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Task 4.21 Report on fixed as well as floating offshore structure concepts

by

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Preface

The aim of Work Package 4 - Task 4.2.1 within ACCESS is the assessment of existing fixed and floating offshore structure concepts, including fixed and floating structures for exploration, production, storage, off-loading and transport, and land-based infrastructure.

Mention of trade names or commercial products in this report do not constitute endorsement or recommendation for use.
Assessments of technology presented in this report are not to be used for design purposes.

The report is prepared by HSVA (Hamburg) as taskleader and IMPaC (Hamburg) as partner in ACCESS WP 4 – Task 4.2.1.

Executive Summary

In the study, different types of fixed and floating structures for the exploration, production and transportation of oil and gas in Arctic regions have been described substantially. The choice of the types of structures depends on various parameters at the planned location. Decisive factors are the predominant on-site water depth, soil conditions, distance from the coast line and environmental conditions (e.g. ice conditions, wind, waves and currents).
The first major exploration and production in ice covered seas were conducted in the Beaufort Sea by American and Canadian oil companies since 1980. Generally, these technical solutions have proven themselves over the years.
The group of "fixed structures” includes the types of structures:

- Artificial Islands (gravel / ice islands)
- Gravity based structures (steel /concrete)
- Jacket & Jack-up structures
- Export/Loading terminals

Artificial islands - Gravel islands

Gravel islands do not belong to the category of "high-tech"-technology. Nevertheless, this type of structure has been used successfully in the Beaufort Sea for decades and can continue to be used for exploration and production in shallow waters, as the example of "North Star" shows.
Based on the proven technology and due to relatively short construction time, the gravel islands are an economical alternative for low water depths to about 20 m. With rising oil prices at the time, it is also conceivable that this type of structure in the future for something deeper water can be used despite increased material and manufacturing costs application.
Landfast ice thickness usually up to 2 m, comprises the nearshore Beaufort Sea for about nine months of the year and has a significant impact on island design and construction methods.
In deeper water, the occurrence of multi-year ice and increased sea ice drift is taken into account. A primary requirement is that the island has a sufficient lateral stability to the ice and wave loads. This is generally provided by the geometry of the island.
Ice ride-up is constrained by the sloped island sides due to friction and ploughing forces and/or, in some cases, by discontinuity in slope. Waves begin to break as they reach the sloped island sides, i.e. energy is dissipated before they reach the working surface. Wave overtopping can be avoided by placing the working surface above the design wave height or by placing a barrier around the working surface perimeter.

Artificial islands - Ice islands

Grounded ice islands have been used successfully for exploration drilling structures in nearshore areas (shallow water) of the U.S. and Canadian Beaufort Sea.
The water depth is a fundamental factor that must be considered when assessing the feasibility of the grounded ice island structures. The technical requirements for the structure generally increase as the water depth increases associated with an increase of construction costs and construction time.
An ice island must be thoroughly founded on the seabed to resist ice loads, which may act through the surrounding ice sheet. This requirement is important because a significant movement of the island during the drilling process can lead to damage to the drill rods.

Ice loads acting on an ice island depend on the ice failure mode, rather than on the driving force of the ice sheet. Ice crushing failure of the surrounding ice sheet limits the upper bound of these loads.
Assuming that the shear capacity of soil beneath the island is less then than the shear capacity of the ice island core, global ice island resistance will be governed by its sliding resistance (lateral stability).
In practice ice islands have been used in water depths of up to about 7.5 m in the Beaufort Sea. Based on a study of C-Core (2005) ice islands could be built up to a water depth of up to 12 m. When planning ice islands, however, the ice dynamics of the surrounding ice cover and the duration of the winter season has to be considered in any case, which often do not allow the construction of ice islands.

Gravity Base Structures (GBS)

Exploration drilling for oil and gas in the Beaufort Sea started from gravel islands in shallow Alaskan State waters in the late 1960's and similarly in the Canadian Beaufort Sea in the early 1970's. With time the activities were focusing on deeper waters.
In 1976, ice reinforced drill ships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system.
Although referred to as "mobile" structures, the caisson structures were not really mobile offshore drilling units (MODU's).
The Single Steel Drilling Caisson (SSDC) was the first MODU-type structure in the Beaufort Sea, coming into service in 1982 and, with the addition of the MAT in 1985, remains the only active bottom-founded exploration structure in the Arctic offshore.
What global size, structure cost and geometry concerns, there is only little difference between dedicated exploration platforms and dedicated production platforms. In fact, an arctic mobile drilling structure is often more expensive than a production platform, because it must cater to a range of water depths, rather than a known set-down depth like a production platform.
A mobile platform needs to be able to operate in a range of different foundation conditions. With production platforms, foundation characteristics are known and top weak layer(s) can be excavated. However this is often not practical in the case of short-term mobilization of an exploration structure.
In areas where substantial multi-year ice can encounter the structure, the ice impact loads become the primary design criteria. Where multi-year ice prevails wave loads are small and do not have a real effect on the design. However in southern areas where only first-year ice occurs (e.g. Bering Sea) the platform is primarily governed by wave loads, which has to be taken into account. In these regions it is required to install monolithic type structures, because ice loads are locally too high to allow the installation of jacket type structures. However the use of solid structures to mitigate local ice load effects, ice bridging and structure vibration results in relatively high wave loads.
Other parameters that have a significant effect on the global structure size optimisation are water depth and foundation conditions. As a matter of fact multi-year ice loads increase with increasing water depth. However deeper water means higher horizontal ice loads and a higher structure associated with higher costs. The foundation conditions can range from “totally inadequate” to “strong enough”.
If the foundation conditions are “totally inadequate” lateral relocation, dredging and /or replacement will be required. If the foundation is “strong enough” the structure can set-down directly on the seabed without any preparations.
In general the foundation requirements for an exploration structure are significantly less than those for production structures operating permanently with respect to the design ice loads, i.e. first-year ice vs. multi-year ice loads and ice ridges.

In multi-year ice areas, there are gravity base structures (GBS) solutions that are considered safe and economical up to around 75 m water depths when foundation properties are good, and up to around 60 m water depths when foundation properties are relatively weak.
There are no known bottom-founded platform design solutions for water depths greater than 100 m that could be considered as workable or proven for multi-year ice areas. In the more southern areas, where multi-year ice is not present and only first-year consolidated ridge loadings are possible, bottom-founded solutions out to 130 to 150 m water depths are potentially viable (*IMVPA, 2008*).

Jacket & Jack-up Structures

The jacket structure is the most commonly used fixed offshore platform. It was first used in the Gulf of Mexico and has since been adapted and modified for use around the world. There are a number of structure types from the single-legged to multi-legged structure.
The ice-strengthened jacket platform was first used successfully in sea ice in the mid-1960s for Cook Inlet, Alaska Development. Conventional jacket designs were modified to make them suitable for sea ice environments.
An important criterion for the design of a jacket structure is the payload that has to be carried by the structure, the capacity of the foundation and the external environmental loads (e.g. ice, wind, waves etc.) must resist the structure.
The loads on Arctic offshore structures are temperature loading, static sea ice loads and the accompanying loads due to ice-induced vibrations. In many cases, the static and vibration loads are the controlling factor (either globally or locally) in the sizing of the structure components. Temperature is generally the controlling factor in material selection.
The load acting on a structure by momentum, ice ridge building and pack ice loading relates to the width of the structure. If the jacket legs are within a certain distance of each other, ice bridging can occur between the legs and higher ice loads will be experienced by the structure compared to the case where the legs are loaded independently (e.g. larger leg to leg distance).
In addition to static sea ice loads, the jacket structure must be able to absorb the vibration. Ice-reinforced jacket structures are more prone to vibration than conventional jackets, because they have less damping capacity and tend to amplify vibrations.
In view of the jacket failure in the Gulf of Bohai and the malfunction of another jacket structure as a result of ice-induced vibrations, jacket platforms do not seem to be particularly practical.
Further development work regarding alternative damping techniques is necessary to reduce ice-induced vibrations on the jacket.
A variety of exploration and development options have been employed or considered for use in the Arctic and other cold regions. These options are summarized in the table below:

Summary of Arctic and Cold Regions Exploration and Development Options (IMVPA, 2008)

Region	US Beaufort Sea	Chukchi Sea	Bering Sea	Cook Inlet	Can. Beaufort Sea	Can. High North	Can. East Coast	Offshore West Greenland	Barents Sea	Kara Sea (Gulf of Ob)	Pechora Sea	Baltic Sea	Sakhalin Island
Bottom-Founded & Fixed Type Structures													
GBS	X	X	X		X		X			X	X		X
Mobile Bottom-Founded	X				X					X			
Barge			X		X								
Jacket/ Monopod			X	X			X						
Jack-up			X	X			X						X
Gravel Island	X				X								
CRI					X								X
Ice Island	X				X								
Floating Structures													
FPSO/FSO			X				X	X					
SPAR							X		X				
TLP							X		X				X
Semi			X	X			X	X					X
Drillship	X	X		X	X		X	X					
Floating Ice Pad						X							
Export and Infrastructure													
Offloading Buoy/ Terminal			X				X				X		X
Export Terminal		X	X			X	X		X		X	X	X
Pipeline	X	X	X		X	X	X		X			X	X
Subsea/ Flowlines	X	X	X		X	X	X	X	X				X

Floating Structures

There are only a limited number of floating exploration or production structures that have been used in ice environments.

During exploration in the Canadian Arctic in the 1980's, floating vessels (drill ships) were used successfully with the support of icebreaking ships for ice management, e.g., CANMAR "Explorer III" drill ship and CANMAR "Kigoriak" icebreaker. In particular, the conical drilling barge "Kulluk", purpose built by Gulf Canada, operated successful in the Canadian Beaufort Sea. This vessel could operate through the open water season until early December (at the latest) with intensive ice management support.

On the Grand Banks of Newfoundland, FPSOs (Floating Production, Storage and Offloading) have been the choice of floating production vessels under potential first-year sea ice and iceberg conditions.

The hulls of both of the existing Grand Banks FPSOs "Terra Nova" and "White Rose" are designed to operate in light to moderate first-year pack ice and can also maintain their moorings in heavy first-year pack conditions (*IMVPA, 2008*).

The ice conditions in Grand Banks are different from those in the Alaska Outer Continental Shelf, because no significant pressure ice ridges are embedded in the ice cover.

Additionally, the hulls of the FPSO's are designed to withstand the energy from a strike by a 100000 tonnes mass iceberg moving at 1 knot. This is an impact event and not a sustained load as might be found in the Beaufort or Chukchi Seas.

Modified SPAR, TLP (Tension Leg Platform) and semi-submersible designs have also been proposed for ice environments. Floating structures have been and will continue to be used for seasonal exploration. A Semi-rigid floater type structure could be considered for year-round exploration, if disconnects is permissible under extreme loading events.
Recently FEED-studies have been carried out and ice model testing in various ice tanks were executed to validate the feasibility of newly developed designs for future operations in high latitudes in the Arctic.
Floating production platforms proposed for ice/iceberg areas are typically designed to be readily disconnected from their moorings and operated in managed ice conditions. The ability of these floating platforms to leave station would allow the vessel to avoid extreme ice loads and also provide the capability for operations on a seasonal basis. The amount of time that it might take any particular floating vessel to reconnect back on station will be a significant consideration in concept selection for any production site (*IMVPA, 2008*).

Export / Loading Terminals

A marine export terminal is defined as a complex of structures and equipment for loading of hydrocarbon products, either pumped to a tanker from a storage facility located onshore or directly from a processing facility.
In most cases, marine transportation of hydrocarbon products starts with large storage facilities located onshore. The land-based components of these facilities (tank farms, loading pump stations, treatment plants, etc.) in the Arctic are basically the same as those in moderate climates (*IMVPA, 2008*).
The main difference is primarily in providing the conditions and the process equipment to allow continuous operation under harsh environmental conditions (e.g. low temperatures, icing and snowfall conditions).
Flow assurance is a critical consideration for arctic and sub-arctic locations. Consequently, to ensure smooth operations, an important aspect of any terminal concept is the need for proper insulation and heat-tracing technology on piping and pipelines.
Alternatively, hydrocarbons may be loaded on tankers at sea or in the vicinity of production platforms, either from the platform storage tanks or from a FSO (Floating Storage and Offloading) vessel. The FSO may also be used in the near shore for temporary storage or trans-shipment loading.
Particularly challenging in the Arctic is the offloading of products to tankers. This operation would need to be conducted in floating ice if year-round operations are going to be carried out. In this case ice management has to be provided by assisting icebreakers or icebreaking supply vessels. Support is necessary because otherwise the ice loads on the FSO may be so large that a safe off-loading operation cannot be guaranteed.
The technical feasibility of export/loading terminals for oil and gas in arctic areas has been documented in a wide range of port facilities:

- Nome (Alaska, Beaufort Sea)
- Cook Inlet (Alaska)
- Anchorage and Valdez (Alaska)
- Godthab and De Long (Greenland)
- Nanisivik (North Baffin Island, Canada)
- St. David de Levis and Caps Noirs (Quebec, Canada)
- Norwegian and Russian ports in the Barents Sea (Murmansk, Arkhangelsk)
- Magadan and Petropavlovsk (Okhotsk Sea, Russia)

The most recent examples are the large oil terminal in DeKastri and the LNG terminal in Prigorodnoye (Sea of Japan), Russia., LNG terminal Aniva Bay (Sakhalin, Russia), oil loading terminal Varanday (Russia), oil loading terminal Primorsk (Russia).
The main challenge of the above mentioned ports and terminals is that these marine structures are to be managed, operated and maintained under adverse conditions (remote area, undeveloped infrastructure, harsh environment and severe ice conditions).
In particular for fixed offshore and floating terminals there is a high risk that these marine structures experiences high lateral ice loads. Floating ice does not only affect the marine structure but also often complicates vessel operations. Additional uplift forces and compression loads on structures may be generated by tidal change due to adfreeze to the structure.
The loads generated through ice/structure interaction, in most cases, govern the design of arctic ports and terminal structures.
A general review of experience in operation of high-latitude oil and gas marine terminals indicates that existing technology of port structures design and construction is sufficient to support operations in the Alaskan Outer Continental Shelf.
While technically feasible, no tanker traffic has been proposed in the Environmental Impact Statement (EIS) for upcoming Beaufort or Chukchi lease sales. Regulatory requirements would require the use of pipelines (if economically feasible) rather than barging or tankering production to shore. An exception may be gas export by LNG or CNG (*IMVPA, 2008*).

