies, and best practices; launch national strategies for addressing greenhouse gas emissions and for adapting to expected impacts, including the provision of financial and technological support to developing countries; and cooperate in preparing for adaptation to the impacts of climate change. All Arctic countries are Parties to the Convention.

To address legally binding issues, the 1997 Kyoto Protocol was adopted. The Kyoto Protocol shares the Convention's objective, principles and institutions, but significantly strengthens the Convention by committing Annex I Parties to individual, legally-binding targets to limit or reduce their greenhouse gas emissions. The Protocol addresses the basic features of a compliance system, but does not contain operational guidelines. Additional agreements regarding a 'Kyoto Protocol rulebook' were addressed by the adoption of the Marrakesh Accords, setting out detailed rules for the implementation of the Kyoto Protocol.

The purpose of the Convention and its Protocol and Accord is the achievement, in accordance with the relevant provisions of the Convention, of the stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened, and to enable economic development to proceed in a sustainable manner.

Key among the assumptions of the Convention is that Parties should protect the climate system on the basis of equity and in accordance with their common but differentiated responsibilities and respective capabilities, with developed nations bearing greater responsibility for addressing these issues. The specific needs and special circumstances of developing country Parties should be given full consideration and the precautionary principle should be observed. The precautionary principle states that where there are threats of serious or irreversible damage, lack of full scientific certainty should not be used as a reason for postponing such measures, taking into account that policies and measures to deal with climate change should be cost-effective so as to ensure global benefits at the lowest possible cost.

All Arctic countries except the United States are Parties to the Kyoto Protocol. The United States is a signatory, but has not yet ratified the Protocol. Further details are at http://unfccc.int/2860.php.

A.2.2.3. Convention on Environmental Impact Assessment in a Transboundary Context, 1991

The Convention on Environmental Impact Assessment in a Transboundary Context, 1991, known as the Espoo (EIA) Convention, stipulates the obligations of Parties to assess the environmental impact of certain activities at an early stage of planning. It also provides a general obligation of States to notify and consult each other on all major projects under consideration that are likely to have a significant adverse environmental impact across boundaries. Arctic countries that are Parties to this Convention are Canada, Denmark (including Greenland and the Faroe Islands), Finland, Norway, and Sweden. Iceland, the Russian Federation, and the United States are signatories to the Convention, but have not yet ratified the Convention. Further details are at: http://www.unece.org/env/eia/eia.htm.

A.2.2.4. Protocol on Strategic Environmental Assessment, 2003

The Protocol on Strategic Environmental Assessment, 2003, known as the Kiev (SEA) Protocol, once in force, will require its Parties to evaluate the environmental consequences of their official draft plans and programs. The Protocol provides for extensive public participation in government decision-making in many development sectors. Strategic environmental assessment should take a broader view of projects and occur much earlier in the decision-making process than an EIA. Finland, Norway, and Sweden are Contracting Parties to the SEA Protocol, while Denmark is a signatory and has not yet ratified the Convention. The Protocol is not yet in force. Further details are at http://www.unece.org/env/eia/sea_protocol.htm.

A.2.2.5. Convention on Wetlands of International Importance especially as Waterfowl Habitat, 1971, as amended

The Convention on Wetlands of International Importance especially as Waterfowl Habitat (Ramsar Convention) provides the framework for national action and international cooperation for the conservation and wise use of all wetlands and their resources through local, regional and national actions and international cooperation, as a contribution towards achieving sustainable development throughout the world. While the original emphasis of the Convention was on the conservation and wise use of wetlands primarily to provide habitat for water birds, over the years the Convention has broadened its scope to cover all aspects of wetland conservation and wise use, recognizing wetlands as ecosystems that are extremely important for biodiversity conservation in general and for the well-being of human communities.

The first obligation of Parties under the Convention is to designate at least one wetland for inclusion in the List of Wetlands of International Importance (the Ramsar List) and to promote its conservation. The Convention uses a broad definition of the types of wetlands covered, including swamps and marshes, lakes and rivers, wet grasslands and peatlands, oases, estuaries, deltas and tidal flats, nearshore marine areas, mangroves and coral reefs, and human-made sites such as fish ponds, rice paddies, reservoirs, and salt pans. There is a general obligation for the Contracting Parties to include wetland conservation considerations in their national land-use planning.

All Arctic countries are Parties to the Ramsar Convention. Further details are at http://www.ramsar.org/.

A.2.2.6. Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal, 1989

The Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and their Disposal was adopted in 1989 in response to concerns about toxic waste from industrialized countries being shipped to and dumped in developing countries and countries with economies in transition. The Convention's principal focus was the elaboration of controls on the transboundary movement of hazardous wastes across international frontiers and the development of criteria for environmentally sound management of the wastes. More recently, work under the Convention has emphasized full implementation of treaty commitments and the minimization of hazardous waste generation, particularly through an 'integrated life-cycle approach' to waste. The Basel Convention covers hazardous wastes that are explosive, flammable, poisonous, infectious, corrosive, toxic, or ecotoxic. The categories of wastes and the hazardous characteristics are set out in annexes to the Convention.

All Arctic countries except the United States are Parties to the Basel Convention. The United States is a signatory, but has not yet ratified the Convention. Further details are at http://www.basel.int/index.html.

A.2.2.7. Rotterdam Convention on the Prior Informed Consent Procedure for Certain Hazardous Chemicals and Pesticides in International Trade, 1998

The Rotterdam Convention on the Prior Informed Consent Procedure for Certain Hazardous Chemicals and Pesticides in International Trade, 1998, is designed to promote shared responsibility and cooperative efforts among Parties in the international trade of certain hazardous chemicals. It aims to protect human health and the environment from potential harm and to contribute to the environmentally sound use of such chemicals by facilitating information exchange about their characteristics to aid national decision-making on their import and export. The Convention enables monitoring and control of the trade in certain hazardous chemicals and also places requirements for labeling and the provision of information on potential health and environmental effects to promote their safe use.

Canada, Denmark (with the exception of Greenland and the Faroe Islands), Finland, Norway, and Sweden are Parties to the Rotterdam Convention. The United States is a signatory, but has not yet ratified the Convention. Further details are at http://www.pic.int/.

A.2.3. Convention Concerning the Protection of the World Cultural and Natural Heritage, 1972

Under the Convention Concerning the Protection of the World Cultural and Natural Heritage, 1972, Contracting Parties have a duty to ensure the identification, protection, conservation, presentation, and transmission of cultural and natural heritage covered by the Convention to future generations. In terms of natural heritage, this includes natural features that are of outstanding universal value from the aesthetic or scientific point of view, and areas that constitute the habitat of threatened species of animals and plants of outstanding value from the point of view of science or conservation. All Arctic countries are Parties to this Convention. For the text of the Convention, see http://whc.unesco.org/?cid=175.

A.2.4. Conventions concerning the rights of indigenous peoples

A.2.4.1. Convention concerning Indigenous and Tribal Peoples in Independent Countries, 1989

The International Labour Organization Convention No. 169 concerning Indigenous and Tribal Peoples in Independent Countries, 1989, establishes a comprehensive set of minimum standards on indigenous rights. It contains a number of provisions related to indigenous lands and resource rights, and thus is of importance in relation to legal questions related to oil and gas operations in indigenous lands and territories. The Convention establishes a duty for States to 'respect the special importance for the cultures and spiritual values' of indigenous peoples of their relationship with the lands and territories 'which they occupy or otherwise use, and in particular the collective aspect of this relationship'. This is a legal recognition of indigenous peoples' special relationship to their lands, and an acknowledgement of the fact that their lands and resources are core elements of their cultures. This provision is the underlying principle for all the other provisions related to lands and resources, and these provisions also are applicable in relation to oil exploitation activities in indigenous peoples' lands and territories.

The Convention establishes an obligation for States to recognize indigenous ownership and possession over lands they traditionally occupy. It also establishes a duty for States to specially safeguard indigenous peoples' right to the natural resources pertaining to their lands, including their right to participate in the use, management, and conservation of such resources. In cases in which the State retains the ownership of mineral and sub-surface resources pertaining to lands, governments must establish procedures through which they consult these people before undertaking or permitting any programs for the exploration or exploitation of such resources. The Convention also establishes the principle of benefit sharing, requiring that the indigenous peoples concerned shall wherever possible participate in the benefits of such activities, and receive fair compensation for any damages which they may sustain as a result of such activities.

The Convention also states that indigenous peoples have the right to decide their own priorities for the process of development as it affects their lives, including the land they occupy or otherwise use, and to the extent possible, exercise control over their own economic, social and cultural development. It obliges governments to take measures, in cooperation with indigenous peoples, to protect and preserve the environment of the territories they inhabit. Furthermore, governments are obliged to consult the indigenous peoples concerned, through appropriate procedures and in particular through their representative institutions, whenever considering measures which may affect them directly. This is highly relevant in relation to planned oil and gas activities in indigenous lands and territories.

Among the Arctic countries, only Denmark and Norway have ratified this Convention. The Convention text is at http://www.ilo.org/ilolex/english/convdisp1.htm.

A.2.4.2. International Covenant on Civil and Political Rights, 1966

The International Covenant on Civil and Political Rights (ICCPR), which is one of the core human rights instruments and forms part of the International Bill of Human Rights, contains two provisions of particular importance in relation to the rights of indigenous peoples in relation to oil and gas activities on their lands: Articles 1 and 27.

ICCPR Article 1(1) reaffirms the political dimension of the right of self-determination, through which 'all peoples' have the right to freely determine their political status, and freely pursue their economic, social and cultural development. The right of self-determination also includes an economic or resource dimension, which is of particular importance in relation to extractive activities on indigenous lands and territories. This dimension is enshrined in Article 1(2) of the Covenant. The core element of this provision is that the people concerned may, for their own ends, freely dispose of their natural wealth and resources. In no event may a people be deprived of its own means of subsistence. The right of self-determination has evolved so that it is now acknowledged that 'indigenous peoples' – similar to all other 'peoples' – have the right of self-determination.

ICCPR Article 27 states that, in those States in which ethnic, religious or linguistic minorities exist, persons belonging to such minorities shall not be denied the right, in community with the other members of their group, to enjoy their own culture, to profess and practice their own religion, or to use their own language.

All Arctic countries have ratified the Covenant, which is at http://www2.ohchr.org/english/law/ccpr.htm.

A.2.5. International conventions regarding the working environment

The following Conventions under the International Labour Organization (see http://www.ilo.org/ilolex/english/convdisp1.htm for Convention texts) have relevance to work in relation to oil and gas exploration, development, production, and transportation.

1. Convention concerning the Protection of Workers against Occupational Hazards in the Working Environment Due to Air Pollution, Noise, and Vibration, 1977 (ILO No. 148). Under this Convention, Parties are required to develop national laws or regulations prescribing measures to be taken for the prevention and control of, and protection against, occupational hazards in the working environment due to air pollution, noise and vibration. Workers are also required to comply with safety procedures relating to the prevention and protection against occupational hazards due to air pollution, noise, and vibration in the working environment. Contracting Parties include: Denmark, Finland, Norway, the Russian Federation, and Sweden.
2. Convention concerning Labour Administration: Role, Functions, and Organisation, 1978 (ILO No. 150). This Convention is intended to ensure the organization and effective operation of a system of labour administration in the Contracting Parties, which should be responsible for the preparation, administration, coordination, and review of national labour policy, and serve to prepare and implement relevant laws and regulations in this regard. Contracting Parties include: Denmark, Finland, Norway, the Russian Federation, Sweden, and the United States.
3. Convention concerning Occupational Safety and Health in Dock Work, 1979 (ILO No. 152). Under this Convention, Parties are required to develop national laws or regulations prescribing measures that, among others, provide for workplaces, equipment and methods of work that are safe and without risk of injury to health; provide the information, training and supervision necessary to ensure the protection of workers against risks of accident or injury in the course of their employment; provide workers with personal protective equipment, protective clothing, and life-saving appliances reasonably required; and establish proper procedures to deal with any emergency situations which may arise. Contracting Parties include: Denmark, Finland, Norway, the Russian Federation, and Sweden.
4. Convention concerning Occupational Safety and Health in the Working Environment, 1981 (ILO No. 155). This Convention requires Parties, in the light of national laws and regulations and in consultation with representative organizations of employers and workers, to formulate, implement and periodically review a coherent national policy on occupational safety, occupational health and the working environment, with the aim of preventing accidents and injury to health arising out of, linked with or occurring in the course of work, by minimizing, as far as practicable, the causes of hazards inherent in the working environment. Contracting Parties include: Denmark, Finland, Iceland, Norway, the Russian Federation, and Sweden.
5. Prevention of Major Industrial Accidents Convention, 1993 (ILO No. 174). This Convention requires Parties, in the light of national laws and regulations and in consultation with representative organizations of employers and workers and other affected groups, to formulate, implement, and periodically review a coherent national policy concerning the protection of workers, the public, and the environment against the risk of major accidents. This policy should be implemented through preventive and protective measures for major hazard installations and promote the use of best available safety technologies. Contracting Parties include Sweden.

A.3. Regional conventions and multilateral and bilateral agreements

A.3.1. Convention for the Protection of the Marine Environment of the North-East Atlantic, 1992 (OSPAR Convention)

The Convention for the Protection of the Marine Environment of the North-East Atlantic, 1992 (OSPAR Convention) merged and modernized the earlier 1972 Convention for the Prevention of Marine Pollution by Dumping from Ships and Aircraft (Oslo Convention) and the 1974 Convention for the Prevention of Marine Pollution from Land-Based Sources (Paris Convention) by providing for the application of the precautionary principle; the polluter pays principle; and the use of best available techniques (BAT) and best environmental practice (BEP), including clean technologies. The Convention provides strategies to direct its work in the protection and conservation of ecosystems and biological diversity, and the prevention and elimination of hazardous substances, radioactive substances, and eutrophication, as well as pollution from offshore sources. The Convention covers the North-east Atlantic including the Arctic portions of this area.

The OSPAR Commission has adopted a number of decisions, recommendations, and other agreements relating to the OSPAR offshore oil and gas strategy. These encompass a broad range of requirements covering discharges from offshore installations, including an emission standard for oily discharges as well as the types of chemicals that may be used and methods to test their toxicity; a management regime for offshore cuttings piles; management of produced water; and disposal of pipes, metal shavings, and other material from offshore operations. Also covered are guidance for environmental monitoring and assessment of data, as well as mandatory reporting procedures to OSPAR on discharges, spills, and emissions from offshore installations.

Arctic countries that are Parties to the OSPAR Convention include Denmark, Finland, Iceland, Norway, and Sweden. Further information, including full documentation relating to oil and gas requirements and monitoring procedures is at http://www.ospar.org/.

A.3.2. Copenhagen Agreement and Nordic Agreement

The Nordic Agreement on Cooperation regarding Combating of Pollution of the Sea by Oil and Other Harmful Substances, 1971 (Copenhagen Agreement), amended in 1993 (Nordic Agreement), is a multi-lateral agreement between Denmark, Finland, Iceland, Norway, and Sweden regarding cooperation on surveillance, investigations, reporting and information exchange to protect the marine environment from oil discharges and other harmful substances.

A.3.3. The Russian-Norwegian agreement on cooperation in combating emergency oil spills in the Barents Sea, 1993

Under this bilateral agreement, the development of Russian-Norwegian Cooperation for Maritime Safety and Oil Spill Prevention in the Barents area is coordinated. An important focus is the monitoring and pre-voyage reporting as part of the Vessel Traffic Management and Information Systems (VTMIS) for the Barents Sea and oil spill prevention and response.

A.4. National laws and regulations

An overview of key national laws and regulations is provided in Table A2.2.

A.4.1. Alaska, United States

In the U.S. Arctic, lands and subsurface rights belong to various individuals, entities, and governments. Oil and gas resources under State lands, including marine areas out to three miles (5 km) from shore, and privately owned lands, belong to and are regulated by the State of Alaska. Resources beneath Native lands are owned by the tribe, Native Corporation, or local government, but are regulated either by the State of Alaska or by the Federal Government. There are many agencies involved in regulating oil and gas activities in the U.S. Arctic. The main Federal and State of Alaska laws relevant to oil and gas activities are briefly described below.

Thus, there are Federal and State jurisdictions, each regulated by similar Federal and State laws (State laws are sometimes stricter). There are different laws and agencies involved in the process depending where the activity is taking place: onshore or marine areas, State, Federal, Native or private lands, wilderness, parks or forests, or under rivers and wetlands.

A.4.1.1. Federal laws and regulations

A.4.1.1.1. Division of responsibility for onshore and offshore areas

For Federally owned lands in the U.S. Arctic, there are two divisions of primary responsibility: onshore and offshore. Each of these areas of responsibility has a separate set of primary laws and regulations and is managed by different agencies of the Department of the Interior (DOI). For onshore Federal lands, the Bureau of Land Management (BLM) is the responsible regulator and the primary laws are the Mineral Leasing Acts (MLA 1920 and 1947) and the Naval Petroleum Reserves Production Act of 1976 (NPRPA). For Federal offshore areas, the Minerals Management Service (MMS) is the primary regulator and the primary law is the Outer Continental Shelf Lands Act (OCSLA) of 1953.

A number of Federal statutes are applicable in relation to both onshore and offshore areas, including the National Environmental Policy Act (NEPA), the Clean Air Act (CAA), the National Historic Preservation Act, the Endangered Species Act, the Migratory Bird Treaty Act, and the Oil Pollution Act of 1990.

Table A2.2. Key national laws and regulations relevant to oil and gas activities in the Arctic.

Alaska, United States	Canada	Greenland	Faroe Islands	Norway	Russian Federation
Oil and gas exploration, development, and production: authorization and regulation					
Onshore, under Federal jurisdiction: Federal Land Policy and Management Act of 1976 (FLPMA); the Naval Petroleum Reserve Production Act of 1976 (NPRPA); Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act of 1947; Alaska National Interest Lands Conservation Act (ANILCA); Oil and Gas Leasing Reform Act of 1987. Offshore, under Federal jurisdiction: Outer Continental Shelf Lands Act (OCSLA) of 1953	In Northwest Territories, Nunavut and Canadian northern offshore: Federal legislation, the Canada Oil and Gas Operations Act (COGOA) and Regulations. In Yukon: the Yukon Oil and Gas Act. Offshore Labrador: the Canada-Newfoundland Offshore Accord Act	Strategy concerning exploration and exploitation of hydrocarbons in Greenland, agreed by the Government of Greenland and the Danish Government in June 2003	Act No. 31 of 16 March 1998 on Hydrocarbon Activities	The Petroleum Act No. 72 of 29 November 1996, and associated Petroleum Regulations	Federal law 'On Subsoil Resources' of 21 February 1992, #2395-1 (as amended of 03.03.1995 #27-FZ, of 10.02.1999 #32-FZ, of 02.01.2000 #20-FZ, of 14.05.2001 #52-FZ, of 08.08.2001 #126-FZ, of 29.05.2002 #57-FZ, of 06.06.2003 #65-FZ, of 29.06.2004 #58-FZ, of 22.08.2004 #122-FZ): the central law governing oil activities, both onshore and offshore. Offshore: Federal law 'On Continental Shelf of the Russian Federation of 30 November 1995 , #187-FZ (as amended by Federal Laws of 10.02.1999 #32-FZ, of 08.08.2001 #126-FZ, of 22.04.2003 #50-FZ, of 30.06.2003 #86-FZ, of 11.11.2003 #148-FZ, of 22.08.2004 #122-FZ (as amended 29.12.2004), of 09.05.2005 #45-FZ)
Environmental impact assessment					
National Environmental Policy Act (NEPA) of 1969	For Federal jurisdictions: the Canadian Environmental Assessment Act. In Nunavut: Nunavut Land Claim Agreement. In Yukon: Yukon Environmental and Socio-economic Assessment Act		Act No. 31 of 16 March 1998 on Hydrocarbon Activities	The Petroleum Act No. 72 of 29 November 1996	Federal law 'On Environmental Review' of 23 November 1995 #174-FZ (as amended by Federal laws of 15.04.1998 #65-FZ, of 22.08.2004 #122-FZ (as amended 29.12.2004), of 21.12.2004 #172-FZ)
Environmental protection: water					
Clean Water Act (CWA) of 1948, 1972, 1977			Act No. 59 of 17 May 2005 on the Protection of the Marine Environment	The Pollution Control Act No. 6 of 13 March 1981	Federal law 'On Environmental Protection' of 10 January 2002 #7-FZ (as amended by Federal laws of 22.08.2004 #122-FZ, of 29.12.2004 #199-FZ, of 09.05.2005 #45-FZ)
Environmental protection: air					
Clean Air Act (CAA) of 1955, 1970, 1990			Act No. 31 of 16 March 1998 on Hydrocarbon Activities	The Pollution Control Act No. 6 of 13 March 1981: Regulation of emissions to the air	Federal law 'On Atmospheric Air Protection' of 4 May 1999 #96-FZ (as amended by Federal Laws of 22.08.2004 #122-FZ, of 09.05.2005 #45-FZ)
Environmental protection: wastes					
Resource Conservation and Recovery Act (RCRA) of 1970, 1976, 1984			Executive Order No. 37 from 8 March 2001 on Usage and Discharge of Substances and Material from Offshore Installations	The Pollution Control Act No. 6 of 13 March 1981: Regulation of offshore discharges; Disposal or decommissioning of facilities	Federal law 'On Industrial and Domestic Waste' of 24 June 1998 #89-FZ (as amended by Federal Laws of 29.12.2000 #169-FZ, of 10.01.2003 #15-FZ, of 22.08.2004 #122-FZ (as amended 29.12.2004), of 09.05.2005 #45-FZ)
Tax on discharges					
				Tax on discharge of CO2 in the petroleum activities on the continental shelf Act No. 72 of 21 December 1990, most recently amended by Act 20 December 1996 No. 100; Regulation No. 1451 of 12 November 2001 relating to Special Duties (NOX)	

Table A2.2. Cont.

Alaska, United States	Canada	Greenland	Faroe Islands	Norway	Russian Federation
Protection of species					
Endangered Species Act (ESA) of 1973; Migratory Bird Treaty Act of 1918. Offshore: Marine Mammal Protection Act (MMPA) of 1972				Nature Conservation Act No. 63 of 19 June 1970; The Marine Fishery Act No. 40 of 3 June 1983	Federal law 'On Wildlife' of 24 April 1995 #52-FZ (as amended by Federal laws of 11.11.2003 #148-FZ, of 02.11.2004 #127-FZ, of 29.12.2004 #199-FZ)
Protection of habitats					
Onshore: Wilderness Act, the Wild and Scenic Rivers Act; Offshore: Marine Protection, Research and Sanctuaries Act (MPRSA) of 1972, 1984				Nature Conservation Act No. 63 of 19 June 1970; The Marine Fishery Act No. 40 of 3 June 1983	Federal law 'On Protected Areas' of 14 March 1995 #33-FZ (as amended by Federal laws of 30.12.2001 #196-FZ, of 29.12.2004 #199-FZ, of 09.05.2005 #45-FZ); Federal law 'On Wildlife' of 24 April 1995 #52-FZ (as amended, see above)
Land use planning and coastal zone management					
Coastal Zone Management Act (CZMA) of 1972, 1990, 1996				The Planning and Construction Act No. 77 of 14 June 1985; The Harbour Act No. 51 of 6 August 1984	Federal law 'Land Code of the Russian Federation' of 25 October 2001 #136-FZ (as amended by Federal laws of 30.06.2003 #86-FZ, of 29.06.2004 #58-FZ, of 03.10.2004 #123-FZ, of 21.12.2004 #172-FZ, of 29.12.2004 #189-FZ, of 29.12.2004 #191-FZ, of 07.03.2005 #15-FZ, of 21.07.2005 #111-FZ, of 22.07.2005 #117-FZ)
Historical and cultural heritage					
National Historic Preservation Act (NHPA) of 1966, and 1992				Cultural Heritage Act No. 50 of 9 June 1978	Federal law 'On Cultural Heritage Sites (Historical and Cultural Monuments) of Peoples of the Russian Federation' of 25 June 2002 #73-FZ (as amended by Federal laws of 27.02.2003 #29-FZ, of 22.08.2004 #122-FZ (as amended 29.12.2004), of 03.06.2005 #57-FZ)
Indigenous peoples					
				The Finnmark Act No. 85 of 17 June 2005	Federal law 'On Territories of Traditional Nature Use of Indigenous Peoples of the North, Siberia, and Far East of the Russian Federation' of 7 May 2001 #49-FZ
Oil spill reporting, response, and preparedness					
Oil Pollution Act of 1990; Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980; Emergency Planning and Community Right-to-Know Act (EPCRA)	In Northwest Territories, Nunavut and Canadian northern offshore: Federal legislation, the Canada Oil and Gas Operations Act (COGOA) and Regulations. In Yukon: the Yukon Oil and Gas Act. Offshore Labrador: the Canada-Newfoundland Offshore Accord Act. Reporting: Arctic Waters Pollution Prevention Act		Executive Order on Health, Safety, and Environment in the Exploration Phase	The Information Duty Regulations of 3 September 2001	Federal law 'On Protection of Population and Territories from Natural and Man-Made Emergency Situations' of 21 December 1994 #68-FZ (as amended by Federal laws of 28.10.2002 #129-FZ, of 22.08.2004 #122-FZ)
Liability for damage to the environment					
Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980, and Superfund Amendments and Reauthorization Act of 1986 (SARA)				The Petroleum Act No. 72 of 29 November 1996; The Maritime Act No. 39 of 24 June 1994	

Table A2.2. Cont.

Alaska, United States	Canada	Greenland	Faroe Islands	Norway	Russian Federation
Health, environment, and safety in oil and gas activities					
Occupational Safety and Health Administration regulations	Canada Labour Code		Act No. 31 of 16 March 1998 on Hydrocarbon Activities; and Executive Order No 35 from 8 March 2001 concerning Health, Safety and the Environment during all Phases of the Hydrocarbon Activities	Health, environment, and safety regulations issued in pursuance of the Petroleum Act, the Pollution Act, the Product Control Act, the Health Personnel Act, the Patients' Rights Act, the Communicable Diseases Control Act, and Health related and Social Preparedness Act.	Federal law 'On Industrial Safety of Hazardous Industrial Facilities' of 21 July 1997 #116-FZ (as amended by Federal laws of 07.08.2000 #122-FZ, of 10.01.2003 #15-FZ, of 22.08.2004 #122-FZ, of 09.05.2005 #45-FZ); Federal law 'On Safety of Hydrotechnical Structures' of 21 July 1997 #117-FZ (as amended by Federal laws of 10.01.2003 #15-FZ, of 22.08.2004 #122-FZ, of 09.05.2005 #45-FZ, and by Federal laws of 27.12.2000 #150-FZ, of 30.12.2001 #194-FZ, of 24.12.2002 #176-FZ, of 23.12.2003 #186-FZ)
Pipelines					
	National Energy Board Act			Bilateral treaties	
Transportation of oil and oil products					
Hazardous Materials Transportation Act of 1975	Canadian Shipping Act; Arctic Waters Pollution Prevention Act (for offshore Arctic tanker transportation)			The Maritime Act No. 39 of 24 June 1994	
Royalties and taxation					
			Act No. 26 of 21 April 1999 on Taxation of Revenues relating to Hydrocarbon Activities; Act No. 16 of 14 February 2000 on Hydrocarbon Tax Administration; Act No. 26 of 7 March 2000 on Amendments to the Hydrocarbon Tax Act	Act No. 35 of 13 June 1975 relating to the taxation of sub-sea petroleum deposits, etc. (The Petroleum Taxation Act)	Federal law of 30 December 1995 #225-FZ 'On Production Sharing Agreements' (with modifications of January 7, 1999, June 18, 2001, June 6, 2003, June 29, 2004 and December 29, 2004)

A.4.1.1.2. Federal laws and regulations relevant to onshore operations

The authority for Federal management of onshore land derives from several statutes, including the National Environmental Policy Act (NEPA), the Alaska National Interest Lands Conservation Act (ANILCA), the Wilderness Act, the Wild and Scenic Rivers Act, the Mineral Leasing Act of 1920 and amendments, which promotes the mining of coal, phosphate, oil, oil shale, gas, and sodium on the public domain, and particularly the Federal Land Policy and Management Act of 1976 (FLPMA) and the Naval Petroleum Reserve Production Act of 1976 (NPRPA). Under FLPMA, the Secretary of the Interior has broad authority to regulate the use, occupancy, and development of public lands and to take whatever action is required to prevent unnecessary or undue degradation of the public lands (43 U.S.C. § 1732). The BLM under the authority of the Secretary of the Interior has the authority to grant permits and regulate the use, occupancy, and development of public lands to meet this objective. The BLM has the responsibility for managing the NPRA. Other statutes with which oil and gas producers must comply include the National Historic Preservation Act, the Endangered Species Act, the Migratory Bird Treaty Act, the Oil Pollution Act of 1990 and others. The Oil and Gas Leasing Reform Act of 1987 established a competitive leasing system for oil and gas resources.

Under the NPRPA, the Secretary has the authority to conduct oil and gas leasing and development in the National Petroleum Reserve – Alaska (NPRA) (42 U.S.C. § 6508). The NPRPA also provides that the Secretary shall assume all responsibilities for any activities related to the protection of environment, fish and wildlife, and historical or scenic values (42 U.S.C. § 6503(b)). In addition, the NPRPA authorizes the Secretary to promulgate such rules and regulations as deemed necessary and appropriate for the protection of such values within the reserve (42U.S.C. § 6503(b)).

The BLM is responsible for issuing oil and gas leases on Federal lands and on private lands for which the Federal government retains mineral rights. The BLM cannot issue leases for lands administered by the U.S. Department of Agriculture, Forest Service without consent from the Secretary of Agriculture. The Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act of 1947 for acquired lands provide the legislative authority for Federal oil and gas leasing. Title 43 CFR 3100 provides the regulatory basis for the BLM to administer Federal oil and gas leasing. Title 36 CFR, Subpart E, provides direction to the Forest Service to administer and regulate surface uses and leases on National Forest System lands.

In addition to State permits, an oil and gas operator must comply with a set of lease terms contained in the Federal lease. The terms of leasing for NPRA (and other lands north of 68 degrees) is set out by the National Petroleum Reserve Act 1976, which stipulates that bidding systems used in lease sales shall be based on bidding systems included in section 205(a)(1)(A) through (H) (!1) of the Outer Continental Shelf Lands Act Amendments of 1978 (92 Stat. 629) [43 U.S.C 1337(a)(1)(A)-(H)]. Thus, the bidding system is the same as the system that the MMS uses offshore. Lease restrictions provide a means to mitigate potentially significant impacts.

A.4.1.1.3. Overview of laws affecting the offshore U.S. Outer Continental Shelf oil and gas program

The Submerged Lands Act of 1953 and the Outer Continental Shelf Lands Act of 1953 were passed in order to define the ownership and boundaries of State and Federal lands offshore. A number of laws regarding responsibility for protecting natural resources and regulating pollution were passed in the 1970s: the National Environmental Policy Act (NEPA), the Coastal Zone Management Act (CZMA), the Endangered Species Act (ESA), the Marine Mammal Protection Act (MMPA), the Clean Water Act Amendment (CWAA), the Clean Air Act Amendment (CAAA), the Marine Protection, Research, and Sanctuaries Act (MPRSA), and the Outer Continental Shelf Lands Act Amendment (OCSLAA). Additional relevant laws from the 1990s include the Oil Pollution Act of 1990, the Clean Air Act Amendment (CAAA), the Coastal Zone Management Act Amendment (CZMAA), and the National Historic Preservation Act (NHPA).

The Outer Continental Shelf Lands Act (OCSLA) 1953, 1978, grants authority: to expedite exploration and development of the OCS; to protect the human, marine, and coastal environments; to obtain a fair and equitable return for the public on OCS resources; and to preserve and maintain free enterprise competition. The Act mandates the establishment of policies and procedures for granting and canceling leases; filing and approving exploration and development and production activities; coordinating and consulting with affected State and local governments; conducting onsite inspections and drills; and imposing civil penalties for failure to comply with regulations. It requires environmental studies of areas included in any oil and gas lease sale. It also ensures that States and local governments have timely access to information regarding OCS activities and provides an opportunity to review and comment on decisions relating to OCS activities. It establishes the Fishermen's Contingency Fund to compensate fishermen for fishing gear and vessel damage or loss caused by OCS operations.

The Coastal Zone Management Act (CZMA) 1972, 1990, 1996 promotes wise use and protection of coastal land and water resources through implementation of individual State coastal management programs. It covers all Federal activities; allows States to review OCS permits, plans, and lease sale notices that affect the land and water uses and natural resources of the coastal zone; creates consistency review procedures and deadlines; and establishes a consistency appeal process, standards, and deadlines.

The Clean Water Act (CWA) 1948, 1972, 1977 regulates pollution in order to restore and maintain the chemical, physical, and biological integrity of waterways. It establishes a grant program to assist municipalities in constructing sewage treatment plants; establishes regulatory requirements for discharges by industry and municipalities; and focuses on point-source pollution – wastes discharged from discrete and identifiable sources, such as pipes. Under this Act, pollutants generated by OCS operations and discharged into U.S. waters must comply with the standards included in a National Pollutant Discharge Elimination System (NPDES) permit.

The Marine Mammal Protection Act (MMPA) 1972 protects and promotes the conservation of marine mammals and their ecosystems and establishes the Marine Mammal Commission. It prohibits the taking of marine mammals and protects their habitats; requires development of international agreements to protect and conserve marine mammals; prohibits importing marine mammals and marine mammal products; and allows for approved incidental, but not intentional, taking of depleted and non-depleted marine mammals through letters of authorization, but allows exemptions for subsistence uses by Alaska and Northwestern Natives.

The Marine Protection, Research and Sanctuaries Act (MPRSA) 1972, 1984, identifies and protects marine environments of special national significance and enhances public awareness and wise use of the marine environment through educational programs and research. It mandates the evaluation, designation, and management of national marine sanctuaries. It prohibits dumping of certain materials into ocean waters except by Federal permit. It also promotes research on the effects of ocean dumping.

The Department of Interior Minerals Management Service (MMS) is responsible for the administration of the offshore leasing system and operations. This body conveys exploration and development rights; assesses environmental information; evaluates mineral resources; manages and inspects offshore oil and gas operations; and manages revenue collection from Federal and Indian lands. Thus, the MMS is the principal U.S. Government Agency that industry must deal with for leases, licenses, permits, resource and economic evaluation and verification, royalty and rent payments, environmental protection and oversight, and safety inspections and enforcement for oil and gas exploration and development on the U.S. OCS. The MMS has full responsibility for developing and implementing a leasing program for OCS oil and gas, for regulating the exploration and development of those resources, and for assuring that production facilities are cleared from the ocean when oil and gas production ends.

The issuance of an Application for a Permit to Drill is an MMS responsibility. The permit applicant must first obtain several permits from other authorities. These include the following.

1. Coastal Zone Management (CZMA) consistency authorization is obtained from the State;
2. Marine mammal protection clearance (MMPA) is obtained from the National Marine Fisheries Service (NMFS) of the Department of Commerce;
3. Water permits (discharge and reinjection) are obtained from the U.S. Environmental Protection Agency;
4. Air emission permits (CAA) are obtained from the U.S. Environmental Protection Agency.

A.4.1.1.4. Federal laws and regulations relevant to oil and gas exploration and exploitation activities onshore and offshore

Laws and regulations relating to environmental protection and pollution prevention

1. The National Environmental Policy Act (NEPA) of 1969 is intended to prevent or eliminate damage to the environment. It mandates the enactment of a unified approach to environmental analysis; ensures that environmental concerns are considered in decision making; and establishes standards for evaluating the environmental impact of major Federal actions through environmental impact statements, environmental assessments, or categorical exclusion reviews.

2. The Oil Pollution Act (OPA) was signed into law in August 1990, largely in response to increasing public concern following the *Exxon Valdez* accident. The OPA improved the nation's ability to prevent and respond to oil spills by establishing provisions that expand the Federal government's ability, and provide the money and resources necessary, to respond to oil spills. The OPA also created the national Oil Spill Liability Trust Fund, which is available to provide up to one billion U.S. dollars per spill incident. In addition, the OPA provided new requirements for contingency planning by both government and industry. The National Oil and Hazardous Substances Pollution Contingency Plan (NCP) has been expanded in a three-tiered approach: the Federal government is required to direct all public and private response efforts for certain types of spill events; Area Committees, composed of Federal, State, and local government officials, must develop detailed, location-specific Area Contingency Plans; and owners or operators of vessels and certain facilities that pose a serious threat to the environment must prepare their own Facility Response Plans (see also Appendix 2.2). Finally, the OPA increased penalties for regulatory non-compliance, broadened the response and enforcement authorities of the Federal government, and preserved State authority to establish laws governing oil spill prevention and response. For additional details on the Oil Pollution Act, refer to http://www.epa.gov/oilspill/opaover.htm.

3. The Clean Air Act (CAA) of 1955, 1970, and 1990 is intended to protect and enhance air quality by the setting of ambient air quality and emission standards for the protection of public health and welfare. It requires the States to design and implement programs to achieve the ambient air quality standards. Alaska has developed regulations (18 AAC 50) to address air quality onshore. The CAA establishes the regulatory jurisdiction of OCS air quality such that the MMS regulates air quality in the western and central Gulf of Mexico and the EPA regulates air quality in the remaining OCS areas, including off Alaska.

4. The Safe Drinking Water Act (SDWA) 1974, 1986, 1996 assures the provision of safe drinking water to all Americans served by public water supply systems. Two mechanisms have been developed to meet this goal. It is required that all public water systems meet minimum water quality standards. These include standards for bacteria, organic pesticides, inorganic substances, and radioactive materials. Secondly, Part C of the SDWA develops a program to protect underground sources of drinking water (USDWs: aquifers with total dissolved solids concentrations of less than 10 000 mg/L and capable of supplying a public water system, 40 CFR 144.3). The SDWA is a Federal/State cooperative effort which is based on federally set minimum standards and regulations administered by the States. Part C of the SDWA sets the basic guidance under which the EPA must develop minimum State requirements. These requirements are that programs shall: (1) prohibit any underground injection which is not authorized by permit or rule issued by the State; (2) require that the applicant for a permit satisfy the State that USDWs are not endangered; (3) include inspection, monitoring, record-keeping, and reporting requirements; (4) apply to underground injection by Federal agencies and by other persons on Federal land; and (5) not interfere with or impede (a) underground injection of brine or other fluids brought to the surface in conjunction with oil and gas production, or (b) underground injection for secondary or tertiary recovery of oil unless such requirements are essential to assure that USDWs are not endangered. Three other important provisions are made which affect groundwater protection. First, underground injection is defined as 'the subsurface emplacement of fluids by well injection' (Section 1421 (d)). Second, endangerment means the presence of a contaminant which may prevent a public system from complying with any national primary drinking water standard or otherwise adversely affect the public health (Section 1421 (d)). And thirdly, the Administrator shall determine each State which needs an underground injection program to protect drinking water sources. If the State, so listed, does not obtain primary enforcement authority, then the EPA shall administer the programs (Section 1422 (a)).

   The 1986 amendments to the SDWA established a Wellhead Protection program that the States may use to protect public drinking wells and springs from contaminants which may have adverse effects on the health of persons. Originally, the SDWA focused primarily on treatment as the means of providing safe drinking water at the tap. The 1996 amendments enhanced the existing law by recognizing source water protection, operator training, funding for water system improvements, and public information as important components of safe drinking water. This approach ensures the quality of drinking water by protecting it from source to tap. The UIC program regulations are found in Parts 144, 145, 146, 147, and 148 of Title 40 of the Code of Federal Regulations and are usually cited as 40 CFR Part 124, 144, etc.

5. The Toxic Substances Control Act of 1976 (TSCA) (15 U.S.C. 2601) is intended to protect human health and the environment from hazardous chemicals by authorizing EPA to track the 75 000 industrial chemicals currently produced or imported into the United States and to require testing of new and existing chemical substances that may pose an environmental or human-health hazard. The U.S. EPA can ban the manufacture and import of those chemicals that pose an unreasonable risk. TSCA also regulates the treatment, storage, and disposal of certain toxic substances, specifically polychlorinated

biphenyls, chlorofluorocarbons, asbestos, dioxins, certain metal-working fluids, and hexavalent chromium. TSCA supplements other Federal statutes, including the CAA and the Toxic Release Inventory under the Emergency Planning and Community Right-to-Know Act (EPCRA).

6. The Resource Conservation and Recovery Act (RCRA) of 1970, 1976, and 1984 regulates the disposal or recovery of hazardous waste. It establishes a 'cradle-to-grave' system to track the movement of hazardous waste from the source to a final disposal or recovery site; requires that hazardous wastes be defined; creates a permit program for hazardous waste treatment, storage, and disposal and prohibits open dumps; and encourages and financially assists States to develop hazardous wastes disposal and recovery programs. The State of Alaska is not authorized for the RCRA hazardous waste program. RCRA includes a special exemption for oil and gas exploration and production activities from the definition of hazardous waste.
7. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) 1980 authorizes the recovery of damages from potentially responsible parties for injuries to natural resources from the release of hazardous substances. It authorizes full restoration of natural resources to pre-injury conditions and compensation for environmental damage. It also creates the Natural Resource Damage Assessment regulations, which provide an administrative process for conducting natural resource damage assessments and outline technical procedures to identify injuries and calculation of damages.

Laws and Executive Orders relating to the protection of species and habitats

1. The Endangered Species Act (ESA) of 1973 protects and promotes the conservation of plants and animals listed as endangered or threatened and their critical habitats. It prohibits the taking of endangered or threatened species and protects their habitats; prohibits Federal actions/permitted activities from jeopardizing the continued existence of any threatened or endangered species; requires endangered species consultations with relevant agencies; requires biological opinions on proposed actions; allows for approved incidental, but not intentional, taking of listed animals and plants but requires letters of authorization; allows exemptions for subsistence uses by Alaska and Northwestern Natives; and prohibits or regulates the international trade of ESA-listed species.
2. The Migratory Bird Treaty Act (Title 16 U.S.C. 703) is intended to protect birds that have common migration patterns between the United States and Canada, Mexico, Japan, and Russia. The Act regulates the harvest of migratory birds by specifying the mode of harvest, hunting seasons, and bag limits.
3. The Magnuson-Stevens Fishery Management and Conservation Act (M-SFMCA) (16 U.S.C. 1801-1883) establishes national standards for fishery conservation and management within the EEZ and oversees the preparation of fishery management plans. One of the key guidelines calls for the delineation of Essential Fish Habitat (EFH).
4. The Alaska National Interest Lands Conservation Act (PL 96-487) of 1980 created the National Wildlife Refuges in Alaska. The Arctic Wildlife Range was enlarged from 8.8 million acres to 19 million acres and renamed the Arctic National Wildlife Refuge.
5. The Rivers and Harbors Act of 1899 requires that a permit be obtained from the U.S. Army Corps of Engineers for construction of a dam, dike, or other structure in or affecting navigable waters. The term 'navigable waters' includes waters subject to the ebb and flow of the tide and/or waters usable for commerce transportation.
6. Executive Order 13186 on Responsibilities of Federal Agencies to Protect Migratory Birds directs all Federal agencies to avoid or minimize the impacts of their actions on migratory birds, and to take active steps to protect birds and their habitat. It directs that agencies ensure that environmental analyses of Federal actions required by the NEPA or other established environmental review processes evaluate the effects of actions and agency plans on migratory birds, with emphasis on species of concern.

Laws relating to the preservation of historic or archeological sites

1. The National Historic Preservation Act (NHPA) of 1966, and 1992, protects historic and prehistoric sites from Federally funded or permitted activities. It created the National Register of Historic Places to designate properties as historic landmarks and requires Federal agencies to consider the effects of their programs and permitting actions on any district, site, building, structure, or object that is listed on or eligible for listing in the National Register of Historic Places. It also encourages similar protection on non-Federal lands (1992 amendments). The Act also established the National Historic Preservation Fund.
2. The Archeological Resources Protection Act of 1979 (ARPA) (16 U.S.C. 470) secures the protection of archaeological resources and sites on public and Indian lands, and encourages the exchange of information between involved individuals and entities.

Laws and Executive Orders relating to relations with and the rights of indigenous peoples

1. The Alaska Native Claims Settlement Act (ANCSA) (43 U.S.C. 1601-1624), which became law on 18 December 1971, recognized Alaska Native Land Entitlements with the creation of Native corporations with Alaska Natives as shareholders and the conveyance of approximately 44 million acres of land, which was a little more than 10% of the entire State.
2. Executive Order 12898 on Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations directs Federal agencies to develop environmental justice strategies to identify and address disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations (including Native American Tribes), with the goal of making environmental justice a part of their mission and achieving environmental protection for all communities. Federal agencies are to

consider the following ways to evaluate environmental justice under the NEPA: identifying the affected area to determine whether minority populations or low-income populations would be affected, analyzing the effects of the agencies' actions on minority populations and low-income populations, evaluating public health data, and assessing possible cultural, social, or historical factors that may be affected by the action. Mitigation measures identified as part of the NEPA process should address significant and adverse environmental effects of proposed actions on minority populations and low-income populations. Moreover, agencies are required to provide opportunities for effective community participation in the NEPA process.

3. Executive Order 13175 on Consultation and Coordination with Indian Tribal Governments directs Federal agencies to establish regular and meaningful consultation and collaboration with tribal officials in the development of Federal policies that have tribal implications, strengthen the government-to-government relationships with Indian Tribes, and reduce the imposition of unfunded mandates upon Indian Tribes.

Federal laws on safety in the workplace

The U.S. Department of Labor, Occupational Safety and Health Administration (OSHA) develops standards for worker safety. OSHA's general industry standards are applicable to the oil and gas well drilling and servicing industry. In addition to these specific standards, the General Duty Clause (Section 5(a)(1) of the OSH Act of 1970) requires the employer to provide a safe and healthful workplace.

Most of the incidents resulting in injury or pollution stem from human error. Since the early 1990, the MMS has encouraged industry on a voluntary basis to adopt company-specific Safety and Environmental Management Programs. The rationale is that safety is not achieved by a set of rules, but rather by a commitment on the part of all workers to avoid accidents.

Federal laws on waste management

The principal method for controlling pollutant discharges is through Section 402 (33 U.S.C. § 1342) of the Federal Water Pollution Control Act (commonly referred to as the Clean Water Act of 1972), which establishes a National Pollution Discharge Elimination System (NPDES). Under Section 402, the EPA or authorized States can issue permits for pollutant discharges, or can refuse to issue such permits if the discharge would create conditions that violate the water quality standards developed under Section 303 (33 U.S.C. § 1313) of the Clean Water Act. The Clean Water Act, Section 403 (33 U.S.C. § 1343), states that no NPDES permit shall be issued for a discharge into marine waters except in compliance with established guidelines.

The guidelines require a determination that the permitted discharge will not cause unreasonable degradation to the marine environment (40 CFR 125.122). Unreasonable degradation of the marine environment means: significant adverse changes in ecosystem diversity, productivity, and stability of the biological community within the area of discharge and surrounding biological communities; threat to human health through direct exposure to pollutants or through consumption of exposed aquatic organisms; or loss of aesthetic, recreational, scientific, or economic values, which is unreasonable in relation to the benefit derived from the discharge.

The NPDES permit system establishes: limits on what may be discharged; times of the year and locations where waste can be discharged; rates of discharge; and the method and frequency of chemical analysis to ensure and demonstrate compliance. The NPDES program has unilaterally prohibited the discharge in the United States of the following: oil-based drilling fluids, free oil, oil-contaminated drilling fluids, diesel oil, produced sand, toxic wastes, and floating solids. Synthetic fluids cannot be discharged, but drill cuttings containing SBF may be discharged.

In the Beaufort Sea, no discharges are permitted within 1000 m of river mouths or deltas during unstable or broken ice periods or open water conditions. Operators are also prohibited from discharging within 1000 m of unique biological communities such as the Beaufort Sea 'Boulder Patch'. Discharge limits are based on water depth. The Northstar Island, the first offshore facility in the Beaufort Sea, is designed to be a zero-discharge facility.

Another method used in Alaska for waste disposal is underground injection. This program is also regulated under the Underground Injection Control Program, another facet of the Clean Water Act. Permit applications are submitted to the U.S. EPA or the State for State submerged lands or to the MMS for OCS lands.

The latest information on water quality standards for the EPA is available in the most recent edition of 40 CFR (paragraph 131) or at the agency's internet website (http://www.epa.gov). State of Alaska water information is available in the most recent version of 18 AAC 70 or at the Alaska Department of Environmental Conservation website (http://www.state.ak.us/dec/).

A.4.1.1.5. Federal requirements for permits for oil- and gas-related activities

Federal requirements for permits in relation to oil and gas exploration and development activities and the associated issuing agency are summarized in Table A2.3.

U.S. Environmental Protection Agency

Under the terms of the Federal Clean Water Act, the NPDES ensures that the discharges comply with technology requirements and water quality standards (standards applicable to the ambient, or receiving waters) set by the State and the EPA. Point sources consist of discrete conveyances such as pipes or man-made ditches. Discharges either directly into a natural water system or into a wastewater collection system require NPDES permits. Currently, the Alaska State Government is not authorized to administer NPDES permitting, hence permit applications must be made through the EPA; however, the State applied to the EPA on 30 June 2006 to gain primacy of the NPDES program.

NPDES permits for OCS and onshore areas are obtained from the EPA either as an individual permit or coverage under a general permit. General permits are available for the North Slope offshore including OCS and State waters. General permits set the requirements for the activity. An applicant notifies the EPA with an application of intent. Authorization to discharge is granted provided that the applicant meets the conditions of the permit. If the operation does not fit under a general permit (i.e., the Cook Inlet General Permit or North Slope General

Table A2.3. General guide to the types of permit required for an oil and gas project in Alaska (modified from Petroleum News, 2005).

Permit	Required for	Comments
Local government (e.g., North Slope Borough, Kenai Peninsula Borough)		
Local government permits	Exploration Development	A local government may require various permits such as development permits for activities within its jurisdiction. Public meetings may be required as part of the permitting process.
Alaska Department of Environmental Conservation		
Oil discharge prevention and contingency plan	Exploration Development	C-plans are needed for drilling in most areas where little is known about the geology or if liquid hydrocarbons may be encountered while drilling. A waiver may be granted if evidence is provided that liquid hydrocarbons will not be encountered. http://www.state.ak.us/dec/spar/guidance.htm#cplans.
Air quality general permit	Exploration Development	http://www.state.ak.us/dec/air/ap/genperm.htm.
Solid waste temporary storage permit	Exploration Development	http://www.state.ak.us/dec/eh/sw/.
Alaska Department of Natural Resources		
Land use permit	Exploration	Needed to cross State lands for seismic or other activities. http://www.dnr.state.ak.us/mlw/permit_lease/index.cfm (Note that the use of land for the construction of a permanent facility is generally covered by the plan of operations for a State lease. A sales pipeline on State land outside of an oil or gas unit requires a right-of-way permit.)
Temporary water use permit	Exploration	Needed from the Division of Mining, Land and Water for the use of water during activities such as drilling. www.dnr.state.ak.us/mlw/water/index.htm.
Water rights application	Development	May be needed for long-term water rights from the Division of Mining, Land and Water. http://www.dnr.state.ak.us/mlw/water/wrfact.htm.
Title 41 permit	Exploration Development	Required from the Office of Habitat Management and Permitting to work in a stream that has fish, regardless of land ownership. http://www.dnr.state.ak.us/habitat/FHpermits.htm.
Coastal zone consistency determination	Exploration Development	Applies to activities within the Alaska coastal zone, which must be found consistent with the Alaska Coastal Management Program before any other permits can be issued. The Office of Project Management and Permitting determines which agency will be issuing the consistency determination for each project. http://www.alaskacoast.state.ak.us.
Lease operations permit	Exploration Development	The Division of Oil and Gas requires a plan of operations for activities on State oil and gas leases or within State-managed units. This is not needed on private lands outside units. http://www.dog.dnr.state.ak.us/oil/programs/permitting/plan_of_operations_info.htm.
Geophysical exploration permit	Exploration	A geophysical exploration permit is required to conduct a seismic survey on State lands or waters. http;//www.dog.dnr.state.ak.us/oil/programs/permitting/applications.htm
Cultural resource clearance	Exploration Development	A letter from the Alaska State Historic Preservation Office stating that an operation does not impact any archaeological or cultural sites is required. An archaeologist may need to review the area of proposed operations. http://www.dnr.state.ak.us/parks/oha/index.htm.
Environmental and cultural training program	Exploration Development	Environmental and cultural training is sometimes a requirement of a State lease.
Gravel sale	Exploration Development	If more than 25 000 cubic yards of gravel is needed, the State has to have a gravel sale. This is not needed if gravel is obtained from a private source.
Habitat or special area permit	Exploration Development	A permit is needed if activities are to take place in a special habitat, a wildlife refuge or other legislatively designated use area. http://www.dnr.state.ak.us/habitat/FHpermits.htm.
Alaska Oil and Gas Conservation Commission		
Permit to drill	Exploration Development	Any drilling operation requires an approved application for permit to drill. http://www.state.ak.us/tocal/akpages/ADMIN/ogdtonmsllt-401.pdf (Needed for approval of changes to the drilling plan. http://www.state.ak.ssllocallakpages/ADMIN/ogclformsll0-403.pdf.)
Sundry permits	Exploration Development	
Annular disposal permit	Exploration Development	This is required for small-scale disposal of cuttings when drilling. Total volume is not to exceed 35 000 bbl through the annular space of a single well and for no longer than one year. There is a need to be able to demonstrate mechanical integrity. http://www.state.ak.us/local/akpages/ADMIN/ogc/forms/10-403AD.pdf.
AOGCC orders	Development	There are a number of AOGCC orders that can apply to drilling and well operations. The order process normally includes a 30-day notice period. AOGCC orders include aquifer exemption orders, disposal injection orders, area injection orders, conservation orders (including pool rules and spacing exceptions), enhanced recovery injection orders, storage injection orders and commission orders. http://www.state.ak.us/local/akpages/ADMIN/ogc/homeogc.htm.
U.S. EPA		
NPDES permit	Exploration Development	A general permit for water discharges within the EPA limits. Individual discharge permits are required for discharges above the allowed amount in the general permit. Only a Notice is required for a general permit. http://cfpub.epa.gov/npdes/ for further information
UIC Class I/V permit	Injection of non-E&P-related waste streams	Owner/operator needs to have an approved permit issued by the EPA for injection of wastes not associated with fluids brought to the surface from downhole oil and gas Exploration and Production activities. Class II injection permits are issued by the AOGCC. Additional UIC information at http://www.epa.gov/safewater

Table A2.3. Cont.

Permit	Required for	Comments
Spill prevention control and countermeasure plan	Exploration Development	Required for an onshore drilling rig.
Facility response plan	Exploration Development	This is a requirement of the Oil Pollution Act 1990. Depending on the location and nature of the operation, this plan could come under the EPA, the U.S. Coast Guard, or the MMS It is part of the State spill response plan. http://www.epa.gov/oilspill/pdfs/frpguide.pdf.
EA	Exploration Development	May be needed for exploration work. For example, the BLM and the MMS require an EA for individual exploration projects.
EIS	Exploration Development	Rarely needed for exploration work. On Federal land or waters, the relevant Federal agency will issue an ElS prior to a lease sale or a project-specific EIS if needed.
U.S. Army Corps of Engineers		
Section 404 Wetlands permit	Exploration Development	When a project involves water, some form of a wetlands permit is needed. One Corps of Engineers application covers all types of permits. If impact is minimal a standard nationwide permit may be applicable. http://www.poa.usace.army.mil/reg.
Section 401 certification (from Alaska Department of Environmental Conservation)	Exploration Development	This is required from the State if there are wetlands involved in the project, to ensure compliance with the State's water quality regulations, and is initiated and implemented by State and Federal agencies. http:// www.state.ak.us/ declwaterlwnpspdwetiandslwetlandspermrtting.hton.
EA	Development	A permanent development will normally trigger the need for an EA.
EIS	Development	A permanent development might trigger an EIS.
Bureau of Indian Affairs		
Access to Native Allotment	Exploration Development	Permits are required from a Native non-profit organization recognized by BIA if a project has to cross over or occur in a Native allotment.
Bureau of Land Management		
Right of way	Exploration Development	Needed for the use of roads or for travel across BLM lands.
Geophysical permit	Exploration	A geophysical permit is required for seismic exploration on BLM lands. Ref. 43 CFR 3150.
Permit to drill (Form 3160-3)	Exploration Development	Permit to drill addresses both the drilling plan and the surface use plan. Ref. Onshore Oil and Gas Order No. 2.
Sundry permits (Form 3160-5)	Exploration Development	Required for changes in a drilling plan and for various activities associated with drilling and production that are not covered under other permits.
EA	Exploration	Needed for rights-of-way, geophysical exploration, and exploratory drilling.
EIS	Development	Development of a field requires that an EIS be written.
Department of the Interior MMS		
Oil and gas geological and geophysical exploration permit	Exploration	This permit allows geological and geophysical exploration to be conducted on the OCS without first having to purchase an oil and gas lease.
Exploration plan	Exploration	Exploration activities within an oil and gas lease on the outer continental shelf require an MMS-approved exploration plan.
Permit to drill	Exploration Development	Any drilling operation in the outer continental shelf requires an approved application for permit to drill, known as an APD, from the MMS.
Development plan	Development	A development plan needs to be approved by the MMS for field development on an MMS lease. The development plan enables field facilities and structures to be permitted. Development of a transportation pipeline from a field requires a right-of-way permit
Oil spill response plan	Exploration Development	Any oil facility seaward of the coastline requires an oil spill response plan approved by the MMS. It could also be a State spill response plan.
EA	Exploration Development	May be needed for exploration work. An EA may be needed for a production project.
EIS	Exploration Development	This is rarely needed for exploration work. On Federal land or waters, the relevant Federal agency will issue an EIS prior to a lease sale. An EIS may be needed for a production project. It may take two to four years to complete.
U.S. Coast Guard		
Facility response plan	Exploration Development	Any marine transportation-related facility that could discharge oil in navigable water, on adjoining shorelines, or in the EEZ requires a Coast Guard-approved facility response plan. This is usually part of the oil discharge prevention and contingency plan.
Fuel transfer manual	Exploration Development	This will be required when working on or near navigable waters.

EA: Environmental assessment; EIS: environmental impact statement.

Permit), then the applicant must apply for an individual permit that meets the water quality standards set by the State and the EPA. A general permit authorizes a category of discharges within a geographical area and is not tailored for an individual discharger. Details of general permits for Alaska oil and gas operations are at http://yosemite.epa.gov/R10/WATER.NSF/NPDES+Permits/General+NPDES+Permits#Oil%20and%20Gas.

The NPDES website at http://cfpub.epa.gov/npdes/ provides detailed information about the NPDES program.

Under the terms of the Federal Resource Conservation and Recovery Act (RCRA), the treatment, storage, and disposal of hazardous waste is managed by the EPA. The State of Alaska is authorized to implement the solid waste program under subtitle D of the RCRA. The EPA manages corrective actions of releases from TSD facilities (facilities that treat, store, or dispose of hazardous waste) including solid wastes that also comprise drilling muds and hazardous waste.

Under the terms of the SDWA, Part C is intended to protect USDWs; it sets the basic guidance under which the EPA must develop minimum State requirements. At present, Classes I, III, IV and V of injection wells in Alaska are administered by the EPA. Granting of an Aquifer Exemption for injection into USDWs (with less than 10 000 mg/L of total dissolved solids) must also be approved by the EPA.

Under the Clean Air Act, the EPA is responsible for conducting 40 CFR Part 55 consistency updates to ensure that permitted actions on the OCS are similar to those onshore. In addition, the EPA is responsible for issuing all air permits on the OCS.

Any onshore drilling operation requires a spill prevention control and countermeasure (SPCC) plan specifying the spill prevention and control measures for the operation. This SPCC plan must be available to the EPA for on-site review and inspection.

Under the terms of the Federal Clean Water Act and the Oil Pollution Act of 1990, the operator of a facility that could cause 'substantial harm' to the environment by discharging oil into navigable waters or adjoining shorelines must prepare and submit a Facility Response Plan to the EPA. A Facility Response Plan must:

- be consistent with the National Contingency Plan and area contingency plans;
- identify a qualified individual who has full authority to implement removal actions, and require immediate communication between that person and the appropriate Federal authorities and responders;
- identify and ensure availability of resources to remove, to the maximum extent practicable, a worst-case discharge;
- describe training, testing, unannounced drills, and response actions of persons at the facility;
- be updated periodically; and
- be submitted for approval with each significant change.

A facility response plan is normally part of the oil discharge prevention and contingency plan that the Alaska Department of Environmental Conservation requires. Information about EPA facility response plans can be found at http://www.epa.gov/oilspill/frps/frp_index.htm. The EPA also publishes a useful guide at http://www.epa.gov/oilspill/pdfs/frpguide.pdf.

A project that involves the Federal government in any way comes under the terms of the National Environmental Policy Act. The NEPA may require an environmental assessment or an environmental impact statement. For oil and gas exploration on Federal lands, the relevant Federal agency will normally issue an environmental impact statement prior to a lease sale.

U.S. Army Corps of Engineers

The U.S. Army Corps of Engineers regulates activities that impact U.S. navigable waters and wetlands. Regulations at 33 CFR Part 329 define navigable waters as waters that have been used in the past, are now used, or are susceptible to use as a means to transport interstate or foreign commerce up to the head of navigation. Under Section 10 of the Rivers and Harbors Act of 1899, a permit is required to do any work in, over or under these navigable waters, or to do work that affects the course, location, condition or capacity of such waters.

Under Section 404 of the Federal Clean Water Act, a permit from the Corps of Engineers is required to discharge dredged or fill material into the waters of the United States. Also, under Section 401 of the Clean Water Act, the Alaska Department of Environmental Conservation has to review the Federal Section 404 permit application to identify potential water quality impacts. When warranted, ADEC will grant Section 401 certification. The Corps of Engineers will require this certification before it can issue a Section 404 permit.

Waters of the United States consist of all surface waters, including all navigable waters and their tributaries, all interstate waters and their tributaries, all impoundments of these waters, all wetlands adjacent to these waters and certain isolated wetlands. Identification of Corps-jurisdictional wetlands was challenged in a Supreme Court case in early 2006. The U.S. Supreme Court decision on wetlands was issued on 19 June 2006 in 'Rapanos v. United States' remanding the issue to a lower court which has yet to rule on the matter. The term 'wetlands' refers to those areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include tundra, permafrost areas, swamps, marshes, bogs, and similar areas.

Depending on the situation, a Corps of Engineers individual nationwide or regional general permit may be required. The Corps of Engineers issues individual permits for specific projects. The permitting procedure involves a public review process as well as a review by the Corps of Engineers.

An individual permit is not necessary if a project falls within the terms of a nationwide permit. The Corps of Engineers headquarters issues nationwide permits to authorize certain activities that are minor in scope and that result in no more than minor adverse impacts. Work done under a nationwide permit must meet regional conditions specific to Alaska as well as the general, nationwide terms of the permit.

If a project requires work that does not fit within the parameters of a nationwide permit, it may be possible to operate under the terms of an Alaska regional general permit. The Corps of Engineers Alaska District Engineer issues regional general permits for activities that are similar in nature and cause minimal environmental impact (both individually and cumulatively) and when the regional permit reduces duplication of regulatory control by State and Federal agencies.

Projects involving a permanent development and requiring a Corps of Engineers permit will normally require an environmental assessment under the terms of the NEPA. An environmental impact statement may be required. Environmental assessments and environmental impact statements are discussed in Chapter 6.

The Bureau of Indian Affairs

Permission is required to cross or work in a Native allotment or surface use land grant area. The Bureau of Indian Affairs has ultimate responsibility for the administration of access to Native allotments in Alaska. However, the Bureau of Indian Affairs generally contracts this administrative role to a recognized Native non-profit organization such as a regional Native non-profit or a village council; this organization would be responsible for issuing an access permit.

U.S. Department of the Interior Bureau of Land Management

Under the terms of 43 CFR 3150, the BLM can issue permits for geophysical exploration on Federal lands in Alaska. These permits last for one year and enable companies to conduct seismic surveys and other geophysical work without having to first purchase an oil and gas lease. Permits are subject to review under the NEPA and may contain restrictions and conditions to mitigate adverse impacts on the environment.

Drilling on Federal land is subject to Onshore Oil and Gas Order No. 2. Before drilling a well on Federal land, an application for a permit to drill, known as an APD, must be filed with the BLM. Onshore Oil and Gas Order No. 1 describes the process for submitting an APD to the BLM. It is possible to file a single APD for a group of wells. The APD includes the drilling plan, a surface use plan, and plans for reclaiming the land. Before approval of the APD, the BLM will require a bond and conduct a site inspection. Changes in the drilling plan may be imposed to mitigate environmental impacts or to ensure that the plan complies with Federal regulations.

Oil and gas development proposals are submitted by sundry notice (Form 3160-5) if the proposal is on a lease or a right-of-way. Projects on Federal lands fall under the terms of the NEPA and require the preparation of an environmental assessment or an environmental impact statement.

U.S. Department of the Interior Minerals Management Service

Under the terms of 30 CFR 251, the MMS can issue permits for geological and geophysical exploration on the OCS. These permits enable companies to conduct seismic surveys and other geological and geophysical work without having to first purchase an oil and gas lease. Applications for permits are handled by the MMS Alaska OCS office in Anchorage. If the exploration involves shallow drilling not requiring a drilling permit, there may be a requirement to submit a drilling plan to the MMS and, possibly, to the appropriate coastal zone management agency.

Under 30 CFR 250.200, exploration activities associated with an OCS oil and gas lease require an exploration plan approved by the MMS. The exploration plan needs to include information such as the activities to be carried out, the type of drilling equipment to be used, the proposed locations of wells, and the safety precautions that will be taken.

Before drilling a deep well on the OCS, an application must be filed for a permit to drill, or an APD, with the MMS. The APD includes a specification of the drilling equipment to be used, the drilling plan, and specification of safety precautions to be used.

Development of an oil or gas field on the OCS will require an MMS-approved development plan. The development plan must include details of planned activities, locations of proposed wells, and descriptions of structures to be constructed. The development plan can be used to permit the construction or field structures and facilities. However, a pipeline that is not part of the field gathering system will require a right-of-way permit.

Regulation 30 CFR 254 states that "if you are the owner or operator of an oil handling, storage, or transportation facility, and it is located seaward of the coast line, you must submit a spill-response plan to MMS for approval. Your spill-response plan must demonstrate that you can respond quickly and effectively whenever oil is discharged from your facility." The regulation defines a facility as "any structure, group of structures, equipment, or device (other than a vessel) which is used for one or more of the following purposes: exploring for, drilling for, producing, storing, handling, transferring, processing, or transporting oil". The term excludes deep-water ports and their associated pipelines as defined by the Deepwater Port Act of 1974, but includes other pipelines used for one or more of these purposes. A mobile offshore drilling unit is classified as a facility when engaged in drilling or downhole operations. The response plan must provide for response to an oil spill from the facility and provisions of the plan must immediately be carried out whenever there is a release of oil from the facility. The training, equipment testing, and periodic drills described in the plan must also be executed, and these measures must be sufficient to ensure the safety of the facility and to mitigate or prevent a discharge or a substantial threat of a discharge. The plan must be consistent with the National Contingency Plan and the appropriate Area Contingency Plans.

Facilities operating in State waters within the 3-mile limit can use the oil discharge prevention and contingency plan required by the State, provided that the plan contents meet MMS requirements. There are also some specific spill prevention requirements that apply to State waters.

MMS oil and gas leases normally include appropriate stipulations and conditions to mitigate potential adverse impacts on the environment. For example, the lessee may have to contact Native organizations to avoid conflicts with subsistence hunting and other activities. In addition to lease stipulations, the MMS may prescribe additional stipulations and conditions for proposed operations or associated activities on the OCS. For example, as a condition to obtain a right-of-way grant, the MMS may require that additional mitigating measures (stipulations) be taken by the applicant to protect humans, marine and coastal environments, life (including aquatic life), property, and mineral resources located on or adjacent to the right of way.

U.S. Coast Guard
Under 33 CFR 154, the owner or operator of any marine transportation-related facility that could reasonably be expected to cause substantial harm, or significant and substantial harm, to the environment by discharging oil into or on the navigable waters, adjoining shorelines or EEZ must prepare a facility response plan. The owner or operator must submit this facility response plan to the local U.S. Coast Guard captain of the port for approval. The Coast Guard requires specific contents for this plan. However, it is normally possible to prepare a single facility response plan that meets the requirements of several regulatory agencies. The plan needs to be consistent with the National Oil and Hazardous Substances Pollution Contingency Plan and any area contingency plans. There are also specific response requirements for a facility operating under the Trans-Alaska Pipeline Authorization Act in Prince William Sound. The U.S. Coast Guard also requires persons to use a Coast Guard-approved fuel transfer manual if they are working on or near navigable waters. Vessels carrying oil as cargo also require a Coast Guard-approved vessel response plan.

A.4.1.1.6. The National Environmental Policy Act and Environmental Impact Statements
The National Environmental Policy Act of 1969 applies to any activity that involves a Federal action or approval. An action taken by the Federal government itself can come under the terms of NEPA, as well as involvement of the Federal government through Federal funding, Federal licensing, Federal permitting or the use of Federal lands as part of a project. In any of these situations, a designated Federal agency needs to ensure compliance with NEPA before the project can begin. As a minimum, NEPA requires that the designated agency identify and disclose the potential environmental impacts of the activity. The agency may then require the development of an environmental assessment to document the impacts. If the agency determines that the environmental impacts are likely to be significant, the agency will mandate the development of an environmental impact statement (EIS).

The BLM manages the Federal onshore mineral estate and is normally the lead agency for NEPA compliance for mineral activities on Federal land onshore. The MMS is the lead agency for offshore activities in Federal waters beyond the State of Alaska's three-mile limit. When the Federal government wishes to initiate an action requiring an EIS, the appropriate Federal agency will prepare the EIS, possibly using external consultants. The agency will complete the EIS prior to a final decision on whether to proceed with the action. For example, when the BLM writes a land use plan or an activity plan, an EIS describing the impacts of the plan is produced. If, on the other hand, an application for Federal funding, licensing or permitting requires an EIS, receipt of the application will trigger development of the EIS. For example, the application to renew the Trans-Alaska Pipeline right-of-way on Federal lands in 2004 resulted in the development of a major EIS for the BLM. When an application for funding, licensing or permitting triggers the EIS, the applicant itself may have to prepare the EIS for Federal review and approval.

An EIS consists of a document that describes the impacts on the environment of a proposed action. The standard government EIS format includes sections that: describe the purpose and need for action; provide alternatives to the proposed action; describe the affected environment; and describe the environmental consequences of the action.

Regulations issued by the President's Council on Environmental Quality set out the steps involved in preparing an EIS. These steps safeguard the rights of both the public and the government to comment on the proposals in the EIS. This process comprises the following steps.

1. Issuing a Notice of Intent in the Federal Register. The notice of intent specifies a period during which public comments on the scope and potential content of the EIS can be gathered.
2. Preparing a draft EIS for review by the public.
3. Publishing in the Federal Register a Notice of Availability for the draft EIS, including a schedule for a public comment period and a specification of how the public can comment.
4. Preparing a final EIS.
5. Publishing in the Federal Register a Notice of Availability for the final EIS.
6. Publishing a Record of Decision in the Federal Register 30 days or more after the final EIS is published. The Record of Decision describes the responsible Federal agency's decision on the proposed action.

Projects that require an EIS must factor ample time for the EIS process into the project schedule. The environmental studies for gathering data for the EIS may take several field seasons to complete and the public review and agency approval process can take many months. The total period required to complete the EIS process depends on the scale and complexity of the proposed action, on the amount of environmental data that are already available, and on the level of public interest. A major EIS can take two or more years to complete.

Several websites provide further information.

- http://www.nepa.gov/nepa/regs/nepa/nepaeqia.htm
- http://ceq.eh.doe.gov/nepa/regs/ceq/toc_ceq.htm
- http://www.gpoaccess.gov/fr/index.html
- http://www.blm.gov
- http://www.mms.gov
- http://www.epa.gov

A.4.1.1.7. Framework of U.S. Arctic Alaska oil and gas leasing arrangements
The leasing activities of the Federal government (MMS for the OCS and the BLM for the NPRA) and the State of Alaska (onshore and coastal waters) are combined because the fundamental aspects of the rights conveyed via a lease and the procedures used to arrive at the decision to lease are very similar. The leasing procedures are not identical, however, as each managing jurisdiction has separate legislation and regulations governing its leasing framework.

A.4.1.2. State of Alaska laws and regulations

A.4.1.2.1. Alaska laws and regulations relevant to oil and gas activities
The Alaska Statehood Act (1959) entitled the State to select Federal lands not already within existing Federal land management status for management by the State.

The Alaska Department of Natural Resources (ADNR) administers various laws and regulations.

1. The Alaska Coastal Management Program Act of 1977 (ACMP) (AS 46.40.10, et. seq.) provides a balance through its guidelines and regulations for conservation of the coastal zone along with the development and use of natural resources. The ACMP states that all activities that may affect coastal resources and uses, whether within or outside the coastal zone, must be consistent with the provisions of the ACMP. Through the ACMP, coastal districts develop coastal management programs with enforceable policies to be included in the ACMP. These district plans must be approved by the Alaska Coastal Policy Council and by the Secretary of Commerce through the Office of the Ocean and Coastal Resource Management. Although Federal lands are excluded from the coastal zone under the Coastal Zone Management Act, uses and activities on Federal lands that affect State coastal zones and their resources must be consistent with the State's management plan.
2. The Alaska Public Land Act (AS 38.05.010 et. seq.) provides for the management of the use of Alaska's public land and water resources. There are several rights-of-way, water rights, and land use permits associated with the Act.
3. The Alaska Anadromous Fish Act (AS 16.05.850) requires that an individual or government agency notify and obtain authorization "to construct a hydraulic project or use, divert, obstruct, pollute, or change the natural flow or bed" of a specified anadromous water body or "to use wheeled, tracked, or excavating equipment or log-dragging equipment in the bed" of a specified anadromous water body. Thus, activities within or across a stream used by fish require authorization if the ADNR determines that such uses or activities could represent an impediment to the efficient passage of fish. Culvert installation, stream realignment or diversion, dams, low-water crossings, and construction, placement, deposition, or removal of any material or structure below ordinary high water all require approval from the ADNR. Construction activities also must be coordinated with critical spawning periods of anadromous fish. All activities within or across a specified anadromous water body and all in-stream activities affecting a specified anadromous water body require approval from the ADNR.
4. The Alaska Fishway Act (AS 16.05.840) requires that an individual or government agency notify and obtain authorization from the ADNR for activities within or across a stream used by fish if the department determines that such uses or activities could represent an impediment to the efficient passage of fish.
5. The North Slope Borough Coastal Management Program attempts to resolve coastal resource use conflicts while providing for both future growth and conservation. The Program highlights development activities that may have significant impacts and sets out requirements to comply with State and Federal regulations and minimize negative impacts.

In addition, the Oil and Hazardous Substance Pollution Control Act prohibits the discharge of oil or any other hazardous substance unless specifically authorized by permit. It requires those responsible for spills to undertake cleanup operations, and holds violators liable for unlimited cleanup costs and damages as well as civil and criminal penalties.

A.4.1.2.2. State of Alaska requirements for permits for oil- and gas-related activities

The State of Alaska has a number of requirements for permits in relation to oil and gas exploration and development activities (Table A2.3). In particular, the Alaska Oil and Gas Conservation Commission Administrative Code stipulates a large number of requirements relating to permits to drill, drilling, well control, and abandonment of wells (http://touchngo.com/lglcntr/akstats/AAC/Title20/Chapter025.htm). There are a number of primary permitting agencies in the government of the State of Alaska, as described below.

Alaska Department of Environmental Conservation

The Alaska Department of Environmental Conservation (ADEC) has a mission to "conserve, improve, and protect its natural resources and environment and control water, land, and air pollution, in order to enhance the health, safety, and welfare of the people of the State and their overall economic and social well being". Plans to drill in an area where there is a possibility of encountering oil require ADEC approval of an oil discharge prevention and contingency plan, or C-plan.

Preparing and gaining approval for a C-plan can be a time-consuming component of permitting a project in the Alaskan Arctic. Operators of oil and gas facilities must provide ADEC with proof of financial responsibility for the cost of responding to the maximum likely oil spill at each facility. The State of Alaska has developed an Alaska Incident Management System, known as AIMS, for managing oil spill response. AIMS is an Alaskan version of the Incident Command System (ICS) that is widely used for crisis response in the United States. The State maintains a register of oil-spill response contractors that can supply resources for spill response work. These contractors generally operate as industry co-ops, in which co-op members pay membership and other fees for access to the use of the co-op's resources.

The high cost of these fees, especially on the North Slope, have been a major obstacle for small companies that wished to enter the Alaska oil and gas industry. Restructuring of the fees in recent years has made the co-ops more accessible for small operators. A number of communities in Alaska also hold caches of pre-staged spill response equipment and have made formal agreements to provide spill response support.

ADEC has been delegated the authority to implement the Federal Clean Air Act and is responsible for issuing major and minor New Source Review permits. Any industrial activity involving emissions to the air, including the operation of diesel or gasoline engines, requires an air quality permit from the ADEC Division of Air Quality.

ADEC regulates the disposal of waste from industrial operations such as drilling; all waste disposal facilities need to be permitted by the State. If possible, most operators avoid having to permit a permanent waste disposal facility by using an existing permitted facility. Use of an existing facility also requires preparation of a waste disposal plan and a temporary waste storage permit.

Alaska Department of Natural Resources

The mission of the ADNR is "to develop, conserve and enhance natural resources for present and future Alaskans". As part of that mission, ADNR regulates uses of State-owned resources, including water. ADNR also oversees the protection of historical or cultural sites and the protection of fish habitats. Most oil and gas activities on State lands will be associated with a State oil and gas lease. A State lessee must prepare a plan of operations for approval by ADNR's Division of Oil and Gas (DOG). The application for approval of a plan must contain sufficient information for ADNR to determine the surface use requirements and impacts directly associated with the proposed operations. The plan must include items such as the schedule of operations; specifications of the use of locations, facilities, sites, and equipment; and plans for rehabilitating the lease area. The plan must also describe operating procedures that will prevent or minimize impacts on natural resources other than oil and gas and that will minimize impacts on features such as fish and wildlife habitats, historical and archaeological sites, and public use areas. When approving the plan, ADNR may attach stipulations that bring the plan into compliance with any mitigation measures specified in the lease and that address any site-specific concerns associated with the plan.

A geophysical exploration permit is necessary for conducting seismic surveys on State lands and waters. This permit is a type of land use permit and is sometimes called a seismic permit. The ADNR DOG is responsible for issuing this type of permit.

Pipeline construction across State land requires a right of way from the ADNR. For common carrier lines, the right of way would be issued by the State Pipeline Coordinator's Office. This office is the State's part of the Joint Pipeline Office. Rights of way for gathering lines will be issued by the ADNR DOG, as a component of a plan of operation approval for pipelines on oil and gas leases or within oil and gas units. Gathering lines outside leases or units will need a right-of-way from the Division of Mining, Land and Water.

A number of activities that involve temporary access to non-leased State lands require a land use permit from the ADNR Division of Mining, Land and Water. Land use permits range in duration from one to five years.

Use of a significant amount of water for an operation that continues for less than five consecutive years requires a temporary water use permit from ADNR's Division of Mining, Land and Water. This permit does not establish a water right but will avoid conflicts with fisheries and existing water right holders.

Water use at a permanent site such as an oil and gas production facility will require a water right, also obtained from the ADNR Division of Mining, Land and Water. A water right allows a specific amount of water from a specific water source to be diverted, impounded or withdrawn for a specific use. Public notice is required if the water appropriation is more than 5000 gallons per day, if the water comes from an anadromous fish stream, or if the water source has a high level of competition among water users.

Notification of the ADNR's Office of Habitat Management and Permitting (OHMP) is required for any proposed activities within or across a stream used by fish. If OHMP determines that such activities could represent an impediment to the efficient passage of fish, a Title 41 fish habitat permit is required. All activities within or across a specified anadromous water body and all in-stream activities affecting a specified anadromous water body also require approval from OHMP. Some common activities that require a fish habitat permit include stream fords, heavy equipment operated on ice, water withdrawal, boat launch, dock construction, and culvert placement.

The Alaska Coastal Management Program

The Alaska Coastal Management Program (ACMP) implements the Alaska Coastal Management Act, passed by the Alaska legislature in 1977 to implement the Federal Coastal Zone Management Act. The ACMP requires that projects in Alaska's coastal zone be reviewed by coastal resource management professionals and found consistent with the ACMP policies and standards. A finding of consistency with the ACMP must be obtained before permits can be issued for a project.

Coastal districts generally consist of cities and boroughs that contain a part of Alaska's coastal area. In coastal areas outside the boundaries of local government, coastal districts known as Coastal Resource Service Areas may be formed. There are 35 coastal districts in Alaska. There has been controversy in the past regarding the geographic extent of Alaska's coastal zone. Most coastal districts develop a coastal management program. Once approved, a district coastal management program becomes a part of the ACMP. During the consistency review process, an affected coastal district reviews a proposed project against the enforceable policies of its coastal management program.

Project Review Coordinators from Alaska's Office of Project Management and Permitting help operators determine whether a project requires an ACMP consistency review and guide them to the State agencies and coastal districts they may need to contact. Operators can also assess the permits that they are likely to need by filling in a coastal project questionnaire. For further information on the ACMP, see the Office of Project Management and Permitting website at http://www.dnr.state.ak.us/opmp/.

The Alaska Historic Preservation Act mandates that any project with State involvement be reviewed for impact on significant historic properties, and there is a similar requirement for projects that involve the Federal government. Staff from the State's Office of History and Archaeology (OHA) provide information on the location of sites and on cultural resources surveys previously conducted in an area. If there is a high potential to discover unknown sites, the OHA may recommend that a new cultural resources survey be carried out. Operators will need a letter from the Alaska State Historic Preservation Office (http:// www.dnr.state.ak.us/parks/oha/shpo/shpo.htm) stating that a project will not impact any archaeological or cultural sites.

Alaska Department of Fish and Game

The Alaska State Legislature has classified certain special areas as being essential to the protection of fish and wildlife habitat. A special area may be classified as a State refuge, a State critical habitat area, a State sanctuary or a State range. A list of special areas is available at www.sf.adfg.state.ak.us/SARR/SpecialAreas/sapermit.cfm. Working or operating in one of these areas requires a special area permit from the Alaska Department of Fish and Game. Permit applications may be submitted to the Department of Fish and Game Office that represents the area in which work will be conducted.

Alaska Oil and Gas Conservation Commission

The mission of the Alaska Oil and Gas Conservation Commission (AOGCC) is to look after the public interest in oil and gas resources and to protect underground supplies of drinking water. Operators need permits from the AOGCC for any activity that involves drilling for oil and gas or injecting material into a well. In addition to regulating drilling operations, the AOGCC regulates oil and gas pool development rules. The AOGCC also employs a team of petroleum inspectors who routinely inspect drilling, production, and metering equipment throughout the State.

Oil and gas drilling within lands of the State of Alaska requires an AOGCC permit to drill. The purpose of the permit is to ensure the use of appropriate equipment and the use of acceptable practices to maintain well control, protect groundwater, avoid waste of oil or gas, and promote efficient reservoir development. The AOGCC permits to drill do not consider issues such as land use. The issuance of a permit does not relieve the applicant from obligations to meet the permitting requirements of any other State, Federal or local government agency.

