Russian – Norwegian Oil & Gas industry cooperation in the High North
Pipelines and Subsea Installations

6th of June 2014

The Core Team:
The pictures on the front page are taken from:
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Introduction by INTSOK

To develop the High North as a new energy province, we must have the necessary technology to operate in vulnerable Arctic areas. The Russian–Norwegian oil and gas industry cooperation in the High North project (RU-NO Barents Project) is the largest project INTSOK has ever undertaken in any market worldwide. The scope of the RU-NO Barents project, as a strategic project for both countries, is illustrated by the participation of both government and industry from both countries, thus being a part of the official Norwegian–Russian Energy Dialogue. The main objective of the RU-NO Barents Project is, through industry cooperation and knowledge of Arctic technology needs, to contribute to the growth of the Russian and Norwegian industry participation in future petroleum endeavours in the High North. Acting on this objective, INTSOK has mobilized the industry to:

- Assess common technology challenges Russia and Norway face in the development of the High North
- Analyse existing technologies, methods and best practice Russian and Norwegian industry can offer for the High North today
- Based on the above: Visualize the need for innovation and technology development the industry in our two countries needs to overcome
- Promote stronger industrial links between our two countries

It is envisaged that the RU-NO Barents project will benefit the industry, supporting their strategic decisions/direction for increased participation in field developments in the High North. The RU-NO Barents Project will be an important arena to promote and ascertain their level of commitment given to innovation and technology development, forging stronger industry links and partnerships across the border to face our common oil and gas technology challenges of the High North. The project shall also prepare the industry to meet and overcome these challenges.

The RU-NO Barents Project focuses on five major areas, which are all crucial to the development of an offshore oil and gas field.

1) Logistics and Transport
2) Drilling, Well Operations and Equipment
3) Environmental Protection, Monitoring Systems and Oil Spill Contingency
4) Pipelines and Subsea Installations (this report)
5) Floating and Fixed Installations

The RU-NO Barents Project could never have been undertaken without the guidance, support and financing from the Norwegian Ministry of Foreign Affairs, the Norwegian Ministry of Petroleum and Energy, Innovation Norway, Finnmark, Troms, Nordland, Rogaland and Akershus County Municipalities, the Barents Secretariat, Rosneft, ConocoPhillips Scandinavia AS, A/S Norske Shell, GDF Suez E&P Norge, Chevron Norge AS, Statoil ASA, Total E&P Norway, Eni Norge AS, ExxonMobil Production & Exploration Norway A/S, Det Norske Oljeselskap ASA, North Energy, FMC Technologies, GE Oil & Gas, the Norwegian Oil & Gas Association, Federation of Norwegian Industries, the Norwegian Confederation of Trade Unions, Petroarctic, Gazprom, Lukoil Overseas North Shelf AS, Krylov State Research Centre, Rubin Design Bureau for Marine Engineering, Union of oil & gas industrialists of Russia, Sozvezdye, Murmanshelf, as well as the University of Nordland/High North Center of Business and Governance, the Gubkin Russian State University of Oil & Gas, OG21 (Norwegian Oil & Gas Technology Strategy), Marintek/Sintef, Greater Stavanger Economic Development and Det Norske Veritas (DNV GL).

The RU-NO Barents project adds industrial weight to Norwegian–Russian energy cooperation in the wake of the maritime delimitation treaty. In addition it facilitates increased petroleum activity in the High North and focus is placed on carrying out the activity in a sustainable and responsible manner, with the petroleum industry taking the lead.
I specifically would like to extend my sincere appreciation for the work undertaken by Hans Jørgen Lindland and the Task Force Core Team for developing this report within the pipelines and subsea installations focus area.

Stavanger, 6 June 2014
Thor Christian Andvik
Project Director Barents Region
INTSOK/RU-NO Barents Project
Foreword

The purpose of this report is to present the work and conclusions of the Pipelines and Subsea Installations Task Force of the RU-NO Barents Project. The task force had 13 members from both countries and representatives from oil companies as well as from the service industry. During the process of writing this report, two workshops were held, one at Gardermoen and one in Arkhangelsk. The workshops were very well attended with broad industry participation. The workshops were characterized by openness and willingness to share views, knowledge and experience. The intention of these workshops was to discuss common challenges when operating in the High North and to discuss existing technologies, methods, best practice and need for innovation and technology development.

In random order, the core team would like to thank the following participants for their contribution during the workshops: Krylov Shipbuilding Research Institute, Det norske oljeselskap, Det norske Veritas (DNV GL), GE Oil & Gas – Norway, LUKOIL Overseas North Shelf AS, North Energy, RUBIN - Marine Engineering Central Design Bureau, The Russian Maritime Register of Shipping, A.S Norske Shell, TOTAL E&P Russia, The University of Stavanger, Technip Norge AS, Statoil ASA, National Oilwell Varco, FMC Kongsberg Subsea AS, DNO, INTSOK, Aker Solutions, Vryhof Anchors, Sevzapkanat-LLC, Bee Pitron-LLC, BENTS-LLC, Bredero Shaw Arkhangelsk, Oil and Gas System Baltia, Jotun Paints-LLC, OZNA Company-LLC, MPCP-CISC, SVAP-LLC, PO Svevmash, Trans-NAO shipping Company-LLC, Savinskiy Cement Plant, MRTS JSC, PKF Solid, RC Engineering, Pskovgeokabel, United Metallurgical Company, Sozvezdye association of oil and gas suppliers, Samaravolgomash, Arctichesky DSK, JSC Zvezdochka, Norbit Subsea AS, Reinertsen AS, Analyse & Strategi Multiconsult, Marintek, ABB ASA, C-Core, Clamp on AS, Exxon Mobil Production and Exploration Company, Innovation Norway, Nexans, North Energy, OneSubsea, Principa North, RS Platou, Ramboll Oil and Gas, Robotic Drilling Systems, Seabox, Siemens, Subsea7, Swift oil and gas and Vninagaz.

This report would not have reached its final destination without the effort made by the core team. The core team has included the following companies represented by: A/S Norske Shell (Sigbjørn Birkeland), ExxonMobil Production & Exploration Company (Leonid Shulkin), Statoil ASA (Hroar Andreas Nes), FMC Technologies (Brede Thorkildsen), Krylov Shipbuilding Research Institute (Vladimir Malygin and Andrew Dulnev), Total E&P Norge AS (Vidar Gabrielsen), Gazprom JSC (Alexey Novikov), Subsea7 (Helga Persson), Rubin Design Bureau (Evgeny Toropov), Technip Norge AS (Igor Kopsov), Det Norske Oljeselskap (Halvar Larsen) and Hans Jørgen Lindland.

It is the hope of INTSOK that this report could spur increased efforts on both sides of the border, to continue to develop technologies allowing safe and sustainable development of oil and gas activities in the High North.

Talgje, 6. June 2014
Hans Jørgen Lindland
Task Force Manager
RU-NO Barents Project, Pipelines and subsea installations
Executive summary
Subsea pipelines and production systems have been used offshore in the oil and gas industry since the early 1960s. The first installations were single wells tied back to platforms only a few kilometers away. Divers were used to connect flowlines and umbilicals to the wells. Gradually the tie back distances were extended, the functionality improved and thus the applications of subsea systems increased. In the early 1990s, it was established that production from the seabed was a realistic option. Since then, vast quantities of hydrocarbons have been produced by the use of such systems. Today subsea production systems are used in all corners of the offshore world, providing solutions to various types of field developments.

With most subsea technologies being developed for more benign conditions, extending operations into the High North requires there to be developed new technologies and solutions capable of handling physical conditions such as sea ice, permafrost and seabed ice scouring. This report aims to contribute to this development by providing a structured review of a) common technology challenges, b) existing technologies, methods and best practice and c) the need for technology development related to subsea operations in the High North. Also, the report contains an overview of the regulatory framework essential to subsea operations in the High North and some of the most notable projects and programmes being carried out to develop subsea technologies and services. The key areas of technology development identified in this report are:

1. Design and installations
2. Power systems
3. Subsea processing and flow assurance
4. Design, installation and operation of pipelines
5. Marine operations
6. Ready for Operation (RFO) activities
7. Life of field considerations

Design and installation
Subsea production of oil and gas rely on a plethora of technologies and services. This includes wellhead and X-mas trees, manifolds and templates, subsea control systems, workover systems, umbilicals, power systems and infield flowline and risers. While there are challenges and technology needs that are generic to these products and systems, this report highlights how Arctic conditions interact with and, occasionally, exacerbate these generic challenges and technology needs. Among the most important challenges identified and debated in this report are changing soil conditions (which is particularly challenging to the design of wellheads, X-mas trees and manifolds and templates), transport, deployment and storage of installations and sensitive subsea equipment in cold temperatures and ice covered waters, attenuation and pressure drops of electric signals of flows of fluids and umbilical and flowline design.

Although current technologies and solutions, such as slender wells, glory holes, batch installations for “wet parking” and ROV/AUV technologies, should all be applicable to operations in the High North, most of today’s technologies and solutions are evolved from more benign conditions. Hence, there is a need for developing technologies and solutions which enable safe and efficient operations under harsher operating conditions. Several technologies and solutions that could be key components in such a development are identified and debated in this report. This include better seabed mapping and wellhead foundations, further development of batch parking and sophistication of ROV/AUV technology, more precise design requirements and contingency analysis methods, improved topside-to-subsea communication and electric and hydraulic control systems and low temperature elastomeric and polymeric materials.

Power systems
For development of large and oil and gas fields within the geographical focus area, the most relevant distances of power supply are covering from 200 to 600-900 km. Subsea Production System (SPS) power supply with the required level of reliability while ensuring acceptable initial expenses and
operational costs, is a key issue for field development. Analysis of SPS power supply demand reveals that electrical equipment and power transmission technologies that have been developed and are applied in international practice, do not exactly comply with the tasks of development of far remote offshore fields in the High North. This report offers a description of various sources of power supply identifying technological challenges related to remote sources of electrical power, electrochemical generators based on fuel cells and nuclear energy sources.

**Subsea processing and flow assurance**

The term Subsea Processing covers various technologies that enable processing of oil and gas on (or below) the seabed prior to transportation to surface facilities or to shore, including separation, boosting, power and controls. Subsea processing technologies can enhance the economics of Arctic offshore oil and gas developments by increasing production rates, addressing flow assurance challenges, reducing topside constraints, reducing environmental footprint, and reducing development costs. In some cases, these technologies may enable development of otherwise inaccessible resources.

Many subsea processing technology elements have been developed, qualified, and installed over the last fifteen years. Launching subsea operations in the High North does, however, accompany new kinds of challenges, most importantly being long-distance subsea power transmission, distribution and conversion, high-pressure subsea compression for gas reinjection, remote monitoring, diagnostics, and inspection, autonomous intervention systems and subsea separation/dehydration/treatment to enable transportation of oil and gas. Elaborating on technologies and solutions being developed to meet these challenges, this report points at technologies and solutions such as Autonomous Underwater Vehicles (AUV) and resident ROVs, remote monitoring, diagnostics, and inspection, and High-pressure subsea compressors.

**Design, installation and operation of pipelines**

The subsea pipeline industry has developed significantly over the last two decades to meet new business challenges associated with larger water depth and with the transportation of aggressive and unprocessed fluids over long distances. In response to this, new pipeline concepts based on corrosive resistant materials, enhanced thermal performance and heating technologies have been qualified and successfully implemented.

Subsea pipelines are expected to be a major building block in the development of gas and oil fields in the High North and are considered to be efficient for transportation of oil and gas to offshore hubs, to onshore processing/storage facilities or into existing transport networks. The harsh environment and the low temperatures in the High North will, however, force some additional pipeline requirements upon both fabrication/installation and operation. In addition to enforced steel materials and coatings able to resist low temperatures, pipeline systems in the High North have to be designed for potential load conditions caused by direct or indirect ice interaction.

**Marine operations**

Challenges to marine operations, highlighted in this report, concentrate on vessel development, human safety (HSE), ROV operations and planning methodology of marine operations under Arctic conditions. While vessel development primarily depends on finding economically viable solutions for winterization and bolstering of vessel designs to sustain low temperatures and sea ice, the report points at operation windows uncertainties resulting from inadequate coverage and reliability of weather forecasts as a key challenge to planning methodology. Considering challenges to human safety, offshore operations requires personnel with knowledge and experience of operating in harsh conditions, more frequent breaks and crew change regulations attuned to operations in remote areas.

Looking forward, this report emphasizes the need for developing small and inexpensive vessels to be used for some tasks. Marine operations related to subsea production will also benefit from development of such technologies as submerged solutions for transport and installations, advanced subsea positioning systems, drop-installation techniques, new line materials and winching solutions, wet storage (wet parking) equipment and moonpool installation methods. Innovation and technology
development to enhance human safety should include new search and rescue (SAR) solutions, education of personnel and vessels designed to shield the crew from the elements during work.

**Ready for Operation (RFO) activities**

Commissioning of the subsea system is to verify that the total subsea production system is working satisfactorily as an integrated system, prior to opening for the flow of oil and gas. Before the development project, upon successful testing and verification of the entire system, hands the responsibility at this point over to the production operation group.

There are previous mentioned limitations and concerns for the various disciplines/activities which will also be applicable for the pre-commissioning/commissioning activities, as the short installation season and concerns around the operating temperatures but these are considered more as concern’s and not need for new technology development.

**Life of field considerations**

The ability to develop subsea fields in a cost effectively way and “subsea to subsea tie-backs”, will be an important enabler for smaller and remote fields, and also how to effectively extend the lifetime of a subsea system. Subsea wells have generally a lower recovery factor compared to fixed installations, but by the continuous development and improvement of subsea equipment and EOR/IOR techniques it is believed that this gap will decrease. It is also the case that in many situations a subsea development is the only feasible option to effectively develop a field.

Challenges that may potentially reduce the life expectancy of an oil field relate to such topics as production availability and production costs, HSE-contingency, well intervention and geotechnical operations, IMR (Inspection, Maintenance and Repair), increased recovery (IOR) and life extensions/abandonment. Within these areas, this report identifies several challenges, most notable being higher operating costs, compressed season for IMR, limit access of vessels used in intervention and insufficient supply of chemicals applied to increase recovery rates.

Considering current technologies, solutions and practices, efforts to sustain and expand the life of an oil field typically have been oriented towards corrective maintenance (meaning that installations and equipment are run until failure) and IOR/EOR solutions such as water and chemical injections, horizontal and multilateral drilling and subsea separation, pumping and compression. For subsea systems in remote and ice covered waters of the High North with limited intervention access, corrective maintenance is not a feasible option, as the risk could be to have an inoperable system for several months. Furthermore, IOR/EOR may be curtailed as remoteness, temperatures, sea ice and environmental concerns may limit the use of chemical injections. Responding to these challenges, this report points at preventive maintenance through improved monitoring technology, light well intervention methods and IOR/EOR by injection of clean or treated sea water as areas where further technology development efforts should be made.
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1. Introduction

The Arctic is estimated to contain approximately 22 percent of the world’s undiscovered, technical recoverable oil and gas resources.¹ One of the major obstacles to fully explore and develop this region as a future energy supply base is the industry’s capability to provide technology and cost effective solutions. Enabling economically viable and environmentally sustainable operations under the harsh climate conditions in the High North will require a new mindset. Although recognizing the challenging operating conditions in the High North, as recovery rates of subsea installations are closing in on those of traditional wells and platforms, subsea processing and production will play a crucial role in future oil and gas endeavours in the High North.

With most subsea technologies being developed for more benign conditions, extending operations into the High North requires there to be developed new technologies and solutions capable of handling physical conditions such as sea ice and changing seabed properties. This report aims to contribute to this development by providing a structured review of a) common technology challenges, b) existing technologies, methods and best practice and c) the need for technology development related to subsea operations in the High North. Also, the report contains an overview of the regulatory framework essential to subsea operations in the High North and some of the most notable projects and programmes being carried out to develop subsea technologies and services. Key areas of technology development identified in this report are:

1. Design and installations
2. Power systems
3. Subsea processing and flow assurance
4. Design, installation and operation of pipelines
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6. Ready for Operation (RFO) activities
7. Life of field considerations

1.1 A framework for industrial development

Although oil and gas companies are the principle actors of innovation and technology development within the subsea segment, the focus area “Pipelines and Subsea Installations” deals with challenges and processes, which have to be addressed to both public authorities and the oil and gas industry. By targeting both the industry and the authorities, the aim is to establish a common understanding of the challenges and potential of the High North, which in turn might result in:

- An overall conceptual strategy for oil and gas development in the High North focusing on major and specific challenges of the area supported by governments and the industry
- An approved list of actions that should be implemented
- A more comprehensive and fundamental understanding of the challenges and how these should be met by use of technology as well as by human skills

The end result shall promote stronger industrial relations between Russia and Norway by indicating the need for future innovation and technology development through, e.g. design of new/improved technology, need for research projects, need for Arctic technology standards update and strengthening industry links.

¹ According to the United States Geological Survey (2008)
1.2 Getting to the bottom of the report

This report is comprised of six chapters, which are structured as following:

Chapter 2 provides an overview of the physical characteristics of the High North. The chapter focuses on challenges related to meteorological, oceanographic and seabed conditions, as well as ice exposure and icing in the Barents Sea, the Pechora Sea and the Kara Sea. The chapter also presents the timeline, according to which oil and gas operations, based on the perceived technology development, are expected to progress.

Chapter 3 offers a short summary of international regulations and standards with relevance to subsea operations in the High North. The chapter also elaborate on the need for further standardization of Russian and Norwegian standards as means to promote development of technology and solutions relevant to operations in the High North.

Chapter 4 represents the main chapter of the report and contains a structured review of common challenges, existing technologies and best practices and the need for technology development within the seven areas listed above. The chapter gives an extensive insight into some of the most important issues being debated by leading actors in the subsea segment considering subsea oil and gas production in the High North.

Chapter 5 highlights some the most notable projects and programmes recently and currently being carried out to promote technology development. The chapter covers joint industry projects (JIP), public initiatives and programs and academic research.

Chapter 6 contains a comprehensive matrix that displays technology and solution providers within different services and product segments.

In addition to the main report the appendices contain additional information and figures and tables of relevance for pipelines and subsea installations.
2. Physical characteristics of operating in the High North

This report aims to target pipelines and subsea installation challenges associated with oil and gas activities in the Barents Sea (including the Pechora Sea) and the Kara Sea (including the Ob and Yenisey river estuaries) (Figure 1). In this chapter, the key physical characteristics and challenges, encountered by companies operating in these regions, are presented. Compared to the North Sea and the Norwegian Sea, operations in the High North are characterized by harsher operating conditions. Potential risk elements include low air temperatures, icing, remoteness, darkness, sea ice, polar lows and fog.

Further, the meteorological forecasts has a higher degree of uncertainty, which may result in prolonged weather windows needed before starting critical operations. In general, there is a lack of long term metocean and ice data to develop a firm design base for ships and offshore units. A report issued by the Research Council of Norway in 2011 concluded that metocean design criteria are missing in order to be able to design for worst case scenarios, i.e. wind, current, temperature, icing etc.

2.1 Key characteristics of High North operations

What makes the High North a true operational challenge is its distinct characteristics. Although the intensity and combinations of these characteristics vary within the Arctic region, the main natural, physical challenges encountered by the oil and gas industry, when operations are expanded towards the High North, could be described as follows:

Low temperatures
Low temperatures are frequent throughout the Arctic during the winter season. Low temperatures could cause cancellations or delayed operations, as installations and equipment need to be protected and personnel are being prohibited from operating outdoor for longer periods. Low temperatures can also cause damage to equipment when stored/operated in cold temperatures.

Icing
In cold temperatures, sea spray may freeze immediately on contact with a vessels or installations providing significant challenges for marine operation and operational safety for personnel. The combination of wind or wave induced icing with air temperature can lead to reduced operability, freezing mechanisms, slippery deck and ladders and also, in some cases, shutting down communication and evacuation systems.
Remoteness
Large parts of the Arctic region are located far from existing infrastructure increasing time of travel for ships and helicopters. Combined with larger uncertainties related to weather forecasts it can be difficult to plan operations.

Darkness
North of the polar circle, for longer periods of the year the sun will not rise above the horizon. Through reduced visibility, darkness can cause prolonged operation times for certain activities, while also representing a challenge to SAR operations.

Sea ice
The sea ice varies in shapes, thicknesses, ages and hardness. The ice conditions in the Barents-, Pechora-, and the Kara seas are dynamic, leading to large annual, seasonal and regional variations presenting different, however, challenges to vessels and installations operating in various parts of the areas. This report highlights the differences of ice conditions in the geographical focus areas.

Polar lows
Polar lows occur when cold winds blow from the ice covered regions in the north over areas with relatively warm sea. Typically, polar are formed quickly and are difficult to predict. Polar lows can endure for a couple of hours to a couple of weeks with strong winds and subsequent precipitation posing a major safety risk and challenge to operations in the Arctic.