Conclusion

Worldwide, there are currently around 790 offshore drilling rigs (jack-ups, semisubmersibles, drillships and barges), and 8,000 fixed or floating platforms. Of these, 116 rigs and more than 1,000 fixed or floating platforms are in European waters (*Sandrea and Sandrea, 2007*). Many offshore installations are likely to be constructed in the near future as explorations in nearly all sea areas. Some of the projects under development concern deepwater exploration activities, particularly in the Northern North Sea, the Black Sea and the Mediterranean Sea. The shelf of the Barents Sea off northern Norway and Russia is also subject to intensive exploration. A substantial increase in offshore activities related to offshore oil and gas exploration is expected in this area in the coming years.
Fixed offshore structures are a family of technological solutions which are well established and proven since tenth of years. A number of realized examples for fixed structures show a variety of technological solutions for very shallow water, shallow water and water depths up to 300 m. Suitable production facilities are installed on artificial islands and concrete or steel made Gravity Base Structures (GBS).The most concepts include Offshore Loading Systems (OLS) or loading facilities on moles or jetties and have to be designed for harsh open water conditions (waves) but also to withstand loads from drifting ice.
As fixed structures have technically drawbacks when the water depth increases and in the case when sea ice occurs, alternative techniques and structure types have beeing developed.
Differences can be found in the individual product export means, such as pipelines or shuttle tankers. The produced volume of oil or gas, the water depths or the distance to shore or the related receiving plant as well as the chosen strategy to reach the next market access point together with the expected field life are influencing the decision for the most favorable offshore structure type solution. For this reason, there is no preferred type of structure that can be used anywhere.
The first family of alternatives belongs to floating surface offshore structures which can be developed, built and tested at invulnerably locations or comparably cheap construction sites before moving to the offshore site and which can be removed with low effort to other places when the field life has reached its end.

New technology developments are required regarding shipping operations, primarily by providing the highest level of safety of tanker operations in ice-infested waters and by maximizing the efficiency of ice management systems.

It is suggested that FPSOs operating in ice covered regions should adapt features of icebreaker designs, such as icebreaking bow, reamers or inclined sidewalls in the waterline to resist ice loads, and azipod drives to be able to manoeuvre efficiently in harsh ice conditions.

Active ice management, a tactical procedure to break the ice around the platform or moored FPSO by icebreakers or icebreaking supply vessels is strongly recommended to enable align FPSO with prevailing ice drift direction by weathervane due to turret and swivel systems. The subsurface buoy is designed to fit into a specially configured compartment in the hull of the FPSO, housing the swivel and bearing around which the FPSO can rotate.

Winterization aspects have to be considered because the FPSO superstructure is also sensitive to atmospheric and sea spray icing and requires necessary measures with respect to winterization of the facilities (*Evers and Richter, 2014*). Significant advantages of moored ship shaped FPSOs are single point disconnection using turret and the ability to self-manoeuvre after disconnection from the mooring lines. The type of an appropriate mooring system varies with water depth and expected response forces respectively mooring line loads due to ice.

The most modern strategy of hydrocarbon production belongs to the subsea production facilities. These facilities are installed completely at the seafloor by means of heavy duty construction vessels. The facilities are permanently connected via export pipelines to a related onshore receiving plant Remote control takes place via multipurpose umbilicals with high bandwidth from the onshore plant and even from all over the world via the Internet. Although fully submerged from time to time these facilities need work over drilling; service requires free access of remotely operated vehicles (ROV) or autonomous underwater vehicles (AUV).

The experience of the past few decades with the installation, operation of offshore exploration and production structures, as well as transportation systems in the Arctic are a solid basis for future developments of innovative technologies, that enable year-round drilling and production with a high level of reliability.

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1 Introduction

Energy security is a term that has recently entered our common vocabulary. Given the political instability of some energy producing countries and the diminishing reserves of oil and gas, energy security is fast becoming one of the leading issues in the world today. It goes without saying that a nation's energy policy is inextricably linked to its access to natural resources, but most accessible reserves are presently being exploited. Dwindling oil and gas reserves means new opportunities are needed if we are to meet the increasing demand for energy within Europe and worldwide (*www.access-eu.org)*.

Recent estimates suggest that 13% of the world's undiscovered oil and 30% of its undiscovered natural gas can be found in the Arctic, almost all of which lie in the offshore marine environment.

The combination of the melting of the Arctic sea ice and the economic and political attractiveness of non-renewable resources, especially sub-sea hydrocarbons, are giving rise to a new Arctic.

Currently strong effects of climate change are taking place in the Arctic. This evolution is quite predictable at short (year) and longer scales (several decades), but it is the decadal intermediate scale that is the most difficult to predict. This is because the natural variability of the system is large and dominant at this scale, and the system is highly non-linear due to positive and negative feedback between sea ice, the ocean and atmosphere.

Already today, due to the increase of the greenhouse gas concentration (GHG) in the atmosphere and the amplification of global warming in the Arctic, the impacts of climate change in the region are apparent, e.g. in the reduction in sea ice, in changes in weather patterns and cyclones or in the melting of glaciers and permafrost. It is therefore not surprising that models clearly predict that Artic sea ice will disappear in summer within 20 or 30 years, resulting in new opportunities and risks associated with the activities in the Arctic.

This climatic evolution is going to have strong impacts on both marine ecosystems and human activities in the Arctic.

This in turn has large socio-economic implications for Europe. ACCESS will evaluate climatic impacts in the Arctic on marine transportation (including tourism), fisheries, marine mammals and the extraction of hydrocarbons for the next 20 years; with particular attention to environmental sensitivities and sustainability.

In this study, different types of fixed and floating structures for the exploration, production and transportation of oil and gas in Arctic regions are described and assessed.

2 Objectives

The main objective of ACCESS work package 4.2 is the description and assessment of existing technologies for a safe extraction of energy resources under Arctic conditions with minimal impact on the Arctic environment. The assessment includes fixed and floating structures (Task 4.2.1) as well as subsea production systems (Task 4.2.2). In addition, the identification of technological gaps that hinder Arctic development as well as technology providing pathways for future developments including the removal and disassembling of offshore facilities as well as problems related to winterisation (Task 4.2.3) are discussed.

Specific objectives of this study (Task 4.2.1) are:

- Description and assessment of existing technologies, e.g. fixed and floating offshore structures regarding to their ability to safely extract energy resources and their impact on the environment. Main objective of this report is to describe technical issues of fixed and floating (offshore) oil and gas facilities suitable for the current use and future use considering the environmental scenarios for the Arctic. These scenarios derive from scientific assumptions made by partners within the ACCESS project analysing the future development of key environmental data for the Arctic.

- Aim of the report is to show information about the most important technological characteristics to perform the exploration and production of oil and gas with fixed and floating structures under given environmental conditions in the Arctic (*http://www.access-eu.org*).

3 History of Oil and Natural Gas Extraction in the Arctic

3.1 General

Commercial extraction of oil in the Arctic began in the 1920s in Canada's Northwest Territories. In the late 1960's exploration drilling for oil and gas in the Beaufort Sea began from gravel islands in shallow Alaskan State Waters and similarly in the Canadian Beaufort Sea in the early 1970's. With time, activities progressed into deeper waters. In 1976, ice reinforced drill ships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system. Exploration activities in Beaufort OCS[1] regions have started in 1982 using gravel islands, ice islands, bottom-founded structures and drill ships (*IMVPA, 2008*).

During the 1960s, extensive hydrocarbon fields were also discovered in Russia's Yamalo-Nenets region, the North Slope of the Brooks Range in Alaska, and Canada's Mackenzie Delta. During the last several decades, the Arctic territories of Russia, Alaska, Norway, and Canada have produced billions of cubic meters of oil and gas.

About 60 of these fields are very extensive, but roughly one quarter of them are not yet in production. More than two-thirds of the producing fields are located in Russia, primarily in

[1] OCS: Outer Continental Shelf

western Siberia, where oil and gas development has expanded dramatically over the past several decades. In total, Arctic oil and gas output currently amounts to approximately 240 billion barrels of oil and oil-equivalent natural gas - nearly 10 percent of the world's known conventional petroleum resources" (*http://arctic.ru*).

Budzig (2009) reported that approximately 61 large oil and natural gas fields have been discovered within the Arctic Circle in Russia, Alaska, Canada's Northwest Territories, and Norway. Fifteen of these 61 large Arctic fields have not yet gone into production; 11 are in Canada's Northwest Territories, 2 in Russia, and 2 in Arctic Alaska. Forty-three of the 61 large Arctic fields are located in Russia.

Thirty-five of these large Russian fields (33 natural gas and 2 oil) are located in the West Siberian Basin. Of the eight remaining large Russian fields, five are in the Timan-Pechora Basin, two are in the South Barents Basin, and one is in the Ludlov Saddle.

Of the 18 large Arctic fields outside Russia, 6 are in Alaska, 11 are in Canada's Northwest Territories, and 1 is in Norway (*Budzik, 2009*).

3.2 Future potential

The rising world demand for hydrocarbon resources and increasing activities for exploration and navigation, due to the fact that polar sea ice retreats, leads to an increase in exploration activities for oil and gas in the Arctic.

The Arctic Council's Monitoring and Assessment Program in 2007 reported that oil and gas activity is expected to either begin or undergo expansion in several areas: offshore Alaska, Canada's Mackenzie Delta, the Barents Sea (Norway and Russia), and many areas of onshore and offshore Russia. (*http://arctic.ru*)

While most offshore areas have not been surveyed for resources, the extensive continental shelves in the region are believed to hold huge reserves of oil and gas. In 2008 the U.S. Geological Survey (USGS) completed the most comprehensive assessment of potential hydrocarbon reserves, using computer modeling to evaluate 25 Arctic geological provinces.

The USGS estimates that the "undiscovered, technically recoverable" stores of petroleum include 90 billion barrels of oil, 1670 trillion cubic feet of natural gas, and 44 billion barrels of natural-gas liquids. These figures suggest the Arctic may hold about 22 percent of the undiscovered conventional hydrocarbon reserves untapped worldwide. (*http://arctic.ru*)

Roughly 85 percent of these potential reserves are thought to occur offshore at depths of 450 meters or less. The majority of untapped natural gas probably lies within Russian territory, while most of the oil is located offshore of Alaska (*http://ww.arctic.ru/climate-change*).

Since most of the Arctic has yet to be physically explored, many experts are sceptical of the recent projections on potential oil and gas reserves. Also, the USGS estimates that nearly 80 percent of the total reserves are comprised of natural gas and natural gas liquids. Developing these resources would involve much steeper costs than for oil, because the transport of natural gas to distant markets requires specialized tankers and storage facilities.

Anatoly Zolotukhin, a Russian expert on oil and gas development, has noted other challenges in exploiting offshore hydrocarbon fields in the Arctic. These include severe climate conditions and the presence of ice, the lack of technology and experience in offshore development, a shortage of qualified personnel, and an incomplete understanding of the environmental risks. Furthermore, he points out, the remote locations of the resources would mean prolonged response times in dealing with emergencies such as oil spills and shipping accidents (*http://arctic.ru*).

4 Areas of Interest

4.1 Selected areas

The Arctic holds an estimated 13% (90 billion barrels) of the world's undiscovered conventional oil resources and 30% of its undiscovered conventional natural gas resources, according to an assessment conducted by the U.S. Geological Survey (USGS). It is estimated that oil and natural gas resources is located in seven Arctic basin provinces: Amerasia Basin, Arctic Alaska Basin, East Barents Basin, East Greenland Basin, West Greenland East Canada Basin, East Greenland Rift Basin, West Siberian Basin and the Yenisey-Khatang Basin as shown in *Figure 1*.

Oil and gas development is still restricted to certain parts of the Arctic, and in that sense oil and gas remains a sub-regional issue of concern. However, the increasing interest in Arctic oil and gas resources, exploration in new Arctic areas; plans for new pipeline routes, the potential use for shipping oil and gas, and the potential impacts of oil and gas related pollution on vulnerable Arctic ecosystems all mean that a circumpolar perspective to Arctic oil and gas development is emerging. (*AMAP, 2010*). It is expected to either begin or undergo expansion in areas like: offshore Alaska, Canada's Mackenzie Delta, the Barents Sea (Norway and Russia), and many areas of onshore and offshore Russia.