The permit application needs to include information about the drilling site, the drilling targets, and the drilling techniques to be used; detailed information about permitting requirements can be found at www.state.ak.us/local/akpages/ADMIN/ogc/functions/OvrSurv/permitprocss.htm.

If after starting a drilling project an operator must diverge from the specifications in the original permit to drill application, the operator must apply for a sundry permit and receive approval for the exceptions to the original drilling plan.

Disposal of drill cuttings in a casing annulus requires an annular disposal permit. The Alaska administrative code places limits on such disposal, including the volume of cuttings that can be disposed.

AOGCC orders most frequently apply to drilling and reservoir management operations. AOGCC orders include aquifer exemption orders, disposal injection orders, area injection orders, conservation orders (including pool rules and spacing exceptions), enhanced recovery injection orders, storage injection orders, and commission orders (including enforcement actions).The procedure for issuing an order usually includes a 30-day public notice period.

A.4.1.3. Local government (North Slope Borough and municipal) legal requirements

Construction projects such as for a building or an industrial structure within the jurisdiction of an Alaska municipality require compliance with local government building codes, building regulations, and zoning rules. Operators will probably also need a permit to access municipal land or municipal rights-of-way. The North Slope Borough, which comprises over 50% of the Alaskan Arctic land area and contains over 99% of Alaskan Arctic oil and gas production, has specific oil industry-related permitting requirements.

The borough has created a set of land management principles and procedures designed to meet the needs of its comprehensive plan; ensure growth and development in accord with the values of borough residents; identify and secure the benefits of development; identify, avoid, and mitigate or prohibit negative impacts of development; and ensure that future development is of a proper type, design, and location and is served by a proper range of public services and facilities.

Under the North Slope Borough Land Management Regulations (NSBMC §§ 19.10.010 – 19.70.060), the North Slope Borough requires compliance with its zoning and permitting ordinances and issues permits for development, uses, and activities on land within the North Slope Borough. The North Slope Borough regulates land uses and activities within the borough to provide for the protection of the health, safety, and welfare of its residents and to assure compliance with environmental policies of local concern.

For zoning purposes, the North Slope Borough has divided its region into four districts.

1. A conservation district encompassing undeveloped areas and intended for nature conservation.
2. A resource district intended for large-scale development and straightforward permitting.
3. A transportation corridor district that provides strips of land for transportation facilities such as roads and pipelines.
4. A scientific district in the Barrow area for the research and development of facilities.

The City of Barrow's zoning commission handles Barrow zoning issues within the city limits.

A proposal to develop an industrial activity in an inappropriate North Slope Borough district requires a rezoning negotiation with the borough. However, if the borough agrees to approve the rezoning, construction permits for the development will still be required.

Table A2.3 describes the regulatory permissions required to drill an oil or gas well in Alaska including in the marine waters in Federal jurisdiction. The table gives a sense of the primary concerns of each of the State and Federal agencies involved in the process and of the redundancy and dependent responsibilities built into the process.

The North Slope Borough requires surety for reclamation or mitigation costs associated with borough permits. To ensure compliance with local building codes, building regulations and zoning rules, there are permitting requirements from the local government if a building or industrial structure is constructed within the jurisdiction of an Alaska municipality. There are also permits needed to access municipal land or municipal rights of way

A.4.2. Canada

The environmental and regulatory review process for the oil and gas industry in Canada is complex and has regional variations, particularly in environmental assessment, which respect the necessity of local and aboriginal involvement. Mapping of the regulatory requirements for oil and gas projects is available for five areas in the north (http://www.oilandgasguides.com). Recent trends in Canadian regulation have been towards goal-orientated rather than prescriptive regulation, and towards developing collaborative mechanisms between regulators. The regulatory approach is still under development.

In the Northwest Territories, Nunavut and Canada's northern offshore, petroleum industry operations are authorized under Federal legislation, the Canada Oil and Gas Operations Act (COGOA) and Regulations. The Yukon Oil and Gas Act applies in Yukon, and for offshore of Labrador, the pertinent legislation is the Canada-Newfoundland Atlantic Accord Implementation Act; both laws have evolved from the Federal model.

Operations under the COGOA are authorized by Canada's National Energy Board. The comparable function for offshore of Labrador is the responsibility of the Canada-Newfoundland Offshore Petroleum Board, based in St John's, Newfoundland.

When plans for field development projects involve the transport of petroleum products between provincial jurisdictions or internationally, other Federal legislation comes into play, specifically the National Energy Board Act for pipelines, and the Canadian Shipping Act and the Arctic Waters Pollution Prevention Act for offshore Arctic tanker transportation.

The COGOA and the equivalent legislation in other jurisdictions treat operational regulatory matters including: granting of operating licenses to companies; authorization of specific programs (such as drilling a well or conducting a seismic acquisition program); approval of development plans (for development of an oil or gas field, including surface facilities and gathering systems) and production arrangements to ensure conservation of oil and gas resources and to optimize overall recovery; approval of emergency response plans; and the setting of financial liability, and ensuring the fiscal capacity of operators to meet the demands of emergency response.

Regulations under COGOA deal with geophysical, drilling, development and production operations and related activities. Operation authorizations issued under this legislation are subject to compliance with these regulations and any terms and conditions which may be attached to the authorization. The National Energy Board has powers to inspect and shut down operations which are not in conformity with regulations or are breaching terms and conditions of the authorization. Operational authorizations also confer responsibilities for worker safety under the Canada Labour Code.

The COGOA also requires companies to submit benefits plans in relation to specific authorized activities. These plans address fair opportunity for employment and business in relation to the operation, as well as matters of training and compensation.

Companies are also obliged to ensure that all legal requirements for certification, licensing, and permitting under other relevant legislation are met. Most operations onshore will require a land use permit and a water license (for use of surface waters).

Prior to issuance of the primary authorization, proposed activities must undergo environmental assessment and review under the Canadian Environmental Assessment Act for Federal jurisdictions. Compliance with the provisions of this act is required where an activity is to be authorized by a Federal regulatory authority. The details of environmental assessment differ across the Canadian North. Final land claim agreements have created specific regimes for environmental review which ensure local participation in the assessment of projects under legislation specific to land claim areas. For example, in Nunavut, a structure for environmental assessment was established by the Nunavut Land Claim Agreement. Since 2003, in Yukon, environmental assessment is being governed by the Yukon Environmental and Socio-economic Assessment Act.

Where land use plans have been concluded, zoning under various regional land use plans will influence the terms and conditions applied to oil and gas operations. Proposals are screened for compliance with these plans.

Within the Canadian Administration, the following organizations play a key role in legislating for and regulating the oil and gas sector in areas of relevance to this assessment:

- Federal Ministry of Natural Resources;
- Ministry of Indian Affairs and Northern Development;
- National Energy Board;
- Canadian Environmental Assessment Agency;
- Federal Department of the Environment;
- Fisheries and Oceans Canada.

Below Federal level, these issues are administered and regulated by the corresponding agencies.

Under the Arctic Waters Pollution Prevention Act, there is a mandatory requirement to report offshore spills. The Canada-Newfoundland and Labrador Offshore Petroleum Board, the Government of the Northwest Territories, and Indian and Northern Affairs Canada each require that spills of 100 liters or more of oil, or mixed products containing oil, be reported to the Spill Report Line. In terms of prevention, the Canada Oil and Gas Operations Act and associated Regulations prescribe safety requirements including work planning and facilities design. The Canada-Newfoundland and Labrador Offshore Petroleum Board has developed contingency planning guidelines and an Offshore Emergency Response Plan in coordination with other northern agencies. Similar provisions exist in other jurisdictions.

A.4.3. Greenland

In accordance with the recommendation of the Joint Committee on Mineral Resources in Greenland, the Government of Greenland and the Danish Government in June 2003 approved a new strategy concerning exploration and exploitation of hydrocarbons in Greenland. Under this strategy, the development of the hydrocarbon sector must proceed in a way that is of the greatest possible benefit to the Greenlandic society. This society must be assured of a reasonable share of the profits accruing from the exploitation of hydrocarbons, just as local communities must be assured of insight and information concerning hydrocarbon activities, in order among other things that the local work force and local firms are involved to the greatest possible extent.

A clear political condition for all activities related to the development of mineral resources in Greenland, not least exploration for and exploitation of hydrocarbons, is that these activities must be carried out with due regard for safety and the environment. The Arctic environment is very vulnerable, and Greenland's economic life and culture are closely bound to nature and the environment.

The present terms for exploration and exploitation licenses are stipulated in a model license. These include surplus royalty, carried partnership, and fees.

A.4.4. Iceland

Petroleum activities are subject to general Icelandic laws and regulations on taxation, environmental protection, health and safety. Exploration for oil and gas in Icelandic waters is regulated by an Act of the Althing (parliament), the Hydrocarbon Act of 2001 as amended in 2007, which concerns the prospecting, exploration, and production of hydrocarbons and is based on Directive 94/22/EC. Other relevant EU legislation, including issues of health, safety and environment (HSE), has been adopted into Icelandic law. Provisions arising from the OSPAR Convention and the MARPOL protocol also apply to oil and gas activities.

A license from the Ministry of Industry is required for prospecting, exploration, and production of hydrocarbons. The Hydrocarbon Act contains provisions for two types of license: a prospecting license and an exploration and production license. Non-exclusive prospecting licenses for geophysical surveys and shallow sediment sampling are issued for a maximum of three years on the basis of Rules adopted on 18 July 2001. The first offering of exclusive exploration and production licenses is scheduled for January 2009. Exploration licenses can be granted for a period of up to 12 years and extended to a maximum total duration of 16 years. On fulfillment of the license conditions, the holder of an exploration license will have priority for an extension of the license for production for up to 30 years.

The general corporate income tax in Iceland is 15%. Taxes on profits and production fees on oil operations are currently under development.

A.4.5. Faroe Islands

The 1948 Home Rule legislation allowed natural resources in the subsoil to be transferred from Danish to Faroese authority. Such a transfer was agreed between the two governments in 1992, granting Faroese authorities full responsibility for the legislation and administration of potential resources. The Faroese Government appointed a Hydrocarbon Planning Commission in 1994 to prepare an oil and gas policy in which consideration for the protection of the environment and fisheries was included.

Summary of Legislative Acts

- Act No. 31 of 16 March 1998 on Hydrocarbon Activities
- Act No. 26 of 21 April 1999 on Taxation of Revenues relating to Hydrocarbon Activities
- Act No. 5 of 8 February 2000 on the First Licensing Round
- Act No. 16 of 14 February 2000 on Hydrocarbon Tax Administration
- Act No. 26 of 7 March 2000 on Amendments to the Hydrocarbon Tax Act
- Act No. 27 of 17 May 2004 on the Second Licensing Round
- Act No. 59 of 17 May 2005 on the Protection of the Marine Environment

Summary of Executive Orders

- Executive Order No. 34 from 8 March 2001 on reimbursement of expenses in connection with hydrocarbon activities
- Executive Order No. 35 from 8 March 2001 concerning Health, Safety and the Environment during all Phases of the Hydrocarbon Activities
- Executive Order No. 37 from 8 March 2001 on Usage and Discharge of Substances and Material from Offshore Installations
- Executive Order No. 113 from 20 November 2003 on Geological and Geophysical Matters in Connection with Approval of Deep Drilling

The Act on Hydrocarbon Activities is the all-encompassing legal framework for petroleum exploration and production in the Faroe Islands. The Act: states that hydrocarbons *in situ* belong to the Faroe Islands; prescribes the granting of petroleum concessions, i.e. the requisite licenses for oil companies to carry out exploration and production of oil and gas; regulates all phases of oil and gas activities, i.e. prospecting, exploration and appraisal, development and production as well as decommissioning; requires licensees to perform environmental impact assessments before undertaking projects assumed to have a major impact on the environment; adopts a functional and dynamic approach to safety, occupational health and emergency procedures for offshore installations; and introduces a supplementary scheme on compensation to fishermen in addition to the general basis of liability.

The Act on Hydrocarbon Activities contains stipulations on conditions concerning health, safety, and environment (HSE) in all phases of the exploration and production activities. This is based on the assumption that there is a great need for effective HSE regulation, control, and coordination in offshore activities and thus these matters should generally be subject to the same legislative act.

The Act establishes a general duty for both public authorities and licensees to plan the activities with due regard for fishing, navigation, the environment, nature and other interests of society.

The Act on Hydrocarbon Activities specifies that prior to inviting applications for licenses, the areas to be offered for licensing and the general terms and conditions on which licenses are to be granted shall be fixed by law. Thus, a bill on the individual licensing round must be tabled in Parliament before a licensing round can be opened. This law also stipulates that licenses or approvals regarding projects assumed to have a major impact on the environment may only be granted subsequent to an assessment of the effects on the environment and after the affected public, authorities, and organizations have been given an opportunity to express their opinion. This provision ensures that environmental impact assessments are carried out before the Government grants a license or an approval to a project.

The Act on Hydrocarbon Activities stipulates that the licensee must obtain a specific permit or approval before undertaking a particular operation. Thus, the drilling of a well is subject to approval by the petroleum authorities. The authorities may also require the licensee to submit an assessment of the environmental impact of the contemplated activities. Furthermore, the Executive Order on Usage and Discharge of Substances and Materials provides that a specific permit for operational usage and discharge of substances must be obtained from the Faroese Environmental Agency, according to OSPAR requirements. This Agency may impose conditions on the permit, for example, concerning the type of chemicals used in the exploration activity, quantities, substitution to more acceptable chemicals, waste management, reporting and monitoring.

In terms of approvals to drill, the Executive Order on Health, Safety and Environment in the Exploration Phase stipulates that the application to the Faroese Earth and Energy Directorate shall contain among other things: a site-specific environmental impact assessment; an integrated and total risk and emergency response analysis; emergency response plans for people, the environment and material assets; and emergency response plans for the drilling of a relief well in case of a blow-out.

The Approval to Drill may impose environmental conditions on the applicant.

The purpose of the Act on the Protection of the Marine Environment is to protect nature and the environment, to preserve human conditions of life, the ecological system and the flora and fauna, thus ensuring sustainable development of society. The Act also aims at preserving a clean and rich sea and preventing and reducing pollution of the sea, the coasts, and the air. For offshore oil and gas projects, this law authorizes the Minister to establish rules concerning the usage and disposal of chemicals, waste management, etc.

The Executive Order on Health, Safety and Environment in the Exploration Phase contains functional and goal-setting requirements that stipulate what the operator shall accomplish in relation to carrying out the activities in a safe and appropriate manner in accordance with good international practice, based on the principle that licensees and operators must demonstrate to the authorities how they plan to comply with the rules and regulations. This Order covers five main topics:

- establishment of management systems for health, safety and environment;
- performance of integrated risk and emergency response analyses for the offshore installation and its operations;
- technical requirements to offshore installations and equipment;
- operational requirements for health, safety, and environment; and
- requirements in connection with information, documentation, reporting, etc.

The Executive Order on Usage and Discharge of Substances and Materials at Offshore Installations governs the use and discharge of materials and substances that derive directly from any hydrocarbon activity at offshore installations. Usage and discharge may only occur according to prior permission granted by the Faroese Environmental Agency. Requirements established under the OSPAR Commission form part of the legislative basis for this Order.

A.4.6. Norway

The Petroleum Act No. 72 of 29 November 1996 provides the overall legal basis for the licensing system which regulates petroleum activities. The Petroleum Act establishes that the proprietary right to sub-sea petroleum on the Norwegian Continental Shelf is vested in the State. Before permission for exploration drilling and production (a production license) can be awarded, the area in question must have been opened up for petroleum activities. An impact assessment, covering such aspects as the environmental, economic, and social effects of such activities on other industries and adjacent regions, must be carried out.

A number of regulations have been established in relation to the Petroleum Act. These relate to various aspects of petroleum activities including the licensing system. The exploration license authorizes geological, petrophysical, geophysical, geochemical, and geotechnical activities. The Norwegian Petroleum Directorate may limit the individual exploration license to apply to particular types of exploration. Regulations under the Petroleum Act also establish a Petroleum Register and its requirements. The Petroleum Register contains a set of required information regarding each license and license-holder.

In addition, regulations relating to resource management provide supplementary provisions within the areas under the Petroleum Act and the Petroleum Regulations which have been delegated to the Norwegian Petroleum Directorate (NPD). These regulations are intended to ensure, among others, satisfactory data acquisition and reporting, and also to ensure that the interests of the fishing industry are duly taken into account in connection with seismic data acquisition. The NPD has issued two sets of regulations relating to resource management: 'Regulations relating to resource management' and 'Regulations relating to measurement of petroleum'. These regulations have been issued in pursuance of the Petroleum Act and the Carbon Dioxide Tax Act, and supplement the provisions in the two acts and in the Petroleum Regulations.

The Pollution Control Act No. 6 of 13 March 1981, most recently amended by the Act of 20 June 2003 No. 45, aims to protect the outdoor environment against pollution as well as to reduce existing pollution and the quantity of waste and to promote better waste management, so as to avoid damage to human health or the productivity of the natural environment. Important regulations under this Act include: the regulation of emissions to the air; the regulation of offshore discharges; and the disposal or decommissioning of facilities. The provisions of this Act also generally apply to exploration for and the production and utilization of natural sub-sea resources on the Norwegian part of the continental shelf, including the decommissioning of facilities.

The target of zero environmentally hazardous discharges to the sea from petroleum operations was established in the Report to the Storting No. 58 (1996-97), Environmental Policy for a Sustainable Development. The main rule is that no environmentally hazardous substances must be released, whether chemical additives or naturally-occurring chemicals. The targets apply in the first instance to new stand-alone developments, and from 31 December 2005 to existing installations, and cover all offshore operations: drilling and well operations, production, and discharges from pipelines. In each case, when deciding on measures, an overall assessment must be made of the environmental impacts, safety concerns, costs, and technical conditions in the reservoir.

Directive 96/61/EC, concerning integrated pollution prevention (IPPC), will be written into Norwegian legislation by 2007. Under this legislation, specific limits for emissions of nitrogen oxides (NOX), based on the requirement for best available techniques (BAT), will be developed. The most important emissions to the air from the petroleum industry are carbon dioxide (CO2) and NOX from energy production and flaring, as well as emissions of nmVOCs (which are regulated by the Norwegian Pollution Control Authority based on the provisions of the Pollution Act) from the loading and storage of oil.

Based on the tax on discharges of CO2 in the Petroleum Activities on the Continental Shelf Act No. 72 of 21 December 1990, most recently amended by Act 20 December 1996 No. 100, a CO2 tax was introduced in 1991 which is the most important instrument for reducing CO2 emissions from petroleum activities. The CO2 tax is to be charged on petroleum which is burned and natural gas which is discharged to air and also on CO2 separated from petroleum and discharged to air, on installations used in connection with the production or transportation of petroleum

Regulations have been issued for the purpose of achieving a high level regarding health, environment, and safety in petroleum activities, as well as obtaining a systematic implementation of measures to fulfill the requirements of the legislation relating to health, environment, and safety (HES). In the HES area, the Norwegian Pollution Control Authority, the Norwegian Social and Health Directorate, and the Petroleum Safety Authority Norway (former NPD) cooperate on joint, total regulations relating to health, environment and safety on the Norwegian continental shelf. The HES regulations are issued in pursuance of the Petroleum Act, the Pollution Act, the Product Control Act, the Health Personnel Act, the Patients' Rights Act, the Communicable Diseases Control Act, and the Health-related and Social Preparedness Act. The regulations are the framework regulations (Royal Decree), the management regulations, the information duty regulations, the facilities regulations, and the activities regulations.

The Act relating to the taxation of sub-sea petroleum deposits (The Petroleum Taxation Act) No. 35 of 13 June 1975 applies to the taxation of the exploration for and exploitation of sub-sea petroleum deposits and the activities and employment related thereto, including the pipeline transportation of produced petroleum.

An Integrated Management Plan for the Barents Sea, involving various government departments and other interested parties, has been developed which aims to establish a framework that will lead to balanced commercial activities related to fishing, sea transportation and the petroleum industry, operating within the concept of sustainable development. The Management Plan will also make it possible to view the impact of all human activities in the same context instead of administering them separately.

A.4.7. Russian Federation

A.4.7.1. Federal laws and regulations

The regulatory system of the Russian Federation at the Federal level is summarized in Chapter 2, section 2.4.7.1 together with the main Federal laws and regulations of relevance to oil and gas exploration and production activities. Some additional information is provided in this section, particularly concerning laws and regulations relating to the environment, including waste management, and the use of natural resources.

The hierarchy of legal acts and responsible bodies in the Russian Federation is listed in Table 2.46. Federal laws and regulations relevant to the regulation of oil and gas exploration, development, and production include the following:

1. The Federal Law on Subsoil Resources (1992, as amended), serves as the framework for the licensing and use of mineral resources in the Russian Federation. The law governs geological investigations, the use and conservation of subsoil resources in the territory of the Russian Federation and within its continental shelf, as well as issues associated with the use and processing of mining waste. This is the central Russian law governing oil and gas activities.
2. The Federal Law on Continental Shelf of the Russian Federation (1995, as amended), defines the status of the continental shelf and the associated sovereign rights and jurisdiction of the Russian Federation in this area. This law contains special provisions for offshore exploration and development as well regulations for activities by foreign companies, which apply to the Russian continental shelf outside territorial waters (i.e., beyond 12 nm).
3. The Governmental Resolution on Approving Provisions On State Control of Geological Investigations, Use and Conservation of Subsoil Resources (2005) approved provisions developed pursuant to the two previous laws, which: i) establish the procedures for state control over geological investigations and the use and conservation of subsoil resources, ii) identify the governmental bodies to carry out this control, and iii) establish their competence, rights, obligations, and operational procedures.
4. Based on the Federal Law on Inland Sea Waters, Territorial Sea and Adjacent Zones of the Russian Federation (1998, as amended) both Russian and foreign companies must obtain permits for the establishment, operation and use of artificial islands, plants, and facilities required for regional geological surveys of the continental shelf as well as for exploration and development of mineral resources deposits.
5. Regulations on Procedures for State Control over Rational Use of Oil and Oil Products in the Russian Federation were approved in 1995. These set forth procedures for state control over the use of oil and oil products and the maintenance of their quality across the national economy of the Russian Federation.
6. The Resolution of the Government of the Russian Federation on Licensing Operation of Power and Heating Networks, Transportation, Storage, Processing and Sale of Oil, Gas and their Products (2002) defines the activities subject to licensing and procedures and rules for licensing.
7. The Order of the Minister of Natural Resources of the Russian Federation on Approving Procedures for Reviewing Mineral Resources Use Applications on Establishing the Fact of Mineral Deposit Discovery by the User of the Mineral Resources Who Financed Geological Exploration of the Field with Own Funds (including Borrowed Funds) for the Purpose of Prospecting and Extraction of Mineral Resources at this Field (2005) is also relevant.

Federal environmental laws and regulations include the following:

1. The Federal Law on Environmental Review (1995, as amended) governs the environmental review processes and aims to implement the constitutional rights of the citizens of the Russian Federation to a good environment through the prevention of negative environmental impacts from economic and other activities. This law requires environmental impact assessments for all major industrial projects.
2. The Federal Law on Environmental Protection (2002, as amended) sets the legal framework for the national environmental policy of providing a balanced approach to socio-economic objectives, conservation of the environment, biological diversity and natural resources to meet the needs of current and future generations, as well as to strengthen the law in the area of environmental protection and environmental safety. It provides environmental requirements for many types of projects, requires permits for discharges, and stipulates regulations on the production of toxic substances as well as regulations on compensation claims.
3. The Federal Law on Atmospheric Air Protection (1999, as amended) establishes the legal framework for regulation of atmospheric pollutants and implementation of the rights of citizens to a good environment and adequate information about its quality.
4. The Federal Law on Industrial and Domestic Waste (1998, as amended) defines the legal framework for industrial and domestic waste handling with the aim of preventing detrimental impacts of industrial and domestic waste on human health and the environment.
5. The Resolution of the Government of the Russian Federation on Approving the List of Hazardous Substances, Dumping of Which in the Exclusive Economic Zone of the Russian Federation from Vessels, Other Floating Craft, Aircraft, Artificial Islands, Installations and Structures is Banned (2000) establishes a list of substances banned from ocean dumping. The Resolution of the Government of the Russian Federation on Approving Maximum Allowable Concentrations and Conditions for the Dumping of Hazardous Substances in the Exclusive Economic Zone of the Russian Federation was also adopted in 2000.
6. The Federal Law Land Code of the Russian Federation (2001, as amended) governs the use and conservation of land in the Russian Federation, while the Federal Law Forest Code of the Russian Federation (1997, as amended) provides the legal framework for the sustainable use, conservation, protection and restoration of forests, and improvement of their environmental and resource potential.
7. The Federal Law Water Code of the Russian Federation (1995, as amended) establishes the legal framework for the use and conservation of water bodies.
8. The Federal Law on Wildlife (1995, as amended) governs the conservation and use of wildlife, as well as the conservation and restoration of habitats with a view to ensuring biological diversity.
9. The Federal Law on Protected Areas (1995, as amended) provides for the establishment, protection, and use of protected areas with the aim of preserving unique and typical natural complexes and sites, natural monuments, flora and fauna, and their genetic fund.
10. The Federal Law on Cultural Heritage Sites (Historical and Cultural Monuments) of Peoples of the Russian Federation (2002, as amended), which regulates the conservation, use, and protection of cultural sites of the peoples of the Russian Federation with the aim of ensuring the constitutional right of access to the cultural values, including also the rights of peoples of other ethnic communities of the Russian Federation to the preservation of their cultural and ethnic identity.
11. The Federal Law on Territories of Traditional Nature Use of Indigenous Peoples of the North, Siberia, and Far East of the Russian Federation (2001) provides the legal framework for the establishment, conservation, and use of the territories of traditional nature use of indigenous peoples of the North, Siberia, and Far East of the Russian Federation to ensure that these peoples can maintain their traditional lifestyles and uses of nature.
12. The Federal Law on Protection of Population and Territories from Natural and Man-Made Emergency Situations (1994, as amended) establishes an emergency response system.
13. The Federal Law on Industrial Safety of Hazardous Industrial Facilities (1997) defines the legal, economic, and social framework for the safe operation of hazardous industrial facilities, with the goal of preventing accidents at hazardous industrial facilities and ensuring emergency preparedness of the operators of such facilities.
14. The Federal Law on Safety of Hydrotechnical Structures (1997, as amended) directs safety issues associated with the design, construction, operation, reconstruction, rehabilitation, and dismantling of hydrotechnical structures, and establishes mandates of the governmental authorities, owners of the hydrotechnical structures and operators with respect to the safety of such structures.
15. The Federal Law on Production Sharing Agreements (1995, with several modifications) establishes the legal grounds for listing subsoil resources areas which can be used on the terms of production sharing. The Production Sharing Agreement (PSA) regulates the terms of subsoil resources use, including the terms and the procedure of production sharing between the parties involved. In addition, there are separate laws listing projects that are eligible for a PSA.
16. Article 253 of the Penal Code of the Russian Federation, Breach of the Legislation of the Russian Federation on Continental Shelf and on Exclusive Economic Zone of the Russian Federation (1996, as amended), is also applicable to oil and gas activities.

A.4.7.2 Laws relating to environmental issues

Legal regulation of compensation for environmental damage

Environmental damage is expressed in terms of quantitative and qualitative losses of natural habitat and is manifested by environmental pollution and damage, the destruction of natural objects and ecosystems, and the loss of natural linkage mechanisms. As an economic category, environmental damage is manifested by economic loss resulting from pollution of the environment, whether it is the loss suffered by society as a whole, individual regions, companies or persons, and representing increased public expense in order to eliminate and restore or compensate the damage, reduced GNP, a more rapid deterioration of buildings, equipment and machinery, and the destruction of monuments of nature, history, and architecture.

In legal terms, 'lawful damage' means damage that is permitted, limited, licensed or regulated. Damage caused by lawful activities is liable to be compensated in instances governed by law (Civil Code, art. 1064, para. 3). Compensation for such damage is carried out as part of the economic mechanism for the use of natural resources, mainly by fees for such use. Compensation for lawful environmental damage by means of pollution fees and fees for use of natural objects is governed by a number of administrative acts, including: the Environmental Protection Act (art. 20), the Sub-Surface Act (arts. 39-48), the Water Code (arts. 122-25), the Forest Code (arts. 103-07), the Animal Kingdom Act (art. 52), the Act on Payment for Use of Water bodies, Government Statute No. 1199 of 19 September 1977 on Minimal Rates of Payment for Timber Sold on the Root, and Government Statute No. 632 of 28 August on Confirmation of the Procedure for Establishing Payment and Its Limits for Environmental Pollution, Waste Disposal and Other Harmful Activities.

The Environmental Protection Act establishes special taxes and other systems as the main means of setting compensation levels; the real expenses incurred in restoring the environment and losses, including loss of profit, are used for this purpose only in the absence of these.

Administrative sanctions

Administrative sanctions for violations of environmental regulations, covering eleven types of offenses (Box A2.1), are applied by an authorized State body of executive power, an official of the relevant State body, or a court. Administrative sanctions can be applied to both natural and legal persons. Violations of environmental regulations are listed in the Environmental Protection Act (art. 84), the sectoral natural resources legislation and the

Box A2.1. Environmental offenses liable to administrative sanctions in the Russian Federation

In the Russian Federation, administrative sanctions may be imposed for the following types of environmental offenses:

- polluting the environment;
- exceeding the maximum permissible biological, radiation, physical, and other harmful impact levels;
- violating environmental regulations on planning, technical and economic provisions, location, building, reconstruction, implementation and operation of enterprises, structures and other objects;
- failing to comply with the environmental regulations when storing, reprocessing, destroying or burying industrial and domestic waste or radioactive, chemical, and other harmful substances;
- violating the rules on transport, storage, and use of chemicals;
- violating the established procedure for extraction, collection, stockpiling, sale, purchase, import and export of objects of the animal and plant kingdoms, raw natural resources, or botanical, zoological or mineral collections;
- spoiling, damaging or destroying environmental protection territories and complexes or ecosystems;
- failing to comply with compulsory environmental restoration and natural resources renewal measures;
- failing to comply with instructions by the State Environmental Assessment Board and orders of the special State environmental monitoring agencies;
- unlawfully spending State environmental fund budget resources on non-environmental purposes; and
- violating the rules on protecting monuments of nature and specially protected territories.

The body hearing the administrative offense case may order only those additional sanctions which are specified in the relevant article of the administrative act establishing liability for the given offense. A single administrative offense may be punished by a basic penalty or a basic penalty in combination with an additional penalty. Two basic penalties may not be applied simultaneously. Administrative sanctions are applied to enterprises, establishments, organizations and individual entrepreneurs for environmental offenses associated with production or other economic processes. Officials are liable for non-compliance with the environmental legislation in cases where ensuring compliance is part of their official duties.

The Administrative Offenses Code (art. 27) includes fines among the basic penalties. It provides for fines of between 0.1 and 100 minimum monthly wages, or of up to ten times the value of the object stolen or destroyed or the illegal profit resulting from the offense. In exceptional cases, involving non-compliance with the obligations ensuing from international treaties and where there is a particular need for a stronger sanction, Russian law may establish a higher penalty.

The sectoral natural resources legislation provides for other levels of fines. The Public Health and Disease Control Act (art. 29) provides that administrative sanctions consisting of a warning and a fine may be applied to officials and citizens for sanitary offenses. The fine is to be imposed by the Chief State Sanitary Officer or his deputy.

Administrative Offenses Code, where they are grouped in the chapter entitled Administrative Offenses with Respect to Protection of the Environment and Monuments of History and Culture.

Sanctions for administrative offenses relating to the environment may include: warnings, fines, confiscation of the item used to commit the offense, withdrawal of special permits (hunting, fishing, transport) and compensated taking of the item used to commit the offense. Administrative sanctions other than those laid down by article 24 of the Administrative Offenses Code may be established by legislative acts of the Russian Federation.

Criminal sanctions

Environmental offenses of a general kind as listed by the Penal Code include the following:

- violation of the environmental protection legislation while operating economic activities (art. 246);
- violation of the rules for handling environmentally hazardous substances and waste (art. 247);
- violation of the safety rules for handling microbiological or other biological agents or toxins (art. 248);
- violation of the Federal legislation concerning the continental shelf and EEZ (art. 253); and
- violation of the regulations governing specially protected natural territories and natural objects (art. 262).

These violations encroach upon the concepts of environmental safety, environmental protection, and rational use of components of the natural environment in combination. In addition, there are a number of special environmental criminal offenses in relation to the use and protection of plants, animals, and aquatic and terrestrial environments (Box A2.2).

Environmental offenses may be divided by type into offenses involving unlawful usurpation (possession) of natural resources (Penal Code arts. 253, 256, 258, and 260) and offenses involving adverse impact on the environment and to the detriment of its quality (Penal Code arts. 246, 247, 248, 249, 250, 251, 252, 254, 255, 257, 259, 261, and 262). The latter group also contains a sub-group of offenses causing destruction or damage to natural resources and natural objects (Penal Code arts. 257, 259 and 261).

The new Penal Code thus gives considerable attention to combating environmental offenses. However, the penal legislation should not be regarded as the main mechanism for environmental protection. Its role, although important, is a subsidiary one. The most important mechanisms for dealing with the problem are economic, educational, and political measures.

Economic instruments for environmental protection

In addition to civil administrative and penal sanctions for violation of environmental legislation, economic mechanisms are steadily gaining importance in the current context of developing market relations. While the administrative method relies on authority and subordination, the economic mechanism is based on the material interests of natural and legal persons. Important instruments of the economic mechanism are: natural resources registers; direct material, technical and financial provisions for environmental protection measures; fees for the right to use natural resources and for polluting the environment; credit advantages; and taxation and freedom from taxation.

Natural resources registers (kadastry)

A natural resources register is a collection of economic, environmental, organizational, and technical indices representing the quantity and quality of the resources and the structure and type of the concern exploiting the resource. Currently, there are eight natural resources registers in the Russian Federation (Box A2.3). On the basis of the registers, a financial assessment of the resource and its market price is made and a system of measures developed to restore and rehabilitate the environment. The registers are compiled by type of resources and form a specific economic-legal entity.

Box A2.2. Special environmental criminal offenses under the Penal Code of the Russian Federation

Special environmental criminal offenses are subdivided according to the nature of the offense and the concepts on which they encroach.

Offenses encroaching on the protection and rational use of the earth and mineral resources and on environmental safety:

- damaging the earth (Penal Code art. 254); and
- violating the rules for protection and use of mineral resources (Penal Code art. 255).
- Offenses encroaching on the protection and rational use of the animal kingdom (fauna):
- unlawful extraction of water fauna (Penal Code art. 256);
- violation of the fish stock protection rules (Penal Code art. 257);
- unlawful hunting (Penal Code art. 258);
- violation of the veterinary rules (Penal Code art. 249, para. 1); and
- destruction of the critical habitat of species listed in the Red Book (Penal Code art. 259).
- Offenses encroaching on the protection and rational use of the plant kingdom (flora):
- unlawful felling of trees and bushes (Penal Code art. 260);
- destruction or damage to woodland (Penal Code art. 261);
- violation of rules for combating plant diseases and pests (Penal Code art. 249, para. 2); and
- unlawful extraction of aqueous plants (Penal Code art. 256).
- Offenses encroaching on the protection and rational use of water bodies and the atmosphere and on environmental safety:
- pollution of water bodies (Penal Code art. 250);
- pollution of the marine environment (Penal Code art. 252); and
- pollution of the atmosphere (Penal Code art. 260).

Box A2.3. Natural resources registers (kadastry) of the Russian Federation

At present, the Russian Federation has eight natural resources registers:

1. The land register, containing data on the qualitative composition of soils, land allocation and use, and landowners. It is kept by the State Committee on Land Resources and Land Use of the Russian Federation (Roskomzem, Land Code of the RSFSR, 1991, art. 110).
2. The mineral deposits register, containing data on the value of each mineral deposit and the mining, economic and environmental conditions for its development. It is kept by the Ministry of Natural Resources (Sub-Surface Act, arts. 30, 32).
3. The water register, including assessment of the present and future condition of water bodies to facilitate planning of water resources use, prevent depletion and restore water quality to meet the established standards. It is kept by Roshydromet; use of underground water is controlled by the Ministry of Natural Resources (Governmental Statute of 23 April 1994).
4. The forest register, containing information on the legal regime governing the forests, quantitative and qualitative assessments of their condition, division and categorization of forests by degree of protection, and valuation data. It is kept by the Federal Forestry Commission (Rosleskhoz) (Basic Forest Legislation, art. 77).
5. The game register, containing quantitative and qualitative assessments of game and strict limits on the hunting of species in steady decline. It is kept by the Hunting Board of the Agriculture Ministry.
6. The fish register, containing quantitative and qualitative assessments of fish stocks in inland waters and kept by the Fisheries Committee.
7. The register of nature reserve territories and objects, which contains descriptions and locations of nature reserves, national parks, game reserves and monuments of nature.
8. The register of polluters, containing descriptions of polluters, emissions, dumping and waste disposal, with composition and quantity.

The last three registers are the responsibility of the State Environmental Committee.

Charges levied for the right to use natural resources and for causing pollution

The Environmental Protection Act (art. 20) establishes two types of charge: for the right to use natural resources and for causing pollution. The first type of charge includes payments for the right to use natural resources, for their excessive and irrational use, and for their renewal and protection.

With regard to the fees for the right to use the sub-surface and mineral deposits, there are three forms of levy: for exploration and prospecting of mineral deposits; for extraction; and for use of the sub-surface for purposes not connected with mineral resources extraction. The procedure for charging is established by Governmental Statute of 28 October 1992.

Other fees are charged for the use of land, water bodies, forest resources, and animal resources (Box A2.4).

The fees for polluting the environment represent more than just a charge for the use of natural resources: they are one of the most effective economic mechanisms, for the levy is collected from the enterprise's profits or capital without recourse to court proceedings and should therefore encourage firms to reduce pollutant emissions and dumping. The monies are credited to extra-budgetary environmental funds and spent mostly on environmental rehabilitation and conservation.

Pollution fees are governed by the Environmental Protection Act (art. 20) and the Governmental Decree of 26 August 1992, which establish the procedure for setting pollution levy rates and limits. The law provides for three types of pollution levy: for emissions and dumping within the established limits; for emissions and dumping above the established limits or without the permission of the environmental protection agencies; and for waste disposal.

There are three stages for establishing the levy: first, the base standards are defined; then differential rates are set; and finally specific fees are established per polluter. The base standards are defined by type of polluter or harmful activity, taking into account the hazards they present for the environment and human health. These standards are developed by the State Environment Committee with participation by the Sanitary and Epidemiological Supervision, the Ministry of Economic Development and Trade, the Finance Ministry and the sub-national authorities. Two types of base standard are issued: for emissions, dumping and waste disposal within the established standards; and for emissions, dumping and waste disposal above the established standards, but within the confirmed or interim agreed limits. These two sets of standards are calculated by the State Environment Committee using the base standards adapted to the environmental situation in the regions.

The specific rates of pollution levy chargeable to individual firms are set by the local authorities together with the specially authorized agencies. Where an enterprise has no permit for emissions and dumping, all pollution is charged as excess pollution; in addition, the local authorities may double the coefficient for Arctic regions. Of the overall monies received, 10% is credited to the Federal budget to finance the local agencies of the State Environment Committee; the remaining 90%, according to the established procedure, is credited to the environmental funds.

An important factor is that pollution fees are classed as taxes and can therefore be charged without recourse to court proceedings. Under the governmental decree interpreting the Environmental Protection Act, where such payments equal or exceed the enterprise's profit, the specially authorized agencies can consider stopping its production or closing it down.

Material, technical and financial provisions for environmental protection measures

State budgetary funding

The State budget continues to provide direct funding for environmental protection measures as it did in Soviet

Box A2.4. Fees for the right to use natural resources in the Russian Federation

In addition to fees for the right to use the sub-surface and mineral deposits, charges levied in the Russian Federation for the right to use natural resources under Art. 20 of the Environmental Protection Act include land fees, fees for the use of water bodies, fees for the use of forest resources, and fees for the use of fauna resources.

Land fees exist in three forms: the land tax, the lease charge, and the regulated land price. The agricultural land charge is established by the constituent parts of the Russian Federation or local governments in accordance with soil composition, quality, area and location. The forestry land charge is applied for the use of forest land where timber is produced (5% of the value of timber sold on the root). The local authorities act as the lessors. The land tax and lease charge monies become part of the local budget and are spent exclusively on land improvement and restoration. The regulated land price is established in the Land Payment Act and represents the value of a plot of land of a given quality and at a given location, taking into account the potential income over the calculated repayment period. In addition to the regulated price, there are contractual, competitive and auction land prices. The regulated price is set by the authorities of the relevant administrative area, and the others by agreement between the parties.

Fees are levied for the use of water bodies and for their restoration and protection. Payment for the right of use is made by users regularly throughout the period of use. Payment for the use of water bodies is divided between the Federal budget (40%) and the budgets of the constituent parts of the Russian Federation (60%). The payment procedure and tariff are determined in accordance with the Federal Water Body Use (Payment) Act.

Fees for the use of forest resources exist in the form of forest dues (taxes) or lease charges and are governed by the Forest Code. The principles for establishing the tariffs of forest dues are laid down by the constituent parts of the Russian Federation, while the precise sums are set by local authorities. Minimum tariffs for timber sold on the root are established by the Federal Government. The lease charge is established by the competent bodies of the constituent parts of the Russian Federation. There is an additional levy for the use of plant resources, including the collection of medicinal herbs and plant material, the picking of fruits and berries and associated activities. This levy is governed by the Forest Code, governmental decrees, administrative acts of the State Environment Committee and local authorities.

There are various fees for hunting and capturing animals, collecting wild birds' eggs, leasing hunting and fishing grounds, etc. The tariff is set by the local authority jointly with the hunting and fishing inspection agencies. The monies are credited to the local budget and used to improve fauna management and fish stock renewal.

times. However, the funding provided was always less than was needed. While environmental pollution in the former Soviet Union and in the Russian Federation was and is equivalent to 7.5–8.5% of GNP, capital investment in environmental protection measures has never exceeded 0.5% of GNP and since 1995 has been 0.1% or less. Such funding cannot compensate for the damage caused to the environment by emissions, dumping and waste disposal.

The adoption of the Environmental Protection Act (art. 17, para. 2) established two additional sources of environmental protection funding in the form of environmental funds and the funds and means of enterprises and establishments.

Environmental funds

Environmental funds are a significant source of funding for local environmental protection measures because they allocate funds mostly to cities and territories suffering particularly severe impacts of pollution and other anthropogenic activities. In addition to the Federal Environmental Fund, there are individual republic, kray, oblast and local funds.

The Federal Environmental Fund is administered by a board appointed by the State Environment Committee. The Fund's main purpose is to finance all types of environmental protection work of national and trans-regional significance.

The republic, kray and oblast funds are established by the appropriate environment and resources management committees. Their monies are used to provide funding and credit for a very large number of local measures and activities, from the setting up of special monitoring equipment and systems and databases, or the development of nature reserves, to the establishment of enterprises to resolve environmental problems. Up to 5% of the funds may be used to build health care facilities and provide medical treatment for people suffering from pollution-related illnesses.

Environmental insurance

In the Russian Federation, this refers to arrangements to protect the property interests of natural and legal persons in the event of environmentally unfavorable circumstances by means of funds established by insurers. The need for such insurance is established by the Environmental Protection Act, art. 23. The Act provides for two types of insurance, compulsory and voluntary, under the same basic system of insurance of natural and legal persons and objects and their property and income in the event of an environmental or natural disaster or accident.

The object of the insurance is the risk of property liability, expressed in property claims against the insurer for the compensation of losses from the pollution of land, water or the atmosphere as the result of an event covered under the policy. An essential condition for an event to be covered under the policy is that it must be sudden and unpremeditated. Where these conditions are not fulfilled, the claim will not be met.

Claims for compensation of damage may be heard by courts or arbitration courts on the basis of the Environmental Protection Act, art. 88, which specifies civil legal liability for damage caused by hazardous sources.

At present, the legislation establishes only the voluntary form of insurance. Because most polluting enterprises do not wish to take it out, the scheme's economic effectiveness is greatly reduced.

Material incentives

Material incentives have been created in addition to the other environmental protection measures. They include: tax concessions (the subtraction from the taxable profits of a sum proportional or equivalent to the sum spent on environmental protection measures); the removal of environmental fund levy liability on environmental protection items; incentive pricing and supplements for environmentally clean production; special credit terms for enterprises which operate an effective system of environmental protection; and more rapid amortization of environmental protection equipment.

Material penalties include: the introduction of special additional taxes on environmentally harmful products and products manufactured using environmentally dangerous technologies; and fines for violation of the environmental legislation.

Fines for the violation of environmental legislation are the most commonly used and most effective measure. Tax concessions and more rapid amortization are very rare and have no discernible impact on the implementation of environmental protection measures.

Legal basis for natural resources use

According to Russian legislation, each company that intends to participate in petroleum production should meet certain requirements and pass certain State-defined procedures (Makhortov, 2006). The stages of petroleum field exploitation comprise: 1) declaration of intention; 2) tender; 3) granting of a license; 4) technical and economic assessment of the project (feasibility study); 5) working draft preparation with an environmental impact assessment and a plan for civilian defense and elimination of the consequences of emergency situations (such as oil spills, etc.); 6) examination of the project and approval by the State bodies responsible for certain areas; 7) State expertise (Federal level); 8) granting of permission to install the platform at the drilling point; 9) monitoring during the process of operation.

The declaration of intention gives the right to participate in a tender in which the State's representatives choose the best candidates, which then obtain the license. After that, the licensee should perform technical and economic assessments of their own projects and prepare environmental impact assessments. All documents prepared by the licensee should be examined by the State bodies. After successful examination, the company has the right to start production. There is a requirement to monitor the environmental condition during the entire production process.

Under Russian legislation, natural resources, including oil, gas, precious metals and minerals, underground waters, and other commercial minerals situated within the territory of the Russian Federation are the property of the State. The right to possess, use, and dispose of subsurface resources is under the joint authority of the Russian Federation and its constituent bodies. Subsurface resources cannot be bought, sold, gifted, inherited, pledged, or alienated in any other way. However, the right to use subsurface resources may be alienated or transferred from one person to another in cases permitted by Federal legislation.

At present, oil- and gas-extraction companies in Russia may operate on the basis of the Federal Law on Subsurface Resources (1992), which establishes the rights and obligations of users of subsurface resources and of the State; the Federal Law on Production Sharing Agreements (1995); and other normative acts governing relations associated with the use and protection of land, water and the environment which arise in connection with the use of subsurface resources.

The Federal Law on Subsurface Resources (1992) regulates relations arising in connection with the geological study, use, and protection of subsurface resources within the territory of the Russian Federation. Pursuant to this law, subsurface resources may be developed only on the basis of a license. The license contains, among others, information on the site to be developed, the period of activity and financial conditions. In addition to payments for the right to use subsurface resources, companies operating on the basis of a license must pay other generally established taxes, such as profits tax and VAT (value added tax).

The Federal Law on Production Sharing Agreements establishes that the extraction of mineral resources and other relevant activities are to be regulated by a particular special agreement to be concluded between a company (the investor) and the State. Such an agreement, essentially a contract between the State and the investor, regulates taxation, currency, and customs issues in detail and helps to ensure stability in these areas. In the context of constantly changing tax legislation, a PSA is intended to serve as an effective instrument for attracting foreign investment.

Licensing

Under the Federal Law on Subsurface Resources (1992), licenses may be granted to both Russian and foreign legal entities. A license is required for the following types of activity: regional geological studies; geological studies including the exploration and appraisal of commercial-mineral deposits; prospecting for and extraction of commercial minerals; development of commercial-mineral deposits, use of mining waste, and related processing work; and use of subsurface resources for purposes unrelated to the extraction of commercial minerals. Subsurface resources may be simultaneously provided for use in a geological study (exploration, prospecting) and the extraction of commercial minerals. A license holder has the exclusive right to develop and extract commercial minerals on the deposit specified in the license.

The provision of a site of subsurface resources for use under a PSA is documented by a license to use subsurface resources. The license certifies the right to use that site, subject to the terms of the agreement, which sets out all essential conditions for use of the subsurface resources. Sites of subsurface resources are provided for: 1) geological study, for a period of up to five years; and 2) extraction of commercial minerals, for the period required to develop the deposit, as calculated on the basis of a feasibility study on the deposit's exploitation, which provides for the rational use and protection of subsurface resources. The period of use of a site of subsurface resources may be extended as required if a commercial-mineral deposit has yet to be fully developed; the procedure for extending this period is determined by the PSA agreement.

Under legislation concerning subsurface resources, an agreement may be concluded between authorized State bodies and a user of subsurface resources to establish the terms of use of that site and the parties' obligations under the agreement. The specific features and characteristics of the tax treatment of PSAs are described below.

Taxation on the oil and gas industry

Extraction and refining companies are subject to profits tax and VAT in accordance with general taxation procedures, in addition to all specific taxes and allocations established for oil- and gas-extraction enterprises in the Tax Code, the Federal Law on Subsurface Resources, and other legislative acts. Enterprises in the oil- and gas-extraction industry thus bear an additional tax burden compared with enterprises in other industries. The tax regime effective in Russia from 1 January 2003 is described here.

Payments for the right to use subsurface resources

Under current legislation, the following system of payments applies in connection with the use of subsurface resources: 1) one-time payments for the use of subsurface resources; 2) regular payments for the use of subsurface resources; 3) the charge for geological information on subsurface resources; 4) the fee for participation in a competitive tender (auction); and 5) the fee for the issue of licenses.

The procedure and rates of payment for the use of subsurface resources and the conditions for the collection of such payments under PSAs are established by those agreements. All legal entities engaged in exploration, prospecting, and extraction of commercial minerals within the territory of the Russian Federation, its continental shelf and its maritime exclusive economic zone are required to make these payments (Box A2.5).

Tax on the extraction of commercial minerals and other applicable taxes and duties

A tax on the extraction of commercial minerals, implemented under Federal Law No.126-FZ of 1 January 2002 (Chapter 26 of the Russian Tax Code), is levied on commercial minerals extracted from the subsurface within the territory of the Russian Federation. The tax base is determined as the value of extracted commercial minerals, calculated based on the volume of extracted commercial minerals and the applicable valuation method.

Taxpayers are entitled to determine the quantity of extracted commercial mineral using two methods: the direct method (using measuring instruments and devices) or the indirect method (based on indicators of the level of the extracted commercial mineral contained in mineral raw materials extracted from the subsurface). However, the direct method has priority, as the indirect method may be applied only when it is impossible to use the direct method. Taxpayers may choose among three methods to determine the value of the commercial minerals extracted (Box A2.6).

The tax rate for oil, gas condensate, and natural gas is set at 16.5% of the taxable base. A zero tax rate is applied for associated gas and normative losses of commercial minerals. The tax on the extraction of commercial minerals under PSAs is to be calculated taking into account the provisions of the Federal Law on Production Sharing Agreements and Chapter 26 of the Tax Code.

In addition to the tax on the extraction of commercial minerals, companies are liable for the payment of excise duties on petroleum products, VAT on such products sold on the Russian market or custom duties on exported products, and a tax on the profits of the company (Box A2.7). The following corporate taxes were also in effect within the territory of the Russian Federation in 2003: unified social tax, assets tax, advertising tax, transport tax, sales tax, unified tax on imputed income (as a special tax regime), and other taxes and levies in accordance with the Tax Code of the Russian Federation.

Box A2.5. Payments for the right to use subsurface resources in the Russian Federation

One-time payments for the use of subsurface resources are levied in connection with certain events specified in the license. The minimum rates of one-time payments are established at not less than 10% of the amount of tax on the extraction of commercial minerals, as calculated based on the average annual projected capacity of an extraction organization. One-time payments are to be made in accordance with the procedure established in the license. The rates of one-time payments for the use of subsurface resources and the procedure for making such payments under PSAs are to be established in the agreement.

Regular payments for the use of subsurface resources are levied on users of subsurface resources in exchange for exclusive rights to explore and appraise deposits of commercial minerals, prospect for minerals, carry out geological studies, and assess the suitability of sites of subsurface resources for the construction of facilities not associated with the extraction of commercial minerals (with the exception of shallow-lying engineering facilities). Regular payments are not charged for: the use of subsurface resources for regional geological studies; the use of specially protected geological sites for scientific, cultural, recreational, and other purposes established by legislation; the use of subsurface resources for the collection of mineralogical, palaeontological, and other geological specimens; and other uses of subsurface resources established by law.

The rates of regular payments for the use of subsurface resources are determined on the basis of economic and geographic conditions, the size of the site of subsurface resources, the type of commercial mineral, the duration of work, the degree of previous geological study of the area, and the level of risk. Payment is made quarterly based on the area of the licensed site granted to a user of subsurface resources, less the returned portion of the licensed site. The rates of regular payments for the use of subsurface resources and the conditions and procedure for collecting such payments under PSAs are to be established by the agreements within the limits established by the government of the Russian Federation.

There is a charge for the use of geological information obtained from the relevant Federal body. The charge for this information and the procedures for paying it are established by the government of the Russian Federation. The rate of this charge under a PSA is to be established in the agreement itself.

A.4.7.3. Basis for environmental requirements in the Russian Federation

From Environmental Requirements on Produced Water Treatment in the Russian part of the Barents Sea: Russian Legislation Review, Svetlana Golubeva, ICF/EKO Ltd, Russia.

A.4.7.3.1. Introduction

Beginning in 1991, the Russian Federation environmental legislation has been systematically revised. The Soviet laws have been replaced by new laws, new resolutions and instructions by the Government of the Russian Federation have been adopted, and many norms and instructions have been revised. The current environmental legal framework includes laws and codes, decrees of the President, resolutions and instructions of the Federal Government, and normative acts issued by the Federal ministries and agencies. The latter may be supplemented by stricter requirements established at the regional level.

Box A2.6. Tax on the extraction of commercial minerals

In determining the basis for the tax on the extraction of commercial minerals, extracted minerals may be valued according to the following methods.

1. On the basis of the sale prices prevailing for the taxpayer in the tax period in question, excluding State subsidies to cover the difference between the wholesale price and the calculated value of the mineral raw materials.
2. On the basis of the sale prices prevailing for the taxpayer in the tax period in question, less VAT, excise duty on excisable types of mineral raw materials, customs duties, transportation costs, and insurance contributions for compulsory freight insurance.
3. On the basis of the value of the extracted commercial minerals, as calculated based on data from tax records maintained in accordance with the rules established by Chapter 25 of the Russian Tax Code, Tax on the Profit of Organizations (where it is impossible to use one of the preceding methods).

During the period from 1 January 2002 through 31 December 2004, legislation stipulated that transitional provisions applied for the taxation of oil and gas condensate extracted from oil and gas deposits. During this period, the taxable base for tax on the extraction of commercial minerals was determined as the quantity of extracted oil in physical terms at a rate of 340 roubles per tonne. In this connection, the tax rate was to be adjusted quarterly by a coefficient reflecting the movement in world prices for Urals-grade oil. This coefficient was determined independently by the taxpayer on a quarterly basis in accordance with the formula:

$$Cf = (P - 8) \times R / 252$$

where P is the average price per barrel in U.S. dollars for Urals-grade oil during the tax period, and R is the average value of the U.S. dollar against the Russian rouble during the tax period, as determined by the Central Bank of the Russian Federation.

Box A2.7. Applicable taxes and duties on the extraction of commercial minerals

In addition to the tax on the extraction of commercial minerals, the following other taxes are applied to extracted petroleum products in the Russian Federation: excise duty, profits tax, VAT, and customs duty.

Excise duties on petroleum products are levied under Federal laws 110-FZ of 24 July 2002 and 191-FZ of 31 December 2002 amended Chapter 22 (Excise Duties) of the Tax Code of the Russian Federation. The amendments, which entered into force 1 January 2003, introduced a new procedure for the taxation of operations involving excisable petroleum products.

From 1 January 2002, the procedure for calculating and paying profits tax is regulated by Chapter 25 (Tax on the Profits of Organizations) of the Tax Code of the Russian Federation. Under Chapter 25 of the Tax Code, organizations and entrepreneurs carrying out entrepreneurial activities in Russia are required to pay profits tax.

Oil, gas, and oil products sold on the Russian market are liable to VAT at a rate of 20%. Table 2.4Rus4 shows the rate of excise taxes in the Russian Federation.

Customs duties are currently levied on exports of oil, natural gas, gas condensate, and oil products. The duty rates for crude oil are established by the government of the Russian Federation on the basis of world oil prices.

The legal basis for environmental protection is the Constitution of the Russian Federation and the Federal law 'On Environmental Protection' (2002), which ensures: the right of citizens to a safe environment; the right of citizens and organizations to receive environmental information; obligations of Federal and other environmental bodies; obligations of industrial facilities with regard to environmental protection; the system of State regulation and management of environmental protection; and responsibility for environmental damage.

According to the Constitution of the Russian Federation (Article 9):

- land and other natural resources shall be utilized and protected in the Russian Federation as the basis of life and activity of the people living in the corresponding territories; and
- land and other natural resources may be in private, State, municipal and other forms of ownership.

Citizens and their associations shall have the right to possess land as private property. Possession, utilization and disposal of land and other natural resources shall be exercised by the owners freely, if it is not detrimental to the environment and does not violate the rights and lawful interests of other people. The terms and rules for the use of land shall be established by a Federal law (the Constitution of the Russian Federation, Article 36). The jurisdiction of the Russian Federation (Article 71) includes: Federal State property and its management; establishment of the principles of Federal policy and Federal programs in the sphere of State, economic, ecological, social, cultural and national development of the Russian Federation; Federal budget, Federal taxes and dues, Federal regional development funds; Federal power systems, nuclear power-engineering, fissionable materials, Federal transport, railways, information and communication, outer space activities; determination of the status and protection of the State border, territorial sea, air space, EEZ and continental shelf of the Russian Federation; and meteorological service, standards, metric system, horometry, geodesy and cartography, names of geographical units, official statistics and accounting.

According to Article 72, the joint jurisdiction of the Russian Federation and the subjects of the Russian Federation includes: protection of the rights and freedoms of man and citizen; protection of the rights of national minorities; ensuring the rule of law, law and order, public security and the border zone regime; issues of possession, use and disposal of land, subsoil, water and other natural resources; delimitation of State property; utilization of natural resources, protection of the environment and ensuring ecological safety; specially protected natural territories, protection of historical and cultural monuments; carrying out measures against catastrophes, natural calamities, epidemics, elimination of their aftermath; establishment of common principles of taxation and dues in the Russian Federation; administrative, administrative procedural, labour, family, housing, land, water, and forest legislation; legislation on subsoil and environmental protection; protection of the traditional habitat and way of life of small ethnic communities; and establishment of common principles of organization of the system of bodies of State authority and local self-government.

According to Article 114 of the Constitution, the Government of the Russian Federation shall ensure the implementation in the Russian Federation of a single State policy in the sphere of culture, science, education, health protection, social security and ecology. Accordingly, activities on the territorial sea, EEZ, and continental shelf of the Russian Federation are under the purview of Federal regulations.

A.4.7.3.2. Environmental protection

Environmental protection in Russia is aimed at preserving and restoring the natural environment, rational use and reproduction of natural resources, prevention of a negative impact of economic and other activities on the environment and elimination of the consequences of such effects. The parties involved in environmental protection include governmental bodies of the Russian Federation, governmental bodies of Russian regions, local government bodies, public and other non-commercial associations, legal entities and natural persons. A negative effect on the environment is an effect of economic and other activity the consequences of which lead to a negative change in the quality of the environment.

Economic and other activities shall be pursued on the basis of the following main environmentally oriented principles:

- the protection, reproduction and rational use of natural resources as prerequisites for ensuring a favorable environment and ecological safety;
- the presumption of ecological threat of planned economic and other activities;
- the compulsory nature of an assessment of effects on the environment when decisions are made in pursuance of an economic or other activity;
- the compulsory nature of the State ecological expert examination of project designs and other documentation indicating feasibility of an economic and other activity capable of exerting a negative effect on the environment, creating a threat to citizens' life, health and property; and
- the prohibition of an economic or another activity the environmental consequences of which cannot be predicted and of the implementation of a project capable of leading to a degradation of natural ecological systems, a change in and/or destruction of the genetic stock of plants, animals or other organisms, depletion of natural resources and other negative changes in the environment.

Negative effects on the environment exerted by economic and other activities include: substance and micro-organism emission and dumping; industrial and consumption waste production and disposal thereof; and physical effects (the quantity of heat, the levels of noise, vibration, ionizing irradiation, electromagnetic field strength and other physical effects).

The construction and operation of oil and gas production facilities and facilities intended for processing, transporting, storing or selling oil, gas and petroleum/gas products shall be permitted if there are polluted land restoration designs for the zones of temporary and/or permanent land allocation, positive State ecological expert examination statements and other State expert examination statements required under law, and financial guarantees for the completion of such projects.

A.4.7.4. Russian procedure of environmental impact assessment

The Russian procedure of environmental impact assessment (EIA) provides for two stages: an environmental impact assessment *per se* and ecological expertise of the documentation providing justification for the planned activity.

A.4.7.4.1. Environmental impact assessment

The EIA materials must be developed by the proponent according to the regulations on assessment of impacts of planned economic and other activities on the environment in the Russian Federation (Goscomecology order No. 372 of 16 May 2000 and registered by the Ministry of Justice on 4 July 2000 under No. 2302).

According to the Federal Law on Ecological Expertise (Article 14), all documents presented on ecological expertise in Russia must include EIA materials. The scope of EIA research and materials therefore is identical to the scope of an ecological expertise defined in Articles 11 and 12 of the law. The environmental assessment procedure is conducted by the initiator of the activity.

General principles in relation to environmental impact assessments include:

- <u>precautionary principle</u>: presumption of potential environmental danger;
- <u>preventive principle</u>: prevention of potential negative impacts on the environment and associated social, economic and other consequences caused by a proposed activity;
- <u>mandatory character</u>: carrying out an EIA is mandatory at all stages of preparing documents substantiating the economic activity which is to be submitted to a State ecological expertise (environmental review);

- consideration of alternatives: in conducting an EIA, the developer must consider alternative ways of achieving the goal of the planned activity;
- public participation: public participation in preparing and discussing EIA materials, which are subject to an ecological expertise, is an inseparable part of an impact assessment process and is provided for by the developer;
- scientific soundness: EIA materials should be scientifically supported, reliable and contain a description of the research conducted, accounting for the interaction between various environmental as well as social and economic factors;
- openness of information: the developer should provide all participants of the EIA process with the possibility of obtaining full and reliable information in a timely fashion; and
- taking account of possible transboundary impacts: in case a planned activity has a potential transboundary impact, the research and preparation of EIA materials should be carried out taking into account the provisions of the Convention on EIA in a Transboundary Context (1991).

The legal basis for an impact assessment includes the following normative (including technical and methodological) and non-normative legal acts, in accordance with the following hierarchy, as defined by the Constitution and legislation of the Russian Federation:

- decisions taken by citizens at referenda and as a result of executing other forms of direct democracy;
- international treaties of the Russian Federation as well as commonly recognized principles and norms of international law;
- the Constitution and Federal constitutional laws of the Russian Federation;
- Federal laws of the Russian Federation;
- Constitutions, Statutes and laws of the subjects of the Russian Federation;
- by-laws issued by the President and the Government of the Russian Federation;
- by-laws issued by Federal ministries and other Federal bodies of executive authorities;
- by-laws of bodies of executive authorities of the subjects of the Russian Federation; and
- acts of the bodies of local authorities.

The EIA materials should contain:

- a description of the characteristics of the planned activity and possible alternatives, including a refusal of the activity;
- the results of analysis of the state of the territory, which the planned activity may influence (the state of natural environments, the presence and character of anthropogenic loads);
- a description of the possible impacts of the planned activity on the environment, taking into account the possible alternatives;
- the results of assessments of risks, the character, scale, and zone of distribution of the possible environmental impacts and a forecast of the ecological and associated social and economic consequences of such impacts;
- proposals on measures to reduce, mitigate or prevent the most significant negative impacts, and an assessment of their efficiency and of the possibility of implementation;
- the results of an assessment of the significance of residual impacts and their consequences;
- the results of a comparison of the expected ecological and associated social and economic consequences of the considered alternatives, including a refusal of the activity; and
- proposals on the program of ecological monitoring and controlling at all stages of implementation of the planned activity, and post-project analysis.

An environmental impact assessment is conducted in three main stages: a preliminary EIA, the EIA process, and the EIA report approval.

A preliminary EIA

For a preliminary EIA, the developer:

- prepares and submits to State authorities a document containing a general description of the planned activity/actions; its purposes; possible alternatives; a description of the conditions of its implementation; and other information as required by existing normative documents;
- informs the interested public;
- carries out a preliminary consultation with interested parties;
- seeks the opinion of permitting authorities to the proposed activity and the degree of interest of the public; and
- conducts a preliminary assessment.

The outcome of this stage enables: obtaining basic environmental information, the identification of interested parties who will take part in discussing the findings of the EIA, and the preparation of the EIA Terms of Reference.

The EIA process

The developer carries out the EIA, considering alternatives for achieving the purposes of the activity, and prepares the draft EIA report (including a non-technical summary); the developer provides the public with the opportunity to become familiar with the draft EIA report and to comment on it; the developer informs the public of the decisions made, accounting for the comments and proposals submitted.

For an investment activity, the developer should carry out the above two stages of an impact assessment at all stages of preparing the documentation for the planned activity which is submitted to a State ecological expertise.

The EIA report approval

The developer conducts public consultation/hearings on the planned activity and keeps records which document the issues where possible disagreements between the public and the developer arise. The draft version of the EIA report must be available for public consultation for no less than 30 days and no later than two weeks before the end of the public discussion (or the date of the public hearing).

Public participation
The EIA Regulations (May 2000) contain a common instruction concerning how public participation is to be organized at the screening stage, during the EIA process, and at the discussion of a draft EIA report. The primary vehicles used to communicate with stakeholders are those that have been successfully employed by other companies and include 'mass media, meetings' and a Community Liaison Officer. The mass media have been used to give occasional updates on the project as well as to provide information on public meetings, if necessary. The main task of information disclosure is to inform the public in the most effective way. The results of an EIA include:

- information on the nature and scale of the environmental impact of the alternative proposed for implementation, and an evaluation of the environmental consequences of this impact;
- identification and taking account of public preferences in selecting the alternative;
- EIA materials which form part of the documentation on a planned activity submitted to an ecological expertise;
- specific decisions which the developer should make regarding the implementation of a planned activity (on siting of the facility, selecting technology, etc.), taking into consideration the EIA of this activity;
- the initiator's selection of a solution (alternative) for implementing a proposed activity or abandoning a proposed activity; and
- incorporation of environmental components in the process of making decisions on the implementation of a planned activity.

A.4.7.4.2. Ecological expertise (environmental review) in Russia
The EIA materials, as part of the project materials (design documentation) for a proposed activity, are submitted for State environmental review. In the process of State environmental review, the specially authorized State structure determines compliance of the proposed solutions with environmental, normative and legal requirements. The public environmental review is implemented by the public organizations. The basic principles of ecological expertise include:

- presumption of potential environmental hazard of any planned economic or some other activities;
- obligation of State environmental review before making a decision on the development consent;
- composite nature of environmental impact assessment of economic and some other activity and its implications;
- obligation of taking into consideration the requirements of environmental safety when carrying out the environmental review;
- reliability and completeness of information presented for environmental review;
- independence of experts of environmental expertise when they exercise their authority in the area of environmental review;
- scientific validity, objectivity and legality of the conclusions of environmental review;
- openness, participation of non-government organizations (associations), responsiveness of public opinion; and
- responsibility of the participants of environmental review and interested parties for organizing, conducting and reliability of environmental review.

Procedure of the State ecological expertise
The State ecological expertise (environmental review) in Russia, including the revised expertise, is conducted only in cases when materials presented by the proponent are in conformity with provisions of the present Federal law, with established procedures for conducting the State ecological expertise, and when these materials include:

1. documentation subject to the State ecological expertise in accordance with Articles 11 and 12 of the present Federal law in the amount determined in due course and containing materials on environmental impact assessment of economic and other activity that is subject to the State ecological expertise;
2. positive conclusions and/or clearance documents of Federal supervision and control bodies and bodies of local self-government that are received according to procedures established by the Russian Federation legislation;
3. conclusions of Federal executive authorities on the object of State ecological expertise in the case of its consideration by these bodies;
4. conclusions of public ecological expertise in the case of its conduct; and
5. materials on consultations of the object of State ecological expertise with citizens and public organization held by bodies of local self-government.

The State ecological expertise is conducted in the case that it is prepaid for by the proponent of the project that is the subject of the State ecological expertise, in full and according to procedures provided for by the duly authorized State body in the field of State ecological expertise.

The time limit for beginning the State ecological expertise is to be no later than one month after payment and acceptance of the necessary materials and documentation in the full amount and quantity in compliance with the provisions of 1) and 2), above. The time limit for the conduct of the State ecological expertise is determined by the complexity of the object to be reviewed, as determined in accordance with normative documents of the duly authorized Federal State body in the field of ecological expertise but should not exceed six months.

Materials reflecting public opinion must be forwarded to an expert commission of the State ecological expertise during the process of preparing a conclusion by the expert commission of the State ecological expertise and during the process of decision-making on implementation of an object of the State ecological expertise.

A positive conclusion of the environmental expert review is a necessary pre-condition for constructing or re-constructing any industrial site and is, in a sense, a building permit from environmental authorities.

Public ecological expertise

According to the Federal law 'On Ecological Expertise', a public ecological expertise (PEE) shall be organized and conducted by public organizations or associations possessing the right for such activity. Citizens, public organizations, and self-government bodies may initiate a public ecological expertise (public environmental review). Results of a public ecological expertise must be taken into account in the State ecological expertise.

A public ecological expertise is conducted on condition of the State registration of an application for its conduct submitted by a public organization or union. In cases where applications for the conduct of a public ecological expertise for one subject are submitted by two or more public organizations, the formation of a unified expert commission is permitted.

A local self-government authority must register (or refuse to register) an application for a public ecological expertise within seven days from the date of its submission. An application for the conduct of a public ecological expertise that did not receive refusal within the named time limit is considered to be registered.

An application from public organizations for the conduct of a public ecological expertise must include the name, legal address, type of activity envisioned by their status, information on the composition of an expert commission of public ecological expertise and on the object of public ecological expertise, and time limits for the conduct of a public ecological expertise. Public organizations responsible for a public ecological expertise must inform the population about its beginning and on results of its conduct.

Refusal of registration of an application for the conduct of a public ecological expertise may take place if:

- a public ecological expertise was previously conducted twice on the object of a public ecological expertise;
- a public ecological expertise was conducted on an object, information on which contains State, commercial or other secrets protected by law;
- the procedure for the State registration of a public organization does not correspond to established procedures;
- the status of a public organization responsible for conducting public ecological expertise does not comply with provisions of Article 20 of the Federal law 'On Ecological Expertise';
- requirements for the content of an application for a public ecological expertise envisaged in Article 23 of the Federal law 'On Ecological Expertise' are not observed.

The conclusions of a public ecological expertise (environmental review) are forwarded to the duly authorized State bodies in the field of ecological expertise, to proponents of the documentation subject to a public ecological expertise and to bodies responsible for decision-making on implementation of ecological expertise projects, and to bodies of local self-government; they may also be transferred to other interested persons or published in mass media.

A.4.7.4.3. Public participation

In the Russian Federation, there are no specific requirements for public consultation based on Russian regulatory guidelines for different types of planning activities. However, there are several documents that make reference to 'informing the public about the project'.

Citizens and public organizations or unions in the field of ecological expertise have the following rights:

- to forward proposals on the conduct, in accordance with the Federal law on ecological expertise, of public ecological expertise of economic and other activity where its implementation influences ecological interests of the population of the relevant territory;
- to forward in written form to competent State authorities in the field of ecological expertise well-founded proposals on ecological aspects of planned economic and other activity;
- to receive information on the results of the conduct of the State ecological expertise of concrete objects of ecological expertise from the competent State authorities responsible for this conduct; and
- to carry out other actions in the field of ecological expertise that do not contradict the Russian Federation legislation.

A.4.7.4.4. State environmental assessments of marine activity

A State environmental expertise on the continental shelf, in the EEZ, in the internal maritime waters and in the territorial sea constitutes a mandatory measure for the protection of mineral and living resources and precedes the implementation of the Federal strategy, programs and plans of the Russian Federation for economic and other activities in the internal maritime waters and in the territorial sea. This review is conducted by the specifically authorized Federal agency (Rosprirodnadzor) for protection of the environment and natural resources in accordance with the procedures established in the legislation of the Russian Federation.

All forms of economic activity on the continental shelf and in the EEZ are subject to a State environmental assessment, regardless of their estimated costs, and require approval by a State environmental assessment. State environmental assessments must be carried out in connection with proposed Federal programs and plans, pre-planning, pre-design and design documents relating to the regional geological study of the continental shelf; the prospecting, exploration and exploitation of mineral resources and the harvesting of living resources; the erection and use of artificial islands, installations and structures; the laying of submarine cables and pipelines and the dumping of wastes (Article 31, Federal Law on the Continental Shelf of the Russian Federation).

A State environmental assessment must be carried out for draft State programs and plans, and for pre-planning, pre-project and project documentation pertaining to the study and commercial exploitation of living resources, the exploration and exploitation of non-living resources and the construction and use of artificial islands, installations and structures, and submarine cables and pipelines (Article 27, State Environmental Assessment of Economic and Other Activities in the Exclusive Economic Zone).

All types of economic and other activities in the internal maritime waters and in the territorial sea are subject to a State environmental assessment, regardless of their estimated cost, departmental affiliation, or form of ownership. Such activities may be carried out only if there is a favorable result in the State environmental assessment conducted at the expense of the user of the natural resources of the internal maritime waters or of the territorial sea.

A State environmental assessment must also be carried out for draft State programs and plans, and for pre-planning, pre-project and project documentation pertaining to the study, exploration and exploitation (commercial use) of the natural resources of the internal maritime waters and the territorial sea, the establishment and use of artificial islands, installations and structures, and the laying of cables and pipelines (Article 34, State Environmental Assessment of Economic and Other Activities in the Internal Maritime Waters and the Territorial Sea, July 1998). A State environmental expertise is based on the obligation of taking into consideration the requirements of environmental safety when carrying out the environmental review.

A.4.7.5. Legislative and regulatory instruments

The Federal Law 'On environmental protection' (2002) aims at achieving a balance between economic development and environmental protection. It stipulates application of qualitative norms and standards, and establishes general environmental requirements for economic activities and mechanisms of their implementation. Some Federal laws are dedicated to specific issues of environmental protection (Federal Laws 'On protection of atmospheric air', 1999; 'On industrial and consumption wastes', 1998; 'On mineral resources', 1995; 'On specifically protected natural territories', 1995; and others).

Resolutions of the Russian Federation Government and Orders from the Ministries and Agencies develop and specify individual provisions of the laws and determine the mechanism of their implementation. State standards (GOSTs) and sectoral standards (OSTs) establish requirements for particular products and facilities, technologies, and equipment. Departmental norms of technological design and building (SniPs) specify particular requirements for the design and construction of industrial facilities and other objects. Sanitary norms (SanPins) and sectoral normative documents (ONDs) classify the industrial facilities by hazard class, and establish requirements for permissible impacts, sanitary-hygienic norms, and standards of environmental quality. Directions, guidance documents, and instructions determine requirements while conducting particular activities, such as assessing the environmental damage, calculating emissions and discharges into the natural environment, and norms of waste generation and disposal (Table A2.4).

On the whole, the legislative framework which regulates environmental protection and the use of natural resources is large. The total number of documents is over 800.

Conventions and international treaties are a major factor in the development of the national strategy and legislation in the area of environmental protection. In accordance with Russian legislation, provisions of the international treaties override the current Federal laws.

Regional legislation in the area of environmental protection and natural resources management is not uniform over the Russian territory. Some regions adhere to a more advanced policy and have a great number of regional documents (Moscow, Saint Petersburg) addressing different environmental issues. In the other regions (Siberia and the Far East), the legislation is mainly closely associated with economic and tax-budget instruments.

Table A2.4. Environmental legal framework of the Russian Federation.

A. Status of documents	
1	International conventions and treaties
2	Laws and codes
3	Decrees of the President
4	Resolutions and instructions of the Government of the Russian Federation
5	Normative legal acts issued by the Ministry of Natural Resources and other Federal ministries and agencies
6	State standards (GOSTs) and sectoral standards (OSTs)
7	Departmental norms of technological design and building (SniPs) and Sanitary norms (SanPins) and sectoral normative documents (ONDs)
8	Directions (RD), guiding documents (MU), instructions
B. Mechanisms (Procedures) of the State Regulation	
1	State environmental expertise
2	State environmental control
3	Environmental monitoring
4	Environmental audit
5	Environmental norms and standards
6	Environmental impact assessment
7	Environmental certification
8	Licensing of environmental activities

A.4.7.5.1. Norms and standards

The system of environmental quality norms, which has been developed within the past fifteen years, forms the basis for granting permits and calculating environmental payments. The most important standards are the standards of maximum permissible concentrations (MPC), which set the maximum levels of the peak and average concentrations of environmental pollutants. MPC standards have been determined for: 479 substances polluting the atmosphere, 2679 substances contaminating water, and 109 substances contaminating soil. These standards are based on the Russian sanitary hygienic requirements and for the most part are stricter than the analogous standards applied in Europe and the United States.

On the basis of these standards, limits and standards of maximum permissible emissions (MPE) and maximum permissible discharges (MPD) for stationary sources of pollution and enterprises are developed. The MPE and MPD limits are developed using approved calculation guidance based on mathematical modeling of pollution transfer and dispersion.

In addition to the MPE and MPD limits, temporary agreed emissions (TAE) and temporary agreed discharges (TAD) can be established for sources and enterprises. In this case, the enterprise is to develop a plan for the reduction of emissions and discharges in compliance with the MPE and MPD levels. The MPE and MPD limits, and also TAE and TAD, are determined in the permits for air emissions and waste discharges, which are granted to enterprises annually.

Another important factor is setting the sanitary protection zone (SPZ) for an enterprise, the minimum size of which is determined on the basis of the sanitary classification of industrial facilities (SanPin 22.2.1/2.1.1.1200-03). People are prohibited from living within SPZs.

A.4.7.5.2. Federal bodies authorized to implement environmental control

Federal bodies authorized to implement environmental control include:

1. the Ministry of Natural Resources, which regulates and controls environmental protection and natural resources usage; within the frame of its competence, the ministry coordinates activities of other agencies;
2. the Ministry of Health and Social Development, which establishes sanitary hygienic norms for environmental quality, and exercises supervision over the sanitary epidemiological status;
3. the Ministry of Agriculture, which establishes rules and exercises control and quarantine supervision over animals and plants; establishes norms of allowable catches of fish and marine animals, and exercises supervision within the frame of its competence;
4. the Ministry of Emergencies on Industrial Accidents Prevention and Preparedness, which monitors and forecasts natural and technologically related emergencies and catastrophes;
5. the Federal Service of ecological, technological and atomic inspection;
6. the Federal Service of the realties cadastres (Zemkadastr), which keeps a cadastre of lands of various destinations; controls the lands' condition;
7. the Federal Service for Hydro-Meteorological Monitoring (Roshydromet), which provides environmental monitoring and maintains the Federal data bank;
8. the Federal Service of water resources;
9. the Federal Service of forestry;
10. the Federal Service of nature use; and
11. the Federal Service for nature use inspection.

Environmental compliance

Legislative and regulatory documents require enterprises to meet the following requirements:

- to prepare substantial materials to obtain the licenses for the use of natural and mineral resources; to meet the license terms;
- to develop projected limits of normative permissible emissions, maximum allowable permissible discharges and maximum permissible limits of waste generation and disposal, which are approved for a period of five years;
- to prepare substantial materials to obtain permits for emissions, discharges, and waste disposal, which are granted for a period of one year;
- to develop an EIA report in cases of reconstruction, modernization and technological conversion, and to submit the report to the State environmental expertise;
- to provide environmental control of operations following the plans and schedules approved by the environmental bodies; to keep records of the acquired data;
- to submit annually data on emissions, discharges, wastes, and environmental payments in the format required for State statistical reporting;
- to develop and implement an action plan on environmental protection;
- to calculate payments for the environmental pollution and natural resources usage, and to make these payments; and
- to create and maintain a database of the environmental legislative and regulatory documents.

Sanctions which can be applied to an enterprise for non-compliance with the environmental legislation and regulations include: penalties; fees, permit or license cancellation; partial termination of the enterprise operations; and closing of the enterprise.

A.4.7.6. Protection and preservation of the marine environment

The protection and preservation of the marine environment and the natural resources of the internal maritime waters and the territorial sea are to be ensured in accordance with the laws of the Russian Federation and the international treaties to which the Russian Federation is a party by the specially empowered Federal executive bodies within the limits of their competence and also by the relevant executive bodies of subjects of the Russian Federation (Article 32, Protection and preservation of the marine environment and the natural resources of the internal maritime waters and the territorial sea).

The quality of the marine environment of the internal maritime waters and the territorial sea shall be regulated for the purpose of establishing maximum permissible norms for effects on the marine environment and the natural resources of these areas, ensuring and guaranteeing the environmental safety of the population, the preservation of the genetic pool and the protection and preservation of the marine environment and natural resources, and also ensuring the rational use and reproduction of the natural resources of the internal maritime waters and the territorial sea.

The maintenance of the marine environment of the internal maritime waters and the territorial sea in a condition which meets environmental requirements will be ensured through the establishment and observance of regulations for the maximum permissible concentrations of harmful substances and regulations for the maximum permissible harmful effects on the marine environment and the natural resources of these areas, and also other requirements and measures established under the laws on environmental protection and the water legislation of the Russian Federation. The procedure for the formulation and approval of regulations for the maximum permissible concentrations of harmful substances and for the maximum permissible harmful effects on the marine environment and the natural resources of the internal maritime waters and the territorial sea will be established by the Government of the Russian Federation. These will be published in Notices to Mariners (Article 33, Regulation of the quality of the marine environment of the internal maritime waters and the territorial sea).

Spent drilling fluid, mud and produced water contain oil, heavy metals, and other toxic chemicals. These are harmful substances which pollute and negatively influence the environment. The dumping of wastes and other matter and also the discharge of harmful substances in internal maritime waters and in the territorial sea are prohibited (Article 37, Dumping of wastes and other matter and discharge of harmful substances in the internal maritime waters and the territorial sea).

The rules for developing and establishing the maximum permissible norms of the impact on the marine environment and natural resources of the internal maritime waters and the territorial sea were approved by the Order of the Russian Federation Government, 10 March 2000, No. 208, based on the Water Code adopted in 1995. However, because a new Water Code came into force on 1 January 2007, new rules for developing and establishing the maximum permissible norms of the impact on the marine environment and natural resources have yet to be approved.

A.4.7.7. Requirements for industrial waste management in Russia

The legal bases for the regulation and control of waste management activities include the Constitution of the Russian Federation (1993), the Federal Law on Environmental Protection (1991), and the Federal Law on Waste of Production and Consumption (1998).