Visibility
Operations in ice covered waters include visual contact with ice, other vessels or installation essential to ensure safety. Fog also represents a challenge in terms of helicopter operations. In the Marginal Ice Zone fog is a phenomenon that occurs frequently. This may cause delays and limitations when considering operations.

2.2 A step-by-step approach to operations in the High North
Present oil and gas offshore activities in the High North take place in the south-western part of the Barents Sea South on the Norwegian side and in the Pechora Sea on the Russian continental Shelf. When Russian operations expands into the northern parts of the Barents Sea and the Kara Sea and with the Norwegian intention to further expand operations northward and eastward, oil and gas activities become more challenging. This calls for a step-by step approach, where operational quality and control must be demonstrated before moving into even more physically challenging areas.

In this respect, the development can to be linked to a timeline that covers the present situation as well as the long term perspectives. Consequently, a timeline is described for the short term, medium term and long term based on assumptions regarding when oil production is viable (Table 1).

<table>
<thead>
<tr>
<th>Activity prospects and time perspective</th>
<th>Geographical regions (areas)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short term (until 2025):(^3)</td>
<td>Barents Sea South (Area 1) and Pechora Sea (Area 2)</td>
</tr>
<tr>
<td>Medium term (2025-2050):</td>
<td>Barents Sea North (Area 3) and Kara Sea South (Area 4)</td>
</tr>
<tr>
<td>Long term (after 2050):</td>
<td>Barents Sea North (Area 5) and Kara Sea North (Area 6)</td>
</tr>
</tbody>
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\(^2\) See Appendix 1 for description of various types of sea ice.
\(^3\) Development projects that are overviewed today, i.e. discoveries resulting from application rounds 22 and 23.
\(^4\) The various “area-numbers” refer to Figure 2.
The three perspectives represent three scenarios described by a high degree of uncertainty. Thus, a careful step by step approach must be applied when preparing for more concrete activities on short and medium term and on long term only for very long lead infrastructure investments, e.g. satellite coverage to improve communication in the High North.

As a tool to describe the inter-dependencies between the time line and the expansion into more ice covered waters (and larger distance from infrastructure and SAR response), the project area is divided into six geographical areas, as illustrated in Figure 2. The six areas represent different challenges regarding, for instance, ice, infrastructure, communications, emergency preparedness and SAR response. The figure has been developed jointly by Russian and Norwegian parties to maintain the views of both parties.

1. No significant sea ice (mostly within SAR response)
2. Sea ice only part of the year (mostly within SAR response)
3. Limited sea ice part of the year (outside present SAR response)
4. Sea ice most of the year (outside present SAR response)
5. Sea ice part of the year (far outside present SAR response)
6. Sea ice most of the year (far outside present SAR response)

Figure 2: Geographical areas of the High North

The oil and gas industry meets different physical challenges in the six areas listed in Figure 2. A main distinction can be made between the concepts Arctic waters and Arctic ice covered waters.

Arctic waters include the ice free waters of the Barents Sea South (Area 1). In these waters ice bergs and drifting ice normally do not represent a risk for maritime and offshore operations. However, challenges and operational risks include: icing on vessels or installations due to low air temperatures, visibility, polar lows and lack of infrastructure especially related to insufficient search and rescue capabilities.

Seasonal ice covered waters include the ice covered waters in the Barents, the Pechora and the Kara seas (Area 2, 3, 4, 5 and 6). The same risks that applies for maritime operations in “Arctic waters”, are also representative for vessels operating in ice covered waters, but in addition, sea ice constitute an explicit risk for vessels and personnel.

In Area 1 and 2 there are currently pipeline and subsea installations in place using conventional designed equipment. Area 3 and 4 will require solutions that extend current state of the art as far as offset distances will increase and time windows for access to the installations will be shortened. Accordingly there is a need for technology development matching the Arctic challenges. Area 5 and 6 represents the ultimate challenges to the industry. Here new ways of installing and operating the
systems must be developed. Workshops conducted in Norway and Russia has clearly identified this challenge and possible solutions have been proposed and are described in this report.

The following sections will present the six development areas, also describing the distinct regional challengers.

2.3 The Barents Sea

2.3.1 Meteorological and oceanographic conditions

Data on environmental parameters in the Barents Sea are scarce and difficult to obtain. Most of the reliable statistics are from land based meteorological stations located along the coast of Finnmark and the Bear Island. There are also three Wavescan metocean data collecting buoys offshore in the Barents Sea. On the Russian side, considerable data is collected, with the Arctic and Antarctic Research Institute (AARI) serving as gathering and analysis center.

For the Barents Sea, there is a lack of empirical meteorological data on temperatures, darkness, snow, fog, icing, rapid weather changed caused by the large temperature gradients between the ice covered and open water, surface winds and polar lows (Figure 3). Such conditions are currently difficult to forecast due to their local formation and relatively small size. In light of current climate change trends, we can expect a decrease of polar lows in the Barents Sea if the ice edge moves further north and east.

![Figure 3: Formation areas of polar lows 2000-2012](met.no)

Considering visibility, for up to six months a year visibility can be below two km. This is partially because of snowfall and partially because of fog, which may reduce visibility below one km. The lack of daylight during polar nights has profound impact on the safety of vessel transport and operations, thereby interrupting the service of the platforms as well as hindering emergency response operations. Visibility measurements at different locations are provided by met.no.
The frequency of polar lows has increased in recent years, with significant numbers occurring in the period between November and April. However, according to recent research the projection is that warmer climate will result in reduced frequency of polar lows. Metocean data has been collected and analyzed by the Norwegian Deepwater Program (NDP). These data is relevant for the western part of the Barents Sea (From 400m water depth).

5 NORSOK N-003 provides design of relevant data concerning the maximum significant wave for different regions. Observations indicate a total average significant wave height of 2.35 m in the ice free southern part of the Barents Sea.6 Seabed bathymetry is typically available for areas within current traffic lanes and required to a large extent for the adjacent regions.

2.3.2 Ice exposure and icing

Since 1979, satellite observations monitoring sea ice extent has been available, thus providing data on the extent of sea ice. These observations are also reflected in the maximum sea ice extent seen in the past decade (Figure 4). However, design relevant knowledge concerning ice thickness, type of ice, presence and size of ridges, pressure zones, short-term drift velocities and general physical and mechanical ice properties is still strictly limited and unreliable. The presence of icebergs in the southern Barents Sea is relatively rare, with the probability increasing toward the Barents Sea North and the Kara Sea respectively.

5 Report, NDP – Needs and opportunities at the start of phase5 – strategy discussions in 2013 by H.J.Sætre 25.1 2014
6 Johannessen (2007)

Temperatures can fall significantly below zero in the Barents Sea, causing additional challenges for the design of vessels (i.e. material compliance) as well as equipment and systems and the operational environment for humans. Furthermore, the effect of wind chill must be considered for humans working in such cold climate as well as icing of the equipment. Thus, winterization of vessels and technical infrastructure, especially heating and isolation, must be adequately addressed.

Since the turn of the twenty-first century, Arctic sea ice has declined relative to its 1979–2000 mean extent. According to the National Snow and Ice Data Center (NSIDC), sea ice extent at the most recent summer minimum (September 2009) and winter maximum (March 2010) was greater than it had been in most recent years. This short-term gain does not, however, indicate a reversal of the long-term decline.
2.3.3 Water depth and seabed topography
The Barents Sea has extremely variable and rugged bottom topography. Iceberg scours in the area is the reason for this. The average shelf depth is about 250 m, and maximum depths reach 400–500 m. The external margin of the shelf in the northern and western Barents Sea is situated at depths of 200–350 m along banks to 400–550 m. This is relevant for subsea field development in short and medium time perspective. For Area 5 and 6 the water depth reaches down to 4000/5000 m. Figure 5 illustrates the variations in water depth.

![Figure 5: Various water depths of the Arctic Ocean (5625m at the deepest)](Source: Arctic Ocean Seafloor Features Map)

2.4 The Pechora Sea

2.4.1 Meteorological and oceanographic conditions
In the Pechora Sea, temperatures are decreasing when moving eastwards and northwards compared to the Barents Sea South. The main sea currents are entering from the Barents Sea South along the Norwegian coast, and from north along the coast of Novaya Zemlya. The difference in water temperature from west to north is not substantial in the Pechora Sea. Thus, few occurrences of polar lows have been observed. Low temperatures and wind during winter time will, however, complicate working environment conditions for all types of operations.

2.4.2 Ice exposure and icing
Eastern and southern heading winds and currents will provide ice covered waters during the winter season. During summer, the ice will disappear. To operate during wintertime, ice classed vessels and support vessels will be needed. In contrast to the Barents Sea South-East, ice bergs are hardly expected in the Pechora Sea. However, according to Krylov State Research Center, the risk of ice bergs must be taken into account in planning and construction. Icing due to lower temperatures and winds constitutes a major challenge to all kinds of operations during winter time. Additional sea spray freezing in open waters will create a major threat to vessels with respect to weight and balance.
2.4.3 Water depth and seabed topography

The Pechora Sea is quite shallow (mostly in the range of 20-60 m). Water depth in the Pechora Sea is less than 150 m increasing in North West in the transition zone with the Barents Sea to 300m.

The presence of permafrost sediments is the main source of engineering risks during the exploitation of oil and gas deposits of the Pechora Sea. The available data on the shelf of the Pechora Sea also suggest that there are subsurface overpressure zones with accumulations of gas and gas hydrates. Studies have revealed numerous diapir-like uplifts made up of frozen ice grounds and related gas accumulations with abnormally high formation pressure.7.

![Figure 6: Icebergs and glaciers of Novaya Zemlya](source: Rosneft)

![Figure 7: Illustration of a diapir rising up through the sediments](source: NOAA Ocean Explorer Gallery)

The figure above gives an illustration of a diapir rising up through the sediments. Faults that form around the diapir can lead to the development of flow systems for gas and fluids, and some of these fluids may nourish seafloor chemosynthetic communities. Pockmarks, or small depressions in the seafloor, sometimes develop above these diapirs.

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2.5 The Kara Sea

2.5.1 Meteorological and oceanographic conditions

When moving into the Kara Sea the overall picture is growing more challenging. Cold winds and currents are entering from north along the eastern coast of Novaya Zemlya into the Kara Sea South basin more or less enclosed by Novaya Zemlya and the Yamal peninsula. Low temperatures and wind during winter time will challenge working environment conditions for all types of operations. Significant occurrences of polar lows are not expected.

2.5.2 Ice exposure and icing

Compared to the Pechora Sea, ice conditions in the Kara Sea are even more challenging. In the Kara Sea South, the sea ice is present most of the year (normally 7-8 months), resulting in a narrow maritime operational window. Due to northern currents and wind, the ice will pack up and multiyear ice is present most of the year. In the Kara Sea North there will be frequent occurrences of ice bergs drifting in with the currents mainly from the Western part of Franz Josephs Land. As water depths in the ice berg origin areas are deep (more than 400 m) the ice bergs from Franz Josephs Land may be similarly large with a deep draught. However, looking at the bathymetry towards Novaya Zemlya the maximum possible ice berg draught is around 250 m both in the Kara Sea North and South. Such large ice bergs may only enter the Kara Sea South along the Eastern coast of Novaya Zemlya, as the central part of the Kara Sea is much shallower. In general, ice bergs are highly anticipated in the Kara Sea North, while less so in the Kara Sea South. Low temperatures and wind in the Kara Sea will imply heavy icing and challenging working environmental conditions in open or partly open waters during winter time.

Studies conducted (in 2012-2013) by Rosneft, Arctic Science and Design Center for Continental Shelf Development (the Arctic Research Center) and AARI established that the most iceberg productive glaciers on the eastern coast of Novaya Zemlya are the Moschny and Nansen glaciers (see Figure 6). The glaciers are fractured by a network of cracks creating small icebergs, the majority of which remain on the near-glacier shoal and disintegrate. A typical linear size of icebergs in the south-western part of the Kara Sea is 40-60 m. Icebergs present a significant danger when operating in the open waters of the Kara Sea. Due to the small size of icebergs it is difficult to track their movements especially in low visibility conditions.

In May 2013 a large iceberg was discovered frozen into the ice, with the above water portion of 70 x 70 x 12 m and the underwater depth of up to 50 m (see Figure 8). When an iceberg freezes into the ice, it becomes surrounded by a belt of ice ridges leading to a multiple increase in the mass of the ice formation. This requires a special approach to design of gravity based structures (GBSs) for a year-round hydrocarbon production.
In 2012, a strong gravity wind blowing from the mountainous coast of Novaya Zemlya towards the sea was studied (Figure 9). In the night from 9 to 10 August 2012 the wind speed of 26 m/s was recorded, the highest wind gust recorded was 55 m/s (about 200 km/h) (Figure 9). Since the duration of storm development is between 3 and 4 hours, and is difficult to predict, it presents considerable danger for offshore and helicopter operations near the coast of Novaya Zemlya. The registered extreme metocean parameters (including wind gusts) must be taken into account for future operations.

2.5.3 Water depth and seabed topography

The average depth of the Kara Sea is 111 m and its area comprises 883 thousand km² with a maximum depth (620 m) in the northern part of St Anna trough some 100 km east of Franz Josef Land (see Figure 10).
In the eastern Barents Sea the water is transformed from warm saline water to cold, less saline intermediate and bottom water. This transformation happens through mixture of cooled Atlantic Water with cold brine-enriched shelf water generated west of Novaya Zemlya, and possibly also at the Central Bank. The moderately cold, low salinity mixture continues to the Kara Sea without further change.

![Figure 10: Illustration of water depths in the Barents -, Pechora - and Kara seas](Source: Byrd Polar Research Center)

### 2.6 Summary

Compared to the North Sea, operations in the High North are characterized by harsher operating conditions, especially during winter. This chapter has provided an outline of the physical characteristics of the High North. Not exclusive to environmental protection and oil spill monitoring and contingency, the chapter has focused on how meteorological and oceanographic conditions such as low temperatures, sea ice, polar lows, darkness, remoteness and reduced visibility can impact maritime and offshore operations.

While the challenges highlighted in this chapter may be considered generic to Arctic operations, the chapter also demonstrates that there are significant variations across areas in Barents Sea, the Pechora Sea and the Kara Sea. In particular, differences in the presence of sea ice is being perceived as having the potential to significantly impact design requirements for vessels, installations and equipment to be applied in Arctic operations. Based on the recognition that operating conditions depend on the location, in which operations are carried out, the industry has deployed a step-by-step approach where operational quality and control must be demonstrated before moving into even more physically challenging areas.

Water depths and seabed topography display considerable variation in the geographical areas included in this chapter. While much of the Pechora Sea is relatively shallow (20-60 m), the Barents Sea has an average water depth of some 250 m. Permafrost sediments is considered the main source of operational risk, with data also suggesting that subsurface pressure zones and the formation of diaper-like uplifts create dynamics in the seabed topography.

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8 Byrd Polar Research Center: [https://bprc.osu.edu/geo/projects/foram/maps.htm](https://bprc.osu.edu/geo/projects/foram/maps.htm)
3. Regulatory framework - international standards

Applicable laws, rules and regulations for respective Norway and Russia and their content and relevance to subsea are a topic which is outside of this study.\(^9\) It is to be highlighted though that harmonizing both countries laws towards direct use of international standards will strongly support the development of common technical and operational solutions, allowing for sharing of industrial resources, technical solutions and competence. This will have an effect also on vessels and rigs such that they more easily can move across the delimitation line.

For subsea and pipelines international standards are widely used in the industry, the most relevant regulations applicable in Norway and Russia are described in the following sections.

**Subsea**

- ISO13628 series aligned with the API 17 series
- Norsok U-001 (Norway)
- GOSTR (Russia)
- ISO 10423 “Wellhead and Christmas Tree Equipment”, aligned with API Spec 6A

<table>
<thead>
<tr>
<th>Identification</th>
<th>Name</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISO 19900</td>
<td>Petroleum and natural gas industries - General requirements for offshore structures</td>
</tr>
<tr>
<td>ISO 19906</td>
<td>Petroleum and natural gas industries - Arctic offshore structures</td>
</tr>
<tr>
<td>API RP 2N</td>
<td>Recommended Practice for Planning, Designing, and Constructing Structures and Pipelines for Arctic Conditions, 1995</td>
</tr>
<tr>
<td>Arctic Governance Project</td>
<td>Arctic Offshore Oil and Gas Guidelines, 2009</td>
</tr>
<tr>
<td></td>
<td>Work relevant for developing codes and standards for the Arctic Region.</td>
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On the Norwegian side, the NORSOK standards are generally well aligned with ISO and API. For the Arctic, however, neither NORSOK nor ISO/API covers these specifically. Technology gaps, identified in the two workshops conducted, will entail qualification to new (not currently identified) and industry agreed requirements.\(^10\) It is here strongly recommended to initiate development of an Arctic specific standard as an addendum to ISO (NORSOK and GOSTR).

On the Russian side, Rubin Design Bureau performed a study on gaps on international standards and Russian standards for the Shtokman Development project. This work could be a good starting point/input for developing an Arctic subsea standard.

It should be noted in this context that post Macondo the United States have issued new requirements to improve safety. An example of this is found in the United Stated Bureau of Safety and Environment Enforcement (BSEE), which put forward requirements to operators for meeting the risk of oil spills.\(^11\) Thus it is quite evident that developing an Arctic standard must be based upon and aligned with industry relevant requirements and practices.

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\(^9\) Standards and regulations are also covered in the following RU-NO Barents Project reports. The Logistics and Transport-report, The Drilling and Well Operations-report and The Environmental Protection, Monitoring Systems and Oil Spill Contingency-report. Link: [http://www.intsok.com/Market-info/Markets/Russia/ RU-NO-Project/Focus-Areas](http://www.intsok.com/Market-info/Markets/Russia/ RU-NO-Project/Focus-Areas)

\(^10\) See Appendix 2

\(^11\) Offshore Magazine Russian Version No 1-2014, p. 46
Pipeline
- DNV-OS-F101 Offshore Standard – Submarine Pipeline Systems
- ISO 13623 Petroleum and natural gas industries – Pipeline transportation systems

Both on the Norwegian and the Russian side, the DNV offshore standard OS-F101 seem to be prevailing. DNV OS-F101 is intended to comply with ISO 13623. The design format in both these standards is based on risk and reliability principles, which are implemented based on defined limit states and corresponding partial safety factors, also referred to as the Load and Resistance Factor Design (LRFD) format.

Within the framework of the existing standards there is a need for development of design criteria and design guidelines covering specific load scenarios, corresponding load effects and potential consequences of failure associated with pipeline developments in the arctic. Uncertainties related to prediction of ice load effects and material resistance in cold climate should be reflected in determination of partial safety factors for the arctic specific limit state conditions.

Marine operations
The governing standards and legislation has a large impact on the marine operations. The in-field search and rescue (SAR) contingency, vessel specifications and weather conditions expected at site are all part of determining the safety measures and the operation design durations for the work at hand.

Today, the marine operations in Arctic waters follow:
- ISO 19901-6:2009 — Specific requirements for offshore structures Part 6: Marine operations
- ISO 19906:2010(E) - Petroleum and natural gas industries — Arctic offshore structures

Examples of other standards regarding work in Cold Climate are:
- DNV-OS-A201- Winterization for Cold Climate Operations (Tentative, OCTOBER 2013)
- DNV Rules For Classification Of Ships Part 5 Chapter 1 - Ships for Navigation in Ice
- DNV - standard for certification No. 3.312 - Competence of officers for navigation in ice
- BS EN ISO 15265:2004 - Ergonomics of the thermal environment — Risk assessment strategy for the prevention of stress or discomfort in thermal working conditions

Approximate correspondence between Ice Classes of the Finnish-Swedish Ice Class Rules (Baltic Ice Classes) and the Ice Classes of other Classification Societies is presented in Figure 11
Figure 11: Approximate correspondence between Ice Classes of the Finnish-Swedish Ice Class Rules (Baltic Ice Classes) and the Ice Classes of other Classification Societies

Source: Baltic Sea Icebreaking Report, BIM 2011-2012

There are some standards and legislation in place for working on the Norwegian and Russian sides of the Barents Sea, but there is a need for new and simplified legislation and standards for working across the Norwegian/Russian border.12

For planning of offshore operations in the High North, procedures and criteria defining weather restrictions have to be updated to reflect the uncertainties in monitoring and in forecasting of the specific environmental conditions.

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12 Highlighted by participants in the industry workshops (see Appendix 2)
4. Challenges, best practice and need for technology development

Subsea pipelines and production systems have been used offshore in the oil and gas industry since the early 1960s. The first installations were single wells tied back to platforms only a few kilometers away. Divers were used to connect flowlines and umbilical to the wells. Gradually the tie back distances were extended, the functionality improved and thus the applications of subsea systems increased. In the early 1990s, it was established that production from the seabed was a realistic option – and since then vast quantities of hydrocarbons have been produced by the use of such systems.