Figure 1 Arctic Oil and Natural Gas Provinces Map (Source: U.S. Geological Survey)

Selected analogue areas are presented in *Table 1.* The table highlights some of the most significant activities undertaken, or considered, in each analogue area, along with the associated structure types and technologies. Subject areas of the Alaska OCS are included for completeness and have been reviewed in the same manner as the analogue areas. Furthermore, structures and/or technology used in one particular area of the OCS may be considered for application in another area of the OCS (*IMVPA, 2008*).

Table 1 Selected analogue areas (source IMVPA, 2008)

Region	Previous Exploration Program, Study, Project	Structures / Facilities
US Beaufort Sea	Northstar	Gravel Island / Pipeline
	Liberty	Gravel Island / Pipeline
	Oooguruk	Gravel Island / Pipeline
	Nikaitchuq	Gravel Island / Pipeline
Chukchi Sea	Chukchi Sea Feasibility Studies	Fixed Structures / Pipelines / Tankers
Bering Sea	Conceptual Studies	Floater, Fixed Structures, Pipeline
Cook Inlet (Alaska)	Various	Fixed Structures
Canadian Beaufort	Tarsiut/Kopanoar/Issungnak	Gravel Island / Pipeline
	Amauligak	Caisson Retained Island / Pipeline
	West Amauligak	Subsea / Pipeline
Canadian High North	Drake PanArctic	Pipeline and wellhead
	Polar Gas	Subsea manifolds / pipelines
Davis Strait/West Greenland	Conceptual Studies	Floater, Subsea & Flowlines
Canadian East Coast	Hibernia	Concrete GBS / Storage
	Terra Nova	Floater, Flowlines & Subsea
	White Rose	Floater, Flowlines & Subsea
	BP Amoco West Bonne Bay	Steel GBS / Storage
Eastern Russia	Sakhalin 1	CIDS / Pipeline
	Sakhalin 2	Molikpaq / Lunskoye / Piltun-Astokhskoye-B / Pipeline
	Sakhalin 4	Bottom-Founded, Pipeline
	Sakhalin 5	Bottom-Founded, Pipeline
Barents Sea	Shtokman	Floater, Subsea & Flowlines
Pechora Sea	Prirazlomnoye	Fixed Structure, Tankers
Karas Sea (Gulf of Ob)	Conceptual Studies	Fixed Structure, Pipelines
Baltic Seas	Kravtsovskoye	Jacket, Pipeline

Cook Inlet

Cook Inlet is a 290 km long estuary stretching southwest from Anchorage to the Gulf of Alaska. Oil was first discovered in Cook Inlet in 1963 and development commenced shortly thereafter.

Infrastructure used to develop Cook Inlet's offshore oil resources consist of fixed jacket offshore platforms connected to land based storage and distribution facilities via subsea pipelines. These structures are subject to first-year ice conditions ranging from 0.5 to 2.0 m thickness.

Canadian High North

A limited number of projects were proposed for the Canadian High North including the Drake PanArctic gas project and the Polar Gas project. A Canadian company, PanArctic Oil Ltd., sponsored the Drake Field subsea completion, which was located in the Canadian High Arctic off of Melville Island. The world's first arctic subsea flow line began transporting gas in April 1978, from a subsea wellhead to production facilities onshore (*Palmer et al., 1979*). The three-year program to design, fabricate and construct was part of a test program to evaluate the performance of the field development concept and demonstrate the feasibility of such an offshore arctic development.

Polar Gas was a consortium of American and Canadian companies formed in 1972 that investigated the possibility of bringing natural gas southward by pipeline from the Canadian Arctic Islands (*Houlding, 1976*). Considerable design work and a research program was undertaken to look at the feasibility of laying pipelines in extreme low temperatures in the Canadian Arctic.

Canadian East Coast

The East Coast of Canada currently has several producing oil and gas fields. These fields are located off the coast of Newfoundland and Nova Scotia. Furthermore, significant exploration activity has been undertaken in these areas and on the Labrador Shelf.

The fields located offshore Newfoundland a the Grand Banks developments: Hibernia, Terra Nova, and White Rose. These developments use structures that are designed to withstand sea ice and iceberg loads.

Although the Labrador Shelf does not have a production project to date, significant exploration has been carried out on the shelf and consideration has once again been given to potential gas production from the area. In terms of sea ice and icebergs, the Labrador shelf is subject to a much harsher environment than the Grand Banks.

The Sable Energy Project, which lays offshore Nova Scotia (near Sable Island), experiences very little sea ice, and the occurrence of icebergs is rarely. The likelihood of sea ice from the Gulf of St. Lawrence encroaching on the Sable development is very low; less than 1 percent based on 30 years of observations (*CEAA, 2005*). Furthermore, only one iceberg has been reported in the Sable development area in the last 60 years, and the probability of future iceberg occurrences is low (*ExxonMobil, 2007*).

Offshore Greenland

Offshore petroleum exploration has taken place off the east, north, and west coasts of Greenland; however, drilling has only been conducted offshore west Greenland. Initial exploration offshore west Greenland took place between the early to mid 1970's with extensive seismic surveys. Following this period, five wells were drilled between 1976 and 1977; however, interest in further exploration was curtailed when well results had indicated that the wells were dry (*Geological Survey of Denmark and Greenland, 2005*).

Throughout the 1990's, interest in offshore west Greenland began to grow and in 1997 additional processing of well data suggested that the Kangamiut-1 (drilled in 1976) showed hydrocarbons (*Geological Survey of Denmark and Greenland, 2005*). In 2000, the sixth exploration well (Qulleq-1) was drilled. No further exploration drilling has taken place; however, offshore exploration licenses were awarded for licensing rounds held in 2002, 2004, and 2006.

In general, a significant portion of the west coast of Greenland experiences sea ice each year during the winter and early spring and, depending on location, icebergs can be encountered frequently (*Mosbech et al., 2007*).

Eastern Russia (Sakhalin Island)

Sakhalin Island is a large elongated island in the North Pacific, north of Japan, which is part of Russia. Projects currently producing oil offshore Sakhalin Island include Sakhalin 1 (ExxonMobil) and Sakhalin 2 (Shell) directly off the east coast of Sakhalin. These projects have been developed using retrofitted gravity base platforms from the US Beaufort Sea (CIDS) and the Canadian Beaufort Sea (Molikpaq). Future proposed projects include Sakhalin 5, which will be off of the northeast coast of the island.

The east coast of Sakhalin Island is an area characterized by storm winds, fog, freezing temperatures in winter, intense snowstorms, sea ice and pressure ridges, and ice gouging. *Table 2* presents information on some of the Sakhalin Island projects currently being considered.

Table 2 Sakhalin Fact Sheet (source EIA, 2007)

April 2007

Sakhalin Fact Sheet

Sakhalin Island, a former penal colony located off Russia's eastern shore (see map), is home to six oil and gas projects. The five projects are currently in different stages of development, and two of the projects, Sakhalin I and Sakhalin II, aim to bring oil and natural gas production online in the near term. Both projects have targeted Asian markets. Three blocks after Sakhalin VI have not been awarded yet.

Name	Sakhalin I	Sakhalin II	Sakhalin III	Sakhalin IV	Sakhalin V	Sakhalin VI
Primary Field/Block Names	Odoptu [Northern and Southern] (onshore), Chayvo (onshore and offshore), Arkutun-Dagi	Sakhalin Energy Investment Company: Piltun-Astokskoye, Lunskoye (will provide most of the LNG, 34 kb/d of oil)	Kirinskii, Veninskaya, Vostochno-Odoptu, Alyashkii	Pogranichny Block, Okruzhnoye fld	Kaigansko-Vasyukansk (active drilling)	Pogranichny
Oil Reserve Estimate	975 million bbl, (Source: IHS Energy)	1.0-1.2 billion bbl (Source: Shell)	Total: 4-5 billion bbl Veninsky Block: 830 million bbl (Source: IHS)	880 million bbl	4.4-5.7 billion bbl	600 million bbl
Natural Gas Reserve Estimate	11 Tcf, (Source: IHS Energy)	17.3 Tcf (Source: Shell)	Total: 27-38 Tcf Veninsky Block: 11 Tcf (Source: IHS)	19 Tcf	15.2-17.7 Tcf	n/a
Net Total Investment	Phase 1: $5 billion	Phase 1: $4.5 billion, Phase 2: $20 billion over next 4-5 yrs.	$13.5 billion expected (ExxonMobil- $80m in geological studies)	$2.6 billion expected	$3-5 billion expected	n/a
Current & Expected Prod'n Level	Max oil production from Chayvo field achieved in Feb. 2007 at 250 kb/d. Commercial gas prod'n expected in 2008	Current: 80,000 bbl/d for 6 months, Phase II: 180,000 bbl/d, year-round oil production expected in Dec. 2007, LNG prod'n expected in Summer 2008	n/a	n/a	n/a	n/a
Primary Project Developers	Exxon Neftegaz (30%), in conjunction with consortium members SODECO (30%), ONGC Videsh (20%), Rosneft (8.5%), Sakhalinmorneftegaz (11.5%), and RN Astra (8.5%)	Gazprom (50%+), Sakhalin Energy Investment Company: Shell (27.5%), Mitsui (25%), Mitsubishi (20%)	Rosneft is primary developer. Veninsky Block: Rosneft (49,8%), Chinese Sinopec (25.1%) and Sakhalinskaya Neftyanaya Kompaniya (25.1%)	BP (49%), Rosneft (51%)	Elvary Neftegaz: BP (49%), Rosneft (51%)	Petrosakh, Alfa Eco
Status/Notes	Mode of gas export still up for negotiation. Exxon prefers pipeline exports to China (cheaper). Other shareholders, Gazprom prefer piping to LNG terminal at Sakhalin II.	Oil production began in 1999; Processing terminal under construction which will have capacity of 66,000 bbl/d of oil, 1.8 bcf/d of gas	Lukoil possibly in cooperation with Gazprom will probably take part in new tenders for Kirinskii and Vostochno blocks.	Rosneft undertaking 3D seismic, to be complete by Oct. 2006.	Rosneft undertaking 3D seismic.BP/Rosneft drilled 3 successful wells during 2006.	3 blocks in Sakhalin VI have not been awarded

Source: Project Homepages (see links section), IHS Energy, Interfax, Russian Energy Monthly (www.easternblocenergy.com), FSU Oil and Gas Monitor, Pipeline & Gas Journal

Russian Arctic (Barents Sea, Kara Sea, Pechora Sea, and Baltic Sea)

A significant part of the world's oil and gas reserves are believed to be in the Russian sector of the Arctic Ocean Shelf. Many of the prospective fields were discovered east of the Ural Mountains, along the Siberian coast (Ob and Taz Bays, Yamal Offshore); however, nowadays more activity has been progressing along the European coast (Barents Sea, Pechora Sea and Kara Sea).

In this context, reference is made to the development of the giant Shtokman gas and gas condensate field in the Barents Sea.

Shtokman field is located approximately 600 km offshore, in 300 to 350 m waterdepth, with ice conditions that include second-year ridges and icebergs.

Technology developments in the Russian Arctic are driven by the same challenges that exist in the American and Canadian Arctic; the hydrocarbons are to be extracted from shelf reserves, which are located in areas of adverse environmental conditions, and they are to be safely delivered to markets in lower latitudes. If there is any difference, it probably manifests in conditions for transportation, and in the available infrastructure which, in the Russian case, is more challenging.

The routes from the main Russian Arctic fields to European and American consumers are fairly long and are through remote areas both in the sea and onshore.

A map showing the location of the main fields of the Russian Arctic is presented in Figure 2. As shown, large offshore and oil and gas reserves are located east of Novaya Zemlya archipelago, in the Kara Sea and near the Yamal Peninsula coast. While a number of future offshore exploration projects are planned for this area, information on work carried out to date is limited (*IMVPA, 2008*)

A number of pipelines have been considered for the Russian Arctic, including pipelines across the Baltic Sea, Baydaratskaya Bay, the Pechora region, and the Barents Sea. Most activity currently being planned for the Barents Sea seems to be for the western part, which is essentially ice free.