The Federal Law on Waste of Production and Consumption, which came into force in July 1998, addresses regulatory principles; delegation of authority for waste management between national, regional and local levels; environmental requirements for waste management activities and facilities; reporting requirements; economic regulation including insurance requirements; and authority for compensation and penalties. A significant aspect of the Waste Law is that it establishes for the first time in Russia the concept of property rights for wastes. This was necessary in order to establish legal responsibilities for the treatment of present and past waste. The Law defines that the property rights for waste belong to the persons or entities whose activity resulted in the production of such waste. Under the Waste Law, special licenses are necessary to handle any type of waste and to transfer waste property rights.

The list of administrative and economic instruments that competent authorities and their regional environmental committees currently or will soon have at hand within waste management is long. It includes:

- licensing of utilization, storage, movement, disposal, dumping, elimination of industrial and other wastes (except for radioactive wastes);
- environmental certification;
- waste classifiers, including creation of regional waste registers;
- ecological passport, aimed at, among others, ensuring a move towards an integrated permitting system regarding waste disposal;
- waste permits by media;
- limits of waste generation;
- permission for waste disposal;
- compensation of damage (liability);
- system of pollution charges (pollution charges for waste disposal);
- pollution charge exemption scheme; and
- environmental risk insurance scheme.

According to the Federal Law on industrial and domestic waste of 24 June 1998 # 89-FZ, all enterprises and persons conducting activities associated with waste production and management must undertake the following.

1. Observe environmental, sanitary and other requirements set by the environmental and health protection legislation of the Russian Federation: Federal laws on Environmental Protection of 10 January 2002 #7-FZ; on Sanitary-and-Epidemiological Welfare of 30 March 1999 #52-FZ; the Water Code of the Russian Federation of 03 June 2006 #74-FZ; on Subsoil of 21 February 1992 #2395-1; and others.
2. Separate waste by kind, hazard class, and other criteria in order to provide for waste utilization as a secondary raw material, processing and disposal.
3. Ensure that industrial waste does not have a negative impact on the environment and human health when temporarily collected on industrial sites before its further use in the waste management cycle or being sent for disposal ('Limited amount of toxic industrial waste permitted for allocation in reservoirs (on polygons) of solid waste', Moscow, 1985, Ministry of Health of USSR, Ministry of Housing and Communal Services of RSFSR).
4. Obtain permission for waste disposal regardless of whether it will be disposed on the owner's or a rented disposal area (permission is granted by the Federal authority responsible for waste management). The permission for waste disposal may be given only when it is proved that the waste cannot be processed (lack of technology, equipment, etc.).

A waste disposal site is defined according to special research (geological, hydrological and other) set by Russian legislation and after approval by the State ecological expertise. Waste disposal sites must be constructed and managed according to requirements adopted by the State geological and ecological expertise, environmental, building construction and sanitary norms and regulations (Sanitary regulation of construction and maintenance of polygons/sites for solid domestic waste, Moscow, 1983, Ministry of Health of USSR; Guidelines for designing the polygons for sterilization and burial of toxic industrial waste (to SNiP 2.01.28-85), Moscow, 1990, Gosstroy of USSR; Sanitary regulation for designing, construction and operation of polygons for burial of non-utilized industrial waste, Moscow, 1986, Ministry of Health USSR; SNiP P-89-80 General Plans of the Industrial Enterprises (as amended in 1985, 1986, 1987 and 1990)).

Waste management activities must be licensed (Federal Law on Subsoil of 21 February 1992 #2395-1; Federal Law on Licensing Certain Activities of 08 August 2001 #128-FZ; The Resolution of the Government of the Russian Federation of 26 August 2006 #524 on Adopting the Regulation on Licensing Activities on Collection, Use, Sterilization, Transportation, Disposal of Hazardous Waste).

Waste of hazard classes I, II, III, and when necessary also IV, can be disposed of only on polygons for sterilization and burial of toxic industrial waste, constructed according to SNiP (Temporary classifier of toxic industrial waste and methodic recommendations of definition of toxic class of industrial waste, Moscow, 1987, Ministry of Health of USSR, State Committee of Science and Techniques of USSR). Disposal of hazardous waste is prohibited on the territory and within 3 km of the borders of towns and settlements, in park, sanatorium, health and recreation zones and zones of sanitary protection of drinking water sources, as well as in the areas of development of geo-tectonic structures and processes. It is prohibited to discharge waste in water reservoirs of integral use, groundwater-bearing strata.

Enterprises are required to register all waste produced, used, sterilized, or delivered to or from others, as well as disposed waste, and to keep books and documents within the terms set by Federal authorities responsible for waste management. Enterprises must present an annual report on production and removal of toxic waste according to Form #2-tp(toxic waste) to regional units of the Ministry of Nature Resources of Russia (Resolution of State Committee on Statistics of Russia of 11 November 1998 #95 on approval forms of Federal State statistic control for 1999). The definition of the hazard class of waste produced and used at the enterprise is a responsibility of the enterprise/nature user (Building Construction Norms and Regulations SNiP 2.01.28-85 Polygons for sterilization and burial of toxic industrial waste. Main regulations for designing, Moscow, 1985, Gosstroy of USSR).

Enterprises must also elaborate projects according to waste production norms and disposal limits (PNOOLR) in order to reduce the production of waste (Resolution of the Government of the Russian Federation dated 16 June 2000 #461 'On Rules for Elaboration and Approval of Norms for Waste Production and Limits for Waste Disposal', amendments dated 14 December 2006 #767, and 29 August 2007 #545). In order to follow the terms of environmental legislation of the Russian Federation, nature users (industry) receive limits for waste production and disposal. The Department of Environmental Protection and Waste Management of the Ministry of Nature Resources is developing the methods documents for waste disposal norms and regulations.

Enterprises must also:

- introduce low-waste technologies based on modern scientific-technical achievements (Federal Laws on Environmental Protection dated 10 January 2002 #7-FZ; on Atmospheric Air Protection of 04 May 1999 #96-FZ, and others);
- carry out industrial environmental control;
- conduct inventories of wastes and waste disposal sites;
- conduct environmental monitoring on waste disposal territories (Federal Laws on Environmental Protection of 10 January 2002 #7-FZ; Resolution of the Government of the Russian Federation of 31 March 2003 #177 on arranging and carrying out State environmental monitoring);
- provide necessary information on waste management activities;
- follow standards for the prevention of emergencies associated with waste management, and respond rapidly to emergencies when they occur;
- confirm the hazard class of produced waste according to the order set by Federal authorities responsible for waste management; make a passport for hazardous waste based on data on hazardous waste composition and properties, and an assessment of their danger. The order of registration is set by the Government of the Russian Federation (Order of the Ministry of Nature Resources of the Russian Federation of 02 December 2002 #786 on approval of Federal waste classification catalogue); and
- pay for negative environmental impacts (Methodic instructions on setting payments for pollution of nature environment registered in the Ministry of Justice of the Russian Federation on 24 March 1993 #190; Resolution of the Government of the Russian Federation of 28 August 1992 #632 on approval of the procedure for setting up payments and their limited amounts for pollution of nature environment, waste disposal and other negative impacts; Resolution of the Government of the Russian Federation of 12 June 2003 #344 on norms of payments for emission of pollutants into atmospheric air by stationary and mobile sources, discharges of pollutants into surface and ground waters, industrial and domestic waste disposal).

Cases of violation or incomplete implementation of the legislation of the Russian Federation in the field of waste management will result in the initiation of disciplinary, administrative, criminal or civilian-rights proceedings (Code on Administrative Delinquencies of 30 December 2001 #195-FZ; Criminal Code of 13 June 1996 #63-FZ; Federal Laws on Environmental Protection of 10 January 2002 #7-FZ; on Sanitary-Epidemiological Welfare of 30 March 1999, and others).

According to the Water Code of the Russian Federation of 03 June 2006 #74-FZ, nature users must receive permission to use water objects for the discharge of sewage and/or drainage waters, or the exploration or production of mineral resources (including oil and gas) (Resolution of the Government of the Russian Federation of 30 December 2006 #844 On Procedure of Elaborating and Taking Decision on Giving Water Object in Usage).

Owners of water objects and water users when using water objects must:

- maintain their sewage systems and hydro-constructions placed on water objects;
- inform executive State and local authorities about accidents and other emergencies on water objects;
- operate emergency prevention and response activities;
- register the amount of water resources taken from water objects and the amount of sewage and/or drainage waters discharged and their quality; carry out regular observations of water objects and their protection zones; present the results of these observations and monitoring to responsible Federal authorities free of charge (Resolution of State Committee of Statistics of Russia dated 11 September 1998 #95 on Approval Forms of Federal State Statistic Control for 1999); and
- protect water objects from pollution and clogging.

A.4.7.8. Extracts from laws and regulations concerning offshore waste disposal in Russia

The Federal law on Inland Sea Waters, Territorial Sea and Adjacent Zone of the Russian Federation of 31 July 1998 #155-FZ (amended 29 December 2004), Article #37: Burial of waste and other material, as well as discharge of harmful substances in inland sea waters and in the territorial sea are forbidden, regulates activities offshore. The discharge of harmful substances does not include emissions of harmful substances, or the discharge of harmful substances needed for carrying out legal marine scientific research aimed at pollution combat or control.

The Constitution of the Russian Federation (article 15, point 4) states: '… if international agreements for the Russian Federation set other requirements than those that are set by the law, the requirements of the international agreement are to be applied'. For example, Russia has signed/approved the MARPOL-73 Convention, as well as the Convention on Prevention of Marine Pollution by Dumping of Waste and Other Matter (1972).

A.4.7.9. Yamal-Nenets Autonomous Okrug nature management

Environmental policy in the Yamal-Nenets Autonomous Okrug (YaNAO) is regulated by regional environmental and other authorities in close cooperation with the okrug and regional administrations and participation of sectoral structures. Special attention is given to the efficiency of control over nature management with the use of authorized sanctions against environmental offenses and mobilization of efforts to respond to accidents and other emergency situations.

Measures are taken to strengthen environmental monitoring. Environmental authorities actively participate in reviews and State expertise of industrial site development projects, and organize the development and amendment of environmental regulatory documents in the context of the YaNAO.

Environmental management in the okrug is based on monitoring data and results of targeted research, scientific, expert and legislative activities.

A.4.7.9.1. Provision of environmental safety in the YaNAO

The development and production of hydrocarbons in the YaNAO is associated with the development of new deposits mainly in underdeveloped areas of the north-east (Nadym-Pur-Taz interfluve, Yamal Peninsula) that will require additional capital-intensive efforts to promote environmentally sound economic activities in the YaNAO land and water areas vulnerable to anthropogenic influences.

Environmental impact assessment plays an important role in decision-making regarding the environmental safety of oil and gas production sites, involving a wide range of experts and engineers to assess emergency situations and performance characteristics on the basis of a system of environmental indicators in the context of the Arctic region.

The provision of environmentally sound engineering solutions should cover all stages of the development of deposits, beginning with the construction of transport lines and exploration sites including the technology for construction, maintenance, and repair of the road surface taking into account the geographical conditions, high dynamics, and reactivity of cryogenic processes typical for perennial permafrost.

At the design stage, optimal structures must be chosen for drilling rigs and other production facilities so that soil cover and permafrost stability will not be affected. The most important aspect of oil and gas production is to implement environmentally sound methods of well drilling. The transition from traditional vertical drilling to directional and horizontal wells plays a key role in this process. A combination of this method with clusters of wells strengthens environmental protection efforts by reducing the volume of excavation work and maximally preserving the tundra's soil cover.

Solvent and gas-water mixture injection, microbiological and electric action on the strata and bottom-hole area of water-flooded zones, deep hydraulic fracturing, and other measures allow oil recovery to increase by 25 to 30% and improve environmental quality.

Improvements in the environmental safety of drilling in the Far North and reductions in the amount of drilling waste can be achieved by techniques based on closed water-treatment systems with the use of efficient shale shakers, and coagulation and flocculation of drilling wastewater by chemicals with further separation into liquid and solid phases in a centrifuge. Another promising method is to decontaminate drilling waste containing adsorbed toxic substances based on the capsulation method with the use of 'Rezol' agent developed by the Ukhta Industrial Institute for the Arctic regions.

Oil residues accumulated in processing equipment, pits and soils in accidents contain from 10 to 70% oil and significantly contaminate soil, water, and air with hydrocarbon compounds. The implementation of a method developed by specialists from the Russian Academy of Science allows oil residues to be processed with the comprehensive utilization of all components by directing water to treatment facilities. By this means, hydrocarbons are extracted along with oil, while the remaining impurities meeting the Maximum Pollution Load conditions can be used for the banking of areas, roads and pits, the construction of embankments.

The practical use of similar techniques with the recycling of industrial effluents and the disposal of sludge and oil residues must be accompanied by the restoration of disturbed lands. The most efficient cleaning of the areas with the further restoration of soil cover contaminated by hydrocarbons can be achieved by the use of biological oil removers.

The consequences of oil spills are the most hazardous for soil cover; thus, environmental protection measures against spills require the development of special regulatory documents determining the procedures, methods and techniques of oil spill containment and further rehabilitation of contaminated areas. For this, significant importance is attached to the development of an integrated system of environmental and operational monitoring and emergency repair and restoration teams equipped with efficient equipment, agents and other means for disaster recovery that are environmentally safe for tundra soils. The actions of these teams are regulated on the basis of the Russian Federation Government Decree on Contingency Plans for Prevention and Elimination of Post-Effects of Oil (Oil Products) Spill No. 613 of 21 August 2000.

A solution to the problem of the utilization of associated gas, over 25% of which (about 930 million m^3) is burnt in flares, is one of the key issues in the protection of air from pollution and greenhouse gases, as well as a more rational use of hydrocarbons in general. The index of associated gas processing at oil processing enterprises in the YaNAO is not only lower than the Russian average

(82.5%), but also does not achieve 95%, as indicated in the license for mineral resource management in West Siberia.

Developed countries use over 95% of associated gas to produce marketable products. U.S. law prohibits burning over 3% of associated gas in flares; otherwise, supervisory authorities will suspend the operation of an oil well. Powerful associated gas processing facilities are installed in the United States to ensure the maximum use of this valuable non-renewable resource. In Norway, a high environmental tax has been imposed on associated gas flaring.

In Russia, the costs of associated gas treatment and processing are warranted only if an oil production enterprise has its own associated gas processing facilities, where the profit on the sale of oil processing and gas chemistry products covers the investments in the construction and operation of associated gas collection systems.

Most of the expenses to achieve the needed level of disposition are spent on the development of small sites distant from each other, which comprise 70% of the total amount of the Russian oil fields, where the losses account for over 40% of the total volume of associated gas.

According to estimates, the processing of 1000 m^3 of associated gas into chemical products (polyethylene, acrylonitril, benzol, phenol, methyl methacrylate, etc.) would return USD 300 or USD 880 per ton of broad fraction of light hydrocarbons or liquefied gas. Consequently, in the context of the YaNAO, the optimization and improvement of the efficiency of associated gas disposition is determined by a system of economic relations and production costs dependent on the pricing policy.

The problem of associated gas should be considered together with the actions aimed at its economically and environmentally sound use including both its injection into the reservoir to increase well flow rates and as a fuel resource for power plants.

The development of the oil and gas sector in the North requires fundamental changes in the methods of pipeline transport and improvements in the quality of the pipelines, which are the major sources of environmental pollution not only in accidents but also during their routine operation. There is a need to develop trenchless pipelines on the river crossings at especially hazardous sections using directional drilling technology that will prevent the destruction of coasts and the contamination of water bodies. The introduction of strong structural materials, existing methods of corrosion protection, and effective pipeline integrity monitoring will contribute to ensuring longer trouble-free operation.

To reduce the risk of accidents, improve the reliability of gas transport systems, reduce energy consumption and, consequently, improve the environmental situation including the reduction of greenhouse gas emissions, it is necessary to intensify the replacement of old and the installation of new gas compressor units with an efficiency factor of up to 36.5% and higher (the average efficiency factor of operating gas compressor units is about 28%) to reduce the consumption of fuel gas by 30% and decrease the volume of pollutants discharged.

The environmental safety of pipeline operations depends to a great extent on environmental and operational monitoring including a range of technical, informational and software means permanently or temporarily located at strategically significant sites and sections of pipeline. The creation of an integral system of environmental and operational monitoring in the YaNAO and its connection to the Siberian and Federal structures is the most important direction for the provision of environmental safety in the region. This can be based on the OAO Gazprom project for the development of the Yamal Peninsula oil fields, containing about 10 trillion m^3 of proven gas reserves. To solve environmental and technological problems in the region, several programs have been developed and partially implemented covering a wide range of issues including social protection of the interests of indigenous peoples of the North.

Scientific and methodological support will be provided with the involvement of a wide range of research and development institutions and highly skilled specialists to ensure the environmental safety of well drilling in the Ob Bay waters, according to the license for geological exploration of the Mys Kamenny bottom area granted to OAO Gazprom. Experience gained in the project proposal for the Pechora Sea resource development, which has received a positive conclusion from the State environmental expertise (environmental review), has been taken into consideration. An analysis of the studies, drilling results, and tests of exploration wells showed that anthropogenic effects on the environment will be local (within the adjacent areas) and insignificant in terms of environmental impact. The results obtained can be used not only for developing an integrated program of environmental and operational safety for the development of hydrocarbon deposits in the Ob Bay waters but also in shelf and coastal areas.

The development of the oil and gas sector in the YaNAO should be accompanied by the implementation of the environmental protection management system.

International experience in the development of natural resources in the Arctic interior, coastal, and shelf areas shows that the justification for the initiation of oil and gas sector activities should be based on the concept of 'sustainable development'. At the same time, it is necessary to achieve a balance between traditional local economic sectors using renewable resources and powerful anthropogenic impacts on the environment.

The development of the YaNAO requires preliminary assessment of the environmental capacity and sensitivity of local and regional natural systems in the implementation of economic decisions based on a full and objective assessment of costs, benefits, and risks. The environmental component is an integral part of environmental, social, and economic problems requiring the establishment of a stable and consistent regulatory framework to provide for a safe and sustainable development of the oil and gas sector under the severe conditions of the Russian Arctic.

Appendix 2.2. Oil Spill Response Systems

This Appendix provides a list of notification centers and principal oil spill response authorities in the Arctic countries and describes the U.S. oil spill response preparedness system, as an example of a well-developed system.

A.1. Regional response organizations

Many centers will accept notification by e-mail as an alternative to telephone, telex, facsimile, or satellite (INMARSET) communication. All notification and response entities are governmental and are listed below.

United States
Notification center: United States National Response Center, c/o United States Coast Guard (G-OPF), 2100 2nd Street Southwest, Room 2611, Washington, DC 20593-0001, USA. Notification to the appropriate State authority may also be required.
Principal oil spill response authority: United States Coast Guard, Office of Response (G-MOR), US Coast Guard Headquarters, 2100 2nd Street Southwest, Washington, DC 20593-0001, USA.

Canada
Notification center: Rescue Safety & Environmental Response Directorate, Canadian Coast Guard (24 hr Operations Center), Department of Fisheries and Oceans, 7th Floor, Centennial Towers, 200 Kent Street, Ottawa, Ontario K1A OA6, Canada.

Alternatively, spills may be reported to the appropriate regional center or nearest Vessel Traffic Service Center: Halifax, Nova Scotia; St. John's, Newfoundland; Placentia Bay, Newfoundland; Port aux Basques, Newfoundland; Saint John, New Brunswick (Fundy Island); Quebec City, Quebec; Sarnia, Ontario; Vancouver, British Columbia; Prince Rupert, British Columbia; and Tofino, British Columbia.
Principal oil spill response authority: Rescue Safety & Environmental Response Directorate, Canadian Coast Guard, Department of Fisheries and Oceans, 9th Floor, Canada Building, 344 Slater Street, Ottawa, Ontario K1A ON7, Canada.

Greenland
Notification center: Grønlands Kommando, Maritime Rescue Coordination Centre Grønnedal, DK-3930 Grønnedal.

Iceland
Notification center: Operations Centre, The Icelandic Coastguard, P.O. 7120, 127 Reykjavik, Iceland.
Principal oil spill response authority: Office of Marine Environmental Supervision, Environmental and Food Agency of Iceland, Suourlandsbraut 24, IS-108 Reykjavik, Iceland.

Faroe Islands
Notification center and principal oil spill response authority: Færøernes Kommando, Mjørkadalur, Postboks 3195, FO-112 Tórshavn, Faroe Islands.

Denmark
Notification center and principal oil spill response authority: Maritime Rescue Coordination Centre, Søværnets Operative Kommando (SOK; Danish Royal Navy), Postboks 483, DK-8100 Aarhus C, Denmark.

In port, vessels must contact the relevant port authority.

Norway
Notification center and principle oil spill response authority: Norwegian Coastal Administration, Department for Emergency Response, PO Box 125, N-3191 Horten, Norway.

Sweden
Notification center and principal oil spill response authority: Swedish Coast Guard, Central Headquarters, Box 536, S-37123 Karlskrona, Sweden.

Finland
Notification center: Maritime Rescue Coordination Centre, Archipelago Sea Coast Guard District, PO Box 16 FIN-20101 Turku, Finland.
Principal oil spill response authority: Finnish Environment Institute (SYKE), P.O. Box 140, FIN-00251 Helsinki, Finland.

Russian Federation
Notification center: State Marine Search and Rescue Coordination Center (SMRCC), Ministry of Transport of the Russian Federation, 1 Bid 1, Rozhdestvenka Str, Moscow 109012, Russian Federation.

- Novorossiysk Maritime Search and Rescue Coordination Centre
- Maritime Rescue and Coordination Centre St Petersburg
- Maritime Rescue and Coordination Centre Murmansk
- Maritime Rescue and Coordination Centre Arkangelsk
- Maritime Rescue and Coordination Centre Vladivostok
- Maritime Rescue and Coordination Subcentre Petropavlovsk-Kamchatskiy
- Maritime Rescue and Coordination Subcentre Uzhno-Sakhalinsk
- Maritime Rescue and Coordination Subcentre Kaliningrad

Principal oil spill response authority: State Marine Pollution Control, Salvage and Rescue Administration (SMPCSRA), Ministry of Transport of Russian Federation, 1 Bid 1, Rozhdestvenka Str, Moscow 109012, Russian Federation.

A.2. National oil spill preparedness and response systems

Chapter 2, section 2.8 summarizes and assesses the oil spill preparedness and response systems of the Arctic countries. In addition, Canada and Norway provided further details on the requirements and organization of their spill response activities, as reported in sections A2.1 and A2.2, below, and the United States supplied a detailed description of its Oil Spill Response System, a summary of which is contained in section A2.3, below.

A.2.1. Canada

The National Energy Board (NEB) is the primary regulatory authority in Canada's NWT, Nunavut, and the Arctic offshore region in relation to the prevention, preparation for, and response to oil spills that may result from oil industry activities (see also Chapter 2, Section 2.8). Similar provisions apply to Yukon and offshore in Labrador.

All oil spills from petroleum industry exploration and development operations in the NWT and Nunavut, and in the Arctic offshore region, are reported through the NWT/Nunavut 24-hour spill report line. There is a mandatory requirement to report offshore spills under Canada's Arctic Waters Pollution Prevention Act. The NEB, Government of the Northwest Territories, and Indian and Northern Affairs Canada each require that spills of 100 liters or more of oil, or mixed products containing oil, be reported via the Spill Report Line. Around five or six spills were reported each year from 1995 to 2004 (a maximum of twelve reported in 1997). The largest reported spill was 397 000 liters in 1997 at Norman Wells when a transfer line from a central processing facility to a storage tank ruptured. Other large spills were 36 729, 35 000 and 103 000 liters (Table A2.5). While the overall number of spill reports of all products, not just oil, in the NWT and Nunavut has increased dramatically since 1999 (from 172 in 1999 to 702 in 2004) due to an increase in mining and oil and gas activity and the added reporting efforts of local environmental monitors, the number of reported oil spills has varied little.

Planning for spills

Canada's northern regulatory agencies assess proposed exploration and production activities to ensure that the company meets regulatory requirements for safety and environmental protection, and for financial and operational capability to respond to an incident. Offshore operations potentially demand a broader level of cooperation between Federal and territorial agencies and – depending on location – with agencies of neighboring countries, to coordinate their emergency response roles.

Prevention

In terms of prevention, the Canada Oil and Gas Operations Act and associated Regulations prescribe safety requirements including work planning and facilities design. The NEB has developed contingency planning guidelines and an Offshore Emergency Response Plan in coordination with other northern agencies. Similar provisions exist in other jurisdictions. Safety and environmental protection are currently under review to bring these requirements in line with international ISO standards.

The operator is required to plan work and design facilities to prevent emergency situations from developing and to have a plan in place to address emergency situations. For onshore operations, the operator is required to declare that equipment is fit for the intended purpose; for offshore operations, a certificate of fitness is required from an approved international certifying authority.

Preparedness

The NEB staff includes engineers experienced in onshore and offshore operations, and appropriately trained and certified inspectors to regulate and monitor northern operations. Memoranda of Understanding are maintained with other key response units such as the Canadian Coast Guard, Northern Affairs program and the NWT/Nunavut Spill Response Line. The NEB ensures that emergency response plans are reviewed annually.

There is an onus on operators to demonstrate preparedness for spills. Companies develop emergency response plans to deal with any safety or environmental emergency. In order to ensure a first response capability, emergency response equipment and materials are ready on site and nearby for immediate deployment.

Table A2.5. Number of reportable oil spills compared to all reported spills (1995-2004).

	NWT 24-hr spill report line [a]	NEB lead agency [b]	Total reportable oil spills [c]	Spill volume range, L		Number of operators responsible
				Low	High	
2004	702	33	5	200	12 000	3
2003	779	42	7	100	36 729	2
2002	611	24	2	800	15 000	2
2001	385	56	7	150	10 000	2
2000	327	48	2	3180	35 000	2
1999	172	6	8	200	10 000	2
1998	190	2	3	100	1 000	1
1997	275	27	12	100	397 000	1
1996	259	16	4	200	103 000	1
1995	205	14	3	158	500	1

[a] Includes all spills reported in NWT & NU; [b] includes all spills assigned as 'NEB Lead Agency'; [c] includes crude oil or condensate or any mixtures with other fluids such as produced water, minimum 100 liters.

Response

Companies are required to perform regular safety and emergency response drills: trained workers and emergency responders carry out regular exercises. The NEB undertakes regular desk-top and field exercises at various levels up to full inter-agency exercises. Inspectors participate in the operator's drills, ensuring that lessons learned are incorporated in amended emergency response plans.

Should a spill occur in the offshore environment during a drilling operation, the NEB has developed an 'Arctic Offshore Incident, Initial Response Procedure', which tracks the incident. As part of this procedure, the operator, regulator or third party notifies the 24-hour spill report line. The NEB is notified and, as part of their investigation, ranks the incident as a Level I, II or III incident:

- Level I: no immediate threat; control of released product completed or pending;
- Level II: some injury or threat to public, moderate adverse environmental effects, first responders and government agencies likely to be directly involved;
- Level III: serious public or company injury or fatality and/or ongoing threat to public, significant and ongoing adverse environmental effects, effects extend beyond offshore facility, immediate and significant government agency and first responder involvement, assistance from outside parties required.

In the event of an offshore oil spill during a Level III Emergency, the NEB would activate its Calgary Emergency Operations Centre and send trained emergency response officers to the site. A Level III designation would be confirmed if the following conditions were met:

- the uncontrolled release of product is continuing and control is not imminent; and/or
- there are significant and ongoing environmental effects; and/or
- there is national and regional media interest; and/or
- there is significant government agency and first responder involvement; and/or
- there is high potential to escalate based on potential fire, explosion or increased release.

Emergency response officers would monitor the company's response to the spill and report regularly to the Calgary Emergency Operations Centre which would coordinate information and any on-site activities with northern agencies such as the Indian and Northern Affairs Canada, Environment Canada, Government of the Northwest Territories, Canadian Coast Guard, Royal Canadian Mounted Police, Canadian Forces Northern Area, Fisheries and Oceans Canada, Inuvialuit Game Council, and the Yukon Oil and Gas Management Branch. The northern agencies in turn could alert or activate various responders to assist the NEB in securing the site or monitoring response activities.

A.2.2. Norway

The Pollution Control Act states that the National Contingency System shall be divided into private, municipal, and governmental contingency areas, each with specific responsibilities. In Norway, all contingency plans and organizations are standardized and coordinated. Hence, in the event of a major national emergency, the national contingency system will work as a single integrated response organization.

The main policy for oil spill clean-up operations involves the use of mechanical methods such as booms and skimmers. Dispersants can be used as a supplement to mechanical recovery (see also Chapter 2, section 2.8).

Organization

Pursuant to the Norwegian Pollution Control Act, the duty to maintain preparedness and the responsibility for clean-up campaigns in the event of acute oil spills is assigned to three main sectors: the national government, the municipalities, and the private sector.

The Norwegian Coastal Administration must respond to oil spills that are not handled by private or municipal preparedness organizations, such as oil spills from ships and major spills from unidentified sources. Additionally, the Norwegian Coastal Administration can provide resources for response operations under private or municipal management. If the party responsible for carrying out the response measures does not master the task, the Norwegian Coastal Administration will assist and possibly take over the management of the operations if required. The Norwegian Coastal Administration is responsible for coordinating private, municipal, and governmental preparedness into a national emergency response system.

In Norway, the approximately 430 municipalities are organized into 34 inter-municipal preparedness areas, each with its own approved contingency plan. The local authorities are responsible for dealing with minor acute spills that occur within the municipality owing to normal activity, and which are not covered by the polluter's private contingency arrangements. The local authorities, including among others the fire departments and the port authorities, collaborate together on municipal preparedness. In addition, the municipalities have an obligation to assist the national government in the event of a major oil pollution incident.

Industrial operations that have the capability of causing significant oil pollution are obliged to establish an adequate level of preparedness. Government requirements primarily apply to operators on the Norwegian continental shelf, crude oil terminals, refineries, and companies distributing oil products as well as major industrial companies. They require the operators on the Norwegian continental shelf to plan for, coordinate, and command oil spill recovery operations in nearshore and onshore locations, in addition to offshore locations. The operators on the Norwegian continental shelf have formed an association – the Norwegian Clean Seas Association for Operating Companies (NOFO) – which manages and maintains oil spill preparedness for its members. In addition to the joint oil pollution contingency plan established through NOFO, each individual operator is required to provide its own oil spill response equipment at the oil fields in case of minor oil spills.

The Norwegian oil industry's oil spill response preparedness

The Norwegian oil industry must establish an oil spill preparedness capability that can handle spill incidents in accordance with defined hazard and accident situations. It is also legally responsible for any acute spills from its activities. The Norwegian Pollution Control Authority (SFT) sets emergency response requirements in association with each drilling permit granted to an operator. These requirements are established on the basis of an environmental risk assessment and emergency preparedness analysis, and are particularly strict for wells drilled in the Barents Sea. The responsible oil companies are required by SFT to prove their ability to perform sufficient surveillance and monitoring, achieve rapid response times for oil spill recovery, and apply beach cleaning during winter conditions.

To meet the Norwegian national requirements related to offshore oil spill preparedness, the companies operating on the Norwegian continental shelf established NOFO as an oil spill response organization, with the objective of protecting the environment. NOFO on behalf of, and together with, the operating companies ensures that the appropriate oil spill recovery guidelines are followed, according to national requirements. In 2007, the members of the NOFO organization were BP Norge a.s., Esso Norge AS, Total E&P Norge AS, A/S Norske Shell, Eni Norge AS, Norsk Hydro Produksjon AS, RWE Dea Norge AS, Amerada Hess Norge AS, Statoil ASA, ConocoPhillips Norge, ChevronTexaco Norge, Pertra AS, Marathon Petroleum Co. (Norway), and Talisman Energy Norge AS.

With the exception of vessels within the facilities' safety zones, the offshore oil companies do not have responsibility for responding to oil spills in relation to ship traffic or the transport of oil products.

Most land terminals have oil spill preparedness requirements for vessels that transport oil products to and from the land facilities (in a geographically delimited area).

Research and development into offshore oil spill countermeasures and preparedness has been given high priority, and the operating companies' active participation and financial support have contributed significantly to developments in this area (see also Chapter 2, section 2.8). Until recently, spill response efforts were mainly confined to mechanical recovery. However, with the increasing interest in other combating methods, exploration, research, and resources are now also being directed toward the use of dispersants.

NOFO has entered into agreements with the Norwegian Coastal Administration and the inter-municipal preparedness areas which relate both to access to and the use of their equipment and personnel in oil spill clean-up operations. In the event of an accidental oil spill from the industry, the Norwegian Coastal Administration will supervise the activities of the operators.

The Norwegian government's oil spill response preparedness

The Norwegian Coastal Administration is responsible for organizing and maintaining the government's oil spill response preparedness, and for coordinating the government, municipal, and private industry preparedness in a national contingency system against oil pollution. This also involves controlling and monitoring any response operations undertaken by the industry or the municipalities. At present, this preparedness consists of the following elements:

- the Norwegian Coastal Administration, Department for Emergency Response in Horten with stations in the cities of Tromsø and Bergen;
- fifteen contingency depots with oil spill control equipment, trained personnel, and small boats (see Chapter 2, Figure 2.155 for their locations);
- four government oil pollution control vessels;
- eight coast guard vessels permanently equipped with oil recovery equipment;
- one specially equipped surveillance aircraft;
- agreements with other governmental authorities and private industry regarding assistance with personnel and equipment resources; and
- international agreements regarding assistance in the event of oil spills, such as the Bonn Agreement concerning the North Sea, and the Norway-Russia Agreement concerning the Barents Sea.

Oil spill response preparedness on Svalbard

The Svalbard Environmental Protection Act provides the basis for establishing oil spill response preparedness on Svalbard. Section 70 of the Act requires that contingency measures be taken against acute pollution.

The responsible company must establish an emergency response system and submit its oil spill contingency plan for approval. Detailed regulations may be issued. In all types of accidents, the Governor of Svalbard should be notified.

The Governor of Svalbard and the Norwegian Coastal Administration have entered into an agreement on sharing responsibility in the event of a ship accident in the Svalbard area. Beyond 12 nm outside the baseline, the Norwegian Coastal Administration will be responsible with assistance from the Governor. Inside the baseline, the Governor will be responsible with the assistance of the Norwegian Coastal Administration. In all situations, the Norwegian Coastal Administration will have the possibility of taking over the responsibility for the clean-up operation.

Facilities that may result in acute pollution must provide the necessary response system. This involves an Environmental Risk Analysis (ERA), implementation of risk-reducing measures, and submission of a contingency plan to the Norwegian Pollution Control Authority or Governor of Svalbard for approval. The facilities are obliged to notify the relevant authorities in the case of an accident and are also required to conduct training exercises on the emergency response procedures.

Response tools available in the Barents Sea

Oil drift, trajectory, and plume models. For over twenty years, the Norwegian Meteorological Institute (DNMI) has delivered an oil trajectory and drifting model service. Based on parameters such as location, oil quantity, and oil type, model results can be forwarded to the oil industry, the Norwegian Coastal Administration, or other customers within 20 minutes. This service is operational 24 hours a day. A major upgrade of the model will be completed in the near future, taking into account deep-water blow outs (oil plumes in the water column) as well as interaction with enhanced weather forecasting models.

Surveillance and monitoring. Since 1980, a dedicated oil pollution surveillance aircraft has been in daily operation in Norway. The on-board Side Looking Airborne Radar (SLAR), IR/UV line scanner, and photo and video equipment can detect and assess oil pollution at sea. The aircraft has all-weather capabilities due to a high altitude performance and long range. A digital image transfer system operates between the aircraft and the government operational command centers in Horten, Bergen, and Tromsø.

Since the early 1990s, radar images from the earth-observation satellites ERS and RADARSAT have been used for early warning and flight planning purposes. Each year the combined use of aircraft and satellites covers more than 10 million km^2 of sea surface, detecting more than 150 oil spills. During tests in 2005 and 2006 to detect oil on water at the *Frigg* field in Norway, the utility of new oil-detecting radar and a hand-held infrared camera has been documented. These will be useful in Arctic areas.

Oil weathering models. In Norway, a research organization has developed an oil database containing the results of extensive laboratory analyses of about 60 different types of oil. In addition, detailed crude assay data for 200 crude oils from Norway and other areas are included. Thus, the Norwegian Coastal Administration has immediate access to oil weathering information (dispersion rate, evaporation rate, etc., as a function of time, temperature, and weather) for a wide range of crude oils. Information from such models, combined with field trials, is vital to risk assessment as well as to contingency planning.

A.2.3. United States

This section provides a summary description of the United States Oil Spill Response System as an example of a well-developed system for the management of oil spill response preparedness.

The Oil Pollution Act of 1990 (OPA 90) fundamentally changed spill prevention and response by making companies ultimately responsible for their actions, and by charging government agencies with taking a more direct role in oil spills. Broadly speaking, U.S. public policy objectives under OPA 90 are the prevention of oil spills, the provision of a comprehensive response regime to clean them up if they occur, and the assessment of appropriate penalties and liabilities to ensure that polluters pay for the damages that they cause and are punished when appropriate.

The requirements of OPA 90 can be grouped into five areas: prevention, preparedness, response, liability and compensation, and research and development.

Responsibilities for OPA 90 implementation and operation are divided between four Federal agencies. The U.S. Coast Guard is responsible for maritime and coastal spills from vessels and marine transportation related facilities, the Environmental Protection Agency for inland spills, the Minerals Management Service for offshore facilities, and the Research and Special Programs Administration for pipelines and related facilities.

OPA 90 directed a large restructuring and expansion of the U.S. oil and hazardous material response system. It contains Federal operational and construction standards which set a technical 'base' augmented by private sector activities and self directed initiatives, and also directs the authority and operations of the National Response System. However, the ultimate operational responsibility for spill response rests with the private sector, for example, with such elements as the vessel and facility response plans, the requirement for periodic private sector exercises defined in frequency and nature by Federal government requirements, and the creation of the Oil Spill Removal Organization program to categorize private sector spill resources. A National Contingency Plan provides a framework under which the National Response System, comprising public and private entities, responds to spill incidents of any magnitude. In addition, a central funding mechanism was established which relies on a limited tax on oil and private sector-sold Certificates of Financial Responsibility (COFRs) to ensure that private sector operators have both Federal (Fund) and market-place (COFRs) sources of funds for oil spill response.

OPA 90 also requires companies to calculate a worst-case discharge (WCD) volume. A spill response scenario must be developed to describe how the operator would respond to the WCD spill in adverse weather conditions. The scenario describes the type of equipment the operator intends to use, how long it will take to deploy, how much is needed, how many people are required, how they will store and dispose of collected oil. It also ensures that they have sufficient personnel available to carry out their spill response plans using in-house and/or response contractor personnel and ensures that all personnel have the appropriate training with current certifications. It requires operators to test their response plans through a combination of notification drills, tabletop drills, and actual deployment drills. Operators are required to test all aspects of their plan during a three-year period.

Responsibilities

Using Executive Order 12777, 'Implementation of Section 311 of the Federal Water Pollution Control Act of October 18, 1972, as amended, and the Oil Pollution Act of 1990', responsibilities were assigned as shown in Table A2.6.

To enhance the prevention of oil spills, OPA 90 set mandatory Federal standards including: additional provisions to address the human element, enhanced equipment and construction standards, enhancement of vessel traffic management, and additional conditions for pilotage and escort vessels for tankers. Key among U.S. government-established prevention standards were:

- double hull requirement for tank vessels;
- enhanced equipment and construction standards;
- operational measures to reduce oil spills from existing single-hull tank vessels;
- national reporting system; and
- vessel traffic services.

Preparedness initiatives are directed by the National Response System (NRS); the national mechanism for emergency response to releases of hazardous substances into the environment or discharges of oil into navigable waters of the United States. The NRS integrates both public and private resources and is divided into three structures: the National Response Team, the Regional Response Teams, and the Area Committees. The Area Committees are supported by participation with State Emergency Response Committees (SERCs) and Local Emergency Planning Committees (LEPCs). Participants include the Federal agencies at all levels, Federal On-Scene Coordinators (FOSCs), Federal agencies, State agencies, local agencies, and the private sector. The response

Table A2.6 The U.S. oil spill response system.

Responsibility	Dept. of Interior	USCG	Dept. of Transportation	EPA
National Response Team	Representative	Chairman if spill in Coastal Zone		Chairman if spill onshore
Regional Response Team	Representative	Representative	Representative	Representative
National Contingency Plan				With approval of OMB
Removal of discharged oil and hazardous substance		In coastal zone		Inland
Oil Spill Response Plans	Offshore facilities including pipelines		Tank vessels & transportation-related onshore facilities & deepwater ports	Non-transportation-related onshore facilities
COFRs	Offshore facilities, including pipelines		deepwater ports	
Oil Spill Prevention	Offshore facilities, including pipelines		Transportation-related onshore facilities & deepwater ports	Non-transportation-related onshore facilities
Inspection of vessels and cargo			X	
Inspection of cleanup equipment	Offshore facilities, including pipelines		Vessels and transportation-related onshore facilities & deepwater ports	Non-transportation-related onshore facilities
Requirement to carry removal equipment			Vessels	
Oil Spill Drills		Tank vessels, on- and offshore in coastal zone		Onshore and offshore in inland waters
Oil Spill Liability Trust Fund		Management, pmt. Of removal costs, claims, natural resource assessment		
Civil Penalties	Offshore facilities, including pipelines		Vessels and deep water ports	

structure which this reflects is designated graphically in Figure A2.1.

In addition to OPA 90, which sets the fundamental structure of the NRS, the NRS is supported by a number of Federal laws and regulations, including:

- Clean Water Act, as amended by the Oil Pollution Act of 1990, Section 4201 provides general emergency response authority to ensure effective and immediate removal of a discharge, and mitigation or prevention of a substantial threat of a discharge, of oil or a hazardous substance when the discharge threatens navigable waters, shorelines, or natural resources of the United States. The Clean Water Act as amended also augmented certain planning capabilities by establishing Area Committees and providing the framework for the development of Area Contingency Plans.
- Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) provides authority to respond whenever any hazardous substance is released or there is a substantial threat of such release into the environment, or there is a release or substantial threat of release into the environment of any pollutant or contaminant which may present an imminent and substantial danger to the public health or welfare. The Emergency Planning and Community Right-to-Know Act (EPCRA), (or Title III of the Superfund Amendments and Reauthorization Act (SARA Title III)), formalized local emergency planning as a component of the NRS and established

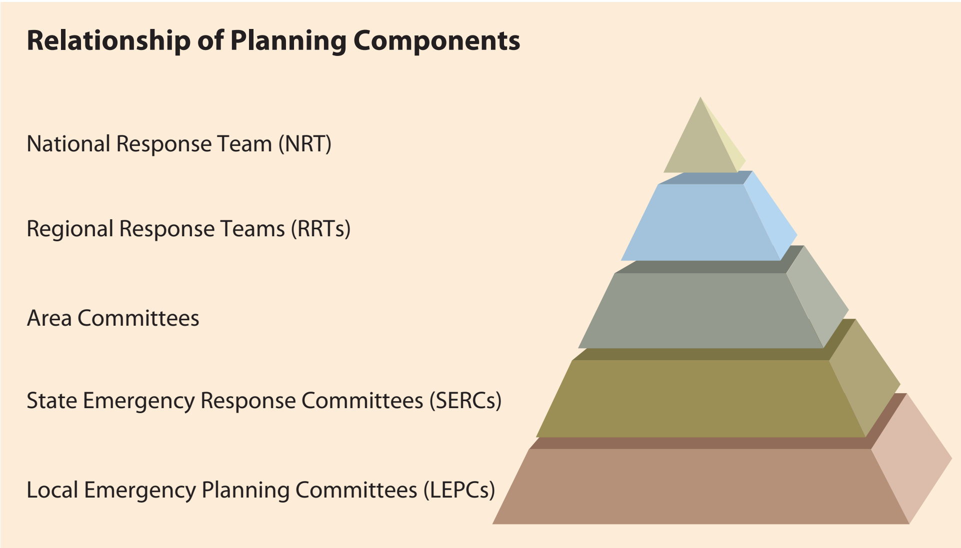


Figure A.2.1. Relationship of planning components for oil spill response.

the State and local link to the Federal system, as well as certain preparedness requirements for and linkages to selected industries. EPCRA provides the framework to encourage coordinated preparedness activities from the local through the Federal levels.

- National Oil and Hazardous Substances Pollution Contingency Plan (NCP) provides the organizational structure and procedures for preparing for Federal responses to discharges of oil and releases of hazardous substances, pollutants, or contaminants. Three fundamental emergency-related activities are performed under the NCP: preparedness planning and coordination for responses; accident notification and interagency communications; and response operations at the scene of a discharge or release.
- Resource Conservation and Recovery Act (RCRA) established the framework to develop regulatory programs to manage solid waste, hazardous waste, and underground storage tanks.

The NRS is guided by a master plan known as the National Contingency Plan (NCP) for the removal of oil and hazardous substances. The NCP provides for the assignment of duties and responsibilities among Federal departments and agencies, identification and procurement of needed equipment and supplies, and the establishment of strike teams consisting of trained personnel and adequate equipment to carry out the removal of oil. The NCP is supported by Regional Contingency Plans and three other response plans: Area Contingency Plans, Vessel Response Plans, and Facility Response Plans. Together, these documents provide a four-tiered planning approach. Logical information flows from the NCP to the regional and area contingency plans, to which are melded the vessel and facility response plans.

This alignment of plans increases the capabilities of the NRS. Roles and responsibilities of all personnel, agencies, and organizations involved in pollution response are clearly identified. Federal On-Scene Command authority to direct all resources in the response effort is defined. However, while the NCP establishes a basis for national spill response operations, it clearly identifies the private sector responsible party as the first line of response, assuming the obligation for cleaning up the spill.

The first level of preparedness planning established below the NCP is the Regional Contingency Plan (RCP). The Regional Response Teams (RRTs) develop a plan for each standard Federal region including Alaska. The purpose of an RCP is to ensure that in an actual incident, there are clear roles and responsibilities for Federal, State, local, and private responders. To the greatest extent possible, any RCP must follow the format of the NCP, and must be coordinated with State emergency response plans, Area Contingency Plans, and Local Emergency Response Committee Plans (LECP).

Below the Regional Contingency Plans are the Area Contingency Plans. The Area Committee is required to prepare an Area Contingency Plan that is adequate, when implemented in conjunction with the NCP, to remove a WCD from a vessel, offshore facility, or onshore facility operating in or near that area.

There is a similar requirement for the owner or operator of a tank vessel or facility to prepare, subject to government approval, a Vessel and Facility Response Plan for responding to a WCD or substantial threat of discharge. These 'private sector' plans are required to be consistent with both the National and Area Contingency Plans and should identify the individual having full authority to implement the removal actions pursuant to the plan. Vessel Response Plans and Facility Response Plans serve to coordinate Responsible Party actions with the FOSCs and local response strategies. They ensure that required resources are planned for and available for immediate use. The relationship between these various plans is shown in Figure A2.2.

The Preparedness for Response Exercise Program (PREP) was developed to establish a workable exercise program. To ensure standardization and uniformity as well as to avoid duplication, the PREP satisfies the exercise requirements of the Coast Guard for marine spills, the EPA for terrestrial spills, the Research and Special Programs Administration's Office of Pipeline Safety for pipelines, and the MMS for offshore platforms. PREP comprises a series of internal and external exercises. The internal exercises are required under the Facility and Vessel Response Plan regulations. The external exercises include large-scale Area exercises for both industry and government. These exercises are conducted with public and private members of the response community and include many of the stakeholders. These exercises validate the readiness of all members of the response community.

Operators are also required to test their response plans through a combination of notification drills, tabletop drills, and actual equipment and operational deployment drills. Operators are required to test all aspects of their plan during a three-year period to ensure that responsible parties can activate, deploy and operate oil-spill response equipment as described in their oil-spill contingency plans.

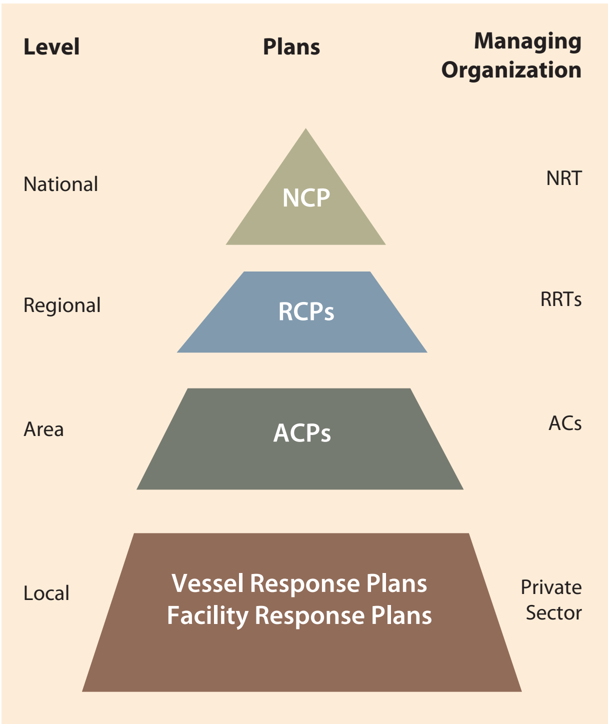


Figure A.2.2. Relationship between planning components.

The NCP requires the FOSCs to be ultimately responsible for response efforts and to coordinate all actions at the scene of a spill or release. With the FOSC in this response management system are Federal and State governments, and the responsible party, to achieve an effective and efficient response, where the responsible party directs the response but the FOSC retains ultimate authority for these actions. This structure is commonly referred to as a Unified Command. The Unified Command is a response management system bringing together Federal and State governments and the responsible party to achieve an effective and efficient response.

FOSCs have the authority to deploy Federal resources to assist with monitoring, sampling, risk assessment, safety and health analysis, clean up, disposal, and other response requirements. The FOSC has certain responsibilities at a site regardless of whether it is a private sector responsible party-led response or a Federal response. These responsibilities include: notification; evaluation assistance in assessing the hazards posed to public health and the environment; decisions on what response action, if any, the Federal government should undertake; and acting as the Site Safety Officer: FOSCs are responsible for all site/response workers from a health and safety perspective. In addition, the FOSC can provide valuable assets to assist State and local agencies during an incident.

The FOSC is supported by a number of specialized groups, two of which have significant roles in maritime spill response: (1) the District Response Groups (DRGs), consisting of personnel and equipment in a designated area, additional pre-positioned equipment, and a District Response Advisory Team; and (2) the National Strike Force (NSF), which functions as a U.S. Coast Guard special force under the National Contingency Plan, providing highly trained, experienced personnel and specialized equipment to the Coast Guard and other Federal agencies to facilitate preparedness and response to oil and hazardous substance pollution incidents. The NSF will respond to spills in the maritime environment and, as requested by the U.S.EPA, in the terrestrial environment.

To enhance the coordination of the many Federal entities that may be called upon by the FOSC and to ensure that private sector resources could have a single organizational structure for response, the Federal government adopted a common response command and control system known as the National Incident Management System (NIMS); often referred to as the Incident Command System (ICS), this serves as the standard response management system for all pollution incidents.

The ICS structure (see Figure A2.3) can be separated into two commands: command staff and general staff. Below the Unified Command, the command staff comprises individuals with specialized skills in liaison, public affairs, safety, and legal issues. The general staff consists of planning, operations, logistics, and finance sections.

Under the ICS, the Unified Command provides the organizational management tool to facilitate and coordinate the effective involvement of the various agencies. It is a unified command that comprises the FOSC, the State representative, the responsible party representative, and the local government representative. This joint organization coordinates the response effort, providing the goals and strategies of the incident response. It creates the link between the organizations responding to the incident and provides a forum for these agencies to make decisions that all responders can agree with. Under this single Unified Command, the various jurisdictions and/or agencies are blended together throughout the Incident Command System to create an integrated response team. Figure A2.4 illustrates the established procedure for an oil spill incident.

Restoration and compensation

OPA 90 addressed the comprehensive liability and compensation mandates for response to oil spills occurring in the navigable waters of the United States

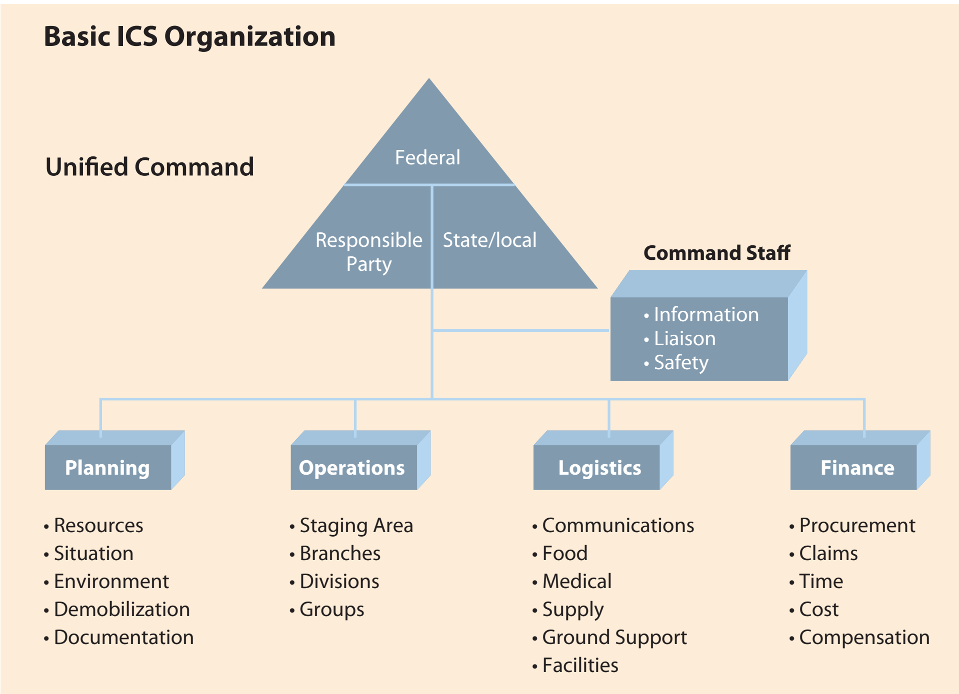


Figure A2.3. The general structure of the Incident Command System.

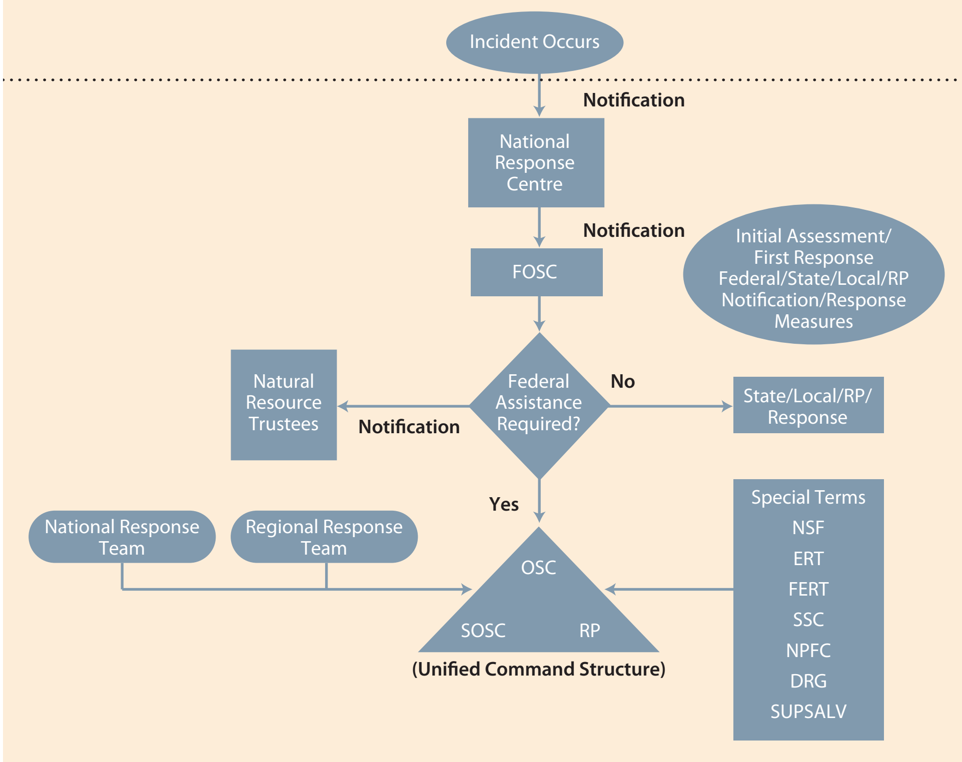


Figure A2.4. Established procedure for an oil spill incident.

and directed that the Oil Spill Liability Trust Fund manage the compensation capability. Certificates of Financial Responsibility ensure that vessel owners or operators have the financial resources to respond to a spill up to their limits of liability.

To ensure that there are sufficient Federal resources to respond immediately to the actual or substantial threat of oil spills, the Oil Spill Liability Trust Fund has two components: an Emergency Fund for removal activities, State access, and the initiation of natural resource damage assessments, and the Principal Fund used for claims and appropriations by Congress.

The financial responsibility of vessel owners and operators is certified through the issuance of Certificates of Financial Responsibility. The primary goals of this program are to ensure that the responsible parties are identified and are financially responsible to the full extent of the law for any expenses involved in a specific water pollution incident. OPA 90 motivates potential polluters to act more carefully by holding them strictly liable for costs and damages resulting from oil spills. New liability provisions make the vessel operator responsible for cleanup, third-party damages, and natural resource damage. All limits of liability are removed if the incident was caused by gross negligence, willful misconduct, or violations of Federal safety, construction, or operating regulations by the responsible party. In addition, the individual States are allowed to set their own liability limits beyond the Federal limit.

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Chapter 3
Social and Economic Effects of Oil and Gas Activities in the Arctic

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3.1. Introduction

3.1.1. Rationale and chapter overview

The purpose of this chapter is to examine the social and economic effects of oil and gas activities in the Arctic, including governance, sustainable development implications, and possible impact on the ways of life of indigenous and non-indigenous residents of the Arctic. The analysis considers effects at the national, regional, and local levels. It also examines the pattern of effects across time, as the mix of activities and their effects may be quite different from one stage to another across the lifecycle of an oil or gas project. Despite differences from one region to the next in geographic context, political and economic institutions, culture and history, and stage of oil and gas development, some common themes emerge.

Oil and gas activities are already major drivers of social and economic change in the Arctic and are expected to expand (see Chapter 2). They have been a significant factor in population change in many regions, and a catalyst for increasing participation in the market economy. But there are many other concurrent causes of social and economic change in the Arctic, and it remains nearly impossible to separate the role of oil and gas or its proportional contribution to specific effects. To explore this topic, the chapter is organized as follows:

- The *Introduction* (section 3.1) provides the rationale for the chapter and outlines the main concepts related to oil and gas effects and the approaches used herein to describe them.
- The *Case Studies* (section 3.2) present examples of the ways in which oil and gas activities affect social and economic systems in the Arctic. The selection of case studies was opportunistic, in that the case studies were for the most part prepared on the basis of existing or ongoing research efforts. The case studies are thus diverse in approach and content, reflecting differences in the circumstances of each region, the history of development to date, and the nature of the research that has been conducted. This diversity affords a variety of insights across stages of oil and gas activities, across political and economic systems, and across types and locations of development. At the same time, however, specific and detailed comparisons are hindered by the lack of consistent statistical indicators or common approaches to examining social and economic effects (a topic also addressed in discussion of knowledge gaps in section 3.3.5).
- The *Discussion and Conclusions* (section 3.3) draw comparative lessons from the case studies and other related material, again emphasizing the distinctive features of the ways in which oil and gas activities create social and economic effects in the Arctic. The conclusions offer general observations about the nature of effects in the Arctic, noting that this field of research is relatively new and so more research will be needed to identify, for example, best practices or specific lessons applicable to future development. Nonetheless, the comparison of experiences to date offers a great deal to those engaged in planning for further oil and gas activities at any stage in their lifecycle.

3.1.2. Distinctive features of the Arctic

The climate and environment of the Arctic affect the seasonal cycle of many human activities. Not only must hunting, fishing and gathering follow the seasonal availability of the animals, but some industrial activities are also strongly seasonal. In the fragile tundra regions, over-land travel is limited to the winter months when the ground is frozen solid. Frozen rivers, lakes, and seas provide a network of winter transportation routes. Ice roads are constructed in the winter to support exploration and development activities, and in some cases to provide access to communities. Offshore, sea ice allows some fishermen and marine mammal hunters a surface on which to travel and hunt or fish. It can also be both a barrier to and a platform for oil and gas activity. In the Arctic, only the northeastern Atlantic region enjoys year-round, ice-free seas due to the moderating influence of the North Atlantic Current.

Much of the Arctic land, and all of the continental shelves, is owned by and/or managed by national or regional governments. Private ownership of land in the north is less prevalent than in the southern zones of the same countries. In North America, most of the privately owned land belongs to indigenous corporations established by land claims settlements or agreements, meaning that it is owned in common by the indigenous inhabitants.

Arctic countries are advanced technologically, economically, and administratively, especially when compared with many other oil and gas producing regions of the world. Thus, national and regional governments have the experience, sophistication, and resources to develop and enforce governance and regulatory regimes for oil and gas activities. The degree of government influence over resource development is high, although not always directed at social and economic effects, particularly at the local level.

Although the Arctic countries are among the world's most advanced in economic and technological terms, Arctic indigenous peoples continue ways of life that have developed over centuries or millennia, adapting to the modern world in a variety of ways. Local initiatives, national legislation, and international conventions help protect this cultural heritage in the Arctic. A crucial part of indigenous cultures is connection to place, increasing their vulnerability to dislocation by industrial and other activities that can separate them from their lands. At the same time, Arctic indigenous peoples have developed tremendous flexibility to deal with the inherent variability of the Arctic environment, increasing their resilience to change.

The Arctic countries are largely market economies, with varying degrees of state intervention in their markets (AHDR, 2004). In regions of Greenland and North America, as well as certain parts of Russia, elements of subsistence economies still exist. Here, wages and cash connect people to the modern market economy, but at the same time acquiring food from the land and sea and sharing or bartering of foods and other goods and services provides a major part of households' production and consumption. The non-market sector mitigates the high cost of living and the limited array of consumer goods in remote areas, buffers volatility in the wage economy, and sustains cultural identity and social capital in Northern communities. This use of the land and sea is vulnerable to environmental degradation. Hunting or herding cannot be easily replaced by another form of employment, traditional foods are not interchangeable with imported foods, nor are cash payments suitable compensation for loss of services outside the market economy. At the same time, Arctic residents may lack the skills and experience needed to participate fully in the wage employment opportunities provided by oil and gas activities. This is not to say that they are incapable of doing so, but that the terms of employment often conflict with cultural practices of following environmental cues rather than those of calendar or clock.

Finally, many Arctic cultures are in a period of rapid social and economic change, of which oil and gas activities are but one aspect (AHDR, 2004; Box 3.1 and Glomsrød and Aslaksen, 2006). Oil and gas technologies are also undergoing rapid changes. The pathways and relationships that produce today's effects may be very different from what was seen in the past or what will be seen in the future. Applying the lessons of case studies in the present to what may take place in the future therefore requires great caution. Attributing observed social and economic changes to oil and gas activities is likewise often difficult. That said, there is no doubt that activities as large and widespread as those associated with oil and gas play a major role in many Arctic regions. The interplay between oil and gas activities and other drivers of change should not obscure the significance of oil and gas activities in Arctic social and economic systems.

3.1.3. Key concepts

Social and economic effects have been studied for many activities in many parts of the world, generating a rich literature and a suite of methods and approaches. The conceptual framework adopted for this analysis has five key dimensions defined below: (1) the geographic scale for assessing effects; (2) governance, planning and response; (3) types of effects; (4) effects over the project lifecycle; and (5) implications for sustainable development.

3.1.3.1. Differences across local, regional and national scale

The case studies address effects at different scales: local, regional and national. Some of the effects described are more relevant at one scale than another. Indeed, the pattern of costs and benefits differs at different scales. For example, revenues from oil and gas may directly benefit the nation state but not the local government, or vice versa, while the social impacts are primarily local. The case studies range from a primarily local focus to a national focus, with some discussion of differences across scales where appropriate.

Box 3.1. Overall economy of the circumpolar Arctic and the contribution from oil and gas activities

A recent publication *The Economy of the North* (Glomsrød and Aslaksen, 2006) provides an overview of the economy of the circumpolar Arctic, particularly covering the importance of the natural resources in the region as well as the traditional production activities of the indigenous peoples. The report covered 28 administrative regions of the Arctic, with the result that its definition of the Arctic region may differ from that used in other publications, including this assessment. Nonetheless, the overall picture it portrays is a useful indication of economic conditions for the circumpolar North.

The overall economic activity of the Arctic in 2003, calculated using 'Purchasing Power Parity' indicators to eliminate differences in price levels among countries, was approximately USD 225 billion. The circumpolar population of the Arctic in 2002 was estimated at approximately 9.9 million, or 0.16% of the world population and 2% of the total population of the countries with territory in the Arctic. The Arctic Gross Domestic Product (GDP) is 0.44% of the global economy, which is greater than its demographic weight of 0.16%.

The primary sector, which is based mainly on the exploitation of both renewable and non-renewable natural resources, is the second largest sector in the Arctic economy. It totals approximately USD 70 billion or 31% of the Arctic GDP, of which roughly USD 53 billion is hydrocarbon production. The large non-renewable natural resources of the Arctic are mainly exploited by national and transnational companies with the capital to support large operations, and thus the capital, equipment, and labor mainly come from outside the Arctic region and the products are sold on the world markets.

In contrast, the primary sector uses of renewable resources, including commercial fisheries, reindeer herding, and forestry, are generally based on local investment and employ local residents. These activities often serve as the backbone of local economies, even though their economic value is only about USD 8 billion.

The secondary sector, manufacturing and construction, ranks third in importance for the Arctic as a whole. The secondary sector plays a substantial role in Iceland, Northern Scandinavia, and Greenland, but overall manufacturing is little developed in the Arctic, which generally imports consumer goods from industrial centers farther south.

The tertiary sector, or service industries, is the dominant sector in the circumpolar region, accounting for more than 50% of all economic activity, and in some regions considerably more. Of this, the public sector, including health and education services, is often the largest component, but other industries such as trade, transportation, and real estate are also important in many Arctic regions.

Economic activity in the Arctic is unevenly distributed. Four of the 28 regions described in *The Economy of the North* account for 74% of the circumpolar GDP. The largest contribution is from Khanty-Mansi, followed in order of decreasing contribution by Alaska, Yamalo-Nenets, and Sakha. The three regions from the Russian Federation contribute 60% of circumpolar GDP, mainly from large-scale extraction of oil and natural gas. The economy of Alaska, with 14% of circumpolar output, is more diversified, with contributions from major oil production, the largest zinc mine in the world, and a large commercial fishing industry.

3.1.3.2. Governance and responses

Social and economic effects of development are mediated by the planning, regulatory, and allocation functions of governments. They are also mediated and mitigated by institutional and informal responses and adaptations. A central feature of social and economic effects is that they are driven in part by what people anticipate. A great deal of planning and preparation is typically involved in the chain of events leading from activities to effects, though some effects are surprises or otherwise unintentional. The goals that are set in relation to oil and gas activities may be economic, environmental, social, political, or some combination thereof. In addition to indicators such as longevity, education, and per capita gross domestic product, the Arctic Human Development Report (AHDR, 2004) notes three additional areas:

- *Fate control* – or guiding one's destiny;
- *Cultural integrity* – belonging to a viable local culture;
- *Contact with nature* – interacting closely with the natural world.

As seen in the case studies, the goals that several Arctic countries and regions have set in response to oil and gas activities support the AHDR analysis.

After setting the goals, planning is required to achieve them. The case studies provide many examples of planning efforts before and during oil and gas activities, with varying degrees of success. An assessment of the causes of success and failure is essential to the development of lessons learned (e.g., Robert-Lamblin (2003) concerning impacts on indigenous peoples). A third category of mediating measures is that of responses, which includes a variety of formal and informal adjustments before, during, and perhaps even after oil and gas activities. These responses reflect individual and institutional learning at all levels, in particular the capacity to adapt based on experience.

3.1.3.3. Effects on social and economic systems

Few, if any, aspects of a social and economic system will be unaffected by oil and gas activities in the vicinity. That said, there are also great differences in the magnitude and direction of those effects, creating a complex picture of negative and positive effects that are inseparable from other processes of social and economic change. Furthermore, a breakdown of various types of effects is only part of the analysis. There are complex interactions among those effects, producing a range of indirect effects that may in some cases be more significant than direct effects. Trajectories of effects may also be non-linear over time and space, changing from negative to positive or vice versa, and encountering thresholds where the rate of change abruptly alters. As with any complex system, it is challenging enough to create a complete description of what has happened. Assessing what will happen in the future can provide only general predictions, and even those must be treated with caution.

Nonetheless, there is a great deal that can be said about social and economic effects, as each of the case studies makes clear. The discussion in section 3.3.3 addresses ten categories of effects: macroeconomics, microeconomics, demographics, health, education and training, governance, cultural integrity, contact with nature, social health, and interactions. The exact effects will differ by lifecycle stage and also in relation to the specific economic, political, cultural, and geographic circumstances of a given time and place. In general terms, however, many effects are likely to be similar. The present analysis pays particular attention to effects that are either distinctive in the Arctic or that may be unexpected or counter-intuitive.

Indirect effects and interactions among the changes to various components of a system are often significant, and can at times shift a negative effect to a positive one and vice versa. Effects are rarely static. Instead, they follow their own trajectories, influenced by the lifecycle of the oil and gas activities as well as by the suite of interactions and iterative adaptations that take place within the social and economic system.

3.1.3.4. Lifecycle stages

Oil and gas development encompasses a wide range of activities through the lifecycle of a project, as noted in Chapter 2. In terms of social and economic effects, there are distinctive features associated with each stage and with the transitions between them (Table 3.1). Each stage raises different issues for planning and governance (Storey and Hamilton, 2003). Of particular interest are the duration of the various stages and the ways in which cumulative development can cause various stages to persist as

Table 3.1. Lifecycle stages with key activities and resulting characteristic social and economic effects.

Lifecycle phase	Activities included	Characteristic effects
Evaluation	Leasing/licensing; resource studies; seismic studies; exploratory drilling; baseline environmental studies; public consultation.	Very low levels of economic activity and employment; some revenues associated with leasing.
Development	Delineation drilling; 3-D seismic surveys; cost analysis; technical studies; environmental field work; public consultation; regulatory application and review, including environmental impact assessment.	Field activity, economic activity, and employment increase; focused public review; possible additional leasing revenues.
Construction	Detailed design of facilities; production drilling; construction of facilities and pipelines.	Peak employment with seasonally high levels of transient labor; economic boom.
Production	Waste injection; waste management; spill emergency preparation and response; environmental monitoring; transport, storage and refining.	Production and revenues peak and begin a long decline; revenues are highly variable with oil prices; while gross product is high and highly variable, employment is relatively low and steady; production jobs are high skill and high pay; workers are mostly non-local.
Enhanced development	Satellite development; enhanced oil recovery.	Employment and economic activity grow with the development of satellite fields; enhanced oil recovery technologies modestly increase revenues and prolong the life of the fields.
Decommissioning	Plug wells; rig removal and decommissioning; land reclamation.	Reduction of employment, personal income and government revenue into region. Disinvestment.

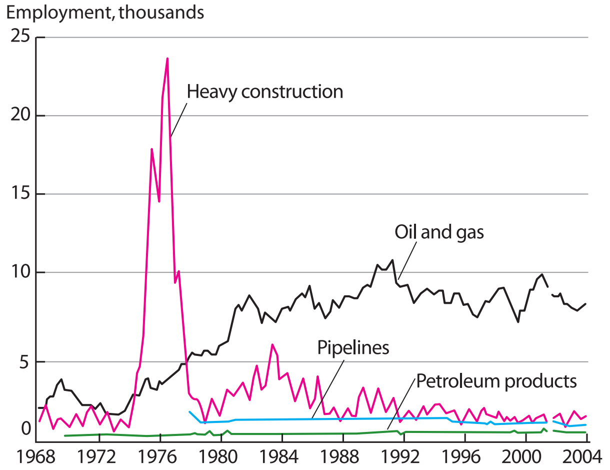


Figure 3.1. Alaska quarterly oil and gas employment, 1968-2004. Note the sharp spike in construction employment during the building of the Trans-Alaska Pipeline in the mid-1970s and more stable, but lower, employment during the production phase that has followed (Alaska Department of Labor statistics).

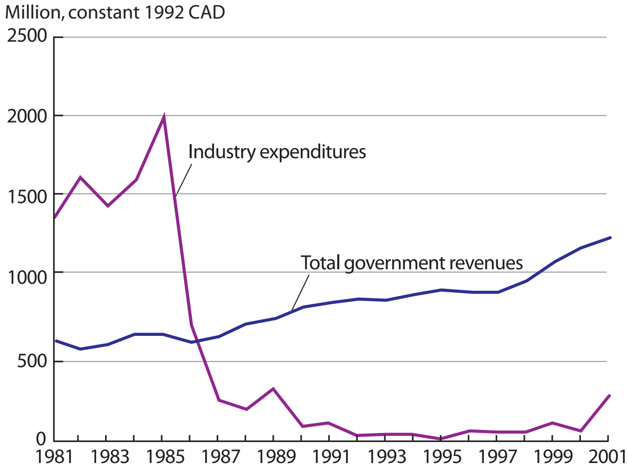


Figure 3.2. Industry expenditures and public revenues (CAD) in Canada's three Arctic territories. The high industry expenditures in the 1980s correspond with extensive exploration and construction, whereas public revenues accrue from lease sales, taxes, and royalties, and are thus more stable (DIAND Northern Oil and Gas Annual Reports 1981-2001).

individual fields follow one another through the lifecycle trajectory. Lifecycle stages must therefore be understood at various scales, from that of a particular field or prospect, to a larger development area, to an entire region or country. An important aspect of these transitions is the degree of mobility of labor required to continue to participate in a given stage. For example, employment is highest during the construction phase (Figure 3.1), which typically entails bringing large numbers of workers to the region in question. If workers are highly mobile, they can relocate to the site of the next large construction project. If workers are not mobile, their employment opportunity is short-lived. Public revenues, by contrast, often come from royalties or taxes, and thus are more evenly spread through the production phase (Figure 3.2). The case studies reflect experiences at different stages in the lifecycle (see Table 3.2), offering insight into the opportunities and challenges associated with the various stages.

Table 3.2. Profiles of study regions.

Region	Population	Ethnicity	Size or significance of oil/gas reserve	Lifecycle stages at present	Resource ownership
Yamalo-Nenets Autonomous Okrug, Russia	500 000	~4% Nenets, ~2% other indigenous peoples	Produces 90% of Russia's gas and 12% of Russia's oil	Production since the 1960s; further evaluation, development, and construction are ongoing	Russian government
Nenets Autonomous Okrug, Russia	41 500	~15% Nenets	Extensive	Production since the 1960s; further evaluation, development, and construction are ongoing	Russian government
North Slope Borough, Alaska	7213	74% Iñupiat	Alpine: 500 million bbl (~80 million m^3) of recoverable oil	Production since the 1970s; further evaluation, development, and construction are ongoing	North Slope: federal, state, and native; Alpine: native
Bent Horn, Canada	Approx. 1300	Predominantly Inuit	2.8 million bbl (~445 000 m^3) of oil were produced	Discovery in the 1970s, production in the 1980s and 1990s, decommissioned in the late 1990s	Canadian government
Norman Wells, Canada	797 (town of Norman Wells); plus 1600 in outlying communities	29.4% aboriginal (Norman Wells); predominantly aboriginal in outlying communities	225 million bbl (~36 million m^3) of oil (as of, Oct 2004); 156 billion cu ft of remaining recoverable gas (2003)	Local production since early 20th century; pipeline south built in the 1980s	Canadian government, with revenue sharing to Dene and Metis
Mackenzie Delta region, Canada	7229	76.6% aboriginal	9695 billion cu ft of gas; 1016 million bbl (~161 million m^3) of oil	Ikhil in production since 1999; Mackenzie still in development	Canadian government and aboriginal
Northern Norway	460 000	~5% Saami	Barents Sea: known: 0.2 billion Sm^3 (~1.3 billion bbl) p.e. Estimated undiscovered: 1 billion Sm^3 (~6.3 billion bbl) p.e.	Barents Sea production to start in 2007; further evaluation, development, and construction are ongoing	Norwegian government
East Greenland	55 000	>80% Greenlandic	31 400 million bbl o.e.	Evaluation	Shared by Greenlandic and Danish governments

3.1.3.5. Sustainable development

The World Commission on Environment and Development defined sustainable development as that which "meets the needs of the present without compromising the ability of future generations to meet their own needs" (WCED, 1987). With regard to non-renewable resources such as oil and gas, this definition implies at a minimum that no lasting harm is done, for example through environmental degradation. A broader interpretation is that such development should also produce lasting benefits, for example through contributing to the cultural, economic, environmental, and social viability of a region or society (e.g., Riabova et al., 2003). Chapters 4, 5, and 6 address the environmental aspects of sustainability. The case studies and subsequent discussion in this chapter illustrate the implications that oil and gas activities have for the future of Arctic societies and the actions that have been taken with future well-being in mind.

3.2. Case studies

The eight case studies describe a range of experiences and circumstances from a variety of perspectives, including major and minor operations. Figure 3.3 shows the locations of the case studies, and Table 3.2 provides a brief summary of certain characteristics of each region and its oil and gas activities. The case studies are presented in the approximate order in which the oil and gas activities in question commenced.

Two case studies about Russian regions, the Yamalo-Nenets Autonomous Okrug (section 3.2.1) and the Nenets Autonomous Okrug (section 3.2.2), describe effects on local indigenous peoples and aspects of the relationship between oil and gas activities and those peoples over time. The case study about Nuiqsut (section 3.2.3) in Alaska likewise focuses on indigenous interactions with the oil industry, in this case in a single village near the large oil facilities on Alaska's North Slope. Three Canadian case studies, Norman Wells (section 3.2.5), Ikhil and the Mackenzie Delta (section 3.2.6), and Bent Horn (section 3.2.7), provide further examples of local responses to and interactions with oil and gas activities, in the context of national policies and practices regarding development and the involvement of indigenous peoples therein. The Bent Horn example is of special interest as the only one in the chapter involving decommissioning. The Norwegian case study (section 3.2.8) examines primarily the national-level effects of offshore oil and gas activity, particularly the governance system established to capture benefits for society as a whole. The Greenland case study (section 3.2.9) looks at efforts to attract and plan for oil and gas activity offshore, in part as a means of securing a greater degree of economic autonomy for Greenland.

Together, these case studies portray the social and economic effects of oil and gas activity from the village level to the national level, illustrating the ways that impacts and benefits can be distributed differently at different levels and the ways in which local and sub-national interests may or may not be addressed in national-level policies and decisions. While the lack of a common set of available

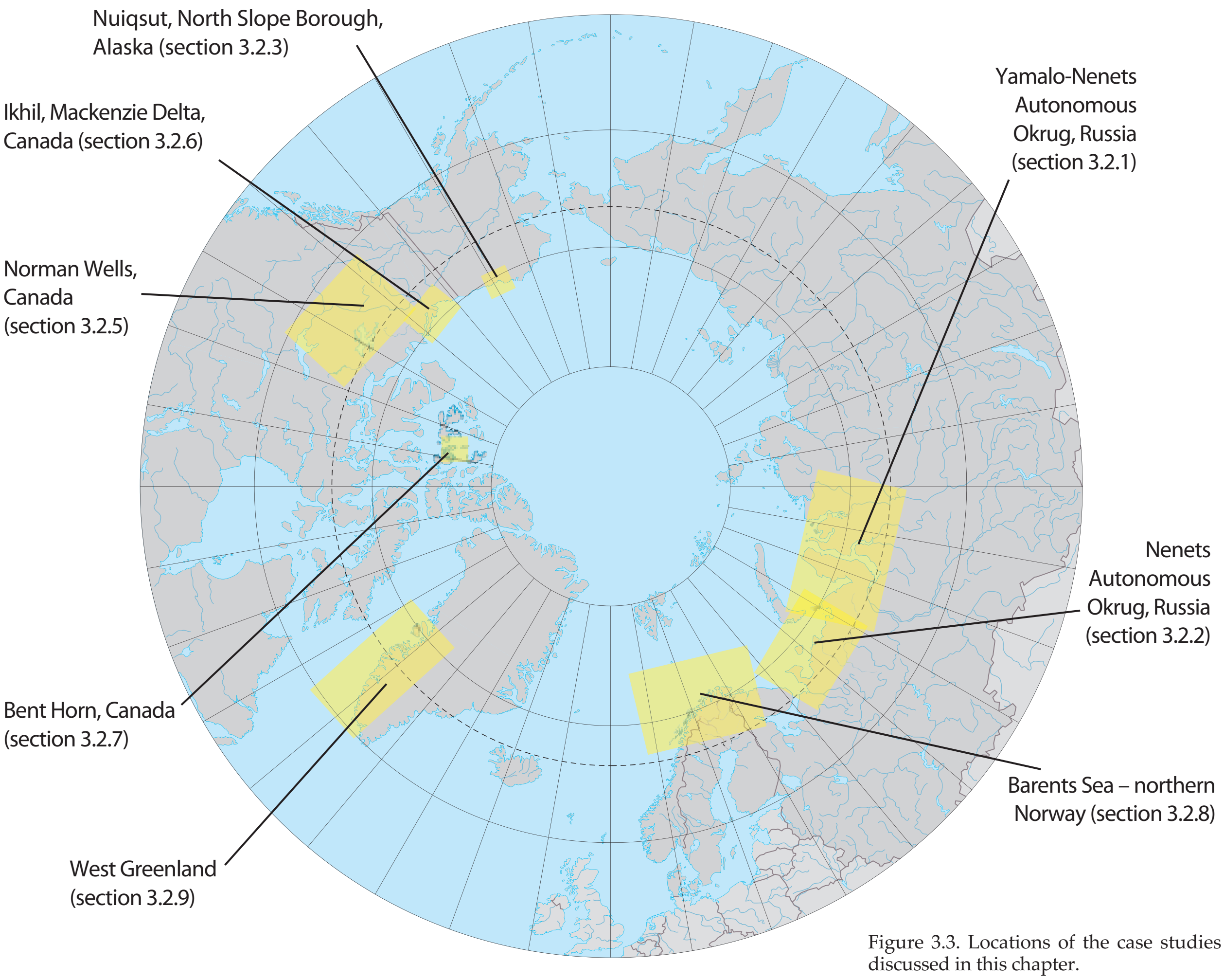


Figure 3.3. Locations of the case studies discussed in this chapter.

statistical measures for social and economic conditions and effects prevents a quantitative comparison between case studies and regions, the collection of descriptions of effects and experiences is nonetheless illuminating and should serve as a useful foundation for further analysis, research, and action.

3.2.1. Yamalo-Nenets Autonomous Okrug, Russia

3.2.1.1. Introduction

The Yamalo-Nenets Autonomous Okrug (YNAO), northeast of the Ural mountain chain in Western Siberia (Figure 3.4), has become the richest Arctic region of Russia, with a gross regional product per capita USD 34 000 (Granberg, 2004). Since the 1960s, Western Siberia has been Russia's main oil and gas producing province. Most oil is extracted in the middle Ob' region (river basin), which reaches from the giant oil deposits close to the cities of Nizhnevartovsk and Surgut in the Taiga regions of the Khanty-Mansiysk Okrug to Noiabrsk and Muravlenko in the taiga of the YNAO. On the tundra of the Yamal Peninsula, oil deposits such as Novoportovskoye, Rostovtsevkoye, and Tambeiskie have not yet been developed. Gas is extracted in the central parts of the YNAO, from 26 deposits, the reserves of which are estimated at 10.4 trillion m^3 (~65 trillion bbl)(Anon., 2007).