Today subsea production systems are used in all corners of the offshore world, providing solutions to various types of field developments. This includes:

- Long distances - multiphase flow - handling flow assurance issues
- Deepwater – producing from subsea wells at 3000m water depth
- High pressure and high temperature wells (1000bar and 170°C)
- Low pressure fields where boosting and subsea separation is used

Over the years huge efforts have been put into making the systems reliable and fit for purpose. Tools and methods have been developed for installation and operation without using divers. Remote monitoring and control of the equipment and the flow process is based on advanced simulation models derived from extensive model testing in multiphase flow loops.

Up until today, the main argument against subsea production has been the limited recovery from subsea wells compared to traditional wells on platforms. However, with new smart-wells and cost effective vessel based interventions more data can be obtained from the reservoirs and the gap between traditional and subsea production is narrowing.

4.1 Global perspective on subsea and pipelines

The subsea industry is today a truly global industry with an industry activity level amounting to billions of NOK in turnover. The figures below show the current and expected activity and investment levels.

Figure 12: EP expenditure by continent
Source: Rystad Energy DCube (2014)
Each region is self-supplied with basic equipment and resources – high technology products though is supplied mainly from Norway, the United Kingdom and the United States. Vessels for installations are partly localized in the respective areas, but can also move between the areas. Thus the systems on the seabed, the tools for operating them and the vessels for support are similar and standardized throughout the industry. Design codes and practices are to some degree harmonized between areas and countries such that an effective utilization can take place, however more work is recommended.

The structure of the industry is basically split in two segments:

- Subsea systems suppliers
  - Four major companies/system houses are operating globally
  - Sub suppliers providing the system houses with components and subparts
- Marine contractors
  - Three major companies
  - Smaller regional based companies are often cooperating with the major companies

When considering subsea oil and gas production in the High North, the industry structure will represent the backbone. Adaptation to meet the severe Arctic conditions will have to be made though. This report gives a direction on how to precede this venture.

The Norwegian industry (and to a lesser extent the Russian) has already been involved in the first generation of Arctic projects, including Hibernia and Terra Nova in the Canadian arctic, Sakhalin II in the Russian Arctic and the Shtokman development. The challenges are associated with defining the ice environment, translating this into effects (loadings) on the equipment and vessels, developing new concepts with fit for purpose functional requirements.

This needs to be accomplished whilst meeting very stringent environmental standards. The High North is environmentally a very sensitive ecosystem. Furthermore, due to its cold climate the area is relatively slow to recover from environmental impact. Also because of large integrated installations with large volumes of hydrocarbons, an accident could potentially cause a lot of harm to the environment.

It is thus quite obvious that operating in the High North will be a costly venture with high risks involved. These are some of the issues that will influence any strategies that will be applied:

- Estimated 22 percent of world’s undiscovered oil and gas reserves
- The subsea and pipeline industry have the technology needed to operate in Area 1 and 2
- For the other Areas 3-6 new solutions need to be developed
- Development cost 45-100 $/bbl – competitiveness with other regions of the world?
- Safe and clean field developments – how to demonstrate?
- Global engineering and construction capabilities – alignment?
- The geographical focus area extends – timeframes for development and coordination/cooperation in the relevant regions
- Oil development – gas development commercial alignment?
- Establish infrastructure to support the remote areas

From the above some conclusions can be drawn:

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13 Aker Solutions, FMC Technologies, OneSubsea and GE
14 Subsea 7, Saipem and Technip
• The interested parties for Area 3, 4, 5 and 6 will have to develop and fund the specific technology needed for the Arctic industry. Only limited part of the development and improvements from other parts of the world will benefit the High North.

• This is basically a common Norwegian Russian challenge, but also relevant for the other countries engaged in the High North.

• Exploration and subsea field developments are already underway in both the Norwegian and Russian parts of the Arctic – built and tested in accordance with international standards.

4.2 Design and installation

4.2.1 Wellhead and X-mas trees

Common technology challenges

The seabed soil conditions in the Arctic can be very different from other areas due to potential presence of frozen soils (permafrost), gas hydrates or a combination of these. The geographical focus areas covered by the RU-NO Barents project includes regions with virtually no presence of these conditions to regions heavily influenced. The occurrence of these soil conditions is more pronounced when moving towards the colder areas, thus the geographical focus areas 2 to 6 are more affected by this.

Soil conditions cannot be stated as “firm” or “soft”, but actually be changing during a life of field. This is a consequence of climatic changes, but also due to the Subsea Production System itself affecting the environment locally. The effect of thawing on the seabed soil can be to reduce or completely lose the capability to support loads. Seismic activity (earthquake) may aggravate the situation as liquefaction of soils can take place. Seabed slides have been found to occur in regions with soft soils (e.g. The Storegga Slide outside Norway in prehistoric time). The understanding of seabed soil conditions is evolving with more information becoming available through research as well as from practical experience from operating in the region but in general further work is required.

In areas where icebergs scrape the bottom or the water depth is sufficiently shallow for ice scoring to occur, seabed structures needs protection or be designed to be sacrificial – the latter meaning that barriers are located sufficiently deep in the seabed to enable closing and effectively sealing off the reservoir.

The cost for establishing a ready producing well with X-mas tree, wellhead and the necessary completion equipment in the well is currently high on the NCS and also in other comparable regions. There are many factors contributing to this however a technology shift towards more slender wells are expected to act favorably in this respect. If slender well technology is adopted for the geographical focus area, it is of vital importance that this is developed to cater for the challenging seabed soil conditions.

For gas fields, it may be more cost efficient to use large bore wells. Hence, technology which combines slim wells with large through bore capacity would be beneficial as this would reduce the number of wells required at a gas field.

Existing technologies, methods and best practice

Current technology for subsea has evolved from more benign conditions and is considered acceptable and safe for areas which are less influenced by the above mentioned seabed challenges, typically in region 1 and 3.

Russian cold climate experience with land based oil & gas production, in particular how to drill and maintain wells, design and installation of surface structures and pipelines, is of relevance. This experience and knowledge should be used when developing technology for subsea fields.
Russian experience and requirements with land based oil & gas production from areas with seismic activity is also of relevance. This experience and knowledge should likewise be used when developing technology for subsea fields.

Risk assessment methodology used in other areas of the oil & gas industry can be a good basis for quantifying risks to wellhead and X-mas trees and should be investigated further.

Technology for protecting wells and X-mas tree by locating them in a trench (glory holes) or silos does exist, but may not be viable economically and/or not suitable for a region.

Slender well technology is being developed, encompassing casing, well equipment as well as drilling methodology and completion technology located above the seabed. The challenge is related to finding good solution for drilling and completion equipment which combines lower cost while still maintaining the required well integrity. Designing a wellhead and X-mas tree should not be of any concern provided the well can be effectively and safely drilled and casings/tubing set using the appropriate technology adopted for the regions requirements.

**Need for innovation and technology development**

- Improved mapping and further studies of the areas thought to be suffering from the seabed challenges; the areas affected the properties of the seabed and the perceived influence on the wells.
- Improved methodology for assessing load and fatigue impact on wellheads – short term during installation and intervention but also through a full life of field scenario. The utilization of instrumentation systems to reduce uncertainty of status should be included in this development.
- New and innovative wellhead foundation solutions (including cement technology and instrumentation for monitoring) for a seabed with changing properties.
- Evaluation of adequacy of current drilling practices for areas where the seabed may contain shallow gas and/or frozen soils.
- Establish clear requirements for the influence of seismic activities on wells and wellhead structures.
- Establish clear requirements for how to protect wellheads and X-mas trees from icebergs as well as scoring ice in shallow waters.
- Establish risk assessment methods for wellheads and X-mas trees (including well barriers) with respect to seabed conditions, ice bergs and scoring ice in shallow waters.
- Improved understanding of the consequences on the environment for wells in a deteriorating state where leakage is a possible consequence thus potentially leading to a catastrophic event.
- Further development of drilling, well and completion technology reducing the size of the well (slender well) while at the same time proving sufficient through bore in the production tubing and X-mas tree thus satisfying the various fields production requirements.

**4.2.2 Manifolds and templates**

**Common technology challenges**

The geographical focus areas 1 to 6 are very diverse with deep water Kara Sea, shallow water Pechora Sea and central regions in the Barents Sea all require different solutions to become viable oil and gas provinces and yield profitable fields.

With manifolds and templates being larger, but, at the same time, similar structures as X-mas trees and with templates also containing X-mas trees/wells, they are affected by the same seabed issues as described in Chapter 4.2.1 However, with manifolds and templates potentially being very large and heavy, further considerations are applicable as given below.
Transportation and installation are to a large degree affected by logistics and with time in transport being long and the window for installation being short in the summer or ice free season, current solutions are not optimal. Heavy lift vessels capable of operating in the High North can be a limiting factor, in terms of availability but also the cost of operating them is of significance. Long transportation and installation time means also that more people are exposed for longer periods of time thus increasing the potential for hazardous situations and subsequent need for SAR services.

The logistic challenges can also lead to equipment needing to be stored through the winter season or in need of being handled through a “cold spot” in spring or autumn. Whenever equipment is stored or handled through such cold periods, extreme low air temperature can damage materials as well as impair functionality of the equipment. Materials suffering from brittleness in cold temperature need special considerations. Likewise, lubricant is also negatively affected and can prevent equipment from functioning properly or lead to damage. Typically affected are connectors requiring lubricants for sliding surfaces or for sealing purposes. It should be noted that summer temperature can also be high thus the temperature span required for the materials are more extreme compared to what is normally encountered in more temperate areas. Typically affected are elastomeric insulating materials used for improved flow assurance.

The ice conditions vary greatly between the six geographical focus areas and will therefore require ice and iceberg management philosophies ranging from avoidance to complete protection against the ice. It should be noted that even tough ice management is an established service in other Arctic regions, it is heavily dependent on the local environmental conditions as well as supporting services such as weather reporting, satellite coverage and surveillance in general (e.g. aerial).

With reduced access most of the year, the availability of the Subsea Production System is expected to suffer when remedying actions rely on current Inspection, Intervention, Maintenance and Repair (IIMR) technology if the reliability of the installed equipment remains the same as in other regions.

Protection from fisheries (trawling) is required in the Norwegian area of the region, but this is not a requirement in the Russian area. Important and large fisheries may change its location or develop in other areas as the sea temperature is changing (currently increasing) hence trawl protection may also become preferred in the Russian region in the future (towards 2050).

Existing technologies, methods and best practice
As stated above, the geographical focus areas 1 to 6 are very diverse and there is a notable lack of technology and experience for some of these areas when considering requirements for full field developments, ranging from drilling of production wells to IIMR activities on installed equipment.

Current technology for Subsea Production Systems have evolved from more benign conditions, but is still considered acceptable and safe for areas which are less influenced by the above mentioned challenges, typically Area 1 and arguable Area 3 with the Shtokman field being a typical example in terms of technology proposed. However, there is no experience with installing and operating equipment for sea areas being ice covered most of the year (Area 6) nor for shallow water being subjected to heavy ice scoring as expected close to shore in the Pechora sea or at the Yamal peninsula (Area 2). Experience from the Kirinskoye field in the Sea of Okhotsk is of relevance for further development of the required technology.

Batch installation and/or “wet parking” of modules at the seabed are known methods for reducing installation time and is considered to be of particular significance when the time available for access – like in a short Arctic season – or availability of an installation vessel is a limiting factor. The method is successfully used in other regions and lends itself for further development and refinement.

Ice management techniques and methods have been developed for other Arctic areas and the experience gained should be used for tailoring the service towards the geographical focus areas 1 to
As stated above, the regions are very diverse and different solutions will be required. Note that the requirements for protection of seabed equipment are different from the protection of surface vessels used for installation or intervention. The vessels may abort/suspend their operation and move whereas the permanently installed equipment obviously stays in situ. Ice management involves every aspect of the operations needed, ranging from detection of ice by human eye, radar, plotting movements, planning of actions etc. to physically removing an ice berg by use of a vessel.

Risk assessment methodology used in other areas of the oil and gas industry can be a good basis for quantifying risks to a range of seabed installations in these more challenging regions. This should be excellent reference material for further development by taking into account the particular challenges in the various regions, herein also relevant logistic issues. Reference is given to work by DNV in the Barents 2020 project.\(^{16}\)

With reduced access most parts of the year, the availability of the Subsea Production System may be affected. In order to improve on this situation, further development of contingency in design to obtain more robust system solutions, more use of CPM and remote inspection techniques and more use of autonomous solution with less dependence on permanently located vessels during IIMR operations are recommended. These techniques are in general in the process of being developed for other regions however the significance for the geographical focus areas of the RU-NO Barents project is even more important.

Technology for protection from fisheries (trawl protection) exists and should be adequate also for the areas requiring this type of protection. It should be noted that dropped object protection is required in all geographical focus areas.

Excavation technology used for digging “glory holes” or pits in the seabed is used in other regions, example vise on the Grand Banks outside of Newfoundland, for protection against icebergs. The excavation operations are large with long time duration and produce much excavated material. It is possible that particles and silt from these operations pose a threat for some areas with sensitive environment (e.g. cold water coral reefs) and important fisheries (e.g. breeding ground) and also the time needed for excavation can be too long in some areas.

**Need for innovation and technology development**

- With Shtokman being a field which has been subjected to thorough studies and evaluation, it is recommended to review the material and provide a “lessons learned” for future reference.
- Development of modular and reduced weight/size solutions optimized for fast installation and potential use of ROV/AUV/submarine technology.
- Development of ROV/AUV/submarine technology for installation of modules and general surveillance and inspection of the seabed structures.
- Further development of batch installation and wet parking technology with the purpose of significantly reducing the time needed during installation.
- Development of technology to reduce dependence on heavy lift transport and installation vessels (e.g. use of buoyancy modules)
- Development of robust system solutions (contingency) for areas where damage caused by ice or denied IIMR access will reduce the availability of the Subsea Production Systems significantly. (e.g. alternative routing of fluids or well stream, redundant communication)
- Develop IIMR strategies to obtain acceptable availability in the various regions including developing CPM technology to match the requirements in the IIMR strategies.
- Further develop risk assessment methodology to cover the challenges in the region

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\(^{15}\) Read more about «Ice Management» operations in the RU-NO Barents Project: Logistics and Transport-Report. Link: [http://www.intsok.com/Market-info/Markets/Russia/RU-NO-Project/Focus-Areas](http://www.intsok.com/Market-info/Markets/Russia/RU-NO-Project/Focus-Areas)

• Develop “ice and iceberg management” philosophies for the various regions as input and guidelines for the particular future field developments.
• Further develop methods for seabed excavations with the aim of significantly reducing time and volume of discharge of silt/particles in environmentally sensitive areas.
• Further development and use of materials and lubricants which does not suffer from extreme cold temperature or large temperature cycles. Use of lightweight materials such as aluminum and GRP should be included in this scope of work as this will also reduce the weight of the equipment.

4.2.3 Subsea control systems

Common technology challenges
The possible long tie back distances coupled with the reduced access for intervention due to rough weather/ice and the logistic challenges of performing an intervention exacerbates the limitations in current control system technology.

With the long tie back distance, signal attenuation in fiber optic lines/electrical lines and pressure loss in fluid lines is of concern and in particular the latter is hardly feasible for the longest step outs due to the size required for through-bore to reduce the pressure drop

The reliability of electrical and electronic components typically used in control modules is of concern and when considering the experience from other areas, malfunctioning of control modules contributes significantly to downtime for production systems. With replacement of control modules requiring an intervention to be performed, this clearly becomes a challenge due to logistic circumstances or rough weather/ice on the sea surface.

Regarding control fluids, the discharge of hydraulic fluids should be avoided as they may contain toxic elements required for the proper performance of the fluid and the control devices (valves, actuators etc.). It should be noted that the reduction or replacement of toxic elements, which is a goal for the development of these fluids in order to increase their environmentally friendliness, may negatively affect the performance of these fluids – i.e. long time stability and content of lubricating elements. In particular for fluids, which may stay in the systems for a very long time of operation, this needs to be considered when designing the systems as well as selecting fluid.

Existing technologies, methods and best practice
The usual configuration of the control system consist of a topside (or at shore) system, a subsea system and the necessary systems connecting these together. A typical description of the technology used is given below:

• Topside:
  o Master control unit which is part of a Distributed Control System for the field/host facility.
  o Electrical power, communication and hydraulic power units

• Communication system from topside to subsea:
  o Power line communication
  o Fiber optic communication
  o Proprietary protocols for communication
  o Communication either directly to each Control module or via a retrievable subsea router module
  o Sensor interface: CAN bus, Ethernet, 4 to 20 mA, IP over RS422

• Electrical power from topside:
  o AC 230 to 3 kV
  o A few systems are using DC

• Hydraulic systems:
  o Two pressure levels, LP is 200 to 350 bar and HP is 700 to 1030 bar
- Redundant supply from topside of both HP and LP
  - Subsea part:
    - Umbilical terminations
    - Subsea control modules and routers
    - Sensors on trees and manifolds
    - Electrical and hydraulic lines (jumpers)

Regarding use of hydraulic fluids, subsea HPU’s for boosting or generating hydraulic pressure can be used if the step out distance is too long for providing hydraulic pressure through an umbilical line. Discharge of hydraulic fluids can be avoided by using closed loop hydraulics. This, however, further reduces the acceptable step out distance when the fluids has to be brought back through a dedicated umbilical line. Alternatively, subsea HPU’s may be used for boosting the return flow also.

Current subsea communication technology is limited to a distance of approximately 200 km without the use of repeaters. With repeaters, there is no practical limitation and this technology is well known and proven from the telecom industry.

All electric control systems are in development by System Suppliers and are expected to replace the hydraulic control systems in the future. For full benefit of electric control systems, all equipment used at a field should use the same technology platform and downhole hydraulic valves should be replaced with electrical equivalents. Electric downhole safety valves are currently in the process of being qualified. However, more work could be needed in order to satisfy particular requirements by the Oil Companies.

**Need for innovation and technology development**

- Further development of hydraulic fluids to reduce content of potential toxic chemicals while still providing the necessary functionality for long and reliable operation of hydraulic systems.
- Further development of technology to eliminate discharge of hydraulic fluids to sea. The fluid could be returned to a host facility, to a catchment tank or possibly be re-injected into a reservoir together with produced water.
- Further development of electrical control systems including work on system architecture and integration of CPM technology for improved reliability and ability for seamless replacement of modules without interruption of operations.
- Further development and qualification of downhole electric valves.
- Further development of technology enabling communication, power distribution and supply of hydraulics for the longest step out distances.
- Development of technology for interfacing and operating ROV/AUV’s such that these can perform tasks independently of surface located vessels. Communication technology for high capacity data transfer including visual streaming (real time) and power supply should be part of the scope.

**4.2.4 Workover systems**

**Common technology challenges**

With ice cover, rough weather, reduced visibility and also the challenging logistic situation reducing the time available for workover and intervention, more effective IIMR operations are needed. Faster operations will, in addition to being more cost effective, also reduce the duration when humans are on the site and exposed to the Arctic environment, thus reducing the potential for hazardous situations and subsequent need for SAR services. Wind and wave conditions ranges from fairly calm to extremely rough the latter being more pronounced in the western part of the area. It should be noted, that the calmer areas are often associated with ice covering the seas, thus access for intervention and installation is always more challenging compared to other areas.
Of particular concern is the fact that the weather services are currently not sufficiently developed in the region to cover all the needs of the oil & gas industry. At the same time, the weather is highly unpredictable with polar lows and freezing of sea spray/precipitation on surface vessels occurring. A polar low can form and disappear within two days and ice accretion rate can be high with several cm/hour being realistic numbers.\(^1\)

Workover or intervention operations can range from simple inspections with ROV to heavy workover operations with, for instance, pulling of tubing or other time consuming activities deep in the well. The latter can span a period of many days and should be compared with the probability of detecting the formation of a polar low and its duration. The methods of operation when performing intervention and technical solutions used needs to take account of this.

If vessels with open areas topside and/or with opening between deck and sea surface are used, the air temperature can also be a challenge. Low temperature affects the brittleness of materials in e.g. risers or umbilicals and also lubricants can become highly viscous or sticky with consequence for the functioning of the equipment. And of course during conditions with heavy snow fall or icing and in combination with wind, no external operations are possible, the conditions quickly becoming a hazard for those needing to work in the open.

If workover and intervention need to take place at the time when ice is covering the sea the intervention vessels needs to have the capability to maneuver in ice (hull strength, propulsion systems, station keeping by anchor or dynamic positioning etc.). The vessel type also needs to protect the intervention equipment from ice as risers, well control packages or umbilicals does not allow for any interference from ice. Moonpool operations could be considered for ice infected water operations.