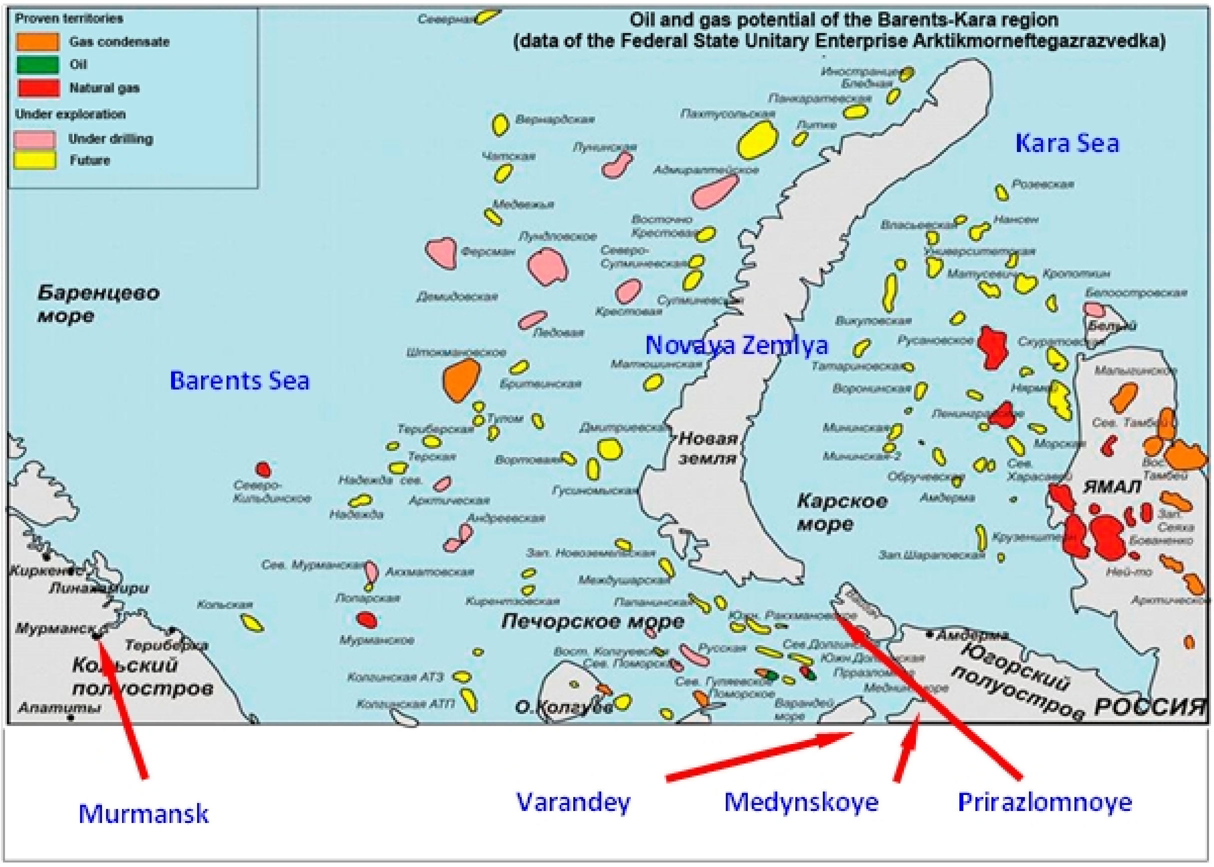


Figure 2 Oil and gas potential of the Barents-Kara region (data of the Federal State Unitary Enterprise Arktikmorneftegazrazvedka), [Source: http://russiancouncil.ru]

5 Structure Types

General

This chapter discusses various types of arctic offshore structures (e.g. artificial islands, fixed, floating and moored structures) that are described and evaluated for their possible applications in Arctic conditions.

5.1 Fixed offshore structures

General

The following paragraphs describe the production technologies generally suitable for use in the Arctic sea with ice coverage, drifting ice and open sea conditions, especially near shore (distance to shore up to 50 km) and in water depths up to ~50 m.

Other technical solutions have been realized in the north part of the North Sea, which is characterized by temporarily very harsh open water conditions. Structures like the GBS belonging to the Sleipner developments are located in up to 300 m waterdepth (refer to *Sleipner GBS Offshore Platform*). They are considered to be the heaviest structures ever built and moved by humans. As these structures are on the other hand very expensive when designed and built for Arctic conditions it seems very unlikely that structures like this will be considered. Thus, they will be only briefly described in this report.

Production of hydrocarbons in very shallow waters is often realized by means of production facilities installed on artificial islands (e.g. gravel drill site pads) or with monohull or multihull GBS. The relevant installation sites are most likely located near shore so that the well stream can be exported via pipeline to a receiving and treatment plant onshore. After treatment undesired fractions of the well stream (e.g. water) are pumped back to the production facility where they are re-injected into the reservoir in order to maintain the pressure or re-injected into the well stream in order to assure a suitable flow regime. In some more modern production scenarios separated (sequestrated) fractions like CO_2 are re-injected into the reservoir in order to reduce greenhouse gas emissions CCS[2] technology, e.g. Sleipner developments, Norway (refer to *Sleipner GBS Offshore Platform*).

In many cases transfer of the complete well stream to a shore plant allows minimizing the functionality and complexity of the offshore installed production facility reducing its CAPEX[3] and OPEX[4]. On the other hand the required related onshore plant must be outlined to handle the amount and characteristics of the produced well stream throughout lifetime of production. Costs and effort can be high in case this plant is located in a remote location, like it is the case in the Arctic; far away from existing infrastructure like the next access point to a local pipeline network, to skilled personnel and to production related consumables, or equipment and spare parts. One example: To move materials and supplies, some of today's strategies employ temporary ice roads connecting near shore facilities with supply bases during the Arctic winter.

Technical solutions relevant for application in the Arctic comprise product export via pipeline, which is most relevant for significant production volumes and when a related onshore treatment plant is available, and otherwise export via shuttle tanker. The latter is combined with case dependent processing of the well stream and subsequent storage in tanks at the

[2] CCS = Carbon Capture and Sorage
[3] CAPEX = Capital Expenditure
[4] OPEX = Operational Expenditure

production platform, e.g. in form of compressed natural gas (CNG), liquefied gas (LNG, LPG[5]), condensate or oil (e.g. as result of a GTL process[6]). These concepts have to make sure that a permanent, year round, ice free access of the shuttle tankers to the loading facilities (e.g. jetties, moles) is guaranteed.

In the following paragraphs exemplarily existing production facilities have been compiled to give an idea of how suitable facilities today look like, how they are outlined in terms of productivity and resulting costs. Note that these examples are not complete but illustrate the variation of technology used in the challenging Arctic environment.

More details about available technology modules which can be used under different environmental scenarios to extract oil and gas from the (offshore) Arctic can be found in (*IMPaC, 2014a*)

5.1.1 Bottom-founded structures

General

In multi-year ice areas of the Alaskan Outer Continental Shelf (OCS[7]), there are bottom-founded, e.g., gravity base structures (GBS), solutions that would be considered safe and economical up to around 75 m water depths when foundation properties are reasonable, and up to around 60 m water depths when the foundation properties are relatively weak.

There are no known bottom-founded platform design solutions for water depths greater than 100 m that could be deemed workable or proven for multi-year ice areas.

In the more southern areas, where multi year ice is not present and only first-year consolidated ice ridge loads are possible, bottom-founded solutions out to 150 m water depths are potentially viable (*IMVPA, 2008*).

Exploration drilling for oil and gas in the Beaufort Sea began from gravel islands in shallow Alaskan State Waters in the late 1960’s and similarly in the Canadian Beaufort Sea in the early 1970’s. With time, activities progressed into deeper waters. In 1976, ice reinforced drill ships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system. Exploration activities commenced in Beaufort OCS regions in 1982 using gravel islands, ice islands, bottom-founded structures and drill ships (*IMVPA, 2008*).

In the early 1980s, five special-built caisson structures were designed and built in the Beaufort Sea to allow year-round drilling and development of regions further offshore in harsher ice conditions (*Timco and Johnston, 2002*).

The five different caisson structures used in Arctic regions are:

- Tarsiut Caisson (concrete caissons)
- Single-Steel Drilling Caisson (SSDC), steel structure
- Caisson-Retained Island (CRI), (steel caissons)
- Molikpaq (steel caisson)
- Glomar Beaufort Sea I (CIDS[8]), concrete and steel structure

[5] LPG = Liquified Petroleum Gas
[6] GTL : Gas-to-Liquids
[7] OCS= Outer Continental Shelf
[8] CIDS : Concrete Island Drilling System

These structures were conceived primarily to extend the depth capability of granular islands. Building an underwater berm and then backfilling the caisson systems with a core of dredged material formed the caisson-retained islands. Compared to conventional island building up to that time, the amount of fill required to achieve stability was significantly reduced. As well, the effects of wave and current erosion during the open water season were reduced. However, these structures still required significant field operations to construct the berms, deploy, backfill, densify the core (Molikpaq requirement), decommission and move.

The SSDC was the first MODU-type structure in the Beaufort Sea, coming into service in 1982 and with the addition of the MAT remains the only active bottom-founded exploration structure in the arctic offshore. The steel SSDC and the CIDS, a similar concrete-steel hybrid concept which is now deployed offshore Sakhalin Island, are ballasted with water.

Table 3 summarizes the chronological drilling history of these five structures in the Beaufort Sea.

Table 3 Deployments of bottom-founded structures in the Beaufort Sea (*source: IMVPA*)

Year	Drilling Unit	Location	Operator	Prospect	Water Depth (without berm), ft [m]	Notes
1981-82	Caisson-Retained Island	Canada	Gulf Canada	Tarsiut N-44	69 [21]	On berm
1982-83	SSDC	Canada	Dome/Texaco	Uviluk P-66	105 [32]	On berm
1983-84	SSDC	Canada	Gulf Canada	Kogyuk N-67	92 [28]	On berm
1983-84	CRI	Canada	Esso	Kadluk O-07	48 [14.5]	
1984	Molikpaq	Canada	Gulf Canada	Tarsiut P-45	74 [24.5]	On berm
1984-85	CRI	Canada	Esso	Amerk O-09	85 [26]	On berm
1985	CIDS	USA	Exxon	Antares	49 [15]	
1985	CIDS	USA	Exxon	Orion	50 [15]	
1985-86	Molikpaq	Canada	Gulf Canada	Amauligak I-65	105 [32]	On berm
1986	SSDC/MAT	USA	Tenneco	Phoenix	60 [18]	
1986-97	CRI	Canada	Esso/Home	Kaubvik I-43	59 [17.9]	
1987-88	SSDC/MAT	USA	Tenneco	Aurora	66 [20]	
1987-88	Molikpaq	Canada	Gulf Canada	Amauligak F-24	87 [26.5]	On berm
1989-90	Molikpaq	Canada	Esso/Gulf	Isserk I-15	38 [11.5]	
1990	SSDC/MAT	USA	Arco Alaska	Fireweed	50 [15]	
1991-92	SSDC/MAT	USA	Arco Alaska	Cabot	55 [17]	
1997	CIDS	USA	Arco Alaska	Warthog	35 [10.5]	
2002-03	SSDC/MAT (now *SDC)*	USA	EnCana	McCovey	35 [10.5]	
2005-06	SSDC/MAT (now *SDC)*	USA	Devon	Paktoa	43 [13]	

Table 4 provides some details on their characteristics, based on the paper by *Masterson et al. ,1991.*

Table 4 Details of fixed structures used in arctic drilling (*Timco & Johnston, 2002*)

	Tarsiut	SSDC	CRI	Molikpaq	CIDS
Drilling Days (per year)	365	365	365	365	365
Base Area (m^2) (including core)	7947	18590	10875	12383	8551
Oceanographic Limitations (wave height - m)	12	12.2	15	12.2	5.2
Limiting Level Ice Conditions (m)	5.6	10	3	10	2
Ice Concentrations	10/10s	10/10s	10/10s	10/10s	10/10s
Design Ice Load - Global (MN)	560	900	436	640	640
Design Local Ice Pressure (MPa)	4.1	8.3	2.8	3.0	6.2
Area for Local Pressure (m^2)	3.7	3.7	0.7	2.3	2.3
Wells Drilled	Tarsiut N-44 Tarsiut N-44A	Uviluk P-66 Kogyuk N-67 Phoenix #1 Aurora #1	Kadluk O-07 Amerk O-09 Kaubvik I-43	Tarsuit P-45 Amauligak I-65 Amauligak I-65A Amauligak I-65B Amauligak 2F-24 Amauligak 2F-24A Amauligak F-24 Amauligak 2F-24B Isserk I-15	Antares #1 Antares #2 Orion #1

SSDC & SSDC/MAT (now SDC[9])

The experience with the Tarsiut Caissons led the company CANMAR to develop a fully mobile, water ballasted concept for year-round drilling. The Single Steel Drilling Caisson (SSDC) was fabricated by modifying the forward half of a Very Large Crude Carrier (VLCC) and the name "Single-Steel Drilling Caisson" was adopted to differentiate it from the multiple concrete caissons used at Tarsiut.

In 1986, the SSDC was modified to prepare it for deployment in the US Beaufort Sea. It was mated with a steel MAT substructure to eliminate the need for foundation preparation (subsea berms) and functioned as a single unit called the SSDC/MAT. In recent years, with a change of ownership, the structure (including MAT) has been renamed the SDC. The structure is a MODU and all drilling and topsides facilities are permanently affixed to the deck, resulting in simpler and faster mobilization for drilling operations. Of the 19 deployments of bottom-founded structures in the US and Canadian Beaufort Sea, 8 were those of the SDC (*IMVPA, 2008*).

The Single-Steel Drilling Caisson (SSDC) was a converted very large crude carrier that underwent extensive modifications to enable its use as a support structure for year-round,

[9] SDC : Steel Drilling Caisson

exploratory drilling in the Beaufort Sea. The structure is 162 m long, 53 m wide at the stern (38 m at the bow), 25 m high and has vertical sides at the waterline (*Johnston and Timco, 2003*).

From 1982 to 1984, the SSDC was installed in the Canadian Beaufort Sea at the Uviluk and Kogyuk sites, where it was placed upon a submerged berm.

In August 1986, the SSDC was connected to a semi-submersible steel base (the “MAT”) in preparation for deployments in the American Beaufort Sea. The MAT allowed the SSDC to operate year-round in water depths of 7 to 24 m without requiring a dredged berm. The MAT was used at the four deployments in the American Beaufort Sea: Phoenix, Aurora, Fireweed and Cabot (*Johnston and Timco, 2003*).

Figure 3 shows a photograph from the SSDC at the Kogyuk site in the Beaufort Sea and *Figure 4* shows the SSDC at the Phoenix site. *Figure 5* is an Artist's cut-away illustration of the SSDC and the MAT.