More than half of the YNAO lies north of the Arctic Circle. The tundra region in the central and northern parts of the YNAO is the main site of current and future gas extraction in Russia. The current annual production level of the YNAO is 550 billion m^3 (19.5 trillion cu ft) of gas and 40 million tonnes (~47 million m^3) of oil, or 92% of Russia's gas production and 12% of its oil production. This makes the YNAO the world's number one gas region with approximately 20% of the production. The region is thus strategically important to the Russian Federation, as well as to the European Union, which is increasingly dependent on these West Siberian energy resources (WEC, 2001; Cleutinx, 2005; Kekukh, 2005) (see Box 3.2).

Besides these hydrocarbon resources, the YNAO is also home to approximately half of all domestic reindeer in Russia, which are herded by close to 15 000 nomads, most of them Nenets. Today, the human population of the YNAO is half a million, which is a bit less than its domestic reindeer population of 550 000. Eighty-two percent of the human inhabitants of the okrug live in cities (Stammler, 2005b).

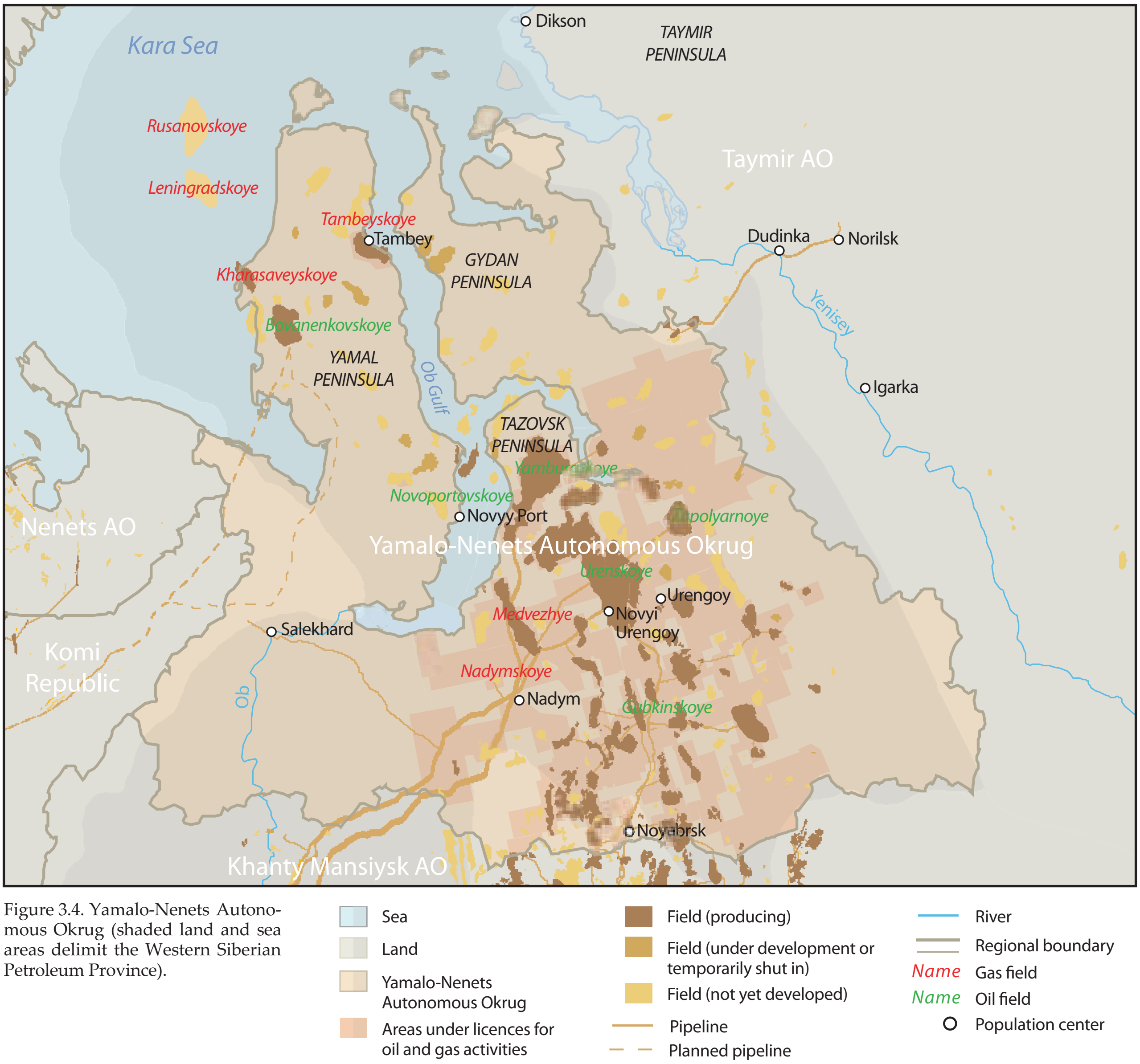


Figure 3.4. Yamalo-Nenets Autonomous Okrug (shaded land and sea areas delimit the Western Siberian Petroleum Province).

Box 3.2. Arctic oil and gas in the Russian economy

Oil and gas production in the Yamalo-Nenets Autonomous Okrug (YNAO) alone is responsible for 20% of the Russian federal government's currency supply, 15% of the transportation sector's income nationwide, and 10% of the country's secondary business activity. As the region has more oil and gas reserves than Western Europe, the United States, and Australia combined (i.e., about 17.5% of world reserves), it will continue to play a major role in the Russian economy for some time to come. The Nenets Autonomous Okrug (NAO) is expected to increase its oil production greatly in the next decade, making this region another major economic force in Russia.

While these Arctic regions produce considerable income, the distribution of those revenues is hotly contested and far from settled (Stammler and Wilson, 2006). For example, the federal government has increased its share of severance tax revenues from oil and gas production. The development of the energy sector is a key priority for Russia and one over which the government is increasingly seeking to re-exert control, reducing revenues to the regions, and establishing a new 'stabilization fund' in 2004 to centralize control over oil revenues and taxation in the context of rising oil prices (e.g., Gelb, 2006). Before 2002, many regions, such as Sakhalin, the YNAO, the Khanty-Mansiisk Autonomous Okrug, and the NAO, were allowed to keep 60% of the tax charged for the 'use of mineral resources' (*izpol'zovanie nedrami*). In 2002, a new federal tax on the 'extraction of sub-surface resources' (*na dobychu poleznykh iskopaemykh*) was introduced in place of the previous tax, 20% of which went to the regional budget in the case of the YNAO and the NAO. This figure was reduced to 13.4% and in 2005 to only 5%. As a last step, as of 1 January 2006, nothing of this tax remains directly in the regions; instead 100% goes to Moscow for redistribution nationally.

Resource rich regions (such as the YNAO and the NAO) cannot expect to get major sums of this money back from Moscow, because they are net payers to the federal Russian budget. Oil companies, meanwhile, aim to achieve maximum profits, which can conflict with government goals of steady income for a longer period. The financial strength of the oil companies gives them considerable influence over government decisions, including regulatory actions. At the same time, the federal regulatory process is often vague, leading to conflicts with industry. Within the industry, some companies attempt to strengthen their position by obtaining more and more licenses, thus owning a major share which may in turn justify the large infrastructure investments required to produce and transport oil and gas.

At the okrug level, high regional productivity has not yet led to substantial investment in social services. In the YNAO, for example, only 25% of the gross regional product is expended on social services, in contrast to 60% in Alaska. Nationwide, government spending on social services accounts for some 45% of the budget, but in the YNAO the figure is only 11%. The region's economy remains heavily oriented to production rather than services, one result of which is that residents have to purchase consumer products from other regions. Even electricity is largely generated in a neighboring region, meaning that the YNAO has to expend considerable sums on purchasing electricity despite producing so much fuel itself. This dependence on a single industry also leaves the okrug's economy at the mercy of world oil prices, decisions by the Federal Energy Commission, and the actions of companies with near-monopolies on oil and gas activity in the region.

Nationally, Arctic oil and gas production has a number of economic effects. It provides a major source of government revenues as well as foreign-currency earnings. Income by residents of the YNAO and NAO is often spent in other regions, boosting consumer demand and thus income there. The federal government also uses oil and gas prices to combat inflation, holding domestic prices below world market levels. Such underselling constitutes a USD 40 billion subsidy to the Russian economy and an additional USD 5 billion donation to former Soviet republics which received oil at the Russian domestic price.

Future effects of oil and gas activities in the Russian Arctic are difficult to predict. The current situation is unlikely to persist, but it remains unclear what will replace it. The okrugs, the federal government, and the oil companies will continue to battle over revenues and regulation. As the accompanying case studies show, the residents of the okrugs are likely to remain caught between these competing forces, while the national political and economic landscape will shape the overall relationship between industry, regional government, and national government.

3.2.1.2. History of YNAO hydrocarbon development

In the early 1930s there were already indications that the Northern Ob' region held large deposits of hydrocarbon resources (Brekhuntsov and Bitiukov, 2002: 7). When Stalin made plans to build a railway across the Siberian Arctic, he had in mind linking these resources to the mainland via a reliable and cheap infrastructure (Mote, 2003). The plan was to link Salekhard via Igarka eastwards to Dudinka and Norilsk, a route leading through major gas deposits to the big metal resources of Taymir. The railway Salekhard-Igarka became well known as 'the dead railway 501', because many Gulag prisoners lost their lives for a project that was never completed. Today, some experts think that the railway would have made oil and gas development much easier. Rumors as well as plans to revive this railway have always been popular, but have recently become more serious, after a written agreement of the Russian railway company with the gas monopoly Gasprom (Anon., 2007; Walsh, 2005: 21).

Serious development of the hydrocarbon resources of the YNAO started in the 1960s. In 1958, a Soviet geological expedition enterprise was established in Salekhard. Its explorations resulted in the discovery of the then-largest-known deposits in the world, including Zapoliarnoe (discovered in 1965, in production since 2001), Urengoiskoye (1966, 1978), Medvezhee (1967, 1972), Yamburgskoye (1969, 1986), Bovanenkovskoye (1971, no production yet), Nadymskoye (1972, no production yet), and Kharasavei (1974, no production yet) (Brekhuntsov and Bitiukov, 2002: 6-8). Whereas all these famous deposits are gas or gas condensate, the discovery of the Gubkinskoye deposit in 1965 proved that the YNAO is rich not only in gas, but also in oil (Brekhuntsov and Bitiukov, 2002: 18).

The extraction of these resources was part of a general Soviet approach to industrialization, which, in addition to economic incentives, had the goal of integrating the Russian Arctic into the Union-wide effort to create a 'single Soviet society of a single Soviet people' (*edinyi sovetskii narod*). Therefore, instead of developing oil and gas deposits with rotational workers, big cities were established in the region to house workers, their families, and the necessary infrastructure to maintain a high living standard in the North for permanent settlers from the South. In the YNAO, the biggest cities of this kind are Novyi Urengoi (population 109 100), Nadym (49 200), Noiabrsk (106 900), Muravlenko (36 800), and Gubkinskii (21 600) (data as of 1 January 2005; Moi Gorod, 2005).

This massive settlement of the North by people from central and southern parts of the Soviet Union is a development characteristic of the Soviet Arctic. It led to a demographic marginalization of the indigenous population. Currently, the 'titular Nation' of the YNAO, the Nenets, account for only 5.2% of the overall population. Furthermore, the influx of migrants has made the YNAO relatively densely populated, with twice the population density of Alaska for example.

Unlike other oil and gas regions in Russia such as the NAO (see the case study in section 3.2.2) and Sakhalin, the YNAO has seen relatively little foreign involvement in development. Some western companies have signed agreements or formed partnerships with Russian companies, but for the most part these arrangements have ended before production began. Currently, two German companies are investing in gas development in the southeastern part of the okrug, with the intent of building a pipeline through the Baltic Sea to northern and western Europe. Gasprom, however, remains the dominant company in YNAO oil and gas activity.

3.2.1.3. The social consequences of Soviet oil and gas development

There were both damages and benefits for indigenous peoples from oil and gas development during the Soviet period. The damages, however, were more direct, whereas the benefits were indirect. During the Soviet period, oil and gas development in the YNAO did not take sufficient account of the local particulars of the region and its indigenous population. The result was significant 'collateral damage' to the environment and to those communities close to the biggest oil and gas deposits. The gas and oil cities of Novyi Urengoi, Nadym, and Noiabrsk and their outposts were constructed without taking into account the significance of these territories as hunting grounds, reindeer pastures, and sacred sites for the Nenets and Khanty population.

The result of this was relocation of indigenous families to other places or their settlement in towns and villages. There they became a minority in a multinational community, and became exposed to many dangers for which they were not prepared: alcohol, crime, prostitution, drugs, and dependence on the state oil or gas monopoly for their support. Removing people from their land cut not only their intimate ties with their environment but also with the basis of their cultures. Being deprived of hunting or herding reindeer, indigenous people also lost their feeling of being one integral part of a single socio-ecological system. Many indigenous village dwellers tell about the psychological instability and depression that were connected to this radical change of their livelihoods:

> *"In the village there is nothing to do except to watch TV and drink. In the tundra, there is always enough work to do, and we are always out in the fresh air"* (Tetia Motia, Nenets Tent Worker, pers. comm.).

Indigenous people were little involved in resource development. Few found employment in the oil or gas sector, and if they did, then only at the lowest level of the job scale, in roles such as stoker at a heating plant, cleaner, dishwasher, or drilling assistant.

There may be several reasons for this. First, many of them find it difficult to get hired for employment on their land, to which they are supposed to relate according to their own cultural practices and values. One reindeer herder explained that you should not stab your knife into the ground, even when it is covered with snow. The land is only to be used on the surface. Oil and gas activities follow a completely different set of relations between people and their land, one that is incompatible with Nenets beliefs. Second, during the Soviet period indigenous peoples did not have their own independent interest groups. They were integrated into the single Soviet political and social system. In this way their formal political agency was very limited and did not allow them to lobby for their interests even had they wanted to.

An institution in which they had influence was the Soviet State farm, *sovkhoz*. *Sovkhozy* were the official land users over most of the territories under which the oil and gas deposits were found. For industrial development, the *sovkhozy* had to sign documents confirming the transfer of land from agricultural use to oil drilling. In practice, however, this was a formality, and there is no evidence that the *sovkhozy* ever were able to delay or stop oil and gas activities.

The crucial decision-making power for big industrial projects was the state planning ministry in Moscow. The bottom line was that all land belonged and still belongs to the state, and it was in the hand of planning officials to make overall decisions for oil and gas development. The distribution of revenues was structured similarly. All income from the oil and gas went first to Moscow, and then part of it was redistributed to the regions. Few if any of the benefits trickled down to the indigenous rural population. Therefore, during Soviet times agency and decision-making were withdrawn not only from the indigenous population, but from the northern regions altogether – a trend that some observers see being repeated in Russia's current centralization policies. This is the framework under which most of the existing oil and gas fields in the YNAO were developed.

On a regional level, however, it would be wrong to assess all oil and gas development in the YNAO negatively. The cities in the south of the YNAO became relatively rich centers, attracting specialists from all over the country. Thus, according to the statistics, the oil and gas industry also raised the living standard of the region, which is due to the high incomes of the industrial population in cities, who moved north for the work. Today, the regional product in the YNAO is eight times higher than the Russian average, and after Moscow and the Khanty-Mansiysk Okrug, the YNAO is considered to be the third richest Russian region (Neelov, 2005). The problem, however, is the unequal distribution of the region's wealth. Little of the money reaches the villages, let alone nomadic households on the tundra.

Similarly, infrastructure has had benefits as well as negative impacts. For example, the opportunities for marketing reindeer herding products increase with the presence of roads and railway connections. In the vicinity of big cities, the population is large enough to create substantial demand. On the other hand, the more remote a place is from permanent human settlement and infrastructure, the better it is suited for reindeer herding. Domestic reindeer are easily disturbed by noise, traffic, and other interferences. The more disturbance to which they are subjected, the less they gain weight, thus leading to sub-optimal slaughtering weights. Thus, reindeer herders in the oil and gas extracting regions of the YNAO must balance the need for remoteness for the health of their herds against the need for proximity to markets.

In the Soviet planned economy, a mutual coexistence between reindeer herding and oil and gas production in Yamal was intended and, indeed, partially achieved. The basic idea was to integrate reindeer herding into the Soviet economy as a meat producing industry. In the YNAO, the large influx of incoming oil and gas workers could be fed with locally produced cheap reindeer meat. The energy needs of villages and reindeer herding enterprises, on the other hand, could be satisfied by the oil and gas enterprises. However, the latter part of the plan did not work as one might expect. Many villages were heated with coal, transported many thousand kilometers from the South, because the fuel supply was run by the state, as was the reindeer herding industry. There were almost no hydrocarbon processing facilities in the North, preventing local use of the resources extracted in the region. Still, the presence of both hydrocarbon development and reindeer herding seemed at least to be not mutually exclusive. From the 1960s to the 1980s, both hydrocarbon extraction and the number of domestic reindeer and nomads increased.

3.2.1.4. The social consequences of post-Soviet oil and gas development

Post-Soviet transformation processes in the YNAO have shown that reindeer herders have never fully depended on the oil and gas industry, even though there is a direct link between the oil and gas incomes of the YNAO and the amount of subsidies paid to reindeer herding enterprises. Whereas gas and oil extraction in 2001 was at 89.7% of the record level of 1992, the number of domesticated reindeer in the YNAO in 2001 was 564 000, 35% higher than in 1989. Reindeer herding as a way of life still forms the basis of this nomadic culture, which continues to prosper despite economic hardships.

Those hardships are connected to the declining oil and gas reserves in the biggest deposits in the southern and central parts of the YNAO, where extraction started in the 1970s. Smaller deposits in the vicinity of these big ones, which are easy to connect to the existing infrastructure, have rather limited reserves. Now the question is about opening deposits in previously untouched areas. These lie in the northern parts of the YNAO, on the Yamal, Tazovsk, and Gydan peninsulas, as well as in the Ob and Taz bays. The development of these deposits is needed in order to maintain current production levels. However, most of these territories are crucial for the local economies of fishing and reindeer herding. Gasprom and other enterprises count the northern YNAO among their strategic priority regions to meet the energy needs of Russia in the near future. Therefore, administrators, industrial enterprises, and indigenous representatives think that a new era of relations between hydrocarbon development and indigenous economies will start soon.

Until the end of the 1990s, the nomads in Yamal felt a direct negative influence from the restructuring process in the Soviet gas monopoly, Gasprom. As long as Gasprom paid taxes to the YNAO, reindeer herding enterprises received subsidies from the YNAO administration, enabling them to supply herders with necessary equipment. When Gasprom's clients paid Gasprom in kind, the YNAO administration did not receive taxes as money anymore, but in kind, for example in flour from Ukraine. Therefore, the YNAO administration had to transfer these in-kind payments, the Ukrainian flour, as subsidies to reindeer *sovkhozy*. By the time the *sovkhozy* received the flour, it was of bad quality and, considering the high cost of transport to the North, more expensive than on the free market. After 2001, this situation largely changed, and monetary subsidies have made the state-controlled reindeer enterprises more competitive with private commercial enterprises supporting reindeer herding. Private vertically integrated reindeer herding companies had developed since the early 1990s, when the successors of the Soviet *sovkhozy* were struggling for their survival. The private companies trade 'velvet' reindeer antlers and meat for staple foods and tundra gear for the reindeer herders. For this additional supply, herders do not have to travel to distant villages anymore, since the private companies fly in with helicopters, sometimes hired from Gasprom or its sub-contractors. Nowadays, both commercial and state controlled enterprises have an important role in supplying reindeer herders (Stammler, 2005b: 305-317).

Nonetheless, the benefits of oil and gas operations and revenues have largely failed to reach herders and other rural residents. Figures for per capita income in the YNAO mask great disparities. On the Yamal Peninsula, for example, more than 50% of the population must make do on an income below the cost of living. The unemployment rate in this center of reindeer herding is 50% for the indigenous population. These figures, however, ignore non-monetary activities, and thus omit extensive herding, hunting, and fishing, which allow people to survive despite their low official incomes. Today, many employees of reindeer *sovkhozy* own shares in Gasprom as a result of its privatization in the early 1990s. This ownership, which extends to other oil and gas companies as well as enterprises in other sectors, can help bring herders and industry closer together, and may lead to the realization of greater benefits for rural peoples of the YNAO.

The first decade after the end of the Soviet Union saw growing indigenous empowerment. Today in the YNAO, the indigenous peoples association 'Yamal for our descendants!' (Yamal Potomkam!), founded in 1989, must be consulted before land is transferred for oil and gas extraction. The YNAO has passed a number of laws for the protection of the indigenous economies, for example on local self government and on reindeer herding. Together with the three recent federal laws on (1) the guarantees of rights for the indigenous peoples (1999), (2) the principles for establishing indigenous communities (*obshchiny*, 2000) and (3) the formation of territories for the traditional use of nature (2001), they form an increasingly solid basis for indigenous representatives to develop their own political agenda.

The founders of Yamal Potomkam! joined forces with ecological non-governmental organizations (NGOs) to protest against the premature development of gas deposits on the Yamal Peninsula. Alongside post-Soviet economic difficulties, this protest led to a moratorium on the further development of the railway connecting the Bovanenkovo gas deposit in northwestern Yamal to the Russian railway network (Barannikov et al., 1989). From the mid-1990s onwards, indigenous hunters and reindeer herders started to register their own communities on territories in the southern central YNAO that are affected by oil and gas development. Communities called *rodovye obshchiny* were able to get land titles and local self-government from 1996 onwards, years before regional or federal legislation stipulated the function of *obshchiny*. However, in those years herders complained about the lack of legislative support, in comparison to their neighbors in the Khanty-Mansiysk Autonomous Okrug, where regional legislation recognized 'clan territories' for taiga dwellers (see Stammler, 2003).

The *obshchiny* have agreements with the oil and gas enterprises, mostly Gasprom or branches of Sibneft, about material compensation for the damages and disturbance to their indigenous economies caused by hydrocarbon development. However, some indigenous representatives think that the amount of this compensation is far too low and that the directors of the *obshchiny* signed unfavorable agreements. One of the problems is that in many cases negotiations in the areas with ongoing extraction focus on compensation for damages that have already happened. Reindeer herders complained that less attention is paid to recultivation of soils and remediation of existing pollution and damage, as well as preventive measures such as considering reindeer migration routes when constructing pipelines. This results in a situation where indigenous residents become deprived of their source of livelihood, the surrounding nature, but receive compensation that still enables them to live on their lands and lead a decent life that can be called traditional, in the sense that their cultural values and certain practices are maintained.

Nowadays, oil and gas enterprises employ indigenous people for organizing their relationships with the local residents, for example the popular Nenets activist and politician Khatiako Ezyngi, who works for Gasprom. This certainly increases their prestige in the region and is good for the public relations of the enterprise. However, it is less clear whether it leads to better agreements between the companies, indigenous communities, and the local administration.

For example, in 2002-2003 a survey revealed that indigenous representatives had significant control only over 8.6% of the compensation and investment finances of a Gasprom branch enterprise for indigenous people (Yuzhakov, 2004: 3). This shows that even though the scope for indigenous agency has significantly increased, it has not yet translated into control over even those finances designated for the indigenous people.

Institution building among indigenous communities significantly influences the relationships between local populations and the oil and gas companies. In the immediate post-Soviet era, enterprises often sought agreements directly with the individual household heads of indigenous camps. This led to a great variety of agreements, depending on the information the household heads had about oil and gas extraction and their negotiating experience and skill. To put it the other way round, the companies could make use of the lack of collective agency among indigenous people, exploiting the lack of information among individuals in the tundra or taiga in their favor. The indigenous communities thus found themselves marginalized. This status was supported by some local and regional administrations together with some of the oil and gas companies. Cases where the enterprises or administrative bodies were hiding oil spills, misleading indigenous households about their rights, and making the problems look less significant than they were, were increasingly reported to researchers and journalists (Novikova, 1997; Stammler, 2003).

In the 21st century, many of these practices have changed, both because oil and gas companies are more concerned about their public image, and because indigenous associations and representatives act more professionally and are better networked. This is a good starting point, before the big northern Yamal deposits are opened. The social impacts of these giant projects are being monitored by research teams from Moscow and Tyumen'. A first example of such procedures has been undertaken in the form of an anthropological expert review of the possible effect on local people of oil drilling in Ob' Bay (Murashko, 2002). However, in the absence of a law obliging companies to carry out such a review and standardization of methods for doing so, this remains a single example. Currently, an important personal factor positively influences the development of collective indigenous agency in oil and gas development: the YNAO Duma speaker, Sergei Khariuchi, is Nenets. He is also the current president of the Russian Association of Indigenous Peoples of the North (RAIPON), a national organization. His high reputation among powerful actors in Salekhard as well as in Moscow has made him the second most powerful person in the YNAO after Governor Yuri Neelov. His political work has been geared toward peaceful coexistence of oil and gas development with indigenous economies, helping to minimize the negative consequences of oil and gas development.

3.2.1.5. Oil and gas workers and reindeer herders of northeastern Yamal

A positive asset for organizing beneficial relationships between hydrocarbon extractors and reindeer herders in the northern YNAO is the good experience that reindeer herders have had with geologists and oil and gas explorers. The following example shows how these positive experiences can be transferred from the exploratory phase into the production phase.

A gas-exploring enterprise called Yamalneftegazgeologiia built the village of Sabetta in 1981 in order to explore the gas and oil fields on the northeastern Yamal Peninsula. The Tambeiskoye deposit opened in the mid-1980s, with more than 100 drilling rigs in the area. Some of the drilling work resulted in what is called 'experimental extraction', in which the deposit is not yet commercially exploited. Gas condensate has been occasionally shipped from Sabetta to Finland, for example in 1999. Reindeer herders remember how they traded Nenets knives and handicrafts for hard currency from the Finnish crew of the tanker that transported the condensate.

At its peak in the 1980s, Sabetta had a population of 500 workers, all of them rotational workers. The village was never considered a permanent settlement. In early 2004, 80 workers were left in Sabetta. The reindeer herders around Sabetta steadily became more entrepreneurial in working with the oil people and sold meat, furs, and also products such as reindeer shoes and other things to the gas workers. The gas workers in turn supplied them with most of the staple products that they needed, such as bread, tea, butter, fuel, guns, ammunition, radios, and so on. These trading relations turned out to be reliable and beneficial for both sides. Reindeer herders have a high regard for some of the Sabetta workers, especially their chairman and the chief cook. In the difficult time of restructuring the economy, these relations continued to be beneficial for both sides.

Table 3.3. Terms of Trade between the gas enterprise and reindeer herders, Sabetta, 2001.

	Rubles	Kilograms of meat
Bread	3.5/loaf	0.7
Ring crackers	10.27/kg	2.05
Flour	3.9/kg	0.78
Sugar	3.3/kg	0.66
Tea India	15/100g	3
Milk	11.73/can	2.34
Milk powder	27.65/kg	5.53
Butter	23.38/kg	4.67
Macaroni	6/kg	1.2
Canned meat	8.50/can	1.7
Soup	4.3/can	0.86
Fuel	5/liter	1

First, the reindeer herders had to contend with the decline of their state enterprise, the *sovkhoz* 'Yamal'skii'. When it became difficult to get supplies from the *sovkhoz*, many started relying completely on the Sabetta gas enterprise for their staples, creating a local cashless economy. Table 3.3 shows the terms of trade between herders and the Sabetta gas enterprise.

These terms of trade were in many cases more favorable for the reindeer herders than those offered by the *sovkhoz* or other commercial enterprises. The gas workers, in turn, also had to cope with a decline of their enterprise, which went bankrupt in 2001. Years before, the leadership had already decided to cancel the import of meat from the south altogether and rely solely on reindeer meat from the herders.

From the mid-1990s onwards, the balance of power in Sabetta was developing in favor of the reindeer herders, since their herds were increasing, whereas the gas enterprise experienced various restructurings. In 2001, the village was in danger of being abandoned, although the remaining workers as well as the reindeer herders were interested in keeping it going. From the late 1990s onwards, some entrepreneurial reindeer herders and their representatives established what was to become the biggest private reindeer slaughterhouse in the YNAO. The facilities, as well as dormitories for workers, the kitchen, and the energy were provided by the gas enterprise on the basis of non-written agreements. Between 2000 and 2004, approximately 6000 reindeer were slaughtered there annually. This was far more than the Sabetta workers could consume, and the herders started to sell the meat to Salekhard, the YNAO capital, and a Gasprom branch enterprise in the south of the YNAO.

The impacts of gas and oil development on the Tambei fields were addressed mainly informally between the Sabetta enterprise and reindeer herders. The official version was that the enterprise got a license to work on the land, for which they paid the official land users, the *sovkhoz* 'Yamal'skii'. But the basis for the good relationship was built largely on other, informal, personal, and uncomplicated interactions. The gas enterprise agreed with herders to keep heavy vehicles and tanks off the tundra during certain seasons in order to preserve pastures. They built local pipelines high enough that herds could graze and walk under them, and used their transport capacities to help the herders as well. For example, in winter, they brought firewood to the nomadic camps, and they collected fresh reindeer meat right from the campsites, so that herders did not have to drive animals to the village for slaughtering. On some occasions, they would even bring staple food to reindeer herders. Finally, of course, they took care of the need for fuel for reindeer herders snowmobiles as well as for the *sovkhoz* itself.

On a personal level, relations between the reindeer herders and the gas enterprise in Sabetta had become very close. The village chairman had an open ear for the immediate and longer-term needs of herders. He knew all the nicknames of the herders, which they honor as an important sign of 'insidership'. The chairman complained that the director of his company in Moscow did not understand the particularities of this 20-year relationship. Sometimes, he found himself more on the side of reindeer herders, for example when he continued to provide fuel for reindeer herders snowmobiles for free. This was during the time of restructuring in 2001, when the bankruptcy administration of the gas enterprise tried to strictly control any kind of informal agreement.

In the meantime, both the herding and gas enterprises took on new institutional forms. The reindeer herders became members of an *obshchina* called Ilebts, a community of mostly relatives, which took over the slaughterhouse in Sabetta (see Stammler 2005a for an in-depth analysis of this case and its relevance to understanding indigenous identity). The gas village is run by a small, independent oil company called Tambeineftegaz. Both sides started to formalize their good relationships and establish a legal basis for them. The *obshchina* now rents the Sabetta slaughterhouse and its surroundings from Tambeineftegaz, which, in turn, buys reindeer meat certified by the *obshchina*. By signing agreements of this particular form, they have built on the good 20-year relationships between individuals. Both sides benefit from the personal continuity. The reindeer herders and their representatives are still the same, and Tambeineftegaz, Sabetta's new owner, kept all the workers, who have a lot of experience working there. The reindeer herders are proud that the boss of Tambeineftegaz comes personally with his family to a reindeer herders camp, drinks tea with herders in their chums (nomadic tents), and listens to their problems.

Both sides are now trying to turn their good relations into a model for other areas. Through clever lobbying from both sides, they receive support from both the Nenets Duma speaker and the Yamal governor. This is important as plans to start large-scale extraction of the northern Yamal deposits become more concrete. On the website of the reindeer *obshchina* (*http://ilebts.narod.ru*), news about the progress of these relations can be followed regularly. This example shows the significance of established long-term relationships between oil and gas workers and reindeer enterprises and their herders. In spite of numerous restructurings, the people involved in the Sabetta case remained mostly the same, allowing for close personal relationships to develop alongside the institutional relationships. In contrast, in cases elsewhere when new workers take over and the old ones are fired, relationships can deteriorate, as happened in another case in the central Yamal Peninsula. There, reindeer herders from the *sovkhoz* in Yar Sale complained that the oil workers brought in from the Khanty-Mansiysk Autonomous Okrug did not know how to behave properly in the tundra and did not follow the unwritten guidelines of tundra solidarity.

This is an argument against recent trends in favor of short-term rotational workers for oil and gas development. The Soviet model of investing in permanent population in the North was expensive, but had the advantage of personal continuity and of building up an understanding

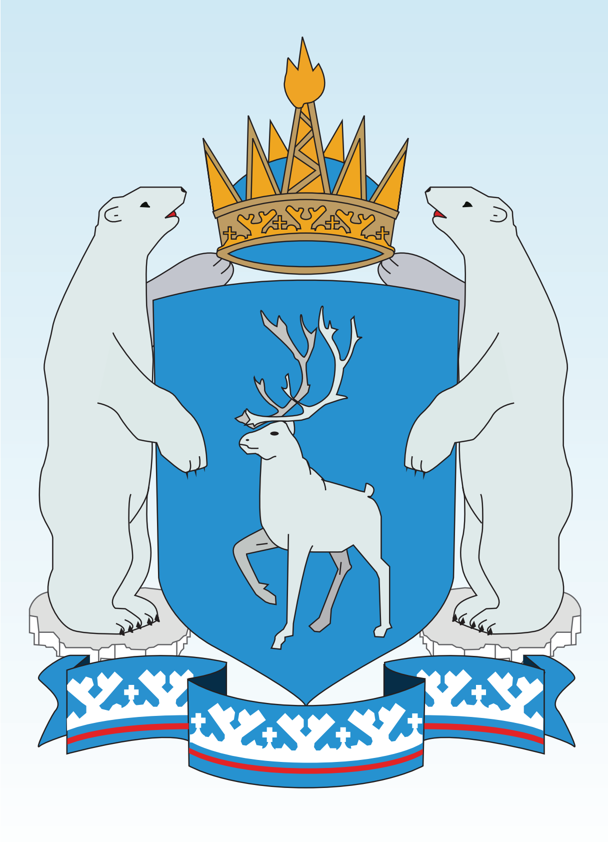


Figure 3.5. The official flag of the Yamalo-Nenets Autonomous Okrug.

of regional particularities by industrial workers, which is less likely to evolve among a purely transient population. The fact that Sabetta workers and others were there for more than 20 years tied them to this northern region, and made them understand at least parts of the needs and conditions for a mobile lifestyle of reindeer herders, an understanding that was reciprocated by the herders.

3.2.1.6. Conclusion

Currently there are two simultaneous developments in the YNAO regarding impacts of oil and gas development. In the southern regions with a longer history of extraction in the Soviet era, considerable damages have already happened, indigenous people are little involved in production or decision-making, and compensation does not always meet the needs of the tundra and taiga inhabitants. In the vicinity of neo-urban spaces in southern YNAO, problems typical of industrial development in rural regions, such as increased crime, infrastructure stresses, violent death, alcoholism, prostitution, lack of perspective, and indigenous marginalization, can be seen. On the other hand, the northern tundra regions in the YNAO have a generally positive record of relations with oil and gas workers in the exploration period of the last 20 to 30 years, similar to the Sabetta case. Thus, in the southern YNAO people have to cope with improving bad past practices, whereas in the northern YNAO, good practices have to be preserved, as plans mature to exploit the huge northern Yamal deposits.

In none of these cases is there much participation of indigenous communities in the ownership of or decision-making about the resources, and only on a very limited level do those communities receive income from resource development. Deposits are always owned by the state and developed by enterprises. In the future, indigenous communities may gain a larger share in those enterprises, but in the YNAO this is likely to be a long process.

The involvement of indigenous people in particular oil or gas projects in the YNAO remains rather limited. However, at a general level, indigenous participation in regional development has increased in the past decade, thanks to organizations such as Yamal Potomkam!, influential politicians such as Sergei Khariuchi, and an increase in collective agency and indigenous networking. These processes are leading in the YNAO to what could be called an integrated regional identity, having both reindeer herding and oil and gas development as important pillars. This trend is mirrored in the official flag of the YNAO (Figure 3.5), which shows a reindeer with a crown, the front of which is an oilrig with a flame. These developments allow for a cautiously hopeful outlook, considering that awareness about the sensitivity of future development in the YNAO north is high on all sides, but that the will exists to organize this development for mutually beneficial coexistence. Such coexistence would work by relying on the benefits from infrastructure and a regional market for reindeer herding, and simultaneously minimizing the disturbance from industrialization to the indigenous economies.

3.2.2. Nenets Autonomous Okrug, Russia

3.2.2.1. Introduction

The Nenets Autonomous Okrug (NAO) includes part of the Timan-Pechora oil region, the third biggest in the Russian Federation (Figure 3.6). It is home to the indigenous Nenets as well as the Russian and Komi settlers, whose ancestors moved to the area starting in the 16th century. The area is mostly covered by tundra, with forest tundra in the south. In the valleys of the Pechora, Pesha, Oma, and Vizhas rivers there are fertile meadows, which have made possible small-scale dairy farming in Russian and Komi villages. However, 75% of the area is reindeer pastures, unsuitable for other agricultural uses. Reindeer herding and fishing have been the backbone of the region for many centuries, for both the indigenous population and the settlers. Today the majority of the Nenets live in 43 rural villages.

The history of oil and gas development in the NAO can be divided into the Soviet and post-Soviet periods. The policy and methods of land use are clearly different in these periods, as are the socio-economic conditions and the political system. In the NAO, the exploration phase of oil and gas activities coincided with the Soviet period, with its centrally planned economy. Production started in the Soviet era, but has continued through the transition to a market economy, in which new structures are forming but many old ones still exist. However, despite the change of the political and economic system, land and subsurface resources are still owned by the state, which regulates their use (see Box 3.3 on page 14). Both the Soviet Union's and the Russian Federation's economic well-being was, and is dependent upon oil and gas production.

3.2.2.2. The Soviet period

In the NAO, large-scale exploration of oil and gas resources started in the late 1950s. In 1958, the *Nenets Geological Prospecting Expedition* was established with headquarters in Naryan-Mar. The expedition, or rather the workers themselves, built houses there before they started prospecting on the nearby tundra and expanding outward from there. In 1966, the first oil deposit was discovered in

Figure 3.6. Nenets Autonomous Okrug (shaded land and sea areas delimit the Timan-Pechora Petroleum Province).

Shapkino, and a year later the first gas deposit in Vasilkovo. However, production did not begin until later. The state concentrated on prospecting activities, organizing new geological prospecting expeditions. More people were needed for this exploration, and so new houses were built in Naryan-Mar and in 1968 a new town, Iskatelei, was erected near Naryan-Mar. In 1974, another town, New Varandei, was built by geologists next to the Nenets fishing and hunting village, Old Varandei. Farther east a base was organized in Amderma, which was a former Soviet mining town and military base. In 1990 its population was 5000, while New Varandei had about 1000 people.

Production started much later and on a small scale. First, in 1977, extraction of gas started in the *Vasilkovo* gas field to supply the needs of Naryan-Mar and Iskatelei. A gas pipeline was also built to the village of Krasnoe, between the field and Naryan-Mar. Only in the second half of the 1980s did oil production begin, first in the island of Kolguev and later in the *Kharyaga* oil field.

In the 1960s and 1970s, the society of the NAO underwent major changes. The state aimed to settle nomadic herders in new, permanent villages. Construction went on in the villages throughout this period, while the number of settled Nenets increased continually. Reindeer herding and fishing were organized in the *kolkhozy* and *sovkhozy* (collective farms) subsidized by the state. Development of the *kolkhozy* and *sovkhozy* determined the development of the villages. Naryan-Mar's economic base was the processing of renewable resources: there were fish and meat plants as well as a sawmill. Unemployment was unknown. The NAO was also a closed territory, where not only foreigners but also the citizens of the Soviet Union needed to get permission to enter if they were not registered as residents of the territory. There was no road connection to the rest of the country, so all transportation to and from the region went by air or water. Inside the NAO, people from rural villages used planes and helicopters as well ships to get to Naryan-Mar. The rural population was consolidated in the villages, which grew bigger as smaller villages were closed and as a result of a high birth rate. Tundra areas between villages were used as reindeer herding pastures and divided between different reindeer herding *kolkhozy* and *sovkhozy*.

The arrival of oil and gas exploration organizations changed the demographic and ethnic profile of the NAO (NAO, 1979, 1989). The population number rose quickly, almost entirely in urban areas. Before the start of active exploration the rural population outnumbered the urban population, but in the 1960s the urban population grew

Box 3.3. Accommodating the interests of indigenous peoples in decision-making associated with oil and gas developments

Historically, indigenous peoples have inhabited the vast territories of the North, Siberia and the Far East of the Russian Federation and have engaged in the traditional activities of reindeer herding, hunting, fishing, and gathering. Large-scale industrial development of the Soviet North from the 1930s onwards was accompanied by a rapid growth of industrial cities and settlements, infrastructure, and communications. The costs of collectivization (replacing individual or private enterprise with collective farms and the like) on the traditional activities of the indigenous peoples and the reduction of traditional territories were compensated by a policy of paternalism (state management of individual and community affairs) and by the state-planned economy.

Following the dissolution of the Soviet Union in 1991 and the transition to a market economy in the Russian Federation, the interrelationships between the state, indigenous peoples and the private sector have changed enormously. The main lessons learned over the past decade include the following:

- The key issue for the political, economic and cultural development of indigenous peoples is the collective right to the land and natural resources. Resolving this issue is based on new principles of partnership between the indigenous peoples and the oil and gas industry with government intervention at all levels.
- Indigenous peoples do not have adequate mechanisms for expressing their rights and interests. The political system of the state does not allow indigenous peoples to have guaranteed representation either in legislative or in executive bodies.
- The Federal authorities deliberately distanced themselves from a fair settlement between the indigenous peoples and the oil and gas industry allowing the regional authorities to resolve conflicts.
- Few regions promoted the socio-economic development of indigenous peoples. Even those that did had few economic agreements between the indigenous peoples and the oil and gas industry and there is a need for more integration of indigenous peoples into decisions affecting their territories and self-governance.
- Development of the Russian economy will depend on exploiting its oil and gas resources and conflicts between the indigenous peoples and the oil and gas industry are certain to continue.

The Russian Arctic currently has areas of traditional indigenous land use activities and areas of modern oil and gas activities. Potential conflicts arise when the locations of the oil and gas activities coincide with reindeer pastures, hunting grounds, fishing areas, and so on. Such conflicts require a more balanced development strategy for the North, one that makes it possible to conserve ecosystems and to combine industrial development and traditional land use activities. Such a strategy must be based on legally-binding policy decisions, especially those taken at the federal level, and must accommodate the interests of indigenous peoples.

Successful development and implementation of socio-economic programs to meet the needs of indigenous peoples will require public participation, a strengthening of existing regulations, and greater involvement of local and regional governments.

Development of natural geological resources has a significant effect on traditional land use activities and the way of life of indigenous peoples. Development leads to changes in the ecological and socio-economic dynamics of a region, which in turn modifies the social and cultural system of the subsistence economy.

Subsurface development has both negative and positive effects on indigenous peoples. Benefits are connected with income generated by consumer and production services associated with the oil and gas activities, and with rental fees for the use of lands. Several federal laws stipulate special rights of indigenous peoples concerning the use of renewable natural resources, compensation for damages, and access to subsistence resources. However, the rights declared in these laws are not fully realized in practice. Continued development and implementation of such legislation should define the status of areas of traditional land use, should delineate federal powers, and should specify the powers subject to local and regional governance.

Comparing the interactions of non-renewable resource users and the indigenous peoples in several of the oil and gas bearing regions of the Russian Arctic points to important needs and lessons. For example, one priority is to develop models for effective governance mechanisms to share power between local and regional levels. Through such comparisons, experiences gained in one region are likely to benefit other regions. This process is also likely to be of benefit to policy makers at the federal level.

Resource extraction activities in the Russian Arctic testify to the fact that the rights of indigenous peoples are often violated. Indigenous peoples rarely receive adequate compensation for the damage to their way of life caused by resource development. The development and implementation of socio-economic programs may become the means for better accommodating the interests of indigenous peoples. One way to finance these programs may be through rental income generated during production of oil and gas resources on areas of traditional land use.

It would be expedient to establish a trust fund with the assets used for implementing socio-economic programs for the indigenous peoples of the Russian Federation. This fund could be managed jointly by the governmental structures and by representatives of indigenous peoples' organizations, for instance, the Russian Association of Indigenous Peoples of the North (RAIPON).

Access to areas of traditional land use for oil and gas activities requires consideration from the perspective of the indigenous peoples. Natural non-renewable resource projects are under ordinary conditions appealing to indigenous peoples. However, for these groups, preserving the traditional ways of life is given more weight than economic gain. The requirements of indigenous peoples should be commensurate with their additional ethnological, social and ecological costs, which require modifying the regulatory process. It is also important for indigenous peoples to form corporations that have the regulatory authority to ensure that concerns are addressed.

A basic principle in the transition from paternalism towards Russia's indigenous people to a partnership relationship is participation in resource development projects, including developing the capacity to provide support services to the oil and gas industry. Providing these services will reduce the general costs of project development and implementation. This participation by the indigenous people will lead to the growth of public welfare and will accommodate their interests in the process of subsurface development and monitoring of the deposits of natural resources. History has shown that when indigenous participation is absent, the result is a high level of costs for the state and often the lack of an adequate system for monitoring oil and gas activities.

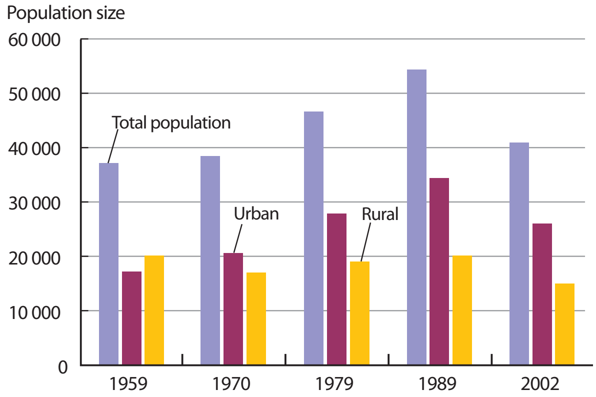


Figure 3.7. Total, urban, and rural population of the NAO over time (Committee of Statistics of the NAO).

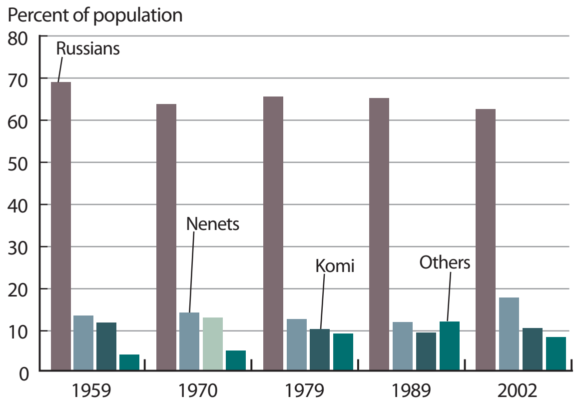


Figure 3.8. The ethnic composition of the NAO population over time (Committee of Statistics of the NAO).

larger due to migration into the NAO as well as to migration from the villages. In the 1970s and 1980s, the urban population grew rapidly while the rural population grew only modestly (Figure 3.7).

The ethnic composition of the population also changed. The indigenous Nenets had been in the minority from the 1920s, but their percentage declined from 13.3% to 11.9% between 1959 and 1989 despite an increase in total numbers of Nenets. The percentages of Komi and ethnic Russians also declined, whereas the number of other nationalities, such as Ukrainians, Belorussians, Tartars, and Udmurts (nationalities which have a long oil history in their areas), grew significantly. In 1959 these groups accounted for 4.9% of the population, and by 1989 had reached 12.5% (Figure 3.8).

By 1989 the oil and gas industry was an important employer: engaging 7700 workers, or 32.8% of the total work force (Kozlov, 1989: 38-39). According to the 1989 census, agriculture (dairy farming, reindeer herding, fishing, hunting, and fur farming) engaged almost 4000 people, of whom 40% were Nenets.

In the Soviet Union, decisions about exploration and production were made in Moscow. Local needs and the environment were regarded as less important than the needs of the country. Oil and gas were important for the state economy, and thus developing oil and gas resources was an important task. The local newspaper described the arrival of geologists as the coming of civilization to the area (Tolkachev, 2000: 85). If the local officials were interested in more rapid development of the industry as a key to the region's economic future, the reindeer herding enterprises were more suspicious. They saw how the prospecting organizations behaved in the tundra. Each drilling site was in action only a year or two. During that period workers drove tractors and all terrain vehicles across the tundra, destroying the vegetation cover. The herders lost lichen pastures to such disturbance as well as to drilling sites. Although they occupy only a small area, reindeer do not graze near active drilling sites because of the smell and noise, making it difficult for herders in the vicinity of drilling activities. Even after drilling finished, the abandoned sites were littered with debris on the ground and chemicals in the soil and water, which led to injuries and poisoning of the reindeer (Tuisku, 2002: 149).

In addition, the presence of geologists and others involved in oil exploration who were unfamiliar with the local culture caused problems. One of the eastern reindeer brigades was left without winter clothes, tents, and supplies because someone had opened their winter sledges during summer time (Ledkov, 1991: 182-183; Tuisku, 2002: 150). Oil workers fished and hunted where they wanted. They also poached reindeer, though for this they were punished if caught. The herders used to visit all people who appeared on the tundra. Some of these geologists and others would provide vodka to the herders, and then take advantage by bartering for meat more cheaply.

The herders, however, do not have only negative memories about the exploration period. Herders of the Varandei territory bartered meat and fish for some other food items, such as potatoes and dairy products, which were not supplied by the *kolkhoz*. The exploratory organizations provided transportation by helicopter between the city and Varandei and the fields, and often took herders back and forth between their pastures and their homes and relatives. Because the oil and gas workers were based locally in Varandei and worked for several years in one territory, even though in different fields, they got to know herders of that area.

Still, the methods used in the industry worried many people. By the end of the 1980s, in the period of Perestroika, it was possible to speak about ecological problems, which were obvious by that time. Oil and gas activities were seen as a threat to reindeer herding, which was the main traditional livelihood of the Nenets. This worry was one of the reasons that a Nenets organization, called Yasavei, was established in 1989.

3.2.2.3. The post-Soviet period

In the 1990s, Russia's political and economic changes nearly ended exploration activities and slowed the start of production. The exploration organizations were privatized. Some were closed, while others were restructured into bigger oil companies. The lack of financing for exploration meant that companies had to reduce staff or were unable to pay salaries. At the same time, the local economy went through a crisis. Productivity declined in every sector except oil and gas. The agriculture sector, especially, suffered the loss of state subsidies and ran heavily into debt. The *kolkhozy* and their successors could not pay salaries on time and worker productivity declined. In this period, private entrepreneurs emerged at the same time that many people found themselves unemployed, a new phenomenon in the region. In the state sector, however, salaries, pensions, and other social benefits were paid with only short delays, in contrast to elsewhere in Russia, where such payments were not made for years. In this situation, many people set high hopes on rapid development of the oil and gas industry, hoping it would provide work and revenue for the region. To help spur such development, the ban on foreign

Box 3.4. Socio-economic structure of the NAO

Industry in the Nenets Autonomous Okrug (NAO) is a combination of oil production enterprises, industry sectors associated with services to the public (food-processing, printing, and other light industry), and supporting industries (electric power industry, metal working, building materials industry and wood working) (Makeev, 2005). Oil activities account for over 95% of the industrial production of the region, and oil is practically the only export product apart from small amounts of cod and haddock. Even as recently as 1994-95, other products such as wood, meat, berries and mushrooms, and other materials were exported from the region. Currently, industrial production shows stable growth in the NAO. The table shows major characteristics of the NAO industrial system in 2002.

In the agricultural sector, some 2700 people were employed in 2001, accounting for 12.2% of the NAO workforce. Although agriculture is vital to employment and income in rural areas in the NAO, it remains financially insecure. In the mid-1990s, the loss of state support and changes in ownership of land, price liberalization, and other changes made most agricultural enterprises nationwide unprofitable. The late 1990s onwards have been a period of adaptation, with increasing stability in the agricultural sector, the return of some state support, and more effective participation in the market economy. Financially, agriculture remains precarious, but production has increased.

In the NAO, reindeer herding is a major part of agriculture, together with other livestock for milk and meat as well as cultivation of potatoes and vegetables for household use. Most livestock is owned by collective enterprises, including 91.5% of cattle, 71.2% of reindeer, and 71.7% of horses.

Industry sector	Volume of industrial production, millions of Rubles	Number of industrial personnel[a]
Overall	12033	4604
Electric power	191.5	197
Fuel	11654	3726
Machinery and metal working	1.0	70
Forestry, wood working and pulp and paper	17.3	98
Light	2.3	65
Food:	164.2	424
flavoring	40.8	158
dairy-and-meat	105.6	187
fishing	17.8	79
Printing	1.6	11

[a]Personnel data are for persons engaged in industrial sector activities, such as food processing, rather than agricultural production.

companies was lifted, opening the previously closed area to foreign investment and foreign presence (see Box 3.4).

The slow start of exploration and production in the 1990s produced social and economic impacts in the NAO. The overall population decreased, particularly as new arrivals moved back out of the region, although since 2002 the population has been increasing slowly. This is in part the result of in-migration due to economic activity, and in part because the NAO is one of the few regions in Russia in which fertility is higher than mortality. This natural population increase is highest in rural areas. The age and sex distribution of the NAO population also differs from the Russian average; 61.3% of the population is of working age, compared with 58.5% nationwide. In this group, men outnumber women by a ratio of ten to nine. The NAO has a relatively small proportion of persons older than working age, in part because many who move there to work move out again when they retire. In this age group, women outnumber men by a ratio of five to two. Some changes have been dramatic in the post-Soviet period. In Amderma, for example, the military base closed and exploration activities ceased. The town's population shrank from 5000 in 1989 to only 600 in 2002.

In 1993, New Varandei was closed, partly for environmental reasons. The village was built on the shore, but the beach was affected by erosion and storms, leaving the town vulnerable. By the terms of a special settling program, the inhabitants of New Varandei were allotted housing in other parts of Russia, although not all wanted to move out. For two decades they lived in the NAO and their children considered the NAO to be their home, but nevertheless they had to leave. Gradually people moved out and by 2000, when the oil company Lukoil built a terminal in New Varandei, there were no permanent dwellers. New Varandei became a production facility without a permanent population. Old Varandei, with a population of 120 and not threatened by the sea, was nonetheless closed due to that fact that all services were located in New Varandei. The local administration provided housing for the local population in Naryan-Mar. However, the Old Varandei population has faced great problems in adjusting to life in the city. Some have heavy drinking problems because they do not have jobs or do not see any prospects in the city life. Many, especially men, wish to return to their home area and continue hunting and fishing. Despite the relocation some people either stayed or have returned to Old Varandei, living without any government or commercial services.

In the 1990s, new regulations and legislation concerning land use were implemented. Now the decisions about subsurface resources are made jointly by the federal and regional governments (see Chapter 2). Moreover, there are new ecological regulations concerning resources use, again under joint federal and local control. The rights of traditional livelihoods, such as reindeer herding, have been recognized in several federal laws (see the previous case study, section 3.2.1).

In the 1990s, the start of production in new fields was very slow. In 1994, the Russian-American joint venture Polar Lights started production in Ardalin. In 1998, production began in Kharyaga by a French-Russian company. Pipelines were built from the fields to the existing pipeline system connecting to the Komi Republic. After 1999, oil activities have started to develop more quickly. Extraction has started in eight fields and construction is underway in an additional 12 fields, with more than a dozen companies involved. Different political groups and different companies are engaged in a political fight about oil resources and development, which has had an impact on the pace of extraction and on regional politics. In 2005, the gubernatorial election centered on oil development issues, and resulted in the election of a new governor with a background in the oil industry.

During the past decade, the overall economic situation has been improved significantly. Oil production has risen sharply, from 3.3 million tonnes (~3.9 million m^3) in 1998, to 4 million tonnes (~4.7 million m^3) in 1999, and to 7.44 million tonnes (~8.7 million m^3) by 2003. Investments have also risen, more than quadrupling between 2001 and 2004. Retail trade doubled over the same period. Revenues for the NAO government have come largely from taxes on oil and gas activities, and the budget has been balanced for several years. Salaries and social benefits have been paid on time, as have various subsidies for activities such as housing construction and agricultural production. These latter activities, as well as various cultural, sports, and health initiatives, are paid through a fund established for socio-economic development, utilizing some of the revenues from taxing oil companies. Despite the rapid development of oil and gas activities, many problems remain. Some were inherited from the Soviet period, such as the lack of housing or poor quality of existing houses and many public buildings, such as schools. The villages lack not only running water and sewage, but in many cases any source of safe drinking water. Unemployment is high in the villages, where the *kolkhozy* used to employ the majority of people, but where now there are fewer activities and thus fewer jobs. The public sector is the most important employer in many villages. The economic distress of the villages is made worse by the lack of good transportation between the villages and Naryan-Mar. Helicopters or airplanes typically fly only once a week and it is difficult to get tickets. The villagers feel that despite the oil money in the NAO as a whole, their life is not improving. However, since the 1990s, the economic situation has improved in some villages. For example, in Krasnoe, where dozens of villagers work in the oil and gas sector, the number of cars is increasing from year to year and the village stores provide a good selection of products and goods. However, Khorei-Ver, which is close to several oil fields, lacks pure drinking water, has unreliable electricity, and, like every other village, has poor quality housing.

In Naryan-Mar, by contrast, people clearly have more money now than they used to have. There are a couple of computer and hi-tech stores and several stores selling clothes and home electronics. The streets are full of cars even though there is no year-round road connection beyond the NAO. More money has also had some negative impacts. Drug abuse and prostitution exist in Naryan-Mar, which the locals report only appeared with the oil boom.

In the 1990s, unemployment was high and it was hoped that the start of construction and extraction would bring jobs for the local population. This has not happened. The unemployment rate has decreased overall since the 1990s thanks to the general economic improvement, but remains steady now, with 80% of the unemployed living in rural villages. The oil companies say that there are not enough qualified workers in the NAO, and that skilled workers are essential to their operations. Thus, they are forced to bring in workers from other parts of Russia. These workers do not settle in the NAO, but travel to and from the region for their work shifts or seasons. They may stay in Naryan-Mar for a couple of days before flying on to the oil fields.

There are, however, some signs of improvement or at least the potential for improvement. While there are no figures on the number of local residents working in the oil industry, there are some local people both in the offices in Naryan-Mar and in the fields on the tundra. Some oil companies pay for local youth to be educated either in Arkhangelsk Technical University, which has a campus in Naryan-Mar, or in an oil college in Usinsk. Also, for interested Nenets, Yasavei, the organization of the Nenets people, has an agreement with some oil companies to provide training.

Jobs in the oil industry are coveted, but for many rural dwellers it is difficult to find a place to live in Naryan-Mar. Because there are no guaranteed flight connections to most of their home villages throughout the year, they have to move to Naryan-Mar if they are to be available for work there or in the oil fields. Krasnoe is the only village connected by a year-round road to Naryan-Mar. Krasnoe, not surprisingly, has many men and women working in the oil fields, which is reflected in the number of new cars and the variety of goods in the shops in the village.

3.2.2.4. Reindeer herding and oil activities: co-existence of two modes of land use

Reindeer herding is still the backbone of rural life in the NAO. However, now only a minority of the Nenets are engaged in herding. In 2004 there were officially 978 herders (male and female), including Komi as well as Nenets herders. Recent legislation of the Russian Federation (see previous case study, section 3.2.1) recognizes the rights of traditional livelihoods. However there is no clear mechanism for taking into account the needs of reindeer herding during development. To start activities, the companies must obtain consent from the reindeer herding enterprises in whose territory they will work. During negotiations they also discuss the routes of pipelines and roads, but some enterprises have nonetheless lost access to some of their pastures due to pipelines.

The companies must pay compensation for the loss of pastures, but these payments are low and paid only once. Thus, the reindeer herding enterprises, which are still experiencing economic problems, aim to conclude special agreements on material and financial help before giving their consent. Currently, development is taking place in the territory of five of the NAO's 19 herding enterprises. The different companies have different attitudes towards reindeer herders, and thus, different kinds of relationships. One representative of a reindeer herding enterprise explained that they have a good relationship with one company acting in their territory. They have discussed all the details of construction with the company, and company representatives have not just visited their camps for one day, but stayed overnight. They do not have any written agreement, but so far the company has given any material help the herders have asked for. With another company acting in their area, they are fighting to get a written agreement because they do not trust this company.

Generally, these agreements are not public and thus many rumors and much misinformation surround them. Many people think that the herding enterprises get a lot of money from the companies. However, the companies rarely give cash, but more commonly provide goods or services such as helicopter flights.

The most famous and most discussed agreement is the one with Yerv, a herder's union. In 2000, Yerv signed an agreement with Archangelgeodobicha, which obtained a license to work in Yerv's territory. Later, this license was transferred to Varandeineftegas, with whom Yerv had a long fight over the agreement. In this area, every herder has a plot of land and is the official land user, but the herders created Yerv and chose a chair to address legal matters such as agreements with oil and gas companies. In 2002, Varandeineftegas suggested to herders that the company would sign agreements directly with the herders, not through Yerv, and pay annually a certain sum of money. The herders turned down the offer, preferring to act as a group (Vasilivetskii, 2002; Volkova, 2002; Vylka, 2002). Many of them did not trust that the company would keep its promises.

Later, Varandeineftegas was restructured into Naryanmarneftegas. Yerv concluded an agreement with this company, too, but considered this agreement to be a continuation of the old agreement, because all the companies were subsidiaries of Lukoil. In spring 2005, one more restructuring took place. Naryanmarneftegas started to act as a separate unit, and Yerv had to negotiate with this newly independent company. The negotiations have been very difficult and, for Yerv, frustrating. Despite the existence of previous agreements, the companies have not consistently upheld their end of the bargain. Some parts of the agreements have created further disputes: although the companies provided transportation for herders when needed and also bought a lot of reindeer meat, Yerv and the herders had higher expectations. In summer 2005, Yerv and Naryanmarneftegas signed a new agreement, including cash payments and the provision of various services. The terms of this agreement were made public, unlike those of previous agreements, and recent newspaper stories have reported the construction of houses for herders (Vybor Naroda, 2005a,b).

Agreements on material help are only one part of the relationships between companies and herders and their enterprises. The different companies have different policies towards herders and herding enterprises, indigenous people, or even all local people. Further, the personalities of local and company leaders and directors and their knowledge of local history and customs play a big role in these relationships. Some companies employ many people who were born in the NAO or have a long working history there, and thus are familiar with local customs and needs of herding. Other companies have brought many people from other parts of Russia who do not respect local people and are not even interested in learning about local conditions. Workers who have worked previously in Western Siberia have a reputation for holding very negative attitudes towards indigenous people.

To get consent from the herders, the companies discuss routes of pipelines and roads, sites of extraction, and other aspects of their activities. However, there are occasions when the companies have started work prior to obtaining official documents and consent from the herding enterprises. The effects of construction on herding can be enormous. The construction period brings many people to the tundra, which worries the herders, who remember the impacts from exploration during the Soviet period. The potential for conflict is large.

The companies have also built winter roads to their fields, from Kharyaga to Ardalin and on to the Varandei fields. These roads are open from December to April, depending on temperature. The public road from the Komi Republic to Naryan-Mar is now being upgraded from a winter road to a year-round road. Currently during wintertime, groups of road workers clear snow from the roads. A steady stream of trucks transports large volumes of materials to the fields. Private vehicles are not allowed on these roads, and even company cars (and those belonging to sub-contractors and other authorized road users) are inspected to prevent alcohol from reaching the fields. Since the creation of the Polar Lights joint venture, the companies have adopted strict new policies in their fields: workers are not allowed to fish or hunt, or to bring in any domestic animals, or to use alcohol during their shifts. Workers flying by helicopter from Naryan-Mar are checked at the airport, but some people fly direct to Varandei from Usinsk, Perm and other cities. If the companies have succeeded in reducing fishing and hunting, the fight against alcohol abuse continues. Drivers manage to smuggle alcohol in, to sell to workers or to barter with herders. Different company policies complicate enforcement in areas where several companies operate.

The quest for satisfactory co-existence also involves the Nenets organization Yasavei. It was founded in 1989 and currently has an office with three employees, paid from federal sources. Yasavei has official status in the NAO, and must be consulted on all matters concerning the Nenets people. Yasavei tries to act as a mediator between reindeer herding enterprises, the Nenets population, and the oil companies. It has been actively seeking contacts with oil companies and since 2001 it has organized round-table discussions with the oil companies. It has also offered to help reindeer herding enterprises in negotiating agreements with oil companies, but the reindeer herders have preferred to negotiate through their own organizations, such as Yerv. Yasavei also wants these agreements to be public and to create a sound relationship between the indigenous population and the oil companies, based on trust and transparency.

Yasavei has also signed its own agreements on cooperation with some companies. Cooperation mostly includes financial help either to or through Yasavei. The companies have helped to send Nenets people to study, to organize a traveling doctor and cultural worker to two reindeer herding enterprises, and to organize the Yasavei congress. Even though Yasavei has official status in the NAO and its role is to protect the rights of the Nenets, it has not been included in all the committees and working groups where such topics are discussed. The local administration's attitude towards Yasavei has varied according to personnel changes in both Yasavei and the local administration. Since 2005, the president of Yasavei has worked as a vice governor for indigenous issues in the local administration.

3.2.2.5. Worries and hopes for the future

Oil and gas development is still in its early stages in the NAO. The local population has seen two different modes of activities. In the Soviet Union, ecology was not an issue and decisions were made only in Moscow. Currently, new legislation requires new methods, and decisions are made partly locally. However, the local decision makers are now mostly newcomers or locals who are connected to oil and gas companies. Thus, many people fear that their needs and rights are not taken into account. Moreover, the share of oil revenues that remains in the local budget has been decreasing every year. The NAO has to give part of its revenues to the Archangelsk Oblast, of which it is part. The NAO's population fears that before the Okrug manages to improve people's wellbeing, most of the oil money will be going outside the NAO.

Reindeer herders, Yasavei, and the Nenets in general are still worried about possible ecological impacts of oil and gas activities on reindeer herding and the tundra. Spills from pipelines, fragmentation of pastures due to pipelines and roads, and other impacts are all a concern. For herders, this is a stressful situation, especially in light of their experience with impacts in the past.

3.2.3. Nuiqsut, Alaska, USA

3.2.3.1. Introduction

Although the Prudhoe Bay area of northern Alaska had been used by indigenous hunters for thousands of years, the area contained no permanent human settlements until the construction of the work camp at Deadhorse in 1968. The nearest settlement is the community of Nuiqsut on the Colville River, which defines the boundary between state lands to the east and the 9.4 million hectare, federally managed National Petroleum Reserve – Alaska (NPRA) to the west (see Figure 3.9). The 1998 development of the Alpine field eight miles north of Nuiqsut marked the first time – aside from the gas wells that provide energy to the community of Barrow – that industrial facilities were located close to people's homes.

With an estimated 454 million barrels (~72 000 m^3) of oil, the Alpine oil field is one of the largest discoveries in the United States in recent decades. The field sits under land owned by Kuukpik Corporation, the Native village corporation established under the Alaska Native Claims Settlement Act of 1971. The field started production in November 2000, and now produces about 100 000 barrels (~16 000 m^3) per day – more than double the original design. It is operated by ConocoPhillips.

The Alpine field currently marks the western extension of the North Slope oil complex. It is a state-of-the-art, roadless, compact field design with directionally drilled wells clustered on two gravel production pads covering 39 hectares. A three-mile road and airstrip connect the pads. The larger pad also contains the production facility, maintenance shed, and housing. A 55-kilometer pipeline delivers crude oil to Kuparuk and from there to the Trans-Alaska Pipeline. A winter ice road connects Alpine and Nuiqsut to Kuparuk, which is served by an all-weather road to Prudhoe Bay and Fairbanks (795 kilometers away).

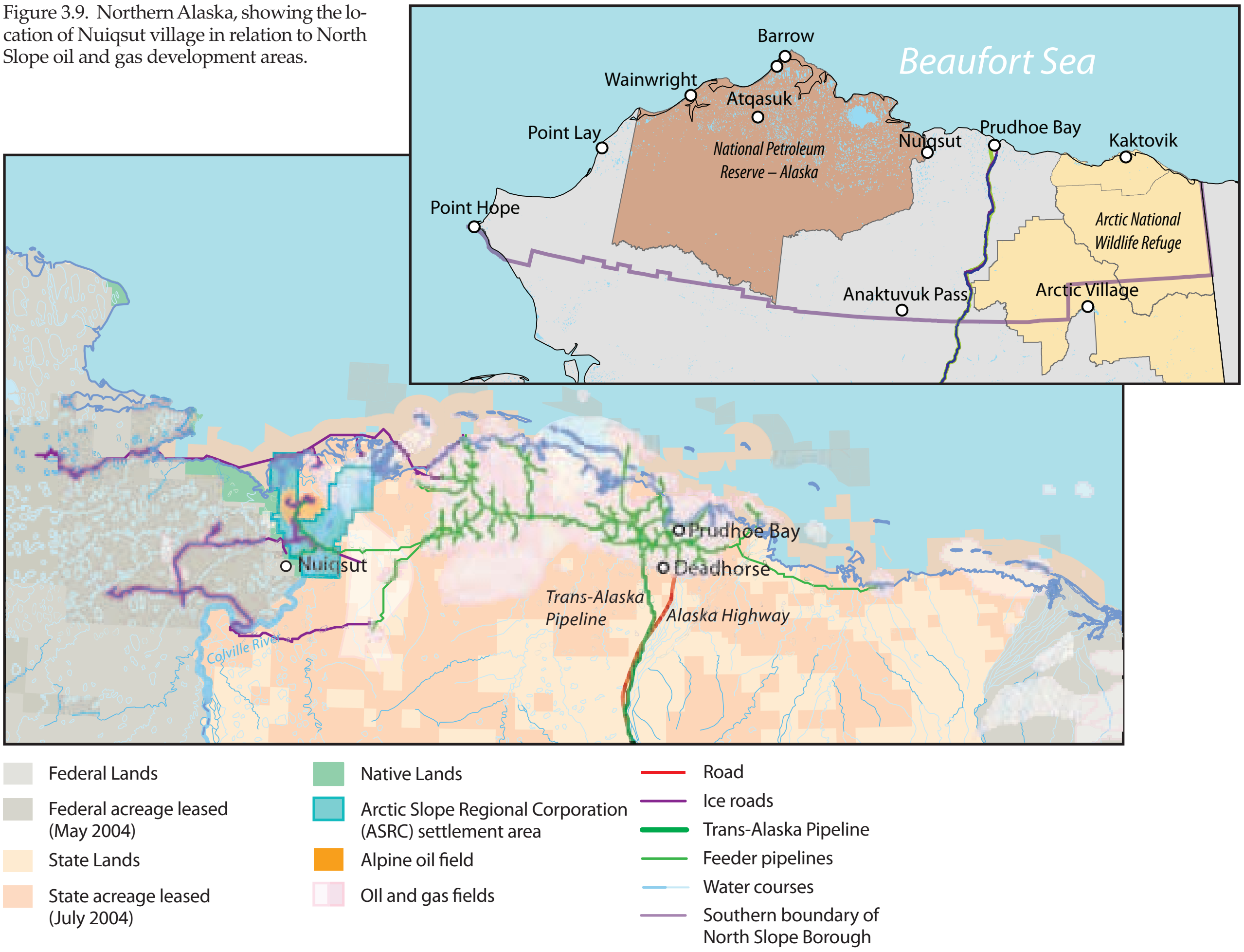
The success of Alpine has led to extensive exploration activity throughout NPRA. ConocoPhillips is now developing two satellite discoveries just north and south of Alpine. The Environmental Impact Statement (EIS) was expanded to include three more discoveries to the west. To address cumulative impacts, the EIS also lays out 22 hypothetical future pads and pipelines branching northeast in the delta and west deep into NPRA. The state of Alaska is now proposing to build a gravel road from Kuparuk past Nuiqsut into NPRA to encourage further exploration and development activity. The Bureau of Land Management recently revised its NPRA regulations to allow greater flexibility with regard to how development activities can meet environmental standards, particularly in the Teshepuk Lake critical habitat area. These revisions have elicited strong local opposition and legal challenge by environmental organizations.

3.2.3.2. The social and economic system

3.2.3.2.1. The North Slope

Alaska's North Slope is the homeland of the Iñupiat people. For thousands of years the Iñupiat have used the land and sea for hunting, travel, and other subsistence activities. The *Prudhoe Bay* oil field could not be developed and the Trans-Alaska pipeline could not be built until Native claims to the land were settled. The Alaska Native Claims Settlement Act (ANCSA) of 1971 provided for the incorporation of the Arctic Slope Regional Corporation (ASRC) and eight village Native corporations to hold title to land and manage the cash settlement of claims on the North Slope. ASRC is active in the oil industry as a surface and sub-surface land owner as well as an oil field services contractor. In 1972, local Iñupiat leaders overcame political opposition from state and industry leaders to incorporate the North Slope Borough as a home-

Figure 3.9. Northern Alaska, showing the location of Nuiqsut village in relation to North Slope oil and gas development areas.



Box 3.5. ASRC's Testimony on Cumulative Impacts

In 2001, the National Research Council's committee on Cumulative Effects of Oil and Gas Activities on Alaska's North Slope visited Barrow, Alaska. Among the statements they heard was the following from Richard Glenn of the Arctic Slope Regional Corporation (ASRC).

"When the U.S. Congress passed the 1971 Alaska Native Claims Settlement Act (ANCSA) it established the foundation for the creation of Native Corporations in Alaska. The Native-owned village and regional corporations were given title to a portion of their traditionally used lands, and cash with which they were expected to start successful corporate enterprises. Incorporated in 1972, the Arctic Slope Regional Corporation was created to manage nearly five million acres of land and capital resources granted to the North Slope Iñupiat under ANCSA. ASRC is based on Alaska's North Slope, and has been witness to many of the changes brought about by oil and gas development in our region.

When viewing the cumulative impacts of more than fifty years of oil exploration and thirty years of oil and gas development on the North Slope, it is easy to assume that most of the positive impacts are well known and should therefore remain unspoken. However, the charge of this panel, researching all cumulative impacts, is too important to rely on such an assumption. We must recognize the positive impacts as well as the negative impacts. I would like to point out some of each, and urge the committee to listen closely to the important testimony of our municipal leaders, and our subsistence hunters and village residents.

Positive impacts

Fifty years of exploration and thirty years of operation by oil industry in a region that has no other significant local economy have left us with many positive cumulative effects. These include benefits to our government, local and regional corporations, community organizations, and North Slope residents. In the early days, the Navy sponsored exploration program brought jobs, money, and supplies to people throughout the region. It also brought a source of heat and electricity to Barrow, the North Slope's largest community. The Navy's close relationship with the people of the North Slope was long lasting; this very building is a product of Navy presence on the North Slope. Research about industrial pollutants from all over the world is conducted here; at this former Navy oil and gas exploration camp. Other more recent positive impacts include:

***North Slope Borough operating revenue** – Our home-rule government derives more than 60% of its annual operating budget, now totaling more than one hundred and fifty million dollars per year, directly from oil and gas tax revenue. Interest from the North Slope Borough Permanent Fund account, a direct descendant of taxed oil and gas infrastructure, is also used for borough operations. The North Slope Borough property tax revenue funds education, police, fire, health, water/sewer, power generation and other municipal services in all borough communities. Think of what life in the North Slope villages would be like without these locally funded services. Compare the quality of life of today to that of the pre-1970s. The borough-assessed revenues have gone far to better the life, health and safety of North Slope residents who see little in the form of state and federally funded programs.*

***North Slope Borough capital projects** – The Borough has had the opportunity to use the promise of future tax revenue to sell bonds for much-needed capital projects in our communities. These include schools, water/sewer facilities, bulk fuel tank farms, fire halls, health clinics, homes and home improvements. The Borough capital funds have at times been augmented to a much lesser degree by proceeds from the Department of Interior in the form of NPRA impact funds.*

***Jobs and careers for village residents** – Our regional and village corporations have participated as partners in oil and gas exploration and development on the North Slope, putting North Slope residents to work and bringing money into our communities. The oil industry project and client base (especially in the area of oilfield construction) has allowed for the corporate development of many Native-owned companies, serving as a stepping stone to business success elsewhere while giving local work to local people. It must be said, however, that most of our village residents do not even see these benefits – oilfield and pipeline operations jobs, for example, have a paucity of our people on their roster. I will return to this point in a moment.*

***Resource revenue for ANCSA corporations** – Alpine is the first oil field to be developed on Native lands, and there may be more. In addition, exploration and lease agreements, the development of gravel and other resources necessary for field development bring much needed revenue to our local native corporations.*

***Direct contributions to programs of benefit to North Slope residents** – As a charitable contributor, the major oil- and oil field service companies are significant supporters of programs such as the Arctic Education Foundation, the Iñupiat Heritage Center, cultural celebration, and many needed social programs. Without North Slope development, these contributions surely would not exist.*

Negative impacts

This is not to say that development has been trouble-free. The early days of exploration, for example, left scars on the tundra, which are still visible today. And we have places like Umiat, where Navy leftovers are a lingering environmental hazard. Nor can we say that industry, and perhaps more importantly, government agencies cannot do more to mitigate the negative effects of development. Some big problems remain unresolved and significant negative impacts demand immediate attention. Negative effects include:

***Stressed municipal operations** – Listen to our municipal leaders, our city and borough leadership. Onshore industry operations have at times tested the limits of some municipal responsibilities. In Nuiqsut, for example, drilling development at the nearby Alpine field swelled the local population, causing everything from village brown-outs to a shortage of health care providers. The local sewage lagoon filled to capacity. They ran out of potable water. Who should pay for the cost of these effects? Today, they are borne solely by our communities. Here, the answer maybe* *requiring industry to assist in the development of local municipal improvements – build new power generation, a second sewage lagoon, or otherwise provide offsetting benefits to the community. Become community citizens, and anticipate the infrastructure changes needed due to the presence of oil development. In Nuiqsut, Phillips' predecessor, ARCO, had this in mind when they opted to make Alpine's natural gas available to Nuiqsut for local use. Even still, the Borough is required to build the infrastructure, at a cost of tens of millions, to bring the natural gas to the village.*

More risk than benefit from offshore development *– The North Slope people suffer a disproportionate share of the risks and, except for some potential jobs, derive almost none of the benefits. This clearly is not fair.*

Displacement of traditional hunting activities, on and offshore *– Listen to our whaling commission and subsistence panels. Caribou are thriving at Prudhoe Bay and Kuparuk, but can our people hunt them? Whales continue in their annual migration, but are at times displaced offshore, making the hunt less successful and more dangerous. The oil industry have shown themselves to adapt their exploration efforts to respect the needs of our whalers. Oil/whaler agreements have developed for exploration. They need corollary agreements for production.*

Disenfranchised residents are not benefiting from development *– Our mayors will also describe to you a generation of residents left out of the cash economy and suffering the effects of disenfranchisement. Some suffer from alcoholism, drug abuse, suicide, and the attendant physical diseases that accompany the shattering of a spirit. Our local government pays many of the health and social costs: counseling, substance abuse treatment for the people suffering from these negative impacts. In addition, hunters have been displaced from traditional hunting grounds, on and offshore bringing added risks to an already dangerous activity. Search and rescue, medical transport, and other emergency service costs are borne largely without significant outside support.*

Summary

The early days of exploration *– the 1940s to 1970s were truly a mixed blessing. Lots of environmental damage, but many benefits to our people. In the recent past, we have formed a local government that depends to a large degree on oil and gas development. Much has been said to lead the public to believe that we simply roll over for oil development on the North Slope. The committee of the National Research Council has probably already learned that this is not the case. We created our borough, a local home-rule government, in part to exercise strong permitting and zoning policies, hounding the oil industry into good environmental practices. We are not complacent with oil development – we are vigilant. Exploration and development methods have improved much over the last twenty-five years, much of it at our insistence. We have argued, fought, commented, complained over the years; and industry has listened and responded. As a result, today's industry is a far cry from the industry of the past. The Alaskan North Slope probably ranks among the cleanest oil-producing regions in the world. It is not perfect, but the negative cumulative impacts have in many ways been mitigated due to our own hard work.*

Positive changes in our communities as a result of oil and gas property tax revenue have not propelled our people into lives of comfort. Rather, it has attempted to bring our communities out of Third World conditions with infrastructure improvements that are taken for granted elsewhere: reliable power, quality health care, local schools, and fire and police protection. Any visitor to our region would see that much remains to be done in this regard. The cost of these services is high; our communities are remote, widely scattered, and located in an unforgiving physical environment.

Clearly more can be done to reduce the negative impacts of oil and gas development in our region. Over the years, we have found that the oil industry listens to our needs and is amenable to changes in projects that benefit the environment or our people. The shrinking footprint of facilities and improvements to oil transmission line design are good evidence of such commitment. For various reasons, though, North Slope residents have not sufficiently filled the ranks of oilfield operations positions. From the outset, the flow of oilfield workers routes through Anchorage and Fairbanks and seems to leave North Slope residents at a logistical disadvantage. In addition, unfair stereotypes often make the village applicant less employable. More can be done to bring these productive career opportunities to North Slope residents.

As North Slope residents, we seem to be able to work with federal agencies tasked with regulating onshore exploration and development of federal lands. For example, many productive achievements have been made with the BLM [Bureau of Land Management] regarding the exploration and development of NPRA. Even so, we continually have to fight to retain our fair share of NPRA impact funds. In addition, we are currently prevented from the economic development of our own lands within the Arctic National Wildlife Refuge. This discrepancy is painful and we are hopeful for its resolution in the coming months.

Regarding the offshore, the MMS [Minerals Management Service] seems to seek local input, but we have seen little in return. The CARA [Federal Conservation and Reinvestment Act] legislation may bring some of the offshore development proceeds to our people; this would be a welcome change.

At the end of the day, if we were to live without the effects of North Slope oil and gas development, we would be turning our clock back to a time when our residents had no real living improvements, no access to local education and quality health care, and no career or corporate opportunities. Problems and some large risks persist, especially regarding offshore development. By listening to those who have the most to lose, and are most familiar with these issues, the industry and government agencies can work with us toward a common solution, and many problems can be resolved."

rule government. The principal motive was to establish local taxing authority and planning and regulatory control over oil development (see Box 3.5).

The North Slope Borough encompasses 230 000 km^2 of land – over 15% of the total area of the state – and 15 340 km^2 of water. Over 70% of the borough is federal lands, including NPRA and 47 866 km^2 of the Arctic National Wildlife Refuge.

The borough provides public services to Barrow, the regional center, and seven remote villages. Access to all North Slope communities is primarily by air. Borough operating expenditures in 2002 were USD 33 692 per capita. Oil property tax revenues comprise 70% of the borough budget. Oil revenues have been declining since 1998, however, following the decline in production from the giant *Prudhoe Bay* field. The *Alpine* field is a welcome offset: it generated USD 15.8 million dollars in revenue for the North Slope Borough in calendar year 2004.

Nearly two-thirds of the 7253 North Slope residents live in Barrow; the rest live in villages ranging from 200 to 700 people. Three quarters of the Borough's residents are Iñupiat, 44% speak Iñupiaq at home, and 14% (primarily elders) are not fluent in English (ACS, 2004). Traditional marine mammal hunts and other subsistence practices are an active part of the culture and economy. More than half (57%) of households rely on bowhead whale, caribou, fish, and other subsistence foods for half or more of their diet (North Slope Borough, 1999). The prominence of whaling captains in the political and corporate leadership demonstrates the key role of the whaling culture in Iñupiat society.