With the geographical focus areas 1 to 6 in general being less than 500 meter deep and in large areas considerably more shallow, it is worth noting that shallow water in combination with harsh weather (rough seas) or heavy ice interfering with the vessel station keeping results in a combination causing large loads to be transferred to the Subsea Production System. In fact, this is more demanding than for deeper waters off the Norwegian coast which however does have rougher sea states than expected in the geographical focus areas.

**Existing technologies, methods and best practice**

Workover, intervention and inspection are terms often used with an overlapping or not strictly defined definition. For the discussions in this report however, the following shall apply:

- **Inspection:** A non-barrier breaching activity performed in the sea externally to the Subsea Production System
- **Intervention:** Any activity performed to manipulate, repair or replace a component (e.g. a bolt), a part (e.g. an actuator) or a module (e.g. a pump module)
- **Workover:** A barrier breaching activity performed inside the x-mas tree or the well, the well being “alive” or in a “killed” state.

The following methods are used in other areas and will also be applicable for the geographical focus areas 1 to 6.

- **Heavy workover using a marine riser (drilling riser) and Blown Out Preventer connecting to a wellhead or a X-mas tree with a workover riser or drillstring performing the actual workover operation.** Typical examples of operations are replacing tubing, changing sand screens or setting a sleeve deep in the well.
- **Workover using an open water riser with a Well Control Package connecting to a X-mas tree.** Typical examples of operations are pulling or setting a plug, performing a coil tubing or wireline service or milling out scale.

\(^1\) Read more about polar lows in Chapter 2.
• Workover using a Riser Less Wireline package (RLWI) where the wireline and tool package is run in the sea before being sluiced (lubricated) into the RLWI unit located on top of the X-mas tree
• Intervention using large dedicated ROV’s or “running tool” units performing special operations on the Subsea Production System. Typical examples are connecting flowlines or installing or retrieving a pump module. Special purpose equipment for e.g. subsea machining or welding is included in this category
• Intervention using general purpose ROV’s. Typical examples are replacing components, open or close valves etc.
• Inspection using ROV or AUV. Typical examples are visual, ultrasonic, leak detection etc.

With the exception of using AUV for inspection, all the methods described above require a vessel to be located in a defined position directly above the location where the intervention work is taking place (“station keeping”). The size of the area, which is acceptable for the vessel to be located in, depends on many parameters such as metocean states, water depth, method of workover or intervention, vessel characteristics and equipment used on the vessel.

Intervention using ROV’s and RLWI connects the vessel to the subsea equipment using flexible wires and umbilicals. Hence, no force from the vessel is transferred to the Subsea Production System. This is a benefit, as it greatly reduces loads on the Subsea Production System and enables a less strict station keeping as long as the wire/umbilicals connecting with the RLWI stack or ROV is sufficiently long.

When connecting a riser system to a well head or a X-mas tree, however, the loads transferred can be huge and potentially barrier threatening and/or cause fatigue to occur if the operations are long and/or frequent. This is not a new situation, with the same being experienced in other regions as well. However, the harsh weather in the Arctic and the uncertainty caused by the seabed soil conditions makes for a cautious approach and evaluation whether current practice is acceptable. A known technology, which is being used, is that of a Riser Management System, which is an instrumentation package measuring the loads and stresses in the riser. The system allows for monitoring real loads and proposes optimal position of the vessel relative to the wellhead/X-mas tree in order to reduce loads. When connecting Riser Management System with the vessel’s systems for riser tensioning, station keeping and sea state measurement, it is possible to predict the riser response and thus, in advance, move the vessel to a more favorable position. When local and real time metocean data is available is also possible to predict even better how the load situation develops, thus making for better planning of the ongoing activities. With the development of improved ice surveillance, it is natural to also include this into the metocean data for the areas where ice is of concern.

**Need for innovation and technology development**

- Development of workover and intervention philosophies for the various regions as input and guidelines for the particular future field developments and the development of the necessary technologies.
- Development of technologies which reduces the need for “tight” vessel station keeping during workover and intervention operation including improvement to GPS positioning systems
- Development of technologies which enables faster workover and intervention operation
- Development of technologies which enables faster yet safe temporary abandonment of operations and subsequent reconnection for continuation.
- Development of technologies which reduces loads on subsea structures during workover and operation. Both normal operations and accidental scenarios shall be considered.
- Development of technologies and services enabling more use of ROV/AUV/Submarines including ability to operate under ice.
- Development of technologies enabling “wet parking and storage” of spares (e.g. control modules).
- Further development of Riser Management System including incorporating ice management services
• Improvement to weather monitoring and prediction services. Of particular interest is to look more into the unpredictability of weather patterns which has the potential to interfere with workover and intervention operations. Ocean currents should also be included in this scope of work.

4.2.5 Umbilicals

Common technology challenges
The length of umbilicals used for tying back fields to shore or to existing infrastructure can be very long. It is possible that some fields may require several hundred kilometers of length.

The size (cross sectional diameter) of the umbilicals will depend on many parameters. However, the need for accommodating large pressure drops by increasing design pressure or reducing pressure drops by increasing the cross sectional area of hydraulic or chemical tubes, needs to be recognized. A consequence of larger size (cross sectional diameter) is an increased reeling diameter, which makes for larger reels thus requiring large space for transport, storage and during installation.

With a large portion of an umbilical being made from polymeric materials, the material used needs to accommodate the low temperature experienced in some areas. The low temperature limitation for the umbilical depends on the material type used. However, it is usual to distinguish between a static and dynamic minimum temperature. The static applies for transport and storage situations whereas the dynamic is applicable when the umbilical is being reeled.

Transport and storage of large umbilicals is therefore of concern, if they are stored outside during the winter or being in transport during a “cold spot” period in the spring or autumn. When the umbilical reels are large, this can be a real challenge and infrastructure may not be in place for these purposes. Reeling of the umbilical is also of concern when this is carried out during spring or autumn if the weather turns cold and the dynamic minimum temperature is encountered. It is also worth noting that workover or intervention umbilicals needs to be protected from cold temperature during storage at base, at vessel or during operation but due to their smaller size, this should not be a challenge.

Existing technologies, methods and best practice
The length of umbilicals used for workover, intervention and installation purposes will be relatively short in all the geographical focus areas (Area 1 to 6) due to the water depth being in general less than 500 meters and in large areas considerably shallower. No challenges are envisaged regarding size and length of these umbilicals and current practice should suffice.

The length of umbilicals used for infield communications will be limited by the actual separation of the various templates, manifolds and individual X-mas tree satellites. Thus, in general similar to what is experienced in other areas, no challenges are envisaged regarding size and length of these umbilicals and current practice should suffice.

Polymers materials become stiffer and more brittle at lower temperatures and it is therefore necessary to ensure that the umbilicals are not operated or handled such that damage may occur. It is normal to set a minimum temperature for reeling which is considerably higher than the allowable minimum temperature for storage. The longest umbilicals need to be transported in sections on large reels onto which they are spooled at the manufacturing site. Connector sections are used for joining these during deployment and current practice should suffice.

Communication signal attenuation is of concern at longs step out distances and “repeater” stations will be required. Current practice should suffice.
Need for innovation and technology development

- Further development of elastomeric material which does not suffer from brittleness in cold climate during storage as well as during reeling.
- Further development of methods and services for transportation, storage and installation which prevents exposure to extreme low temperature.

4.2.6 Infield flowlines and risers

Common technology challenges

The infield flowlines will be affected by much of the same factors as wellheads, X-mas trees, template and manifolds. The same considerations thus apply and reference is given to the description of these.

In cases where the flowline could be damaged by scraping icebergs or scouring ice, the flowlines can be required to be dug down deep into the seabed to a safe distance. Depending on the conditions on the field and the likelihood of damage, it can be acceptable that the flowlines are sacrificial, in which case, they should be designed such that they do not transfer excess loads to the X-mas trees, templates or manifolds. Weak link functionality in the pipe terminations, with the ability to seal off the flow if the flowline becomes damaged, could cater for this scenario.

Flowlines furnished with external insulation materials needs to be protected from extreme cold temperature during transport and storage, as commonly used types of insulation materials may suffer and become brittle.

Production risers are permanently installed extensions of the flowlines. As they are extended from the sea bottom up to the vessels their functionality needs to be mated with the functionality dictated by the vessel/platform. For platforms or vessels designed for disconnection in case of, for instance, ice berg encounters, they need to be connected to a disconnectable and re-mateable swivel system where all Subsea Production System interfaces are handled.

As stated earlier, the combination of shallow water and rough weather is a particularly challenging situation. Hence risers, being flexible or made from steel, need to have the best fatigue life characteristics. With the water depth for the most parts of the High North being less than 500 meters and usually considerably shallower, flexible risers are the most viable alternative and for gas probably the only alternative due to the large internal diameter required.

As for the infield flowlines as described above also risers needs to be protected from extreme cold during transport and storage in order to avoid damage to polymer materials.

Existing technologies, methods and best practice

A particular feature of infield flow lines is that their accurate length is determined by the “as installed” location accuracy of X-mas trees, templates and manifold and often is an in situ measurement to determine the manufacturing dimensions for the flow lines required. This is a time consuming activity where, first, the measurement needs to take place subsea at the field, secondly, the information needs to be provided to the manufacturer for implementation and finally, the flowlines shipped to the field for installation. Clearly, this is a time consuming and less than optimal solution for an area where access is limited to the short summer season and also affected by logistic challenges.

Infield flowlines are generally neither designed with weak-link functionality nor the ability to seal off the flow in case of damage. Subsea Production Systems will, however, be able to shut down and seal of the hydro carbon flow provided the damage to a flowline does not affect the rest of the system. Weak-links for pipe lines are available and in use in other regions for protecting the Subsea Production Systems and the technology should be fairly straight forward to adapt to the requirements within the geographical focus area.
Regarding cold temperature, transport and storage services needs to cater for the requirements prescribed by the materials and it is not realistic that the lower temperatures in the region are acceptable while the materials still shall provide their insulating or load carrying capability without suffering from brittleness.

Another feature of cold temperature exposure is that fatigue properties at low temperature is not studied nor regulated in codes and regulations to the same degree as for higher temperatures. With seabed temperature as low as -2°C it may be that some applications are on the borderline, in particular when equipment is subjected to a combined a stressful environment of Cathodic Protection, H2S, hydro carbons in general, low temperature and large cyclic loads.

Need for innovation and technology development

- Further development of low temperature polymeric materials for insulation purposes in flow lines or risers.
- Further investigation into low temperature effects of fatigue in a “multi influenced environment”.
- Development of flowline technology which eliminates the need for exact infield measurements of “as installed” locations of connection points
- Further development of weak-link and “seal off” functionality as part of flowline termination connections, including possible legislation issues.

4.3 Power systems

This chapter is based on the task force discussions and two public workshops as part of this work. Which power supply solutions that are most appropriate will, however, be a matter for decision makers when considering future subsea activities within the geographical focus area.

For development of large and unique oil and gas fields within the geographical focus area, the most relevant distances of power supply are spanning from 200 to 600-900 km.

4.3.1 Subsea Production System power supply

Subsea Production System (SPS) power supply with the required level of reliability while ensuring acceptable initial expenses and operational costs, is a key issue for field development. Analysis of SPS power supply demand reveals that electrical equipment and power transmission technologies that have been developed and are applied in international practice do not exactly comply with the tasks of development of far remote offshore fields in the High North.

In general, electric-operated equipment of SPS may be divided into the following groups:

a) SPS control system including:
   - SPS valve actuators
   - Instrumentation
   - Subsea control modules
   - Interruptible power supplies.

b) Electrical operated units:
   - Pumping units (pumps, compressors)
   - Injecting units (water injection pumps, inhibitor injection pumps)
   - Direct electrical heating of flow line or risers

For the purpose of selecting power supply system types, SPS may be classified according to the two following groups:

- Low power SPS that include wellstream gathering system equipment and SPS subsea control system only, with a total demand of 10 kW;

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18 See Appendix 2
• Large power SPS that include wellstream gathering system equipment (SPS subsea control system), wellstream processing and transport system equipment (separators, multi-phase pumps, injection pumps, compressors for gas compression) with a total demand up to 250 MW.

The challenge of low power SPS power supply has been solved. However, selection of configuration for SPS power supply system depends on a field management plan, i.e. whether an offshore production platform will be used at the field or not. Cost of SPS power supply equipment is rather low and near the same in both cases. Furthermore, capital expenditures (CAPEX) are determined by length of a cable line.

4.3.2 Remote sources of electrical power

Existing technologies, methods and best practice

For large power SPS, electric power transmission from power supplies via subsea power cables may be:

• at 3-phase power frequency high voltage alternate current (AC);
• at 3-phase low frequency high voltage AC;
• at high voltage direct current (DC).

When using power frequency AC with long distance to any power supply source, the power loss in the cable line increases and make the power transmission impractical for certain distance and SPS capacity. To reduce the loss, power transmission may be at high voltage direct current (HVDC), at 3-phase low frequency alternate current (LFAC) or at 3-phase alternate current with Volt-Ampere Reactive (VAR) compensation.

LFAC power transmission is an inefficient solution since it allows only partial loss reduction during AC transmission. Moreover, it requires development of frequency converters, technical complexity and a level cost being comparable with HVDC system converters (rectifiers/inverters).

LFAC power transmission using VAR systems does not completely solve the challenge of reduced losses in the cable line.

Advanced systems for transmission of power of hundreds megawatts to distance of hundreds kilometers are HVDC power transmission systems. Main components of DC power transmission systems are power rectifiers and inverters. A rectifier must be connected to a power supply and an inverter providing power conversion into 3-phase AC.

CAPEX for SPS electric power supply systems with onshore power supplies are proportional to the distance between SPS and the shore that is due to significant costs of subsea HV cable itself and its installation. SPS power transmission systems with HVDC and LFAC power transmission require large-power static converters designed for subsea applications. This is currently not available.

Common technology challenges

• Today, supply of electricity from an onshore regional power supply system is challenging, considering the absence of such systems along the Russian Arctic coast. However, it is not unlikely that such system can be developed in connection with development of infrastructure supporting activities on the Northern Sea Route.
• Supply of electricity to SPS through a cable from a support vessel is one possible alternative, if the operational conditions allow it.
• Supply of electricity from an intermediate landing point for helicopters (territorial combination of transportation facilities and power engineering facilities) taking into account the territorial remoteness of fields on the Arctic shelf exceeding distance range of helicopters.
From an economical point of view, the coastal autonomous sources could be considered as part of the operational onshore fields. In a long term, the Yamal peninsula could be considered. This approach partially allows using the existing power sources with required increase of power in order to decrease expenses for creation of a power infrastructure.

The lack of cable items for power lines operating in ice conditions at alternating temperatures (defrosting – thawing)

**Need for innovation and technology development**

- Power transmission for very long distances – more than 500 km
- Subsea converters DC/AC

### 4.3.3 Electrochemical generators based on fuel cells

**Existing technologies, methods and best practice**

Electrochemical generators (ECGs) based on fuel cells have high efficiency in connection with direct conversion of chemical energy into electrical energy and they are characterized, in particular, by absence of rotating parts.

At present the operational life of fuel cells is limited to approximately 6000 hours (250 days of continuous operation). However, an increase up to 40 000 hours (more than 1600 days or more than 4 years) is possible. Achievable power of the fuel cell battery exceeds 1 MW. At the same time, there is a need of creating the batteries with significantly more power.

**Common technology challenges**

- Absence of technology for delivery of fuel (hydrogen) and an oxidant (oxygen). Obviously, production of indicated components is reasonable in coast conditions with its conversion in cryogenic condition for the further transportation and storage in underwater conditions.
- There is no experience of ECG operation in underwater (under-ice) conditions.
- There are no reliable means (cable less) for SPS communication with a coast infrastructure for management of SPS operation

**Need for innovation and technology development**

- Extend lifetime beyond 250 days in continuous operation
- Improve battery capacity beyond 1 MW

### 4.3.4 Nuclear energy sources

**Existing technologies, methods and best practice**

Currently, no subsea independent power plants based on air-independent electric power sources with capacity of 30 MW (or higher) have been developed. There are several technological directions for development of such power plants including subsea nuclear power plants (NPP), but none of them has currently been implemented. Engineering capability for unmanned subsea nuclear power plants production will first of all require development of fundamentally new onshore control and automation systems. However, there is no existing regulatory documentation for such applications, neither in Russia nor other countries. Currently, applicable regulatory documents do not permit to have remote control systems and operators for NPP.

The nuclear energy sources usually consist of a steam generation plant and a turbo-generating installation on the basis of a steam turbine drive. The noted power sources meet all requirements for marine underwater anaerobic sources. Creation of sources of any unit power is possible.

Based on the requirements for power consumption of the subsea production systems, the sources’ unit power can be 5 – 30 MW. The load being 10% of design load can be considered as the low limit for the given type of installations.
For actuating the installation (nuclear energy source) an auxiliary energy source of low power is required.

According to rough estimates, cost of a subsea nuclear power plant may be from 1, 5 to 5 billion US Dollar depending on installed power that would significantly increase CAPEX for the SPS power supply system. Significant operational expenses (OPEX) related to atomic power engineering must also be taken into consideration.

**Common technology challenges**
- Absence of approved technologies in the oil and gas industry for maintenance and repair of nuclear energy sources in underwater and under-ice conditions.
- The achieved reliability of existing types of turbine generators using nuclear energy sources require periods of autonomous operation without technical maintenance, which are significantly shorter than the open for intervention period in the Arctic.
- Development of organizational measures on preparing of qualified personnel and realization of these measures are necessary for fulfillment of all work concerning maintenance and repairs.
- Possible legislative limitations regarding nuclear energy sources being the part of the production systems in Arctic conditions

**Need for innovation and technology development**
- Increase subsea nuclear power plants capacities above 35MW

### 4.3.5 Main factors for selection of a power source for Subsea Production System
- Actual demand for the electric power of SPS consumers.
- Actual remoteness of SPS from coastal autonomous sources.
- Actual remoteness of SPS from a coastal infrastructure at usage of local sources as a part of SPC.
- Ice conditions (absence of ice, seasonal presence of ice, occurrence of ice formations, and permanent presence of ice).
- Depths of SPS placement
- Cost of providing power to the SPS system
- Required production (uptime) availability
4.4 Subsea processing and flow assurance

The term Subsea Processing covers various technologies that enable processing of oil and gas on (or below) the seabed prior to transportation to surface facilities or to shore, including separation, boosting, power, and controls. Figure 13 below shows a generic subsea processing arrangement for an oil field.

Subsea processing technologies can enhance the economics of Arctic offshore oil and gas developments by increasing production rates, addressing flow assurance challenges, reducing topside constraints, reducing environmental footprint and reducing development costs. In some cases, these technologies may enable development of otherwise inaccessible resources, for instance, by allowing year-around subsea production under ice.

Many subsea processing technology elements have been developed, qualified, and installed over the last 15 years (e.g. subsea and downhole liquid boosting, 2-phase separation, electrical power transmission). Development and qualification of other key technology elements is on-going and the first applications may be expected within the next 10 years, (e.g. 3-phase and compact separation, compression, electrical power distribution/conversion (AC, <150 km at ~60 MW)). However, the following major technology gaps currently exist and will require significant technical effort to develop:

- Long-distance (>150 km) subsea power transmission, distribution and conversion (low frequency AC, DC)
- High-pressure subsea compression for gas reinjection
- Remote monitoring, diagnostics, and inspection of subsea machinery and power components
- Autonomous intervention systems
- Subsea separation/dehydration/treatment to obtain sales quality oil and export quality gas

4.4.1 Separation

Common technology challenges

Economics of remote subsea fields in the High North may be enhanced by separating the multi-phase well-stream near the subsea drill center, boosting hydrocarbons and re-injecting produced water. This way, only “useful” components of the subsea production stream are transported back to the host platform, which may be located tens or even hundreds kilometers away. Subsea separation technology can, therefore, reduce the cost of subsea pipelines and topside infrastructure, improve flow assurance (e.g. simplified hydrate management, reduce slugging), and ultimately increase recovery from subsea fields by enabling production to a lower wellhead pressure and/or a higher water cut.
**Existing technologies, methods and best practices**

Gravity separation technology allows separation of multi-phase fluids at the seabed next to the subsea drill center. It is based on the proven topside separation technology, which features a separator vessel, level detectors and process control valves, and sand/solids handling system, where all components are marinized for subsea service. Subsea pumps are used to boost the pressure of the separated fluids. To date, mostly 2-phase gravity separation systems have been installed, typically for either gas/liquid separation with liquid boosting, or for hydrocarbon/water separation and water re-injection.

Subsea scrubbers, which are a type of gas/liquid gravity separator, have been designed and qualified for use upstream of subsea compressors.