Figure 3 SSDC at the Kogyuk site in the Beaufort Sea. Sprayed ice rubble is surrounding the structure (*Timco & Johnston, 2002*)

Figure 4 Photograph of the SSDC at the Phoenix site. Note the large rubble field surrounding the structure (*Timco and Johnston, 2002*)

Figure 5 Artist's cut-away illustration of the SSDC and the MAT (*Timco and Johnston, 2002*)

5.1.2 Artificial islands

General

Grounded ice islands have been used successfully as exploration drilling structures in near-shore areas of the US and Canadian Beaufort Sea. In practice, operational ice islands have been employed in water depths of up to 7.6 m in the Beaufort Sea.
Based on work sponsored by the MMS[10], the use of operational ice islands might be achieved in water depths of up to approximately 9 m. The MMS Ice Island Study 2005 suggests that "incremental improvements in equipment capacity with higher productivity would allow islands to be constructed into deeper water and it is considered that 12 m water depth should not present a problem".

The use of ice islands in the near-shore Chukchi Sea would likely be infeasible due to the unstable and unreliable land-fast ice zone. Ice islands would be generally infeasible for Norton Sound due to its warmer and shorter winter season. However, definite conclusions can only be reached when conducting more detailed studies (*IMVPA, 2008*).

Floating ice drill pads are generally not considered in the Beaufort Sea due to the prevailing ice movement.

The first grounded flooded ice island was built by Union Oil in Harrison Bay, Alaska in 1976/77. Grounded ice islands have generally been constructed in less than 9 m water depth. The use of sprinkling and spraying on experimental and relief well pads has allowed these methods to be developed with lower risk to project schedules. Spray ice was also used to form protection structures around grounded drilling structures such as the CIDS[11] platform offshore Alaska in the mid 1980s.

Grounded ice islands are constructed in a similar way like floating islands. In this caset artificial ice is built up on top of the natural ice sheet to increase its thickness until it becomes grounded on the seabed. However, since the water column is shallow, any movement of the island in relation to the seabed will damage the drill-string, and so the design requirement is to eliminate any differential movement. The island is therefore designed to withstand the horizontal force applied by the surrounding ice sheet by providing resistance through contact with the seabed. An additional requirement is to maintain the stability of the rig foundation, which will undergo creep settlement of the ice under loading.

As with floating platforms, start of construction is limited by the formation of stable ice and access to the drilling location. Generally, to date, platform design has been performed using the natural ice to support equipment and personnel during construction.

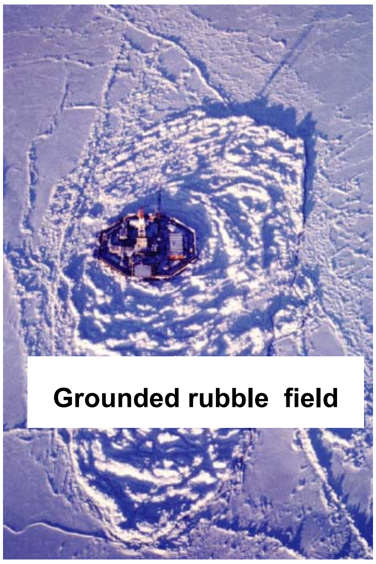
The first grounded ice island to be used for exploration drilling was constructed by Union Oil in Harrison Bay in 1977/78. It was grounded in 3 m water depth using flooding techniques by applying thin layers of seawater to the ice surface and allowing it to freeze in place. Generally, however, the relatively slow build-up rates achievable with flooded ice techniques limit the usefulness of these structures as grounded ice platforms. It is more suited to the construction of roads, which require less ice thickness.

Spray ice islands have been used to stabilize rubble fields and for potential use as relief drilling pads, such as at Tarsiut (*Neth et al., 1983*), Alerk (*Weaver and Poplin, 1997*), Kadluk (*Kemp et al., 1988*) and Isserk (*Poplin and Weaver, 1992*).

[10] MMS = Minerals Management Service
[11] CIDS: Concrete Island Drilling System

5.1.2.1 Caisson-Retained Island (CRI)

Similar to the Tarsiut Caissons, the Caisson-Retained Island or CRI was planned and built by Esso Resources Canada and first deployed in 1983 (*see Figure 6*). The island was built with steel instead of concrete, The CRI was developed to reduce the amount of dredged material and was comprised of eight individual hinged steel caissons placed in a ring and held together with steel wire cables. Like the Tarsiut Caissons, the core of the CRI was filled with dredged material to provide the base for drilling operations and provide resistance to wave and ice loads. The CRI was deployed three times in the Canadian Beaufort Sea from 1983 – 1987. The structure has not been active since that time.



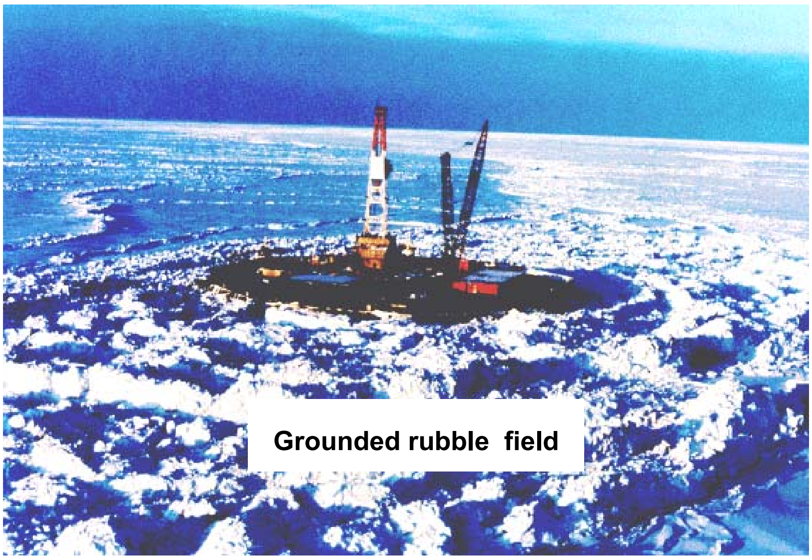


Figure 6 Grounded rubble field around the CRI at the Kaubvik site (left) and ice rubble surrounding the CRI at the Amerk site (right), [*after Timco and Johnston, 2002*]

Example: Mobile Arctic Caisson (MAC) Molikpaq

The Molikpaq, developed by Gulf Canada Resources Ltd. and operated by Beaudril, took the Esso steel caisson-retained island concept one step further. The Molikpaq is a Mobile Arctic Caisson (MAC) which was deployed in the Canadian Beaufort Sea in 1984 (*Figure 7*) and used for exploration drilling for four winter seasons in the Canadian Arctic.

The structure is a monolithic, water-ballasted steel annulus with a self-contained deck for drilling and topsides facilities, but unlike the fully water ballasted SSDC and CIDS, Molikpaq relied on a densified sand core to provide the bulk of its resistance to environmental loads. Like the Tarsiut Caissons and the CRI, Molikpaq is not a true MODU.

The outer face of the Molikpaq was designed for extreme ice features. The structure can operate without a berm in water depths ranging from 9 to 21 m. In greater water depths, the structure was designed to sit on a submerged berm that can vary in depth, as required. In deep waters, the angle of the outer face is 8°, whereas in shallower waters, the angle of the face is 23° (*Figure 8*). Ballasting of the caissons was entirely by water. To achieve the design resistance under dynamic load, densification of the hydraulically-placed core is required (*Timco and Johnston, 2002*).

Figure 7 Photograph of the Molikpaq with accumulated crushed ice on upstream side

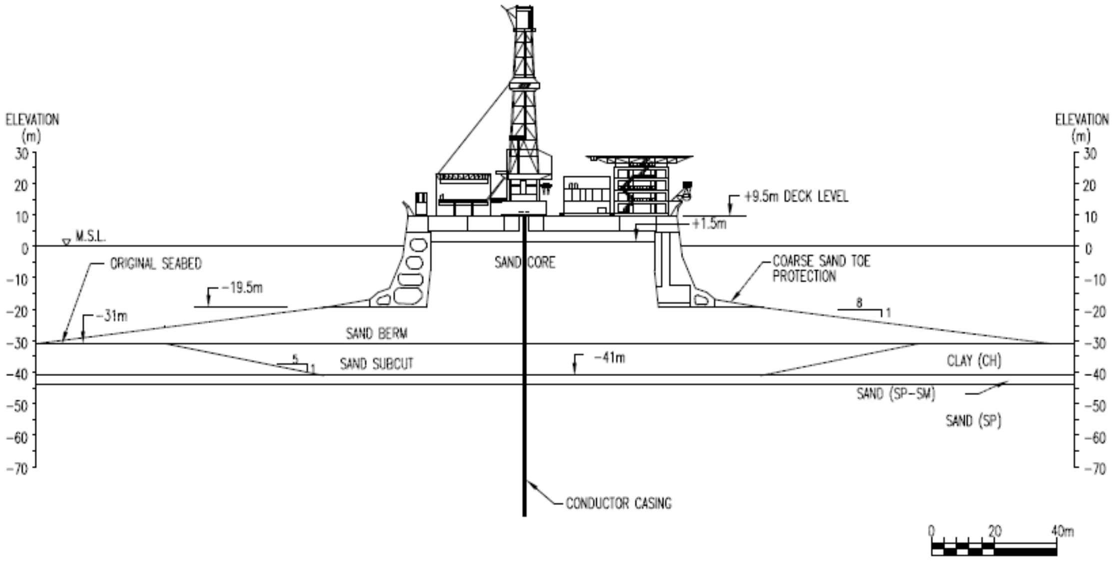


Figure 8 **Cross-section view of the Molikpaq at the Amauligak I-65 site in 1985-1986 (*Timco and Johnston, 2002*)**

The unit began operations in 1984 and drilled four locations in the Canadian Beaufort Sea (*Table 5*). It was mothballed in 1990 and later modified and redeployed in 1997 as a permanent production facility in the Sea of Okhotsk off Sakhalin Island, Russia .

The only Beaufort Sea production was from Amauligak with Molikpaq, when during extensive well testing they loaded a tanker which was offloaded in the south.

Table 5 Details of the Molikpaq deployment in the Beaufort Sea (*Timco and Johnston, 2002*)

Site	Year Deployed	Water Depth (m)	Setdown Depth (m)	Subcut Depth Below Seabed (m)	Berm Height Above Seabed (m)	Core Height Above MSL (m)	Fill Quantity (m^3)
Tarsiut P-45	1984	25.5	19.5	3.5	6.0	2.0	450,000
Amauligak I-65	1985	31.0	19.5	9.0	11.5	1.5	1,400,000
Amauligak F-24	1987	32.0	15.8	16.0	16.2	4.8	2,200,000
Isserk I-15	1989	11.7	13.4	1.7	N/A	-3.8	70,000

Example: Caisson Retained Island "Tarsiut Island" (Canadian Beaufort Sea)

The Tarsiut caissons were the first caisson-type structure used in the Arctic. They were floated to a berm at the drilling site and after being ballasted down with sand the internal core was filled with dredged material. *Figure 9* shows the caissons floated to the berm of Tarsiut Island. The 7950 m^2 structure was used to drill one well in 1981/82 and left on site and during the winter of 1982/83 a dedicated research program was carried out on the platform.

The caissons have been stored, bottom founded near-shore in Thetis Bay, off the coast of Herschel Island in the Canadian Beaufort Sea since 1984. The caissons have been repositioned in 2001, and annual inspections are conducted to document damage or movement. *Figure 10* shows the Tarsiut relief pad built next to the main caisson retained drilling island.

Figure 9 Caissons floated to the berm of Tarsiut Island

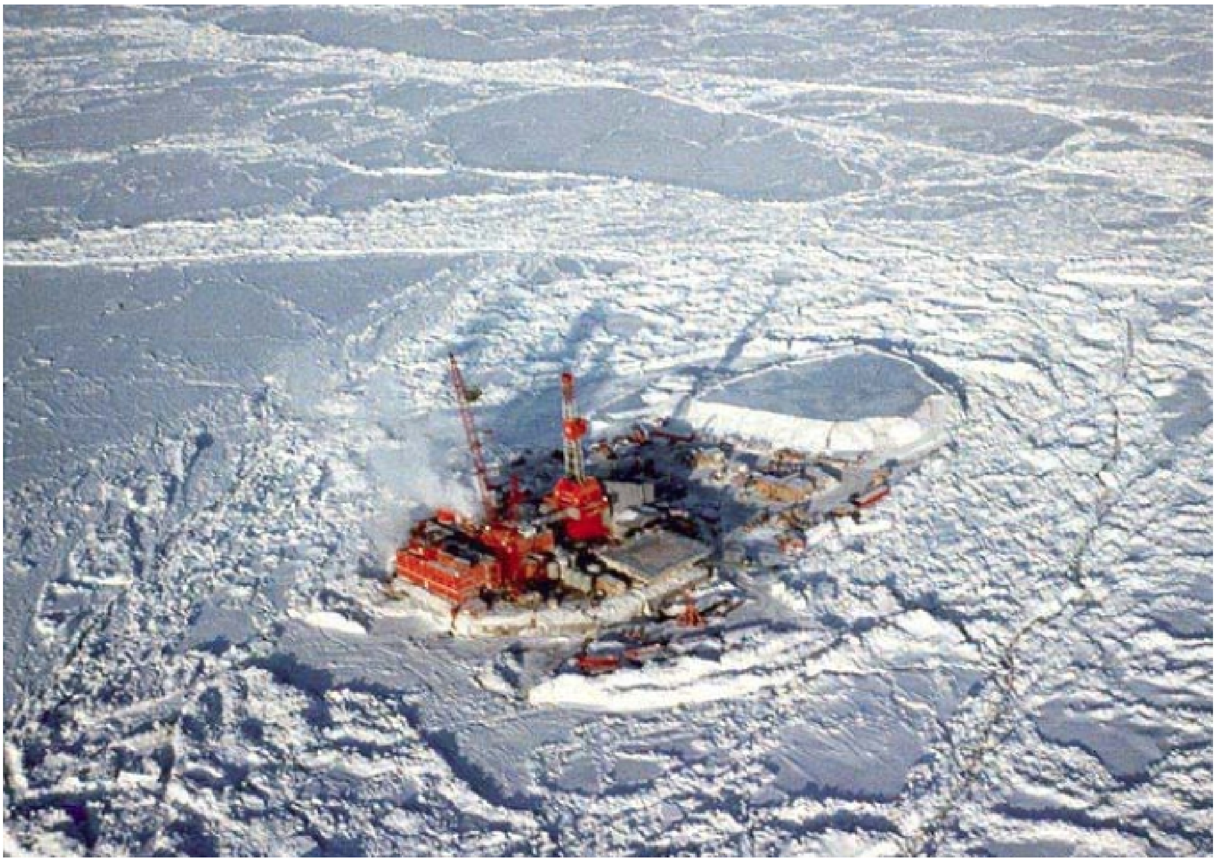


Figure 10 Tarsiut Relief Spray Ice Island (*ICETECH, 2008*)

Example: Oil Production Island Mittelplate (North Sea, Germany)

The drilling and production island Mittelplate is like a compact, liquid-tight steel and concrete shell on the sand flats of the Mittelplate region in the German Wadden Sea (*Figure 11*).