Thirty-eight percent of the Borough population is under 18 years of age. Three quarters of the population over 25 years graduated from high school or hold equivalent diplomas, and 17% have a bachelor's degree or higher. Nearly three quarters (72%) of the working age (16+) population in the Borough is in the labor force; of these, 15% are unemployed. The borough is the primary employer for local Native residents (43%); the village corporations are second (18%). Trapping and craft-making also provide some income. The median household income is USD 63 173; 9% of residents have incomes below the federal poverty guidelines (ACS, 2004).

North Slope oil field operations provide employment to over 5000 non-residents, who rotate in and out of oil work sites from Anchorage, other areas of the state, and elsewhere in the United States. Census figures for the North Slope do not include this transient population.

3.2.3.2.2. Nuiqsut

Nuiqsut, located in the Colville Delta 35 miles from the Beaufort Sea and 275 kilometers southeast of Barrow, is an Iñupiat community of 416 residents. They have a mixed economy, with traditional hunting and fishing activities providing most of their food and serving as the cultural foundation of the community. As a result of the Alaska Native Claims Settlement Act of 1971, the community received fee simple title to 589 km^2 of land, plus three million dollars, and a for-profit village corporation – Kuukpik Corporation – established to manage it. The community was resettled in 1973 and a city government was organized in 1975. The community also has a federally recognized tribal government, the Native Village of Nuiqsut. By the time oil was discovered under Kuukpik lands in 1994, Nuiqsut had had two decades of local self-government institutions and a generation of sophisticated political leadership forged through the decades of the land claims struggle.

Nuiqsut residents depend heavily on subsistence resources for food and on the seasonal cycle of shared activities as the cultural foundation for the community. In 1993, the year before oil was discovered, they harvested 336 kilograms of bowhead and beluga, seal, caribou, moose, and fish per person. The processing and sharing of these foods are important social mechanisms in which more than 90% of households participate. In 1998, wild foods constituted half or more of the household diet for more than two thirds of the households (North Slope Borough, 1999). Elders are the group most dependent on subsistence foods and on sharing from relatives.

3.2.3.3. Initiatives for local control

Key to understanding the history of Nuiqsut's relationship with oil is the observation of former mayor Leonard Lampe that "Nuiqsut's opportunity lay in managing the inevitable" (Spiess, 1999). The leaders of Nuiqsut anticipated oil development and did their best to prepare for it. In 1979 they adopted a cultural heritage plan known as the Nuiqsut Paisangich (Brown, 1979). The objectives of the plan are:

1. to control the pace and magnitude of change;
2. to protect the natural environment and wild resources;
3. to establish the historical/cultural/subsistence resources and values of the village;
4. to adapt landownership to the traditional law of free access and use; and
5. to perpetuate traditional activities to assure transmission of cultural values to future generations.

The Nuiqsut Paisangich identified five strategies:

1. to consolidate local powers of government to protect village lands;
2. to devise cooperative agreements for participation in management of land and seas beyond the village;
3. to adapt existing borough, state and federal authorities to advance village interests;
4. to seek new authorities that increase village influence; and
5. to hire a cultural guardian to educate outsiders and advocate for the way of life and values of Nuiqsut.

The community had strong internal differences of opinion regarding oil development in their homelands. Yet following the discovery of oil they were able to forge a united front: the City of Nuiqsut, the Native Village of Nuiqsut, and Kuukpik Corporation signed a cooperative agreement regarding oil and gas development and designated Kuukpik as the lead negotiator for all three. While tensions remain, the city and tribal governments effectively work in ways complementary to Kuukpik to protect community values in the face of development.

While the village corporation owns the surface of its lands, subsurface mineral rights are owned by the regional Native corporation, ASRC. ARCO, ConocoPhillips's predecessor in developing Alpine, had to negotiate a surface-use lease agreement and a pipeline right-of-way with Kuukpik, and the terms of the oil and gas lease and the unit agreement with ASRC. Kuukpik had unusual leverage over ASRC through section 1431(o) of the Alaska National Interest Lands Conservation Act (ANILCA), which it used to negotiate a 1.25–1.5% royalty share in the oil.

Kuukpik Corporation wanted, but did not get, more development in Nuiqsut, including a base camp, air strip, and a permanent gravel road. In the surface-use agreement between Kuukpik and ARCO Nuiqsut did get:

- 500 000 cu ft (~14 150 m3) of natural gas per year (the Borough is responsible for constructing the pipeline and processing facilities);
- USD 60 000 per year for the Kuukpik Subsistence Oversight Panel, an advisory council of local subsistence hunters who monitor development activities, mediate conflicts, and seek remedies for any adverse impacts;
- oil spill response team training and employment;
- use of winter ice roads (ice roads were built to support construction activities and have been continued every winter since);
- full hunting and fishing access at the site;
- first preference for work to Kuukpik Corporation and its eight joint ventures;
- good faith local hire for Nuiqsut residents; and
- matching funds for scholarships for industry job training.

Kuukpik also received USD 1 million at closing, annual land rents, and production payments in addition to their royalty share from ASRC. Fifty percent of Kuukpik's royalties are deposited in a fund in which the principal is preserved in perpetuity and the earnings will be used to pay dividends, scholarships, and elder assistance. Nuiqsut Constructors, a joint venture between Kuukpik and an ASRC subsidiary, performed all the primary construction work for the Alpine field, including opening the gravel mine, hauling gravel, and constructing the storage and production pads.

The Kuukpik Subsistence Oversight Panel, with representatives appointed by the city, the tribe, and Kuukpik Corporation, meets regularly in Nuiqsut to hear testimony from the company and contractor representatives and community residents concerning environmental and social impacts of industry facilities and activities. They negotiate with ConocoPhillips to make changes in operations in order to mitigate problems that are identified. They hold the company to a high standard of performance. A subsistence representative works in the field to monitor compliance with environmental stipulations and to mediate disputes with hunters. The subsistence representative is selected by the community and reports regularly to the Kuukpik Subsistence Oversight Panel, but is paid and supported in the field by ConocoPhillips.

A salient theme in the story of Nuiqsut is the question of local control. Table 3.4 shows the history of *Alpine* field development. Note the amount of legal wrangling in the early history as Nuiqsut/Kuukpik pro-actively positioned itself to obtain direct economic benefits from oil development and manage impacts; then, after the facilities were built and production was underway, note how little leverage they had in the subsequent development decisions.

In the Alpine satellite development plan hearings in 2003, Leonard Lampe, president of the tribal council, testified that the promises of local control over the terms of development, including lots of work and insignificant social and cultural impacts, were unfulfilled. He said that when *Alpine* first started,

> *"[village corporation leaders] were assured that they were going to get their share of work, their share of programs. But now …we're begging for those agreements to be in place, to make sure someone makes sure that the village corporation, village entities get their fair share of work. … It shouldn't be like this when you're the landowner, you're the stakeholders here.*
>
> *When Alpine first started, we were assured by our corporation that this wouldn't be a significant impact on our village. It has. It has been a significant social, cultural impact on the village… These are impacts that nobody is addressing.*
>
> *These satellites are just the beginning. This is an opening door to the whole west side of NPRA. Once this door is open, there's no stopping it"* (BLM, 2003).

Table 3.4. Alpine field timeline.

1973	Nuiqsut village re-established by 27 families moving from Barrow. Village ANCSA land claims certified in the Colville River Delta. Additional claims still pending.
1985	Texaco discovers oil in the Colville Delta. Following a lengthy dispute concerning a land swap with the state, ASRC reasserted mineral rights subsurface to Kuukpik Village Corporation lands.
1987	Kuukpik and ASRC settle a dispute regarding the scope of Kuukpik's right to approve or veto any development on its land.
1992	Kuukpik negotiates a share of oil royalties from ASRC.
1994	ARCO discovers commercial quantities of oil at Alpine. Advisory panel established by agreement with Kuukpik and ARCO.
1996	Discovery declared commercially viable, and the environmental evaluation document was released.
1997	Surface use agreement between ARCO and Kuukpik takes effect.
Dec. 1997-2000	Construction and development drilling.
1999	ConocoPhillips acquires ARCO.
Nov. 2000	Start of production; ConocoPhillips begins permit process to develop two satellite accumulations north and south of Alpine; projected start date is 2005.
2002	Three additional discoveries of oil to the west in NPRA warrant expanded development planning.
2003	Exploration activity extends throughout NPRA to the west, in Harrison Bay to the north, and in the Colville Delta to the northeast, as well as in the foothills to the south; the Kuparuk field complex lies to the east and two pipelines and fields have been developed in the southeast.
2004	The State of Alaska announces a plan to build an all-weather road through Nuiqsut into the NPRA to promote exploration and development.
Jan. 2005	BLM opens the Teshepuk Lake critical habitat area—a major subsistence resource for Nuiqsut, Atqasuk and Barrow—to exploratory drilling.

3.2.3.4. Net effects

3.2.3.4.1. Population

Nuiqsut population increased 37% from 1990 to 1999, then decreased 4% to 2003, for a net increase of 17% overall or 1.4% annually. The borough as a whole followed the same pattern but less sharply, for a net population change of 21%. A significant factor in this pattern is the trend in oil revenues to the North Slope Borough.

3.2.3.4.2. Business income

The value of Kuukpik's royalty share is estimated at more than USD 10 million per year. Land rents and fees for services bring in another USD 600 000 per year. Under the Surface Use Agreement provision for first preference for work, Kuukpik Corporation and its eight joint ventures received approximately USD 250 million in contract work related to *Alpine*. Contract activities included construction, catering, seismic, surveying, trucking, and security. The business experience was also valuable for Kuukpik, whose other business activities include operating a fuel, hardware, and sporting goods store in Nuiqsut; operating a contract post office; and, through its Nanuq subsidiary, performing North Slope construction work.

3.2.3.4.3. Public works

The community has also benefited from NPRA community impact grants totaling USD 14 million over twelve years. Three quarters of this – USD 10.6 million – was for natural gas conditioning, pipeline, and local connections for the community's share of the natural gas from *Alpine*. Nuiqsut indirectly benefits from North Slope Borough property tax revenues from *Alpine*, which amounted to USD 15.6 million dollars in 2004: that is about one quarter of what it cost the Borough to build the new piped water and sewer system in Nuiqsut.

3.2.3.4.4. Employment

According to the U.S. Census, employment in Nuiqsut grew from 103 in 1990 to 176 in 2000. The construction industry experienced an eight-fold increase in employment, from 5 to 43 jobs. Public administration employment increased four-fold from 8 to 34 jobs. The third largest growth sector was retail trade, which grew from 6 to 13 jobs. Health, education, and social services employment actually declined. The major employers in 2003 were the Borough (48 out of 121 employed respondents) and Kuukpik Corporation (37); 3 respondents worked for the oil industry (North Slope Borough, 2004).

Data through 2003 provided by the Alaska Department of Labor show that there were spikes of construction employment in the winter of 1998 and summers of 2001 and 2002, but that the overall employment trend follows that of the North Slope Borough, declining since 1998. Closer analysis in comparison with other Borough villages, however, shows a modest increase – 12 to 20 jobs – in Nuiqsut's all-season employment, which may represent an enduring expansion of the local economy. While there have been spikes of full employment, unemployment is the norm. The Borough census provides a low-end estimate of 10% unemployment in the winter of 2003. Winter is the high season for ice roads and activity in the oil fields; without Borough construction projects, unemployment is higher in the summer and autumn.

It is notable that few Nuiqsut residents have jobs at *Alpine* or in the oil industry. The Surface Use Agreement provided for training and good faith local hire at *Alpine* for Nuiqsut residents. To meet this commitment ConocoPhillips offered internships and multi-year on the job training opportunities and provided financial incentives to contractors for hiring, training and retaining Nuiqsut residents. Yet as of June 2003, four Nuiqsut residents were working full time in housekeeping and entry level jobs in the Alpine operations group and six full time in training or at entry level in the construction group (BLM, 2004). There are also several part-time jobs held by Nuiqsut residents such as air quality monitoring, ice road monitoring, subsistence representative, and ice road clean up. This low level of employment has been frustrating for residents. "They told us there'd be 50 jobs at Alpine", said the mayor (Rosemary Ahtuangaruak, personal interview, Anchorage Alaska, October 22, 2003). No locals were employed constructing the gravel pad for the recently developed field 27 kilometers south of Nuiqsut at Meltwater. Even when Kuukpik gets an ice-road construction contract, local hire is modest.

There appear to be four barriers to oil field employment: skills, required licenses and certifications, drug tests, and social/cultural barriers. Kuukpik's workforce development program has worked creatively with the state and with various companies to provide access to the required training, licenses, and certifications. Skilled jobs require extended training, however, and enrollment rates for these programs are low and drop-out rates high. Community leaders in Nuiqsut and the Borough are in the process of adopting strict drug policies in an effort to decrease drug use and increase work-readiness. How to address the social and cultural barriers to employment is less clear. Most of the work and training opportunities require leaving the community for extended periods. Many young people are uncomfortable living and working away from the village with non-Native people, miss their Native foods, and, especially among young families, do not want to be separated. Also, some prospective employees have not embraced the cultural behaviors expected of industrial workers, such as following the clock and placing wage-work ahead of other activities.

3.2.3.4.5. Standard of living

The cost of living in Nuiqsut has declined and the standard of living improved. The 'free' natural gas provided under the Surface Use Agreement would be more expensive than diesel for heating and power generation if the total capital cost of the pipeline, gas conditioning plant, gas distribution system and gas fired electrical generators were paid for by local residents. But Nuiqsut residential customers have reached an arrangement with the Borough to pay only the incremental costs associated with the operations and maintenance of the system. As a result, the residents of Nuiqsut are slated to pay the lowest energy rates in Alaska: a flat USD 25 per month for gas and USD 0.08 per kwh for electricity.

The ice road has only modestly reduced shipping costs for bulk items. The biggest changes resulting from the ice road are an increase in private vehicle traffic in and out of Nuiqsut and a much broader array of consumer goods available at the local store, which is triple the size of the old one. Consequently, residents now spend a much larger share of their income locally. The community has many amenities that were not available ten years ago. The Kuukpik work camp serves as a hotel and restaurant for the community and provides hot lunches to seniors. The community hall, health clinic, ball fields, and recreation center have all been expanded and upgraded. With average household income now approaching USD 60 000 per year (North Slope Borough, 2004) – this is still below the statewide average household income of USD 69 000 (ACS, 2004) – piped water and sewer service, partial road access, and a full array of consumer appliances and goods, Nuiqsut residents now have access to a middle class standard of living.

3.2.3.4.6. Subsistence

While there have been no documented declines in the number of caribou or other wildlife resulting from oil development at *Alpine*, access is becoming more difficult and fear and anxiety are acute. Access for hunting is not prohibited at *Alpine*, but pipelines and facilities interfere with travel and the use of firearms. Caribou have been observed to shy away from pipelines and alter their migration (Napageak, 2001). Noise, pipelines, roads and air traffic – there were more than 3600 flights to and from *Alpine* in 2001 (BLM, 2004) – divert wildlife away from the community. As a result, fewer hunters find game in their traditional areas and successful hunters must travel further to find game.

The landscape is also changed visually and aesthetically, making hunting less enjoyable and more difficult. The gas flares and lights of *Alpine* are visible from Nuiqsut. With many more nonresidents in the area and more low-flying aircraft and helicopters, there is a real loss of solitude and cultural privacy out on the land. Informants report less time on the land in traditional activities with their kids. People are displaced from the traditional areas that they know well and must find and learn about new places to hunt to avoid development. This materially reduces the inter-generational transmission of traditional knowledge and skills.

Offshore oil and gas exploration and development is another threat. Field observations from Alaska Native experts and scientific studies have confirmed that marine seismic exploration caused migrating bowhead whales along the mid-Beaufort Sea coast to deflect their course up to 35 kilometers from an operating seismic vessel and to avoid the area within 20 kilometers of the vessel (Richardson, 1997, 1998, 1999; NRC, 2003). Whaling crews at Cross Island reported having to travel greater distances to hunt, increasing their risk at sea and the length of time required to tow the whale to land and butcher it, thereby lowering the quality of the meat (NRC, 2003). Recent industry agreements have largely resolved this problem, but other concerns, such as the locations and effects of offshore pipelines and facilities, continue. The Iñupiat are particularly concerned about the likelihood of an oil spill in the Beaufort Sea, the difficulty of cleaning one up, and the damage it would do to marine resources. For the most recent federal Beaufort Sea Lease Sale (186), analysts estimated an 8–11% chance of an oil spill of 1000 barrels (~160 m^3) or more over the life of a project (Minerals Management Service, 2003).

3.2.3.4.7. Culture

Traditional culture is strong in Nuiqsut. Ninety percent of the residents are Iñupiat. Participation in whaling, butchering, sharing, and the *nalukataq* (celebration of successful whaling featuring a blanket toss) are still quite strong and whale populations are healthy. People are still eating subsistence foods every day, and sharing is frequent. While there are baseline data on language fluency, sharing, and respect for elders in Nuiqsut, not enough time has passed to isolate the effects of oil and gas development on these cultural values, or to distinguish these from the broader trends across the North Slope.

The expanding cash economy introduces new social stresses. Informants report that access to jobs is unequally distributed creating differential access to income and a pattern of winners and losers that affects self-esteem. Furthermore, as the corporation and community have had to deal with unprecedented high-stakes decisions, emerging differences in interests within the community have engendered conflict and strained the traditional consensus approach to decision-making.

3.2.3.4.8. Community

There are many more nonresidents coming through town. The hotel is the work camp for crews of nonresident workers working on the ice road and other activities in NPRA. Government and industry officials come to town for meetings and events several times each month. Researchers doing environmental field studies and social surveys come to collect data for environmental impact statements and other reports. Large numbers of outsiders and transients erode the sense of community, cultural privacy and local control that are a valued part of the cultural heritage of Nuiqsut (Brown, 1979).

3.2.3.4.9. Social problems

Alcohol is an endemic problem in Alaska Native villages and Nuiqsut is no exception. Alcohol sales and possession are prohibited, yet alcohol use and abuse persist. Locals report that alcohol problems vary directly with money: when dividend checks or paychecks come in, alcohol consumption spikes. Absenteeism, child neglect, accidents, and assaults all increase with alcohol consumption. Criminal offense data for 1998 to 2003, the years for which such data are available, show that rates of arrest for drug and alcohol offenses in Nuiqsut are similar to those of the North Slope Borough as a whole, but with a slight upward trend that is not present Borough-wide. This may be related to the ice road, which no other North Slope village has. To stem the importation of alcohol, ConocoPhillips, with community support, has recently instituted round-the-clock, random searches at the existing *Alpine* security checkpoint on vehicles entering the ice road.

Criminal offense rates in Nuiqsut vary year to year. Regression analysis reveals that the variations correlate with employment, not with population changes or with the trend for the Borough as a whole. The correlation between employment and property offenses – robbery, burglary, larceny, and motor vehicle theft – is particularly strong: 60% of the variation in property crimes may be explained by employment activity. High unemployment raises concern about how to engage people in productive activities that provide meaningful roles, especially young men.

3.2.3.4.10. Sense of well-being

The negative effects of development on mental health are notable, particularly concerning anxiety and sense of efficacy. Local people feel under siege. Fear of development or the loss of resources and way of life is an accumulating effect in and of itself. Alaska Natives told the committee that "anxiety over increasing offshore and onshore oil and gas activity is widespread in North Slope communities" (NRC, 2003: 224).

Mayor Ahtuangaruak (Ahtuangaruak, 2003) wrote:

> *"We are within eight miles of the Alpine oil development project, often referred to as an example of how new fields have a smaller footprint. The Alpine oil field already includes roads and pipelines, and we face new development with a gravel road from it to three new oil fields and new leases now being offered in the National Petroleum Reserve and across the Beaufort Sea. The NPRA is our backyard, and the Iñupiat people of this region have been hunting and fishing and living off the land here for thousands of years. Our way of life is increasingly threatened by the cumulative effects of oil and gas development. Seismic vibrators looking for oil and frequent helicopter flights have disturbed the caribou herds where I live. Big herds of caribou do not come through our town anymore, and most of our hunters have found it hard to even get caribou. Our elders tell me that the caribou are having problems, as more are seen with illnesses. Fish have been decreasing in numbers, and species are being affected. Fish caught in the net have been deformed, yellow, with increased parasites, in the muscle or reproductive glands, and some are skinny with a bitter taste to the meat. Many people at the ongoing, never-ending meetings scheduled in the village have voiced these concerns, but development activities continue to be approved… Many people in our village have grown up with their parents attending meetings about development, and they are still occurring… One of our biggest concerns is a road and what new development that will bring."*

Testimony at the Bureau of Land Management's NPRA subsistence advisory board meeting in Nuiqsut on 16 August 2001 addressed the same theme (BLM, 2003). After extensive discussions of the possible impacts to fish of seismic vibrations and pumping lake water for ice roads, Thomas Napageak said, "The fish must feel like me: industry is closing in." Bernice Kaigelak elaborated:

> *"What I predicted happened: Alpine expanded, and is almost surrounding us. This is Eskimo land. We have lost rights to our land. We have impacts and no compensation… Oil companies come to all the meetings: 'We want to drill there, we want to drill there.' They will come whether we say no or not... What is the procedure to stop or put a hold on areas that we think are sensitive for subsistence? We want it in black and white: legal. What we say at meetings is forgotten."*

Leonard Lampe described the erosion of social and cultural capital:

> *"Like we see today, elders against elders, youth against youth, labeling people, who's good and who's bad. You know, we all thought we were prepared as a village to face the social, cultural impacts, but today that's proof that we are not. We are getting against each other. We are getting against each other's organizations. We are not working together. They are being an impact on us. We are not strong as we thought we were going to be five years ago today. Look what's happening today. Everyone's getting against each other and it all comes down to money. That's what it all comes down to. We all seem to forget where we come from. We all can't move the clock back like people are saying. We cannot move and live in the past. But we need to remember that, you know, the Iñupiat way of life is working together, and we need to teach you that as well."*

3.2.3.5. Sustainability

The net effects on community sustainability can be assessed in four dimensions: economic assets, natural assets, human assets, and social and cultural assets.

3.2.3.5.1. Economic assets

The economic benefits of *Alpine* for the community have been huge: Kuukpik's revenues are over USD 10 million per year, personal income is up 40% over the decade (North Slope Borough, 2004), community infrastructure is greatly expanded, and all the goods and amenities to support a middle-class lifestyle are now available. The downside is increasing dependence on the cash economy. Furthermore, most of the jobs have been in construction, which is not locally sustainable. Kuukpik has established a permanent fund that promises a sustainable income stream into the future, though its uses and expected payouts are still unknown. Initiatives to enhance the sustainability of the cash economy must include getting more residents qualified and employed in oil field jobs. But even this is not a sustainable strategy for the long term, because the oil fields will eventually run dry.

3.2.3.5.2. Natural assets

At the outset, the gain of cash benefits against the loss of a portion of the homeland traditionally used for subsistence seemed like a reasonable tradeoff. The planned facilities at *Alpine* were limited to two pads and one pipeline. But the community did not anticipate and plan for the rapid expansion and cumulative impacts of oil and gas exploration and development throughout NPRA. While the actual effects of development activity on wildlife population numbers are thus far uncertain, the effects on the distribution of wildlife and their availability and access for subsistence hunting are clearly serious. The cumulative effects on wildlife of expanding industrial activity may be greater, and the prospects are of great concern to local residents.

3.2.3.5.3. Human assets

Training and employment at *Alpine* for local residents thus far have been disappointing. Only a handful of residents have low-level jobs at *Alpine*. While an on-the-job training program has been instituted for skilled trades, few residents have participated, completed the training, and entered full-time employment. Unemployment and drug and alcohol use in the community, particularly by young males, are continuing concerns. While whaling is still strong, loss of land access and use and impacts on wildlife are interfering with hunting and the inter-generational transmission of traditional knowledge and skills. Offshore oil development poses an even greater perceived threat to residents' traditional livelihood, lifestyle, and identity. The negative effects of development on mental health are notable, particularly with regard to anxiety and sense of efficacy.

3.2.3.5.4. Social and cultural assets

Iñupiat cultural identity is strong, adaptable, and resilient. Regional institutions reinforce the local culture, and whaling, the cornerstone of Iñupiat culture, is thriving. Yet the social fabric of the community is strained by the loss of use and local control of their traditional homeland and increasing inequality and conflict. In addition to the relentless expansion of extensive field activity on the land, the endless cycle of meetings, monitoring, and such takes a toll on local people's time, emotional energy, and sense of autonomy. Leadership resources in the small community are over-committed and cannot be stretched to address all the issues that require their attention.

3.2.3.6. Conclusion

Local control and autonomy are key assets for community sustainability because they permit the local community to balance benefits and costs, manage impacts, and effectively adapt to sustain the community for future generations. Compared with many indigenous communities throughout the world, Nuiqsut is in an enviable position. They had strong property rights, a strong home-rule borough government dedicated to preserving Iñupiat land use values, and strong community institutions and leadership. (A comparative analysis of Nuiqsut's institutional assets and the socio-historical precursors for these is offered by Haley 2004.) But their powers of local control have not been sufficient to protect and balance their community's long-term interests. Their property rights on Kuukpik lands were enough to secure substantial economic benefits from development at *Alpine*, but their lack of property rights in NPRA or offshore in the Beaufort Sea preclude them from limiting the extent of development in traditional use areas they depend on for subsistence. While they are granted a voice in the policy-making process, the weight of institutionalized interests is stacked against them. NPRA and the continental shelf are currently managed to increase the scale and pace of domestic oil and gas production in the national interest. This prevents the community from controlling the extent of development and the pace of change, thus limiting Nuiqsut's ability to manage change and successfully adapt.

3.2.4. Canadian Arctic case studies: Regional history

3.2.4.1. Historical setting

Canada's Arctic region has provided its aboriginal[1] inhabitants with food, housing, and clothing, and beginning in the 19th century, opportunities for fur trading and commercial harvesting. In the early 20th century, aboriginal people were involved in an active fur trade and the Inuvialuit in particular were well off, even by southern Canadian working class standards, from the income they were able to make from whaling and fur trading activities at various locations along the coast including Herschel Island, Shingle Point, and Kittigazuit (Alunik, 2003).

The people of the region have adapted to the general effects of western influences and the compounding influences of major developments over the last two hundred years. As the fur trade became established, the economy moved from subsistence hunting to trapping for fur and trading for goods. Through trade, aboriginal people were exposed to new diseases and alcohol, both of which had a devastating effect upon their populations. With the whalers and traders came missionaries who brought new religions and mobilized school-aged children to residential schooling away from home villages and families. Traditional land-based lifestyles were prevalent until the early 1950s when western influences from settlement and development effects began.

The first oil and gas development, in the Mackenzie Valley, followed the stories of early European explorers who became acquainted with the occurrences of oil seeps and their significance to the indigenous people. A large oil seep at Rond Lake near Fort Good Hope was used as a source of tar that fur traders scooped into kegs for trade at fur trading outposts (GNWT, 2001a). Imperial Oil first explored for oil here in 1920 at the site of an oil seep in Norman Wells. A local refinery supplied the region.

Imperial began exploring for oil on the Arctic coast in 1958, and exploration continued throughout the 1960s with the encouragement of the federal government. The discovery of immense quantities of oil and gas at Prudhoe Bay in Alaska in 1968 sparked the hope of a similar discovery in Canada's Arctic, and prompted the arrival of more geologists looking for telltale subsurface geological anomalies on similar continental shelves.

The first exploration well was drilled in the Mackenzie Delta region in 1966. The first major gas find, was made by Imperial Oil in 1971, and comprised 2.8 trillion cu ft (~79.2 billion m^3) of natural gas. Other significant discoveries in the area, followed by offshore oil and gas exploration beginning in 1973, resulted in an exploration boom that fostered the first road into the region, the Dempster Highway (1979). Increasing exploration prompted regulatory applications for a major natural gas pipeline from Prudhoe Bay across the North Slope of Alaska to the Mackenzie Delta and south along the Mackenzie River Valley to North American markets. Aboriginal people of the region responded by organizing to have their land claim rights recognized and the social and environmental impacts of such a large-scale development assessed.

A federal Commission of Inquiry, headed by Mr Justice Thomas Berger, with a mandate to "examine the social, economic and environmental impact of the gas pipeline", recommended a ten-year moratorium on the pipeline to "allow sufficient time for Native claims to be settled, and for new programs and institutions to be established" (Berger, 1977). Justice Berger recognized that, failing this, development would "bring limited economic benefits, [and] its social impact would be devastating."

The Committee for Original People's Entitlement (COPE) organized in 1970 to represent aboriginal interests. According to Nellie Cournoyea (COPE organizer, pers. comm., 2006):

> *"COPE was not formed to exclusively settle Land Claims. It was formed to organize, lead and respond to the challenges that we saw. It aimed to intervene and act. We were witnessing development on our lands and we wanted to respond. It was also a creature of government in that a formal organization was needed to receive funds to represent Inuit people. COPE played more of a role as an activist organization than a Land Claims rights organization.*
>
> *COPE's initial desire was then for a pan-Canadian Inuit-based approach. The Inuit had to break off into a regional claim due to the lack of organization in the Eastern Arctic. COPE had one of its first big organizational meetings in Fort Rae. The intent was to bring aboriginal groups together to address common issues. The Inuit wanted more of a national organization and approach then. At the Fort Rae meeting, aboriginal advisors were cautioning the Dene from joining non-treaty groups. How government responded to treaty and non-treaty claimants at the time clearly influenced how we were shaped as collective organizations."*

COPE was active right across the Canadian Arctic on a collective land claims initiative. Over time, the Dene along the Mackenzie Valley and the Inuit in the Eastern Arctic recognized the need to pursue their own individual claims

[1]It is the practise in Canada to use the term 'aboriginal' to refer to 'indigenous residents'.

for their own regions and dropped out of COPE. A specific Inuvialuit Claim was submitted to the federal government in 1977, an Agreement-in-Principle was signed in 1978, and the Inuvialuit Final Agreement (IFA) was signed in June 1984 (Government of Canada, 1984).

Plans for a Mackenzie Valley pipeline also stimulated debate on the rights of the Dene and Métis in their homeland. In 1976 and 1977, Canada agreed to negotiate comprehensive land claims in the Mackenzie Valley south of the IFA settlement area. Negotiations began in 1981 and led to the signing of the Comprehensive Dene-Métis Land Claim Agreement-in-Principle in September 1988. The Dene-Métis agreement failed shortly thereafter but the Gwich'in then pursued their own land claim and reached a settlement agreement in 1992 (Government of Canada, 1992).

Oil and gas development and production did not follow land claims settlement in the North, however. World market prices, high during the 1970s, had crashed by the mid-1980s. This, along with lack of transportation infrastructure to southern gas markets and the eventual ending of federal funding programs and tax incentives, brought a corresponding end to Delta and Beaufort exploration. The last offshore well was drilled in 1989, and the last onshore well was drilled in 1991.

Gas prices did not begin to recover until 1999. By then, the Inuvialuit Petroleum Corporation, with partners Enbridge Inc. and AltaGas, completed the Ikhil Gas Project, 50 kilometers north of Inuvik and the first commercial project of its kind above Canada's Arctic Circle. The project was built when industry interest was low but while energy costs in the Arctic remained high. Two wells, a production facility, and a pipeline supplied natural gas to Inuvik for heating and power generation.

The return of the petroleum industry to the Canadian Arctic came after a period that enabled the settlement of aboriginal interests and the establishment of the groundwork for them to participate in a more effective way.

3.2.4.2. Setting out new ways to manage development

A broad range of governments and their agencies now share the overall authority for resource management. These institutions have evolved out of the settlement of aboriginal rights and interests in the aboriginal settlement areas. The overall management process is designed around participatory collaborative and cooperative arrangements between institutions.

Non-renewable resources in the Northwest Territories and Nunavut are still largely under the jurisdiction of the federal government. The Yukon now has jurisdiction over natural resources. Aboriginal governments have distinct surface and sub-surface land holdings. Co-management bodies have been established under land claim agreements, generally to carry out land use planning, renewable resource management, environmental assessment, and land and water management. They may also take on cumulative impact monitoring. The management of oil and gas resources on federally owned land, called Crown land, is a federal government responsibility. A regularized system for annual exploration rights issuance in the region was successfully implemented in the late 1980s.

The regime also ensures that industry and government partners work with aboriginal peoples and northerners to strengthen northern communities by building an oil and gas sector into the northern economy through the submission of a Benefits Plan for the federal Minister's approval (Government of Canada, 1985). The plans set out the operators' policies and programs to make employment, training, and supply and service contract opportunities available to Canadians and Canadian firms, with first consideration given to northern residents and northern businesses.

Land claim settlement agreements set out institutions and approaches for their organizations and the federal and territorial governments to manage developments and their social and economic effects in the Region. The agreements set out measures to ensure consultation, roles in co-management institutions, and requirements for benefits to assure employment, training, and businesses opportunities. They also set out terms for the aboriginal relationship with government and developers wishing to work within the region, and to set the foundation for the future.

3.2.4.3. Regional settings

3.2.4.3.1. The people, society, and economy of the Mackenzie Delta

The people of the Mackenzie Delta region live in the regional center of Inuvik and in seven smaller communities within the Inuvialuit and Gwich'in Settlement Regions (Figure 3.10). The coastal communities, Tuktoyaktuk, Holman, Paulatuk, and Sachs Harbour, are primarily Inuvialuit. The populations of Fort McPherson and Tsiigehtchic are primarily Gwich'in. Aklavik and Inuvik are home to both Gwich'in and Inuvialuit people. The predominantly Inuvialuit and Gwich'in population exceeds 90% in the smaller communities and reached 59% in Inuvik in 2001 (Table 3.5). Almost half of the population in the communities is under 25 years of age.

Inuvik, or 'place of the people' in Inuvialuktun, is located on the East Channel of the Mackenzie River. The largest of the region's communities, it is the regional center for government and is made up of approximately 40% Inuvialuit, 20% Gwich'in, and 40% non-aboriginal people.

The Cold War need for Distant Early Warning – DEW Line – radar tracking sites along the Arctic Coast brought the first large-scale wage employment into the region in 1955. A 'model Arctic Town', Inuvik, was built in the late 1950s as the new administrative center in the region, complete with

Figure 3.10. The Mackenzie Delta region.

Table 3.5. Demographic indicators (GNWT, 2003a).

	Beaufort Delta	Inuvik	Smaller communities
Population in 2001	7229	3451	3778
1991-2001 Population change (%)	-5.5	-9.7	
Ethnicity (% aboriginal)	76.6	59.0	91.9

airport, radio and military base. As an Inuvialuit elder has written, "the large majority of Native people in the Delta were 'bush-oriented' and active fur trappers. But since the Dew Line construction era, the majority have become dependent on wage labor" (Alunik, 2003).

Inuvik grew as the government brought in a 55-bed hospital, a Royal Canadian Mounted Police detachment, and a Canadian Armed Forces base. A bank, schools, and post office were quickly built, making it the region's commercial and administrative center. It now acts as the central communications hub and starting point for oil and gas exploration and is also the end point of the Dempster Highway connecting the region to southern markets. It is the major transportation, health, and education center for the region. Today, with a population of 3586 (GNWT, 2003b) Inuvik offers a full range of products and services for the entire area.

The Inuvialuit and Gwich'in economy is a modern-day mixture of traditional harvesting, wage-based business development, and employment in the government, tourism, and oil and gas sectors. This mixture has evolved to its current state through a series of modernization and development-related trends. The oil and gas sector has been only one development-related influence in the region.

Resource harvesting pursuits contribute to a high level of country food in the diet in all communities except Inuvik (Table 3.6). While trapping declined with the crash in fur prices in the 1980s, hunting and fishing remain strong. Harvesting has provided both a continued attachment to the land and culture as well as a cushion for the boom-and-bust cycle of the wage economy. Traditional activities are best communicated through traditional language, as resource harvesting maintains a central role in the preservation of the social and cultural system in the Mackenzie Delta region.

The predominant employer in the region is government, reflecting the growth of regional health, education, and service institutions (Table 3.7). The overall participation rate of those considered to be in the labor force averages 60% in the communities and 80% in Inuvik. Unemployment is significantly higher in the smaller communities.

Most wage earners are either non-aboriginals or persons possessing a post-secondary diploma or degree. The level of high school attainment and training overall is reflected in the number of adults attaining grade nine. Vodden (2001) indicated that "perhaps the single most troubling indicator relating to the economy of the ISR [Inuvialuit Settlement Region] is the high school graduation rate that is extremely low" and more troubling relative to other areas of the north.

Community wellness determinants of social health in the communities outline a set of conditions that have resulted from a fragmentation of community life, loss of parenting skills, decline of traditional language and knowledge use, and mobility into and out of the wage economy. Alcohol abuse is seen as a primary influence of social condition, and

Table 3.6. Traditional pursuit indicators.

	Aboriginal language speakers[a], % of aboriginal people	% Primary country food households[a], half or more of food consumed in home	Trappers[b], % of population 14+	Hunters and fishers[b], % of population 14+
Inuvik	25	31	6	46
Aklavik	19	61	15	36
Tuktoyaktuk	25	71	10	60
Paulatuk	58	83	13	73
Holman	27	72	-[c]	64
Sachs Harbour	28	44	6	69
Fort McPherson	27	81	13	35
Tsiigehtchic	31	73	11	58

[a] GNWT (2001b); [b] GNWT (1999); [c] too small to report.

Table 3.7. Modern economy indicators.

	Did not complete Grade 9 in school, % of adults, 15+ in 1996[a]	Government service % of labor force in 1996[b]	Participation rate[d], % of population aged 15+ that are in the labor force, 2003	Employment rate[c], % of population aged 15+ that were employed during the week prior to the survey, 2003	Unemployment rate[d], % of the labor force that was unemployed during the week prior to the survey, 2003
Inuvik	11	45	80	74	6
Aklavik	28	50	57	42	27
Tuktoyaktuk	34	44	61	45	27
Paulatuk	40	40	65	58	12
Holman	38	48	59	47	20
Sachs Harbour	29	43	69	60	-
Fort McPherson	31	49	59	48	21
Tsiigehtchic	38	54	64	60	13

– Data unavailable; [a] GNWT (1996); [b] Statistics Canada (1996); [c] GNWT (2003a); [d] GNWT (2003b).

shows up in the offense rates and numbers of children in care (Table 3.8). Royal Canadian Mounted Police (RCMP) commanding officers in several small communities estimated that 90% or more of their calls for service were alcohol-related (Devon Canada, 2004: 7-48; RCMP "G" Division, 2002). The Government of the Northwest Territories (GNWT) has undertaken Social Agenda Pilot Projects and Social Impact Workshops related to the Mackenzie Gas Project (MGP) to better focus the discussion on community wellness around major resource projects.

3.2.4.3.2. The people, society, and economy of the southern Mackenzie Valley

This traditional Dene homeland includes the Mackenzie Valley south of the Inuvialuit homeland and west of Nunavut (Figure 3.10). These lands are shared by the Gwich'in, Sahtu Dene, Deh Cho Dene, Tlii Cho Dene (Dogrib), Sayisi Dene, Métis people, and a growing number of non-aboriginal residents. Dene are part of a large Athapaskan family of First Nations whose roots extend as far south as the Navajo territories in the southern United States.

Two Treaties were reached with the Dene in 1899 (Treaty 8) and 1921 (Treaty 11) that covered the area that now includes Norman Wells. For Dene, the treaties were the means to a political relationship with non-Dene authorities. Economic considerations prompted the federal government to seek the second treaty, covering the rest of the area, some 20 years after the first one, when an expanding economy made the opening of northern Canada an attractive prospect.

Comprehensive claims negotiations, the modern fulfillment of Treaties 8 and 11, began in 1974. Two regional claims have since been reached, one between the federal government and the Gwich'in (Government of Canada, 1992) of the Mackenzie and Peel Valleys and the Mackenzie Delta, the other between the federal government and the Sahtu Dene and Métis. The Sahtu Dene and Métis Claim (Government of Canada, 1994) secured title to 41 437 km^2 of land, subsurface rights to 1813 km^2, 'capital transfer' of CAD 75 million, and payments equivalent to a share of resource royalties, including those from the *Norman Wells* oil field. Provision was also made for co-management of renewable resources.

On May 23, 2001, representatives of the Deh Cho First Nations, the GNWT and the Government of Canada, together signed the Deh Cho Framework Agreement and the Deh Cho Interim Measures Agreement. These two agreements are the result of negotiations, which are consistent with Treaties 8 and 11. The Framework sets out the basis for ongoing negotiations and addressing the processes for managing land use planning, land withdrawal, oil and gas benefits plans and other arrangements.

Table 3.8. Community wellness indicators.

	Income support beneficiaries, average 2002 monthly number/1000 population[a]	Alcohol offense rate, per 1000 population, 2001[b]	Children in care, per 1000 population, 2002[c]
Inuvik	49	553[d]	27
Sachs Harbour	37		0
Aklavik	112	405	32
Tuktoyuktuk	55	293	36
Paulatuk	139	59	no data
Holman	229	–[e]	no data
Fort McPherson	38	478[d]	55
Tsiigehtchic	88		no data

[a] GNWT (2003a,b); [b] RCMP Local Detachments (2002); [c] GNWT (2002a); [d] communities reported together per 1000 population; [e] too small to report.

3.2.4.3.3. The people, society, and economy of Eastern Arctic Canada

As noted in Chapter 2, the Arctic islands and offshore areas of Canada's eastern Arctic region have significant potential for oil and gas discoveries (Figure 3.11). These areas lie within or adjacent to Canada's newest territory, Nunavut. Nunavut is sparsely populated and does not have a well-developed economic base. Most communities are small, with predominantly Inuit populations and with local economies heavily dependent on public sector activities and transfer payments.

Oil and gas exploration began in the eastern Arctic region of what was then a much larger Northwest Territories in the late 1950s and led to the drilling of an initial exploratory well on Melville Island in the Queen Elizabeth Islands in 1961. Subsequently, an industry/federal government consortium gave rise to Panarctic Oils Ltd. (Panarctic) later in the 1960s. Panarctic operated large-scale seismic and exploratory drilling programs onshore and on ice-covered offshore waters between late 1960s and early 1980s.

Beginning in 1968, Panarctic drilled 159 wells in the Queen Elizabeth Islands and adjacent areas, expending CAD 583 million of investors' risk capital and pioneering on-ice drilling and the inter-island transportation of drilling rigs by truck over ice-covered waters (Panarctic Oils Ltd., 1982; Kennedy, 1988). Although some oil resources and substantial volumes of natural gas were discovered, by the early 1980s several ambitious applications from industry to government regulators for approvals to produce and transport natural gas by various means from the Queen Elizabeth Islands had been shelved.

There were insufficient natural gas reserves to support the Polar Gas Project's proposed large diameter pipeline to southern Canada and the projected high capital and operating costs of the Arctic Pilot Project's proposed Arctic LNG (liquefied natural gas) tankers indicated that they would be uneconomic (Polar Gas Project, 1977a; Arctic Pilot Project, 1979; Allooloo, 1980). Thus, by the early 1980s, Panarctic was finding it increasingly difficult to attract exploration funds from others and was looking internally for ways to generate new revenues.

The eastern Arctic communities of Resolute, Grise Fiord, Arctic Bay, and Pond Inlet were not averse to responsible non-renewable resource exploration or development in the region. However, their predominantly Inuit populations placed a higher priority on the settlement of the Inuit land claim that had been submitted to the federal government in 1976 (Inuit Tapirisat of Canada, 1976; Allooloo, 1980). All four communities depended on an annual sea-lift of goods and fuel and, thus, were not opposed to limited, well-regulated summer shipping activities. The communities looked to the federal government to minimize the number of ships and the extent to which summer ship traffic conflicted with marine mammal migration and Inuit resource harvesting activities (DIAND, 1980).

By contrast, the communities opposed industry's conceptual plans to use the Northwest Passage for the year-round shipment of oil or LNG from northern Alaska and the Canadian area of the Beaufort Sea (DIAND, 1980; Dome et al., 1982). The communities made their opposition

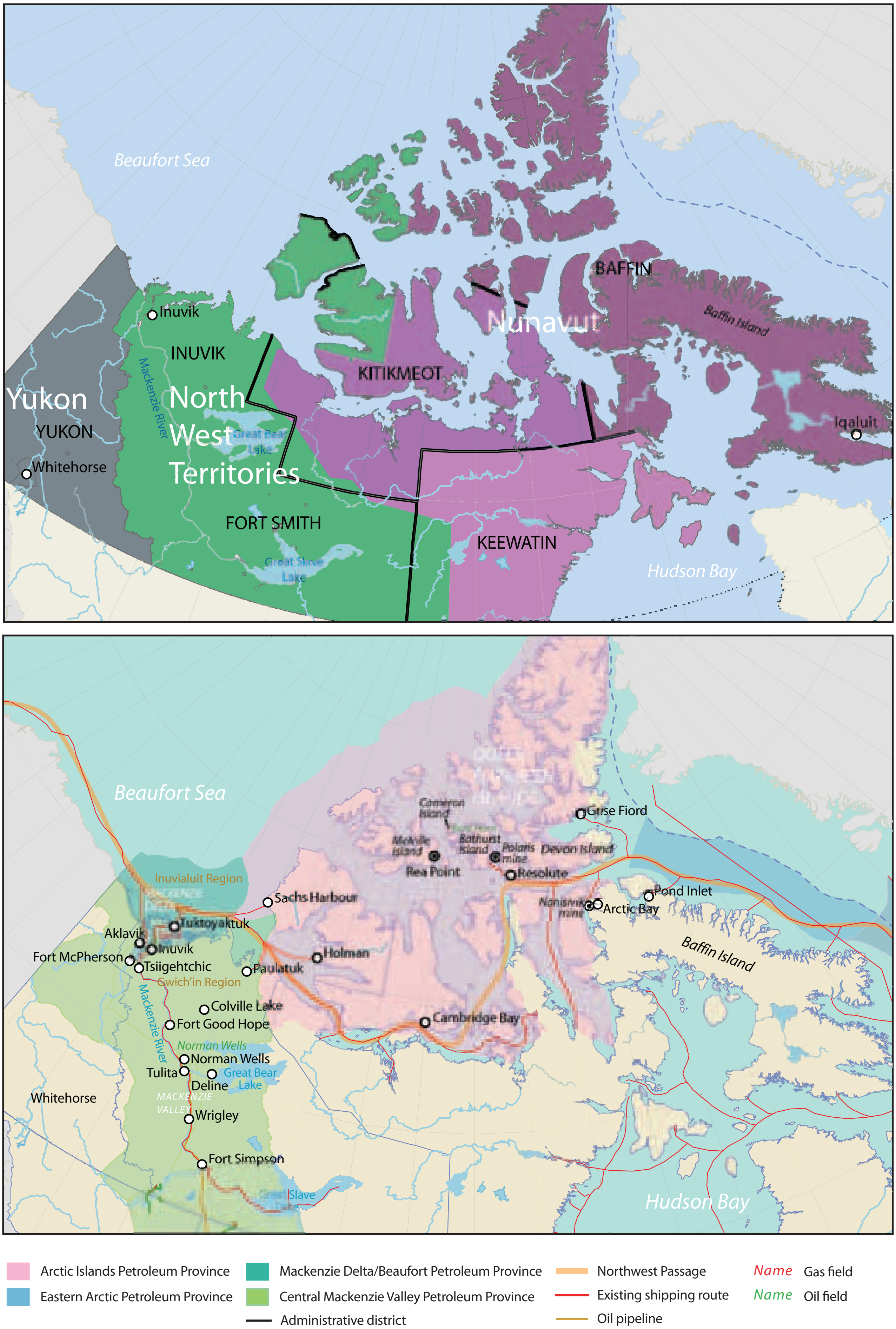


Figure 3.11. Canada's Arctic Territories (upper map) and Arctic Petroleum Provinces (lower map).

known to government environment assessment panels and at government-sponsored workshops in the late 1970s and early 1980s (Canada, 1979; DIAND, 1980, 1984; Ault and Jacobs, 1981).

Panarctic's yearly summer sealift from southern Canada to its supply base at Rea Point, Melville Island included a tanker load of fuel. The communities tolerated the tanker's annual trip to Rea Point. Ice conditions along the shipping route to Rea Point were less severe than the conditions around Cameron Island, 120 kilometers to the northeast. Melville Island and Cameron Island were of little direct interest to Inuit in any of the communities. Melville Island was far beyond the lands and waters that Inuit used for resource harvesting, one exception being hunting for polar bear, an activity recently initiated by Inuit from Resolute and Grise Fiord (Freeman, 1976; Polar Gas Project, 1977b; Schwartz, 1982). No resource harvesting by Inuit occurred on Cameron Island or in adjacent waters.

Panarctic officials visited Resolute and Grise Fiord (located some 300 and 500 kilometers, respectively, to the east of Cameron Island) several times each year during the 1970s and early 1980s to inform residents about the company's activities and future plans. Few residents in either community actually worked for the company. There were usually enough part-time and full-time employment opportunities available locally (Panarctic Oils Ltd., 1982).

In 1984 Grise Fiord's estimated population was 110 and approximately the same number of people resided permanently at the Resolute townsite (Hardy Associates, 1984). Up to two hundred other Canadians lived and worked at a largely self-contained air transportation service enclave adjacent to the Resolute airport, seven kilometers from the townsite (Panarctic Oils Ltd., 1984; Nortext Multimedia Inc., 1997).

Arctic Bay and Pond Inlet were the largest communities in the region, with estimated 1984 populations of 400 and 700 residents, respectively (Hardy Associates, 1984). These two communities were situated on the northern part of Baffin Island, some 700 to 800 kilometers southeast of Cameron Island and Rea Point. Since 1970 Arctic Bay and Pond Inlet had supplied most of Panarctic's Inuit workers (Alexander, G., retired vice-president, Panarctic Oils Ltd., pers. comm., 2006). The Inuit worked at Panarctic's Rea Point supply base and, to a lesser extent, at the company's exploration sites elsewhere in the Queen Elizabeth Islands. The employment with Panarctic was seasonal and, for many years, was based on a 'two weeks with Panarctic / two weeks at home' rotation schedule. Panarctic supplied return air charter transportation between the communities and the work locations.

The seasonal nature of the work, the rotation schedule, and the fact that most employment opportunities occurred during the darkest months of winter, a time when few renewable resource-harvesting activities were undertaken, were attractive to the communities (Goudreau, 1973; Roberts, 1977; Panarctic Oils Ltd., 1982). Panarctic used community-level voluntary labor pools and locally-based employee recruiters/expediters in the 1970s, introducing a 'name call' system to its employment arrangements in the early 1980s to better facilitate the training and promotion of individual workers.

In the mid-1970s when the Nanisivik lead and zinc mine on Baffin Island was constructed and began operations, some Inuit in nearby Arctic Bay and, to a lesser extent, in Pond Inlet, who had worked for Panarctic until then accepted the mining company's offers of year-round employment. Another sixty Inuit in the two communities continued to work for Panarctic via the labor pools. However, as the company's exploration activities in the Queen Elizabeth Islands declined later in the decade, employment opportunities with the company decreased. By the early 1980s, Inuit in Arctic Bay and Pond Inlet had become concerned about their prospects for continuing employment with Panarctic.

In the early 1980s a second lead and zinc mine, Polaris, situated on Little Cornwallis Island, between Resolute and Cameron Island, went into production and provided another employment possibility for Inuit in the region. Polaris's rotational employment schedule (six weeks in / two weeks out) was unattractive to most Inuit and, in the opinion of one long-time local observer, had contributed to family discord in Resolute (Tagak, 1980). By 1984, only one Inuk in Grise Fiord and one Inuk in Resolute worked at Polaris (Hardy Associates, 1984).

In 1984, the GNWT was seeking the transfer of the federal government's responsibilities for the management of non-renewable resources, including oil and natural gas, to the territorial government. In the interim, the GNWT wanted to have a larger and more visible role in the federal government's review and approval process for non-renewable resource development projects. In this vein, the GNWT had released a formal Resource Development Policy statement in 1983. The statement set out the territorial government's general conditions for project support and its intention to establish Development Impact Zones (DIZ) and DIZ Societies in areas where mining or oil and gas activities were proposed or underway (GNWT, 1983).

By 1984, with the cooperation of community leaders, the GNWT had initiated DIZ Societies in several areas, including the Lancaster Sound region. The GNWT hoped that DIZ Society meetings would provide useful fora for discussions at the regional level of non-renewable natural resource exploration and development projects by communities, governments and industry. The GNWT expected that the DIZ Societies would provide territorial ministers with regional-level advice on proposed projects. Territorial ministers would take such views into account when formulating the GNWT's advice and recommendations to federal decision-makers.

3.2.5. Norman Wells, Canada

This case study was drafted in support of the Canadian federal government's contribution to the Arctic Monitoring and Assessment Programme (AMAP) report on the Social and Economic Consequences of Oil and Gas Activities in the Arctic. This case study looks into (1) how social and economic impact mitigation was set up and (2) the reported social and economic effects of the construction phase of the Norman Wells Oilfield Expansion and Pipeline Project in the Mackenzie Valley region of Canada's Northwest Territories, 1980 – 1985. This case was undertaken as a secondary source review only and relied on available, published literature only. As a basis for this study, the Norman Wells Socio-Economic Monitoring Program and Dene Nation Studies were used as the main reference sources, supplemented by the findings of other research efforts.

3.2.5.1. Introduction

The Norman Wells Oilfield Expansion and Pipeline Project (the Norman Wells Project) was the first major development proposal to proceed in the Canadian north and followed a

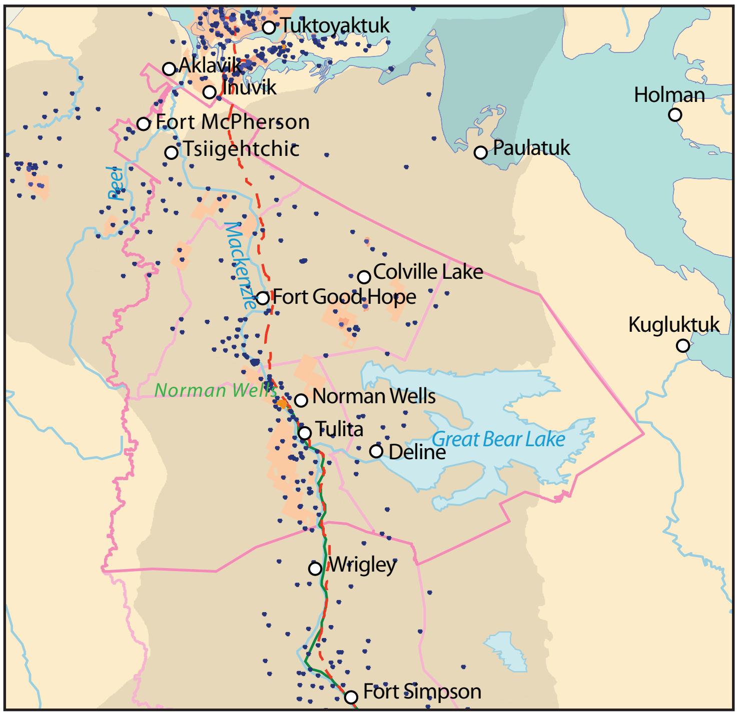


Figure 3.12. The Norman Wells region (shaded land and sea areas delimit the Central Mackenzie Valley Petroleum Province).

flurry of proposals and reviews throughout the 1970s with project developments, other than exploration activity, yet to occur. In 1977, the government-sponsored Mackenzie Valley Pipeline Inquiry (Berger, 1977) called for a ten-year moratorium on a large-diameter natural gas pipeline from the Mackenzie Delta until aboriginal land claims issues were resolved.

Imperial Oil began a drilling program in the area in 1919 and erected a small refinery in 1933 that supplied the needs of the local community and the region's mining industry. The oilfield was expanded in the 1940s to supply, via the CANOL pipeline, the wartime oil needs of the Alaska Highway. The pipeline only operated for a couple of years. It was not until 1979 that Imperial began discussions to expand production and to construct a small diameter pipeline to connect the field to southern markets.

The communities in the region (Figure 3.12) were small with predominantly aboriginal populations: Fort Franklin, now called Deline (population 550), Fort Good Hope (600), Fort Norman, now called Tulita (375), and Colvile Lake (75). In 2003, Norman Wells itself had 797 residents, 234 of whom were aboriginal. Considerable public interest remained focused on all northern development projects as continuing aboriginal rights, northern governance, and the ability to address social and economic effects of projects in remote regions had yet to be formally addressed.

A CAD 530 million expansion of the processing facilities to handle increased oil, gas and water production and pipeline in the 1980s was built with the drilling of over 200 wells and the construction of six artificial islands in the Mackenzie River. The Norman Wells Project today produces about 5300 m^3 of crude oil per day, which is shipped on an 870-kilometer long, 32-centimeter diameter pipeline to southern Canada.

3.2.5.2. Norman Wells project review and mitigation and monitoring approach

3.2.5.2.1. Review process

In the early 1980s, the federal Environmental Assessment and Review Process (EARP) governed the determination of adverse effects of federal projects, programs, and activities. The Norman Wells Project was referred to the Federal Environmental Assessment Review Office, and a panel was appointed to conduct an environmental and socio-economic review of the project proposal. By the time the panel was formed, the proponents had already submitted an environmental impact statement, which was subsequently reviewed and distributed for public review.

The four-month review period was extended, and during this time both the proponents and the panel undertook public information programs including community visits and public meetings, advertising, and distribution of literature on the proposed project. A key challenge for all parties was determining the types of information needed to address outstanding concerns. Following consultations, the panel submitted its review of the project to the federal Minister of the Environment, recommending that the project did not proceed until important deficiencies in the proponents' planning and in government preparedness to address social and economic issues could be addressed. The federal government gave Imperial Oil delayed approval to expand the *Norman Wells* oil field and Interprovincial Pipeline Limited permission to construct the pipeline.

In July 1981, the National Energy Board granted Interprovincial Pipeline Limited permission to construct the pipeline. The scope and scale of the project in comparison to the small population, traditional culture and land use, limited infrastructure, and local capacities within the region raised a number of concerns. The federal and territorial governments indicated that their support for the project would depend on the companies' demonstration of local opportunities to participate and adequate mitigation against harmful impacts. Recognizing the divergence in local capacity to cope with the scale of the project, the federal government announced approval of the project subject to a two-year delay in construction to allow all parties to ensure local capacity and develop mitigation initiatives (DIAND, 1981). The federal government and the National Energy Board approvals recognized that the Norman Wells Project would provide an economic boost to the Mackenzie Valley, but recognized further that benefits of the project could be negated by drawbacks. As part of the approval, CAD 21.4 million of federal funding was set aside to "help Northerners deal with expected opportunities and any adverse consequences of Norman Wells construction work" (DIAND, 1981). Efforts to involve the Dene in ownership and business opportunities in project construction were attempted. The federal Minister reached an agreement with Interprovincial Pipeline Limited to "offer up to 20% of their equity in the pipeline" (DIAND, 1981), but the offer was refused as inadequate by the Dene Nation. An Imperial Oil offer to establish an aboriginal drilling company, Sheetah Drilling, was realized. Sheetah obtained drilling contracts during the expansion project and remains active today.

3.2.5.2.2. Setting up social and economic impact mitigation and monitoring

To address concerns of social and economic impacts, social and economic agreements were reached and socio-economic monitoring programs were undertaken for the oilfield expansion and pipeline projects. The Socio-Economic Action Plans included a number of specialized action plans covering issues such as northern business opportunities, security, information and consultation, and operations and maintenance training and education. Quarterly and annual reports on implementation were tracked. In general, the Socio-Economic Action Plans were intended to guide decision making and to minimize harmful and optimize positive impacts of the project. An assessment of cumulative effects of development on the region was not part of the regulatory or general practice of environmental assessment at the time.

The Socio-Economic Monitoring Program aimed to collect social and economic data to review "the distribution of benefits and costs from the Norman Wells Project to be determined along the lines recommended by both the FEARO [Federal Environmental Assessment Review Office] and the NEB [National Energy Board] reports" (DIAND, 1981). A comprehensive, external, social and economic monitoring program was set out through the University of Saskatchewan, funded by the federal government (Meldrum, 1986). The program was designed to gather pre- and post-construction information on local population and households and businesses.

3.2.5.3. Findings on social and economic effects from project construction

The Socio-Economic Monitoring Program assessed six overview questions on the experience of the Norman Wells Project's construction effects on local communities and populations (Stewart and Bone, 1986). The findings from the program are summarized with reference to Stewart and Bone's questions.

1. Would aboriginal people be able to fully participate in an industrial project of this type?

More than 1500 northerners were directly employed in the project, representing over 84 000 person-days (Mahnic, 1994). Aboriginal employment on the Norman Wells Project represented 22% of the labor force during each year of construction and initial operations. As employment grew throughout the project, aboriginal participation grew along with it.

Perceptions of acceptable levels of northern and aboriginal employment varied. The need for adult education and training was seen as acute and the responsibility of government and industry (Métis Association of the Northwest Territories, 1982). The relationship of training to employment was telling – 88% of unemployed aboriginal people in the study communities had never completed high school, whereas 80% of those who had completed high school were employed. The achievement of higher education levels was recognized as a long-term activity that required the attention and ongoing cooperation of all parties.

Today, 30% of the operations and maintenance labor force is aboriginal, a result of ongoing efforts to develop and train local residents (Imperial Oil, 2002, 2003).

2. Would aboriginal people be able to withstand the social upheaval resulting from rapid changes that this project may cause?

Rapid change was most directly affected at the regional hub of the project, Norman Wells. Norman Wells was the only community directly in the middle of project developments, and had indeed been formed fifty years earlier to service the oil find. The impact of people migrating for project opportunities was not identified as a problem in the three predominantly aboriginal communities, which are located away from construction and construction camp activity. Rapid change on the individual and family group had more effect.

Social concerns, often driven by increased alcohol and drug abuse during short-term projects, were raised. It was recognized that increased stress facilitated higher levels of abuse and social effects (Métis Association of the Northwest Territories, 1982; Dene Nation, 1986a). Significant infrastructure investments in the communities were seen, especially at Norman Wells, which saw a new school, recreation center, a regional airport, and gas distribution system.

Air commuting was an important part of the project's employment and community/family approach (1) to mitigate the population impact on Norman Wells and (2) to maximize northern residents having access to jobs at Norman Wells and on the pipeline. Air commuting was coordinated both out of Edmonton, a regional center some 1000 kilometers to the south, and in the north utilizing existing air schedules connecting northern communities. Air travel was paid for by employers.

3. Would there be a large influx of southerners into these northern communities disrupting the traditional society?

The population of Norman Wells rose by 60% between 1981 and 1985. Over 70% of households had resided in the community for less than five years, while the remainder comprised long-term residents showing a significant turnover in community population. The air commuting system was designed to temper the influx of southern workers into Norman Wells, reducing the stress on local services and impact on traditional lifestyles. Increases in the populations of Fort Norman (Tulita), Wrigley, and Fort Simpson were due to natural increases and normal levels of migration.

4. Would increased participation in the wage economy result in the destruction of aboriginal culture and traditional activities?

Consumption of country food increased slightly during the project. Although incomes rose, income level did not seem to have a bearing on the amount of country food consumed. In 1985, 60% of aboriginal households earning more than CAD 30 000 per year consumed medium to high amounts of country food in their diets (Bone, 1985). Correspondingly, the number of trappers in the three predominantly aboriginal communities fluctuated but did not change significantly during construction.

Concerns were raised about how traditional pursuits were not directly considered and integrated with the economic planning developed to engage northerners on the project (Métis Association of the Northwest Territories, 1982; Dene Nation, 1986b). The opportunity to utilize and enhance traditional activities, through food supply, for example, could have helped to support the traditional economy at the same time.

5. Would an adequate amount of benefits from the construction of the project flow to local residents?

Determining what amount of benefit from an industrial enterprise is adequate is a value-based determination. Clearly there are different circumstances when comparing large industrial organizations with traditional, rural, and northern communities. As discussed, 22% of the labor force was aboriginal and household incomes rose during construction. There were minimal differences in income levels between the pre- and post-construction periods. The northern air commuting system facilitated northern worker participation on the project.

Local employment participation was correlated with community proximity to the project, project-specific training, and corresponding level of proximate development (Mahnic, 1994). Communities did express concern about the level of benefit provided from the project, and felt that their interests were not fully considered (Mar, 1985).

The introduction of industrial activity did spur many aboriginal organizations to enter into new forms of corporate arrangements for the first time. Sheetah Drilling was established and still operates today. Community-based organizations set up specific development corporations to manage business affairs. These development corporations entered into joint-venture business arrangements to combine local know-how and capacity with corporate expertise and capital.

Equity participation to ensure long-term benefits in the project was not realized, although offers were made (DIAND, 2001). The potential benefits realized from a 20% pipeline ownership offered to the Dene, as noted in section 3.2.5.2.1, would have provided a significant return of benefits to the region.

6. Would most of the benefits flow to southern Canada?

Given the large size of the project compared to the size of base economic activity in the region, it was anticipated that much of the total construction expenditure would be spent in southern Canada and outside of the region. Construction-related benefits did flow south, reflecting the local capacity of business to respond to a project of this scale and the nature of government taxation. Forty-six percent of the expenditures in the major community of Norman Wells 'leaked' to southern Canada, whereas 3% of the taxation and royalty revenues stayed in the north (Bone, 1984).

Over the long term, a small benefit stayed in the region. The GNWT collects property taxes on the pipeline and oilfield facilities. However, the federal government was the responsible authority for oil and gas management and received royalties at the time. The federal government's financing arrangement with the GNWT, which provides transfer payments to support regional government activity, set out a structure that limited the ability of the GNWT to retain those taxes (a formula including property and corporate tax) from the project.

The land claims agreements provide that Canada will make payments to the Dene and Métis equivalent to a share of the royalties that the Crown receives each year from oil and gas produced from the *Norman Wells* oil field.

3.2.5.4. Conclusions

The Norman Wells Project was an early lesson in Canadian history on the development of northern oil and gas resources. The project was being developed at the same time that a new Canadian Constitution was being considered, one which recognizes aboriginal rights. Efforts were made to build understandings and accommodations with local, aboriginal, and other interests with the project, an approach that had not been tried before.

The Norman Wells Project started out with a recommended delay to enable communities to build capacity so that they could participate in the project. In the end, the project was finished under time and within budget. The heightened desire of aboriginal people to seek increased benefits from this project are being reflected in today's application for a major 1.2 million cu ft (~34 000 m^3) per day gas pipeline through the Mackenzie Valley.

While the perceptions of the social and economic effects of the Norman Wells Project vary, a key lesson has been the development of mitigation and monitoring approaches. As a new form of activity in the north, such approaches were attempted to address social and economic concerns in ways not previously attempted in Canada. The Social and Economic Action Plan and Social and Economic Monitoring Program were initiatives aimed to mitigate and monitor the effects of activity on the local population.

3.2.6. The Ikhil Gas Project and the Mackenzie Delta region, Canada

3.2.6.1. The Ikhil Gas Project

3.2.6.1.1. Introduction

Developing a natural gas reserve for local markets, the Ikhil Gas Project became the first operation to develop and distribute gas north of the Arctic Circle in Canada. The project provides Inuvik residents and businesses with a secure supply of natural gas for electrical power and heat generation at a lower cost than diesel fuel that must otherwise be shipped 2500 kilometers from Edmonton, Alberta.

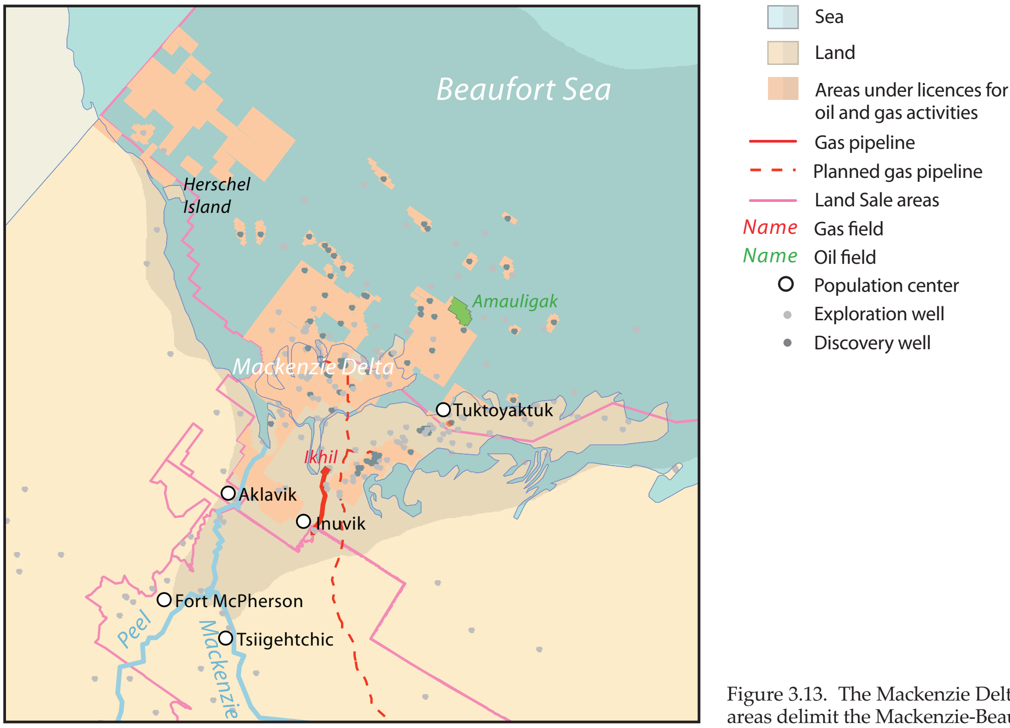


Figure 3.13. The Mackenzie Delta region (shaded land and sea areas delimit the Mackenzie-Beaufort Petroleum Province).

The project is based on Inuvialuit-owned lands at a site approximately 50 kilometers northwest of Inuvik (Figure 3.13). It is located in the heart of the Mackenzie Delta hydrocarbon basin, which contains an estimated 34% of Canada's remaining natural gas (Morrell, 2003). The Ikhil gas reservoir, 13.74 billion cu ft (~0.39 billion m^3), was discovered in 1984 by Gulf Canada as the initial sixteen-year long oil and gas exploration boom in the region was beginning to wane. The gas from this reservoir was clean (99.9% methane) and needed no further processing prior to being used for local gas distribution.

The discovery was on an exploration license issued before the settlement of the Inuvialuit land claim interests, and is now in the middle of an Inuvialuit land block. The Inuvialuit-owned Inuvialuit Petroleum Corporation (IPC) acquired the federal government's interest in the field in 1985 as part of the Crown rights transferred through the Inuvialuit Final Agreement. The 25% federal interest in the field derived from the Crown back-in provisions of the National Energy Program. The IPC bought the remainder of the field in 1993 from Shell Canada as part of its strategy to develop local gas for local markets. In 1996 the IPC announced plans to reopen the original well and test the reserves for the potential supply of gas to Inuvik.

Two key supply agreements were reached to gain financing for the project. The local Northwest Territories Power Corporation came on as the first major customer, agreeing to convert its diesel-powered electrical generation facility to use natural gas. Inuvik Gas Ltd. (the project's distribution company) negotiated a natural gas distribution franchise agreement with the Town of Inuvik in 1997.

The Ikhil Gas Project was designed to use a 50-kilometer long, 15-centimeter diameter natural gas pipeline into Inuvik. One hundred days of construction on the frozen tundra in the early winter of 1999 completed the pipeline, production facility, gas gathering system, and two new gas wells. Total project cost was approximately CAD 44 million, equally split among the three joint venture participants – the IPC, AltaGas, and Enbridge Inc. That summer, a 25-kilometer long gas distribution system for local retail customers was installed throughout Inuvik. By 2004, Inuvik Gas had approximately 80% of the market for heating fuel.

The project marked a return of the oil and gas industry after a significant hiatus from the boom times of the 1970s and 1980s. The return came through the initiative of the Inuvialuit to secure the rights and develop the first gas production project in the Canadian Arctic, establishing their new leadership role in the future development of the industry.

3.2.6.1.2. Responses

Key responses to address the Ikhil Gas Project are detailed through changes to the components of and adaptations to the social and economic system for a development-phase activity. This section focuses on both the industry approach to facilitate responses to the project and regional preparedness and changes to address the project requirement.

3.2.6.1.2.1. Long-term preparation to fully participate in the oil and gas sector

The IPC worked towards its long-term vision to develop the capacity to invest in and develop gas projects in the Inuvialuit Settlement Region. The IPC was created one year after the settlement of the Inuvialuit Land Claim as part of the Inuvialuit Regional Corporation's group of companies. The IPC aimed to become a profitable, medium-sized, diversified, and integrated petroleum company. Initially, it successfully developed oil and gas properties in southern Canada.

The Inuvialuit Regional Corporation's group of companies also includes the Inuvialuit Land Corporation, Inuvialuit Investment Corporation, and the Inuvialuit Development Corporation (IDC). Its mandate is to preserve and increase financial compensation, distribute a portion of earned income to beneficiaries, manage Inuvialuit lands, manage economic, social, cultural, educational, training, and employment programs for the benefit of Inuvialuit, and to provide technical and administrative support to community corporations.

The IPC set out to build its commercial capacity to play a major role in the Western Arctic petroleum industry when interest in oil and gas exploration returned to the region. After building significant experience and profitability in southern Canada, the IPC began to take the steps necessary to produce and distribute local gas reserves for local markets. In 1989, the IPC saw that the education and training of Inuvialuit for staff and management positions were of fundamental importance. The IPC was mandated to design a training program to "increase the number of graduates from high school and provide counseling and infrastructure for college and university students."

The IPC initiative fostered the creation of the Inuvialuit Education Foundation, which today provides education assistance to enable beneficiaries to access and complete post-secondary education. The Foundation was endowed by the IPC and the Inuvialuit Regional Corporation. Today, donations from industry and the Inuvialuit group of companies support the foundation. By 1993, the IPC had 16 full-time Inuvialuit employed in the oil and gas industry under its Work South program.

Governments played a critical role in supporting the Inuvialuit approach to the project. The federal and territorial governments provided grants of over CAD 1.5 million, or close to 10% of the initial budgeted costs (5% of the final) to IPC to develop the prospect. The territorial government and the IPC developed the Inuvik Conversion Incentive Program to partner with residential customers to share, three ways (IPC, Territorial Government, customer) the costs for converting from home heating oil to natural gas (up to CAD 1300 each).

3.2.6.1.2.2. Ensuring benefit opportunities

Benefit opportunities from project developments are secured through Participation Agreements that are tied to rights for access to/on Inuvialuit-owned lands. These agreements can include provisions for covering costs of permitting and inspection, wildlife compensation, habitat restoration, impact mitigation, employment, service and supply contracts, education and training, and equity participation or other similar types of participatory benefits.

The Inuvialuit Land Administration negotiated a Participation and Access Agreement with the IPC (Inuvialuit Land Administration, 1997). Federal Benefits Plan interests in ensuring benefits to northern Canadians as a whole, through the Canada Oil and Gas Operations Act, were satisfied through the Inuvialuit Land Administration agreement with IPC.

The Participation Agreement set out terms to ensure social and economic benefits by ensuring employment, training, and business opportunities for Inuvialuit and Inuvialuit-owned businesses. Employment opportunities were facilitated by IPC best efforts to identify and advise Inuvialuit of employment opportunities. They prepared an Employment Plan to enable people to plan for opportunities and to set out employment targets. A minimum wage of CAD 13.00 per hour for work by the IPC was established, compared with an NWT-regulated CAD 7.00 per hour. Employment opportunities were granted first to Inuvik-based Inuvialuit and secondly to all other Inuvialuit. Training and skill development were undertaken in consultation with the Inuvialuit Land Administration and other Inuvialuit institutions to optimize training opportunities.

Specific business arrangements were set out through the Agreement for the Inuvialuit group of companies controlled through the Inuvialuit Regional Corporation. Companies were to make supplies and services available at "competitive rates and in a timely manner" to the IPC. Specific business arrangements were set out, primarily, for IDC-owned companies:

- fixed-wing air transportation through Aklak Air;
- rotary-wing transportation through Inuvialuit Projects Inc.;
- camps, catering, and food supply through Stanton Distributing;
- expediting, heavy equipment, and light vehicles through locally owned businesses; and,
- marine and freight barge transportation through Northern Transportation Company Limited.

General business opportunities were provided on an IPC best efforts basis to identify and involve Inuvialuit people in business opportunities arising from the project. The IPC was to divide the work into small contracts and provide them with sufficient lead-time to prepare bids and to arrange financing and transportation of equipment to assist businesses in accessing and financing opportunities.

To ensure that all aspects of the development provide benefits, all project contractors and sub-contractors were to comply with the terms and conditions of the Participation Agreement with the IPC. A Review Committee was established to review and evaluate progress set out in the Agreement and to continue to identify training opportunities.

3.2.6.1.3. Effects

The project is a small-scale gas production and local distribution project with no reported negative social effects during construction or operations. The Ikhil Gas Project has proven the Inuvialuit's ability to develop local energy resources through the provisions of their Inuvialuit Final Agreement. Energy price, construction-phase, and business capacity effects are outlined below.

3.2.6.1.3.1. Cost of energy

The primary benefit associated with the project is the lower cost of energy for consumers in Inuvik. Over a 15-year period, the gas replacement of fuel oil will save the Northwest Territories Power Commission CAD 20 million. The Ikhil Gas Project originally aimed to provide energy at 15% less than the costs of (in situ) diesel-generated electricity and associated heat generation. An average residential customer was forecast (2004) to save CAD 700 per year on home energy costs. Pricing in 2004 was 22.5% less than diesel fuel costs.

3.2.6.1.3.2. Economic effects

A key focus of the Participation and Access Agreement was to maximize Inuvialuit employment and business opportunity. During the construction phase of the project, Inuvialuit beneficiaries undertook 41% of the work on the project and benefited from on the job training and skill development initiatives (Table 3.9).

Today, six of the eight employees running Inuvik Gas Limited are aboriginal, holding skilled, full-time positions with the company (Enbridge Inc. personnel, pers. comm., 2005). Two of the employees had developed their skills in the industry through the IPC's employment training and Work South initiatives and were able to find permanent work in the region.

Table 3.9. Construction phase employment.

	Total	Inuvialuit	Gwich'in	Other northern	Southern
Person-days	25 122	10 300	1000	1300	12 522
%	100.0	41.0	3.9	5.1	50.0

Inuvialuit Regional Corporation, Community Comprehensive Benefits Agreements. Annual Reports.

3.2.6.1.3.3. Business capacity

The approach to developing the Ikhil Gas Project led to an increase in Inuvialuit business capacity for the IPC and a number of the Inuvialuit group of companies. The project is owned equally by IPC (through its subsidiary Ikhil Resources Ltd.), AltaGas Services Inc., and Enbridge Inc., adding mid-stream and distribution expertise to the IPC's exploration knowledge. Each partner owns an equal share of Ikhil Gas Limited, which owns the reserves, wells, and production and gathering systems, and an equal share of the distribution company, Inuvik Gas Limited. The IPC's short-term strategy is to operate the Ikhil and Inuvik facilities and its financial assets in anticipation of opportunities to participate in oil and gas discoveries on Inuvialuit lands within five years. Today, IPC's assets are:

- Ikhil Joint Venture: One-third interest in two wells, processing facilities, and gas pipeline that supplies natural gas to Inuvik;
- Inuvik Gas Ltd.: One-third interest in the natural gas distribution system in Inuvik; and
- an investment portfolio of CAD 23 million, currently managed by the Inuvialuit Investment Corporation.

3.2.6.2. Mackenzie Delta Exploration 2000–2003

3.2.6.2.1. Introduction

Throughout the 1990s, the federal government issued annual Calls for Nominations soliciting expressions of interest from the petroleum industry for exploration rights in the Mackenzie Delta region. For several years, the calls received no responses from industry as world market prices were too low to support expensive frontier exploration. In 1999, with prices starting to rise along with concerns about future supply from established gas fields in southern Canada, the industry nominated lands of interest and responded positively to a Call for Bids for Exploration rights (see Table 3.10). Exploration licenses were awarded to two companies for exploration in different areas throughout the Mackenzie Delta. The companies total work bid commitments that secured their license totaled more than CAD 180 million.

By the winter of 2000 interest by the petroleum industry in the region was very high, and the subsequent Call for Bids resulted in the issue of nine exploration licenses over 9000 km^2 of land with work bid commitments totaling CAD 722 million.

The Inuvialuit also held a sale of oil and gas rights on their own lands in 2001, which resulted in bonuses paid to the Inuvialuit Regional Corporation (IRC) of CAD 75 million in addition to the work commitment bids. Altogether, work commitments made in 1999 and 2000 promised the drilling of 14 wells in the Delta region over the life of the exploration licenses.

The Gwich'in Tribal Council has not put any of the exploration rights to their sub-surface lands up for bid.

3.2.6.2.2. Exploration activity

The calendar year of 2001 spanned two winter drilling seasons and saw the return of drilling rigs to the Delta after an absence of ten years. In February 2001, Petro-Canada drilled the Kurk M-15 well at a cost of CAD 25 million using Rig #60, a new purpose-built, Arctic-class rig owned by Akita-Equtak Drilling, a joint venture of the IDC and Calgary-based Akita Drilling. The well was subsequently abandoned after testing during the following winter showed it held no commercial quantities of gas.

Three shallow and relatively inexpensive wells were drilled on Crown land in Gwich'in territory near the community of Tsiigehtchic. Junior exploration company Devlan Exploration took over the rights to three Exploration Licenses from the company that initially held them and that was about to let them expire at the end of March 2001. Devlan, using Akita Rig #14, started the first well at the beginning of February and managed to finish all three by the deadline.

Gulf Canada, which was purchased by ConocoPhillips later in 2001, conducted a test program at its Parsons Lake property in February 2001. Ten seismic programs were conducted, including four 3-D programs for Chevron Canada, two 2-D programs for Petro-Canada, one combined 2-D and 3-D seismic program for Devon Canada on Inuvialuit lands near Tuktoyaktuk, a similar one for Shell Canada on Crown land, and one 2-D program each for EnCana and Burlington Resources. Additionally, a marine seismic program in the Beaufort Sea was conducted in the summer of 2001 for Devon Canada, which acquired four exploration licenses in its takeover of Anderson Resources later the same year.

Table 3.10. Oil and gas lands held under license and value of work commitments.

	Thousand hectares of new Crown licenses [a]	Thousand hectares of new Inuvialuit licenses [b]	Thousand hectares of total Lands under License [c]	Crown License Value, CAD millions [d]	Inuvialuit License Value, CAD millions [e]	Total value, CAD millions
1998	0		1100			
1999	310		1300	180.0		180.0
2000	700	215	2015	467.0	75.0	542.0
2001	0		2015			
2002	50		2215	14.3		14.3
2003	0		2215			
2004	56		2271	61.8		61.8
Total	1116		2271	723.1	75.0	798.1

[a] Lands issued in Licenses (DIAND, 1998-2004); [b] Inuvialuit Lands Administration; [c] total Crown and Inuvialuit Lands under License. Lands do not total, some land relinquished; [d] Work bid for Crown license value; [e] Total cash bonus and work bid value for Inuvialuit License.

Three companies, Devon Canada, Petro-Canada, and Shell, conducted geochemical surveys on their respective leases, and Petro-Canada also sent a geological field party into the Richardson Mountains, west of Aklavik.