Compact separation systems may offer cost savings over gravity separation systems, especially in deeper water where the size/cost of gravity separator vessels may become prohibitive. They range from relatively simple pipe/caisson separators and slug catchers to sophisticated dynamic devices (e.g. cyclones) that increase separation efficiency by accelerating the fluids. Several such systems have been installed or undergoing qualification.

In the short term perspective (next 5-10 years), it is expected that the use of 2-phase separation technologies will increase, as more operating experience is gained with the recently-installed systems. In particular, gas/liquid separation with liquid boosting has seen several recent applications in deep water, where it was selected instead of more conventional riser-base gas lift.

Several designs of downhole separation systems have also been proposed, (e.g. for water separation and re-injection inside the well-bore of a subsea well). To date, downhole separation systems have not been deployed subsea due to persistent concerns regarding their reliability and the cost of intervention.

**Need for innovation and technology development:**

Technology improvements are needed to increase the separation efficiency and operating range (e.g. turn-down performance) of subsea separation systems. Compact separation systems also require further development in the areas of slug control and fast-acting control systems.

Further improvements in technology will be required to facilitate the use of subsea separation systems in remote subsea fields, especially in the areas with reduced accessibility due to ice cover, e.g. technologies for:

- Remote condition monitoring and diagnostics
- Oil-in-water and solids-in-water measurement
- On-line removal and disposal of sand/solids
- Subsea leak detection
- Autonomous subsea intervention systems with year-around, all-weather surveillance and maintenance capabilities, e.g. Autonomous Underwater Vehicles (AUV), resident ROVs, or submarine-based systems.

Longer-term developments of subsea fluid conditioning technology (e.g. gas dehydration systems, compact electrostatic coalesces for oil de-watering) will be required to achieve export quality hydrocarbons, which could further reduce the need for topside processing facilities. This could allow, for example, direct tie-in from a subsea gas field to a gas export pipeline network, or subsea storage of stabilized oil and subsequent offloading to tanker for transport to market.

**4.4.2 Pumping**

**Common technology challenges**

Transport of well fluids over long distances will be required in the Arctic to facilitate the development of remote subsea fields. The ability to add energy to the well-stream will therefore be critical to
achieving and maintaining commercially-attractive production rates. Subsea and downhole pumping technology allows efficient boosting of a single-phase or multiphase well stream.

For subsea fields in deeper water, subsea and downhole pumping technology also offers an alternative artificial lift method vs. gas lift for subsea wells, flowlines, and risers.

Some subsea fields in the High North will require water injection for pressure support. For remote subsea fields, the costs of surface water-treatment facilities (topside or on-shore) and the subsea water injection flowlines can be significantly reduced by utilizing subsea raw sea-water injection systems placed near the water injection wells. Depending on the reservoir properties, the raw sea-water may require pre-treatment prior to injection into the reservoir such as filtration, anti-bacteria treatment, or sulphate removal. Subsea water injection pumps are then used to boost the sea-water pressure prior to injection into subsea wells.

One of the key challenges with subsea processing of hydrocarbons in the remote subsea fields is the disposal of produced water. Separating produced water on the sea-bed near the wellhead location and re-injecting it back into the reservoir offers significant flow assurance advantages. It will also accommodate lower environmental footprint, as well as facility/pipeline cost reductions compared to the conventional method of separating, treating, and disposing the produced water via the topside/on-shore facilities. Again, subsea water injection pumps are the used to boost the produced water pressure prior to injection.

**Existing technologies, methods and best practices**

Subsea multi-phase pumps have been installed with up to 2.5 MW motor power and can generate up to 130 bar of differential pressure. They can also handle multi-phase fluids between 0 - 90% GVF at the pump inlet. This technology is relatively mature, and a Mean Time To Failure (MTTF) of up to 4-5 years has been documented. In the near-term (next 5-10 years), multi-phase pumps should be available with larger power (5-6 MW) and higher differential pressure (up to 160 bar).

Subsea single-phase pumps, which are suitable for raw sea-water injection and produced water re-injection, have been installed with up to 3 MW motor power. They can generate up to 225 bar of differential pressure. MTTF of up to 4-5 years can be assumed. In the short term, single-phase pumps should be available with larger power (5-6 MW) and higher differential pressure (up to 310 bar).

Downhole pumping can provide efficient boosting inside the well-bore of a subsea well, which can be used as an alternative to, or in combination with, sea-bed boosting. Electrical Submersible Pumps (ESP) have been installed with up to 1.2 MW motor power, can generate up to 220 bar of differential pressure, and can handle multi-phase fluids between 0 - 50% GVF at the pump inlet. MTTF of up to 2-3 years can be assumed.

Electric power supply systems used for subsea and downhole pumping utilize AC-based transmission technology with topside Variable Frequency Drives (VFD). For longer tie-back distances (typically more than 15 km), high voltage power transmission (up to 36 kV AC) is used to minimize the electrical losses in the power cable, and a subsea step-down transformer is used to reduce the transmission voltage to what is required for the pump motor (typically less than 6.6 kV).

**Need for innovation and technology development**

Technology development efforts for subsea pumping should be focused on increasing the rating of subsea pumps in terms of motor power, differential pressure, water depth, and casing pressure.

Development of alternative, environmentally-friendly barrier fluids for subsea pumps can reduce environmental impact in case of accidental discharge.
Further improvements in technologies for remote condition monitoring and diagnostics of subsea pumps will be required to facilitate the use of subsea pumps in remote subsea fields, especially in the areas with reduced accessibility due to ice cover.

4.4.3 Compression

Common technology challenges

Development of offshore gas/condensate fields in the Arctic may require transporting wet gas between subsea wells and onshore processing/export facilities over long distance (more than 500 km in some cases). After several years of production, reservoir pressure in a typical gas field declines and compression is required to maintain production levels. While on-shore compression may provide a temporary solution, offshore compression near the subsea wells will likely be required at some stage to maximize production rates and resource recovery. Studies show that subsea compression is often the most economic option for offshore compression and may be the only technically-feasible option in the areas with significant ice cover and with water depth exceeding 100 m (currently viewed as a limit for ice-resistant platforms). Highly reliable subsea compression systems will be required for the remote arctic fields, especially in the areas with reduced accessibility due to ice cover.

Subsea compression will require technology and infrastructure for generation and transmission of large amounts of electric power (over 25 MW) over long distance, followed by subsea distribution and/or conversion of this power to match the requirements of subsea power consumers (compressors, pumps, control systems, etc.). Subsea power technology is addressed in Section 3.3 of this report.

Existing technologies, methods and best practices

Two types of subsea compression systems have been developed and qualified in the past 15 years:

- Dry gas compression – gas and liquids are separated in a scrubber, gas is compressed using a high-speed centrifugal compressor, liquids are boosted using a liquid pump, and gas and liquid streams are recombined and transported to host facilities in a multi-phase pipeline. This technology is based on the proven topside compression technology, i.e. hermetically sealed, centrifugal compressor with active magnetic bearings, which is marinized and adapted for subsea use. Dry gas compressors are qualified for up to 12.5 MW unit motor power. It should be noted that the dry gas compressors have been designed to operate continuously with a small amount of liquids in the gas stream, and can even tolerate large amounts of liquid (up to 20-30% by weight) during upset conditions.

- Wet gas compression – multi-phase flowstream is compressed using a compressor designed to handle both gas and liquids. These systems do not require separation of multi-phase flow upstream of the compressor (a small flow-homogenizer vessel is still required). This technology is based on the subsea multi-phase pump technology, i.e. helico-axial impeller design, which is adapted for high GOR fluids by using two counter-rotating rotors. Wet gas compressors are qualified for up to 5 MW unit motor power.

The key advantage of the wet gas technology is its simplicity and compactness, as it eliminates the need for many components required for dry gas compression (e.g. separator, pump, anti-surge controls). The key advantage of the dry gas technology is the higher compression power achievable per compressor, which makes it more suitable for larger fields. For both types of compressors, MTTF of up to 4-5 years can be assumed, although this theoretical MTTF requires validation based on field experience.

In the past 15 years, a number of components have been qualified for subsea compression systems including compressors, pumps, separators, electric power supply and distribution systems, and control systems. Several joint industry projects are on-going to develop and qualify the next generation of subsea compression components, which will expand the operating range of subsea compressors in terms of power, differential pressure, water depth, and fluid composition, as well as bring additional equipment suppliers to the market.
In the short term perspective (next 5-10 years), it is expected that the first several subsea compression systems will be installed, and their use will likely increase as more operating experience is gained.

## Need for innovation and technology development

Further technology development is required in the following areas:

- **Dry gas compression systems** require simplification/optimization to reduce the number of system components which could result in less complex, more compact design (reduced footprint, lower weight). In addition, improving their liquid tolerance could expand their application range.
- **Wet gas compression systems** require scale-up to increase their unit power, flow rate, and differential pressure.
- **High-pressure subsea compressors** will be required for subsea gas reinjection.
- **Electrical power distribution and conversion components** (e.g. transformers, switch gear, variable frequency drives (VFD), uninterrupted power supply (UPS)) will require a pressure compensated, liquid filled packaging to reduce their size/weight. Liquid filling of VSD’s etc is also expected to increase reliability, due to more stable environment for components (better cooling), and also less complicated cooling. The weight will not necessarily be reduced due to the weight of the oil and the limited water depth in these areas (not very thick pressure vessel walls).
- **Electrical power connectors and penetrators** will need further development to accommodate the requirements of long-distance, high-power transmission systems, which in the future may be featuring higher voltage (up to 145 kV) and either low-frequency AC or DC transmission technology.
- **Further improvements in technologies for remote condition monitoring and diagnostics of subsea compressors** will be required to facilitate the use of subsea compression systems in remote subsea fields, especially in the areas with reduced accessibility due to ice cover.

### 4.4.4 Flow assurance

#### Common technology challenges

Flow assurance is expected to be a major challenge in the High North due to long distances, cold temperatures, and rough sea-bed profiles. The ability to accurately predict and manage multiphase flow of well fluids from subsea wells to a platform or onshore facilities is critical to the subsea production in the arctic, especially from the remote fields located tens or even hundreds kilometers away from the host facility.

#### Existing technologies, methods and best practice

Several commercially available simulators, such as OLGA® and LedaFlow®, are available for modeling multiphase fluid flow in pipelines. These programs provide the ability to predict flow assurance problems such as hydrates, liquid accumulation and slugging, wax deposition, sand accumulation, etc., and are the main tools used by flow assurance engineers to design multiphase pipeline systems.

Conventional techniques for flow assurance include:
- Pipeline insulation to maintain fluid temperature above hydrate or wax formation temperature
- Inhibitor chemicals to prevent formation/deposition of hydrates, wax, or asphaltenes
- Pigging to remove liquid or solid accumulations

Recent technological advances, such as subsea separation (gas/liquid or oil/water) and subsea electrical heating of pipelines offer additional flow assurance tools for subsea production.

#### Need for innovation and technology development

The existing multiphase flow simulation programs have limitations (high uncertainty/low accuracy) when modeling/predicting behavior of certain types of fluids, which, combined with the need for long-
distance transport and large diameter pipelines, can introduce significant errors in the flow prediction. Specific examples are

- Ability to predict pressure drop in pipelines transporting heavy/viscous oil, or
- Ability to predict liquid accumulation in gas-condensate pipelines with low liquid content (especially for large-diameter pipelines).

The lack of quality experimental data complicates the development and validation of new multiphase flow models. This type of data, both from the laboratory-scale and full-scale experiments, will be needed to calibrate/validate the flow simulation results.

New/improved models for multiphase flow, with improved capabilities to predict flow instability, slugging, and liquid accumulation will facilitate development of remote field in the arctic.

4.5 Design, installation and operation of pipelines

Common technology challenges

Subsea pipelines are expected to be a major building block in the development of gas and oil fields in the High North. Due to lack of infrastructure, harsh environmental conditions and limited access from the sea surface, field developments based on subsea production, subsea processing and long distance pipeline tie-backs are assumed to become attractive. Pipeline systems are also considered as efficient for transportation of oil and gas to offshore hubs, to onshore processing/storage facilities or into existing transport networks.

The harsh environment and the low temperature define additional pipeline requirements both during fabrication/installation and during operation. An accurate environmental design basis is important for definition of pipeline fabrication and installation windows. Subsea pipeline installation should, in general, be limited to periods without surface ice. Installation windows are further challenged by the potential large distance between the onshore construction/support site and the offshore location.

Pipeline steel materials and coatings have to resist the potential low temperatures during fabrication welding, installation and operation. Low temperatures during operation are most relevant for landfall and onshore sections in addition to the riser and the topside sections of the pipeline system.

The strategy for operation of pipeline systems should cover both planned and unplanned activities. Unplanned activities could for instance include pipeline repair operations, which require special attention in periods with surface ice. Planned survey and maintenance activities supported by surface vessels have to be limited to periods of the year without surface ice and with moderate weather conditions.

Pipeline systems in the High North have to be designed for potential load conditions caused by direct or indirect ice interaction. Exposure to ice loads is most relevant at the platform interface (i.e. upper riser section), in shallow water areas with ice ridges, and for landfall and onshore pipeline sections with permanent or temporary ice conditions. The pipeline exposure to ice loads, in terms of load frequency and type of interference load effect, is assumed to change significantly between the geographical focus areas 1-6.

Existing technologies, methods and best practice

The subsea pipeline industry has developed significantly over the last two decades to meet new business challenges associated with larger water depth and with the transportation of aggressive and unprocessed fluids over long distances. In response to this, new pipeline concepts based on corrosive resistant materials, enhanced thermal performance and heating technologies have been qualified and successfully implemented. New pipeline concepts have been developed in parallel with more cost-effective fabrication and installation methods. These technologies and concepts are assumed to make an important starting point for development and innovation of new solutions applicable for the High North.
From the mid 1990’s limit state design criteria based on risk and reliability principles have been introduced in most pipeline design codes and standards. This means that all individual threats to the pipeline can be designed to a common safety level accepted by the authorities and the industry. The principles of risk based limit state criteria are also important for optimization of the pipeline design and for assessment of load conditions with low probability of occurrence.

For assessment of new design load conditions caused by pipeline ice interaction, the same design principles should be adopted. This means that new safety margins need to be calibrated, reflecting the uncertainties of design input data and as well as uncertainties related to the pipeline ice response modelling.

Tools and methodologies for pipeline operating integrity management have developed significantly over the last twenty years. This relates both to new monitoring and inspection technologies defining the input to the integrity assessment as well as to models and tools used for prediction of changes and trends in the integrity condition. Most aspects of the pipeline integrity management should be reconsidered and further developed to meet the challenges of the High North.

The water depth in the Barents region, which is generally less than 500 m, is not assumed to cause any major challenges to the pipeline design and installation. The efficiency of pipeline fabrication and installation has continuously improved by introduction of new installation vessels, more accurate design criteria and more efficient welding methods. However, pipeline fabrication and installation methods need to be further developed to meet the specific challenges in the High North.

Need for innovation and technology development

- Establish an accurate and extended design basis covering the new environmental conditions with characteristic parameters for:
  - Sea surface ice conditions, including statistical parameters for icebergs and ice ridges where relevant.
  - Polar low statistics.
  - Seabed ice scouring statistics.
  - Landfall and onshore sections with continuous and discontinuous permafrost.

- Develop design methodologies and analysis models for simulation of Arctic specific load conditions and phenomena such as:
  - Design methodologies for pipelines in shallow water conditions exposed to the threat of ice gouging. This typically includes the development of reliable pipe-soil-ice interaction models and corresponding pipeline design criteria to define an optimized pipeline protection cover depth based on risk principles.
  - Design methodologies for pipeline sections exposed to ground movements induced by discontinuous permafrost and pipe-soil-ice interaction effects.

- Develop design solutions for pipeline landfall sections with challenging soil and ice conditions. Case specific landfall solutions are normally needed to meet the requirements from variable sea ice conditions, coastline erosion effects, exposure to discontinuous permafrost or interaction with fresh water around river deltas.

- Develop equipment for efficient deep seabed trenching. In potential ice scouring regions the pipeline could be protected from direct ice contact by lowering the pipeline into a seabed trench. The required seabed trenching depth is typically larger than 3 m, which is outside the range of most trenching equipment currently available on the market.

- Develop pipeline concepts enabling long distance transportation of unprocessed or partly processed well fluid. This may be developed as integrated subsea processing and transport solutions.

19 The need for winterization of construction and support vessels is further discussed under in Chapter 4.6
• Develop safe and cost-efficient pipeline fabrication and installation methods meeting the challenges of harsh environmental conditions, remoteness and lack of infrastructure. This could typically cover:
  o Pipeline welding procedures at low temperature.
  o Pipeline coatings resistant to low temperatures.
  o Installation procedures reducing the consequences of polar lows.
  o Optimized transit and installation periods.
• Develop survey, maintenance and repair concepts minimizing the need for surface vessel support.
• Develop pipeline monitoring and inspection concepts giving updated information about the internal flow condition and the pipeline integrity condition, which are independent of the weather and sea surface ice conditions.

4.6 Marine operations

This chapter covers the marine operation and construction aspects of operating in the High North.20

4.6.1 Vessel development

Ice classifications of vessels are many and cover, for instance, hull strength and structural design, propulsion systems, engine output and performance in ice according station keeping by anchor or dynamic positioning etc.

Common challenges21

Specialized vessels needed for advanced marine operations in ice covered waters are expensive to build, and often not cost efficient in work outside ice covered waters. Therefore, the economical basis to build such construction vessels is dependent on the number of future investments in the High North.

Existing technologies, methods and best practice

There have been some projects performed in ice covered waters. For example CSO Constructor performed diving operations Offshore Sakhalin in ice covered waters. The vessel was performing saturation diving in water depth of 30 m. The operation was supported by three icebreakers. The vessel also performed lifts over the side of the vessel, as lee was mostly clear of ice.

Figure 14: CSO Constructor in diving work
Source: Technip

20 The general challenges operating in the Arctic areas, such as harsh weather, polar Lows, ice, icing and SAR is widely discussed in the RU-NO Barents Project Logistics and Transport - Report http://www.intsok.com/Market-info/Markets/Russia/RU-NO-Project/Focus-Areas, and will only be covered without description in this section. However, these factors have strong implications on marine operations.
21 The following challenges and proposed solutions/need for further investigations was discovered and discussed during the INTSOK workshops in Oslo and Arkhangelsk.
Projects currently executed in the High North rely on use of vessels winterized on a project by project basis or less often on vessels purpose built for cold climate operations.

Winterization of vessels includes, for example, heating cables, building shelters, safety equipment fit for colder climate and protected from weather, rescue equipment placement and hot steam equipment for de-icing of deck and equipment. In addition, work through the moonpool and ROV moonpool launching will be needed for vessels operating in harsh climate. These technologies are already widely used.

It has been proven very costly to winterize a regular vessel/drill rig for harsh environments as the layout of the vessels is not optimized for, for example, heat cable installation, steam equipment and shelter on deck. It has also been the case for some offshore construction companies that ice breakers have been used outside ice-season to perform lighter construction work, even though a vessel fully designed for construction in ice is not efficient in open waters due to its hull design. Also, vessel design for colder climates, with smaller open deck space, is not optimal for construction work in other parts of the world.

**Need for innovation and technology development**

There is a need for new vessels in ice covered waters being fully designed for Arctic climate. The development of these ships is driven by the upcoming offshore investments. Also, the possibility that the marine operations will be performed by ROV/AUV to a greater extent may change the fleet needed in the High North.

The RU-NO Task Force has identified following needs for the future upcoming projects in the Barents Sea:

- Use of small/inexpensive vessels for some tasks
- Submerged transport & installation
- Advanced subsea positioning systems

**4.6.2 Human safety**

Offshore operations onboard construction vessels are to a large extent dependent on skilled personnel. If operations are to be performed in a similar way as it is today moving into ice covered waters, darker, colder and more remote areas, the following aspects discussed below needs to be addressed.

The Barents 2020 program concluded that the current standard, NORSOK S-002, provides the best baseline for further joint work on working environment and human factors for offshore and maritime operations in the Barents Sea. It offers a reasonably comprehensive guidance on working environment issues. However, there is a need for further development of HSE standards, including vessel winterization and stress management, for work in cold climate.
Common challenges related to personnel working offshore in the High North

- Offshore personnel competency:
  Challenge: Personnel being trained for cold climate operations.
  Best practice: Many groups of professionals have the experience from working in Arctic environment and can transfer this knowledge to the oil and gas industry. Already a number of new professions have been identified for this type of work. For example, four people were dedicated to Ice Management during the diving operations at Sakhalin II.
  Need for development: Certification of personnel operating in cold climate (including practical training) and experience transferred between industries would be needed.