It is secured with high sheet piling against external like waves and ice. From the island, nothing can penetrate uncontrollably outside, even rain and spray are collected and treated.

A seepage is not possible. In addition, a comprehensive disposal system ensures the protection of the Wadden Sea and North Sea. The drilling and production operations are covered multiple times by complex monitoring and control systems.

The special location requires careful work and represents an extreme challenge for people and technology to take into account all environmental aspects. Many facilities of the only 70 x 95 m large artificial island have been developed with high investments specifically for the conditions of the sensitive production area. The basic principle is the reliable isolation from the Wadden Sea.

The island “Mittelplate”produced since its completion in 1987 until now about 20 million metric tonnes of oil.

Figure 11 **Artificial island Mittelplate in the German Wadden Sea (*source RWE Dea AG*)**

Example: Concrete Island Drilling System (CIDS) Glomar Beaufort Sea 1

This structure was operated by Global Marine in the American Beaufort Sea. It is made of a steel mud-base, concrete "brick" units through the ice zone and steel deck storage barges (see *Figure 12*). The steel units are not exposed to severe ice loading. The brick units are of a honeycomb construction that provide an optimum strength to weight ratio.

The forces imposed by the ice are distributed evenly throughout the structure. The "silos" within the honeycomb structure are used only for water ballast, like the tanks in the base. Ballast and deballast is entirely by water. Under normal conditions, the deballasting and reflotation process can be completed in three days. This structure was used only in the American Beaufort Sea (*Timco and Johnston, 2002*).

Figure 12 Concrete Island Drilling System (CIDS) Glomar Beaufort Sea 1 surrounded by ice (*Timco & Johnston, 2002*)

5.1.2.2 Gravel Islands

Although not a “high tech” technology, gravel islands have been successfully used in the Beaufort Sea for decades and continue to be viewed as a candidate structure for exploration and/or production in this area of the Alaskan OCS.

Since no gravel island structure has been used in the Chukchi Sea, a more detailed assessment would be required to determine feasibility for gravel islands in near-shore Chukchi Sea due to the ice environment, which may be more dynamic than in the Beaufort Sea. In the near-shore Bering Sea, gravel islands may be subject to higher waves and larger wave loads, which would need to be taken into consideration during detailed assessment.

Exploratory drilling for oil and gas started in the Mackenzie Delta area of Northern Canada in the mid-sixties. After several years of extensive on-shore exploration, the first offshore Arctic well was drilled by Imperial Oil in the winter of 1973 - 1974. This well was drilled from the artificial island, Immerk B-48, where construction had started using a cuttersuction dredger in the summer of 1972. This island was constructed at a fairly sheltered location in the offshore delta in a water depth of 13 m. There was no drilling from the island during the first winter in order to demonstrate that the island could withstand the winter ice conditions. The island resisted successfully, and after adding additional fill during the next summer, drilling has started (*Croasdale and Marcellus, 1977*).

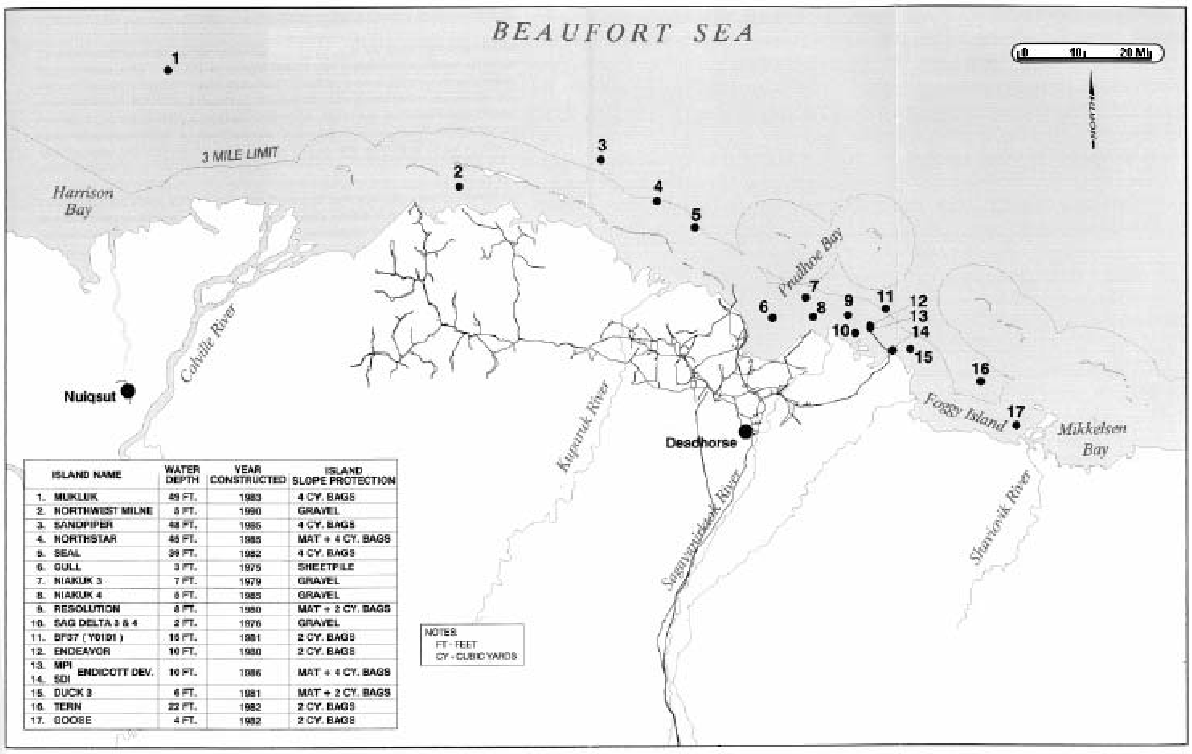
As shown below in *Table 6 ,* 31 artificial granular islands have been built in water depths ranging to 19 m in the Canadian Beaufort Sea.

Table 6 Exploratory Drilling Islands used in the Canadian Beaufort Sea (*from Timco, 1998*)

Date	Island	Island Type
1972	Roland Bay L-41	
1973	Immerk B-48	Sacrificial beach island
	Adgo F-28 Pullen E-17	Sandbag retained island Hauled island
1974	Unark L-24	Hauled island
	Adgo P-25	Sandbag retained island
	Garry P-94	Hauled island
1975	Nerlerk B-44 Adgo C-15 Ikattok J-17 Nerlerk F-40	Sandbag retained island
1976	Sarpik B-35 Kugmallit H-59	Sandbag retained island
	Unark L-24A	
	Arnak L-30	Sacrificial beach island
1977	Kannerk G-72 Isserk E-27	Sacrificial beach island
1978	Gary G-07	Hauled island
1979	Adgo J-27	Sacrificial beach island
1980	Issungnak 2O-61	Sacrificial beach island
1981	Alerk P-23	Sacrificial beach island
1982	Issungnak O-61	Sacrificial beach island
	West Atkinson L-17	Sandbag retained island
	Itiyok I-27	Sacrificial beach island
1984	Adgo H-29	Sandbag retained island
	Nipterk L-19	Sacrificial beach island
1985	Nipterk L-19	Sacrificial beach island
	Adgo G-24	Sandbag retained island
	Minuk I-53	Sacrificial beach island
	Ellice L-39	Sandbag retained island
1986	Arnak K-06	Sacrificial beach island
1987	Angasak L-03	Spray ice island
1989	Nipterk P-32	

Between 1975 and 1990, 17 gravel islands were constructed in the Alaskan Beaufort Sea (*Figure 13*).

In 2001, Seal Island (known as Northstar now), initially used for exploration, was rebuilt by BP Exploration Alaska (BPXA) for the Northstar production project. Both Northstar and Endicott are production islands.



ISLAND NAME	WATER DEPTH	YEAR CONSTRUCTED	ISLAND SLOPE PROTECTION
1. MUKLUK	49 FT.	1983	4 CY. BAGS
2. NORTHWEST MILNE	5 FT.	1990	GRAVEL
3. SANDPIPER	48 FT.	1985	4 CY. BAGS
4. NORTHSTAR	45 FT.	1985	MAT + 4 CY. BAGS
5. SEAL	39 FT.	1982	4 CY. BAGS
6. GULL	3 FT.	1975	SHEETPILE
7. NIAKUK 3	7 FT.	1979	GRAVEL
8. NIAKUK 4	5 FT.	1985	GRAVEL
9. RESOLUTION	6 FT.	1980	MAT + 2 CY. BAGS
10. SAG DELTA 3 & 4	2 FT.	1976	GRAVEL
11. BF37 (Y0191)	15 FT.	1981	2 CY. BAGS
12. ENDEAVOR	10 FT.	1980	2 CY. BAGS
13. MPI / 14. SDI ENDICOTT DEV.	10 FT.	1986	MAT + 4 CY. BAGS
15. DUCK 3	6 FT.	1981	MAT + 2 CY. BAGS
16. TERN	22 FT.	1982	2 CY. BAGS
17. GOOSE	4 FT.	1982	2 CY. BAGS

Figure 13 Alaskan Beaufort Sea Manmade Islands (*modified from US Army Corps of Engineers, 1999*)

Land fast ice, ranging up to 2 m thickness, covers the near-shore Beaufort Sea for about nine months of the year, and has a considerable influence on construction methods and island design. In the deeper water areas the occurrence of multi-year ice has to be considered.

Gravel islands not only need sufficient sliding stability to withstand the forces generated by moving ice, but also the possibility of ice ride-up also has to be taken into account.

Artificial islands have been built either during the winter by trucking granular fill over the ice or in the short Arctic summer using dredges. Islands have been constructed of gravel, sand, silt and a mixture thereof. Slope protection has been designed to match the measured and predicted sea-state, which also influences the island freeboard needed to avoid wave over-topping. Slope protection methods for artificial islands have included anchored poly-filter cloth and sandbags, concrete units, rock fill, and sacrificial beaches.

Optimum granular artificial island designs have to account for constructional constraints, working area required, ice action, wave action and geotechnical factors.

For exploratory drilling, a stable platform is required for drilling. Drilling operations can last from about 30 - 160 days. The actual time will depend on the well depth, drilling factors, and whether any testing of discovered hydrocarbons is conducted.

In the early 1970's, of the numerous offshore drilling concepts which were considered, artificial granular fill islands were selected to initiate Arctic offshore drilling. They had the advantage of short lead-time and the use of proven technology. Also they could be built to withstand the year-round environment and thus the drilling rig could stay over the well until it was completed. The main disadvantages of islands are the short construction period available in the summer, and also the fact that in deeper water, the construction times and costs increase rapidly.

The design of artificial granular islands for ice-infested waters is normally governed by the resistance of the structure to ice loads. It is also influenced by materials and techniques available for construction as a function of location and season. *Figure 14* shows the two basic designs utilized in the Canadian Beaufort Sea for the construction of granular fill artificial islands. The figure illustrates islands in 5 to 7 m water depth.