The winter of 2001-2002 was the busiest of the years considered in this case study. Four exploratory wells and three research wells were drilled in a four-month period beginning in very late December 2001. Devon Canada and partner Petro-Canada each drilled two wells, with one of the Devon Canada wells, Tuk M-18, resulting in an announcement of gas reserves of approximately 200-300 billion cu ft (~5.7-8.5 billion m^3). The other three wells were not successful.

The research wells were drilled by a Japanese company, Japex, on behalf of the Geological Survey of Canada and an international team of scientists. They were studying the feasibility of recovering and producing the abundant natural gas hydrates found at depths of nearly 1200 meters in the Delta region.

There were 15 seismic programs conducted to evaluate exploration licenses, five more than in the previous winter. Seismic programs are more labor intensive than drilling operations, meaning that even more people were employed in the region than during the winter before. Some 20 camps, including the main base camp at Swimming Point, owned and operated by Arctic Oil and Gas Services, a joint venture between the IDC and E. Gruben's Transport from Tuktoyaktuk, housed well over 1000 workers. Twenty-five percent of the workers were Inuvialuit, and an undetermined number were Gwich'in.

Nine of the seismic programs were 3-D, including an extensive 3-D project at Parsons Lake for ConocoPhillips. The other six were 2-D programs. Offshore, in August Devon Canada finished its marine seismic program started the summer before on its four exploration licenses, which had now been consolidated under one license. Other work in that same winter included a return of the geological field party into the Richardson Mountains, a geochemical sampling program, and two environmental field programs.

The following winter, 2002-2003, saw a marked decrease in activity as companies evaluated the large amounts of data collected in seismic programs from the winter before. Further, uncertainty about the costs associated with Canada's commitment to the Kyoto Protocol coupled with uncertainty about the likely in-service date for a proposed Mackenzie Valley pipeline meant that companies were reluctant to commit the huge amounts of money necessary for further Delta exploration.

Chevron Canada drilled one well, North Langley K-30, just 11 kilometers from Shell's Niglintgak property. This well proved to contain commercial quantities of gas, the first new discovery of gas onshore in more than 20 years. Devon Canada and Petro-Canada each drilled one well, both unsuccessful. For Petro-Canada, this well marked the end of its northern drilling exploration program for a few years.

The number of seismic programs was greatly reduced from previous years. EnCana had one 2-D program and one 3-D program near Tuktoyaktuk on Richards Island, employing 80 people. In addition to drilling, Chevron also conducted a seismic program on its Langley property.

In the Gwich'in Settlement Region near Tsiigehtchic, Devlan Exploration drilled one well and completed the three wells started in the 2000-2001 season.

3.2.6.2.3. Responses

According to IRC Chairperson Nellie Cournoyea, the key response to the rush of exploration activity (2000-2004) began years before with the negotiation and eventual implementation of the Inuvialuit Final Agreement in 1984, which established the basis for the Inuvialuit response to the 2000-2003 exploration rush. The settled claims, which came with millions of dollars of federal money as part of the settlement, also gave the Inuvialuit and Gwich'in the financial capability to start businesses of their own under their respective development corporations, either through outright ownership or through joint venture partnerships. Control over business development meant each group was developing the financial means to address some social issues such as education, childcare, training, and employment.

Responses to specific issues fell into a number of categories such as business development, education and training, long-term participation in petroleum exploration and development and partnerships, to name but four of the main ones.

3.2.6.2.3.1. Business development

The mandate of the IRC is to preserve and increase financial compensation, distribute accumulated wealth to beneficiaries, manage Inuvialuit lands, manage economic, social, cultural, educational, training and employment programs for the benefit of Inuvialuit and to provide technical and administrative support to community corporations. The IRC saw that the best way to do this was to develop businesses that would employ its land claim beneficiaries, and to earn income through the development corporation's subsidiaries and joint ventures.

Thirty years of exploration meant that the Inuvialuit were very much aware of the rich potential for oil and gas development and eventual production, both onshore and offshore. Accordingly, one of the IRC's long-term goals was to develop the capacity to invest in and develop petroleum projects in the Inuvialuit Settlement Region. One year after the claim was settled, the IRC created the IPC with the aim to have it develop into a profitable, diversified, and integrated oil company. In its early years, it successfully developed oil and gas properties in southern Canada. By 1993, the IRC saw the IPC as the vehicle with which to develop the Ikhil Gas Project, and eventually divested it of some of its southern holdings in order to invest in the project.

Even before the land claim was implemented, the IRC was looking at getting into the petroleum service industry. Inuvialuit have drawn upon established federal programs for capital funding to help initiate their investment in several key enterprises, such as drilling rigs. Through the IDC, it signed a joint venture agreement with Atco Drilling in 1983 to form what eventually became Akita Equtak Drilling. Akita Equtak now owns three purpose-built, Arctic-class drilling rigs, two of which have been used to drill all of the exploration wells in the Inuvialuit Settlement Region since 2001. The third has been employed by Akita to drill wells in Alberta where there was enough exploration activity to keep it fully employed. The IDC's investment in these rigs was CAD 25 million in 2000.

The Inuvialuit were quick to respond in 2000 when it became apparent that the oil and gas industry was renewing its interest in exploration in the Mackenzie Delta. In addition to its investment in Akita Equtak, the IDC began laying the business foundations to position it to take advantage of the northern oil and gas industry as it developed. The company formed partnerships or started companies to get involved in environmental consulting work, logistics and transportation, surveying, camps and catering services, and oilfield services. In some cases the partnerships were with other Delta area companies such as its Arctic Oil and Gas Services joint venture with E. Gruben's Transport from Tuktoyaktuk. In other cases, the IDC formed partnerships with multinational companies, such as the creation of Inuvialuit Oilfield Services with Schlumberger.

In 2000, the IRC held a sale of oil and gas rights on their own lands, the first time they had done so. Chevron Canada bought rights for the Inuvik #1 and #2 blocks, Petro-Canada bought the rights for the Tuktoyaktuk #2 blocks, and Anderson Resources bought the rights to the Tuktoyaktuk #3 block. The sales allowed the purchasers rights for an initial ten-year term with two five-year renewals, and gave the IRC options to buy-in on discoveries, royalty payments, and guaranteed employment. The sales resulted in bonuses paid to the IRC of CAD 75.5 million in addition to the work commitment bids.

Land management needs increased after the sale of these leases. More staff were hired for the Inuvialuit Land Administration and more than 40 land claim beneficiaries from Aklavik and Tuktoyaktuk were trained to work as environmental monitors. Several worked for the Inuvialuit Land Administration or for seismic companies conducting programs the following winter.

Gwich'in participation in the oil and gas sector did not have the advantages of a settled land claim during the 1980s. By the time oil and gas activity returned, however, the Gwich'in claim had been settled, providing new tools such as the Gwich'in Development Corporation to facilitate their participation. While oil and gas are not as prevalent in the Gwich'in territory, the Gwich'in have nonetheless been active in developing a strong business presence based out of Inuvik.

3.2.6.2.3.2. Education and training

The objectives of Section 16 of the Inuvialuit Final Agreement (Government of Canada, 1984) seek to encourage economic self-reliance for beneficiaries through education, employment, and training programs. In addition to addressing post-secondary education needs through the Inuvialuit Education Foundation, the IRC sought to improve employment opportunities for beneficiaries in the oil and gas sector.

Through Akita Equtak, the IRC was instrumental in establishing a rig-hand training initiative in 2001. Although many Inuvialuit and Gwich'in individuals had worked in the industry during the 1970s and 1980s, the long gap in activity during the 1990s meant many were no longer interested in working on drill rigs, were too old for rig work, or had skills that were outdated. The initiative was a collaboration of several industry companies that made donations of cash, equipment such as a drilling rig and a smaller service rig, supplies such as drilling mud, and facilities such as the new camp that was used for the duration of the school session. Additional funding and participation came from the federal government and the territorial governments of Yukon and the Northwest Territories, plus the expertise of Aurora College in Inuvik, which set up the program and ran other oil and gas courses itself. Planning was completed by early July 2001 and by the end of the summer 85 individuals – Inuvialuit and Gwich'in beneficiaries and aboriginals from other NWT regions and from the Yukon – were trained to work on a drill rig. Many found jobs during the following winter's activity.

Industry saw sobriety and job training to be of paramount importance, especially after two fatal accidents during the winter of 2001–2002. Job offers to work on rigs, seismic programs, and in the camp facilities were made to people after they had successfully passed drug and alcohol testing. Once hired, workers were given safety training, first aid training, hazardous materials handling training, and equipment handling instructions. Workers willing to fly to Edmonton, Alberta, were given more advanced training at the industry-sponsored Petroleum Industry Training School.

The emphasis on training and sobriety extended to any contractors and sub-contractors supplying services and labor to the industry exploration companies. SHARE – Safety, Health and Respect for the Environment – was a joint initiative of industry, government, and the Inuvialuit and Gwich'in. It was started to ensure that minimum safety standards and operating procedures were implemented on every industry-related worksite in the Delta.

3.2.6.2.3.3. Long-term participation in the oil and gas sector

Renewed interest in Delta exploration also revived interest in building a natural gas pipeline. First proposed in 1974, the pipeline route traveled along the Mackenzie Valley from Inuvik to Alberta where it could tie into existing natural gas transportation infrastructure. Four companies holding Significant Discovery Licenses in the Mackenzie Delta, originally granted in the early 1970s – Imperial Oil, Shell Canada, ConocoPhillips Canada and Exxon Mobil Canada, known collectively as the Producers Group – completed a feasibility study in late 2001. In January 2002, they announced their intention to proceed with the pre-development work needed to file a comprehensive regulatory application and environmental assessment for construction and operation of a Mackenzie Valley pipeline, a gas gathering system in the Delta, a gas treatment facility at Inuvik, and a natural gas liquids pipeline from Inuvik south to Norman Wells.

These applications were subsequently filed on October 7, 2004, moving the project into the regulatory and environmental review phase, which is expected to be completed in 2008. The entire development is known as the Mackenzie Gas Project. The pre-development phase is anticipated to cost more than CAD 250 million by the time the decision to construct the project is made. That decision is expected some time in 2009, pursuant to the issue of environmental and regulatory permits. The entire project is expected to cost more than CAD 7 billion, and is planned to be operational by 2010.

The Delta portion of the project is anticipated to have impacts on the area during construction of the gas gathering systems, related production facilities, the gas conditioning facility in Inuvik, and the start of the Mackenzie Valley pipeline that will begin at the Inuvik gas facility. Several thousand skilled and unskilled workers will be needed during the construction period, expected to last three winter seasons. Efforts are being made now to try to mitigate the impact on local people, social services, business, housing, infrastructure, and supplies.

The anchoring fields, *Taglu*, *Niglintak* and *Parsons Lake*, will be developed on Crown lands and the gas gathering and processing system will be on Crown and Inuvialuit Lands. The Inuvik Area Facility, to process sweet natural gas and natural gas liquids, is to be located on Gwich'in traditional lands. The project has the potential to be operational for 25 years or longer, meaning that business development, education, and training opportunities will continue for at least that long for both the Inuvialuit and Gwich'in beneficiaries, as well as other northerners and indeed all Canadians.

It should be noted that without transportation infrastructure to move natural gas to southern markets, there will be neither further exploration nor any development of facilities or gas gathering systems in the Mackenzie Delta. With the average Delta exploratory well costing CAD 25 million or more, and 2-D and 3-D seismic programs costing several times more than the equivalent programs in Alberta, exploration costs are too high to continue without the guarantee that production would follow and a return on investment could be made within a reasonable length of time. Should oil and gas activities cease, the economies of the Inuvialuit and the Gwich'in would suffer tremendous downturns and unemployment rates would reach the levels seen throughout the 1990s when there was no petroleum exploration and very little of any other kind of economic activity.

3.2.6.2.3.4. Collaboration and partnerships

The re-introduction of the oil and gas industry into the region came with a more collaborative and partnership-based approach. The lessons learned and level of local employment participation seen in the last exploration phase led to the development of the Inuvik Regional Training Partnership, which brought in members from all orders of government and industry to set out approaches to train local people to take advantage of employment and career opportunities. The partnership structure enabled parties to bring forward training ideas that were outside specific industry needs, including personal financial management courses and other family and community issues that were limiting people's access to training and employment.

The Town of Inuvik took a leadership role in bringing the parties together by hosting the now-annual Inuvik Petroleum Show. The 2005 show sold out at a capacity of 700 and covered topics ranging from exploration updates to managing social issues. All sessions had representation from key parties of industry, government and communities.

In January 2000, aboriginal leaders from across the Northwest Territories met in Fort Liard to discuss the renewed interest in the Mackenzie Valley pipeline and the possibility of owning all or part of it. Negotiations began later that year between the Aboriginal Pipeline Group and the Producers Group, resulting in a Memorandum of Understanding in 2001 that set potential aboriginal equity ownership at one-third of the pipeline.

The Inuvialuit and the Gwich'in remain active participants in the Aboriginal Pipeline Group. Each group has two members on the Aboriginal Pipeline Group's Board of Directors, which also has members who reside in the other regions in the Mackenzie Valley through which the proposed pipeline will pass. The present Chair of the board is the Gwich'in Tribal Council President.

3.2.6.2.4. Effects

The new series of exploration licenses issued in the Mackenzie Delta region have created short-term natural, economic, human, and social resource effects that can be assessed during the exploration activity itself. Data available to assess activity are largely secondary and do not cover all four years under this case study.

3.2.6.2.4.1. Natural

The land area under disposition as exploration, production, or significant discovery licenses in the Mackenzie Delta region increased between 1999 and 2004. The Crown lands held under license increased from 1.3 to 2.1 million hectares.

3.2.6.2.4.2. Economic

The expenditures from exploration activity over the 2000 to 2004 seasons showed the variance of capital expenditure, growth in Inuvialuit participation, and displacement effects of new and temporary spending in the region.

Contract work expenditure in the region varied from CAD 78 million in the early winter months of 2001 to CAD 310 million the following winter, which was over 10% of the gross domestic product of the entire Northwest Territories (Table 3.11).

Inuvialuit-owned or -controlled business participation as prime or sub-contractors ranged from 42% to 78% of overall contract expenditure. As the exploration cycle developed, Inuvialuit business participation increased in project activity. The rapid growth of contract expenditures in the region had an employment and trade availability displacement effect on existing hospitality, community, and service sectors. These sectors had difficulty keeping and replacing workers at competitive wage rates and accessing trades to undertake work.

Employment in direct exploration-related activity showed a significant base level of Inuvialuit and northern worker participation. Involvement in project activity ranged from 25% to 36% for Inuvialuit beneficiaries. As the total number of person-days of employment declined, the ratio of Inuvialuit

Table 3.11. Contract work expenditure reported as part of the companies' Participation and CCBA Commitments (IRC, 2000–2004).

	Value, CAD millions	% Inuvialuit participation
2000–2001 [a]	78.329	58.0
2001–2002 [b]	310.471	62.4
2002–2003 [c]	101.550	42.0
2003–2004 [d]	88.291	75.0

[a] Reported as 'Total Spent on Goods and Services'; [b] participation of subcontracting not calculated; [c] net participation (contracts minus subcontracts to non-Inuvialuit companies); [d] net participation not subtracted from totals.

Table 3.12. Employment (IRC, 2000–2004).

	Total person days	% Inuvialuit	% Gwich'in	% other northern	% southern
2000–2001 [a]	7 511	23.4	n/a	7.7	68.9
2001–2002	197 855	25.1	n/a	19.0	55.9
2002–2003 [b]	94 066	34.0	6.0	17.0	43.0
2003–2004 [c]	42 983	36.0	5.0	8.0	51.0

n/a – Not available; [a] not adjusted to new construction data; [b] no employment data reported. Gwich'in employment totaled 6%; [c] Gwich'in employment totaled 5% (5 out of the 13% northern employment).

Table 3.13. Percentage participation and employment rate, Inuvialuit Settlement Region.

Inuvialuit Settlement Region[a]	1994[b]	1999[c]	2002[d]
Participation rate	60	66	66
Employment rate	40	46	47
Unemployment rate	33	30	27

[a] Data not available to separate out key Gwich'in communities; [b] GNWT (1994); [c] GNWT (1999); [d] GNWT (2002b).

Table 3.14. Overview of the social and health impacts in Inuvik from recent oil and gas development.

Positive impacts	Negative impacts
Increase in self esteem and self worth	Increase in substance abuse, gambling, crime, violence, family breakdown, suicide rate has increased dramatically for the month of May
	More displaced people both male and female
Increase in local people accessing home ownership	Lack of affordable housing, overcrowding
Increased employment and family income	Shift in priorities from wellness and healthy families to making money by leadership, governments, aboriginal organizations and community members
Employment opportunities for students upon completion of coursework both at a high school and college level	Students not completing courses to go to work, both at high school and college level
	Inability to compete with wages of the industry causes difficulties in hiring for local organizations, governments and businesses
Increase in understanding of the importance of traditional activities e.g. on the land programs for high risk youth	Lack of appropriate and affordable childcare and safe places for children and youth; increase in child protection cases
Increased support for the importance of education	
Collaboration between governments, aboriginal organizations and industry to identify, develop and provide local training	No protocol to deal with industrial accidents (Critical Incident Stress Debriefing)
Much more awareness related to social impacts compared to the previous 'oil boom'	Increase in the demand for services for most service providers during time off from work and upon completion of seasonal work
	A lot of talk, but no action plan to address the social impacts in a coordinated manner
Health services, educational facilities, infrastructure (better communications and social services, etc.)	Burnout of service providers such as family counselors at Turning Point

note: Based on feedback from: Family Counseling, RCMP, Transition House, Inuvik Housing Authority, Clergy, Health, GNWT Health and Social Services, Turning Point, Social Services, Ingamo Hall, Aurora Campus, NWT Training Center, Inuvik Justice Committee.

workers increased suggesting a core number of available beneficiaries to participate in the activity (Table 3.12).

3.2.6.2.4.3. Human

The level of employment, overall participation in the workforce, and level of training increased during the exploration cycle. The number of residents in the Inuvialuit Settlement Region participating in the wage economy increased from 60% to 66% over the period of little or no exploration activity to the return to activity in 1999 and 2002 (Table 3.13). The overall unemployment rate decreased from 33% to 27%.

Inuvialuit beneficiaries showed an increased interest in training as the level of exploration increased. The number of post-secondary training applications from Inuvialuit beneficiaries increased from an estimated 75 in 2002 to approximately 175 in 2004, reflecting the increased awareness of and interest in developing improved skills and job position from the industry (IRC Human Resource Team, pers. comm., 2005).

The opportunity of employment for Inuvialuit beneficiaries was limited by a number of factors, including (IRC, 2004a):

- absence from workplace (failure to report);
- drug and alcohol issues;
- lack of child care;
- personal problems;
- camp living;
- lack of training opportunities; and,
- lack of training for advancement.

3.2.6.2.4.4. Social/health/cultural

In 2001, the Inuvik Interagency Committee undertook a review of the social and health effects of recent oil and gas activity in Inuvik as a result of the return of oil and gas development in the region. The Committee found a range of social and health impacts reported by social service agencies (Table 3.14).

A primary social concern is substance abuse, referring both to the relationship between an increase in development activity and abuse and to the relationship between substance abuse and other offenses (Devon Canada, 2004: 7-48). A number of factors are seen as contributing to these concerns, including rotation and mobility of work and level of community concern.

Comparing the relatively inactive 1999–2000 winter with the activity of 2002 shows an increase in alcohol use and related offenses but does not show the cause or causes of the increase. Table 3.15 shows the overall increase in recorded offenses per 1000 population. The data can serve as indicators of the degree of family dysfunction and the weakness in community social controls. While the data do indicate that offense rates were substantially higher, comparisons to communities with little mobility into the oil and gas sector showed similar trends. The nature of the factors leading to the increase in all communities is unclear.

The increase in exploration activity was likely to have been a large contributor to the decline in income support payments in the region. While the mid-1990s saw a relatively stable flow of income support, there was a drop in payments made in 2000–2002 (Table 3.16).

The traditional patterns and influences of harvesting are pre-empted by movement into and out of seasonal wage employment. The timing of the exploration season, most intense between January and April, coincides with some harvesting activities undertaken across frozen land and ocean. Cumulative influences of English-based training, decline in aboriginal language use, mobility for wage employment, and low returns from trapping all influence the traditional cultural and subsistence practices. The time frame of this exploration cycle is too short to assess the overall effect from oil and gas activity.

3.2.6.3. Conclusions

3.2.6.3.1. Preparing for the future, respecting tradition

The return of oil and gas activity to the Mackenzie Delta region started locally, with the IPC taking on the Ikhil Gas Project in the mid-1990s. By 2000, with changes in natural gas supply, significant bids were made to resume exploration in the region, on both Crown and Inuvialuit Lands. Preparations to address the social and economic effects of oil and gas activity were made with lessons learned from historic industry cycles in the region and the development of new institutions that govern and regulate activity.

The goals of the Inuvialuit and the Gwich'in settlement agreements recognized the need to address traditional and cultural values while working with new opportunities. They aimed to protect cultural identity and values within a changing northern society while enabling participation in the modern and traditional economies. From these agreements, new legislation and management boards were established to recognize these values and provide local participation in the development outcomes in the region. Both Gwich'in and Inuvialuit leaders are active today in preparing for the future while respecting traditions:

> *"This time, northern aboriginal people are at the planning table. In a sense, we are now wearing two hats. One hat we wear identifies our traditional role as guardians and stewards of the land. The other hat represents our emerging role as business opportunity developers…*
>
> *Protecting the land is a top priority. We also have a responsibility to develop an economic base for our children and grandchildren. I lived in a tent as a teenager. I know what it is like to chop wood and haul it by dog team. But my grandchildren will never make their living from the land. That part of our world has changed forever. That's why I am determined to take advantage of the economic opportunities that controlled, responsible resource development will bring."* (Fred Carmichael, President of the Gwich'in Tribal Council and current Chair of the Aboriginal Pipeline Group. Message from the Chair: *http://www.mvapg.com/page/page/2501879.htm).*

> *"We have already seen the hustle and bustle of oil and gas exploration and its impact on our people. The last time around it had come and gone in less than twenty years.*
>
> *Now, two decades later we are better prepared to meet this oncoming development head on and benefit from it. Our claim has given us the means to ensure we are full participants in the many economic opportunities that have already begun.*
>
> *IRC and the business members of the Inuvialuit Corporate Group have worked diligently during the past year to provide beneficiaries with employment, training and business opportunities wherever the oil and gas industry is active in the Inuvialuit Settlement Region (ISR). This will continue to be one of our primary and collective goals for 2001 and beyond.*
>
> *While recognizing the importance of obtaining the economic benefits from this renewed activity, IRC must also play an active role in ensuring the associated social impacts on our communities are both recognized and given adequate attention."* Nellie Cournoyea, Chair and CEO of the Inuvialuit Regional Corporation (Inuvialuit Development Corporation, 2000).

3.2.6.3.2. Courage to take leadership in the industry

Regional organizations have made steps to invite industry back, after gathering the courage to take proactive steps forward (Russell Newmark, former President of the IPC, pers. comm., 2006). The Inuvialuit have entered into concession agreements on their land and led and partnered in the Ikhil Gas Project. The Gwich'in leader Fred Carmichael has taken a central role in promoting the Aboriginal Pipeline Group's ownership option in the Mackenzie Valley Pipeline and the development of a potential aboriginal construction consortium to build the project. The Town of Inuvik has helped lead the return by facilitating key partnerships and hosting the Annual Inuvik Petroleum Show, which attracts over 700 participants.

The ability of companies in the region to successfully develop and complete exploration projects and northern Canada's first residential energy distribution system point to an increased capacity and corporate sustainability to identify and take on projects. The Ikhil Project required convincing an anchor tenant to subscribe to the project, finding two financial and technical partners to participate, the regulatory capacity to gain project approvals, and the concurrence of beneficiaries and community members that promoting and undertaking a risk-capital enterprise was in people's interest.

3.2.6.3.3. Social and economic effects remain a core focus

As people of the region have seen exploration activity on a large scale, they now are benefiting in a long-term way from the development of the resource. Local employment and contract participation increased during the Ikhil pipeline development and the return of industry exploration to the region. The standard of living improved with the relative drop in energy prices (CAD 700 per household less than the cost of diesel). Exploration booms have traditionally raised prices in the region; this activity has helped to lower the cost of living.

The challenge to maintain cultural integrity while encouraging industry remains, and is evident in the issues and debates that occur in project reviews.

Table 3.15. Percentage increase in offenses between 1999 and 2002 for selected offenses, fourth quarter rates, selected NWT areas (RCMP Statistics, 1999 – 2002).

Study area	Year/4th Quarter	Alcohol offense	Drug offense	Spousal assault	Young offenders
Beaufort Delta Region	1999 – 2002	167	125		194
Inuvialuit Settlement Region	1999 – 2002	149	n/a	128	126

Table 3.16. Annual per capita income support payments (CAD) (Devon Canada, 2004: 7-30).

	1998	1999	2000	2001	2002
NWT	318	310	259	214	210
Inuvik	470	429	334	257	238
Tuktoyaktuk	713	607	364	235	194
Fort McPherson	499	501	383	206	132

"We had a robust traditional and renewable resource economy at the time that oil and gas showed up in the 1970s. We wanted to continue this and use the oil and gas industry as an opportunity for the renewable resource industry. We set up the Fort Mcpherson Canvas Shop, undertook activities with the muskox herd and qiviik [highly prized wool from muskox], developed freezers in the communities so we could harvest, store and sell fish and game. We wanted to capture those not interested in oil and gas and give them an opportunity. However, the focus and drive for training funding seemed to be towards oil and gas almost exclusively." Nellie Cournoyea (Chair of the IRC, pers. comm., 2005).

Effects on social well-being and community wellness fluctuated with the transition into and out of the exploration cycle. The Inuvik Interagency Committee reported on the positive and negative effects observed by key social service agencies during the exploration phase.

"One concern with impact assessments is the tendency to focus on negative social effects. With the Devon wells in 2001-2002 we wanted to address that, we organized a six to seven month work season for people from Tuktoyaktuk by aligning training programs, work rotations and clean up, as compared to shorter six to eight week jobs. This longer-term employment approach showed real positive social effect – ask the RCMP". Russel Newmark (Former President of the IPC, pers. comm., 2005).

Ikhil's contribution to an increased sustainability of the Mackenzie Delta region can be counted in many ways. The cleaner-burning natural gas has made a noticeable difference in the air quality in Inuvik, according to local residents, especially during the cold winter months. Annual reduction of carbon dioxide emissions is forecast to be 12 500 tonnes, improving the overall air quality in Inuvik.

3.2.6.3.4. Developing capacity to lead and respond

After a period in which the role and rights of different regional organizations was established for work to do with land claims and devolution of federal powers to regional governments, organizations are now setting out and building external partnerships (IRC, 2004a). The IRC hosts an annual series of meetings with industry in June each year to review progress and address concerns and identify solutions.

Organizations have been working to develop capacity to respond and to partner with other key organizations for help in delivering programs and training. Local and site-specific training was provided during the construction of Ikhil and with other exploration projects. A key, multi-year, CAD 14 million oil and gas training partnership (government/industry/aboriginal) was established in 2004 that will help train aboriginal people in the Northwest Territories to take better advantage of oil and gas exploration and development activity.

AltaGas and Enbridge invested in Ikhil as they saw the value in establishing solid partnerships that would lead to building better regional capacity and more opportunities.

"The success of IPC demonstrates that aboriginal Canadians can work co-operatively and harmoniously with professionals within industry to develop viable and successful business corporations". Inuvialuit Petroleum Corporation Annual Report (1990).

Table 3.17. Desired outcomes in managing project social impacts, Inuvialuit settlement region.

- Minimizing negative project effects that will exacerbate current negative social trends and compound health and social problems at the individual, household and community levels.
- Balancing regional, territorial and national interests and responsibilities with respect to the project's positive and negative impacts.
- Distributing the project's social and economic benefits to the ISR and other northern regions and communities equitably, reflecting:
    - o the level of project activity in the area;
    - o the measures of related efforts required for mitigation of negative social effects in a region and community; and
    - o the potential burden and significance of unmitigated negative social impacts and the short- and long-term measures that are required to address them.
- Building social capital and strengthening social determinants of health and community well-being.
- Maintaining and strengthening social–cultural systems.
- Contributing to the social development of sustainable communities.

3.2.6.3.5. Identifying and setting out social and economic goals

Recognizing the need to help guide project effects, a set of desired outcomes was described in a recent Inuvialuit report (Table 3.17, IRC, 2004b). These outcomes provide a perspective and a challenge for all to address. Experience to date indicates that these goals are feasible, but will take continued cooperation and commitment by the organizations, agencies, and others involved in the region.

3.2.6.3.6. Developing review and monitoring mechanisms

The development of goals for the region and desired outcomes to manage social and economic effects shows signs of an increased focus in determining the future of the region while hosting industry activity. Developing follow-up systems to test the accuracy of and effectiveness of the social and economic measures can help all parties better see the pathway to achieve those goals.

The Inuvik InterAgency Committee has started undertaking informal reviews of the effects of activity (Inuvik InterAgency Committee, 2001). However, little work has been done to review and monitor the social and economic effects of oil and gas activity. This case study provides a small contribution to that effort.

3.2.7. Bent Horn, Canada

3.2.7.1. Introduction

The Bent Horn project was a small-scale, multi-year, onshore oil production and associated summer tanker transportation activity in the southern Queen Elizabeth Islands and adjacent Northwest Passage area of Arctic Canada. Between 1982 and 1999, the project progressed from conceptual development and planning, through information sharing, consultation and environmental and regulatory reviews and approvals, construction, twelve years of summer operations, followed by decommissioning, abandonment, and site clean-up.

The project produced oil from a single well in the *Bent Horn* field on Cameron Island (see Figure 3.11) and shipped the oil in a Canadian-owned, ice-strengthened oil/cargo vessel, M.V. *Arctic*, through Byam Martin Channel and into Melville Sound and Barrow Strait where often the oil was transferred to a conventional tanker for onward shipment to market. When necessary, M.V. *Arctic* had icebreaker assistance from the Canadian Coast Guard. Site decommissioning, abandonment, and cleanup activities on Cameron Island were conducted on a seasonal basis between 1996 and 1999 (Alexander, G., Retired Vice-President, Panarctic Oils Ltd., pers. comm., 2006; Graw, A., Former inspector, National Energy Board, pers. comm., 2006; Hornby, E., Regional Lands Manager, Northwest Territories Region, DIAND, pers. comm., 2006).

The project was conceived and operated by Panarctic Oils Ltd., a Canadian company controlled by Petro Canada Inc. Initially conceived in 1982, the project was formally proposed to Canadian federal government agencies in 1984 for review and approval. In early 1985, the project received government approvals, subject to various terms and conditions, several of which are highlighted here (DIAND, 1985). Later that year production and storage facilities were constructed on Cameron Island and seasonal oil production and shipping activities began (Panarctic Oils Ltd., 1986; Duguid, A., Former project engineer, Panarctic Oils Ltd., pers. comm., 2006). Most of the oil produced between 1985 and 1996 was shipped to Petro Canada's refinery in Montreal (Alexander, G., pers. comm., 2006). On occasion, *Bent Horn* oil was delivered to refineries in Denmark or France. Panarctic terminated the project in 1996 at the request of Petro Canada (Alexander, G., pers. comm., 2006).

The project was small in terms of the land footprint of the production and storage facilities, oil production, and tanker shipments. However, it demonstrated that onshore commercial oil production in the southern Queen Elizabeth Islands and the shipment of oil in an Arctic Ice Class III tanker into the eastern area of the Northwest Passage during late August and early September could be conducted safely. No oil was spilled during tanker loading, transfer and shipping activities (Alexander, G., pers. comm., 2006).

The project produced a profit for Panarctic and seasonal employment and service and supply contract opportunities for Inuit, other northerners and other Canadians and their businesses (Panarctic Oils Ltd., 1996; Alexander, G., pers. comm., 2006). The project enabled the Government of Canada to test and confirm its ability to coordinate the review, approval, and monitoring of small-scale Arctic oil production and associated summer tanker activities. The royalties received by the Government of Canada were commensurate with the seasonal nature and small-scale of the project.

The planning, consultation, review, and approval processes for the project began in 1982–1983 and provided opportunities for the four, predominantly Inuit, communities in the region to be kept informed and to influence project planning and government decision making. Panarctic, for example, shared its draft plans and regulatory application materials with the communities nearly a year before submitting them to government.

At the invitation of the federal Minister of Indian Affairs and Northern Development (Minister), for the first time the Government of the Northwest Territories was able to play a significant, but indirect, role in establishing the terms and conditions for the approval of a northern non-renewable resource development project (DIAND, 1985; Nerysoo, 1985). In addition, the territorial government obtained a commitment from the Minister that he would seek a mandate from the federal Cabinet to initiate negotiations regarding the transfer of oil and gas management responsibilities to the territorial level (DIAND, 1985). This commitment led to the signing of an agreement-in-principle between the Government of Canada and the GNWT in 1988 that set out a basic framework for a possible future northern energy accord between the two governments (Government of Canada and Government of the Northwest Territories, 1988).

By 1984, an embryonic High Arctic DIZ Society (commonly termed 'HADIZ'), established in accordance with the GNWT's Resource Development Policy statement of the previous year was in place for the Lancaster Sound area in the region. The communities of Grise Fiord, Resolute, Pond Inlet and Arctic Bay were members (Canadian Arctic Resources Committee, 1984a,b; Myers, B., Retired senior official, Project Development Division, Northern Affairs Program, DIAND, pers. comm., 2006). By this point, Panarctic already had fourteen years of direct and productive information sharing and consultative relationships with the four communities. Neither the company nor the communities wanted HADIZ's regional-level meetings to take the place of Panarctic's community-level visits (Alexander, G., pers. comm., 2006; Myers, B., pers. comm., 2006). Accordingly, Panarctic informed and consulted Inuit and other northern residents at both the HADIZ level and the community level as the company formulated and tested plans for the Bent Horn project.

3.2.7.2. The project

Beginning in 1982 and through early 1983, Panarctic identified and evaluated concepts for bringing one or more of its past oil discoveries into early production. The company was particularly interested in potential projects that could make use of the equipment, supplies and materials already on-hand at its Rea Point (Melville Island) supply base, including steel plates for a large storage tank.

The closest Panarctic-operated onshore oil discovery to Rea Point was the *Bent Horn* field on Cameron Island. Panarctic's West Bent Horn A-72 well, a 1976 discovery, was a potential source of light oil for seasonal production, short-term storage, and transportation via tanker to a refinery in southern Canada. Cameron Island had a Panarctic airstrip suitable for use by C-130 Hercules aircraft and, in an emergency, could be reached via another Panarctic airstrip. The island was close enough to Rea Point that personnel, equipment, supplies, and materials could be flown there at low cost.

Although summer ice-navigation conditions in the Cameron Island area were more difficult than along the normal resupply route to Rea Point, Panarctic's studies indicated that a suitably ice-strengthened tanker should be able to reach the island two years out of every three years. Initially, Panarctic considered having the same tanker that brought the company's annual fuel supply to Rea Point continue on to Cameron Island to pick up *Bent Horn* oil on its return voyage. It soon became apparent that a tanker capable of operating in much heavier ice conditions would be needed.

For economic reasons, Panarctic's project planners favored the use of an ice-strengthened tanker to transport oil from Cameron Island only to a northern location where lighter summer ice conditions were common, for example, in sheltered areas offshore of Polaris or Resolute. At such locations, the oil cargo could be transferred safely to a conventional tanker for onward shipment to a refinery. The tanker-to-tanker transfer would alleviate the need to charter an expensive Arctic Ice Class Zone III tanker for the entire trip from Cameron Island to the refinery. In 1983, Panarctic began discussions with shipping companies in Canada and elsewhere to locate a suitable ice-strengthened tanker. One possibility was M.V. *Arctic*, the Canadian-owned ore carrier that transported mineral concentrates from the Nanisivik mine on northern Baffin Island to European markets. The ship's owners were prepared to convert M.V. *Arctic* to an oil/bulk carrier and, with federal government assistance, to strengthen the hull so that the vessel would be able to operate safely in the heavy ice conditions near Cameron Island. However, no contractual arrangements with M.V. *Arctic*'s owners were in place when Panarctic filed its Bent Horn regulatory applications.

Panarctic planned to bring the Bent Horn A-02 well on Cameron Island into production, erect a large steel storage tank (18 000 m^3 capacity, i.e., sufficient storage for a tanker load of oil), build a protective berm around the tank, construct a small-diameter pipeline between the wellhead and the storage tank and install a flow line from the storage tank to the island's shoreline area.

Panarctic envisioned that the project would proceed in two phases. In phase one, sufficient oil would be produced each summer to support two or, possibly, three tanker shipments in late August and early September. The volume of oil produced and number of tanker trips each summer would vary according to ice conditions. In phase two, one or more additional storage tanks and tankers would be added to the project. Planning for phase two would not begin until near the completion of phase one.

Panarctic informed governments and communities that the project would not increase its existing employment needs or operating expenditures (Alexander, G., pers. comm., 2006). Rather the project would employ seven of Panarctic's long-time employees from southern Canada, most of whom were on layoff status; provide work for some long-time Inuit employees from the region's communities, Inuit who otherwise would be unemployed; provide business for the company's current catering and camp service contractors; and use equipment, materials and supplies already in the Arctic. The scale of the project, seasonal nature, and phased approach to implementing it were seen as compatible with the federal government's interest in demonstration projects and fully in keeping with the communities' opposition to year-round shipping in the Northwest Passage (Faulkner, 1984; Panarctic Oils Ltd., 1984).

3.2.7.3. Project review, approvals, reporting and monitoring

In October 1984, Panarctic applied to the Minister and to the Canadian Coast Guard for approvals to proceed with the project. Panarctic submitted a development plan, onshore contingency plan, and a benefits plan to the Minister and a marine contingency plan to the Canadian Coast Guard. Federal officials conducted an Initial Environmental Evaluation (Evaluation) of the proposed project in accordance with the then Federal Environmental Assessment and Review Process Guidelines. Following the Evaluation, the Minister determined that there was no need for a formal environmental assessment review panel to consider the proposed project.

The Minister designated a senior official of his department as the government pathfinder for the project (Myers, 1986). This was the first time that a pathfinder had been used for a northern non-renewable resource development project in Canada. At the direction of the Minister, federal officials consulted with officials of the GNWT throughout the review of the proposed development plan, benefits plan and contingency plans. Officials of both governments consulted jointly with HADIZ to ascertain the views of its member communities prior to project approval (Canadian Arctic Resources Committee, 1984a,b; Myers, 1984, 1985). The territorial Minister for Energy, Mines and Resources (GNWT Minister) and the Minister reviewed the advice received from HADIZ. HADIZ was concerned that phase one of the Bent Horn project, once approved, could lead to large numbers of tankers transiting Melville Sound and Lancaster Sound each summer, perhaps even year-round. HADIZ sought assurances from government that the Bent Horn project was not the thin edge of a wedge and that no increase in summer tanker traffic would be authorized without further review and public consultation.

The Minister considered it important that Panarctic provide Canadian shipping firms, including the owners of M.V. *Arctic*, with a full and fair opportunity to bid on the charter contract for the ice-strengthened tanker. The GNWT Minister wanted Panarctic to explore ways to use Arctic oil in the Arctic. Ministers and Canadian Coast Guard officials considered it was critical that the company refine its proposed contingency plans prior to project commencement.

Accordingly, when the federal Minister approved the development and benefits plans for the Bent Horn project in February, 1985, the terms and conditions included:

- a requirement for an environmental and socio-economic review of phase one of the project by the two governments prior to the commencement of phase two, i.e., there would no more than two to three tanker shipments of oil each year until this mid-project review had been completed;
- a requirement that Panarctic commit in its benefits plan to follow a formal 'designated item process' when qualifying potential bidders and requesting bids for the charter contract for the ice-strengthened tanker;
- an acknowledgement that the company had committed via recent correspondence with the GNWT to undertake studies of the potential use of Bent Horn oil in community and industrial electrical generating facilities in the region and, where there was interest, to undertake oil deliveries on a commercial basis for testing purposes; and
- a requirement that Panarctic complete the development of its proposed onshore contingency plan and submit it for approval prior to the beginning of construction.

In addition, the Canadian Coast Guard required that Panarctic refine and finalize its marine contingency plan to the satisfaction of the Canadian Coast Guard prior to the start of shipping activity. Panarctic was required to submit an annual report on its Bent Horn operations and shipping activities to the Minister and to keep GNWT officials informed of the results of its efforts to increase the use of northern businesses and to find a market in the region for Bent Horn oil. The company was expected to keep HADIZ and its member communities informed of activities and to place an Inuit observer on the tanker during the initial voyage to Cameron Island. Panarctic was required to arrange for icebreaker support for the first trip and, depending on the severity of ice conditions, for voyages to and from Cameron Island in subsequent years.

Soon after the project began operations, Panarctic applied for and received permission from government regulators to place twenty-six rubber storage bladders in an area protected by a berm on Cameron Island. This additional seasonal storage capacity helped to facilitate the second tanker shipment in years when ice conditions were favorable.

The volume of oil produced and the number of tanker shipments each summer between 1985 and 1996 did not trigger the requirement for a mid-project review. Phase two of the project did not proceed although Panarctic did give some consideration to the possibility of trucking oil over ice between Cameron Island and Rea Point to better facilitate increased tanker shipments.

Following Petro Canada's 1996 corporate decision to end the Bent Horn project, federal officials and inspectors approved and monitored the decommissioning, abandonment, and clean-up of the oil production and storage facilities on Cameron Island (Graw, A., Former inspector, National Energy Board, pers. comm., 2006). The facilities were disassembled and regulatory authorization was given for Panarctic to bury decontaminated materials. A large pit was blasted out of the permafrost on Cameron Island, filled with approved materials and appropriately capped.

3.2.7.4. Social and economic effects

3.2.7.4.1. Community and regional levels

The project had no apparent social and economic effects on the four communities, apart from generating some short-term employment opportunities for Inuit from Arctic Bay and Pond Inlet and increased business activity for a contractor in Resolute.

During the development of its regulatory applications and benefits plan, following the submission of its applications to government for project approval and throughout the project's construction, operations and close-out, Panarctic officials met several times each year with the four communities. In addition, the company met with HADIZ and kept it informed of plans and activities prior to project approval, soon after the M.V. *Arctic* had completed its first trip from Cameron Island and during the remainder of HADIZ's active life in the 1980s (Myers, 1985; Panarctic Oils Ltd., 1998). Panarctic and government officials participated in workshops with HADIZ in September 1984 and September 1985 (Myers, 1984, 1985).

Up to ten Inuit from Arctic Bay and Pond Inlet were employed for various periods during the 1985 construction period, during the subsequent installation of rubber storage bladders to augment oil storage capacity on Cameron Island and during the decommissioning, abandonment and site clean-up period. Most of the Inuit workers were employed at the Rea Point supply base in warehouse and expediting activities.

Panarctic endeavored to develop a market for *Bent Horn* oil in the region or elsewhere in the Canadian North. Initially, the company negotiated arrangements with the Northern Canada Power Commission and the Polaris mine to supply *Bent Horn* oil for test purposes. The Polaris power generation experiment required a single shipment of 5000 barrels (~795 m^3) of oil. The arrangement with the Commission required Panarctic to commit almost a million dollars for modifications to offloading, flow line, and oil storage facilities at Resolute. The Commission contracted to utilize *Bent Horn* oil in one of its diesel electrical generators there for a four-year test period (Alexander, G., pers. comm., 2006; Duguid, A., Former project engineer, Panarctic Oils Ltd., pers. comm. 2006; Greenslade, J., Former chief engineer, Panarctic Oils Ltd., pers. comm., 2006).

Ultimately, the Commission decided not to enter into a second contract. One consideration was that an unpleasant odor was produced when *Bent Horn* oil was burned in the Resolute power plant. There had been complaints from local residents. Additional capital expenditures would have been necessary to resolve the problem.

Panarctic used *Bent Horn* oil to fuel equipment, heaters and generators at its Rea Point supply base and at its exploratory drilling sites for several years (Anon., 1988). This in-house market declined as the company's exploration program diminished in the early 1980s (Greenslade, J., pers. comm., 2006). With Panarctic's cooperation, in the early 1990s the GNWT took the lead in examining the potential market for *Bent Horn* oil at mines in the Coronation Gulf region of the Northwest Territories, an area where one mine was in production and several others were under active consideration. The GNWT commissioned a study of the economic feasibility of building and operating a small topping plant at Bent Horn to produce diesel fuel for northern mines (North of 60 Engineering Ltd, 1993). The limited demand and the high transportation costs that would be incurred in supplying the mines made the proposition uneconomic.

During the decommissioning, abandonment, and clean-up of the production and storage facilities on Cameron Island, Panarctic offered to make the heavy equipment located there, such as a front-end loader, available at low cost to the community of Resolute, i.e., usually only a portion of the cost of a C-130 Hercules flight between Cameron Island and Resolute (Alexander, G., pers. comm., 2006). The Resolute community council responded positively and obtained a front-end loader for local use at low cost. Panarctic worked out an arrangement with a local contractor in Resolute whereby Panarctic paid 'in kind' for work at the Bent Horn site. The contractor was able to acquire nine C-130 Hercules loads of equipment, material, and supplies, ranging from heavy-duty tools to a fully equipped mobile camp (Kheraj, A., Manager, Southcamp Inn, pers. comm., 2006).

3.2.7.4.2. Territorial level

The Bent Horn project indirectly helped the GNWT to make progress towards several of its key objectives. The GNWT was able to obtain a Ministerial-level advisory role in the federal project review and decision-making process. In addition, the federal Minister acknowledged the GNWT's Resource Development Policy initiative, including the formation of DIZ societies, and the GNWT's desire to begin negotiations to transfer the responsibility for managing oil and gas to the territorial level. These were significant accomplishments.

The GNWT was successful in its efforts to encourage Panarctic to designate Yellowknife, Northwest Territories as an additional pickup and drop-off point for northern employees and as a loading point for food and other consumables from northern suppliers during the construction period. Later, Panarctic was able to demonstrate to GNWT officials that a stop in Yellowknife during the summer *Bent Horn* oil production period, when fewer supporting flights were necessary, increased aircraft fuel and aircrew costs to such an extent that it was not cost-effective.

3.2.7.4.3. National level

The federal government benefited from the Bent Horn project in several respects. The project provided an opportunity to test the environmental assessment and regulatory regime then in force. In particular, it enabled government to test the effectiveness of using a senior federal official as a pathfinder. The pathfinder successfully coordinated and expedited interdepartmental and intergovernmental project reviews and approvals at the policy level as well as the technical level.

The project demonstrated to industry, government and other observers, nationally and internationally, that small-scale seasonal Arctic oil production and shipping activities could meet with support from local residents when the northerners were involved in project planning and project reviews from the early stages. Commensurate with the scale and the seasonal nature of the project, the federal government received several hundred thousand dollars in royalties on the oil produced (Violini, L., Northern Oil and Gas Branch, DIAND, pers. comm., 2006). Canadian Coast Guard icebreaker escort assistance, when necessary, was provided on a fee-for-service basis.

3.2.7.5. Conclusion

The Bent Horn project is an example of a successful, small-scale, multi-year, Arctic oil production and transportation activity that progressed from concept to seasonal production and shipping through shut down and clean-up within less than two decades. The project provided an opportunity for the Government of Canada to demonstrate that federal government agencies had the ability to regulate small-scale onshore oil production and associated seasonal oil tanker traffic in the southern Queen Elizabeth Islands and the eastern part of the Northwest Passage. Industry was able to implement a profitable project without an oil spill or negative impacts on the region's four communities. Close cooperation among the proponent, governments and communities was a key factor as was the federal government's use, for the first time, of a designated pathfinder at the official level to coordinate timely reviews and approvals.

3.2.8. Barents Sea – northern Norway

3.2.8.1. Introduction to the region

Norway's territory extends from the North Sea well into the Arctic Ocean. The country's jurisdiction extends to more than two million km^2 of ocean – six times Norway's land area (Figure 3.14). The oceans and the continental shelves are rich in natural resources, providing for fisheries and petroleum industries that are globally significant and critical to the country's economy. Norway is the world's third largest exporter of fish as well as oil. In 2005, the petroleum industry accounted for 25% of Norway's Gross Domestic Product (GDP), 52% of its export earnings, and 33% of government revenue (Ministry of Petroleum and Energy, 2006: 144). The same year, the fishing industry accounted for about 5% of the value of Norway's exports.

All Norwegian petroleum activity is offshore. There are no onshore reserves or reservoirs. The exploitation of offshore reserves is much more demanding than onshore developments in terms of technology and costs. Norway has a modern, market economy with a centralized system of governance. Policies for the utilization of natural resources are adopted and applied at the national level. Economic and social impacts at regional and local levels are therefore largely determined by the national governance system.

This case study is limited to petroleum activities in the Norwegian part of the Barents Sea. Regular production is scheduled to start there in late 2007. This case study therefore considers impacts that have occurred before regular production commenced. Where impacts after 2007 are referred to, the discussion is of a tentative nature.

3.2.8.1.1. Waters under Norwegian jurisdiction

The waters under Norwegian jurisdiction range from 55° N in the North Sea to 84° N north of the Svalbard archipelago in the Arctic Ocean. In addition, Jan Mayen Island to the north of Iceland and east of Greenland is under Norwegian sovereignty. These waters are commonly referred to as three sea regions: The *North Sea* in the south borders the *Norwegian Sea* at 62° N, while the *Norwegian Sea* borders the *Barents Sea* off northern Norway and Russia to the east (Figure 3.14). More than half the waters under Norwegian jurisdiction are north of the Arctic Circle.

3.2.8.1.2. Major aspects of the petroleum policy

The utilization of petroleum resources is guided by a national petroleum policy, which applies to the whole country. There is no separate Arctic or northern petroleum policy. The critical issue in the development of the petroleum industry is to ensure that the resources are utilized in an optimal manner. The chief objective of the petroleum policy in Norway, including northern Norway, is to maximize the long-term benefits from the industry for the good of Norwegian society as a whole. Fundamentally, this is achieved by regulating the pace of development of the industry. The petroleum sector is currently in a transition, where oil production has reached its maximum and will taper off over the next 50 years (Ministry of Petroleum and Energy, 2004b), while the production of gas will become increasingly important. With a maturing industry in the south, the need to boost exploration efforts in the north and to improve the utilization of existing fields in the south has become urgent. The lead-time from the start of exploration until production begins can be very long, however, and the *Snøhvit* field, discovered in 1984, is the only one in the Arctic that will come into production in the near future.

3.2.8.2. The social and economic system

3.2.8.2.1. Demographics

Ten percent of the country's population, 460 000 people, lives in northern Norway. The county of Finnmark, off which the Barents Sea petroleum developments take place, has a population of 73 000. Norway's only indigenous population, the Saami (around 30 000 persons nationwide), have their largest presence in Finnmark. Except for the plateau areas of the inner part of Finnmark, where the communities are largely Saami, many communities in Finnmark are populated by both Saami and Norwegians.

Two trends mark the recent demographic developments of northern Norway: first, while Norway as a whole has seen a 10% growth in its population over the last decade, the population of northern Norway has fallen by 1.2% (Agenda, 2003:7). The most important factor in this regard is that people have moved out of the region, a trend that is closely linked to economic conditions and expectations. Since younger people are most likely to move, the region has seen a strong reduction of people aged 20 to 29.

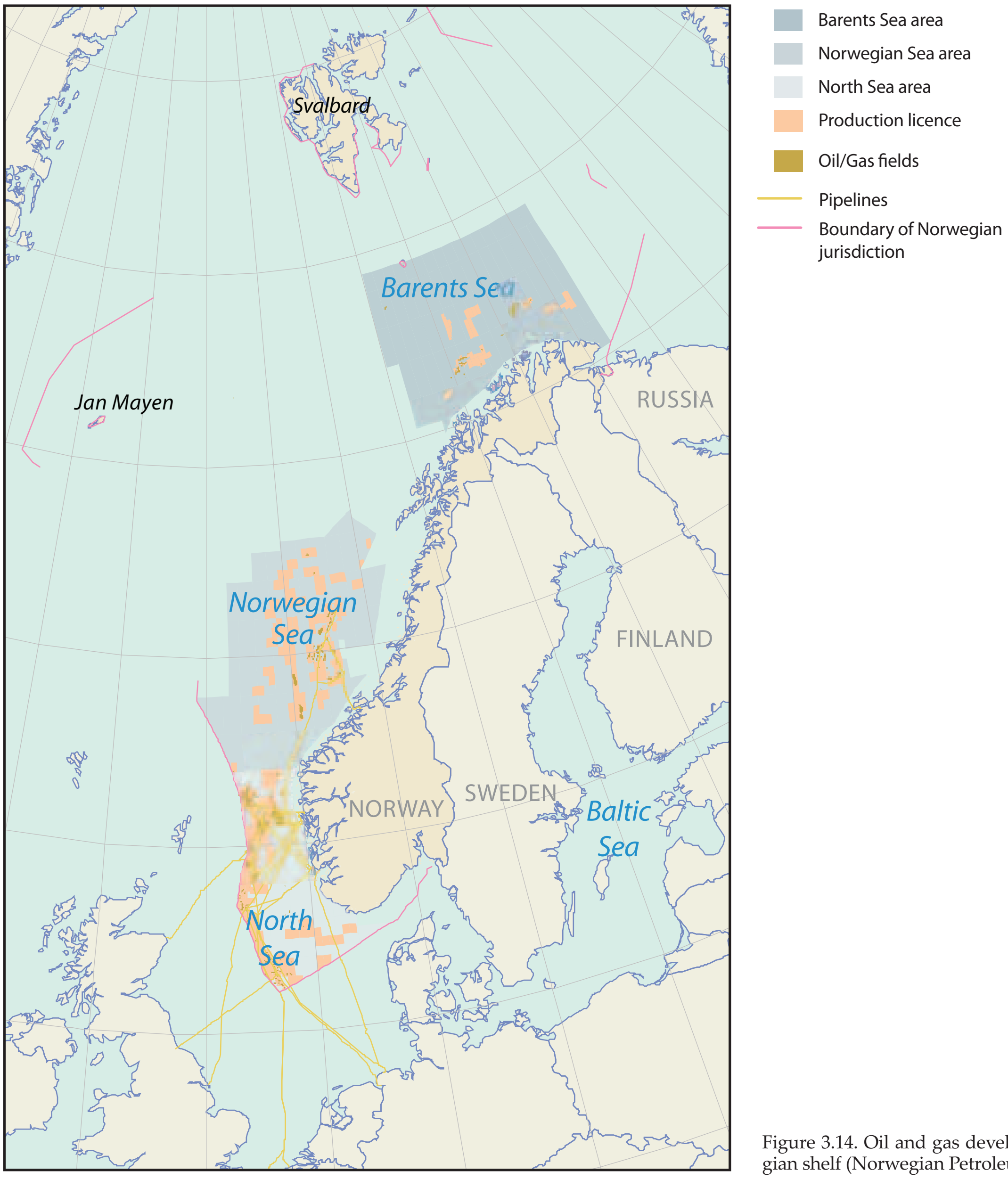


Figure 3.14. Oil and gas development on the Norwegian shelf (Norwegian Petroleum Directorate).

The second trend is the shift in the workforce from primary sectors to service industries. The total number of people employed in northern Norway was 228 000 in 2001 (Agenda, 2003:8). Over time, fewer people work in fishing and agriculture, while employment in the services sector, tourism in particular, is growing. The fisheries sector has traditionally been important to employment in northern Norway. The number of fishermen has been much reduced over the last decades, reflecting a substantial increase in the efficiency of the industry. In 2001, the fisheries sector accounted for 7% of employment in the region. In some coastal areas fisheries are however still important to employment.

Public services are generally very important for employment, and about half the working population in northern Norway is employed in the public sector. The most important institutions are the armed forces, the health care system, education, and municipal services. About 85% of the population with higher education works in the public sector (Agenda, 2003:18). Unemployment has been high compared to the rest of Norway, but has been reduced over the last decade (Agenda, 2003:7). At the national level, unemployment in October 2006 was 2.2% of the workforce as a whole, and 2.8%, 2.2%, and 3.6% in Nordland, Troms, and Finnmark counties, respectively (Aetat, 2006). A series of bankruptcies in the fisheries sector, caused by low profitability owing to an increasingly competitive and globalized fish processing industry, has caused unemployment to rise in some coastal communities. In northern Norway, the number of fish processing plants has reduced by 60% over the last decade (Fisk, industri og marked, 2006).

Elementary education is compulsory in Norway and the population is literate. A relatively high percentage of the population in the north has higher education. In 1999, 55% had higher education (high school), while another 17% had one to four years of college-level education. Four percent of the population holds a university degree (Agenda, 2003:31). Northern Norway has one university (University of Tromsø), with all major academic disciplines represented, as well as colleges in Alta, Kautokeino, Tromsø, Narvik, Harstad, Bodø, and Nesna. A number of research institutes are also based in the region, particularly in Tromsø. These include the Norwegian Polar Research Institute, Akvaplan NIVA, a branch of the Institute of Marine Research, and the Norut Gruppen research consortium.

3.2.8.2.2. Settlement patterns, land and sea use, and land status

Over the last decades, settlement patterns in the region have been characterized by increasing centralization, with people leaving remote areas and moving to central areas with greater job opportunities. This tendency pertains to younger women in particular. Some coastal areas have thus lost a third of their population in the course of two decades (Agenda, 2003:9). By 2002, 67% of the population was living in urban or semi-urban areas (Agenda, 2003:31).

A few major population centers hold a large share of the population: Bodø (44 000 inhabitants) and Narvik (19 000) in Nordland, Tromsø (62 000) and Harstad (23 000) in Troms, and Alta (17 000) and Hammerfest (8500) in Finnmark.

Northern Norway is mostly sparsely populated, and in a comparative perspective land is abundant. While areas that are arable generally are privately owned, the state is by far the most important owner of land in the region. New legislation was adopted in 2005, establishing an arrangement that provided for more Saami influence over the use of land areas in Finnmark.

The Norwegian coastline is around 22 000 kilometers long, counting fjords and islands; by straightline measurement it is 2650 kilometers long. More than half is in northern Norway. In coastal areas, the local perception is that land is becoming increasingly scarce, due to urban sprawl, the growth of aquaculture, development of infrastructure for transportation, establishment of protected areas, military installations, and so on. Relative to the situation in southeastern Norway, or in continental Europe, it would seem however that this is only the case near the cities. The major uses of the sea are for transportation, tourism, fishing, aquaculture, recreation, and for military purposes. In relation to the petroleum sector, there are some potential issues of competing use with fisheries (see section 3.2.8.3.6).

3.2.8.2.3. The governance system

3.2.8.2.3.1. Nature of the political system

Norway has one, uniform political system applying to the whole country. There is no particular political arrangement for the northern part of the country, except for Svalbard, where Norwegian sovereignty is exercised according to the provisions of the Svalbard Treaty of 1920 (Arlov and Hoel, 2004). Norway has a parliamentary system of government. Major policy decisions must be confirmed by Parliament, which also adopts legislation and approves the Government's budget proposals. Norway has a strong tradition for centralized government, with little scope for regional or local policies that deviate from the national standard. At the regional level, the 20 counties have seen their influence waning relative to the state, and they are now mostly concerned with issues relating to secondary education, transportation, and culture. The number of counties may be reduced in the future as part of an effort to streamline regional government structures. Also at the regional level, governors (*fylkesmann*) ensure that the regional authorities implement policies according to national standards. At the municipal level, 434 *kommuner* are responsible for the provision of basic services in health, education and other welfare areas that are to be performed to standards set by the Government.

The Saami people have their own parliament. In some administrative matters, the Norwegian government has transferred authority to the Saami Parliament. The Saami people are integrated into the Norwegian welfare system. As Norwegian citizens, Saami receive the same benefits from the income from the petroleum activity through the national tax regime and welfare distribution system as every other citizen.

The political culture of the country is relatively consensus-oriented (Heidar, 2001), and there is a long-standing tradition for cooperation between the state and the private sector. Such corporatist structures are important to all policy sectors (Olsen, 1983), and it is taken as a given that organized interests are to be consulted and represented in policy-making processes. In the petroleum sector, organizations representing interests in the industry therefore play a distinct role in the formulation and execution of the petroleum policy. By law, the Government is also required to consult stakeholders when developing policy in any issue area.

3.2.8.2.3.2. The petroleum regime

The overarching objective of the Norwegian petroleum policy is to secure the largest possible share of revenue for the common good, through responsible resource management based on safety, preparedness, and the environment. The country's petroleum policy has been based on a three-pronged strategy to this end: national control over the development of the industry, the development of a domestic petroleum industry, and participation by the state in the activity.

The objective of national control has been achieved through the development of a comprehensive policy and institutional framework, dominated by a Ministry for Petroleum and Energy and a Petroleum Directorate. The 1996 Petroleum Act, building on the first act from 1963, provides for the licensing system that is at the heart of the regulatory regime for the petroleum sector. The act gives the Government considerable power to regulate all aspects of the industry, from the issuance of permits to the manner of bringing petroleum to the market.

The development of a Norwegian petroleum industry, a means for control over sector developments, included the establishment of a state-owned petroleum company – Statoil – in 1972, as well as a private company Saga, and a petroleum division of Norsk Hydro, Norway's biggest industrial conglomerate, in which the state is the major shareholder. (Saga was later taken over by Norsk Hydro.) An extensive, privately owned industry providing goods and services to the petroleum companies was also cultivated.

Since its inception, there has been broad agreement that the petroleum industry should be developed in a gradual and considered manner, in order to secure maximum benefits over time. New areas are therefore opened up only gradually. Since 1965 there have been 20 such rounds in which the Government has announced new areas for exploration and exploitation. For each round the government issues a number of licenses for exploration of designated geographical areas ('blocs'). A permit is normally issued for an initial phase of up to 10 years, during which the companies that hold the permit are obligated to explore the area and assess its production potential. When obligations are fulfilled, the companies can claim up to half of the permit area for exploitation purposes for up to another 30 years.

In general, activities are strictly controlled. At the various stages of field development the companies are required to present comprehensive plans that must be approved by the relevant authorities. Specific permits are needed for the different stages of development. Exploratory drilling, for example, requires approval from the Petroleum Directorate, the Petroleum Safety Authority and the Norwegian Pollution Control Authority. Also, operators must perform environmental and socio-economic impact assessments for fields that are to enter production, as well as for the associated infrastructure and transportation systems. These impact assessments are subject to a public hearing before being approved by the authorities as part of the Plan for Development and Operation. The operators are also required to plan for the termination of the activity in any given field.

The 1996 Petroleum Act provides that the Government can decide how and where the petroleum that is produced should be brought ashore. Such decisions can be important in providing for land-based industries in relation to the petroleum industry. Generally, one has attempted to make as effective use of the existing infrastructure as possible, and only allow for a few major industrial developments onshore. When new infrastructure is built, opportunities arise also for the establishment of related land-based facilities, and such decisions may have major economic consequences for the affected communities. The development of *Snøhvit* has brought the first land-based facility for production and export of LNG in Norway and Europe. The onshore development and its location were decided on by the involved companies on the merits of economic criteria, although earlier in Norway's petroleum development history, regional considerations had greater influence.

3.2.8.2.3.3. Environmental regulations

The exploration for and exploitation of petroleum entails a number of activities that have environmental consequences. Activities on the Norwegian shelf are therefore subject to a regulatory regime that is relatively strict. The 1981 Pollution Control Act imposes a number of regulations on all types of emissions.

Organic compounds, oil, and chemicals used in production are the most important in terms of discharges to sea. Of these, water from the reservoir following the oil and gas ('produced water') and containing oil is currently the most significant. The levels of emissions set by domestic regulations are mandated mainly by international agreements.

Carbon dioxide (CO_2), nitrogen oxides and non-methane volatile organic compounds, are the most important emissions to air from the petroleum industry in a national context. For example, 28% of the national emissions of CO_2 are from the petroleum industry (Ministry of Petroleum and Energy, 2004b). The main source for these emissions is the production of energy at the production installations. Here, too, emission levels are mandated primarily by international agreements.

The 1996 Petroleum Act requires an operator to perform a detailed environmental impact assessment before permission to develop a field can be issued. An important environmental measure is the CO_2 tax introduced in 1991. This applies to all burning of fossil fuels entailing emissions of CO_2. In 2006, the CO_2 tax was NOK 0.79 per Sm^3 gas or liter diesel.

For the Svalbard archipelago, where some minor petroleum exploration projects were undertaken in the 1960s and 1970s (Arlov, 2003), the 2002 Svalbard Environmental Protection Act prohibits exploration for and exploitation of petroleum in the area, on land as well as in the waters out to the territorial limits.

The only difference between the national petroleum regime and that for the northern regions concerns environmental regulations: there shall be no discharges of produced water during regular operations, and, except for the drilling of the top-hole, produced water and other drilling debris shall be re-injected or taken onshore, if no better solution exists. Special measures are introduced to protect the fisheries. Among other things, there are geographic and temporal restrictions on drilling and seismic activity.

3.2.8.2.3.4. Jurisdictional issues

A number of boundaries remain to be drawn in the marine areas of the Arctic and the Northeast Atlantic region is no exception. In 1965, the countries bordering the northern part of the North Sea agreed to the delimitation of the continental shelf of that area. In the North, the boundary with Russia in the Barents Sea remains unresolved. The disputed area is about 173 000 km^2 (Figure 3.14). One reason for the failure to agree on a boundary may simply be that there has not been a critical need for a solution (Kvalvik, 2004). The development of petroleum reserves on both sides of the disputed area in the Barents Sea may however make agreement on the delimitation of a boundary more urgent.

While the 1920 Svalbard Treaty states that Norway has sovereignty over the archipelago and its territorial waters (Ulfstein, 1995), other provisions of the treaty give citizens of other parties to the treaty equal rights as regards economic activity (Arlov and Hoel, 2004). Subsequent developments in ocean law, most importantly the 1982 United Nations Convention on the Law of the Sea, has provided for extended coastal state jurisdiction over natural resources.

3.2.8.2.4. Economics

3.2.8.2.4.1. Nature of the economic system

Norway has a market economy with a comparatively large degree of state intervention. Little or nothing remains of subsistence or non-monetary economic transactions. In the decades following the Second World War, economic development was to a large extent led by the state, and state ownership in important industries was prevalent. Since the 1980s, the role of the state in the economy has significantly reduced, and many state-owned companies have been wholly or partly privatized as part of government-led privatization programs – a development of which Statoil is a case in point.

The economy is to a considerable degree based on the exploitation of natural resources and exports of raw materials or products based on these resources. This has been the case for centuries. As pointed out in section 3.2.8.1, petroleum is by far the country's most important natural resource, accounting for one-third of state earnings in 2005. Other important natural resources are fish and minerals other than petroleum.

With the petroleum sector accounting for about one third of the state's income, this sector has been and will be essential to the maintenance of Norway's high standard of living, which is currently one of the highest in the world, with per capita income at about USD 38 500 (The Economist, 2006: 251; the exchange rate used throughout this case study is USD 1 = NOK 6.5). The revenue accruing from the petroleum activity has been critical in building an extensive welfare state, including one of the world's most generous pension and healthcare systems.

3.2.8.2.4.2. Structure of property rights

In the 1963 Continental Shelf Act, Norway claimed jurisdiction over the continental shelf and introduced legislation that made the Norwegian state the owner of the natural resources there. This development has since been reinforced by the establishment of an Exclusive Economic Zone (EEZ) in 1977, which provides for jurisdiction over natural resources in the ocean out to 200 nautical miles (370 kilometers). Jurisdiction over the continental shelf may extend beyond the EEZ, depending on geological and geographical conditions. Coastal states are currently in the process of stating their claims to the continental shelves beyond EEZs, as part of a process under UN auspices.

Norway's ocean territory and its resources belong to the people of Norway. Marine areas cannot be appropriated by anyone, although the Government may grant permits to persons, businesses, or organizations for specific purposes, for example for aquaculture or for military ends. In such cases regulations as to how the area can and cannot be used would normally apply. Also, these rights are use rights, rather than property rights. Such use rights can only be exercised when a number of conditions attached to them are observed, for example the obligation to perform environmental impact assessments. They are normally also awarded for a limited time period. As regards petroleum resources in particular, the 1985 Petroleum Act (*Lov om petroleumsvirksomhet nr 11 1985*) explicitly states that the state owns submarine petroleum deposits, and that the petroleum resources are to be managed so as to benefit Norwegian society as a whole (paragraph 3). The law requires the authorities to manage the resources in such a way that Norwegian business interests are promoted, and to do so with due regard to other activities, regional policy considerations, and the protection of the environment.

3.2.8.2.4.3. Income

During its four decades of existence, the Norwegian petroleum industry has become by far the most important sector of the country's economy(Figure 3.15). The key mechanisms in generating the state's income from the petroleum sector are an institution called the State's Direct Financial Interest (see section 3.2.8.2.4.5), which provides revenue from the sale of oil and gas, and the tax and fee regime applied to the petroleum industry. Tax income is substantial. In 2005, for instance, total income to the state from petroleum activity was NOK 283 billion (USD 44 billion). Taxes and duties levied on the petroleum industry accounted for 58% of this sum (Ministry of Petroleum and Energy, 2006: 186).

During the 40-year period that the industry has been in operation, it has contributed a cumulative value of some NOK 5000 billion (USD 769 billion) to Norwegian society (Ministry of Petroleum and Energy, 2006: 144). Roughly half of this income has been invested in the Norwegian Government Pension Fund, established in 1990 to provide for macro-economic flexibility and as a financial reserve. In Norway, as in most western countries, the population is rapidly aging, and the pension system will come under increasing strain as the number of retirees increase relative to the number of persons working. The assets in the Pension fund are invested abroad to avoid undesirable effects on the Norwegian economy.

Also, the Parliament in 2001 adopted a decision rule (*Handlingsregelen*) for the use of funds from the state's Pension Fund. The fundamental idea is that the surplus from the fund can be spent by the Government. Spending is however to be moderate, so as not to over-stimulate the economy as a whole and disturb macroeconomic stability. The decision rule specifies that annual expenditure by the Government should not exceed the annual real surplus of the capital in the fund, and exceed 4% of its value. It follows that the amount that can be spent increases with the value of the fund, which by the end of 2005 was NOK 1399 billion (USD 215 billion), and is expected to double by 2009.

There is broad agreement in Parliament that public spending based on petroleum income has to be kept in check in order not to overheat the economy. The idea is, however, subject to considerable debate. While the level of public spending per capita is among the highest in the world, it does not suffice to meet demands for new or refurbished schools, roads, hospitals, and other welfare benefits.

3.2.8.2.4.4. Employment

Total employment in the petroleum industry was 80 000 in 2005 (Ministry of Petroleum and Energy, 2006: 49). This is about 3% of the total workforce in the country. Some 15% of the persons employed in the industry are women. Petroleum companies are established in eight of the 434 municipalities (*kommuner*) in the country, and associated industries are located in 135 municipalities (Ministry of Petroleum and Energy, 2004a). There is a strong concentration in certain areas, in particular Rogaland and Hordaland counties in southwestern Norway. More than two thirds of the turnover in the commercial (as opposed to public) sector in Rogaland county is associated with the petroleum industry (Ministry of Petroleum and Energy, 2004b).

An industry consisting of about 1200 businesses (Ministry of Petroleum and Energy, 2004b: 11) providing various services for developing and operating petroleum activities has also developed. This industry employs about 44 000 people (Ministry of Petroleum and Energy, 2004b: 67), and delivers goods and services estimated at NOK 40 billion (USD 6 billion) in 2003 (Ministry of Petroleum and Energy, 2004b: 68). Annual investment levels in the petroleum industry vary considerably. As of 2005, the total investment since the start of the industry was NOK 1900 billion (USD 292 billion). Over the last decade, annual investment levels have ranged between NOK 48 billion and 88 billion (USD 7.4 billion and 13.5 billion) (Ministry of Petroleum and Energy, 2006: 188). The need to maintain investment levels is a major concern in the development of national petroleum policy. The activity in associated industries providing goods and services to the petroleum industry often depends on investments that result in large contracts. The manufacturing industry in particular is often located in areas with few alternative employment opportunities. The opening of new fields for petroleum development is therefore a sensitive issue in regional politics.

3.2.8.2.4.5. Financial interest in industry activities

Initially, participation by the state in the development of the oil industry occurred through the ownership of Statoil.

This arrangement became increasingly controversial, and in 1985 Parliament established a separate state entity, the State's Direct Financial Interest (SDFI), to take care of the state's interests in the petroleum industry. SDFI owns the state's shares in the fields that are developed. Through SDFI, the state participates in the development of petroleum fields, and invests, takes risks, and earns revenue in the same way as commercial companies. The state participates in 86 licenses (Ministry of Petroleum and Energy, 2004b: 75). In 2005, the state's income through SDFI was NOK 111 billion (USD 17 billion) (Ministry of Petroleum and Energy, 2006: 186).

Since 2001, SDFI has been run by Petoro Inc., a 100% state-owned entity. Also in 2001, Gassco was set up to handle the transportation of gas to the European market. Statoil had previously performed this task. A new regulation in the European gas market required a reorganization, however, and the pipeline infrastructure is now coordinated through a joint transport system called Gassled. Since the establishment of Petoro and Gassco in 2001, state ownership is exercised through shareholding corporations where the state owns 100%. Statoil was owned 100% by the state until 2001. Shares are now traded in the stock markets of Oslo and New York, but the state retains about 80% of the shares. The grounds for the partial privatization of the company were a wish to strengthen its commercial focus and competitive edge, and to provide it with the same legal foundation for doing business as its competitors.

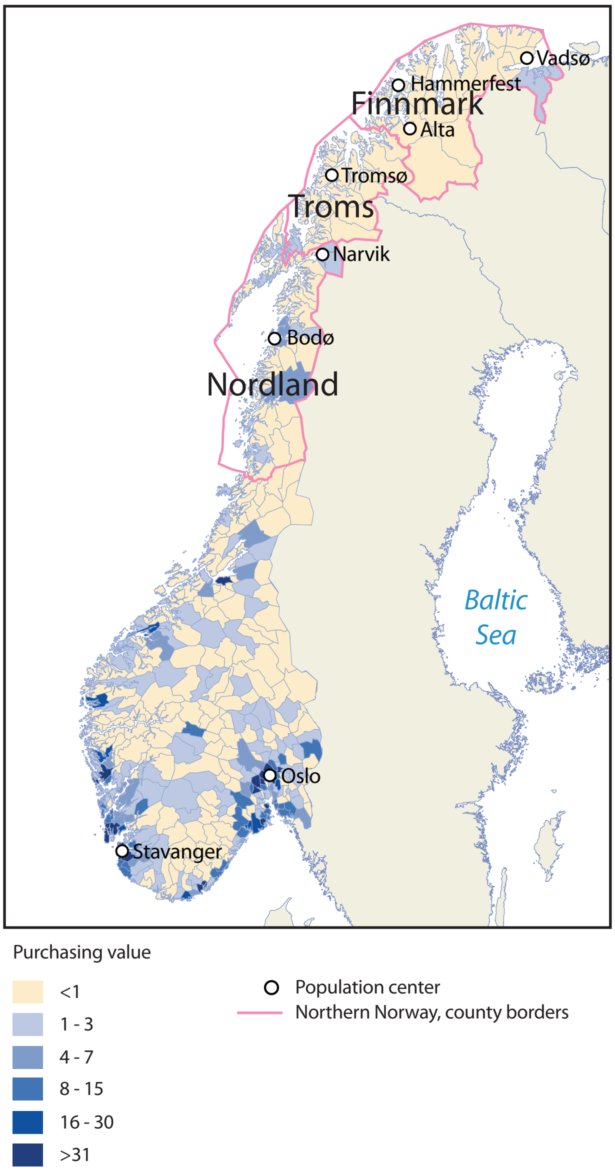


Figure 3.15. Purchases of goods and services in the petroleum sector (Norwegian Petroleum Directorate).

3.2.8.2.4.6. Tax and royalty regime

While the 1996 Petroleum Act provides for the regulation of the petroleum industry, the Government's power to tax the industry is provided by the 1975 Petroleum Tax Act. The taxation regime for the petroleum industry is fundamentally the same as the general tax regime for any business in Norway, i.e. 28% on net income. However, due to the super-profitability stemming from the resource rent of natural resources in general, and petroleum in particular, a special tax of 50% is levied on top of that. All costs incurred in the development of a field are however deductible. In addition to the tax, companies must also pay certain fees: an area-fee of NOK 7000 to 70 000 per km^2 per year, and, as mentioned in section 3.2.8.2.3.3, a CO_2 tax. Until 2005, a production fee also applied to some fields.

3.2.8.3. Responses and effects in the north

3.2.8.3.1. Introduction

Petroleum development in the Barents Sea is in an early phase. The first field is expected to come into production in late 2007. The socio-economic effects of petroleum development in the north are therefore related to the exploration phase and the construction of the facilities required for production. Most effects are to be explained by the relatively centralized governance system in the petroleum sector.

The level of exploration activity is to a large extent determined by expectations of the future price of petroleum, existing knowledge of the geology of the area to be explored, and the size of the areas that are opened for exploration. By 2004 about 60% of the Norwegian continental shelf was open to exploitation for petroleum (Ministry of Petroleum and Energy, 2004a). For 9% of this area, permits have been issued for actual production. Several million kilometers of seismic transects have been acquired in the Norwegian Arctic (see Chapter 2), about half north of 62° N (Ministry of Petroleum and Energy, 2004a). The high price for crude oil from 2004 onwards has contributed to increased attention in the Arctic region.

3.2.8.3.2. Recent developments in the north

The Barents Sea (Figure 3.16) area is defined for petroleum purposes as the area west of the area of overlapping claims with Russia and southwards along the North Norwegian coast to the Arctic Circle (this definition is in contrast to the usual one, which is the sea to the east of a line running from North Cape in Finnmark to South Cape on Spitsbergen). The area around the Lofoten Islands is treated as a separate region, due to its ecological sensitivity and importance for fisheries. Exploratory drilling has been pursued for a long time in the Barents Sea, with 42 licenses issued for that purpose since 1980. Sixty-four wells have been drilled, but few significant discoveries have been made. This limited success and the need to identify more reserves led to the establishment of a 'Barents Sea Project' in 1997, to stimulate industry interest in further exploration. This included the opening of new areas for exploration, modifications to the fee structure, and other measures meant to attract the interest of the major petroleum companies that have the know-how and capital to operate in such areas. For the same reason, the Government announced in 2003 the largest new areas for exploration since 1965. New licenses for the southern Barents Sea were awarded in 2006.

In addition to the desire to maintain activity over time, these domestic developments in Norway are spurred on by increases in the price of petroleum and an increasing interest on the part of major companies in stepping up their activity in the north. At the same time the European Union and the United States are seeking to reduce their dependence on Middle East energy sources and to diversify their supply base. Another important consideration for Norwegian authorities is recent developments in the petroleum sector in Russia and the need to match that on the Norwegian side of the border (Ministry of Foreign Affairs, 2005).

The Barents Sea poses particular challenges with regard to geology, the protection of the environment, co-existence with fisheries, and operations in cold conditions. Also, the long distance to markets and the lack of infrastructure for transportation of petroleum makes the development of operations relatively costly. The remoteness of the region makes ship-based transport the most attractive option for bringing the production to market (Barlindhaug, 2005).

The first significant petroleum development in the Barents Sea area is the *Snøhvit* field, plans for which were approved by Parliament in 2002, and which will start production in late 2007. The field was discovered in 1982, and consists of several smaller fields (*Snøhvit, Askeladden,* and *Albatross*). The operator is Statoil, but a number of other companies also participate, among them Total and Gaz de France. The field development is based on subsea installations and equipment, rather than conventional offshore production platforms. The gas and gas condensate will be pipelined onshore to Melkøya near Hammerfest, 140 kilometers away, where the gas is to be processed into liquefied natural gas (LNG). Purpose-built vessels will bring the LNG to the market in the United States and on the European continent. The total costs of development are about NOK 58 billion (USD 9 billion), of which the LNG facility accounts for more than half. The oil field *Goliat*, discovered in 2000 to the east of *Snøhvit*, is another candidate for development. It has not yet been decided whether development is economically feasible, and additional wells will be drilled to ascertain this.

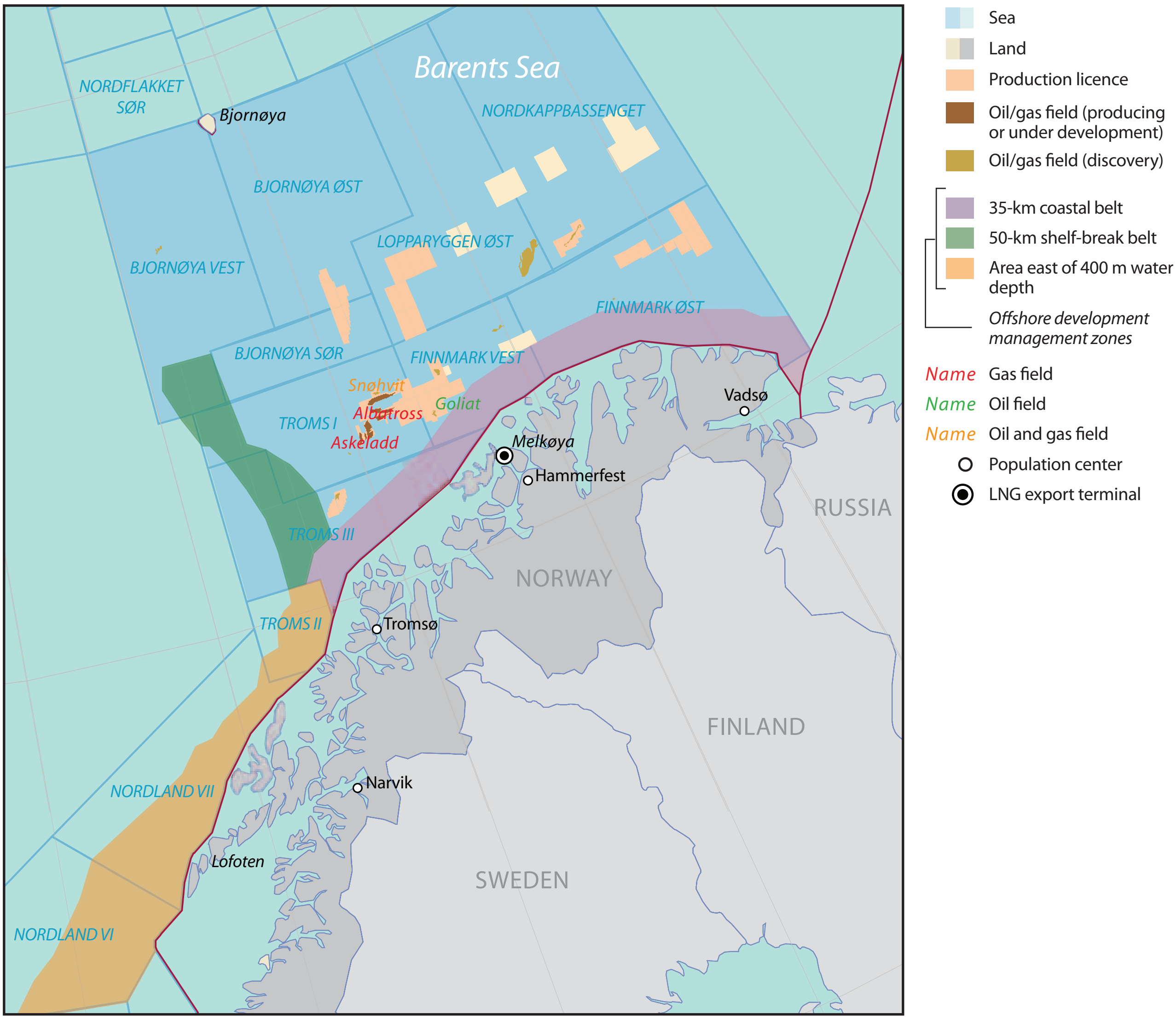


Figure 3.16. Zoning arrangements in the Lofotens – Barents Sea area.