- Operation time:
  Challenge and best practice: Today, the cost of vessel operations is one factor driving planning of the marine operations. Based on the current experience from offshore operations in cold climate, operations are more time consuming compared to operations in southern areas. When manual work is performed by personnel in Arctic conditions, there is need for more breaks, the operation needs to be more thoroughly risk assessed and the weather needs to be closer monitored.
  Need for development: New methods of working in harsh environment and planning of operations according to human factor.

- Crew change:
  Challenge: Offshore crew rotation is regulated both international and national legislation. With the vast distance from site to shore in the geographical focus areas crew rotations will limit the operations based on the current schemes.
  Need for development: Further research on how crew rotation from logistic/transport hubs will affect marine operations durations and costs. Research on alternative ways to transport vessel crew for crew change (intermediate helicopter landing areas, fast crew change vessels or other), considering the weather conditions in areas 2-6).

It is recommended to further examine how to ensure HSE aspects of offshore personnel with regard to working rotation, whilst ensuring operation continuity. Also, operational duration needs to be further examined.

Need for innovation and technology development
The harsh environment met by personnel working offshore in the High North call for development of improved SAR capabilities, crew change planning and relevant education/training.

The equipment used and placed on the vessels, for example winches, crane hooks and sea fastening, needs to be designed in line with cold climate engineering principles.

The NORSOK S-002 – (Working environment) need to be updated with true meteorological data from the areas that Norway and Russia now are looking into as places of marine operations.

4.6.3 Change in nature of Marine operations in the Arctic
The nature of the geographical areas investigated suggests that a change in the methodology of planning offshore operations and maintaining offshore installations might be needed. Some examples are given below, including why these changes are to be expected.

Common installation challenges
Weather forecasting and operation window:
Offshore operation design duration is closely connected to the empirical weather data and current weather forecasts at the time of operation as risk reducing measures. These parameters are part of the sea state and weather window limitations of the operations. Thus, reliable weather forecasts are
important in order to decide start/stop of activities due to change in weather conditions. In addition, to
wave and wind, special considerations should be made on ocean current estimation/forecasting. All
this data is used for determining the weather window needed for an operation.

In deep water, the installation operations are more time consuming and require longer weather
windows than used to in moderate water depths. In combination with heavy module weight, it is
important to have access to reliable weather forecast and reliable weather windows adapted to the
installation operation in order to perform in a safe and cost-effective mode.

Need for innovation and technology development
New installation methods and abandonment procedures will be needed in the ice covered areas in the
High North. These need to take into account the rapid-shifting weather and ice conditions in these
waters. During the RU-NO workshop, the following suggested areas for further work was identified:
- Drop-installation techniques
- New line materials and winching techniques
- Wet storage of equipment
- Larger extent of moonpool installation methods
- Laying abandonment procedures

4.7 Hook up, commissioning and ready for operation (RFO) activities
Commissioning of the subsea system is to verify that the total subsea production system is working
satisfactory as an integrated system prior to opening for the flow of oil and gas. Tasks to be performed
and requirements to be fulfilled are as follows.

4.7.1 Commissioning flowlines and flowline isolation valves
The purpose of the test is to verify the integrity of the flowline and prepare the flowline for
introduction of production fluids. This also includes the dewatering of flowline, which prepares the
flowline for startup, and test the subsea and topside/onshore located isolation valves.

Integrity testing of flowline line systems
The purpose of the test is to verify the integrity of the flowline. This test sequence is successfully
completed when no leak is detected for the required test period (normally between 8 h and 24 h) or,
depending on local regulations, after a proper stabilizing time. This test should also include all remote
tie-in’s subsea/topside isolation valves.

Dewatering of Flowline
The purpose of dewatering the flowline is to prepare for start-up. The flowline can be filled with
diesel, crude, nitrogen or natural gas.

4.7.2 Verification of topside-located subsea production control equipment
The purpose of the test is to verify proper functioning of topside-located subsea production control
equipment and to verify the interface to other topside systems. This test also includes verification of
the interface between the subsea and topside located equipment. Verification of the ESD functions,
including response-time monitoring, should be part of the test.

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22 See appendix 2.
23 The following chapter is based on ISO 13628-1
4.7.3 Verification of topside-located equipment which can be defined as utility systems for the subsea production system

The purpose of the test is to verify proper functioning of equipment which can be defined as utility systems for the subsea production system. Typical systems are HPU, Chemical Units, Anulus Bleed systems.

Common technology challenges
- Short operational installation season
- Temperature limitations topside
- Discharge to environmentally sensitive area

Existing technologies, methods and best practice
Commissioning/Pre-commissioning of subssea system is bespoke engineered for each development/system. A detailed program is managed to ensure the compliance of the development/system towards international and national requirements. All part of the system is tested in details to ensure the integrity and functionality of the system. The testing and verification may consist of a multiple location activity where there is a strong need for an interface management. These locations can consist of, but are not limited to, topside/onshore location, pipeline installation vessels, IMR vessels and ROV vessels. Pre-commissioning/commissioning can be very time consuming activities and be performed with several teams/vessels over a long time interval. This creates a need for a cross discipline/time management for the pre-commissioning/commissioning/RFO activities.

Need for innovation and technology development
There is no new technology development identified to bring developments into the High North. There are previous mentioned limitations and concerns for the various disciplines/activities which will also be applicable for the pre-commissioning/commissioning activities, as the short installation season and concerns around the operating temperatures, but these are considered more as concerns and not need for new technology development.

4.8 Life of field considerations

The ability to develop subsea fields in a cost effectively way and “subsea to subsea tie-backs”, will be an important enabler for smaller and remote fields, and also how to effectively extend the lifetime of a subsea system. It is seen as important that license owners collaborate to develop common production and transport systems in the remote areas, as this should create positive synergies.

Subsea wells have generally a lower recovery factor compared to fixed installations, but by the continuous development and improvement of subsea equipment and EOR/IOR techniques it is believed that this gap will decrease. It is also the case that in many situations a subsea development is the only feasible option to effectively develop a field.

The sea ice conditions vary from season to season, but based on the location within the geographic focus areas. These are some of the main characteristics
- Ice almost all year around
- Ice part of the year
- Drifting ice and ice bergs

4.8.1 Production availability and operating cost

Common technology challenges
The harsh weather conditions within the geographical focus areas, whereas some areas are ice covered all year around, means that the access to the subsea equipment could be limited, especially during the winter season. The requirements for an intervention vessel could therefore potentially be much stricter.
compared to other places in the North Sea, and the availability could be limited due to limited number of vessels. The production system availability and reliability is therefore of large importance.

Operational expenditures (OPEX) for a subsea production facility is normally lower compared to a traditional solution with manned platforms/FPSOs, and a subsea system in some of these areas could also be the only option due to the extreme weather. However, the weather, remoteness and the lack of adequate infrastructure will again lead to special requirements for the intervention vessels and oil spill surveillance that will increase the OPEX cost compared to other areas.

**Existing technologies, methods and best practice**

Currently, the maintenance of subsea equipment has to a large extent been based on corrective maintenance, meaning that a unit is replaced after it has failed. For subsea systems with limited intervention access this is not a feasible option, as the risk could be to have an inoperable system for several months. Condition monitoring of critical components/equipment is a key factor to achieve high availability of a subsea production system.

Today, there are systems for condition monitoring of subsea equipment, but typically there are limitations in the flexibility, i.e. manufacturer specific systems.

**Need for innovation and technology development**

There has currently been an increased focus on preventive maintenance and the systems that is required to make this happen. To be able to effectively monitor the system, the requirement for number of sensors and communication will increase, which potentially could be a threat to the reliability as the complexity increase (number of penetrations etc.). However, the need to know the status on equipment is generally believed to be more important than the risk of more penetrations etc. The use of these sensor data is also of importance, as they need to be put into a system that could process the data and predict a future failure by i.e. comparison of trends etc. Systems for this should be flexible, also between manufacturers. There are methods for building these systems, i.e. Bayes, Neural network, Fault tree.

Preventive maintenance could also be based on planned maintenance campaigns in fixed intervals, but field specific operation experience and the use of predictive software systems may reduce the requirements for these.

Acoustic censoring for condition monitoring on a wide range of equipment, leakage detection etc., is a technology where there are some operational experience, but more work should be done to enhance the flexibility etc.

**4.8.2 HSE-contingency**

**Common technology challenges**

Subsea developments will naturally have no people on site, and will based on this have an increased HSE benefit for people. Some new subsea intervention operations and possible use of divers, compared to a traditional offshore development could increase the personnel risk, but overall HSE risk is thought to be significantly reduced.

**Existing technologies, methods and best practice**

Generally subsea activities/interventions have a huge focus from the involved personnel, and have generally a good track record. However, the harsh weather condition in these areas introduces some new challenges i.e. cold climate clothing, icing on vessel, wind/waves etc.

**Need for innovation and technology development**

In some of these areas there could be an uncertainty both linked to the seismic and the soil (can be liquefied). Insulation of production tubing/pipelines in order to not thaw the soil is therefore important.
In addition, measurement and monitoring of both reservoir and geophysical properties could be combined to better predict the behavior and possibly give an early warning. There could be a possibility to use “earthquake signature waves (P&S waves) as an “early warning”, prior to serious shaking of equipment. This could then be used as info to initiate early shut down.

4.8.3 Well interventions

Common technology challenges
Well interventions do very often require large vessels, which can be limited in availability, have high cost and also introduces stress on the wellhead with a heavy riser.

A failing subsea X-mas tree is a source for large potential costs, both linked to workover and loss of production. In an area with limited access and possible harsh weather conditions, an effective method for dealing with failing X-mas trees is of great importance. A “piggy back recovery XT” could possibly be an alternative for a full workover.

Existing technologies, methods and best practice
Traditionally, well interventions have been performed from drilling rigs as an automatic extension of their role in drilling and completing wells. However, lighter intervention vessels have been introduced to the market in recent years, with the ability to do more of the work that previously required a rig.

Need for innovation and technology development
Wellhead fatigue due to the loadings from a riser during well interventions is generally a topic for concern. The ability for online monitoring of the wellhead stresses is therefore important, in addition to the development of methods for light interventions (riser less technology). Light intervention methods and vessels could increase the availability and decrease the cost for the areas that are not covered with ice all year, as the intervention time should decrease as well. However, the harsh weather conditions will probably dictate a certain size on the vessels.

4.8.4 Geotechnical operations

Common technology challenges
The sea conditions vary based on time of year, and also where in the geographical focus area the facilities are located, varying from ice all year around to no ice and drifting ice bergs.

Drifting ice bergs could potentially damage subsea equipment and pipelines significantly. Deeper trenching of pipelines is a mean to deal with this, and there are ongoing developments in this area.

Existing technologies, methods and best practice
Piping in more traditional areas is normally covered in gravel, trenched or uncovered on seabed. There are some experiences in areas with drifting ice bergs (i.e. outside Newfoundland), where subsea templates have been placed in glory holes.

Trenching of pipelines is today a commonly used method, but the trenching depth is limited and is not sufficient to protect against large ice bergs.

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24 According to Idar O. Grytdal
25 A piggy back “Piggy back recovery XT” is a set of valves to be located on top of a X-mas tree with failed functionality. Operation of the well will be handled by the “Piggy back set of valves – i.e. the piggy back XT
26 For more information read the RU-NO Barents Project Drilling, Well Operations and Equipment-report, Chapter 5. Link: http://www.intsok.com/Market-info/Markets/Russia/RU-NO-Project/Focus-Areas
Need for innovation and technology development

Subsea trees could typically be installed in “glory holes” to be protected by drifting ice bergs, but this is an expensive method, and more efficient solutions should be examined. Another option is to place the equipment in “Silos”, which is an evolving technology.

An adequate system for monitoring ice bergs drifting and sizes in these areas is very important to be able to safely operate in these remote areas. There are no recognized ice berg sizes that can be used as design load for wellheads, pipelines, process equipment (ref “100 year” wave), and guidelines for design and handling of these incidents should be developed.

Another area that needs new thinking is protection of pipelines in soft soils, where trenching is not possible, and a new method should be developed for these areas.

4.8.5 IMR – Inspection, Maintenance and Repair

Common technology challenges

The limited access to the subsea equipment set high requirements to the production availability, possibly by sparing philosophy, but also high focus on “planned” preventive maintenance.

The limited access to some of these areas will require an increased level of autonomy, sensors, communication and pre-fault indication. Development in these areas is ongoing, but gaps are still to be closed.

There have been examples that special requirements to modules (from i.e. oil companies), but also linked to a relatively fast development of subsea technology, has led to difficulties with access to spare parts. This is of course also linked to the requirement for a good spare part philosophy, but also points to the need for standardization.

Existing technologies, methods and best practice

The current maintenance philosophy for subsea equipment is in large extent based on corrective maintenance, which means that equipment runs until failure. The philosophy has been to have limited number of sensors on the equipment, but the trend now is to increase the number of sensors and then the amount of information that is possible to retrieve from equipment.

Linked to repair philosophy failed equipment is typically replaced with an identical, and taken onshore for repair. This is a philosophy that will most likely continue as today.
Need for innovation and technology development
There should be an increased focus on preventive maintenance, compared to the more “traditional” corrective maintenance. In many cases it is required to retrieve the units for service and replacement. Preventive maintenance will typically be performed based on:

- Risk and Safety issues
- Taking advantage of platform turnarounds
- To mitigate identified problems in campaigns
  - Adequate systems to identify any problems in an early phase is therefore of significant importance

Equipment and modules will very often be transported to shore and vendor for service, and there is therefore a need for spare equipment. The transport vessel may also need to be ice breaker classified for some of the areas that are covered by ice more or less all year around.

Sufficient communication between designers, installers and IMR will be a key factor to be able to develop high availability on the production system.

Subsea plants in remote areas could have strong requirements for resident autonomous systems due to the limited accessibility. The ability to inspect equipment, wellhead and pipeline, and possibly also do smaller maintenance/repair operations could be of high importance in order to keep the system in a safe operational state. In addition the weather in this area is more unpredictable compared to other places, with sudden changes in the conditions (polar lows etc.), which could limit the access from a surface vessel. There are some ongoing developments on resident AUV’s with repair/ROV capability for these purposes, but despite our knowledge in this field there are currently none in operation.

Real time status monitoring linked to equipment functionality, pipe-, wellhead fatigue and leakages/ruptures are important, and a part of monitoring potential environmental hazards. Monitoring of fatigue on wellheads has been a focus area for the last couple of years, and there are ongoing developments within this area.

Another gap is linked to monitoring of the seabed linked to unstable soil/hydrate (i.e. caused by thawing) near the pipeline and wellhead. This thawing can lead to “liquefaction” of the soil, and can cause serious damage as equipment will lose their support.

4.8.6 IOR/EOR
Common technology challenges
For fields with a long step out, the availability of chemicals could be a challenge as this transport could be inefficient in a very long umbilical. Options for subsea storage of chemicals and a system for easy replacement of the chemicals will lead to a more efficient system design.

Existing technologies, methods and best practice
An important benefit by having the production system subsea is that the separation is performed at higher temperature, which makes the separation easier. Over a fields lifetime the water cut will increase and therefore to separate out the water and re-inject this either in a disposal well or preferably as pressure support could increase the recovery. Reject directly to sea is also an option, but this will require further development both in subsea water polishing technology and OIW measurement. By removing the water the transport system will also be much more effective, both linked to smaller pipeline diameter and energy consumption, i.e. boosting pumps.

27 According to Statoil, Idar Grytdal
The water depths in these areas are limited (no requirement to use compact separation equipment due to this specific reason), and this flexibility should make it easier to build a production system that will be effective in a large lifespan, thus limiting the requirements for modifications. However, fluid properties will of course influencing this design.

**Need for innovation and technology development**
Chemicals to enhance the recovery are an option, either by mixing chemicals directly into the produced water or into sea water, before reinjection into the reservoir. Subsea storage of chemicals could be a key factor for this approach, as this gives a more flexible solution especially for long step outs compared to an expensive umbilical.

Subsea systems for injecting clean sea water (no sulphate/particles/O2) for pressure support in oil producing wells are currently being developed. The industry has lately focused more on the possibly positive effects injection of treated sea water could have on the reservoir performance.

4.8.7 Life extensions/abandonment

**Common technology challenges**
In order to have a life extension for a subsea plant, some modifications will most likely be required. With that in mind a life extension will be more feasible if the system is flexible modularization and standardization. Standardization is relevant both between oil companies and equipment vendors, i.e. recommended practices, communication, connections etc.

Collaboration between license owners and possibly governments will be a vital element to fully develop the possibilities and synergies in an area, and could be a very important element for life extensions.

Abandonment strategy in these areas is probably of even more importance compared to many other places as the harsh conditions with ice bergs etc, may require that all seabed equipment are removed.

**Existing technologies, methods and best practice**
A typical design life today is 25 years. The experience from the North Sea and other areas is that most platforms/systems operate much longer than the initial design life. The amount of work linked to verification and documentation of a life extension exercise is large, and this work will probably also be more time consuming when most or even all equipment is subsea.

**Need for innovation and technology development**
With respect to the Design life discussion above, a proposal could be to examine the consequences of increasing the design life of the subsea plant.
5. Innovation and technology development

This chapter contains a review of some of the most notable innovation and technology development projects and programs being carried out to enable sustainable and effective subsea operations in Arctic waters and the High North. Generally, the identified projects can be organized according to the following categories:

- Seabed geology and geophysics
- Design, installations and operations of subsea production systems
- Power systems
- Pipelines
- Marine operations

The projects and programs mentioned in this chapter differ quite substantially in scope reaching from projects targeting the whole industry, such as OG21 and the Barents 2020, to more concentrated efforts aimed at developing a particular technology or service. Also, while some of the projects and programs are still in their infancy, others have reached maturity or have been completed recently.

Oil and gas companies are the principle actors in developing new subsea technology applicable to Arctic operations. Typically, the oil and gas companies approach innovation and technology development through a combination of innovation in field development and long term R&D strategies. As with other areas of the oil and gas industry, Joint Industry Projects (JIP) and cooperation between operators, suppliers and academic institutions are important arenas for innovation and technology development. In Norway, the government also plays a crucial role in facilitating innovation and technology development through its policy implementation system (e.g. Innovation Norway, Research Council of Norway).

5.1 Seabed geology and geophysics

Petrobar/BarMod and Barents Sea Rock Properties (BarRock)

Different research projects carried out at the University of Oslo. The projects include a quantitative modelling of tectonic development and processes responsible for vertical movements in Barents Sea sedimentary basins, analyses of rock property distributions in shales and sandstones in the uplifted Barents Sea area and to study porosity, permeability, seal integrity and deformation related to primary and secondary petroleum migration in uplifted cemented sedimentary sequence.

5.2 Design and installations

OG21- TTA4

The OG21 was established in 2001 by the Norwegian Ministry of Petroleum and Energy as a means to promote development and more effective use of technology in the Norwegian oil and gas industry. The purpose of the OG21 strategy is “to align the various stakeholders to a common direction and understanding regarding technological challenges as well as technological opportunities”. In implementing the national petroleum research strategy, the OG21 has identified four so-called “Technology Target Areas” (TTA). These areas are:

- Energy efficient and environmentally sustainable technologies (TTA1)
- Exploration and increased recovery (TTA2)
- Cost effective drilling and intervention (TTA3) and future technologies for production

28 The Research Council has published a list of the publicly funded research under the PETROMAKS and DEMO programmes. The list is available at: 
http://www.forskningsradet.no/servlet/Satellite?blobcol=urldata&blobheader=application%2Fpdf&blobheadername=Content-Disposition%3A%26blobheadervalue1=%3Bfilename%3D%22Petroleumenergieffektiviseringengelsk.pdf%22&blobkey=id&blobtable=MungoBlobs&blobwhere=1274500004371&ssbinary=true

29 OG21 (2012)
• Processing and transportation (TTA4).

Subsea innovation and technology development is primarily treated in TTA4. Based on assessments by leading experts from the oil and gas companies, manufactures and academic institutions, the TTA4 has singled out a list of five focus areas with relevance to subsea innovation and technology development:
1. Subsea power transmission and distribution
2. Integrity management technology
3. Extended multiphase transport
4. High Performance subsea separation for long distance transport
5. Real-time condition monitoring technology

Subsea Valley
A business cluster with members primarily representing subsea companies from the greater Oslo area. In addition to its annual subsea conference, Subsea Valley has launched a project aimed at enhancing the member companies’ knowledge. This includes cooperation with academic and R&D institutions and other business clusters. The cluster has established a bachelor’s degree program in subsea studies and implemented a subsea module in the master’s degree program of Systems Engineering at the Buskerud Vestfold University College.