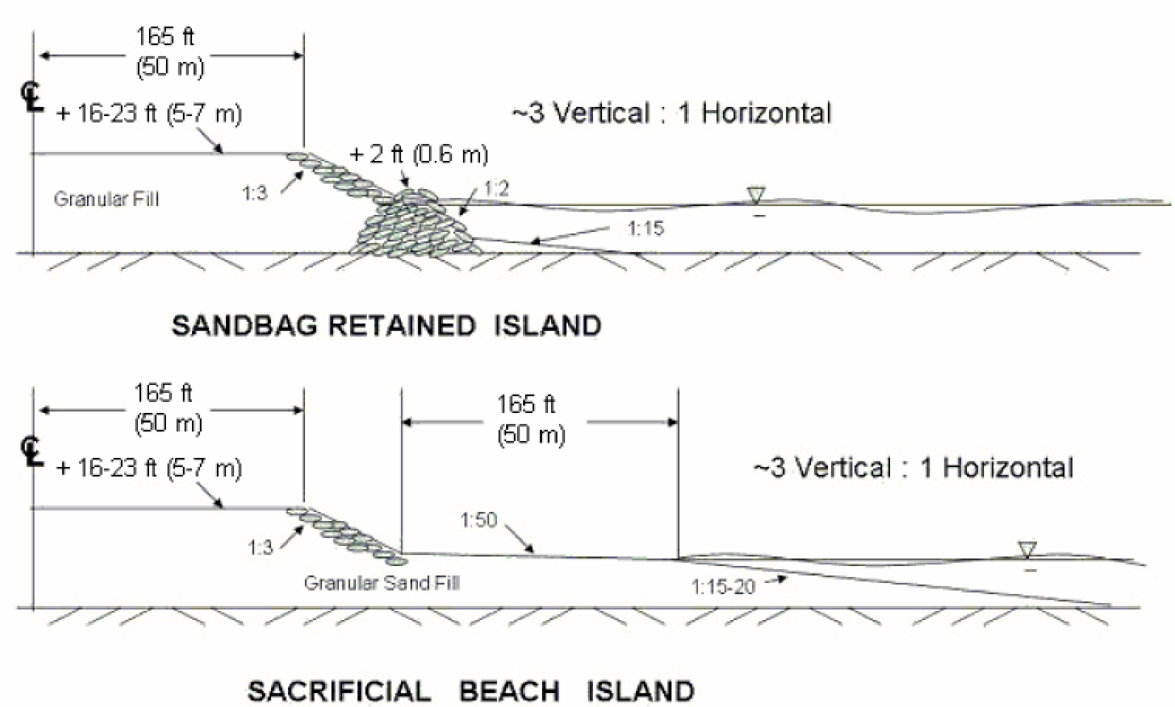


Figure 14 **Basic Designs for Granular Fill Artificial Islands in the Canadian Beaufort (*source: IMVPA, 2008*)**

The deepest granular fill island was Issugnak O-61 in 19 m water depth. The island took 3 seasons to complete and required about 5 million m^3 of fill.

A photo of the first deepwater sacrificial beach island, Arnak L-30, is shown in *Figure 15* under wave action in 1976. This photo shows a large amount of redistribution of the sand from the sacrificial beach to the lee side of the island. This sediment transport behavior was a feature of the design.

Figure 15 Imperial Oil's Arnak L-30 September 1976 showing wave action on the sacrificial beach island design (after *Croasdale and Marcellus, 1977*)

Referring to *Table 6* of the islands constructed in the Canadian Beaufort Sea, 13 were Sandbag Retained Islands, 13 were Sacrificial Beach Islands, 1 (Sarpik B-35) was protected by filter-cloth with concrete units attached (which proved to be problematic) and the remaining 5 were classified as hauled islands (shallow water islands not requiring significant erosion protection). The choice of design to a large extent was based on the availability (and cost) of construction equipment (*IMVPA, 2008*).

Example: Artificial Island "Northstar" (Alaska, USA)

The production island *Northstar* is located about 19 km northwest of Prudhoe Bay in the Beaufort Sea in about 12 m of water depth (see *Figure 16* and *Figure 17*). Northstar is the first Arctic offshore field connected to shore only by pipeline. The produced oil flows via a subsea pipeline to the Trans- Alaska Pipeline System.

BP designed a facility that produces and processes the field's fluids from a 20000 m^2 artificial island that is protected from sea ice by concrete armor, a steel sheet pile wall and underwater bench and berm system.

Prudhoe Bay is located about 970 km (by air) north of Anchorage and about 1940 km south of the North Pole.

Main Characteristics

The following are the key data of the Northstar development:

Licensee/Operator: BP (~98.6% stake) and Murphy Oil (~1.4% stake)

Location: 9.7 km offshore Alaska coast, 19 km northwest of Prudhoe Bay

Expected field life: ~25 years

Discovery 1984 (start of production 2001)

Water depth: 12 m

Reserves geographical area:	~70 sq km
Platform type:	artificial Island
Northstar dimensions	~20.000 sq m
Original Oil in Place	310 mboe (barrels of oil equivalent ; conversion base: 1.0E-6 Mboe)
Annual exports	16.4 mboe (average)
Cumulative Oil Production:	148 mboe (to date 31.12.2010)

No. of Wells:

Oil Producers	19
Gas Injection	6
Water Injection	0
WAG Injection	2 (Water Alternating Gas Injector)

Export: via Pipeline (another pipeline re-sends gas for injection)

Personnel:	around 200 direct jobs and at least 400 indirect jobs
Training:	BP invests in several training, educational and social welfare activities in Alaska
Services:	Onshore support services

Figure 16 Northstar production facility in shallow water (photo left: island under construction in winter ice conditions) [source: http://www.bp.com]

The Northstar oil field was discovered in the Beaufort Sea in 1983 by Shell (*SPG Media Limited, 2007g)*.
The "Northstar," is the world's first year-round Arctic offshore oil drilling station and was developed in 1999 and 2000 on an artificial gravel island, and includes a subsea pipeline.
Northstar Island is an about 20000 m^2 manmade production island which was built upon an abandoned/deteriorated exploration island Seal Island. It was chosen to utilize Seal Island because significant cost and time savings would be realized through rebuilding (and subsequent expansion) as opposed to starting from the beginning and building a new island. Furthermore Seal Island was able to reach 95% of the reservoir (*US Army Corps of Engineers, 1999*).

Northstar Island is grounded in approximately 12 m water depth and is located about 9.7 km offshore. Seasonal access to the island is achieved via ice roads.

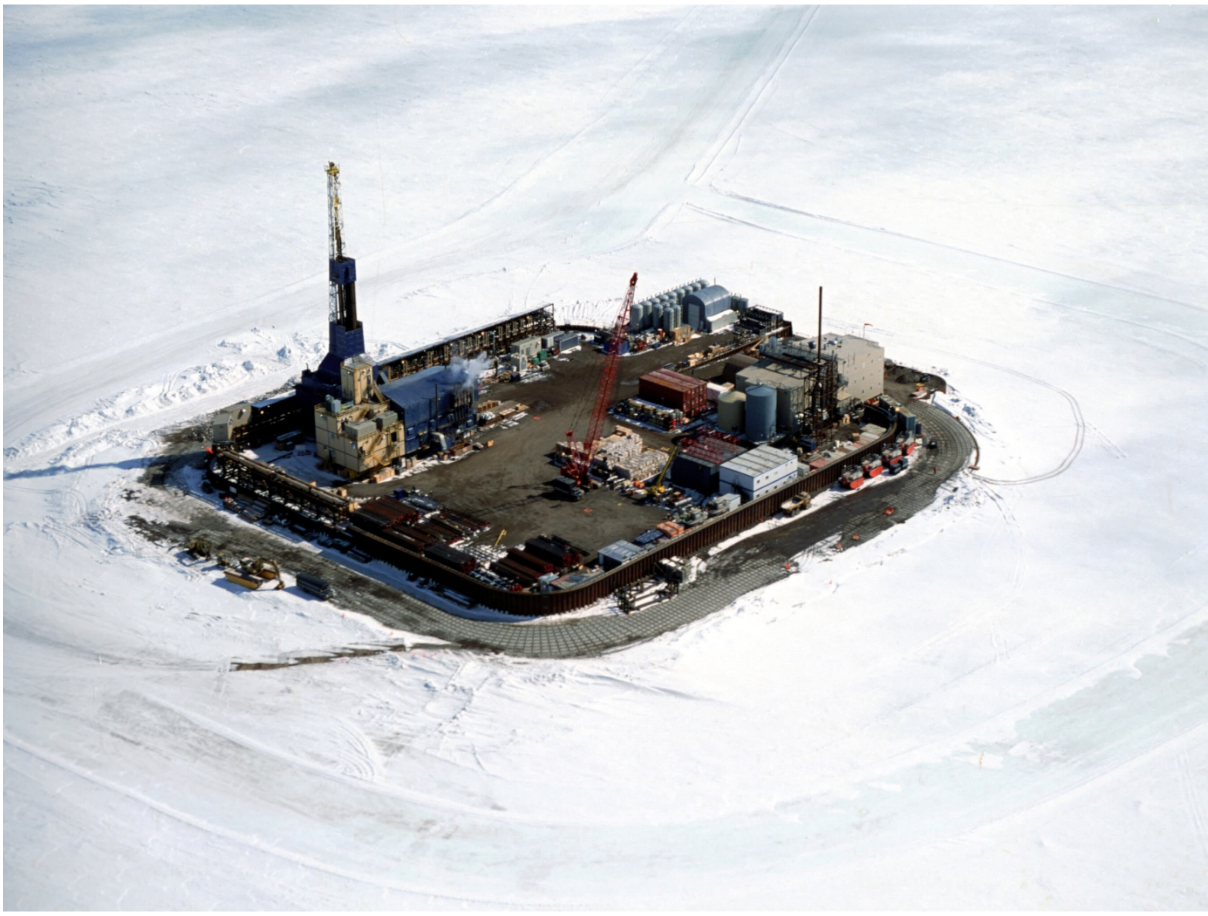


Figure 17 Northstar Production Island (courtesy: BP)

Example:Artificial island Oooguruk

The gravel island was completed in 2006 in about 1.4 m water depth and stands 7 m above the seafloor (see *Figure 18*). An equivalent of 22000 truckloads of gravel was used to construct the island (*Wright, 2006*). In the summer of 2006, side slopes were constructed on the island to resist ice loads; slope protection is provided by gravel bags (8000 in total). The settlement of the island has been estimated of about 1 m, which will require maintenance of the island. Wick drains were installed to speed up consolidation settlement from two and a half years to nine months (*Knott, 2006*).

From this island, approximately 40 horizontal wells are drilled. Twenty of the wells are production wells, and the other half are injection wells.

Also in 2007, a buried three-phase subsea flowline and facilities were installed to transport production to existing onshore processing facilities at the Kuparuk River Unit.

First oil was achieved at Oooguruk in June 2008 within five years of discovering the field. The production is processed at the onshore Kuparuk River Unit and then transported to the Trans Alaska Pipeline System. Drilling on Oooguruk continued until 2010, ramping up production gradually. It was expected to reach peak production in 2011 at a rate of 15000 to 20000 bopd, Oooguruk has an estimated field life of 25 to 30 years.

Figure 18 Artificial gravel island "Oooguruk"

Example: Endicott Island

Endicott Island located at 70° 21′ 0″ N and 147° 57′ 30″ W was the first production island constructed (see *Figure 19*). The Endicott oil field is located in the Beaufort Sea, about 13 km east of Prudhoe Bay. The oil field was discovered in 1978 by the Sohio Alaska Petroleum Company and later on operated by BP Exploration (Alaska).

This project pool has been developed from two artificial gravel islands that are located approximately 6.4 km offshore in 0.6 to 4.3 m water depth. These islands are connected through a 8 km long gravel causeway, which supports the 39 km long pipeline where processed oil is sent from Endicott Island to the Trans-Alaska Pipeline, and then to Valdez, Alaska for further shipment.

The causeway was constructed in 1984-85. Endicott production began in July 1986. During the peak production years from November 1987 and October 1993, Endicott averaged about 104250 barrels of oil per day (BOPD). Production has declined over the years to the point where during the last 8 months of 2004, production from Endicott was 17600 BOPD.

Figure 19 Man-made Endicott Island in the Beaufort Sea (photo by P. Lawrence)

5.1.3 Spray Ice Islands

The first use of an island built completely from spray ice for exploratory drilling was carried out by Amoco at Mars, Harrison Bay, in 1986. This island was built on the landfast first-year ice in 7.6 m water depth, to provide a completed freeboard of 7.5 m. The 330 m diameter platform required 4 pumps to produce about 1 million m^3 of ice during the 45 day construction program. *Figure 20* shows the Mars ice island during drilling operations (*IMVPA, 2008*)

Figure 20 Mars Spray Ice Island (*C-CORE, 2005*)

The technical and financial success of this platform led to spray ice becoming the material of choice for the construction of grounded platforms in shallow water in the Beaufort Sea.

Construction cost savings on the order of 50% were quoted compared to sand and gravel islands previously used, as demonstrated in *Figure 21*. The construction of another 3 exploration spray ice islands in the 1980s at Angasak, Nipterk and Karluk reinforced the advantages of spray ice construction.