3.2.8.3.3. Policy development and new institutional arrangements

The uses of the ocean are generally regulated on a sector basis, with different sets of legislation applying according to type of use. A new and comprehensive Oceans Resources Act is being developed, and will provide a basis for improved coordination of different types of use of the oceans and their resources.

A significant institutional development, following growing levels of activity in a number of marine industries, is the Comprehensive Management Plan for the Barents Sea. This initiative grew out of a report to Parliament in 2001–2002 on the environmental status of the country's oceans (Ministry of Environment, 2002). The rationale for the report and the policy laid out in it is that it is necessary to coordinate the various human uses of the oceans to ensure that the total human impact on the marine environment does not exceed the limits of sustainability. The Barents Sea is the first area for which such a plan is established, and the intention is that such plans are to be developed for all Norway's ocean areas.

The purpose of the management plan is to establish a holistic framework for decision-making that takes into account the interests of fisheries, petroleum, and transportation, as well as the environment. The plan, which was adopted by the Norwegian Parliament in 2006, essentially provides for when and where petroleum activities can take place in the Norwegian part of the Barents Sea and in the Norwegian Sea southwards to the Lofoten archipelago. The preparatory work for the plan included assessments of the impacts from fisheries, shipping, petroleum development and external forces such as climate change on the ocean environment. On the basis of this assessment, total environmental impact was assessed under different scenarios, with particularly vulnerable areas and seasons identified. One significant conclusion from this work is that the greatest risk for major accidents is related to transportation of oil.

The plan as adopted by Parliament provides that petroleum development is banned in certain areas until 2010. In other areas activity is limited to certain periods of the year. These are areas where conflicts with fisheries are seen as too significant, or where oil spills may have severe environmental impacts. The plan will be reviewed at regular intervals, first in 2010. Figure 3.16 shows the areas that are closed to development as well as those where seasonal restrictions apply.

It is not envisaged that the execution of the plan will require changes to the sectoral organization of the authorities that are responsible for policy formulation and implementation. The idea is that the current institutional apparatus will be able to reconcile the various concerns raised by the implementation of the plan. The adoption of the plan created considerable political controversy. While the development of a petroleum industry in the north is very popular there, environmental organizations in particular were opposed to the expansion of petroleum-related activities in this region.

3.2.8.3.4. Transportation

In the last few years, petroleum shipments from ports in the Kola and Archangelsk regions in northwestern Russia through the Barents Sea and along the North Norwegian coast have increased. Beginning in earnest in 2002 with a volume of 2 million tonnes, shipments increased to 12 million tonnes in 2004 and are likely to increase considerably over the next decade. While the frequency of petroleum shipments in the region is not yet high compared to that of the major facilities in southern Norway, it may increase as a consequence of operations on the Russian side of the border (Bambulyak and Frantzen, 2005). In the near future these shipments will remain based on oil from Siberia that is pipelined to the Kola Peninsula (Hønneland, 2005). In the longer term, petroleum from fields in northwestern Russia, including the Barents Sea, may come to dominate (Barlindhaug, 2005). The actual course of development in this regard is, however, dependent upon decisions of Russian authorities as to the routing of pipelines and the pace of development of new fields.

In response to the increase in tanker traffic along the Norwegian coast, Norwegian authorities have adopted a number of measures to minimize potential damage from an oil spill. Improvement in tugboat services, including increased Coast Guard presence and an agreement with trawlers that they can assist vessels in distress, is being developed. Another measure was the extension of Norwegian territorial waters from 4 to 12 nautical miles in 2004. This measure makes it possible to force tanker traffic to sail in designated traffic separation lanes. Also, from 2007, a traffic control center will be operative in Vardø (Bambulyak and Frantzen, 2005). Additional spill protection and collection gear has been deployed. In addition to these measures, the emergency preparedness of the Norwegian petroleum industry in conjunction with activity in the area will reduce the total environmental risk associated with severe incidents related to the traffic (Ministry of Petroleum and Energy, 2004b).

The evaluation of oil spill risk is, however, not complete without also considering the risk due to oil transportation through Norwegian waters. A significant number of smaller accidents and near-accidents have occurred in both freight and fuel/crude transport and on-shore refining in the past 30 years. Risk evaluations of the likelihood for future accidents have been carried out implying that while 'acceptable risk level' may be an environmental objective for petroleum exploration and extraction, 'no discharges' is unlikely to be a realistic objective for transportation. While the Norwegian petroleum industry may co-exist with fisheries interests, environmental costs of oil exploration in the Barents Sea are not currently fully internalized in contingency planning. Current pollution legislation admits liability for economic damage due to oil spills, but not environmental damage to biodiversity or ecosystem function (Forurensningsloven, 1981).

3.2.8.3.5. Economic effects

3.2.8.3.5.1. Initial assessments

Potential socio-economic effects resulting from various scenarios for the development of petroleum in the southern Barents Sea – an area of 68 550 km^2, about the size of Belgium and the Netherlands combined – was accounted for as part of the process leading up to the re-opening of the area for petroleum activities in 2003. The development of new petroleum fields requires the performance of extensive impact assessments for both environmental and socio-economic effects (see section 3.2.8.2.3.2).

A comprehensive assessment based on three scenarios involving different levels of development from low to high was carried out. Depending on the scenario, total investment levels are likely to range from NOK 42–152 billion (USD 6.5–23.4 billion) for the 2005 to 2020 period (Ministry of Petroleum and Energy, 2004b: 106).

The effects on employment will be significant, in particular in areas where the petroleum-related industry is already well established, namely in western Norway and in the Oslo area. The scenario with the highest level of activity (that is, no restrictions on where drilling can be carried out) predicts an additional 15 000 man-years of employment, of which 4200 will be in northern Norway. For the basic scenario (with a number of restrictions on drilling), the corresponding figures are 5000 and 1000.

3.2.8.3.5.2. The effects of *Snøhvit*

Local effects in northern Norway can be significant where developments are taking place onshore. With the first petroleum field in the north, *Snøhvit*, coming into operation in 2007, the socio-economic effects are substantial in Hammerfest. Jobs, housing, and local tax income are among the local variables most strongly affected.

The absence of petroleum-related development in this region until recently does not, however, imply that northern Norway has not benefited from the activity in the North Sea. The income generated by the state from the petroleum industry over the last three decades has benefited the nation as a whole, including northern Norway. The main effect of petroleum development for northern Norway – a substantial increase in living standards and the level of public services – has already taken place, as elsewhere in the country. It is not likely that large-scale development in the region will do much to alter this for northern Norway as a whole. The revenue generated from the industry from now on will serve to offset the decline in the state's income from the sector. Any petroleum developments in the north, however large, are likely to directly affect only the communities where shore-based activities occur. Indirect effects will be spread throughout the country.

An important, but difficult to quantify effect of petroleum development is that it brings considerable optimism to communities and regions where employment opportunities have been scarce. Also, these prospects have led the Saami parliament to claim rights for the indigenous populations to petroleum resources off Finnmark *(http://www.sametinget.no/artikkel.asp?MId1=1&MId2=2&AId=1164&Back=1)*. The issue of corporate social responsibility in this regard has also been raised (Fjellheim and Henriksen, 2006).

An increased regional income from the development of the petroleum industry comes from the new business opportunities that arise, and from the increased tax base provided by a growth in employment. While local businesses that provide goods and services for the petroleum activity may see a larger market, a highly specialized petroleum-associated industry already exists in the country. The experience thus far from the Snøhvit project is that local businesses in fact have been able to land significant contracts, more so than was expected in advance. According to the Statoil web site *(http://www.statoil.com/statoilcom/snohvit/svg02699.nsf?opendatabase&lang=no&artid=5C2B505E04B0E5B3C1256B9E002770D2)*, contracts for NOK 2.9 billion (USD 450 million) have been awarded to enterprises in the three northern counties as of June 2006. The bulk of this (NOK 2.2 billion) has gone to enterprises in Finnmark county. The total Snøhvit contract volume awarded to the industry in Norway is about NOK 21.5 billion in the development phase (USD 3.3 billion), out of a total Snøhvit investment of NOK 37.2 billion as of January 2006 (Angell et al., 2006: 15). This is significantly higher than expected. Fifty-five percent of the contracts to Norwegian enterprises have gone to Rogaland county (Angell et al., 2006: 15). The annual contract volume to local business when the project enters a regular production phase is estimated at NOK 240 million (USD 37 million).

As regards socio-economic effects stemming from an increased local tax base, these come partly from increases in income tax from the increase in the work force and partly from increases in property tax income. Under the Norwegian tax system, people pay a substantial income tax to the municipality where they live, so the increase in the local work force in Hammerfest (350–400 people in a town of 8500 inhabitants) can bring a significant increase in income taxes. With respect to property tax, Statoil currently pays about NOK 100 million annually in property tax, also a significant contribution to the finances of the municipality. As a result, the Hammerfest municipality plans to invest NOK 800 million (USD 123 million) in enhanced public infrastructure and welfare in the years ahead (Angell et al., 2006: 13). Such investments will in turn make Hammerfest a more attractive place for businesses, and may bring further economic activity and employment (Angell et al., 2006: 13). A long-term decline in population in Hammerfest has been reversed.

A recent study (Angell et al., 2006) provides some additional data. Between 2001 and 2005, the number of people employed in Hammerfest increased by 23% (881 persons), largely due to *Snøhvit*. Some 400 of these persons also live in Hammerfest. The service sector and public administration are among the most rapidly growing sectors, and a majority of the new jobs go to women. This development has halted a long-term decline in the population and turned Hammerfest into a growth area. Over the same period, the remainder of Finnmark county had a decrease in employment of 20% (Angell et al., 2006: 14).

3.2.8.3.5.3. The broader picture

It is not likely that shore-based activities related to the industry will take place in many locations. The experience from the development of the industry in the south is that shore-based activities are concentrated in a few centers, as the economies of scale dictate few and large facilities. The associated industry tends to cluster around these centers, as in the concentration of petroleum-related activities in Rogaland county. In northern Norway, there are currently four communities with facilities related to the petroleum industry. Basic infrastructure (helicopter bases, etc.) for servicing the platforms in the northern Norwegian Sea exists in Sandnessjøen and Brønnøysund. The Petroleum Directorate has an office in Harstad, as does Statoil. And a number of companies opened branch offices in Hammerfest during the construction phase for the LNG facility.

A report containing scenarios for the development of the petroleum industry in the north through 2030 (Barlindhaug, 2005) foresees the growth of a sizeable related industry in the north. In the period up to 2012, more than one thousand new jobs may emerge, and that figure doubles for the following decade (Barlindhaug, 2005: 34). In terms of contract volumes, regional businesses can expect contract volumes of the order of NOK 17.5 billion (USD 2.7 billion) over 15 to 20 years (Barlindhaug, 2005: 38).

A significant economic effect in communities where development takes place onshore and where employment is local is the increased tax income for the municipalities, as is the case in Hammerfest. Income tax constitutes a substantial share of the total income of municipalities, and increases in employment can affect budgets positively. This only applies, however, to those municipalities where significant petroleum activities are located. Company tax is however paid to the municipality where the company is registered, which in the case of the petroleum sector is normally in the Oslo or Stavanger area. This means few, if any, of the petroleum companies are likely to contribute much to local tax income in the north beyond an eventual property tax, though that may be considerable. The same applies for the major firms in the associated industry. On the other hand, the communities in the north, as in the rest of the country, benefit from the income generated by the general national tax regime to which the petroleum sector is subjected.

3.2.8.3.6. Natural and environmental resources – right of access

The areas of the northern oceans under Norwegian jurisdiction have been open for exploration for petroleum for more than 25 years. The prospects of large-scale developments and regular production that emerged during the 1990s brought a debate on the course these developments were to take. Following considerable controversy over the future development of petroleum in the north, Parliament in 2001 decided to close the area (except the *Snøhvit* field) for further activity, pending a comprehensive assessment to assess the benefits and risks associated with petroleum development in the region.

With the completion of the assessment in mid-2003, Parliament decided later that year to re-open the southern Barents Sea area for year-round petroleum activity. Some areas that are considered particularly vulnerable or important to fisheries remain closed to petroleum activities, as decided in the comprehensive Management Plan. These areas include the Lofoten Islands, coastal areas in Troms and Finnmark counties, important fishing grounds, Bjørnøya (Bear Island), and areas of interaction between sea ice and the open sea (Figure 3.16).

An important issue for fisheries is the risk of pollution from petroleum-related activities. During the more than 40 years of petroleum activity on the Norwegian continental shelf, 60 fields have been developed along with 400 associated facilities (Ministry of Petroleum and Energy, 2004b: 8). Eleven thousand kilometers of pipelines have been built. Around 2.1 billion tonnes (~2.5 billion m^3) of oil and 730 billion Sm^3 (~25.8 trillion cu ft) of gas have been produced. In this period only one major accident has occurred (the *Bravo* blowout in 1977, resulting in a discharge of more than 1000 m^3 of oil). In general terms, the experience from the North Sea is that fisheries and the petroleum industry can co-exist (St. meld nr. 8, 2005-2006).

Norway's northern waters are the basis for some of the country's most important fisheries. Commercially dominant fish stocks such as cod and herring, which spawn in the Barents Sea and along the North Norwegian coast, are in healthy condition (IMR, 2004), and provide the basis for major Norwegian and Russian fisheries. Most important fish stocks in the region have a migratory range that includes both Norwegian and Russian waters, and they are therefore managed by a joint Norwegian–Russian Fisheries Commission. Foreign fishermen have extensive fishing rights in Norwegian waters. The area is globally significant in terms of fisheries. Including Russian waters, the living marine resources in the area are the basis for an industry producing some NOK 14–15 billion (USD 2.2 billion) annually. Marine mammals are also exploited for domestic markets in Russia and Norway.

The fact that these areas are important to the fishing industry may also imply that possible pollution episodes in relation to petroleum activity may have economic consequences that are disproportionate to the physical and biological damage to coastal and marine ecosystems caused by oil spills. Food markets are generally sensitive to incidents involving pollution, and even small spills can cause major reactions in the market. In anticipation of a disaster, the Norwegian Seafood Export Council has developed contingency plans for handling pollution-related episodes. (See also Chapter 5 for further discussion of tainting of fish by oil.) The Norwegian fishing industry, with a limited domestic market, is dependent on exporting most of its production, and is therefore expected to be particularly sensitive to pollution-related incidents and their perception in the markets where Norwegian fish are sold.

To reconcile the fisheries and petroleum interests, the Government established a committee on which organizations representing fisheries and the petroleum industry were represented along with the relevant ministries and directorates. An example of the corporatist system at work in the petroleum sector, the committee considered the re-opening of the southern Barents Sea for petroleum activities in 2002–2003. Following a comprehensive study, a concluding report contained compromises and identified points of disagreement. Fundamentally, the fishing interests and the oil industry agreed that they could co-exist. Disagreement was basically over levels of risk and how zoning arrangements could be used to separate the activities. A report (Ministry of Petroleum and Energy, 2004c) sets out the areas where fisheries activities need special protection: the coastal areas and major fishing banks. These concerns were later taken into account when the Government decided in late 2003 to re-open the southern Barents Sea for petroleum activities, and were addressed in the management plan for the Barents Sea.

The Norwegian environmental protection agency (State Pollution Authority, 2000) has developed a model for prioritizing oil spill responses based on environmental sensitivity of coastal resources, including recreational areas, fish farming areas, and other coastal economic interests. A multi-criteria, priority-setting methodology is used to balance the different interests in the case of an acute oil spill reaching the coastline.

3.2.8.3.7. Conflict resolution

Conflicts are normally resolved in the courts. The consensual nature of Norwegian politics, as well as a tendency to word legislation in general terms, does however mean that the society is generally less litigious than is the case for example in the United States. Also, the practice of having contentious issues studied by committees where those interests that are affected are represented tends to work towards reducing the level of tension and help resolve conflicts in advance of development.

However, natural resource damage claims in the Norwegian legal system do not admit environmental liability as under the US Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and 1990 Oil Pollution Act (OPA). This lack of economic liability may lead to an undervaluation of such damages in the authorities' and petroleum sectors' oil spill contingency planning.

There is still considerable disagreement between environmental organizations such as the World Wide Fund for Nature and the Government regarding the extent to which plans for oil exploration off the Lofoten archipelago have accounted for environmental concerns. Environmental organizations also question the risk of discharges due to accidents *(http://www.bellona.no/no/energi/fossil/nord/31977.html).*

3.2.8.3.8. Infrastructure availability
The general infrastructure for communications in northern Norway is very good compared to other regions at similar latitudes. There are many airports, many of which have several flights a day to Oslo, making same-day return trips possible. Road networks are extensive and are maintained during winter. On the coast, a coastal liner runs a north–south operation that passes each day. In addition, regional ferry and fast-boat networks are extensive.

The petroleum-related infrastructure in the south is extensive, with an 11 000-kilometer pipeline system connecting the production fields to land terminals and markets, and a number of designated harbor facilities. A recent study envisages the connection of new, northern fields to this existing infrastructure (Barlindhaug, 2005), so as to utilize existing distribution networks to European markets.

3.2.8.4. Sustainability of northern operations

3.2.8.4.1. The broad picture
Petroleum activity in Norway is offshore, subject to a national governance system, and important to the country's economy. While regular production has taken place on the shelf in the North Sea for nearly 35 years, petroleum development in the Norwegian Arctic is just about to become a commercial reality. While parts of the region have been open to exploratory activities since 1980 (not counting certain small-scale activities on Svalbard in the 1960s and 1970s), the decision to develop fields with a view to regular production is a recent one. This is driven primarily by the need to maintain the overall pace of development of petroleum resources on the Norwegian shelf, thereby maintaining the state's income from petroleum-related activities. The *Snøhvit* gas field, which consists of several smaller fields, is scheduled to come into operation in 2007.

An important part of the petroleum activity picture in the Norwegian north is also the transportation of petroleum from Russia to western markets, which is expected to reach significant volumes during the next decade. Developments on both sides of the Norwegian–Russian border in the north are also part of a broader energy-security complex, in which northern regions are becoming increasingly important to the global energy supply. New concerns include the increase in oil transportation along the Norwegian coast in recent years.

Since regular production has not yet started on the Norwegian side of the border, there is limited experience to draw on when discussing sustainability aspects of these operations. The governance system for the activity is essentially the same for the whole country, so some observations can be made on the basis of experience in the North Sea and the Norwegian Sea.

3.2.8.4.2. Sustainability as a concept
The question of sustainability usually relates to whether the use of the natural environment can be sustained indefinitely. In the case of natural resources where reserves are limited, as the case is for petroleum, this is not possible. The sustainability issue in such cases therefore has more to do with whether operations happen without irreversible harm to the environment, and how use of the resources may harm the environment. In a wider sense, sustainability may also be thought of as including issues relating to sustaining economic and social viability of societies, including how societies carry out contingency planning for accidents, and liabilities of responsible parties.

3.2.8.4.2.1. Environmental sustainability
In terms of environmental sustainability, petroleum operations in Norway are in general subject to a comparatively strict environmental regime. An objective of 'zero harmful discharges' to sea was introduced in a 1996 Report to Parliament (Ministry of Environment, 1997). Subsequent reports to Parliament have reconfirmed and elaborated upon this objective, and all existing production facilities were to meet this target by the end of 2005 (Ministry of Environment, 2003). The preference for new field developments is re-injection of produced water. This is a prerequisite for developments in the Barents Sea. Drilling operations in that region shall also have zero discharges, except for those resulting from the drilling of the top-hole section for the surface casing.

The only difference between the national petroleum regime and that for the northern regions, then, is in regard to environmental regulations: there shall be no discharges of produced water during regular operations in the north, and produced water and other drilling debris shall be re-injected or taken on shore (with the exception of drilling of the tophole). Demanding as they are, full compliance with such regulations poses challenges to the industry.

Also, special measures have been introduced to protect the valuable fisheries in the region, through the management plan for the Barents Sea (see section 3.2.8.3.6). There are restrictions on the locations where drilling and seismic activity can take place, and also certain temporal regulations to avoid activity during fish spawning. The plan will be reviewed in 2010, and the controversy that surrounded its adoption in 2006 is likely to be revived.

In terms of risk of spills, work on the Barents Sea management plan identified tanker traffic from Russia as the greatest environmental risk. While a number of measures have been implemented to reduce the likelihood and impact of accidents, increase in tanker traffic will pose a major challenge in terms of environmental sustainability, as planned tanker traffic may also pass through sensitive areas (Bambulyak and Frantzen, 2007).

3.2.8.4.2.2. Economic and societal sustainability
Maturing fields in the North Sea and the need to maintain the pace of development in the industry, along with an increasing global demand for petroleum, are the most important driving forces behind petroleum developments in the Norwegian Arctic. For the Norwegian side of the Barents Sea, the reserves are estimated at 0.2 billion Sm^3 p.e., while the undiscovered resources are estimated at 1 billion Sm^3 p.e. The authorities therefore encourage exploration activities.

In terms of economic and social sustainability, it is important to note that petroleum activities are subject to a national regime, and that regional and local effects to a large extent are a result of the constraints and incentives provided by that regime. A critical element of the Norwegian petroleum policy is an overarching objective to provide for the highest possible value creation from the petroleum activity. The policy is based on national control over the development of the industry, the development of a domestic petroleum industry, and participation by the state in the activity. The pace of development, taxation of revenue, and the re-distribution of petroleum income is therefore decided at the national level. Regional or municipal authorities have no formal role in these decisions.

Creation of a pension fund, along with a policy that limits the spending of petroleum revenue in the short term, are significant aspects of the petroleum governance system. The revenue from petroleum activity has greatly benefited the population of the country, which enjoys a living standard among the highest in the world. This applies also to the population in the north, since the state's petroleum income is spent on the country as a whole. The future development of petroleum resources has the potential to bring substantial revenue and create a significant number of jobs and businesses and may therefore be important to regional development. As noted in section 3.1.3.4, different stages in the lifecycle of development have different effects. In general, exploration and construction generate more jobs than production, whereas production lasts longer and continues to contribute tax revenue. At the local level, socio-economic benefits accrue first to those communities where operations are located, as is the case with Hammerfest in Finnmark county.

The Norwegian model for distribution of wealth generated by exploitation of petroleum resources places the Government at the nexus of the distribution system. Petroleum activities are subject to heavy taxes, and the spending of this income is proposed by Government and approved by Parliament. The allocation procedure is therefore fundamentally democratic, in the sense that the representatives of people decide on the use of funds.

3.2.9. Greenland

Greenland is currently exploring its potential for oil and gas development, in terms of both finding reserves and planning for social and economic effects. This case study describes the Greenlandic system and efforts to date to promote and prepare for oil and gas activity. The data come from publications of the Home Rule Government (Statistics Greenland, 2001-02; Government of Greenland, 2004).

3.2.9.1. Political, social, and economic system

3.2.9.1.1. The political system

In accordance with the 1979 Home Rule Act, the Greenland Home Rule Government is constituted by an elected parliament, *Landstinget* (the Greenland Parliament) and an administration headed by *Landsstyret* (the Cabinet). Members of Parliament are elected for a four-year period, though elections may be held before the end of the four-year period. The Cabinet is elected by Parliament. The Ministries carry the political as well as administrative responsibilities so that practically all central functions are conducted through one organization, headed by the minister in question.

Greenland is divided into the regions of West Greenland, North Greenland, and East Greenland. There are 18 municipalities in Greenland. One of these, Qaanaaq, is in North Greenland, while Ammassalliq and Ittoqqotoormiut are in East Greenland. The remaining municipalities are in West Greenland. Municipal autonomy in Greenland was first introduced in 1975, and among other things empowers the municipalities to levy taxes. Among the municipal responsibilities are a number of technical functions, social, cultural and educational responsibilities, sports facilities, the local environment, and the administration and management of the settlements. The municipalities are the closest link between the public sector and the citizens.

Internationally, the Danish government carries out foreign policy on behalf of Greenland, with participation by the Home Rule government. In 1992, Greenlandic representation was established at the Danish Embassy in Brussels, Belgium.

3.2.9.1.2. The social system

On 1 January 2003, Greenland had a total population of 56 676, an increase of 137 persons over the previous year. Of these, 49 941 were born in Greenland, and 6735 were born outside Greenland, mainly in Denmark. After some years in the early 1990s during which the population decreased, this figure has been rising since 1993. However, the annual increases have been less than one percent.

Harbors are a very important part of the infrastructure of the country as practically all supplies of goods and a large percentage of passengers are transported by ship between the towns and the settlements. The harbors also serve the fisheries. Effective and safe harbors are thus of essential importance to society.

Air transport is also important, particularly as all passenger traffic to and from Greenland is by air. The airports at Narsarsuaq and Kangerlussuaq are the gateways to Greenland from Copenhagen. Flights from Iceland land at Kulusuk in East Greenland. Airports, heliports, and helipads also serve the domestic airborne passenger and goods traffic. Air traffic in Greenland is organized in part by service contracts, determined by agreement between the Home Rule government and the operator, and in part through free competition.

3.2.9.1.3. The economic system

Historically, the Greenlandic economy has been characterized by fluctuating growth rates, which is to be expected in a society with a small population and dependent on natural resources. Periods of high growth rates have alternated with periods of considerable negative growth. In the period 1981 to 2002, Greenland's Gross National Product grew an average of 1.2% each year, with the annual figure ranging from –11.7% in 1990 to +7.8% in 1998.

After a considerable fall in production in the early 1990s, the Greenlandic economy grew each year from 1994 to 2001. The fluctuating growth rates are especially linked to the Greenlandic economy being highly dependent on the fishing industry and thus on the status of fish resources, developments in the fishing industry, and on the prices of fish products. Greenland has only limited influence on prices, which are set by the world market. A large part of the Greenlandic economy is also dependent on yearly block grants from the Danish state.

In 2002, Greenland's export of goods was DKK 2140 million (as of June 2007, USD 1 = DKK 5.54) and its import DKK 2891 million, generating a deficit of DKK 750 million. From 1998 (with a deficit of DKK 1038 million) to 2001 (with a deficit of DKK 215 million), the trend had been toward smaller deficits. 2002 broke this trend.

Apart from products from fishing and hunting, few goods are produced in Greenland, and so imports include practically all the articles used for consumption in households, in trade and industry, in the institutions, and for investment. Imports reached their highest value in 1988 at DKK 3495 million. Since then imports have fluctuated between approximately DKK 2200 and 2947 million.

Fish products, including prawns, comprised about 88% of Greenland's exports by value in 2002. The value of exports in that year was down 4%, or DKK 93 million, from the previous year. Market price on prawns, by far the most important export product, has been lower in recent years. Most export is to the European Union. In 2001, the United States surpassed Japan as the largest buyer of Greenlandic products outside the European Union.

3.2.9.2. Responses and effects

As no major oil production has yet occurred in Greenland, this section describes the licensing/sector policy (which has resulted in the granting of two exploration and exploitation licenses within the last two years) aimed at developing the exploitation of oil and gas in Greenland.

3.2.9.2.1. The mineral resources system

Greenland's mineral regulations are found partly in the 1979 Act on Greenland Home Rule and partly in the Act on Mineral Resources in Greenland (1998). The mineral resources system makes Denmark and Greenland jointly responsible through a Joint Committee for Mineral Resources in Greenland through which major questions regarding mineral resources are addressed. The Joint Committee has five members appointed by the Greenland Home Rule Government and five members appointed by the Danish Parliament. Its chairman is appointed by the Queen on a joint recommendation from the Danish Government and the Greenlandic Cabinet. Since 1 July 1998, the administration of mineral resource activities has been carried out by the Home Rule Directorate of Mineral Resources, known as the Bureau of Minerals and Petroleum, which also acts as the secretariat for the Joint Committee.

3.2.9.2.2. Sector policy

In June 2003, the Government of Greenland and the Danish Government approved a new sector policy concerning exploration and exploitation of hydrocarbons in Greenland. In the field of oil and gas, this sector policy implements ideas presented in a September 2000 plan entitled 'A Vision for the Future', prepared by the Home Rule Government (2000). The goal of the plan was to create framework terms and conditions that provide optimum conditions for commerce and industry as a means to ensuring continued growth, employment, and income: "Greenland must work towards increased political independence through greater economic self-sufficiency based on increased market focus and a well-balanced distribution policy."

3.2.9.2.3. Political visions and strategic framework

There is broad political consensus in Greenland that efforts should be made to develop the petroleum sector into a sustainable industry that can make a substantial contribution to Greenland's economy. The overall aim of the policy is to provide a competitive framework so as to generate not only industry interest but also a willingness to invest in petroleum exploration in Greenland. At the same time, all activities related to the development of petroleum resources in Greenland must be carried out with due regard to the environment and to safety.

It is also of critical importance that activities in the petroleum sector create maximum benefit to Greenland, i.e., to secure for the community a fair share of the profits arising from the exploitation of these resources and to ensure that local labor and local enterprises are involved to the greatest possible extent. The main objectives are that:

- society must receive a fair share of profits from exploitation;
- local awareness of the activities must be ensured;
- local labor and local enterprises must be used to the greatest possible extent; and that
- activities must be carried out in a safe and environmentally acceptable manner.

The 2003 sector policy on oil and gas includes a number of specific action plans whose purpose is to generate knowledge and set up framework conditions that are attractive to the oil industry, while at the same time taking the vision and objectives formulated by the government into account. Sector policy focus areas are:

- framework for attracting private investment;
- competitive tax and royalty regime;
- competitive regulation;
- research and marketing;
- capacity building – education and employment;
- health, safety, and environment (discussed in section 3.2.9.3); and
- priority for exploration regions and implementation of policy.

3.2.9.2.3.1. Framework for attracting private investment

A main objective of the sector policy is to provide focus on and stimulate exploration of the most prospective and readily accessible regions, by offering attractive terms and conditions and opening new license areas, so as to attract oil industry investment to Greenland in competition with the other frontier regions of the world. In this connection, it is important that the relevant authorities issue clear announcements as to how, when, and on what terms exploration and exploitation licenses will be granted in Greenland.

The allocation of oil and gas exploration and exploitation licenses is in principle based on one of the two models: (1) licensing rounds (tendering) and (2) open-door procedures. Licensing rounds means that companies submit applications for licenses to explore and exploit oil and gas in geographically delimited areas. Licensing rounds are typically limited to a period of three or six months during which applications must be submitted. Licensing rounds are announced on the basis of predetermined conditions. An open-door procedure differs in that it is possible to apply for oil and gas exploration and exploitation licenses at any time. Historically, Greenland's license policy has mainly been based on open-door procedures.

The 2003 sector policy concludes that licensing rounds are an effective way of making oil companies interested in Greenland's hydrocarbon potential. It is believed that licensing rounds as such may attract the interest of oil companies in hydrocarbon opportunities in Greenland. In addition, experience shows that a licensing round may be an incentive for the seismic industry to acquire new commercial seismic data that the oil industry can use to assess the areas in question. This is evident from the fact that, since the announcement that licensing rounds would be used as the general basis for the granting of licenses, the seismic industry has acquired much more new seismic data in the announced licensing areas for the purpose of selling it to the oil industry.

3.2.9.2.3.2. Competitive tax and royalty regime

The drafting of the new license policy has been based on an acceptance of current realities, in particular that the oil industry regards Greenland as a frontier area. Therefore it has been important to establish a stable and consistent legal and political framework so as to minimize the industry's perception of risk. In 2001, the fiscal terms in Greenland were compared with terms and conditions in Newfoundland, the United Kingdom west of Shetland, the Falkland Islands, and the Faroe Islands. Based on knowledge of geological structures, logistics, and other conditions in the various areas, the general assessment was that fiscal conditions in Greenland should be on a par with or even more attractive than those applying in the Faroe Islands.

The resulting model has the following features: (1) 30% corporate tax; (2) no royalties based on sales; (3) 7.5% surplus royalty when in-house pre-tax return exceeds 23.75%, increasing to 17.5% and 30% when the rate of return reaches 31.25% and 38.75% respectively; (4) the publicly owned company Nunaoil holds 12.5% of each license, but does not pay its share of the costs until after the exploration phase; and (5) a number of fees to cover various public expenses.

3.2.9.2.3.3. Competitive regulation

A key element of the sector policy is that, prior to a new licensing round, the conditions for obtaining exploration and exploitation licenses should be laid down in a model license so as to give the industry advance information about the framework conditions applying to oil and gas activities in Greenland.

The general conditions outlined in this model license include specifications regarding the duration of the license, the rights of other parties in the license area, regulations concerning technical and environmental matters, agreements concerning the training of personnel, procedures for approval of activities, inspection, obligations in the event of default on the part of the licensee, reporting, employment, choice of suppliers, mutual agreements between partners in the license, transfer of the license, insurance and guarantees, and obligations on expiry or relinquishment of the license.

The advantage of model licenses is that the industry will know the general conditions in advance and that negotiations with applicants will be limited to terms constituting competitive parameters. The most important of those terms are work programs and the size of license areas.

3.2.9.2.3.4. Research and marketing

Many countries around the world compete to attract the attention of oil companies. Greenland, therefore, must at a minimum publicize and promote geological data and information about geological surveys that illustrate the potential of finding commercially viable oil and gas reserves. Previously, regional mapping was typically conducted via publicly funded surveys. If a prospect looked promising on the basis of the regional data, oil companies would then carry out the more specific and more detailed surveys. Today, a more comprehensive approach is expected on the part of the public sector, making it necessary at times for the public sector to carry out more comprehensive geological and geophysical surveys to help identify which prospects are most promising.

Public-sector authorities in Greenland thus conduct various projects on an ongoing basis to generate new and better knowledge about oil and gas potential that may in turn increase private companies' interest in exploration. These projects include the acquisition of seismic data, the collection of seabed samples, airborne geophysical surveys, geological analyses and mapping, the preparation of digital material, geochemical analyses of selected areas, and so on. The general trend is that the oil companies are reluctant to invest in exploration in frontier areas unless and until publicly funded studies have laid the groundwork for the assessment of oil and gas potential.

The most important purpose of such projects is thus to enable Greenland to make a major marketing effort concerning oil and gas potential through participation in international fairs and exhibitions, newsletters to the industry, publication of information in international journals, promotion on the Internet, and direct marketing aimed at selected international oil companies. Projects relating to hydrocarbons, however, are very expensive. Consequently, Greenland needs access to continuous funding for such work if it is to be internationally competitive with regard to oil and gas development.

3.2.9.2.3.5. Capacity building – education and employment

The overall aim of Greenland's sector policy is to develop oil and gas activity so that it can support economic development throughout Greenland through increased income generation, new jobs, competence building, and so on. In connection with oil and gas exploration, typically lasting two to three months, the local labor market will experience a brief increase in the demand for seamen, divers, harbour and logistics people, hotel and catering personnel, pilots, air hostesses, airport personnel, and other services. In connection with the establishment of oil and gas production, many different local workplaces can be created, although a great deal of the production equipment itself will have to be made by companies and in locations with special competence and experience in such tasks.

It is important to note that the building of local competence to supply the oil industry should take place at a pace that matches the economy and the extent of oil exploration. It would be inexpedient to train oil specialists in Greenland if it turns out that no commercial oil production can be established in the country. The time frame and uncertainty associated with oil exploration mean that, at the present time, Greenland's education policy should not be oriented towards an oil industry but towards the current labor market. If commercially exploitable hydrocarbon discoveries are made in Greenland, a very large proportion of the oil industry's demand for labor will be for people with the kinds of vocational training noted above as well as other skills.

Instead of seeking to train and educate oil specialists here and now, Greenland's policy recognizes that it makes more sense to train local labor to carry out job functions that are currently in demand by local commerce and industry. If the oil industry in Greenland is developed, a very large proportion of the manpower needed will be identical to the manpower currently needed by local commerce and industry. Once commercially viable discoveries have been made, there will be a solid foundation in Greenland for building competence specific to the petroleum industry.

A baseline Social Impact Assessment is being prepared with a view to creating a reference framework for the oil companies' assessment of the social consequences of oil/gas activities. Local insight and knowledge of hydrocarbon activities must be ensured, also with a view to ensuring that local labor and enterprises are employed as widely as possible. In addition, competence building in Greenland in the field of oil and gas must form an integrated part of the overall education policy in Greenland.

3.2.9.2.3.6. Priority for exploration regions and implementation of policy

The authorities update their knowledge of the exploration potential for oil and gas on an ongoing basis, for example by means of projects relating to the acquisition of seismic data that make it possible to assess oil and gas potential. As a result, the authorities are able to prioritize areas according to the degree of interest they are expected to hold for the industry. A general characteristic of the oil industry is that it sets aside limited funds for the assessment of exploration potential in frontier areas such as Greenland. Consequently the design and selection of projects relating to oil and gas, future license areas, and licensing rounds must always have a time frame that allows the oil industry to incorporate these matters into their long-term planning.

The selection and delimitation of areas to be offered for licensing are governed by the following criteria: (1) knowledge of regional geology; (2) seismic identification of large geological structures with potential for oil and gas; (3) information from other geophysical surveys, e.g., aeromagnetic data; (4) satellite image studies of slicks on the sea surface that can reveal possible oil seeps from the sea bed; (5) environmental considerations; (6) ice conditions; and (7) nominations or other input from the oil industry. The

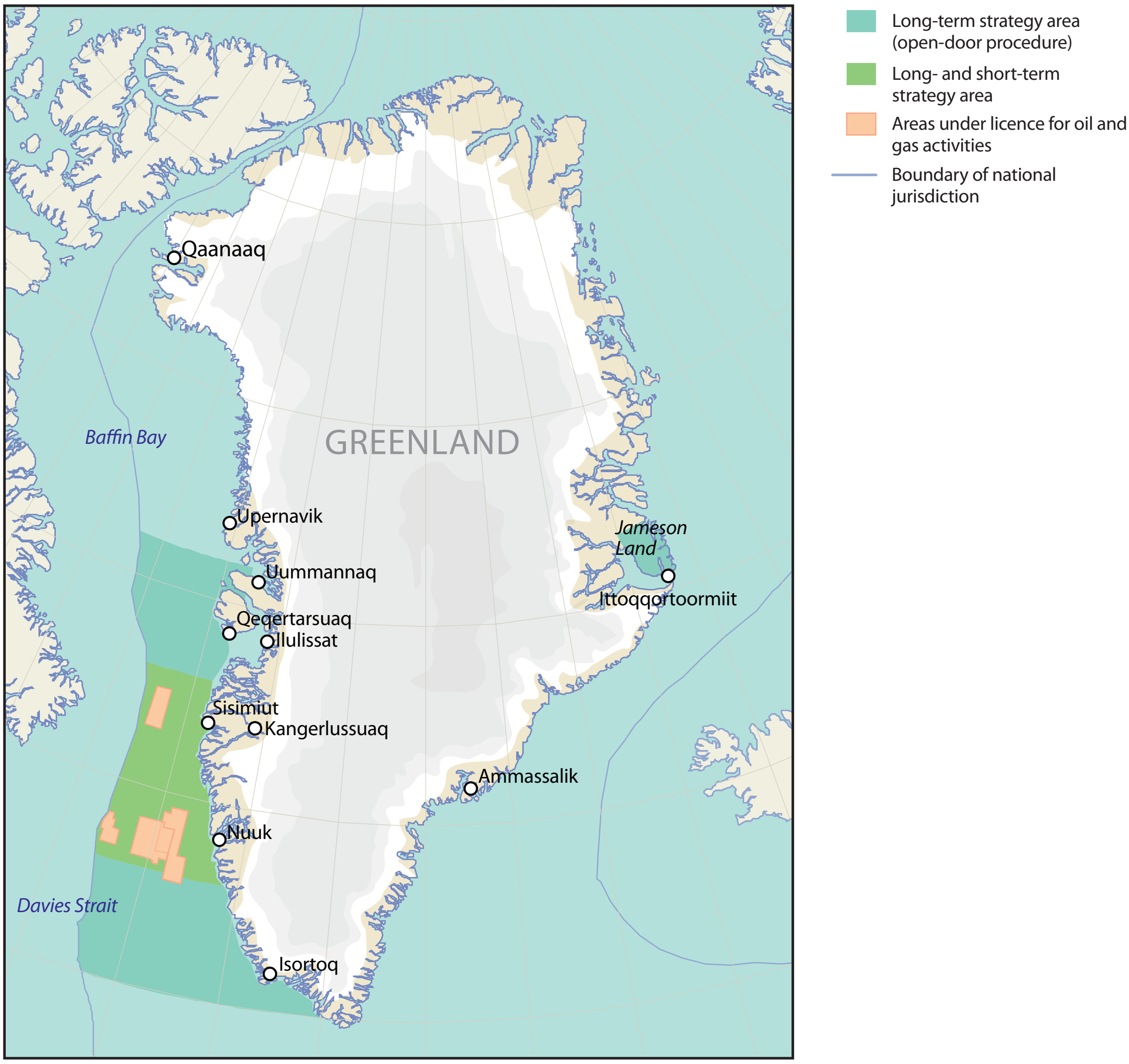


Figure 3.17. Areas under licence and areas comprising Greenland's sector policy for oil and gas activities in the coming years.

operative hydrocarbon strategy in coming years will thus focus particularly on those areas that, according to surveys carried out to date, have the greatest oil and gas potential and where exploration and production can be carried out without detriment to the environment. The short- and longer-term focus areas are shown in Figure 3.17.

3.2.9.3. Sustainability

As noted in section 3.2.9.2.3, there is broad political consensus in Greenland that the petroleum sector should be made into a sustainable industry that can make a substantial contribution to Greenland's economy, and that at the same time such activities must be carried out with due regard to the environment and to safety. Thus, physical and biological environmental conditions are an important factor in relation to the commencement of hydrocarbon activities in Greenland. Oil and gas activities must be carried out in compliance with good international practice and shall be based on modern health, safety, and environmental principles so as to ensure sustainable use of resources. All oil and gas activities in Greenland are therefore covered by the provision laid down in the Act on Mineral Resources in Greenland that activities may not be initiated until approval has been granted by the relevant authorities.

3.2.9.3.1. Environment

From a biological point of view, West Greenland's offshore areas are the most productive in Greenland. They are important for birds and marine mammals, and most fishing in Greenland takes place there. Because fisheries play an important social and economic role, their special needs and requirements must be considered carefully in relation to future activities in these waters. The most important physical environment problems in relation to oil exploration in Greenland are sea ice and icebergs, which constitute operational problems in certain areas.

With a view to including West Greenland's offshore areas between 68° N and 71° N (the Disko-Nuussuaq area) in future license offerings and in accordance with international practice, a strategic regional environmental impact assessment of the area is currently being prepared. This assessment includes geographic, oceanographic, climatological, and biological conditions of relevance to oil and gas activities. The strategic environmental assessment must focus on the environmental impact of oil activities, in particular impacts on: (1) biodiversity; (2) ecosystem structure and function; and (3) other industries that rely on the environment in the region, such as fishing, hunting, and tourism. Studies of the importance of ice and seabed conditions for oil activities in the area west of Disko-Nuussuaq will also be carried out.

3.2.9.3.2. Health and safety

In connection with exploration, deep wells are drilled under high pressure, which may cause blowouts. Work under high pressure and the treatment of oil and gas in offshore installations imply risks of fire and explosions with consequent risk to human life and equipment, for which reasons public regulation is needed. Furthermore, hydrocarbon activities also imply a need for regulation of the procedures for approval of seismic survey activities, sea installations such as drilling ships or rigs, class approvals of ships operating for a company, rules for drilling safety, and rules for operational procedures, and so on. In the course of 2007, a new executive order will be issued on the regulation of Health, Safety, and Environment in connection with oil activities. This set of rules will cover all phases of oil exploration and exploitation.

3.3. Discussion and conclusions

Although the case studies described in section 3.2 provide a wealth of information about past, present and potential oil and gas activities in the Arctic countries, differences in content, format, oil and gas history, and other factors prevent detailed comparisons among them or with experiences elsewhere in the world. This section presents a more general discussion of the common themes from the case studies and some broad observations about effects and lessons learned, including a consideration of about further studies.

3.3.1. Differences among local, regional, and national stakeholders

It is hardly surprising that different groups have different views on the allocation of costs and benefits from oil and gas activities. As summarized in section 3.3.3, oil and gas activities have many effects on social and economic parameters, and these effects are unevenly distributed. Physical disturbance from oil and gas infrastructure is obviously a greater impact to those people in the immediate vicinity than to those far away, whereas economic gains can accrue far beyond the area where oil and gas are produced. The case studies illustrate many of these differences.

In Norway, the effects of oil and gas activity are largely the same across scales, because the development is offshore and benefits accrue nationally. The domestic tax system collects revenue and redistributes it through the public welfare system. Onshore facilities provide local economic benefits, but not to the degree associated with onshore production in other regions. As a result, the tensions that exist over oil and gas development are not predominantly between local and national perspectives or constituencies. A restrictive environmental regime reduces negative impacts, which helps keep tensions low since no one group suffers the bulk of the impacts whereas the entire country benefits from the revenues.

In the Russian Arctic, by contrast, the differences have typically been extreme. In the Soviet era, for example, local residents received lower wages than persons who moved to the area, presumably reflecting the need for extra incentives to encourage workers to move north. Residents of the Nenets and Yamalo-Nenets Autonomous Okrugs received few direct benefits from oil and gas activities. The majority of jobs went to workers that had moved in from elsewhere, the economic gains accrued primarily to the national government, and the environmental impacts fell most directly on those using the land for reindeer herding. Nonetheless, some local benefits were seen in terms of better infrastructure and support for health care, as well as the development of markets for reindeer meat.

Since the Soviet era, conditions have changed dramatically. Local groups such as Yerv and Yamal Potomkam! have succeeded in gaining direct compensation or other benefits from oil and gas activities. The population of the Yamalo-Nenets region increased between 1989 and 2002 (AMAP, 1998; State Committee for Statistics, 2003), making it the only region in the Russian Arctic to grow over that period. Differences across scales still exist, but there is more discussion between the various stakeholders, and more attention given to the situation of local residents.

In Canada, land claims agreements have given indigenous residents considerable control over the pace and extent of development in their areas. In Alaska, the situation is more complex, because Nuiqsut's lands lie amid much larger developments. Although the village corporation can affect what happens on its lands, it is largely powerless to influence what happens on state and federal lands nearby. The course of development at the Alpine field is thus determined not only by what Nuiqsut wants to achieve, but by the demands of other oil fields, related infrastructure, and industry goals for the North Slope as a whole.

In Nuiqsut, too, there are tradeoffs between various interests even at the local scale. Hunting and fishing access is important, but may conflict with economic opportunities from oilfield development. Hunting and fishing, regarded as essential to the social and cultural health of the community, cannot be replaced by wage employment and imported foods. Thus the tradeoff cannot be considered on a purely monetary basis. Meanwhile, considerable financial benefits from development accrue at the regional (North Slope Borough) level, and to the State of Alaska, whereas environmental effects are again largely at the local level. Nuiqsut's ability to influence decisions made by regional and state governments is greatly constrained by its small size as well as its remoteness from both the regional center of Barrow and the state capital of Juneau.

An essential contributor to the degree of tensions or synergies across levels is the distribution of power to the various stakeholders, as provided by the various national political systems. In the Mackenzie Delta region in Canada, considerable local power means considerable local influence, increasing the ability of the community to shape development for maximum local benefit with minimum local cost. In Nuiqsut, local power helps, but is constrained by larger forces on the surrounding oilfields. In Russia, minimal local power in the Soviet era has been replaced with at least some local influence recently, allowing local residents to exert some influence on their own behalf. On the other hand, in Norway, the national regime has ensured a relatively equal distribution of the wealth generated by the petroleum activity among its population. The interplay between local and national influences and effects deserves further study, for example to assess the circumstances under which local influence and benefit are realized with or without reducing regional and national influence and benefit. Furthermore, better networking and capacity among indigenous organizations has enabled them to be more effective advocates.

3.3.2. Comparison of governance and response across case studies

In keeping with the advanced administrative capacity of Arctic countries, governance of oil and gas activities is taken seriously. Such responses include establishing appropriate environmental management regimes, promoting economic development, and seeking equitable distributions of the costs and benefits of oil and gas activities.

As the North American case studies show, governance responses can also occur at the local level, in municipal governments as well as for organizations such as corporations set up in land claims agreements. In Russia, the degree of local involvement in governance has typically been lower, first due to the centralized structure of the Soviet state and later due to the political and economic upheaval at the start of the post-Soviet era. More recently, local groups such as Yerv and Yamal Potomkam! have begun organizing themselves, in part to gain a greater share of the benefits of oil and gas activity while reducing negative impacts. In Norway, and in Greenland's approach to planning so far, governance regarding oil and gas has been concentrated at the national level, emphasizing the retention of earnings by government to be used for the common good. The national emphasis is not surprising, given that oil and gas reserves in Norway and Greenland are offshore, thus reducing local roles and impacts in comparison with on-shore activities in North America and Russia. Also, the distribution of revenue through the welfare system enhances the legitimacy of the national governance system. Alaska and Norway have both used oil and gas revenues to establish trust funds for long-term benefit.

In the on-shore cases, local governance efforts have focused on securing economic opportunity and benefit, while also protecting the environment and cultural practices. In Alaska and Canada there has been emphasis on training workers, though the success of such programs has been mixed. Kuukpik Corporation and the Inuvialuit Development Corporation have been able to use oil and gas activity as a catalyst for further business development. In Russia, Yerv has managed to secure some payments to local residents for land use. Oil and gas workers have created a market for local products such as reindeer meat, which supports a traditional activity that has also been harmed by the environmental impacts of oil and gas activity. Culturally, revenues from oil and gas have been used to support cultural programs and to improve local involvement in social and environmental planning and management. For example, the North Slope Borough in Alaska has established several wildlife management programs, aimed at sustaining traditional hunting, and funded largely through revenues from oil and gas activity in the region (Huntington, 1992).

In addition to formal regulatory response, a variety of other responses have arisen as well, mitigating impacts at the individual and community level. The development of markets among oil and gas workers in Russia is one response by reindeer herders. In Nuiqsut, hunters have adapted their activities to avoid oil facilities. And the winter that there was lots of construction work on *Alpine*, the community allocated jobs equitably, ensuring that every household had at least one wage earner and someone at home to care for children and elders. The *Bent Horn* project, too, made use of community labor pools.

3.3.3. Effects on social and economic systems

As noted in section 3.1.3.3, this analysis of social and economic effects uses nine categories. This section considers interactive effects among the nine categories.

3.3.3.1. Macroeconomic effects

Oil and gas activity can greatly increase regional and national GDP (see Figure 3.18). At a regional and national level, this increase makes possible overall economic growth, increased investment, and the creation of public trust funds for future benefit, as has been done in Norway and Alaska. During the peak times of activity in the lifecycle of oil and gas activities, the demand for labor can create labor shortages, and the demand for goods and services can drive prices up. In the production phase, labor demands are lower but revenue is at its peak. In Norway, for example, petroleum activities accounted for only 3% of national employment in 2003, but 18.8% of GDP, 24.8% of government revenues, and 46% of export earnings.

The tax structure for oil and gas activities can shift the tax burden away from individuals and other sectors, further stimulating economic growth through increased discretionary spending.

3.3.3.2. Microeconomic effects

Oil and gas activity can serve as a powerful engine for economic growth, through increased income from oil and gas employment, through the growth of businesses supporting oil and gas activities, and from the stimulation of overall economic activity. This is especially true during the peak of employment and activity in the construction phase, but the effects can persist throughout the life of a project, particularly in combination with greater regional revenues at the macroeconomic level, which may contribute to a larger overall economy. At the microeconomic level, the case studies illustrate the growth of markets for reindeer meat in Russia as well as the creation of businesses and new lines of business in Nuiqsut and the Mackenzie Delta region. Kuukpik Corporation and the Inuvialuit Development Corporation have used this economic stimulus to diversify their businesses. In Hammerfest, Norway, the *Snøhvit* development will bring substantial annual tax revenue to the municipality.

3.3.3.3. Effects on demography

Oil and gas activities, and particularly the associated economic growth, lead to increased regional populations from in-migration and reduced out-migration. Longer life expectancy in recent decades, from better public health and health care, may also be due in part to the economic growth provided by oil and gas activities. The Yamalo-Nenets Autonomous Okrug is the only region of the Russian Arctic to have increased in population between 1989 and 2002 (ACIA 2005). Both that region and the Nenets Autonomous Okrug saw dramatic population increases when oil and gas were first developed, due in part to the Soviet strategy of establishing cities near petroleum and mineral deposits, in contrast to the Alaskan and Canadian strategies of having workers commute to remote areas by air. In Alaska, nonetheless, the statewide population has increased dramatically since the development of North Slope oil fields, in part due to growth of the overall economy and state government revenues. The population of the North Slope Borough also increased, but since 1999 has begun to decline. In Inuvik, the population declined between 1991 and 2001, largely due to the economic impacts of reduced oil and gas exploration.

In addition to overall population size, oil and gas activities can shift demographic patterns. Areas with strong development tend to have a relatively large proportion of young males, and thus relatively smaller proportions of women, children, and the elderly. Demands for social services can thus be shifted accordingly, including an increased need for police activity.

3.3.3.4. Health effects

The effects of oil and gas on individual health are addressed in Chapter 5. In this chapter, it is noted that development and associated rapid changes in economic conditions (either upwards or downwards) can lead to social disruption such as substance abuse, domestic violence, and so on. When people move or are moved away from their homelands and their cultural setting, mental health can suffer. On the other hand, the availability of financial resources can lead to improved availability of health services such as doctors, hospitals, and so on. Determining the overall net gain or loss in health requires more detailed studies than are currently available.

3.3.3.5. Effects on education and training

Responses to oil and gas activities often include education and training programs, both directed to careers in the petroleum industry and towards higher education in general. In Inuvik and Nuiqsut, for example, there are scholarship programs funded by industry and others for local students who wish to pursue a university education. There are also technical training courses for industry jobs, an emphasis that has been considered in Greenland and will be pursued if oil and gas prospects are developed. In Russia, fewer training opportunities have been provided, consistent with the approach of recruiting large numbers of workers from outside the Arctic regions. Among the considerations in training programs are whether there will continue to be job openings for the skills being taught and whether the conditions of employment attract and retain workers once trained.

In Inuvik, the Inuvialuit Development Corporation has targeted specific, long-term jobs for its training program. In Nuiqsut, meeting local-hire targets has proven difficult. Potential workers may not like the week-on, week-off pattern of work, may not be willing to take mandatory drug tests, or may not be willing to leave the region for long-term training in the higher skill occupations. Furthermore, as oil and gas activities move through their lifecycle, and specific jobs shift to different geographic areas, job retention may require willingness to move, separating local residents from their homelands and extended families. While non-local workers also must move away from home and family, they have already made that break and thus may be more willing to accept a mobile lifestyle. In northern Norway, petroleum development has brought greater demand for university-level education related to the industry.

3.3.3.6. Effects of and on governance

As discussed in section 3.3.2, greater resources for the institutions of environmental and economic governance increase their ability to play substantial roles in regulation, adaptation, management, and so on. Furthermore, as demonstrated by the Norwegian case, regulatory regimes (regarding environment as well as economics) in particular are more likely to be effective if established in advance of the activity, rather than as a response after activity has begun. On the other hand, establishing effective governance regimes can be particularly challenging, given the high economic value of oil and gas compared with most other natural resources. In the Inuvik region, oil and gas revenues and associated business development have acted in concert with land claims agreements to increase local capacity for governance. Similar changes have been seen in Alaska's North Slope Borough and in Nuiqsut itself. In Russia, the lack of revenues to local institutions in the Soviet era prevented the development of effective local governance. Recent shifts indicate a growing role of local institutions, though how far that will continue remains to be seen. In Norway, oil and gas activities provide considerable revenue to the national government, allowing it to provide extensive social services throughout the country. Greenland aspires to similar goals, perhaps even more urgently due to the desire to reduce financial dependence on Denmark.

3.3.3.7. Effects on cultural integrity

In North America, local communities identify cultural protection as a priority in their planning for oil and gas development. Throughout the Arctic, modernization has tended to disrupt traditional social and cultural practices in many ways. Oil and gas activities can exacerbate this trend, by environmental degradation as seen in Russia, or by increasing the pace of societal change, as seen in Alaska and Canada. At the same time, oil and gas revenues to local institutions can be used to provide cultural programs, protect local practices, and strengthen a sense of cultural identity. The North Slope Borough, for example, has used oil revenues to support an extensive and costly program to protect bowhead whaling from international regulatory attempts to end this practice (Huntington, 1992). The Inuvialuit have expanded wildlife management programs. Yerv and Yamal Potomkam! in Russia are beginning to promote ways to use oil and gas activities to sustain local cultures and practices.

3.3.3.8. Effects on contact with nature

As discussed in Chapters 4, 5, and 6, oil and gas activities can have considerable negative impacts on the environment, primarily on a local scale. For local residents, these impacts can alter traditional hunting, fishing, herding, and gathering practices through environmental degradation or by the creation of physical barriers such as pipelines that can affect animals or people. Larger scale impacts may stem from accidents during transport (e.g., oil spills) or widespread pollution (AMAP, 1998). By creating local markets for traditional products, such as reindeer meat, oil and gas activities can also help sustain contact with nature, as seen in Russia. In the North Slope Borough, income stemming directly or indirectly from oil and gas activities has been associated with high production of traditional foods (Kruse, 1986). This result can be attributed in part to the ability of North Slope residents to retain revenue from development in their region. More recent expansion of the oilfield infrastructure, for example around Nuiqsut, has increased the significance of physical barriers to access, perhaps offsetting or more than offsetting the benefits of increased income.

3.3.3.9. Effects on social health

Social health can be considered as the smooth functioning of society, whether at the community level, regionally, or nationally. Oil and gas activities can increase divisiveness, particularly if benefits and costs are not shared equitably, but can also stimulate social cooperation and provide revenues to support social programs. Economic stimulus, particularly during booms and busts, can lead to increased drug and alcohol use and consequent social problems such as domestic violence, divorce, and crime, particularly during transition periods. In the Yamalo-Nenets area, cooperative relationships are being established between reindeer herders and oil and gas workers and industry representatives, which may create a better overall social milieu. In the Nenets area, by contrast, controversies over who is to benefit from cooperative programs with organizations such as Yerv may tear the region's social fabric as some gain and others lose. In Inuvik, oil and gas activities may be associated with increases in drug and alcohol abuse and related offenses, though these increases occur at transition times and not just during boom periods. In Nuiqsut, alcohol and marijuana use are high, making many potential workers unable to pass mandatory drug tests as noted in section 3.2.3.4.4. At the same time, informal responses to the challenges posed by oil and gas infrastructure can be seen as increased social cooperation. For the North Slope Iñupiat, preventing development impacts on bowhead whale hunting is key to continued social health, as is also the case for Inuvialuit and beluga hunting.

3.3.3.10. Interactive effects

As the discussion in the preceding parts of section 3.3.3 has indicated, the various effects cannot be considered in isolation from one another. Similar stimuli can lead to different outcomes depending on the particular situation and how the various effects interact. For example, economic opportunity can spur population growth, stressing cultural integrity by the influx of newcomers, creating social problems and consequent social and individual health impacts. Or, similar opportunity can be harnessed to improve local resources, which can be used for more effective governance, which in turn may improve cultural programs, leading to better social health. The case studies provide examples of both courses, with the additional complexity that may be expected in real-world situations. What the beneficial outcomes have in common is a concerted effort to plan for oil and gas effects. In the Mackenzie Delta region, development slowed for many reasons in the 1980s and 1990s, which allowed for the creation of local capacity. In Norway, setting clear national goals and developing a comprehensive regulatory regime for the activity helped plan specific regulations, in advance of oil and gas activities, that have resulted in substantial national benefit. In Russia, Soviet-era planning took little account of local interests. In recent years, improved local planning has helped ameliorate the situation to some extent. While the precise course of activities and effects is difficult or impossible to determine in advance, the broad scope of impacts can be ascertained, together with a sense of the tradeoffs and synergies that can be anticipated among various categories of effects.

3.3.4. Looking to the future

Looking forward, the social and economic effects of oil and gas activities can be considered in terms of their long-term effects on the environment and on society. Oil and gas activities certainly have the potential to create severe negative environmental impacts, as noted in Chapters 4, 5, and 6. They also have the potential for both negative and positive social and economic effects, as described in the case studies in section 3.2. This section discusses the ways in which the course of past and current activities may or may not contribute to sustained societal benefits, following from the definition of 'sustainable development' quoted in section 3.1.3.5.

The course of development to date is only a rough guide to its future course. Context is important. Technology changes. Individuals and institutions learn and adjust based on experience. The planning taking place in Greenland reflects experiences elsewhere, just as Mackenzie Delta development reflected an assessment of earlier work in that region as well as what had occurred elsewhere in Canada and on Alaska's North Slope. In Russia, the disconnect with the past is profound, due to the collapse of the Soviet system. Nonetheless, a review of the trend of effects in each case together with a comparison

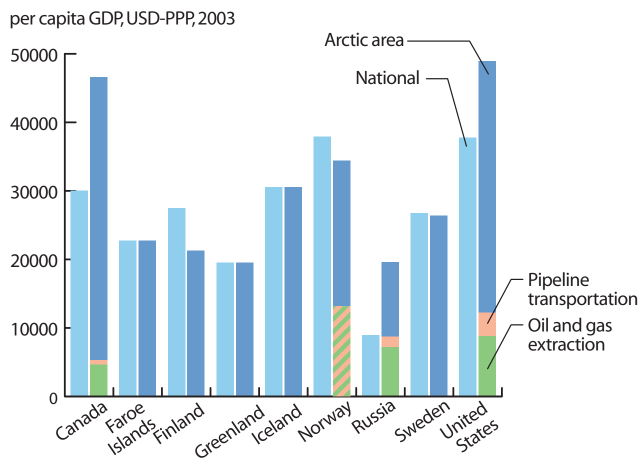


Figure 3.18. GDP in Arctic regions compared with national averages (2002) showing the contribution of oil and gas extraction and pipeline transport to the regional GDP (Glomsrød and Alasken, 2006).

across cases can help identify broad expectations for the next decade or so.

In Russia, recent years show an increasing involvement by local organizations. This trend is unlikely to stop, though how much influence those organizations will ultimately have remains to be seen. In the absence of agreements similar to the land claims settlements made in Alaska and Canada, it seems unlikely that local organizations will exert anything close to the level of control seen in Alaska and the Northwest Territories. On the other hand, better communication and cooperation between industry and local residents may help reduce negative impacts and increase opportunities. In half a century of operations, oil and gas activities have caused considerable environmental degradation, but reindeer herding and other traditional practices continue. If those practices can be sustained indefinitely, the overall cultural integrity of the indigenous peoples of the regions may be preserved.

In Alaska, oil development is expanding westward into areas used for subsistence hunting by Nuiqsut and three other communities, and northward into the Beaufort Sea. Gas production is on the horizon as well. Nuiqsut will remain in the midst of oilfield infrastructure, with the drawbacks and the opportunities that entails. The crucial question is whether Nuiqsut residents can continue traditional practices such as whaling, hunting and fishing and pass those skills on to future generations. The role of oil and gas development in this question is unclear. Income may support hunting by making possible the acquisition of boats and snowmobiles and fuel. On the other hand, greater travel distances to hunting and fishing sites requires greater time commitment, which may conflict with work schedules, the school year, and other constraints on time. Economically, Kuukpik Corporation's growth and diversification will still depend on customers and clients, who are likely to be oilfield companies or local residents whose income stems directly or indirectly from oil and gas. Nuiqsut's sustainability depends on its ability to find a balance that makes Nuiqsut both an attractive and an affordable place to live for its residents.

In Canada, greater local influence gives the Inuvialuit Development Corporation and the institutions created by the Inuvialuit Final Agreement a great deal of influence over the future of the region. As elsewhere in the Arctic, greater education and employment opportunities are a double-edged sword. Those who remain in the region can help stimulate growth and further economic and social development, but many who go to university seek employment elsewhere, reducing the net gain for the region itself despite the positive impact on individuals who enjoy a greater range of choices. The next decade in the Mackenzie Delta region is likely to see expanded exploration and the start of development and production. A key question is whether the investment in preparation for gas development will pay the dividends that local leaders expect in terms of jobs, net regional income, and minimized social and environmental disruption.

In Norway, experience to date in the North and Norwegian seas indicates ample capacity to manage oil and gas activities to attain the goals set by the Norwegian polity. Barents Sea plans expressly consider sustainability, and this concept will be extended elsewhere in Norway over time. What changes this will entail remain to be seen. Unless the goals are substantially changed or a serious accident occurs, Barents Sea development and the domestic regulatory system will follow a largely similar course to that seen to date in the North and Norwegian seas. The risk of an oil spill from tanker transport past the Norwegian coast remains a major concern. Norway's ability to establish a strong environmental and economic regulatory regime in advance of oil and gas activity is a key part of its success, as is its political stability.

In Greenland, oil and gas activities may begin within the next decade. If so, the adequacy of planning efforts will be determined by experience. For training programs, the key variable is likely to be the pace of lifecycle stages, and whether they allow sufficient time to train a workforce. For revenue retention, Greenland will need to strike an appropriate balance between encouraging exploration and development and ensuring that profits are adequately distributed. Oil and gas have the potential to reduce dependency on Denmark and to diversify the economy beyond fishing. Both steps would affect Greenland's social and economic system, though employment is unlikely to shift substantially away from the public sector. As in Norway, the offshore location of development reduces local impacts and may allow for broader sharing of benefits since no region can claim special rights with regard to ownership of the resource.

In all cases, the chief question in terms of sustainability is the degree to which oil and gas activities can be used as a means and not an end. Development may last for a long time in some areas, but the resources are finite. Planning for a decade may not be particularly difficult, especially given that the production phase for many oil and gas fields lasts longer than that, and the planning and preparation phases may take longer still. Sustainability in these cases is a longer-term issue, though the trends towards or away from sustainability may well become apparent in the next decade.

3.3.5. Knowledge gaps and further studies

The lack of common statistical measures hindered the ability to compare experiences and effects in the various case study areas. Some statistics are not collected in all locations, some are collected differently, and some simply could not be obtained. Beyond basic demographic information, important indicators such as employment rates for local residents, contribution of oil and gas activities to regional gross domestic product, occupational health and safety data, and others were either unavailable or incompatible across case studies. Thus, for example, documenting trends in local employment rates or the distribution of revenues may not be possible even for one locale, much less as a comparative exercise for the Arctic as a whole.

To fill these gaps and provide a more solid foundation for further research and comparison, social and economic statistics related to oil and gas activities should be collected on a circumpolar basis. These statistics should include, for example:

- Employment;
  - employment statistics specific to the oil and gas industry in the Arctic;
  - percentage of local work force working in industry activities;
  - industry employment by local resident/indigenous/gender variables;
- Wage income from oil and gas activities;
- Industry expenditures;
  - by life-cycle stages;
- Royalty and tax revenues;
  - local, regional, and national;
  - recipient;
  - public and private trust fund investments and holdings;
  - revenue sharing;
- GDP contribution;
  - total and percentage, regionally and nationally, on an annual basis;
- Social infrastructure;
  - industry role;
  - industry contribution;
  - educational and training opportunities;
- Occupational health and safety;
  - rates of accidents, injuries, deaths; and
  - loss of work hours due to accidents.

To develop these and other indicators, a small working group or task force could be created to review: (a) which indicators are currently tracked in various oil and gas regions of the Arctic; (b) which of these could be extended to all regions; (c) which new indicators should be tracked, recognizing that feasibility is a key factor; and (d) what types of analyses such a consistent set of indicators will allow.

A second and related step is to develop methods and indices for measuring the effectiveness of various actions to reduce negative and promote positive effects from oil and gas activities. Various methods exist for doing so at the case study level, but extending these to circumpolar comparisons requires additional work to refine consistent approaches that accommodate the different contexts of each region. Such assessments should address, for example:

- Effects on access to and availability of subsistence resources;
- Effects on cultural practices and cultural integrity;
- Effectiveness of socio-economic mitigation and opportunity measures; and
- Information sharing and consultation.

As with the development of indicators, a small working group or task force could review the anticipated benefits of these and other comparative assessments of effectiveness and then identify the steps needed to conduct such assessments.

3.3.6. Conclusions

In the Arctic regions where it has occurred, oil and gas development accounts for a substantial proportion of GDP. In Norway, the economy is reasonably diverse. Elsewhere in the Arctic, there are few other industries or economic drivers outside the public sector. Oil and gas activities therefore exert or have the potential to exert a major influence on Arctic social and economic systems. Population trends support this interpretation, with large increases in areas where oil and gas activities spur substantial economic activity. Oil and gas activities may overwhelm social and economic systems, or those systems may be able to harness oil and gas activities to achieve other goals. Effective governance is thus a key variable with regard to successfully responding to the challenges and opportunities presented by oil and gas activities. Functional regulatory regimes for the environment as well as the economy, ideally set up in advance of the activities in question, are essential components of such governance.

A number of trends and patterns are apparent from the case studies. Lifecycle stages present specific trajectories of employment, revenue, activity, and so on. The most dramatic of these, such as large-scale construction but also accidents such as oil spills, are also relatively brief. Capitalizing on these windows of opportunity requires careful timing. Training a workforce for jobs that are transient in nature will produce at best a brief benefit, and at worst a workforce for which there is no employment to be found. By contrast, overall revenues are greatest during production, which requires relatively few workers. Thus, direct employment and revenue may not match well. Harnessing revenue to create economic stimulus and thus overall gains in employment and services may offer a longer-term benefit than aiming for jobs in industry. Here, too, planning is necessary to determine appropriate goals and the means to achieve them. In turn, this requires effective institutions, capable of learning from experience, and with the power to act effectively.

Costs and benefits are not evenly distributed across stakeholders, or from local to regional and national levels, or throughout the lifetime of a development. The distribution of power is one factor in shaping the degree to which such unevenness creates tensions and negative impacts, or can be reduced for broad benefit. When local organizations and institutions lack power, local interests may be neglected, so that costs are borne disproportionately by local residents while benefits accrue primarily at the regional and national level. When local organizations have control through regulatory authority or land and resource ownership, more benefits are likely to be retained locally and local ability to respond and adapt are likely to be enhanced. Norway, however, provides a counterexample, with the benefits of oil and gas being distributed throughout society by national policy and regulation.

Looking to the future, the question is how oil and gas activities can contribute to the overall sustainable development of Arctic regions. Oil and gas development has brought tremendous wealth and associated improvements in public health, education, and other services to a generation of Arctic residents in some regions, and promises similar benefits in others. While these activities and revenues may persist for many decades, they still extract finite resources and thus will eventually end. In other regions, oil and gas development has degraded the environment and disrupted local social and cultural systems leaving a legacy of negative impacts that reduce the potential for sustainability or the assets that contribute to it. The lesson is that institutions matter. Oil and gas activities can be harnessed to stimulate broader economic growth, to support the retention of cultural practices, and to increase financial, human and social capital that provide lasting benefits. An essential determinant is the ability to plan, act on those plans, and adapt based on subsequent experience.

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Chapter 7
Scientific Findings and Recommendations

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7.1. Introduction

This assessment was designed to build upon and update the previous AMAP assessments of oil and gas activities conducted in 1997 and 1998 as part of larger assessments of the state of the Arctic environment. The previous assessments looked primarily at the specific issue of hydrocarbon pollution from oil and gas activities and its effects. Since 1998 there has been growing interest in oil and gas in the Arctic. Concomitant with this escalating interest has been the development of new and improved techniques and technology, updated environmental legislation, regulations, and industry practices, and an increased public awareness of the Arctic. The current assessment, by taking a broader view of 'activities,' is more comprehensive providing a history and near-term projection of the oil and gas industry for each Arctic country. It also considers a wider range of effects. In addition to hydrocarbon pollution, this assessment looks at effects of polycyclic aromatic hydrocarbons (PAHs) and other substances, noise, and physical disturbances on individual organisms, populations, habitats, ecosystems and human health. A major addition to this assessment directed by the Arctic Ministers is a consideration of the social and economic effects, and potential effects, of oil and gas activities in the Arctic. The assessment also addresses the vulnerability of Arctic species and ecosystems to oil and gas activities, including accidental oil spills. The findings of this assessment are more thorough than previous assessments but in some cases are still incomplete due to lack of certain information.

For onshore oil and gas activities, the main issue identified is physical impacts, disturbances and habitat fragmentation of the terrestrial environment. Early oil and gas activities caused long-term effects in the terrestrial ecosystem, such as scarring on the tundra due to a general lack of understanding of the sensitivity of the Arctic environment and the slow rates of recovery. Even more recent operations have caused impacts such as changes in drainage, changes in distribution of wildlife populations, and local effects from large oil spills such as the Komi spill in Russia. New technology and methods have significantly reduced damage caused by operations, but these changes are cumulative and as activities expand or overlap, the impact may still be long term and in some cases may even be increasing.

For the marine and freshwater aquatic environments, the main issue of concern is the risk and potentially large impact of accidental oil spills. The *Exxon Valdez* oil spill in Prince William Sound in the Gulf of Alaska happened outside the area considered for this assessment, but did affect sub-Arctic populations of birds, mammals, fish and other organisms and demonstrated the extent of damage that could be caused by a large oil spill in Arctic marine waters. So far, no large oil spills have occurred within the Arctic and sub-Arctic marine area addressed in this assessment. Arctic animal populations are often highly aggregated during breeding, feeding or migration, and an oil spill could potentially affect a large fraction of populations of seabirds, fish and marine mammals. Thus, a large oil spill in ice-covered waters could represent a threat to populations and even to species.

Arctic oil and gas activities have had both positive and negative effects on socio-economic conditions of communities near the activities. The social effects are generally greatest at the local level, while economic effects are often also evident at the regional and national levels. The assessment concludes that adaptive development of management and supervisory systems and evolving advances in technology and best practices have lessened the effects of oil and gas activities. Careful planning, diligent application of rules with necessary control and enforcement, use of best technology and techniques, and continued adaptation to changing conditions may reduce the effects of current and future activities. Even so, the cumulative effects are of growing concern as Arctic activities expand. Evidence shows that accidents will happen and best practices will not always be followed.

The vast majority of the Arctic environment, away from local sources from human populations and activities, is largely pristine with regard to oil hydrocarbons and PAHs. Concentrations are low and close to natural background levels, although these levels are elevated in some areas from natural sources such as oil seeps (e.g., the Mackenzie Valley and Buchan Gulf in Canada) and erosion of coal-containing bedrocks around Svalbard. Even though no regional (large-scale) effects on the environment or clear population level effects on fauna or flora have been documented and no effects on human populations in the Arctic have been substantiated, crucial data are missing. This assessment has been limited by the lack of detailed information on inputs of contaminants from point sources of oil and gas activities such as oil and gas fields, and on the concentrations and gradients in contaminants in the vicinity of such point sources. Thus it has been difficult to assess the degree and areal extent of pollution effects at the local level around such facilities. This has also affected the ability to assess exposures of humans and wildlife populations in areas with onshore oil and gas activities. There has also been a lack of information on the status and trends in animal populations in areas of oil and gas activities and no comprehensive or reliable studies of Arctic populations that may have been exposed to oil and gas pollution.

This assessment distinguishes between effects occurring on local and regional scales. Local is taken to mean the area near point sources of pollution, infrastructure or disturbances from oil and gas activities. This can be oil fields, various facilities, villages, cities, airports, etc. The local scale would typically be smaller than 1000 km^2. Regional is used to mean larger areas such as a whole region of a country, for instance the North Slope region of Alaska, the Mackenzie Delta region, the Yamal region, the Pechora Sea region, etc. The regional scale would typically be of the order of 10 to 100 thousand km^2.

7.2. Main findings

The main findings of the assessment follow. These are presented as short statements with supporting text that frame the issues and provide the main justification for the findings. There are ten main findings, each broken down into a short set of sub-findings. The ten findings cover a range of topics. Finding 1 addresses oil and gas resources and the history and future projections of oil and gas activities in the Arctic. Finding 2 covers socio-economic effects, while Findings 3 and 4 consider the sources and levels of pollution by hydrocarbons and other substances from oil and gas activities. Findings 5, 6 and 7 deal with environmental effects: physical impacts on the terrestrial environment are presented in Finding 5, the potential effects from oil spills in aquatic environments are presented in Finding 6, while toxicological and other effects are presented in Finding 7. Finding 8 addresses effects on human health. The two last findings cover technology and use of best practices (Finding 9) and governance (Finding 10).

Finding 1: Oil and gas activity in the Arctic is likely to increase

F1.A. Hydrocarbon resources in the Arctic are substantial

Arctic production accounts for as much as about 10% and 25% of the world's total oil and gas production respectively. The present data indicate that Russia has produced 80% of all Arctic oil and 99% of all Arctic gas, with lesser production from the United States, Norway and Canada. Many estimates of oil and gas resources from the Arctic exist, and although they vary according to the different methods and criteria used to calculate them, all indicate that a significant percentage of the world's discovered oil and gas reserves and remaining undiscovered oil and gas resources are in the Arctic. One estimate of discovered oil and gas has 5% of the world's oil and 22% of the world's gas in the Arctic. The present data indicate that northern Russia has 75% of known oil reserves and 90% of known gas reserves in the Arctic. Although highly uncertain, some estimates indicate that up to 25% of the world's undiscovered oil and gas resources reside in the Arctic. While these estimates are disputable, the Arctic certainly contains a large amount of undiscovered resources. Russia, Norway and the United States are thought to have the largest amount of undiscovered Arctic oil resources, while Russia, the United States and Canada are thought to have the majority of undiscovered Arctic gas. Offshore, currently available information indicates that Russia, the United States and Norway have the largest undiscovered Arctic resources on their continental shelves. Offshore shelf areas in Canada have had some positive exploration results from drilling in the 1970s and 1980s, while Greenland and the Faroe Islands are in the initial stages of evaluation. These areas should not be discounted as possible major sources of future production.

F1.B. There is a long history of oil and gas exploration and production in the Arctic

Oil seeps were known to indigenous people and the early explorers for a long time. Commercial Arctic oil and gas activities have been occurring onshore for many decades in Russia, the United States, and Canada, first beginning in the 1920s. Early exploration efforts in the 1940s to 1960s used poorly adapted technology and methods and were characterized by an initial lack of understanding concerning the environmental consequences of the activities. Offshore exploration started in the 1970s and early 1980s in all Arctic countries with petroleum provinces. As new techniques were developed, exploration activities both onshore and offshore accelerated, mainly through the 1980s but in some areas into the early 1990s. These exploration activities covered large areas of previously unexplored Arctic lands and seas. Hundreds of thousands of line kilometers of 2-D seismic data were collected and large numbers of exploratory wells were drilled in this period. However, of the discoveries made very few were large enough to justify their development. Since most of the activities did not result in discoveries, large areas of the Arctic were subsequently taken out of consideration for development due to the lack of potential economic resources.

During the 1980s and continuing into the present time, the methodologies employed by much of the Arctic oil and gas industry have changed in two important ways. First, there has been an increase in development drilling in known fields and in smaller accumulations adjacent to existing oil and gas transportation infrastructure. Second, there is an increased reliance on seismic data to evaluate potential geological targets, reducing the required number of wildcat wells to discover oil and gas. New large-scale infrastructure projects are either under construction or in advanced stages of evaluation in Alaska, Canada, Norway, and Russia, indicating that high levels of seismic and drilling activity will continue in many parts of the Arctic for the foreseeable future.

Oil and gas were discovered in the northwestern parts of Russia as early as the 1930s, and have been produced from the northern Timan-Pechora and western Siberian provinces since the 1960s and 1970s. Activity in these areas remains high. Many thousands of kilometers of pipelines have been built to transport oil and gas from northwestern Russia to other regions of the former Soviet Union. Exploration for oil in Alaska began in the 1920s, and in 1967 the large *Prudhoe Bay* oil field was discovered. Following the construction of the 1300-km Trans-Alaska Pipeline in 1977, oil production and large-scale infrastructure development began and is still ongoing in northern Alaska. Canadian Arctic exploration efforts resulted in the discovery of oil in the Norman Wells region from which seasonal production began in the 1920s. Production expanded in the 1980s resulting in the construction of a 900-km pipeline south to Alberta. Oil was discovered in the Arctic Islands at Bent Horn in 1976 and small amounts of oil were produced and shipped by tanker from 1985 until 1997. Significant amounts of gas and some oil were discovered after an intense exploration effort in the Mackenzie Delta and Beaufort Sea region, with smaller discoveries of oil or gas in other parts of the Canadian Arctic. The Mackenzie Valley pipeline, which is being proposed to ship gas from the Mackenzie Delta south to Alberta, is currently undergoing environmental assessment and regulatory review.

Norway's Arctic exploration efforts, which began in the early 1980s, led to production from the *Draugen* field in the Norwegian Sea in 1993 and then from several other fields. The *Snøhvit* gas field in the Barents Sea is under development with production scheduled for 2007. Very high levels of exploratory activity are currently being conducted in the Norwegian part of the Barents Sea. Exploration seismic and drilling efforts have also taken place and are ongoing in Greenland and the Faroe Islands and seismic exploration has taken place offshore of Iceland. While exploration has not yet yielded oil or gas discoveries in these areas, and is being conducted at relatively modest levels, efforts to date have produced results warranting further evaluation.

F1.C. Levels of oil and gas activities in the Arctic are affected by many factors

Many factors ultimately control whether and when Arctic oil and gas development activities will take place. These include international political factors such as energy security for developed countries and demand for energy from emerging economies. Other factors include resource potential and the chemical, geological and physiographic nature of the deposit; long-term trends in oil and gas prices; legal, regulatory, and economic controls; lands made available for activities; environmental, political and economic risk; technological development; and capacity of existing infrastructure or development of new supporting infrastructure.

Operating costs of activities in the Arctic must account for harsh and challenging working conditions such as limited or non-existent infrastructure, low temperatures, seasonal darkness, permafrost, sea ice, changing climate, and high transportation costs, as well as increasingly complex regulatory controls to protect the environment and people living and working in the Arctic.

The lead time from discovery to development is usually equal to or longer than that for other parts of the world. A dedicated program for onshore development may take ten years or more between discovery and production. Offshore development and development in smaller, more remote and/or more environmentally sensitive areas onshore, may take 15 to 30 years to develop – or may never be developed.

F1.D. Oil and gas activities are likely to expand into new areas

Areas thought to have high resource potential, whether previously explored or unexplored, are being considered for more focused exploration activities. Throughout the Arctic, areas are being made available for exploration licensing and leasing. If development results, it will lead to increased capital investment and expanded infrastructure.

Plans are in place for near-term (<10 years) and mid-term (10–15 years) future development and further exploration for oil and gas in the Arctic. In Russia, oil and gas production activities will grow in the northern Timan-Pechora and West Siberia provinces and in the Kara and Barents seas. This development is likely to include the construction of a major oil pipeline for Arctic oil transport to the Pacific Rim, and several new marine terminals and subsequent Arctic tanker traffic to markets, including Arctic tanker routes. In Alaska, oil production will continue in the Arctic Alaska province on the North Slope and Federal onshore and offshore lands and may include gas production if a major pipeline is constructed to transport gas to the lower 48 states. In Canada, expansion of oil and gas exploration is likely to occur in onshore and offshore areas including the Mackenzie Delta, and gas production will increase with the construction of the Mackenzie Valley gas pipeline. Norway is planning continued exploration and development activities in the Norwegian and Barents seas with associated offshore pipeline and tanker transport.