Centre for Autonomous Marine Operations and Systems (AMOS)
Located at the Norwegian University of Science and Technology (NTNU), AMOS aims at delivering path breaking technology solution within marine hydrodynamics, marine constructions and cybernetics. Research results shall contribute to the development of intelligent ships, marine constructions and autonomous marine vessels for surface, subsea and aerial use. This includes intelligent steering systems for permanently submerged vessels and robots.30

PETROMAKS 2
The programme is one of the Research Council’s large-scale programmes. It replaced the PETROMAKS programme which was concluded in 2013. The programme will support the Research Council’s strategies for research in the Arctic and northern areas, international cooperation and innovation. Considering subsea innovation and technology development, the PETROMAKS programme focuses on:
• Knowledge regarding multiphase pipeline flow and flow assurance
• Subsea electrical power supply and distribution with a long tie-in distance
• Fluid characterisation, fluid mechanics and the management of produced water
• Challenges related to the development and operation of offshore fields resulting from ice and the icing of installations and equipment, as well as the development of new materials
• Integrity management and monitoring
• Advanced sensors for control and early failure detection
• Subsea gas processing

DEMO2000
Financed by the Norwegian Ministry of Petroleum and Energy and administrated by the Research Council of Norway, the purpose of the DEMO2000 is to qualify and to pilot new technology that contributes to cost reductions and increased efficiency and production on the Norwegian Continental Shelf. The programme entails close cooperation between suppliers and oil and gas companies prioritizing:

30 A complete list of research projects being carried out at AMOS is available at: http://www.ntnu.edu/amos/research
• Technology that improves exploration and recovery
• To enhance the cost-effectiveness of drilling and intervention
• Qualifying future technologies for production, processing and transport
• To develop a competitive supplier industry in Northern Norway
• Encourage the Norwegian supplier industry to develop innovative technical solutions and products that are internationally competitive and safeguard expertise and jobs in Norway
• Encourage the majority of operating companies on the Norwegian continental shelf to contribute to the realisation of DEMO 2000 projects

Deepstar
Founded in 1992, the joint industry technology development project Deepstar aims at promoting technologies that increase production and reserves. Deepstar provides a forum to execute deepwater technology development projects, while also providing financial and technical resources to the deepwater industry. The project operates in two-year funding phases, with funding and support for each phase stemming from the membership fees from each member. Projects, currently being executed with funding from Deepstar, focus on innovation and technology development within areas such as seafloor boosting, subsea systems and flow assurance.

Norwegian Deepwater Programme
The purpose of the Norwegian Deepwater Programme (NDP) is “to join forces between the deepwater licences in Norway in order to carry out cost effective preparations for safe and efficient drilling and field development”. NDP encompassed five projects, covering the following disciplines:

• Biological effects, baseline assessments, ecological consequences, including fate of oil and gas from deepwater releases (Environmental Project)
• Meteorological and oceanographic data acquisition of ocean currents, waves, ocean modeling and technology development (Metocean Project)
• Technology related to cost effective deepwater riser and mooring configurations (Riser & Mooring Project)
• Shallow seismic, geological and geotechnical data acquisition and geological modeling (Seabed Project)
• Technology related to deepwater subsea production systems, processing and flow assurance (Subsea Project)

Procap 1000, 2000 and 3000, Brazil
The Deepwater Technology Program, PROCAP, made it possible for Petrobras to explore and produce oil and natural gas at depths of more than 2000m and contributed to the company being awarded, in 1992 and 2001, two OTC prizes, considered “Oscars” in the oil industry, for the development of innovative technologies which benefited the global offshore industry. PROCAP, in its 1000m and 2000m versions, made possible the exploration and production of oil and gas at water depths of more than one thousand and more than two thousand meters, respectively. Now, in the PROCAP 3000 version, the program is already providing knowledge and technology to explore and produce in water depths of 3,000 meters.

32 An overview of the phases, and their focus areas, is available at: http://www.deepstar.org/
33 Norwegian Deepwater Programme (2014) http://www.epim.no/norwegian-deepwater-programme/about-ndp
34 A more detailed information on the projects is available at: http://www.epim.no/norwegian-deepwater-programme/projects
35 Petrobras Magazine 57th Edition Technological Solution
Robotic Drilling System JIP (Confidential to Participants)
Robotic Drilling Systems (RDS, formerly Seabed Rig AS) started out with the ambition to develop a Seabed Rig to carry out cost-effective drilling from a location at the seabed, for deep water and arctic applications. The Seabed Rig would consist of a patented encapsulated and pressure compensated design, to ensure an environmentally friendly solution with zero discharge to sea and the same safety barriers as for conventional drilling. The Seabed Rig would be unmanned with automated and robotized working operations to be remotely controlled and supervised from an interactive 3D interface. A feasibility study and a Phase 1 containing preliminary technical design and description of operational procedures were carried out in 2006 to 2008 (driven by Statoil).

Major results from a subsequent Phase 2 (with Statoil as sole operator), “Prototype test of fully automated drilling rig”, included the world’s strongest robot-arm with associated selected tools and an axis control system for controlling several robots on a drill floor. The Phase 2 convinced stakeholders that it is possible to achieve an Autonomous Drill Floor. The next step for the Autonomous Drill Floor is qualification at full capacity in order to mature the technology before proceeding with the Seabed Rig concept. In the Phase 3 Shell and ConocoPhillips joined up with Statoil to establish a robotic drill floor inside the Ullrigg Test Facility. Here the robotic technology is qualified for later offshore implementation including EX classification of equipment and with drilling a test well as the final milestone. This is a means to evaluate the drill floor system on the Seabed Rig. A future JIP could address remaining challenges in the process towards a commercial Seabed Rig, including potential arctic case studies.

NCE Subsea
NCE Subsea was established in order to contribute to further development of one of the world’s most complete subsea environments – the subsea industry in the Bergen area. The cluster’s main focus is on the markets for maintenance, modification and operation of subsea installations. The environment includes a great number of suppliers of services and high-tech products. Over time a close collaboration has been established among industrial actors, R&D institutions, schools and authorities in the region. The regional cluster consists of some hundred companies and organizations with subsea as their only or main business area.

ITF36
The Industry Technology Facilitator (ITF) was established in 1999. It is a “not for profit” organisation owned by 30 major global operators and service companies. The key objectives of the ITF are to identify technology needs, foster innovation and facilitate the development and implementation of new technologies. The ITF has been responsible in launching more than 190 new collaborative and revolutionary joint industry projects (JIPs) and supports the development and implementation of new technologies by the following means:

- identify the shared technology needs of our member companies
- seek out innovative solutions
- access the technology development funds
- launch collaborative joint industry projects
- create field trial opportunities
- deliver technology implementation

The topics addressed by these ITF sponsored technologies include seismic resolution, complex reservoirs, cost-effective drilling and intervention, subsea, maximizing production, integrity management, and environmental performance.

36 Based entirely on ITF’s own description. The information is available at http://www.itfenergy.com/index/about
Barents Sea Gas Infrastructure

Resources in the Barents Sea could play a key role in maintaining Norwegian gas output in the 2020s and beyond according to a Gassco report on new gas infrastructure from the Barents Sea published in June 2014.

The Barents Sea Gas Infrastructure (BSGI) Forum, with participation from 26 oil and gas companies on the Norwegian Continental Shelf, was established to investigate the potential for new cost effective gas infrastructure for the resources in the Barents Sea. The analyses were based on a unique set of data with the latest resource estimates from the field operators. Volume scenarios were developed to span the potential outcome of near-term exploration activities in the Barents Sea. The Norwegian Petroleum Directorate, the industry association Norsk olje og gass and the Norwegian power transmission system operator Statnett have also participated as observers in the BSGI Forum.

5.3 Power systems

ABB/Statoil JIP
Statoil and ABB have entered an agreement to develop solutions for subsea electrical power transmission, distribution and power conversion systems for water depths down to 3000 m and over long distances. The agreement is in the form of a cost-shared joint industrial programme (JIP) led by Statoil on behalf of other participating oil companies, with ABB as the technology developer. The agreement follows a large subsea electrification study executed jointly by Statoil and ABB during 2012. The JIP will develop technologies needed to provide electrical power to subsea pumps, electrical submersible pumps and subsea gas compressors for projects on the Norwegian continental shelf, in the Gulf of Mexico and other places around the world. The technology will also enable the transmission of electrical power over long distances. This is important for the development of remote fields located far from infrastructure, including Arctic areas. The total cost for the programme, which has duration of five years, is USD 100 million, including ABB funding.

5.4 Pipelines

SATURN Cold Flow project
The purpose of the SINTEF project is to demonstrate an innovative and ground-breaking technology solution which allows: subsea field developments based on ultra-long cold multiphase, wellstream transport in uninsulated pipelines, with no heating requirements and no chemical additives, and with, very simplified subsea equipment and control procedures. The goal is achieved through a novel recirculation scheme for seed particles of gas hydrates and wax. These act as nucleators and growth controllers for further precipitation phenomena and eliminate deposits and plugs. The end result of the process is an easily flowable slurry with inert particles suspended in the liquid phase.

5.5 Marine Arctic Operations

Barents 2020
Barents 2020 was initiated 2007 as a bi-lateral initiative between Norway and Russia to harmonize HSE regulations and standards in the Barents Sea. Barents 2020 was conducted in four phases: the first two phases focused on identification of relevant standards and the latter two phases focused on six prioritized areas summarized below. While focused on the Barents Sea, Barents 2020 became a leading player in the advancement of global Arctic capability. Key achievements from Barents 2020 include:

- Identification and prioritization of most relevant standards to the Barents Sea (and Arctic)
- Unanimous support for ISO 19906, Arctic offshore structures, as providing a common basis for Arctic offshore structures.
- Identification of gaps, and guidance on gap closure for prioritized areas

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37 The report is available at: [http://www.gassco.no/Documents/099808.pdf](http://www.gassco.no/Documents/099808.pdf)
38 Based entirely on SINTEF’s own description. The information is available at: [http://www.sintef.no/home/SINTEF-Petroleum-Research/Projects/2003/Saturn-Cold-Flow/](http://www.sintef.no/home/SINTEF-Petroleum-Research/Projects/2003/Saturn-Cold-Flow/)
- Input for national and international standardization efforts aimed at Arctic standards.
- Catalyst for initiation of ISO/TC67/SC8, Arctic Operations

The Phase 4 priority areas are:

- Guidance to ISO 19906 for design of stationary floating structures in ice
- Workshops completed on practical use of risk assessment, for Barents Sea Installations
- Guidance on Escape, Evacuation and Rescue for the Barents Sea
- Guidance on safe working environment for offshore activities in the Barents Sea
- Guidance for ice management based on ISO 19906 for Barents Sea operations
- Regional environmental guidelines for the Barents Sea to reflect MARPOL Special Area (SA) requirements for discharges and emissions from oil and gas related ship traffic and offshore units

**SAMCoT (NTNU)**

SAMCoT was established as a Centre for Research-based Innovation by the Research Council of Norway to meet the needs related to the increased activities in waters such as the Eurasian Arctic, East Greenland and the Chukchi Sea. Hosted by the Norwegian University of Science and Technology (NTNU), SAMCoT has positioned itself as a leading national and international centre for the development of robust technology. SAMCoT provides the scientific know-how necessary to meet the challenges caused by ice, permafrost and climate change. In addition it will set the foundation for the further development of environmentally adapted coastal infrastructure. Six work packages (WPs) constitute the different research areas that will address these challenges:

WP1 – data collection & Process Modelling; collecting and analysing data on sea ice, icebergs, metocean and coastal permafrost, and process modelling
WP2 – material modelling; modelling of ice ridges and permafrost
WP3 – fixed structures in ice; developing analytical and numerical models to predict the action from ice on fixed single and multi-leg structures
WP4 – floating structures in ice; developing numerical tools that predict the behaviour and actions on floaters in ice
WP5 – ice management and design philosophy; establishing a design philosophy that considers the use of ice management
WP6 – coastal technology; developing technology and guidelines for the development and design of environmentally friendly and sustainable coastal structures and provide erosion protection

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6. Technology/solution providers

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8. Appendices

Appendix 1 - Various types of sea ice

Sea ice varies in shape, thicknesses, age and hardness, representing different challenges to navigation. These are some of the more frequent types of sea ice:

- **New Ice**: Recently formed ice composed of ice crystals that are only weakly frozen together (if at all) and have a definite form only while they are afloat.

- **Nilas**: A thin elastic crust of ice (up to 10 cm in thickness), easily bending on waves and swell and under pressure growing in a pattern of interlocking "fingers" (finger rafting).

- **Young Ice**: Sea ice in the transition stage between nilas and first-year ice and 10-30 cm in thickness.

- **First-Year Ice**: Sea ice of not more than one winter's growth, developing from young ice having a thickness of 30 cm or more.

- **Old Ice/multi-year ice**: Sea ice which has survived at least one summer's melt. Its topographic features generally are smoother than first-year ice and can be a few metres thick. Old ice is also much harder than first year ice, and can be much more damaging to ships, if hit at a normal cruise speed.

- **Ice Massifs**: are manifested as extensive accumulations of close or very close ice that are found in the same region every summer.

- **Drift ice**: is ice that floats on the surface of the water in cold regions, as opposed to fast ice, which is attached "fastened" to a shore. Usually drift ice is carried along by winds and sea currents, hence its name, "drift ice".

- **Pack ice**: When the drift ice is driven together into a large single mass, it is called pack ice. Wind and currents can pile up ice to form ridges three to four meters high, creating obstacles difficult for powerful icebreakers to penetrate. Typically areas of pack ice are identified by high percentage of surface coverage by ice: e.g., 80-100%.

- **Ice floe**: is a large piece of drift ice that might range from tens of meters to several kilometers in diameter. Wider chunks of ice are called ice fields.
Appendix 2 – Summary of workshops

The tables below define some of the Arctic technology gaps for standard subsea production systems. The tables are compiled from the breakout session discussions at the 1st Industry workshop in Oslo on the 22nd of October 2013 and the 2nd Industry workshop in Arkhangelsk on the 6th of February 2014. The results have been used when compiling the task force report.

For suppliers of some products, systems and services, it is relatively easy to identify who the companies are whereas for others, it is more challenging. Some companies provide a multitude of products and services whereas others supply only key components, which can vary depending on the project and customer. Also, defining the status for what is “solved”, “in progress” and “a gap” is not straightforward as this often is confidential within the companies with impact on future business.

1st Industry workshop in Oslo on the 22nd of October 2013

The table below is a draft defining the Arctic technology gaps for standard subsea production systems. The table is based on OG21 – National technology Strategy for the 21st Century reports ([www.og21.no/](http://www.og21.no/)) as referenced and based on the RU-NO team’s awareness of the Arctic – challenges as well as suppliers.

<table>
<thead>
<tr>
<th>Technology Challenge</th>
<th>Is it solved?</th>
<th>Solution Provider(s):</th>
<th>Comments:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Primary equipment – “the production system”</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wellhead</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Methodology for assessing load and fatigue impact on the wellhead for a seabed with changing properties due to thawing of soil/hydrates.</td>
<td>No (a gap)</td>
<td>Solution providers/references: FMC, Aker, GE, OneSubsea, Drill-Quip</td>
<td></td>
</tr>
</tbody>
</table>
| Wellhead foundation solutions for a seabed with changing properties due to thawing of soil/hydrates. | No (a gap) | Solution providers/references: - DNV | - Can a premade conductor be installed prior to drilling the well? The installation of conductor does not require the use of a BOP.  
- Can the well be used as pile for supporting the wellhead and structures around the well?  
- Is it possible to isolate the well?  
- Some “seabeds” have a very poor definition of seabed/mudline and the hydrates can form very close to the mudline. This is a serious case for “liquefaction” due to heating/thawing and seismic disturbances.  
Solution providers/references: - Neodrill caisson – supplier of premade conductors. |
| Evaluation if current drilling procedures for areas where the seabed may contain shallow gas and/or frozen soils are adequate to protect against incidents. | In progress | Comments: - Introduce protective measures in drilling procedures.  
- Test before drilling (e.g. seismic or monitor for “seepage” of gas) | |
<table>
<thead>
<tr>
<th>Monitoring and recording of Life of Field loads</th>
<th>In progress</th>
<th>Solution providers/references:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>- Drilling companies</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Seismic companies</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Seismic activity:</th>
<th>No (a gap)</th>
<th>Comments:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Requirements for subsea systems including</td>
<td></td>
<td>- Can onshore (oil field?) requirements from Russia be used as a guideline for subsea?</td>
</tr>
<tr>
<td>wells are missing. What is an acceptable</td>
<td></td>
<td>- Can a more extensive measurement and monitoring regime be used to better predict seismic behavior?</td>
</tr>
<tr>
<td>consequence for the installed equipment and</td>
<td></td>
<td>Monitoring of the reservoir and geophysical measurements of the seabed could be combined to build “a field model” which enables early warning.</td>
</tr>
<tr>
<td>what mitigating measures needs to be</td>
<td></td>
<td>- Earthquake signature waves (P and S waves) should be evaluated to check if a warning can be issued prior to serious “shaking” of the equipment is taking place. The postulate is that early detection can be achieved and used for initiating an emergency shutdown prior to damage being caused to the equipment.</td>
</tr>
<tr>
<td>considered.</td>
<td></td>
<td>- Monitoring of the reservoir and geophysical measurements of the seabed could be combined to build “a field model” which enables early warning.</td>
</tr>
<tr>
<td>- Soil can become liquefied</td>
<td></td>
<td>- Earthquake signature waves (P and S waves) should be evaluated to check if a warning can be issued prior to serious “shaking” of the equipment is taking place. The postulate is that early detection can be achieved and used for initiating an emergency shutdown prior to damage being caused to the equipment.</td>
</tr>
<tr>
<td>- Well and wellhead can be damaged</td>
<td></td>
<td>- Earthquake signature waves (P and S waves) should be evaluated to check if a warning can be issued prior to serious “shaking” of the equipment is taking place. The postulate is that early detection can be achieved and used for initiating an emergency shutdown prior to damage being caused to the equipment.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Protection of wellhead (and tubing):</th>
<th>No (a gap)</th>
<th>No (a gap)</th>
<th>Comments:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clear requirements for how to protect the</td>
<td></td>
<td></td>
<td>- It should be considered if methods used for e.g. risk assessment of platforms could be used for a risk assessment of a well.</td>
</tr>
<tr>
<td>wellhead are missing.</td>
<td></td>
<td></td>
<td>- “100 year” ice incident scenario comparable to a “100 year” wave or storm</td>
</tr>
<tr>
<td>A better risk assessment method for wellheads are needed</td>
<td></td>
<td></td>
<td>- Trawling activities to be included</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- The method used for protecting the well should be included in this assessment</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Reduce probability of an incident</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Reduce consequence of an incident</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>- Describe what is the actual “barrier” protecting against a particular risk</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Xmas-tree</th>
<th>Yes (glory holes) Silos (in progress)</th>
<th>Solution providers :</th>
</tr>
</thead>
<tbody>
<tr>
<td>Protection from ice and icebergs</td>
<td></td>
<td>FMC, Aker, GE, OneSubsea, Drill-Quip</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Solution providers/references:</th>
<th></th>
<th>- DNV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Template and manifold</td>
<td>Solution providers:</td>
<td>Comments:</td>
</tr>
<tr>
<td>-------------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>For many of the areas now explored, drilled and considered for development, current technologies and standard system solutions (&quot;Shtokman type&quot;) should be acceptable</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>For ice covered areas, there is need for a new strategy for preventive measures in order to obtain an acceptable availability.</td>
<td>No (a gap)</td>
<td>Comments: Technologies recommended for consideration are:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Resident AUV/ROV solutions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Improved CPM solutions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Improved monitoring solutions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Increased redundancy solutions</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- New or additional barrier functions preventing accidents</td>
</tr>
<tr>
<td></td>
<td></td>
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</tr>
<tr>
<td>For ice covered shallow waters, need better methods for assessing the forces from scraping ice.</td>
<td>No (a gap)</td>
<td>Comments: Current knowledge and solution concepts are not considered sufficient for these arduous conditions</td>
</tr>
<tr>
<td>Foundation solutions for a seabed with changing properties due to thawing of soil/hydrates.</td>
<td>No (a gap)</td>
<td>Comments: Can premade conductor be installed for supporting seabed structures?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Is it possible to isolate the seabed from thawing?</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Some “seabeds” have a very poor definition of seabed /mudline and the hydrates can form very close to the mudline. This is a serious case for “liquefaction” due to heating/thawing and seismic disturbances.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A better understanding of how the seabed properties in Arctic areas and how they may change due to heating is required</td>
<td>In progress</td>
<td>Comments:</td>
</tr>
<tr>
<td>Protection from ice and icebergs</td>
<td>Yes (glory holes)</td>
<td>Comments:</td>
</tr>
<tr>
<td></td>
<td>Silos (in progress)</td>
<td></td>
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<tr>
<td></td>
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</tbody>
</table>
A better understanding of how ice and icebergs will influence on the installed equipment is required.
- A regional perspective (areas 1–6) and with a view to how this will change over the life time of the field

| Comments: |
|------------------|------------------------|
| - It should be considered if methods used for e.g. risk assessment of platforms could be used for a risk assessment of a well. |
| - “100 year” ice incident scenario comparable to a “100 year” wave or storm |
| - Trawling activities to be included |
| - The method used for protecting the template/manifold should be included in this assessment |
| - Reduce probability of an incident |
| - Reduce consequence of an incident |
| - Describe what is the actual “barrier” protecting against a particular risk |
| - Metocean should be expanded with ice and iceberg prediction |

| Solution providers/references: |
|-----------------------------|------------------------|
| - DNV |
| - SINTEF |
| - Russian institutes (who?) |

<table>
<thead>
<tr>
<th>Umbilical</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution providers:</td>
</tr>
<tr>
<td>Aker</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Control system</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution providers:</td>
</tr>
<tr>
<td>FMC, Aker, GE, OneSubsea, Drill-Quip</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>All electrical control systems, reduced umbilical(OG21TTA4)</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Hydraulic fluid properties – nontoxic fluids for discharge may not be optimal as a hydraulic fluid</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Eliminate discharge of hydraulic fluids to environment – closed loop hydraulics or the use of electrical control system</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Long distances – signal attenuation in cables/fibers and hydraulic pressure loss in umbilical</th>
</tr>
</thead>
</table>
| **Need a new control system philosophy for electric control systems.** | **No (a gap)** | **Comments:**  
- All aspects including operation of downhole equipment needs to be considered.  
- If electric control systems is perceived as “the future”, considerations on “far out” and “under ice” needs to be part of this philosophy.  
- Autonomous functionality should be included in this philosophy (for the control system itself and for external functions (e.g. AUV))  
- The control system philosophy needs to include also aspects of subsea processing and flow assurance for long step out distances.  

**Solution providers/references:**  
- FMC, OneSubsea |

| **Development, qualification and field testing of electric downhole safety valve.** | **Ongoing** | **Comments:**  
- The technology is not yet considered “trustworthy” and needs more testing as it is a significant change from current DHSV valves technology (hydraulic)  

**Solution providers/references:**  
- Haliburton |

| **Electric control system is not a requirement but is perceived as an improvement** | **Ongoing** | **Comments:**  
- More reliable,  
- More opportunity for CPM of the control system  
- More responsive compared to hydraulic systems.  
- Large cost saving on umbilical.  

**Solution providers/references:**  
- FMC, OneSubsea |

| **Subsea HPU for operation of downhole safety valves is an alternative to electric DHSV.** | **Ongoing** | **Comments:**  
- A subsea HPU for DHSV may not be large, complex and expensive  

**Solution providers/references:**  
- FMC |

| **Condition and performance monitoring** | **Solution providers:**  
FMC, Aker, GE, OneSubsea, Drill-Quip, Kongsberg Gruppen |

| **Sensor technology and condition monitoring for subsea production systems (incl. pipeline) (OG21TTA1)** |
| **Online stress and fatigue monitoring (OG21TTA4)** |
| **Condition monitoring – structures (wellhead to topside) (OG21TTA4)** |
| **Integrity management (OG21TTA4)** |
| **Reliable online stress and fatigue monitoring (OG21TTA1)** |
| **Real-time monitoring for accidental discharge of chemicals and hydro carbons** | **Ongoing** | **Solution providers/references:**  
- FMC, Kongsberg Maritime |
<table>
<thead>
<tr>
<th><strong>Materials</strong></th>
<th><strong>Solution providers/references:</strong></th>
</tr>
</thead>
</table>
| Development of lubricant technologies satisfying HOCNF (yellow) or equivalent acceptable for the environmental conditions in Arctic | Ongoing | - Product suppliers  
- SINTEF |
| Extreme low air temperature in winter is detrimental to many materials, often in combination with high summer temperature. Britteness, cyclic stress, crystallization etc. | Ongoing | - SINTEF (Arctic materials II project)  
- Material suppliers in general |
| Code requirements for low temperature is not always well defined or ambiguous for low temperature | No (a gap) | - SINTEF  
- Russian institutes (who) |

<table>
<thead>
<tr>
<th><strong>System technology</strong></th>
<th><strong>Solution providers/references:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Fate and effect of EOR/IOR chemicals</td>
<td>Ongoing</td>
</tr>
<tr>
<td>Fluid characteristics and compatibility in PWT systems</td>
<td></td>
</tr>
</tbody>
</table>
| Flexible produced water treatment technologies | Ongoing | - FMC, Aker, GE, OneSubsea, Drill-Quip, Reinertsen  
- Oil companies |
| Improved condensate and water management technology and systems | Ongoing | - FMC, Aker, GE, OneSubsea, Drill-Quip, Reinertsen  
- Oil companies  
- Regulating authorities |
| Technologies for flow assurance over long distances in a cold environment when there is possibility for hydrates and/or waxing | Ongoing | - FMC, Aker, GE, OneSubsea, Drill-Quip, Reinertsen  
- Oil companies  
- Regulating authorities |
| Robust system design for areas where intervention and clearing of flow assurance issues (e.g. hydrate plug) is difficult due to ice conditions in order to achieve the same or acceptable availability. | No (A gap) | Comments:  
- Because of limited access, need a more stringent “barrier” philosophy  
- Does gas field in the Arctic require a new design philosophy? |
| Because of limited access due to weather, remoteness and ice, consider if there is a need for a more stringent “barrier” philosophy to achieve the same or acceptable safety. | No (a gap) | Solution providers/references:  
- FMC, Aker, GE, OneSubsea, Drill-Quip, Reinertsen  
- Oil companies  
- Regulating authorities |

<table>
<thead>
<tr>
<th><strong>Operation of subsea production system</strong></th>
<th><strong>Oil companies</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Operation integrated environmental monitoring technologies</td>
<td>Oil companies</td>
</tr>
</tbody>
</table>
| Real-time integrated monitoring and modeling systems to minimize effect of operational discharge | Oil companies  
- Regulating authorities |
| Regional field specific ice management philosophies and system solutions with supporting technology (e.g. satellite) | Ongoing | - “Ice management” companies  
- Oil companies  
- Regulating authorities |
<table>
<thead>
<tr>
<th><strong>Secondary equipment</strong> – “for service of the installed production system”</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>General consideration</strong></td>
</tr>
<tr>
<td>Development of technologies which reduces the need for vessel station keeping for long periods</td>
</tr>
<tr>
<td>Development of technologies for faster yet safe temporary abandonment of operations.</td>
</tr>
<tr>
<td><strong>Solutions for secondary containment - accidents</strong></td>
</tr>
<tr>
<td>Systems for remote leak detection, real time monitoring and control of pipelines, risers, injection wells, subsea and surface equipment (OG21TTA1)</td>
</tr>
<tr>
<td>Leakage detection (OG21TTA4)</td>
</tr>
<tr>
<td>Leakage control systems for gas, condensate and chemicals for long distance, subsea and downhole processing (OG21TTA1)</td>
</tr>
<tr>
<td>New solutions to detect, contain and clean up spills (OG21TTA1)</td>
</tr>
<tr>
<td>Safe, robust and fast responding systems to control chemical, gas and condensate spills (OG21TTA1)</td>
</tr>
<tr>
<td>Containment if fluids are broaching around well (OG21TTA3)</td>
</tr>
<tr>
<td>Pig or resident isolation plugs which can be deployed – in well or in pipe/flowline in case of leakage.</td>
</tr>
<tr>
<td>A more advanced inspection program can reduce danger of unplanned leaks hence recommended, in particular for areas which are inaccessible like under the ice</td>
</tr>
<tr>
<td>Systems for monitoring of hydro carbon leakage should be able to distinguish between naturally occurring seepage from the sea bed and leakage from a production system.</td>
</tr>
<tr>
<td><strong>Intervention in well – barrier breaching</strong></td>
</tr>
<tr>
<td>The capability of Riser Management Systems should include real time monitoring to enable better prediction of the real operating conditions</td>
</tr>
<tr>
<td>Improved weather prediction methods through the use of a “tighter grid” should be developed in order to improve weather prediction.</td>
</tr>
</tbody>
</table>

**Comments:**
- Natural leeks can cause false alarms.
- Tracer technology in well stream

**Solution providers/references:**
- Research institutions

**Comment:**
- This would give a larger operating window and more opportunity for finishing critical operation

**Solution providers/references:**
- FMC

**Comments:**
- Satellites
- Buoys
- Ships
- Etc.
<table>
<thead>
<tr>
<th>Need to have a better understanding of how the unpredictable arctic weather will cause interruptions in drilling and intervention operations.</th>
<th>Ongoing</th>
<th>Comments:</th>
<th>Better ways for predicting Better ways of disconnecting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution providers/references:</td>
<td>Det Norske Metrologiske institutt Russian institutes?</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>GPS system accuracy needs to be improved in the Arctic.</th>
<th>No (a gap)</th>
<th>Comment:</th>
<th>GPS is more accurate in other areas The Russian system GLONASS may have better accuracy and should be considered as an alternative or in combination with GPS:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution providers/references:</td>
<td>“GPS” system operators</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Intervention at seabed – external to barrier</th>
<th>Solution providers:</th>
<th>FMC, Aker, GE, OneSubsea, Drill-Quip, Helix-Well Ops, Subsea 7</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Technologies and services enabling more use of ROV/AUV solutions and with a reduced dependency for vessel station keeping. Ability to operate under ice.</th>
<th>Ongoing</th>
<th>Solution providers/references:</th>
<th>FMC, Aker, GE, OneSubsea, Drill-Quip, Subsea 7</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Wet parking of spare parts (e.g. control pods) and replaceable by resident ROV or AUV</th>
<th>No (a gap)</th>
<th>Comments:</th>
<th>Use of “hyperbaric” or “protective” chambers if dept or water exposure is a problem should be considered.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution providers/references:</td>
<td>FMC, Aker, GE, OneSubsea, Drill-Quip, Subsea 7</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Installation of equipment</th>
<th>Solution providers:</th>
<th>FMC, Aker, GE, OneSubsea, Subsea 7, Technip</th>
</tr>
</thead>
</table>

| Technologies and services enabling more use of ROV/AUV solutions and with a reduced dependency for vessel station keeping. Ability to operate under ice. | Solution providers/references: | FMC, Aker, GE, OneSubsea, Drill-Quip, Subsea 7, Technip |
### Inspection of equipment

On-site inspection technologies (i.e. AUVs) to obtain more frequent or online inspection:

**Solution providers:**
- FMC, Aker, GE, OneSubsea, Drill-Quip, Subsea 7, Kongsberg Gruppen

### Transport of equipment

<table>
<thead>
<tr>
<th>Exposure of large structures and equipment to extreme weather conditions</th>
<th><strong>Transport companies</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td><strong>Solution providers/references:</strong></td>
</tr>
<tr>
<td>- Transport contractors</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Need an agreed recommendation by oil companies and industry for an acceptable “transport requirement”. Minus 60 deg C is to strict or for some structures, seals, electronic cards etc.</th>
<th><strong>Solution providers/references:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td>- Oil companies</td>
</tr>
<tr>
<td>- National regulation authorities</td>
<td></td>
</tr>
</tbody>
</table>

### Onshore storage of equipment

<table>
<thead>
<tr>
<th>Exposure of large structures and equipment to extreme weather conditions</th>
<th><strong>Arctic bases</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td><strong>Solution providers/references:</strong></td>
</tr>
<tr>
<td>- Arctic bases</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Need an agreed recommendation by oil companies and industry for an acceptable “storage requirement”. Minus 60 deg C is to strict or for some structures, seals, electronic cards etc.</th>
<th><strong>Solution providers/references:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td>- Oil companies</td>
</tr>
<tr>
<td>National regulation authorities</td>
<td></td>
</tr>
</tbody>
</table>

### Onshore testing of equipment

<table>
<thead>
<tr>
<th>Exposure of large structures and equipment to extreme weather conditions during system testing prior to installation</th>
<th><strong>Arctic bases</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td><strong>Solution providers/references:</strong></td>
</tr>
<tr>
<td>- Arctic bases</td>
<td></td>
</tr>
</tbody>
</table>

### Onshore service and repair

<table>
<thead>
<tr>
<th>Regional availability of services with certified Oil &amp; Gas “capabilities and/or a proven track record</th>
<th><strong>Arctic bases, service providers</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td><strong>Solution providers/references:</strong></td>
</tr>
<tr>
<td>- Arctic bases</td>
<td></td>
</tr>
<tr>
<td>- Service providers</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Efficient logistic organizations for supply of spares and services</th>
<th><strong>Solution providers/references:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td>- Logistics companies</td>
</tr>
<tr>
<td>- National institutions (e.g. customs)</td>
<td></td>
</tr>
</tbody>
</table>

### Other activities

**Codes and legislation**

<table>
<thead>
<tr>
<th>Lack of and/or limited applicability, transborder legislation differences and national priorities and preferences</th>
<th>In progress</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Solution providers/references:</strong></td>
<td></td>
</tr>
<tr>
<td>- Canada, Greenland/Denmark, Iceland, Norway, Russia, USA</td>
<td></td>
</tr>
<tr>
<td>- ISO, API, Arctic Governance Project</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Formulate a “best practice” for Arctic with near term focus on Norway and Russian areas.</th>
<th><strong>Comments:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>No (a gap)</td>
<td>- First step should be to make a strategy for this work</td>
</tr>
<tr>
<td><strong>Solution providers/references:</strong></td>
<td></td>
</tr>
<tr>
<td>- National regulatory institutions</td>
<td></td>
</tr>
<tr>
<td>- Classification companies (e.g. DNV)</td>
<td></td>
</tr>
</tbody>
</table>
### Technology Challenge

<table>
<thead>
<tr>
<th>Primary equipment – “the production system”</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Technology Challenge</strong></td>
</tr>
<tr>
<td></td>
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<tr>
<td></td>
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</tbody>
</table>

**Wellhead**

<table>
<thead>
<tr>
<th>Solution providers:</th>
<th>FMC, Aker, GE, OneSubsea, Drill-Quip</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comments:</td>
<td></td>
</tr>
</tbody>
</table>

- These issues have not been dealt with in “real life” projects to date in the areas to be covered by the RU-No project.

- The permafrost can be very thick (800 meters) but also areas which are in a “close to thawed condition” can be a challenge, where isolated “ice lenses” can still remain intact with permafrost.

- It is recommended to use experience from land based wells or from other regions if experience does exists.

  - Study the phenomena
  - Evaluate if current technology can be adapted for subsea use
  - Develop new methods and technology to solve the challenges

- A solution could be to develop structures located on the sea bed which supports the wellhead. New approaches for solutions remain to be seen.

<table>
<thead>
<tr>
<th>Wellhead foundation solutions for a seabed with changing properties due to thawing (melt down) of frozen soil/hydrates.</th>
<th>No (a gap)</th>
<th>Comments:</th>
</tr>
</thead>
<tbody>
<tr>
<td>- Further studies are recommended in order to understand the issues properly.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Areas affected by permafrost and gas hydrates.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- The properties (e.g. thickness) of the permafrost and gas hydrates.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- The geology in general with the perceived influence on the drilling of the well and the well in a producing state.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Test drilling of wells in permafrost including injection of stabilizing cement or other mitigating measures should be performed in order to obtain more knowledge and experience.</td>
<td></td>
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</tr>
<tr>
<td>- It is also recommended to study the influence on the environment if a well is in a deteriorating state.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Are the leakage expected to be small and insignificant or is a major blow out a likely scenario?</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Template and manifold | **Solution providers:**  
FMC, Aker, GE, OneSubsea, Drill-Quip, Reinertsen |
|-----------------------|------------------------------------------------|
| For many of the areas now explored, drilled and considered for development, current technologies and standard system solutions ("Shtokman type") should be acceptable. | Yes | **Comments:**  
- The Shtokman project should be studied to provide lessons learned - there should be much valuable information to be gleaned from such an activity due to the large work scope executed.  
- The use of this technology which to a large degree is based on existing technology from other areas is acceptable however may not be optimal. This should be investigated through concept studies in order to come up with more optimal (cost effective) solutions.  
**Solution providers/references:**  
- FMC, Aker, GE, OneSubsea, Drill-Quip, Reinertsen |
| The areas to be investigated through the RU-No project (area 1=>6) are quite diverse in environmental conditions. | No (a gap) | **Comments:**  
- We need different solutions adapted to the conditions. As an example, there is a huge difference between deep water Kara sea and shallow water Pechora sea.  
- In the Russian areas, there is no requirement for trawl protection however protection from dropped objects are still required.  
**Solution providers/references:**  
- FMC, Aker, GE, OneSubsea, Drill-Quip, Reinertsen, Kongsberg Maritime, Subsea7 |
| Subsea structures/modules should be designed to accommodate the seabed conditions as well as the challenging logistics situation. | No (a gap) | **Comments:**  
- Modules should be tested as complete units prior to installation. This will increase the reliability and thus ensure a minimum of offshore operations.  
- Templates and manifolds could be designed with buoyancy modules and floated into position in order to reduce the need for large heavy lift vessels.  
- The use of submarine technology for installation is immature but has a potential in the long perspective (2040 and beyond).  
- Successful use of AUV technology requires that the size of the modules is reduced. Compact and lightweight modules will be an enabler.  
**Solution providers/references:**  
- |
<table>
<thead>
<tr>
<th><strong>Subsea Processing</strong></th>
<th><strong>Solution providers:</strong> FMC, Aker, GE, OneSubsea</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discharge of produced water to sea is not an optimal solution even if level of contamination is within the acceptable levels.</td>
<td>In progress</td>
</tr>
</tbody>
</table>
| **Comments:** | - Chemicals used for treatment of the reservoir and well can be environmentally unacceptable if discharged to sea. Discharge to sea, even in very small quantities may disqualify certain chemicals.  
- Injection into the reservoir for oil fields has a value as it increases the reservoir pressure but is not relevant for gas fields, thus the two distinctive cases of gas fields and oil fields have different drivers.  
- Injection into the seabed to dispose of the water is anyway a preferred alternative. It can however be very costly to inject the water offshore and for gas fields it might be a better alternative to transport the water to shore.  
- The cleanliness of the water needs to match the reservoir requirement. Therefore is possibly a treatment (filtering) of the produced water required prior to injection. |

| **Design and operation of complete subsea factory with all aspects of processing included.** | In progress |
| **Comment:** | - Each field has different requirements for subsea processing. It will usually be more cost effective to provide processing capability onshore. Thus processing in order to ensure good flow assurance is the “key driver” also in the Arctic areas. For the Shtokman field, small volumes of liquid dropping out were the major challenge.  
- Processing and stabilization of the hydro carbon to enable subsea storage and subsequent offloading to ship is – for some fields – an alternative to long distance pipe lines. |

<table>
<thead>
<tr>
<th><strong>Power generation</strong></th>
<th><strong>Solution providers:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Local power generation for small power consumers</td>
<td>In progress</td>
</tr>
</tbody>
</table>
| **Comments:** | - Typical power requirement is 10 kW for a field  
- One option is to use electrochemical generators (fuel cell) where the fuel is hydrogen or possibly using methanol.  
- The methanol needs to be sufficiently clean to avoid contamination of the fuel cell. It can therefore be a challenge to use the methanol used for “inhibiting” the subsea production system. |
Local power generation for large power consumers. Gas fields needing compressors will have the largest requirement in terms of power, the Shtokman field would require 90 MW.

<table>
<thead>
<tr>
<th>System technology</th>
<th>In progress</th>
<th>Comments:</th>
</tr>
</thead>
</table>
| Technologies for flow assurance over long distances in a cold environment when there is possibility for hydrates and/or waxing | In progress | - Typical power requirement is 5 – 30 MW depending on the fluid composition, pressure and transport distance.  
- A “power hub” could be located at the “support hubs” which is needed for helicopter activities. These “hubs” would enable use of conventional power generators like gas turbines or diesel engines. These types of engines needs to be protected from the humid and corrosive air close to the sea however this is established practice at most offshore installations hence not considered a large challenge, although increases the operating cost of the power plant.  
- Nuclear power plants can be made modular and a typical power output from a reactor module is 30 MW. The plant can never be completely shut down hence a need for dumping power is needed. A typical low power utilization limit for a plant is 10% however 1% is too low. Therefore up to 3MW may have to be dumped (this would not be a big challenge, the sea can easily absorb this power by cooling a resistive circuit).  
- A nuclear power plant consists of two distinctive systems – the steam generating system and the power generating system. The steam generating system can be made very robust without the use of pumps whereas the power generating cycle uses a more traditional steam turbine with its traditional “turbine” issues. It is therefore recommended investigating how reliability for the steam turbine can be optimized. |

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<td>Codes and legislation</td>
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