In the mid- and far-term (15–25 years) exploration is likely to continue and extend into new offshore Arctic shelf areas, and onshore exploration activities around existing fields and in new areas are likely to take place in Alaska, Canada, Greenland, eastern Siberia and northeastern Russia. Development as a result of these activities is, however, unlikely to occur within the mid- to far term due to the typically long lead time between exploration and development. New pipelines and marine terminals are likely.

On the horizon (>25 years), it is possible that unconventional oil and gas resources may be developed in Arctic areas. These deposits include viscous or 'heavy' oil, coal-bed methane, and potentially vast methane hydrate deposits both onshore and offshore.

F1.E. Arctic oil and gas transportation systems will expand

Existing transportation infrastructure for oil and gas in the Arctic includes pipelines, tankers, vehicles, and railcars. In Russia, transportation of oil and gas to refineries and users is accomplished by a combination of pipelines, coastal barges, shuttle tankers, large tankers, supertankers, railcars, and trucks. By some estimates, Russia's pipeline system comprises approximately 150 000 km of gas- and 50 000 km of oil-product lines and a significant number of kilometers of oil and gas collection and gas distribution lines, but as yet there are minimal trunk lines in the Arctic. There has been an increase in the volume of oil transported by tankers along the Norwegian coast from Russia. In 2002 the volume was 4.7 million m^3; in 2004, 14 million m^3; in 2005, 11 million m^3; and over 12 million m^3 in 2006. By some estimates, Russia may have the capacity to ship more than 46.6 million m^3 of oil per year by 2010 and over 115 million m^3 of oil per year by 2015. In the United States, oil is transported from the North Slope of Alaska by the 1300-km Trans-Alaska Pipeline to southern Alaska and transferred to tankers for export. In Canada, oil from the *Norman Wells* field is transported by pipeline 900 km south to Alberta and then on to southern markets. In Arctic offshore Norway, oil is transported to shore by tankers and gas is transported by subsea pipelines to the mainland. In Alaska and Russia, many of the Arctic pipelines are at or near their operational life expectancy.

Several major pipeline projects are planned in the near- to mid-term in the Arctic. In Russia, many new pipelines are being built to augment an aging system. Two major projects being planned are the Eastern Siberia-Pacific Ocean pipeline system (ESPO) that will carry oil from the eastern Siberian oil fields to the Pacific coast of Russia for regional export. The other major project, now on indefinite hold, is an oil pipeline thousands of kilometers long from the fields in Timan-Pechora and western Siberia to an Arctic port in the Murmansk area, where oil will be shipped by tanker to Europe and the United States. There are new projects underway to expand port capacities or to construct new ports for loading of tankers in the Russian North. Should Canada approve the 1200-km Mackenzie Valley gas pipeline, this will allow the first production from gas fields of the Mackenzie Delta and the Central Mackenzie, with eventual development of Beaufort Sea discoveries. The pipeline will connect to existing pipeline systems in southern Canada. The Alaska natural gas pipeline is likely to be built, connecting the Alaska North Slope with pipeline transport to Canada and the United States mainland, allowing gas to be commercially produced for the first time in northern Alaska. Depending on the final route, this pipeline could be 2600 to 3400 km long.

In areas of new discoveries where infrastructure does not exist, such as the Chukchi or East Siberian seas, new transportation infrastructure will need to be built.

Finding 2: Oil and gas activities are major drivers of social and economic change

Oil and gas activities are a catalyst for the growth of the regional and community market economy and infrastructure, and frequently also for the introduction of new decision-making systems and values. But there are many other concurrent causes of social and economic change in the Arctic, and it remains nearly impossible to separate the role of oil and gas activities or their proportional contribution to specific effects. Every region is unique in its particular resources, geographic context, political and economic institutions, culture and history, and stage of oil and gas development, so the opportunity to generalize is limited.

F2.A. Social and economic effects of oil and gas activities are mitigated by the planning, regulatory and allocation functions of governments

Effective governance includes the ability to plan for and respond to societal impacts of development, strong environmental regulation and supervisory responsibilities, public involvement in decision-making, and a pragmatic working relationship among industry, government, and the public. The distribution of power is a major factor in shaping the degree to which unevenness creates tensions and negative effects. When local organizations and institutions lack power, local interests are likely to be neglected, so that costs are borne disproportionately by local residents while benefits accrue primarily at the regional and national levels.

The initial presence of and prospects of additional activities by the oil and gas industry have heightened the desire of local governments and regional indigenous groups to be involved in the regulation and monitoring of industrial activities, to receive sufficient funding to cope with increased program and service workloads, and, in some areas, to share in the wealth created. In Alaska, the North Slope Borough was created. In Canada, land claim settlements introducing co-management boards and self-governance were established and land claims continue to be settled. One feature of local participation is the use of local boards that recognize the value of both local and traditional knowledge in the decision-making process. In Canada, the federal government undertakes consultations on oil and gas activities to identify decisions or actions that could infringe on indigenous peoples' rights under the Canadian constitution and, wherever possible, to accommodate the concerns expressed by indigenous peoples. In Russia, the degree of local involvement in governance has typically been lower, firstly due to the centralized structure of the Soviet State and later due to the political and economic upheaval at the start of the post-Soviet era. More recently, local groups such as *Yerv* and *Yamal Potomkam!* have begun organizing themselves, in part to gain a greater share of the benefits of oil and gas activity while reducing negative socio-economic and environmental impacts. In Norway, and in Greenland's approach to planning so far, governance regarding oil and gas has been concentrated at the national level, emphasizing the retention of earnings by government to be used for the common good. Norway and Alaska have both used oil and gas revenues to establish trust funds for long-term benefit.

F2.B. Socio-economic effects vary according to the scale and 'life-cycle' stage of oil and gas activity

'Life-cycle' stages of the oil and gas industry vary in scale and area, ranging from a particular field or prospect, to a larger development area, to an entire region or country. Many Arctic regions are at early stages in the oil and gas 'life cycle' and are experiencing the initial effects of large development projects. Social and economic effects tend to increase and be more local at the exploration and construction phase, then to stabilize and be more regional in the production stage.

The remote and technologically intensive nature of Arctic development has focused industry on larger reserves to finance the high capital costs of bringing the resource to market. This intensity increases the social and economic effects at the various stages. Construction will bring local employment, business and market economy effects. For example, employment is highest during the construction stage, which typically entails employing available local labour and bringing large numbers of workers to the region. If workers are highly mobile, they can re-locate to the site of the next large construction project. If workers are not mobile, their employment opportunity is short-lived. Also during construction, employment normally shows seasonally high levels of transient labour.

By contrast, public revenues often come from royalties or taxes, and thus are more evenly spread through the production stage. During this stage, production and revenues peak and begin a long decline, although revenues are linked to oil prices and so are highly variable. While production is high, employment is relatively low and steady. Production jobs are high skill, high pay, and workers tend to be non-local.

F2.C. Indigenous Arctic people are becoming more involved and more affected as oil and gas development expands in the Arctic

Indigenous people are becoming more active participants in oil and gas activity in the Arctic, as decision-makers, owners, employees and community service providers. Land claim settlements in Alaska and northern Canada have resulted in indigenous people becoming private land-owners, co-management participants and business participants in the industry.

Much of the Arctic land areas, and all of the continental shelves, are owned by and managed by national or regional governments. Private ownership of land in the north is less prevalent than in the southern zones of the same countries. In North America, most of the privately owned land belongs to indigenous corporations established by land claims agreements, meaning that it is owned in common by the indigenous inhabitants. Some of these agreements resulted from the desire of governments to settle indigenous claims in order to make areas available for oil and gas activities and pipeline rights-of-way.

The interaction between the oil and gas industry and indigenous people is facilitating social and economic change. Protecting cultural heritage is a high priority throughout the Arctic, from local initiatives to national legislation and international conventions. A crucial part of indigenous cultures is connection to place, increasing their vulnerability to dislocation by industrial and other activities that can separate them from their lands. At the same time, Arctic indigenous peoples have developed great flexibility to deal with the inherent variability of the Arctic environment, increasing their resilience to change.

The Arctic countries are now largely market economies, with varying degrees of state intervention in their markets. In regions of Greenland (Denmark), North America and Russia, elements of subsistence economies still exist. Wages and cash connect indigenous people to the modern market economy, but at the same time acquiring food from the land

and sea and sharing or bartering of foods and other goods and services provide a major part of households' production and consumption. This non-market sector mitigates the high cost of living and the limited array of consumer goods in remote areas, buffers the volatility in the wage economy, and maintains cultural identity and social capital in Northern communities.

Industry expansion across the Arctic has increased the overlap between traditional use of the land and oil and gas activity. Techniques are being employed to use traditional knowledge in project planning, environmental assessments and regulatory decision-making.

F2.D. The economic value of oil and gas activities plays a significant role in national, regional and local-level effects

Oil and gas activities can be harnessed to stimulate broader economic growth and to increase financial capital that provides lasting benefits. These activities are likely to form the largest sector of the Arctic Gross Domestic Product (GDP). The value of the oil and gas activities is also a factor in regional and national policy-making. For example, the decline in oil production in Alaska is highlighting the need to diversify and plan for other sources of revenue. The value of Norwegian production has facilitated national policies to distribute benefits and invest trust revenues. Oil and gas activities in northern Canada have been limited to several substantial exploration booms and a limited amount of oil and gas production. Construction of the proposed Mackenzie Valley pipeline can be considered as a basin-opening project that would lead to a new round of exploration, development and production.

Oil and gas revenues have brought wealth and associated improvements in public health, education, and other services to a generation of Arctic residents in some regions. However, in other regions, development has had adverse effects on the environment and disrupted local social and cultural systems, leaving a legacy of negative effects that reduce the potential for sustainability.

Oil and gas revenues can also support the retention of cultural practices. Harnessing these revenues to create economic stimulus and overall gains in employment and services may offer longer-term benefits than aiming for jobs in industry. In some instances revenues from oil and gas may directly benefit the national government but often not the local government. In contrast, the social effects are primarily local.

Finding 3: Contamination from oil and gas activities in the Arctic is relatively minor compared to inputs from natural seepages

F3.A. Natural oil seeps comprise the majority of the total input of oil hydrocarbons to the Arctic environment

Hydrocarbons normally found in petroleum have been detected in all compartments of the Arctic environment. However, many hydrocarbon compounds can be produced by processes other than those leading to the formation of petroleum (petrogenesis). Hydrocarbons in the environment are formed through four distinct processes: pyrogenesis (combustion), diagenesis (natural degradation in sediments), biogenesis (biological production) or petrogenesis. Each process produces a characteristic profile of individual compounds although there is considerable overlap. A selection of 20 to 30 parent and alkylated polycyclic aromatic hydrocarbons provide an excellent diagnostic tool for identifying petrogenic contributions. These compounds have been used as a surrogate for establishing the presence of petrogenic hydrocarbons. In order to quantify the relative contribution from the different sources, it is necessary to have datasets that quantify individual parent and alkylated compounds. Such information is limited for the Arctic. It is therefore difficult to quantify the petrogenic contribution on an Arctic-wide scale with certainty. However, some datasets are available and suitable for quantifying petrogenic hydrocarbons in some regions.

This assessment has attempted to estimate the relative magnitude and importance of different sources of petroleum hydrocarbons and PAHs influencing the Arctic environment. On an Arctic-wide basis and using incomplete quantification of individual contributors to each input pathway, it has been estimated that natural oil seeps are contributing most to the total input of oil hydrocarbons. Oil spills may be the second largest source, greater than non- oil and gas related industrial activities, atmospheric deposition, and activities related to oil and gas excluding spills.

F3.B. Several sources of emissions and discharges of petroleum hydrocarbons and related contaminants exist in the Arctic, and result in local pollution in some areas

Important anthropogenic sources of oil hydrocarbons and petrogenic PAHs in the Arctic include the general use of refined petroleum products, oil and gas production, and loss in transportation via pipelines, railways, and ships. Other sources include shipping accidents, runoff from land, rivers, industrial activities (e.g., oil and gas terminals, refineries, smelters, and mines), and routine discharges from ships and fishing vessels. Inputs of oil hydrocarbons to the Arctic also derive from long-range transport from the heavily industrialized northern hemisphere, especially pyrogenic PAHs which result from the combustion of almost any carbon-based fuel. Long-range transport to the Arctic takes place through the atmosphere, by river flows and by ocean currents. The atmospheric transport pathway contributes only small amounts of petroleum hydrocarbons, but significant amounts of pyrolytic PAHs. On land most of the hydrocarbon contaminants will be contained within the immediate vicinity of the discharge or spill. Atmospheric emissions can affect much larger areas.

Several river basins in Canada and Russia are petroleum enriched. These north-flowing rivers carry oil hydrocarbons to the adjacent seas. Currently, the source for most of this transport is natural. These rivers may also contribute oil hydrocarbons to the northern seas as a result of shipping accidents, blowouts, pipeline ruptures, runoff from towns, cities and industrial facilities, and from long-range atmospheric transport to snow within the catchment area.

F3.C. Arctic oil and gas activities are currently a minor source of oil hydrocarbons and PAHs on a regional scale, but can be important locally

On a regional scale, the current discharges and emissions associated with the oil and gas industry are estimated to contribute a relatively small fraction of the total input of oil hydrocarbons. This could rise to a much higher fraction when oil and gas production in the Arctic peaks. In the past, oil and gas activities have led to pollution on a local scale, sometimes severe pollution. An example is the Komi oil spill in 1994, which actually comprised several minor spills from a pipeline over a period of several months. An estimated 100 000 tonnes were released that polluted 280 hectares (2.8 km^2) of marshland/freshwater. An evaluation of the extent and importance of local pollution around point sources from oil and gas activities has generally not been possible due to a lack of detailed information. Waste disposal methods and procedures employed by the oil and gas industry are central issues in evaluating the effects associated with the industry. In some areas, sumps were used to store process water and drilling fluids and were sealed and abandoned after drilling ceased. Studies have shown that a number of these sumps are leaking and more may lose their integrity as climate change causes erosion of the permafrost.

Oil spills information from the North Slope of Alaska for 1995 to 2002 indicates that around half the spills were from the petroleum industry in the area. Transport and spills associated with the general use of petroleum were the source of the remainder of spills. Similar sources of spills are likely in Russia and other Arctic regions.

Modern technology and improved practices have raised expectations for dramatic improvements in Arctic land-based and offshore discharges and emissions. All Arctic countries have stopped discharges of oil-based drilling mud. Most countries now use water-based drilling fluids, and synthetic-based muds have replaced oil-based muds in most cases where such fluids are necessary. Spent muds and cuttings are disposed of in approved disposal sites onshore or re-injected into approved underground reservoirs. Onshore, treated produced water is still discharged to surface waters and land in Russia, but re-injection of produced water and wastes is becoming standard practice in the Arctic. Most countries are moving toward re-injecting produced water from offshore production. The use of 'environmentally-friendly' chemicals is being encouraged. There is continuous improvement in waste handling procedures. Improved technology, more stringent standards, and heightened awareness of the need to reduce emissions have resulted in significant environmental benefits.

F3.D. Oil and gas exploration, production and transportation have the greatest potential for large-scale accidental or long-term releases of contamination to land and sea

Drilling of oil and gas wells is much more extensive in the development and production phase than during exploration, while the types of emissions and discharges are similar. Specific to the production phase are emissions from flaring, venting and production testing, and the potential releases of production chemicals, contaminated production water and wastes from drilling. The transport phase of activity has the greatest potential to release oil and hazardous substances into the environment. Tankers and pipelines are the main potential sources of spills.

Finding 4: Levels of oil hydrocarbons and PAHs in the Arctic environment are generally low, except in some local areas

F4.A. Low background concentrations of oil hydrocarbons and PAHs occur in the Arctic marine environment

Levels of oil hydrocarbons are generally low in the Arctic marine environment, and fall within ranges normally considered to be background. For all sea areas, levels in sediments are generally well studied. Less information is available on levels in sea water and marine biota.

In the northern North Atlantic Ocean, Barents Sea, Russian northern seas, sea areas around Alaska and the Queen Elizabeth Islands in Arctic Canada, concentrations of oil hydrocarbons and PAHs in sediments are low, and levels found can usually be attributed to natural sources. In the Eurasian northern seas the highest background levels of petroleum hydrocarbons and PAHs are found around the Svalbard archipelago. The main source of the PAHs is probably the erosion and weathering of coal-rich sediments, while marine oil seeps make a smaller contribution. Elevated baseline levels also occur in sediments in the vicinity of the Mackenzie Delta and Beaufort Sea Shelf, mostly due to inputs from natural seeps along the Mackenzie River and offshore. Elevated concentrations are found in some coastal areas such as Buchan Gulf (Canada) and river estuaries of Russia. The sources to the latter are both natural and anthropogenic.

Natural petroleum seeps from land and rivers and natural marine seeps are important contributors to the background levels of oil hydrocarbons and PAHs found in large parts of the Arctic marine environment. Offshore petroleum industry in the Arctic is limited, and has only a local impact close to the oil and gas production fields.

F4.B. Information on oil hydrocarbons and PAHs on land and in freshwater systems is more limited than for the marine environment, but indicates low levels in areas distant from human activities

The assessment of oil hydrocarbons and PAHs in freshwater systems and on land is not as good as for the marine environment, due to limited information available for this assessment. Only Russia has conducted extensive systematic, long-term monitoring of petroleum in the terrestrial and freshwater systems of the Arctic. However, the information available from these studies has been condensed to the point that it is difficult to identify contamination hot spots or to establish concentration gradients. Another factor limiting data comparability and the value of the data for establishing trends is the use of several analytical methods for which quality assurance data are insufficient or lacking entirely. For Canada and Alaska, information from a limited number of studies was used. For Greenland, Iceland, the Faroe Islands and Norway, very few studies have been carried out on land. For most Arctic countries the measurement of petroleum hydrocarbons and PAHs in biota has not been a high priority in most monitoring programs because concentrations in biota are usually low and input to the environment is assumed to be low. PAHs are also readily metabolized by many organisms and thus do not reflect exposure history through accumulation. An important exception is that PAHs are measured in biota after oil spill events in order to document the level of bioaccumulation and exposure of the biota.

In areas remote from human populations the concentrations of oil hydrocarbons and PAHs in ice, freshwater, soil and biota generally fall within the lower end of the global range.

F4.C. Elevated concentrations of oil hydrocarbons and PAHs are usually found close to industrial and urban communities in the Arctic

Areas where higher concentrations of oil hydrocarbons and PAHs are found are usually associated with point sources of human activities. In the oil and gas fields of northwestern

Russia there are reports of many cases of local contamination from accidental spills and discharges, overloading of treatment facilities, and leakage from waste deposits such as sludge pits. Soils in some areas have accumulated large amounts of oil (up to 10% by weight) that will last for many decades under conditions of natural degradation, representing long-term pollution. In offshore oil fields on the Norwegian shelf to the Norwegian Sea, discharges of drill cuttings have contaminated the sediments in near-zones around the discharge points, totalling about 80 km^2 of bottom habitat for all the fields combined. Monitoring has shown disturbance of the benthic fauna over an area of about 14 km^2 and that the area is decreasing due to natural recovery. Monitoring of abandoned onshore drill sites on the North Slope of Alaska has shown some local contamination but generally of limited extent.

The data sets available for this assessment have, with the exception of the Norwegian offshore fields, generally not been detailed enough to establish the areal extent of local pollution or to establish quantitative relationships between sources and concentrations in the environment.

Finding 5: Physical impacts, disturbances and habitat fragmentation are the main issues for terrestrial environments

F5.A. Oil and gas activities leave a physical 'footprint' on land

Exploration and development of oil and gas fields on land leave a physical 'footprint' in the terrestrial Arctic environment. Infrastructure in the form of gravel pads, buildings, waste sumps, roads, airstrips and pipelines transforms the areas occupied. Gravel extraction for the construction of pads and roads, for example, may leave physical scars or disturb stream habitats. Oil and gas infrastructure causes direct physical impacts on the Arctic tundra and other habitats.

More diffuse physical near-zone impacts are also associated with the infrastructure. Dust from roads may affect the physical conditions and vegetation out to a few hundred meters. Roads and other constructions may also influence the hydrology of flat tundra landscapes. Pipelines and roads may impede migrations of animals, and traffic and human presence may cause avoidance in some species, while others may be attracted. Avoidance effects may extend out several kilometers. There are also positive effects from roads, gravel pads and structures as they can provide relief from insect harassment for caribou/reindeer. Pregnant female caribou/reindeer, and those with calves, appear to avoid structures and human activity to a greater extent than other caribou/reindeer. The long-term effect of these changes on caribou/reindeer, and other species that might show similar behaviours, are complex and unclear and require more research in the light of possible expanding oil and gas activity.

Networks of roads, pipelines, settlements and human presence contribute to habitat fragmentation that can affect wildlife. Oil and gas activities and development are but one sector of several contributors to habitat fragmentation. The spatial configuration of infrastructure and disturbances is an important aspect for the degree of environmental impact. Roads, pipelines and clearings for seismic transects are linear configurations that can have disproportionately large effects either by impeding migration for instance for caribou/reindeer, or by providing migration corridors for predators like wolves. Design of the infrastructure (e.g., elevated or buried pipelines) and traffic control may significantly reduce the environmental impacts. On a larger scale, removal of oil and gas from geological formations may lead to the subsidence of the ground surface and this may affect wetland habitat and the nesting of shorebirds and waterfowl.

F5.B. The physical impact of past activities has affected varying proportions of tundra environments

Tundra environments are fragile and vehicles leave tracks that remain for long periods. Summer travel on thawed ground, although a practice abandoned by most countries, is particularly damaging. Varying proportions of tundra environments have been damaged by tundra travel and construction of infrastructure related to oil and gas exploration and development. On the North Slope of Alaska, infrastructure and gravel mines occupy an area of about 100 km^2, which is less than 0.1% of the area of the coastal plain tundra. Tundra travel may have impacted an area of similar extent. Larger areas are affected in the oil and gas regions of northern Russia, reflecting the more extensive activities there. In the Yamalo-Nenets Autonomous Okrug, the total area of disturbed land is over 1500 km^2, constituting about 0.13% of the okrug area. On the Taz Peninsula, more than 6000 km^2 of tundra have been disturbed, equivalent to about 1.5% of the total area. In the Arctic, the rate of recovery of disturbed terrestrial systems is very slow due to the severe climate and low availability of nutrients.

F5.C. Modern oil and gas activities leave smaller physical 'footprints' than corresponding activities in the past

Improvements in drilling technology allow fewer and more compact drilling pads. This reduces the area occupied by infrastructure, the amount of gravel needed, and the scale of construction. Tundra travel for seismic activities and other purposes occurs on frozen ground in winter with specially designed vehicles that leave little or no impact on the vegetation and the ground. Movement of equipment and supplies on ice roads in winter reduces the need for permanent roads that may disturb wildlife in the summer period.

The physical 'footprint' from infrastructure and travel is now substantially smaller using current technology and best practices than it was during the earlier period of oil and gas activities. Real-time monitoring of wildlife combined with traffic control and other mitigating measures has also substantially reduced the disturbance from oil and gas activities in some areas. Although new oil and gas activities leave a smaller footprint, this is sometimes additional to impacts from earlier activities. The cumulative effects from past and present activities may continue to increase, albeit at a slower rate than in previous years.

F5.D. Oil spills on land have limited spatial extent compared to oil spills at sea but may have long-lasting impact

Oil spills on land are a potential source of impacts to the Arctic environment. Old mixed-product pipelines or gathering lines are prone to leak from corrosion, and substantial amounts of oil and other substances have been spilled in terrestrial environments. Even low-pressure product pipelines thought to be less prone to leak, have shown substantial corrosion as at Prudhoe Bay, Alaska in August 2006. There are reports that in the Russian north, substantial amounts of oil have been lost from pipelines during transport. The Komi oil spill in Usinsk in 1994 drew large attention and spread into the freshwater system of the Pechora River. Despite the large amount of oil spilled (>100 000 tonnes), the environmental impacts appeared to be limited to a moderately restricted area. About 7 km^2 of land was designated as severely impacted by oil and an area perhaps ten times as large was impacted to some degree.

In contrast to the open marine environment where spilled oil can spread and affect large areas and long coastlines, terrestrial oil spills are less mobile. The soil of the active layer above the permafrost may become saturated and relatively small areas may hold large amounts of spilled oil. The oil may resist bacterial decomposition because of low levels of oxygen and retain its toxic components for decades. The oil can get into freshwater systems, as did the Komi oil spill, but the spread is more limited than for marine spills. Terrestrial spills are amendable for containment, recovery, and remediation actions. For these reasons, oil spills on land are of less environmental concern than marine oil spills.

This is not to say that terrestrial oil spills are unimportant. Large amounts of oil have been spilled and persist in the Arctic, contaminating considerable areas of tundra and wetland environments. This represents a threat to wildlife and a risk of contaminated food and water and of health impacts on humans in the affected areas. Also, the clean-up response to terrestrial oil spills can have physical effects on wildlife, terrestrial environments, archaeological resources, human health, and local socio-economics. However, the occurrence of natural oil seeps in most areas of terrestrial Arctic oil operations is a far greater source of oil than that spilled. There is insufficient information to judge what impacts may be associated with these seeps.

Finding 6: Oil spills have the greatest potential to impact aquatic environments

F6.A. Small oil spills are relatively frequent while large spill events are rare

Spills are inevitably associated with exploration, production, transportation, storage and use of oil, gas and/or their refined products. The frequency of spills decreases with increasing size of the spill, and small spills (a few to some hundred liters) occur relatively frequently while large spills are quite rare. This is illustrated by global spill statistics, which predict a frequency of about 2 spills greater than 10 000 tonnes annually from tanker accidents and less than 0.1 spills from blowout. In the Environmental Impact Statement for the Alaskan Beaufort Sea, anticipated annual occurrence rates of spills larger than 160 m^3 (1000 barrels) were 0.13 and 0.10 spills standardized per billion barrels (160 million m^3) of oil produced, for spills from platforms and pipelines, respectively.

Oil spill statistics indicate the probabilities of spills but not when and where they will occur. This is addressed by risk assessments. There have been no major oil spills in ice-covered waters within the area of the current assessment since spills resulting from actions during the Second World War. This is partly due to the still limited extent of offshore operations in the Arctic, but also to better supervisory and operational practices. Globally, the frequency of oil spills from tankers, platforms and pipelines has been declining, reflecting improvements in technology and operational performances. This no doubt also benefits operations in the Arctic. At the same time, the harsh environmental conditions and the presence of sea ice make operations in the Arctic inherently more risky than at more southerly latitudes.

F6.B. Seabirds and fur-bearing marine mammals are vulnerable to oiling

Seabirds and some marine mammals are vulnerable to oil on the sea surface. Their sensitivity results from the physical coating of feathers or fur with oil. This causes a loss of thermal insulating properties and body heat, leading to hypothermia and often death. This is particularly serious for organisms living in cold environments. Seabirds that spend most of their time swimming or diving are more vulnerable than those spending most of their time airborne or snatching food from the surface. Arctic seabirds generally have long-range spring and autumn migrations, are colonial or semi-colonial, and have a slow reproductive capacity with delayed maturity of adults, low fecundity and high adult survival, characteristics which make some species particularly sensitive to oiling. Physical oiling was the mechanism responsible for the high acute mortality of seabirds and sea otters (*Enhydra lutris*) in Prince William Sound following the *Exxon Valdez* spill, an event that occurred outside the geographical area for the current assessment. In this case, for several seaduck populations, the high mortality caused by physical oiling was followed by effects that lingered for more than a decade after the spill. Harlequin ducks feed in the intertidal zone, and at oiled coasts they had lower survival and lower body mass and showed a decline in densities compared to stable numbers on shores that had not been oiled. The effect was caused by long-term contamination from persistent subsurface reservoirs of unweathered spilled oil in the intertidal zone.

Seabird eggs are particularly sensitive to oiling, with minute amounts of some oils causing death or mutation of developing embryos. Studies have shown that oil transported back to the nest on the breast feathers of adult birds is sufficient to cause mortality in incubated eggs. Hence, any release of oil to the Arctic marine environment from oil and gas activities could cause death to adult birds from direct oiling or mortality in incubating eggs. The ingestion of oil by seabirds, whether from preening of oil-coated feathers or ingestion of contaminated food items, can lead to changes in reproductive hormones and the immune system. These changes could ultimately reduce the rate of reproduction. Also, fur-bearing animals, including polar bears (*Ursus maritimus*), can increase the dosage they receive by ingesting oil when attempting to clean fur by licking it.

Marine oil spills have the potential to cause decline in seabird populations, and single seabird colonies may be deserted. Some species that concentrate in a few areas can suffer a greater population decline after a single spill than more dispersed populations. Seabirds are slow- reproducing species with long population recovery times. Populations can have some resilience to catastrophic high mortality because there can be pools of non-breeding birds that become active breeders when the breeding population is lost through natural or man-made causes. Hence populations of some species recover more rapidly than others owing to natural mechanisms of response to catastrophic events. However, not all species have such characteristics and a major oil spill would undoubtedly affect some species for very long periods of time.

Seals, in particular young pups, are also vulnerable to oiling. Harp seals (*Phoca groenlandica*) congregate in the Gulf of St. Lawrence to bear their pups on the ice each spring. A spill of about 600 m^3 of Bunker C oil occurred there in 1969, and it was reported that several thousand adult seals and pups were oiled and an unknown number killed. Although the Gulf of St. Lawrence lies outside the area of the current assessment, it is ice-covered in winter, and the impact of such a spill is relevant to the Arctic situation. Whelping areas, where large numbers of seals aggregate annually on the ice, are found in the Davies Strait region (hooded seals, *Cystophora cristata*), in the southern Greenland Sea/ Jan Mayen area (hooded and harp seals), and at the entrance to the White Sea (harp seals). Whelping areas for spotted (*Phoca largha*) and ribbon (*Phoca fasciata*) seals are found in the southern part of the annual pack ice in the Bering Sea.

F6.C. Whales have low vulnerability to oiling in general but their vulnerability could be higher in ice-covered waters

Whales depend on their layer of blubber and not on pelage for thermal insulation, and hence physical oiling is less acutely harmful. This is also the case for many Arctic seals and the walrus (*Odobenus rosmarus*). Whale skin is very tough and tolerant to oil, although mucous membranes of the eyes and respiratory pathways may be irritated and damaged. Inhalation of vapours from a fresh spill could potentially harm whales that do not escape from the scene of a spill.

There is limited evidence for effects of oil on whales in spill situations. Observations of killer whales (*Orcinus orca*) in Prince William Sound suggested that there were effects on the social behaviour of at least one group of individuals and fifteen killer whales disappeared between autumn 1988 and summer 1990. These whales were so well known that they were recognizable as individuals, and this loss represented an unprecedented change for these animals. Fouling of baleen may represent a special threat to the large baleen whales. Bowhead whales (*Balaena mysticetus*) may skim feed on Arctic zooplankton in the surface layer in leads and openings in the ice. This species may be more vulnerable should oil concentrate in this special environment.

Bowhead, beluga (*Delphinapterus leucas*), narwhal (*Monodon monoceros*), and walrus have seasonal migrations from wintering areas in the southern parts of the sea-ice distribution in winter into the high Arctic in summer. The spring migrations take place early before the general ice break-up and follow systems of leads and polynyas in the ice. This is also the time when these migrating mammals give birth to their calves. Owing to the confined nature of their migration habitats where they depend on the openings in the ice for breathing, they could potentially be sensitive to oiling in this situation.

F6.D. Even small spills can affect many animals if they occur at times and places where the animals have congregated in large numbers

The circumstances of an oil spill are often more important for the extent of damage to animal populations than the size of the spill. Large numbers of seabirds have been reported dead following relatively small spills, whereas some large spills have been associated with relatively low mortality. The decisive factor has been the concentrated occurrence of animals or their vulnerable life stages and the overlap with the spilled oil.

Seabirds and marine mammals can be highly aggregated in the Arctic. Seabird colonies may range in size from hundred thousands to millions of individuals that feed in the vicinity of the colonies. Seabirds also aggregate to feed in polynyas and leads in the spring prior to breeding, for molting at sea after breeding, and for wintering in polynyas and the marginal ice zone in the low Arctic or in open sub-Arctic waters. In these situations they are highly vulnerable to oil spills.

Marine mammals also congregate in confined areas for purposes such as pupping and molting, or live normally in social groups. Harp and hooded seals aggregate in large numbers at specific sites to give birth to their pups on the ice. The northern fur seal (*Callorhinus ursinus*) is very concentrated at breeding colonies, the largest being at the Pribilof Islands. A spill near such concentrations of marine mammals can have an impact disproportionate to its size.

Bowhead and beluga have seasonal migrations between wintering areas in the northern Bering Sea and the Davis Strait region, into the high Arctic during summer. Narwhal have similar migrations from their wintering area in the Davis Strait. These migrations follow recurrent systems of shore leads and polynyas that develop in late winter and spring. During migration and feeding the whales may occur concentrated in the restricted areas of open water in the ice where they may be sensitive to oil spills.

Several species of migratory waterfowl and shorebirds have staging areas in coastal habitats. Some of these areas are very important because a large fraction of the population aggregates there and feeds to fuel for the southward autumn migration. These areas are very sensitive to oil spills. Examples include the Yukon-Kuskokwim Delta in western Alaska, Izembek and other lagoons on the northern side of the Alaska Peninsula, estuaries in Yamal and Gydan and the Lena Delta in northern Russia, and the Mackenzie Delta and sites along the southern shores of the Coronation Gulf and Queen Maud Gulf in northern Canada.

The ice edge at the transition between ice-covered and open waters has a special biological significance. The ice provides resting places for birds and seals, while the ice edge phytoplankton bloom and concentrated occurrence of zooplankton and small fish may provide good feeding conditions. Polar bears also frequent the marginal ice zone hunting for ringed seals (*Phoca hispida*). The ice edge may be a particularly vulnerable zone due to the concentrated occurrence of marine life and the possible accumulation there of drifting oil.

F6.E. Small cod-fishes that spawn under the ice are sensitive components of Arctic marine ecosystems

Polar cod (*Boreogadus saida*), Arctic cod (*Arctogadus glacialis*), saffron cod (*Eleginus gracilis*), and navaga (*Eleginus navaga*) are Arctic cod-fishes that spawn under the ice in winter. The eggs have a long incubation time and hatch when the ice starts to melt and spring growth of plankton resumes. These small cod-fish species are important in coastal and offshore parts of the Arctic marine ecosystems. There is limited information on their population structure and their specific spawning areas.

Potentially, an oil spill in winter could overlap with the spawning areas of these cod-fishes and impact on the eggs or larvae. This could affect the recruitment and size of the populations and have repercussive effects on other parts of the ecosystems due to the roles of these fishes as prey for animals at higher trophic levels.

Other fish species are also sensitive to oil spills. Pacific herring (*Clupea pallasi*) and capelin (*Mallotus villosus*) spawn on sandy beaches and in shallow subtidal waters where the eggs adhere to the bottom substrate. Several coregonid whitefish species spawn under the ice in rivers and lakes where the eggs incubate to hatch in spring. Pacific (*Hippoglossus stenolepis*), Atlantic (*H. hippoglossus*), and Greenland (*Reinhardtius hippoglossoides*) halibuts spawn along continental slopes in the Bering Sea, Norwegian Sea, and off Iceland, western Greenland, and Labrador. The eggs have a long incubation time and could be sensitive to oil spills from deep blowouts in these areas.

F6.F. An oil spill in ice-covered waters could have a large ecological impact

The impact of an oil spill in ice-covered waters depends in part on the amount and fate of the oil and its overlap with sensitive organisms. The ice cover would tend to preserve the hydrocarbons in the oil. Exposure to volatile components could therefore be longer, and higher concentrations could be maintained than under open-water conditions because the evaporative pathway is much reduced.

Large effects could possibly occur if the oil overlapped a spawning area of polar cod or other small cod-fishes that spawn under ice. The same applies to congregations of seabirds or marine mammals where they have come to feed or, in the case of marine mammals, to breathe. If the oil spread along the lead systems that bowhead, beluga, narwhal, and walrus use on their seasonal migrations, the potential conflict could be large. The same is the case if the oil spread along ice edges with concentrated occurrences of seabirds and seals. In worst-case scenarios, large fractions of populations could be affected and killed.

The extent of ice cover is a key determinant for the impact of a spill in ice-covered water and for the possible remedial actions that can be taken. One hundred percent ice cover of sufficient thickness to support clean-up equipment and crews using terrestrial clean-up techniques allows highly efficient spill remediation and limited subsequent impact in some spill situations. Thin ice or broken ice prevents the use of either terrestrial or open-water marine techniques, limiting response to burning in place. The worst-case scenario for an Arctic marine spill is a low volatile crude spilled in broken ice conditions at a time and place when animals have congregated.

Finding 7: Oil and gas activities have had environmental effects locally but long-term changes to Arctic wildlife populations have not been documented

F7.A. Pollution effects due to oil and gas activities in the Arctic are local

Oil hydrocarbons can be acutely toxic to aquatic life forms if they occur at high concentrations. Low-boiling aromatic compounds in the low parts-per-million concentration range in the water kill fish if they are exposed for periods of a few days. Variations in sensitivity occur among species and life stages, with sensitivity to acute effects of oil generally greater in larval stages. At lower concentrations than those causing acute effects, chronic responses may occur. Chronic effects are most often of concern with exposure via sediments because hydrocarbons can persist there for decades or more, and studies have shown that such exposure can result in tumours and genetic changes. Chronic effects are relevant in the Arctic because degradation rates are slower there. Studies to estimate 'no observable effect concentrations' (NOECs) from chronic exposure studies indicate that these fall in the low µg/L range. Sunlight enhances greatly the toxicity of several PAHs to aquatic organisms, especially those organisms that are translucent and occupy shallow habitats where light can penetrate.

There are a wide range of mechanisms whereby oil hydrocarbons and PAHs exert their toxicity. These include effects on cell membranes such as anatomical and physiological effects on gills, effects on the central nervous system such as narcosis and behavioural changes, biochemical effects including changes in levels of enzymes and hormones, induction of tumours, and others. The limited information available on truly Arctic species suggests sensitivity similar to that of temperate species. However, because petroleum hydrocarbons degrade more slowly under cold and dark conditions, Arctic organisms may be exposed to higher levels for longer periods. Also, the clearance of hydrocarbons taken up in cold-blooded organisms through metabolism and excretion is slower in colder temperatures, effectively extending retention of hydrocarbons within body tissues. This could lead to more prolonged toxicological effects under Arctic conditions compared to temperate conditions.

The concentrations of oil hydrocarbons and PAHs in the Arctic are generally low and close to background levels. Biological effects on aquatic and terrestrial animals are therefore not expected away from locally contaminated areas. There is considerable input of oil from natural seeps in some areas of the Arctic and it has not been clearly established whether or not there are biological effects associated with these inputs.

Local contamination occurs in some areas due to spills and other inputs of hydrocarbons and PAHs from oil and gas activities and other sources. Concentrations may exceed those where effects can occur. Documented effects on communities of benthic animals were found in cases such as in a near-zone where contaminated drill cuttings had been released from offshore platforms in the Norwegian Sea. Similar detailed information from other parts of the Arctic (e.g., Russia and Alaska) was not provided for this assessment. This has prevented an assessment of the current levels of exposure of terrestrial plants, mammals and birds to chemicals produced and used by oil and gas activities in the vicinity of facilities. Chemicals of potential concern include volatile compounds and vented gases, oil, petroleum products and oilfield chemicals. Exposure in mammals and birds occurs by the inhalation of volatile components, ingestion of contaminated food and water, and the absorption of chemicals through the skin. Domestic animals have been exposed to oilfield chemicals in temperate regions and have shown a wide range of biological effects, although their significance is unknown. Small mammals near petrochemical facilities have also shown genetic effects due to hydrocarbon and metal exposure but the extent of these exposures in not known in the Arctic.

The data on concentrations of petroleum hydrocarbons from Russian terrestrial environments are aggregated for larger geographical areas and the inter-comparability of field data with concentrations reported in toxicological studies is uncertain. It has therefore not been possible to evaluate the extent of areas of local contamination, and whether these might reach the scale of a regional problem rather than a local problem.

F7.B. Physical impacts in the marine environment are local

Physical impacts in the marine environment may occur during drilling and the construction of infrastructure for drilling, production, and transportation. Constructing gravel islands necessarily covers a finite area of the seafloor with gravel and thus buries organisms in the affected area. Plumes of sediment often form down-current from the island construction operation and may affect plankton and benthos. If the gravel islands were for exploration wells, they were often left in place to erode or persist. Abandoned gravel islands may also provide new habitat for organisms. Temporary ice islands have a local and transient effect on the seafloor and seafloor organisms. Limited physical disturbance of the seafloor can be caused by drill ships, which leave anchor depressions around the vessel, bottom-founded drilling structures, and seafloor excavations.

Discharge of drill cuttings in the marine environment where permitted, will form a pile of cuttings that will cover a relatively small area, although fine particles may spread to be thinly distributed over a wider area. Organisms would be affected under the pile of cuttings and possibly by plumes of mud from unwashed cuttings. Such effects are usually limited to a few km^2 of seafloor at most.

Marine pipelines may be laid directly on the seafloor in waters not affected by destructive ice or oceanographic processes, or they may be buried, such as the Northstar pipeline in the U.S. Beaufort Sea. Pipelines laid on the seafloor may disturb mobile bottom dwelling species and have a limited effect on organisms directly beneath them. Pipelines may disturb archaeological resources such as shipwrecks if laid on top. Surveys using remote sensing devices or television will usually mitigate such disturbances. Trenching the seafloor for burying pipelines or for installing sub-sea completion systems will disturb the areas trenched and possibly areas down-current if plumes of sediment are released during trenching or backfilling the trench.

F7.C. Noise associated with oil and gas activities is a source of disturbance

The highest sound levels from oil and gas activities in onshore areas are from aircraft. Low-flying aircraft may disturb Arctic wildlife and can have a negative impact particularly on species that are aggregated during important stages in their life cycles. This includes aggregations of flightless geese and seaducks during their annual molt, aggregations of geese, ducks and shorebirds at staging areas where they feed to fuel their migrations, and seabirds at their breeding colonies. It also includes walrus haul-outs and calving areas for caribou/reindeer.

In offshore areas, the noise source related to oil and gas activities with the highest potential for affecting marine life is airguns used in seismic surveys, and the animals most at risk are marine mammals. Seismic surveys are monitored to ensure that close contact with marine mammals is avoided, but how this distance is determined varies from country to country and species to species. The effects from sound are generally local to a zone near the source. This may extend tens of kilometers in the case of offshore seismic surveys where avoidance effects on whales such as bowheads have been observed. However, this would affect a limited fraction of the total population and be transitory, and there is no evidence that local effects have scaled up to have a significant effect on populations. Disturbance may also occur from traffic by ships, icebreakers, and tankers associated with oil and gas activities. The many different sources of sound associated with oil and gas activity in the onshore and offshore Arctic regions, combined with rising ambient sound levels from other human sound sources, may lead to cumulative effects from all sources.

F7.D. There is little evidence that Arctic oil and gas activities have caused long-term changes to Arctic wildlife populations

Oil and oil and gas activities have the potential to affect Arctic animal populations, as was clearly demonstrated in the case of the *Exxon Valdez* oil spill in Prince William Sound although this event happened outside the Arctic. Many examples of local effects on individual animals have been documented in the Arctic. However, it is not known whether local effects, such as acute mortality or chronic effects on individuals from oil and hydrocarbons, and disturbances and displacement of individuals from infrastructure and activities, have accumulated to produce a clear and detectable effect on the size or status of Arctic animal populations. Evidence suggests that any such effects are unlikely to have occurred at a scale where they have represented a threat to populations or species. Whether this is true in Russia is not known because there is insufficient information to enable an evaluation.

Arctic species are often widely distributed and many have high intraspecific variation in the form of sub-species in different areas. Fish, birds and mammals also form distinct populations or stocks that occur in a spatial and geographical context and may be reproductively separated from other populations or stocks. The status of populations or sub-species may vary, some being large and healthy while others are small or declining and considered to be endangered or threatened. The vulnerability of populations or sub-species is related to their status because sub-species with small populations and/or endangered status may be more vulnerable to additional stress than sub-species in better status.

Documenting effects at the population level for fish, birds and mammals is confounded by their large natural variation and the lack of knowledge and monitoring of population changes. The caribou populations on the North Slope of Alaska have been particularly well monitored in relation to oil and gas activities. While some disturbance and change to caribou distributions may have occurred, any negative effects were not enough to prevent a large increase in the populations from the 1970s to the 1990s. It is not known how important any negative effects would be in herds that are currently in decline.

Although evidence of population effects is currently limited, subtle effects could still be occurring and could become more expressed in future under different climatic conditions and in combination with effects from other activities. Monitoring and documenting such effects may be a challenge that will require considerable effort.

F7.E. Exposure to oils affects the quality of fishery products for human consumption by imparting undesirable tastes and odours

Hydrocarbons taken up by fish and distributed to muscle can impart tastes and odours that render the fish unfit for human consumption. This is usually the most important economic loss when spills overlap areas used for commercial or subsistence fisheries. Tainting occurs in exposures that last for minutes to hours in fish with high levels of fats in muscle (e.g., salmonids, coregonids) but is less important for lean species like cod or saithe (*Pollachius virens*). Tainting of salmonid fish can be retained for periods of weeks to months. The components responsible for tainting are likely to be the low-boiling aromatic compounds. Based on experience from the *Braer* spill in Shetland, retention of tainting may be even longer for some invertebrate species. In subsistence fisheries, tainting or fear of contamination has been responsible for large declines in uses of subsistence foods. The only known example of tainting within the Arctic is the tainting of whitefish following a small spill of diesel fuel into the Cameron River, NWT, Canada.

Finding 8: Human health in the Arctic can potentially be affected by oil and gas activities but there is limited information to assess if effects have occurred to date

F8.A. Some components of crude oil have the potential to cause acute and chronic human health impacts

Oil and gas exploration, extraction and transportation activities, regardless of where they occur, have the potential to cause short-term and long-term adverse effects on human health. Such effects, if and when they occur, are likely to be local with respect to the source, whether near the drill or production site or as a result of oil spills.

Human exposure to volatile substances associated with oil and gas activity in the Arctic is primarily via inhalation, and only slightly by skin contact and by oral intake. Exposure to less volatile compounds like oil and some PAHs, is primarily by oral exposure and skin contact and less by inhalation. Exposure duration to volatile substances (mainly after an accidental spill) is short-term (acute) and may only last for a few hours. In general, human reactions to acute exposure to petroleum components are mainly transient. Exposures to oil and PAH contamination, which may result from an accidental spill or local contamination at a production site, tend to be longer-term (sub-chronic or chronic).

Inhalation exposure resulting from flaring at the well head and open burning of spilled oil can be dangerous because the particulate matter which may result is easily inhaled, retained in the lungs, and can contain high concentrations of bio-available contaminants (PAH, sulfurous compounds, dioxins, furans, and metals). While flaring of gas and open burning of oil are now only occasional events in most of the Arctic region (Alaska, Canada and Norway), there is information that flaring is a regular activity in parts of Russia. Short-term flaring in remote areas (away from local populations) will not affect health because the exposure concentrations in the air of the toxicants emitted will be very low and well below those reported in most urban environments.

Dermal exposure (via skin contact) of humans and animals to crude oil has been shown to produce toxic effects. Most skin-related effects are transitory, for example, once exposure ceases, skin inflammation is likely to clear up in seven to ten days. However, repeated skin exposure in mice to some PAHs has resulted in skin cancer and highlights a need to limit repeated human skin exposure to oil during exploration, production and spill clean-up.

Several PAHs can be ingested in food and water although human populations tend to avoid eating contaminated food or surface water which is clearly tainted (visible oil, taste or odour detection). Ingested PAHs, some of which are known carcinogens when inhaled or applied to skin, are not thought to contribute significantly to ill health, and the risk of excess cancer related to ingested PAH is very low. Smoked and open fire-roasted foods have a higher PAH content than most foods obtained from oil contamination zones where they are considered unsuitable for personal consumption based on their taste and odour. In the Arctic, oral exposure of populations living on or near contamination sites or spill zones to fresh oil is rare. Volatile aromatic compounds evaporate rapidly and degrade quickly in sunlight. They do not appear at concentrations of concern in food and surface water. Groundwater may be contaminated with volatile organic compounds, metals and oil; however, concentrations are usually very low and effects, if any, tend to be transitory.

F8.B. Cancer risks in regions of oil and gas activity have not been established

Based on animal studies, both benzene and some PAHs have been classified as carcinogens. One study from a region in the southern hemisphere has reported elevated cancer rates among an exposed population; however, these results have not been supported by similar studies in other regions. In general, it is unlikely that there is much excess cancer in most of the Arctic region as a result of oil and gas activity because exposures to known carcinogens are likely to be very low and very few people are likely to be exposed. A statistically significant identification of excess cancer under these conditions (low exposure and low numbers of exposed individuals) would be difficult, if not impossible. Benzene, a human carcinogen, tends to occur at very low concentrations in the vicinity of oil and gas operations. Due to its vapour pressure, benzene volatilizes to the atmosphere after a spill and airborne levels decline rapidly (less than 24 hours) to concentrations below the levels of concern specified by health agencies in several Arctic countries.

F8.C. Psychological damage appears to be a consistent impact of oil spill situations

Psychological damage which may be manifest as diagnosed post-traumatic-stress-disorder (PTSD) or other measures of effect has been sustained for up to, and beyond, two years in some studies of spill-affected human populations in sub-Arctic regions. Effects are felt by individuals in both non-indigenous and indigenous communities; however, in the case of published oil spill investigations, the effects have been more strongly felt by indigenous communities and by women within those communities. These psychological outcomes are important and can lead to social and economic impacts such as domestic violence, lost income and loss of community structure. Tainting of food as a result of oil contamination or fear of tainting, can lead to dietary changes in the community and among individuals and can also result in psycho-social impacts.

F8.D. There are insufficient human exposure and epidemiological data available for the Arctic region to conclude whether non-occupational population groups are currently affected and to undertake a robust risk assessment

In general, there is no good characterization of contamination sites in the Arctic region and a complete lack of exposure information for Arctic populations living near to oil and gas activities. While few people appear to live in the vicinity of most areas of activity, there are several persistent references to serious land contamination in some parts of Russia and anecdotal reports of poor health in populations living near these areas. However, there are no peer-reviewed studies of health outcomes in non-occupationally exposed Arctic populations.

Sub-Arctic populations have experienced transient effects related to volatile off-gases (nausea, headaches, lethargy, irritability, runny noses, sore throats and eyes, depression) and oil (skin irritation, cough). Risk assessments for Arctic populations could make use of epidemiological studies of these sub-Arctic populations exposed to oil and its components following spills, but only if detailed information on exposure, living conditions, health status and other parameters are available for the Arctic populations. The lack of health impact information for Arctic populations reflects the limited number of spills near Arctic communities, and the difficulty of conducting meaningful and statistically reliable health studies in small communities with small populations.

Physiological, psychological, and social impacts are all linked. It is clear that oil and gas activities by themselves and in combination with other 'determinants' of health (e.g., education, access to health care, nutritional status, family income, social status, genetic and biological endowment, personal lifestyle choices) could affect the physical, mental and social health of individuals and communities in the Arctic. Furthermore, cumulative impacts of environmental exposures are important. Local populations in the vicinity of oil and gas activity may be affected by exposures to spills, particulates, gases, and sanitary waste. They may also be affected by traditional foods contaminated by persistent contaminants and metals which arrive in the Arctic via long-range atmospheric transport from sub-Arctic regions. Food stress, which can affect nutritional status, may come from pressure to change diets due to contamination, lost access to prey, or social pressure.

It is likely that indigenous people would be more affected by oil and gas activity than non-indigenous individuals as a result of their proximity to oil and gas exploration/extraction areas, their poorer general health and socio-economic status, and their greater vulnerability to changes in traditional ways of life (living off the land, community cohesion, food sharing). Local employment and migrant workers associated with oil and gas activities could introduce and spread infectious diseases into indigenous communities, affecting family health and community structure and operation. Crowded conditions, re-infection of home communities, loss of access to traditional foods and social structure, and access to alcohol and drugs will all play a part in this process. It is not possible to quantify this risk as it will vary from location to location and is dependant on documented physical health outcomes. Poor early detection and health service response will compound and confound the combined effects of health stressors.

F8.E. Oil and gas activity in the Arctic can have a positive impact on health

There are likely to be some beneficial impacts of oil and gas activity on health (i.e., physical, mental and social well-being). These relate to more employment and availability of disposable income, better sanitation and access to health care and improved transportation.

Finding 9: Technology and use of best practices have lowered environmental impacts, but additional risks may occur as conditions change or new areas are explored and developed

F9.A. Technology and practices have adapted and evolved to deal with Arctic operating and environmental conditions

Experience with effectiveness and impacts of past activities, and growing concern by industry, governments, interest groups, the general public, and local residents, have led to the development of new technologies and practices for Arctic oil and gas activities. These are specifically adapted to the Arctic region and continue to evolve. Very few modern Arctic oil and gas facilities are operated as they were twenty years ago; large and capital-intensive developments such as the *Snøhvit* field in the Barents Sea were just not possible twenty years ago. Technological advancements have been applied to Arctic oil and gas exploration and development activities and these have significantly reduced the impact on the environment.

Impacts on the environment and on biological resources can be mitigated or reduced by Arctic specific technology. This is demonstrated by the use of low impact seismic techniques in the boreal forest, tundra and wetland areas. Reduction in environmental impacts results from the increased use of vibrator vehicles, development and use of light-weight vehicles to reduce ground pressures, and reduced breadth and necessity of cut lines. Offshore, new air-gun technology and improved operating procedures have reduced the impact on the marine environment. Three-dimensional seismic surveys are more focused and able to image the subsurface more accurately, thereby reducing the number of wells that need to be drilled to define a possible deposit.

Well drilling technology and well design have undergone significant changes in the past 20 years. New exploration wells are drilled in the winter, and technology using ice roads or roadless access, and drill pads made of ice, leave virtually no footprint and have minimal impact. Changes to rig design and well drilling methods have reduced the size of development drill pads by 30% to 40% compared to the size of earlier pads. Deep well injection of waste drill cuttings/muds, other drilling wastes, and produced water from oil fields plays an important role in reducing surface impacts.

However, improved practices are not consistent across the Arctic and damage from development continues in some areas.

F9.B. Changing conditions at existing fields and exploration and development in new areas may introduce additional risks for potential impacts on sensitive Arctic species and habitats

Management and maintenance of infrastructure in aging Arctic oil and gas fields need diligent application of best technologies and practices for monitoring and integrity assessment. Equipment will need to be upgraded and infrastructure elements may need repair or replacement. As the end of life approaches for some of the largest and oldest fields, decommissioning activities may take place. These activities are relatively new to the Arctic and are expensive to address. Even though the cost of producing diminishing oil reserves grows enormously as fields age, the use and development of the best available technology and best practices is essential and should not be neglected.

Oil and gas activities are likely to expand into new areas of the Arctic. This expansion may require, and be facilitated by, further adaptation and improvement in technology. Some of these new areas will be further into the high Arctic, and the expansion may represent additional risk for potential impacts to sensitive Arctic species and habitats.

A warming climate has many implications for Arctic technology and practices. In addition to adapting current technology and practices to the effects of changing climatic conditions, new technologies and practices may need to be developed. The effects of thawing permafrost can erode coastal and riverbank facilities, damage field and transportation infrastructure, and compromise well integrity and therefore require the urgent application of adaptive engineering, and the development of new design solutions. A longer ice-free season in the Arctic seas may allow petroleum and transportation industry access to areas in deeper water farther out on the Arctic shelves and Arctic Ocean, but also requires improving technology and practices for emergency response at ever more remote and distant locations. Longer open-water seasons also cause accelerated wave erosion of the coast, loss of ice and ice-edge wildlife habitat, and disruption of local indigenous communities that depend on a subsistence way of life. If landfast ice becomes less stable or is lost for longer periods, an important platform for winter transport and operations will be lost and increased broken ice conditions near shore will also make it harder to respond effectively to spills.

While new ways to reach and produce oil and gas efficiently and safely is a driver for the development of new technology and best practices, environmental, emergency response, and engineering requirements for mitigation, prevention or elimination of adverse environmental or cultural impacts are also major considerations. These technologies and practices must continue to evolve and to adapt to changing and new conditions.

Finding 10: Governance, regulatory systems, and international standards are important aspects of the performance of the oil and gas industry in the Arctic

F10.A. The use of international standards and best practices are contributing to a reduction in negative environmental and socio-economic effects from oil and gas activities

Operational requirements related to financial considerations are working to bring common operating standards to Arctic projects. Increasingly, Arctic operations are conducted either by publicly traded international companies and/or are financed at least in part from international financial organizations. Large companies have increasing interest in adopting accepted international standards, technology, techniques, and practices due to shareholder and stakeholder concerns and through requirements set by most international finance institutions like the World Bank. This has increasingly led to industry conforming to a number of internationally accepted standards in order to fully participate in the worldwide petroleum market. These standards include common reporting requirements for reserves, petroleum quantity and quality measurement, safety procedures and environmental protection.

Government regulators are also communicating between countries and across jurisdictions through various forums and thus have increasingly incorporated accepted international standards, technology, techniques and practices into their rules, regulations, and guidance documents. All Arctic nations including those with more traditionally prescriptive regimes contain goal-setting or performance-based features in their regulatory systems, which allow industry to use the latest and best technology and techniques as they become available.

Internationalization of the petroleum industry and the increasing use of international standards and practices by Arctic nations have contributed to the reduction in potential negative environmental and socio-economic effects from oil and gas activities.

F10.B. Arctic national oil and gas legal regimes are relatively stable, modern and designed to protect human health, rights of indigenous residents and the environment, but in some cases regulatory systems are outdated, incomplete, or enforcement is inadequate

All Arctic nations with oil and gas activities have a legislative and regulatory base within which these activities are allowed. There are many similarities among these regimes; they allow for access to the resource, they regulate the activities associated with exploration, development, production, transportation, and decommissioning, and they protect national interests including security, financial, environmental, social and cultural interests. All these legislative and regulatory regimes have undergone some degree of change over time and are still changing. Although some aspects of these systems change due to new data, evolving technologies and practices, and as a result of accidents or events, most Arctic nations have stable and predictable regulatory regimes. Russia has undergone the greatest shift, having evolved from a non-commercial oriented central economy system to a modern legislative and regulatory regime in a very short period of time. The Russian system is still in a state of transition.

Transparent and clear regulations and laws allow industry and government to plan and conduct operations in a predictable and systematic manner while keeping all stakeholders, including Arctic residents, informed and involved. All Arctic countries have systems that accommodate public involvement and allow some form of legal challenge and intervention in projects that do not meet required standards.

All Arctic nations are politically stable compared to many of the other oil and gas producing countries. The clarity and transparency of regulatory regimes are important factors in protecting not only industry and government interests, but also for protecting the environment, human health and socio-economic well-being of Arctic residents. Under such governance, industry is able to make financial commitments and proceed with planning activities, while adhering to even very complex regulatory requirements for safety, environmental protection, and conservation of resources. Governments can also set out comprehensive controls and standards and can plan accordingly to identify and address concerns over proposed activities. Interested parties and the public may also be afforded enough time and information in order to have input or plan for these activities at a local and individual level.

Even though all Arctic countries thought to have petroleum potential have modern legal regimes for oil and gas activities, there must be effective control of these activities. No matter how complete and comprehensive the legal system, without adequate regulations to implement these laws or without confidence that these regulations are adequate or evenly applied to activities, the protection of occupational safety, and economic, environmental, and cultural security are compromised. To ensure that regulations are adequate and consistently applied they should be continually reviewed and assessed for their effectiveness. The regulatory system should allow for changing and updating of rules and required standards to adapt to new conditions and technology. Governments should ensure that the authorities are properly trained and staffed to enforce regulations and to ensure that compliance, inspection, auditing and monitoring procedures are followed. Regulatory control should continue to be based on the best available science, technology and practices.

7.3. Recommendations

This assessment has been conducted to provide a basis for the development of policy and management measures. The assessment is scientific and is the responsibility of the team of authors that was given the task to carry out the assessment. It is not the task of the scientific authors to provide detailed advice on policy or management measures; this advice is prepared by the AMAP Working Group based on the scientific findings of the assessment. However, the scientific authors have provided some general recommendations relating to the management of oil and gas activities in the Arctic, which reflect the main findings.

The findings of this assessment build upon a large amount of scientific information from monitoring and research that was compiled and examined, and documented in the preceding chapters of this report. The present section provides recommendations that aim to improve the basis for future assessments by generating comparable data from all Arctic countries. One aspect is the lack of information on particular topics and particular areas. It is likely that in many cases this information did exist, but that for various reasons it was not accessible or made available for the assessment. A second topic is the need for monitoring to update existing information. A third issue is the need to address certain gaps in knowledge by research.

Each of the preceding chapters of this report concludes with a set of recommendations. The summary recommendations listed in this section reflect these recommendations, and the individual chapters should be consulted for further details, background, and the context to the statements made here.

7.3.1. Managing oil and gas activities in the Arctic

Prevention of oil spills

R1. In all aspects of oil and gas activities, attention should be focused on the prevention of oil spills. The highest priority should be to prevent oil spills in ice-infested marine waters. In this respect it is recommended that consideration be given to:

- the conduct of risk assessments in association with all means of transport of oil and gas;
- the use of best practices and technology in transport and storage of oil;
- seasonal restrictions on oil and gas activities;
- the need for protected areas closed to oil and gas activities;
- strengthened capabilities and improved coordination of oil spill prevention, preparedness, and response; including
- rapid availability of adequate oil spill response equipment and well-trained personnel.

Use of best practices

R2. Oil and gas activities have the potential to cause significant impacts on Arctic ecosystems and peoples, but this can to a large extent be prevented by use of the best and most appropriate technologies and practices. Arctic countries should require the use of best available technologies and practices, including where appropriate:

- appropriate consultations and collaboration with communities that may be affected, to develop strategies for avoiding negative impacts while harnessing economic and other opportunities;
- closed-loop drilling systems where drilling wastes are re-injected or cleaned and safely deposited;
- transportation, including pipelines, and other infrastructure to be built or modernized, and maintained according to the highest industry and international standards;
- ‘roadless’ development techniques to reduce the physical impacts of roads;
- conduct of activities on frozen land in winter months to avoid physical impacts on the ground and vegetation;
- seasonal restrictions on activities to avoid disturbance to wildlife in sensitive periods and areas; and
- monitoring of wildlife to regulate activities to reduce disturbance and impacts, including the use of marine mammal observers aboard seismic, icebreaking, and other ships to avoid close approaches and disturbance.

R3. Clear and flexible regulations should continue to be used that are goal-oriented and supported by appropriate guidance to reduce the risk of accidents and the extent of environmental effects, and to improve safety. Emphasis should be given to compliance monitoring of infrastructure and practices to ensure that standards and regulations are effectively and consistently followed. Arctic countries should establish a mechanism through which to share experiences, and should coordinate and cooperate concerning their methods of risk and impact assessments and management of the oil and gas industry. Arctic countries should use an adaptive management approach to ensure that new information can be incorporated into the management and decision-making processes and changes in conditions can be accommodated or mitigated.

Pollution prevention

R4. It is possible to operate oil and gas activities with little or no discharge of contaminants to the environment. A policy aiming for zero routine discharge of harmful substances should be adopted in order to prevent pollution of the Arctic environment. This should include:

- reducing or ending the flaring of associated natural gas (except in emergencies and for safety reasons);
- reducing or eliminating discharges to the terrestrial and aquatic environment and ending the use of sumps and pits for the disposal of spent muds and cuttings from onshore drilling and production operations; and
- using material and chemicals that are environmentally manageable and techniques that conserve, recycle and reuse waste.

R5. Action should be taken to clean up and remediate sites that are badly polluted, including old or abandoned sites, in order to significantly reduce or prevent threats to the health of human populations and wildlife living in the area.

7.3.2. Lack of information for assessment

A certain amount of the information required for this assessment was probably available in principle, but was not provided for the assessment or could not be obtained through ordinary means. The recommendations in this section are intended to provide a better basis for future assessments.

Point sources of pollution and concentration gradients

R6. To provide the basis for an assessment of the quantities of waste from Arctic oil and gas activities and the treatment of such waste, it is recommended that better reporting procedures be developed for:

- waste management measures, including re-injection or discharge, and recycled or reused volumes and the chemical composition of wastes; in particular
- produced water discharge volumes, disposal methods and locations, and chemical composition including polar components such as alkylated phenols and other substances.

R7. Point sources of operational discharges and emissions from oil and gas activities need to be identified and the types and amounts of contaminants released should be monitored and reported. These data should be stored and made available from regulatory agencies in the Arctic countries. This should also be the case for accidental spills and releases. Concentrations of the released contaminants in the environment should be monitored and reported, allowing assessment of gradients and areas affected by contamination. This would enable assessment of the degree and area of pollution.

R8. Contaminated sites from spills and releases from past oil and gas activities should be identified and monitored to determine the degree of pollution in terms of concentrations, areas affected, and risks to humans and wildlife (see also R14).

Habitat fragmentation

R9. Information on pipelines and other infrastructure that can act as impediments to wildlife movements, or as attractors to wildlife, should be provided. The information should include an inventory of line length (kilometers), locations, types, placement (whether on ground, raised, or buried) and age of all pipelines (both transmission and in-field pipelines) in the circumpolar regions.

R10. In order to assess the degree of habitat fragmentation, information on roads and associated traffic should be provided. This should include all roads and traffic in the areas of oil and gas activities, to contribute to assessment of cumulative effects.

R11. Information on air traffic related to oil and gas activities should be provided, in particular low-flying helicopters and fixed-wing aircraft that disturb wildlife.

Socio-economic conditions and human health

R12. Countries should be encouraged to collect and compile comparable Arctic oil- and gas-related socio-economic statistics. A circumpolar assessment of the socio-economic effects of oil and gas activities in the Arctic requires the collection and compilation of intercomparable information and associated collection protocols on a number of parameters including employment, wages, gender, industry expenditure, GDP contribution, social infrastructure, use of subsistence resources, cultural practices, consultations, mitigation, and occupational health and safety.

Standards and regulations

R13. Given the large volume of detailed national regulatory laws, standards, guidelines, and procedures for oil and gas activities in force in the Arctic countries, it is recommended that a compilation be made by the Arctic Council and its working groups and periodically updated.

7.3.3. Monitoring to improve the basis for assessment

Monitoring is an important source of data and information in the conduct of assessments. Based on this assessment, the recommendations below have been developed to improve and enhance the development and implementation of monitoring programs and the use of the resulting data.

Contaminated and polluted areas

R14. Contaminated sites within the Arctic from past and current oil and gas activities should be located, mapped, and characterized (size, history, contamination, geology, biology) to determine their potential impact on humans and biota in the surrounding environment. Reports of adverse impacts on animals and human populations near contamination sites can only be verified if there is a full identification and characterization of these sites.

R15. A selection of contaminated sites should be chosen for long-term monitoring of the degradation and fate of spilled oil, petroleum hydrocarbons, PAHs, and other oil-related substances. This would assist in the prioritization of and decisions for remediation and rehabilitation of sites, as well as in assessing future risks of environmental and human health effects.

Compliance monitoring

R16. Monitoring of facilities is necessary to assess industry compliance with legal and technical standards applicable to the oil and gas industry in Arctic countries; this should include, in particular, monitoring of pipeline integrity, drilling and well work-over activities, and the construction of facilities, as well as groundwater reservoirs and areas near onshore wells and pipelines to ensure that there is no evidence of leakage from the oil or gas facility and that environmental quality standards are being met.

Integrated monitoring and assessment

R17. Consistent, rigorous monitoring programs should be developed using measures that can be applied throughout much of the Arctic to allow the detection of changes in the environment, society, and human health. Such programs should include new tools, such as biological markers of exposure and effects and sociological indicators of change.

R18. Monitoring programs should measure physical, chemical, biological, and socio-economic conditions that may be impacted by oil and gas activities, and should be based on internationally agreed protocols for chemical and biological monitoring. Before petroleum activities commence, monitoring should begin with a comprehensive baseline investigation, which should incorporate existing information, and comprise as a minimum all monitoring sites and variables planned to be used in the long-term monitoring program.

R19. Chemical and biological monitoring should be conducted using appropriate quality assurance in relation to the design of the sampling program, the collection of samples, and the analytical procedures used. Where possible, participation in Arctic-wide or international intercomparison exercises on analytical measurements is recommended to promote comparability in the results among the institutes and laboratories conducting monitoring in the Arctic. In addition, a systematic approach to the handling, evaluation, and reporting of all types of data to be used in assessments should be developed for use on a pan-Arctic basis.

R20. The specific compounds of petroleum hydrocarbons that elicit most of the toxicological effects recorded in laboratory experiments (e.g., volatile aromatic compounds) are usually excluded from environmental monitoring programs; such programs tend to focus on the more persistent, high-molecular components. To bridge this gap and allow assessment of the environmental concentrations of these more toxic compounds would require the monitoring programs to pay particular attention to the compatibility and comparability of the data.

R21. Monitoring should be conducted so as to enable a distinction between impacts due to oil and gas activities and impacts from other sources, including natural climate variability and climate change and social changes from causes unrelated to the oil and gas industry. Monitoring needs to be tailored according to the type of oil and gas activity and to the nature of the potentially affected environment, and should be coordinated in regional ecosystems (e.g., LMEs [Large Marine Ecosystems] for the marine environment) so that interactions and cumulative effects from multiple activities may be examined.

Animal populations
R22. High taxonomic diversity within many Arctic animal species, divided into several subspecies and stocks, is related to a high degree of site fidelity and local adaptation of breeding populations. This is an important aspect of the functional integrity of Arctic ecosystems, which must be taken into account in impact assessments. There is a need for better identification of population structures and for the monitoring of populations and subspecies of Arctic mammals, birds, and fish species.

Human health
R23. Pan-Arctic monitoring of human health status should be conducted in relation to oil and gas activities, including psychological impacts as well as the levels of contaminants in ambient air, water, food, and human tissues, to allow an assessment of current population exposure and health, with special focus on community assessments and on children and women of reproductive age.

Environmental impact assessment
R.24. A large number of regional project-specific environmental impact assessments and statements (EIA and EIS) have been carried out in relation to oil and gas activities in various parts of the Arctic. These summarize knowledge and use results from monitoring programs. There is scope for better use and streamlining of the production of EIA/EISs as well as of pan-Arctic assessments such as the current assessment. As a first step this should be explored through an exchange of information and experiences among the Arctic countries.

7.3.4. Gaps in knowledge

This assessment has identified many gaps in knowledge of the impacts of Arctic oil and gas activities on the environment, biota, and human populations of the Arctic. This is partly due to an incomplete understanding of environmental conditions in the relevant areas of the Arctic and of the species and populations of the many plants and animals that live there as well as their ecological interactions. There is also incomplete knowledge of the socio-economic and health effects on the human populations of the development of the oil and gas industry in the often remote areas. The recommendations in this section illustrate some of the areas in which research and other studies are needed to provide a better overall picture.

Research to improve technology
R25. The Arctic countries should facilitate and cooperate on research to improve technology in relation to oil and gas exploration and development. In particular, research into less impacting drilling and seismic technologies should be continued.

Oil spill clean-up
R26. Given the great difficulties encountered in responding to oil spills under Arctic conditions, research should continue into oil spill clean-up technology, and response strategies and techniques for Arctic waters, including spills on ice, under ice, and in broken ice.

Comparative studies of socio-economic effects
R27. To enhance understanding of socio-economic effects of Arctic oil and gas activities, it is recommended that future studies include the following:

- compilation of Arctic oil- and gas-related socio-economic statistics on a circumpolar basis;
- comparative studies of the effectiveness of socio-economic mitigation and opportunity measures; and
- comparative and case studies on the effects on access to and availability and quality of subsistence resources (e.g., fish, game, caribou/reindeer).

Human health
R28. To enable scientists and regulators to determine potential health effects, studies should be conducted on the exposure of the general human population in the Arctic to chemical elements and compounds released from oil and gas activities, and on the impacts of these substances on human health. Future quantitative risk assessments must include site-specific and population-specific study data.

R29. Given the lack of information in the peer-reviewed scientific literature on the environmental and human health impacts of oil and gas activities in Russia, which has the largest production and transportation of oil and gas in the Arctic, studies should be conducted on the impacts of oil and gas activities on human health in Russia and the results be made available for future assessments.

Contaminated sites (e.g., previous spill sites) and natural seeps
R30. Sites of accidental oil spills, as well as the sites of experimental studies in various regions of the Arctic during the 1970s and 1980s, should be revisited on a regular basis and monitored using modern detailed chemical and biological techniques to determine the fate, persistence, and long-term effects of toxicologically significant petroleum hydrocarbon components. Soils and plant species should also be monitored for evidence of toxic metabolic by-products from the degradation of the hydrocarbons. Monitoring the recovery of these sites should include small mammals, birds, and any other species present.

R31. Natural seeps are sources of ongoing hydrocarbon inputs and thus provide valuable research sites. Such sites should be used for basic research on the transport and fate of hydrocarbons under Arctic conditions, as well as for research on biological effects and adaptations by local biological communities to long-term exposure. The metabolism of oil and formation of metabolic by-products, rates of transformation of hydrocarbons, and colonization by bacteria and other biota offer important insights into hydrocarbon chemistry and the fate and effects of hydrocarbons in the Arctic. Mechanisms of adaptation, if any, by local biological communities may offer insights for sites that may become contaminated chronically by the oil and gas industry.

R32. In relation to research on remediation and revegetation of oil-contaminated areas, follow-up studies should be conducted at many of the previously contaminated sites using new methods of analysis in order to provide information on the rates of degradation of the hydrocarbons and other industry-related contamination, with the ultimate aim of improving success in returning the sites to their natural state.

Behaviour and fate of oil in sea ice

R33. There is still limited information on the behaviour and fate of the many crude and refined oils and petroleum hydrocarbon components in ice-infested Arctic marine waters. Continued research on this topic should be high priority. Better knowledge is essential to improve assessments of the transport, fate and effects of spilled oil in ice-covered waters, including oil under ice carried by currents and oil drifting with the sea ice.

Exposure and toxicology

R34. There is little information available relating to the exposure of terrestrial birds and mammals to oilfield chemicals and releases from production sites, and most of the large amount of information on the effects of hydrocarbons on aquatic organisms concerns temperate or sub-Arctic species. Research is required on a wide range of the potential biological effects of these chemicals under conditions and with species and life stages appropriate to the Arctic, including, among others, studies of acute and chronic toxicity, genetic effects, and combined effects with, for example, exposure to sunlight. This includes studies of linkages between the diverse sub-lethal effects and the risks they pose to individuals and populations of Arctic animals.

Animal populations and ecosystems

R35. Fish populations are intermediate links between lower and higher trophic levels in aquatic ecosystems. Polar cod (*Boreogadus saida*) and Arctic cod (*Arctogadus glacialis*) are two species that play key roles in high Arctic marine ecosystems. There is need for research on the basic biology of these species, and their populations should be identified and mapped.

R36. There is a general need for better knowledge about population structure, both genetically and geographically, of Arctic mammals, birds, fish, and key invertebrate species. This is basic information required for better description and assessment of the status and vulnerability of the Arctic biota and ecosystems. Priority should be given to threatened species, subspecies, or populations, and to species that are important food resources to Arctic inhabitants.

R37. Further research is needed on the fundamental ecological interactions between Arctic species and the possible changes in these interactions as oil and gas development in the Arctic expands and as the ecosystem changes, particularly in response to a warming climate. Studies should be conducted to provide basic information on relationships and changes in key ecological processes, activities, and habitats, including features such as nesting, molting and staging waterfowl, shorebirds and seabirds, spawning areas for fish, calving or pupping and molting areas for marine mammals, migration corridors for fish and marine mammals, and changes in predatory species, prey, diseases, and parasites.

Sensitive areas

R38. Ecologically sensitive areas should be mapped, and oil spill trajectory models should be further improved and used to determine areas most at risk from oil spills. This would improve the basis for attempts to decrease or eliminate the probability of an oil spill affecting sensitive areas, for setting priorities for response strategies and deployments, as well as for helping to determine the shipping routes least at risk from spills.

Coordination of research

R39. This assessment has drawn on data and information from many national research programs in Arctic countries. Given the need for such data and information to be obtained on a comparable basis among the various participating organizations in the Arctic, so that results can be compared across the entire area, it is recommended that the coordination of research across the Arctic be improved to provide for the use of, where possible, common methodologies, species, and publication guidelines. This applies to research on contaminant levels and biological effects in terrestrial and aquatic species and the health of human populations. Furthermore, as new methods emerge, they should be calibrated against earlier methods if appropriate, so that comparisons may be made for data obtained over a long period of time. Statistically-based standards of analytical quality should be agreed upon and stated in reports.

Glossary

AMAP	Arctic Monitoring and Assessment Programme
ANCSA	Alaska Native Claims Settlement Act of 1971
ANILCA	Alaska National Interest Lands Conservation Act
ASRC	Arctic Slope Regional Corporation (Alaska)
bbl	Barrels (of oil)
bbl o.e.	Barrels of oil equivalent (equals the same amount of energy)
CAD	Canadian dollars
CO_2	Carbon dioxide
COPE	Committee for Original People's Entitlement (Canada)
cu ft	Cubic feet
DIZ	Development Impact Zones (Canada)
DKK	Danish kroner
EEZ	Exclusive Economic Zone
EIS	Environmental Impact Statement
GDP	Gross Domestic Product
GNWT	Government of the Northwest Territories (Canada)
HADIZ	High Arctic DIZ Society (Canada)
IDC	Inuvialuit Development Corporation (Canada)
IPC	Inuvialuit Petroleum Corporation (Canada)
IRC	Inuvialuit Regional Corporation (Canada)
LNG	Liquefied natural gas
NAO	Nenets Autonomous Okrug
NGO	Non-governmental organization
NOK	Norwegian kroner
NPRA	National Petroleum Reserve - Alaska
RAIPON	Russian Association of Indigenous Peoples of the North
SDFI	State's Direct Financial Interest (Norway)
Sm^3	Standard cubic meter
USD	United States dollars
Yamal Potomkam!	The indigenous peoples association 'Yamal for our descendants!'
YNAO	Yamalo-Nenets Autonomous Okrug

Oil and Gas Industry Conversions

(after http://www.eppo.go.th/ref/UNIT-OIL.html)

Petroleum hydrocarbons, and the refined products made from crude oil are generally quantified either by volume or by weight. In the United States, the basic units of volume are (US) barrels or (US) gallons; and for weight, (metric) tonnes or US (short) tons. In other countries, the SI system is generally applied, with cubic metres (m^3) and (metric) tonnes as the most commonly used units for volume and weight, respectively. The relationship between volume and weight is usually determined by density (the alternative measures being relative density or specific gravity).

Oil equivalents (o.e.) are used to express quantities of oil and natural gas in units that can be combined / compared.

In the United States in particular, oilmen reckon quantities of oil produced, moved or processed in barrels per day (bpd or b/d). A loose but simple rule of thumb for conversion is that a barrel a day is roughly 50 tonnes a year, but the relationship varies according to density and so according to product.

Conversion factors for volumes

Base unit	Equivalent
1 cubic metre	1000 litres
	6.2898 (US) barrels
	264.17 (US) gallons
	219.97 Imperial gallons
	35.315 cubic feet
1 litre	0.001 cubic metres
	1000 cubic centimetres
	0.26417 US gallons
	0.035314 cubic feet
1 (US) barrel	0.15899 cubic metres
	158.984 litres
	42 (US) gallons
	34.9726 Imperial gallons
	5.6146 cubic feet
1 (US) gallon	0.0037854 cubic metres
	3.7854 litres
	0.133681 cubic feet
	0.0238095 (US) barrels
	0.83268 Imperial gallons
1 Imperial gallon	0.004561 cubic metres
	0.028594 (US) barrels
	1.20094 (US) gallons
	0.160544 cubic feet
1 cubic foot	0.028317 cubic metres
1 gross ton (shipping)	100 cubic feet = 2.83 cubic metres of permanently enclosed space

Conversion factors for weights

Base unit	Equivalent
1 metric tonne	1000 kilograms
	1.10231 US (short) tons
	0.98421 Imperial (long) tons
1 kilogram	0.001 (metric) tonnes
	2.20462 lbs (pounds)
1 US (short) ton	0.907186 metric tonnes
	0.892857 Imperial (long) tons
	2000 lbs (pounds)
1 Imperial (long) ton	1.01605 metric tonnes
	1.12 US (short) tons
	2205 lbs (pounds)

Conversions based on the assumption that all weights are weights in air, as used for computing bulk commercial quantities of petroleum.

Conversion factors for volume to/from weight

Base unit	Equivalent
1 cubic metre of oil	0.855 tonnes
1 barrel oil	0.136 tonnes
1 tonne oil	1.1696 cubic metre
	7.3529 barrels
1 barrel oil equivalent	1 barrel crude oil
	160 cubic metres gas
	5487 cubic feet gas (based on average energy equivalent of TOTAL gas reserves)
1 m^3 oil equivalent	1008 cubic metres of gas
	35600 cubic feet of gas
1 million standard cubic feet of natural gas	172.3 barrels crude oil equivalent
1 (US short) ton LNG	1.22 tonnes crude oil (energy equivalent)
	52300 standard cubic feet of gas

Conversion factors for flow rates

Base unit	Equivalent
Gas: 1 normal cubic metre per day	37.33 standard cubic feet per day
Oil: 1 barrel per day	approximately 50 tonnes crude oil per year

Liquefied methane

Base unit	Equivalent
1 ton of liquefied methane	approximately 16 barrels
	approximately 50 000 cubic feet (1400 cubic meters) of natural gas, depending on methane content

Product specific gravity ranges

	Specific gravity	Barrels per metric tonne
Crude oils	0.80 – 0.97	8.0 – 6.6
Aviation gasolines	0.70 – 0.78	9.1 – 8.2
Motor gasolines	0.71 – 0.79	9.0 – 8.1
Kerosines	0.78 – 0.84	8.2 – 7.6
Gas oils	0.82 – 0.90	7.8 – 7.1
Diesel oils	0.82 – 0.92	7.8 – 6.9
Lubricating oils	0.85 – 0.95	7.5 – 6.7
Fuel oils	0.92 – 0.99	6.9 – 6.5
Asphaltic bitumens	1.00 – 1.10	6.4 – 5.8

Interfuel conversion factor

While individual crude and gases vary widely in quality, certain standard qualities are often assumed for statistical purposes:

Reference fuel	Barrel of oil equivalent	Ton of oil equivalent	1000 cubic feet of natural gas
Calorific value	5.8×10^6 Btu gross	43×10^6 Btu gross	1×10^6 Btu gross
Conversion factors	1	0.14	5.8
	7.41	1	43.0
	0.17	0.02	1

Based on these qualities, the following equivalent rates of consumption can be used with reasonable accuracy:

Liquefied natural gas, tonnes per year	Natural gas, 10^6 million cubic feet per day, 10^9 million normal cubic metres per year	Oil, tons of oil equivalent per year	Oil, barrels of oil equivalent per year
1	1.41	1.22	25
0.71	1	0.87	18
0.82	1.15	1	20
0.04	0.056	0.049	1

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AMAP
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