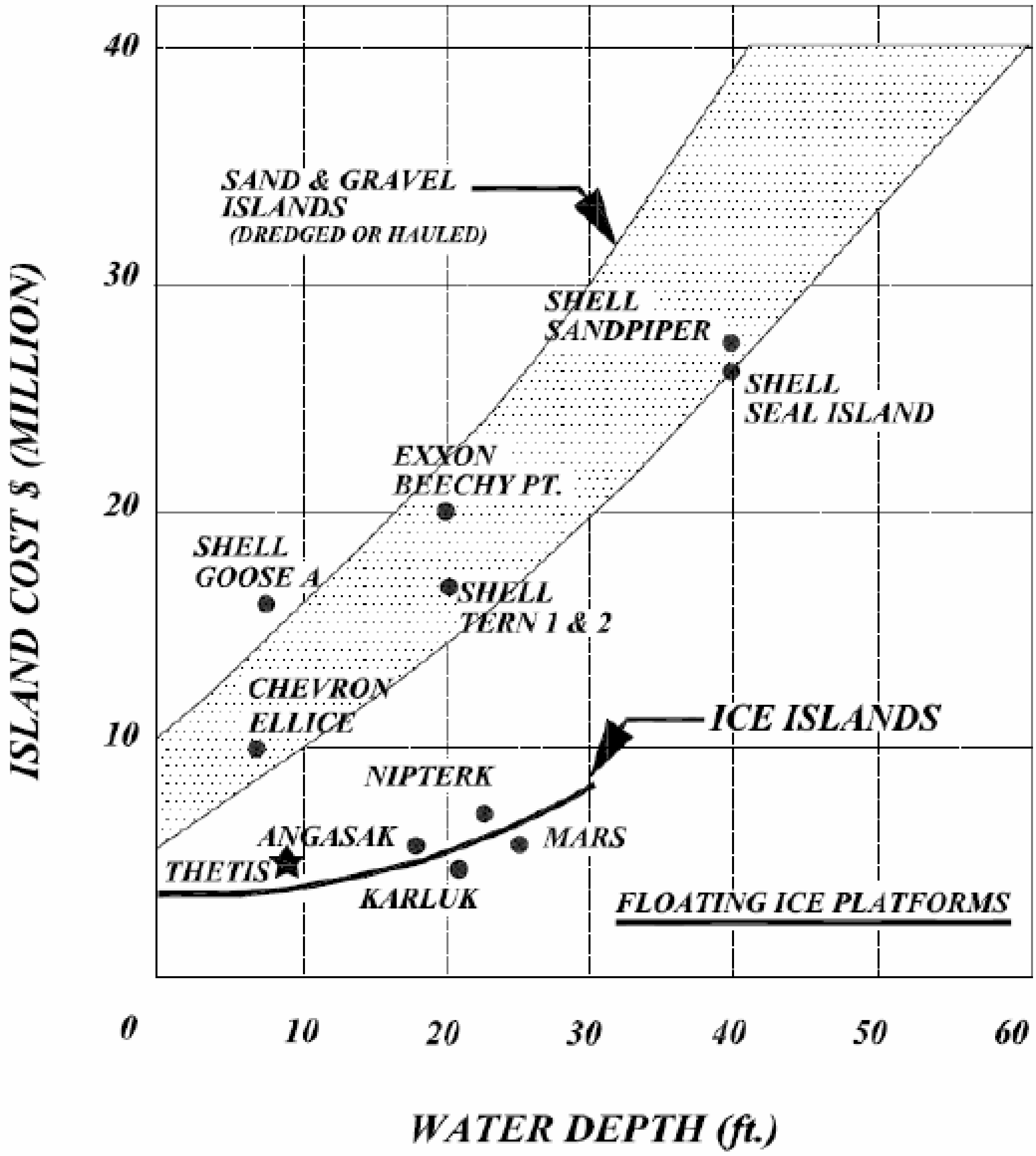


Figure 21 Cost comparison between gravel and ice islands (*C-CORE, 2005*)

Operational spray ice islands were built at the Thetis Field in 2002/03, where a number of innovative techniques were successfully used. This allowed the drilling of 2 wells using the same rig in the same season. A summary of grounded artificial ice island construction is presented in *Table 7.*

Table 7 Summary of Grounded Artificial Ice Island Construction

Name	Operator	Location	Technique	Use	Dates	Water Depth, ft (m)
	Union Oil	Harrison Bay, US Beaufort Sea	Flood	Experimental Island	1977/80	9.8 (3)
	Exxon	Harrison Bay, US Beaufort Sea	Flood, Spray	Experimental Island	1979	9.8 (3)
	Esso	Canadian Beaufort Sea	Spray	Experiment	1980	
Tarsiut	Gulf Canada	Canadian Beaufort Sea	Spray	Relief Pad	1981/82	63 (19.2) on Berm
Alerk island	Esso	Canadian Beaufort	Spray	Relief Pad	1982	38 (11.6)
SSDC Uviluk	CANMAR	Canadian Beaufort Sea	Spray	Experimental Protection Structure	1982/83	98 (30)
Kadluk 0-07	Esso	Canadian Beaufort Sea	Spray	Relief Pad	1983/84	44 (13.5)
Sohio Rubble Generator	Sohio	McKinley Bay, Beaufort Sea	Spray	Experimental Protection Structure	1983/84	43 (13)
Ice Island Experiment	Exxon	Canadian Beaufort Sea	Spray	Experimental Island	1983/84	45 (13.7)
Big Gun Expt., MV Kigoriak	Esso	McKinley Bay, Beaufort Sea	Spray	Experimental Protection Structure	1983/84	46 (14)
SSDC Kogyuk	CANMAR	McKinley Bay, Beaufort Sea	Spray	Experimental Protection Structure	1983/84	93 (28.4)
CIDS Antares Barrier	Exxon	Alaskan Beaufort Sea	Spray	Operational Protection Structure	1984/85	49 (14.9)
Cape Alison C-47	PanArctic	Ellef Ringnes Island, Canadian Arctic	Spray	Operational Floating Island	1984/85	259 (79)
MARS full-scale prototype	Sohio	Harrison Bay, US Beaufort Sea	Spray	Experimental Island	1984/85	30 (9.1)
Mars	Amoco	Harrison Bay, US Beaufort Sea	Spray	Operational Island	1985/86	25 (7.6)
Angasak L-03	Imperial/Esso	Canadian Beaufort	Spray	Operational Island	1986/87	18 (5.6)
Nipterk P-32	Imperial	Canadian Beaufort	Spray	Operational Island	1988/89	23 (6.9)
Karluk	Chevron	US Beaufort	Spray	Operational Island	1988/89	25 (7.6)
Isserkl-15	Imperial	Canadian Beaufort Sea	Spray	Relief Pad	1989/90	38 (11.5)
Ivik	Pioneer	Thetis, Harrison Bay, Alaska	Spray	Operational Island	2002/03	9.8 (3)
Oooguruk	Pioneer	Thetis, Harrison Bay, Alaska	Spray	Operational Island	2002/03	12 (3.7)
Natchiq	Pioneer	Thetis, Harrison Bay, Alaska	Spray	Operational Island	2002/03	7.5 (2.3)
Kashagan, Sunkar Site	Agip KCO	North Caspian Sea	Spray	Operational Protection Structure	2002/03	
Kashagan, Aktote Site	Agip KCO	North Caspian Sea	Spray	Operational Protection Structure	2003/04	
Kashagan, Kairan Site	Agip KCO	North Caspian Sea	Spray	Operational Protection Structure	2003/04	

The design criteria used in practice for spray ice islands suggests that the strength of the island itself is rarely critical in determining resistance to lateral ice loads, but rather the sliding shear force developed between the island and the seafloor. The general practice has therefore been to adopt a safe, lower-bound strength profile and undertake a check that it is adequate.

5.1.4 Jacket & jack-up structures

General

Several jacket type structures have been evaluated for use in the south Bering Sea (*PMB Systems Engineering et al., 1983*); these being an eight leg template jacket, a four plus four template jacket, and a steel mono-tower jacket. The evaluation identified the four plus four steel template as the most suitable jacket concept for the South Bering. The areas considered were the St. George's, Navarin and North Aleutian Basins in water depths ranging from 91 to 137 m.

The four plus four template jacket as shown in *Figure 22* has eight legs complete with skirt piles. The four end legs terminate beneath the surface giving the structure a clean water plane, which is expected to prevent ice bridging of the legs. The four double walled legs are on a spacing of 30 x 43 m and contain the wells and risers (*PMB Systems Engineering et al., 1983*). *Figure 23* shows examples of other jacket platforms.

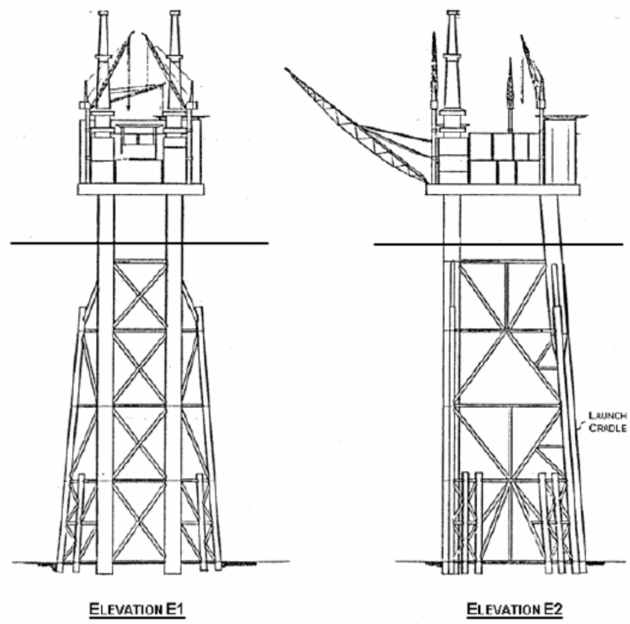


Figure 22 Four plus Four Template Jacket (modified from *PMB Systems Engineering et al., 1983*)

Figure 23 Examples of jacket platforms

A jack-up rig is a type of mobile offshore oil and gas drilling platform that is able to stand still on the sea floor, resting on a number of supporting legs. The most popular design uses 3 legs. The supporting columns may be moved up and down by a hydraulic or electrical system. The whole rig can also be jacked up when the supporting legs touch the seafloor. During transit, the platform floats on its hull and is typically towed to a new location by offshore tugs. Jack-up rigs provide platforms that are more stable than semi-submersible platforms but can only be placed in relatively shallow waters, generally less than 300 m water depth. The rig acts as a kind of platform. This type of rig is almost used in connection with oil and/or natural gas drilling (*www.oil-rig-photos*).

The jack-up drilling rig was first introduced to the offshore industry in the mid 1950's. The jack-up rig was developed to provide a fixed base drill rig capable of operating in harsh environments (wave only) with the flexibility to relocate to alternate drilling locations.

A jack-up drilling rig consists of a hull, legs and a lifting system. A wide variety of hull styles, legs and lifting systems exist. The variation is primarily a result of the trade off the designer must make between drilling stability and buoyancy stability.

Rig installation involves a wet or dry tow to site. Wet tows usually occur over short distances. Under wet tows, the rig provides its own buoyancy. Dry tows typically occur over large distances. During dry tow, the rig is carried on a barge or on the deck of a transporter.

Once on site, the rig's legs are lowered to the seabed and the hull is elevated to provide a stable work deck. The rig is now ready to begin drilling operations. Removal of the rig is the reverse of the installation (*IMVPA, 2008*)

The ice reinforced jacket platform was first successfully used in sea ice in the mid 1960's for Cook Inlet, Alaska developments. Previous studies have suggested that jacket structures are suitable for areas of the Bering Sea. However, these studies did not consider the vibration responses associated with the dynamic ice loading. Jacket type structures could likely be made to work in light first-year ice and in water depths less than 60 m. However, the jacket structure's potentially poor response to dynamic loading and the need for conductor system protection are significant design issues for application in the Bering Sea.

Current design practices and understanding of jacket design make their application in general unsuitable for the Beaufort and Chukchi Seas.

Developments in jack-up technology and the advancement of ice maintenance programs indicate that the operating range and season of jack-up exploration could potentially be extended in the Bering Sea (*IMVPA, 2008*).

A modern drilling jack-up operating in ocean environment is capable of working in wave heights of 24 m, in winds of 100 knots, in water depths approaching 152 m and to drill depths of 10700 m (*BASS and OTD/KeppelFels, 2005*).

A study by CKJ Engineering (*CKJ Engineering, 1997*), the development and implementation of a jack-up drilling program on the Grand Banks of Newfoundland (*Bagnel, 2007*) and the anticipated construction of a new Russian ice-resistant jack-up rig are indicative that the operating range of jack-up drilling rigs can be marginally expanded to include areas of seasonal sea ice and of marginal sea ice concentration.

In light of CKJ's study, the successful implementation of a jack-up drilling program in Newfoundland, the anticipated construction of ice-resistant jack-ups and the continued development of jack-up rig technology, an extension of a traditional seasonal jack-up drilling program may be considered also for the Bering Sea (*IMVPA, 2008*).

The ice-resistant jack-up rig Arkticheskaya (*Figure 24* and *Figure 25*) was constructed and built at the Severodvinsk Shipyard, Russia. It is being constructed to operate in Arctic water depths of up to 100 m and in 0.5 m thick drifting ice (*MNP Global, 2007*).

Journalist Atle Staalesen from Barents Observer reported on 5 July 2011: "Gazprom's new Arkticheskaya jack-up rig is undergoing testing in the White Sea. The rig, which has been under construction at the Zvezdochka yard in Severodvinsk for more than 15 years, has set course for the White Sea where it is to undergo testing. The rig, which is built for Gazprom, is designed for operations in Arctic waters and will be used primarily in the Pechora Sea. It has a 88 m long and 66 m wide platform and can house 90 workers. The maximum drilling depth is 6500 m (*Barents Observer, 2011*).

Figure 24 Schematic illustration of Gazprom's new Arkticheskaya jack-up rig (source: *Barents Observer, 2011*)

Figure 25 Gazprom's new Arkticheskaya jack-up rig (source: *Barents Observer*)

Assessment of Jacket & Jack-up Structures

Jacket platforms are used in general as permanent production structures, however they serve the offshore industry also as an exploration structure. The jack-up combines the mobility of a floating structure with the jacket platform's properties of wave transparency and fixity. The jacket structure is the most common fixed offshore platform in the world. It was first used in the Gulf of Mexico and has since been adapted and modified for use all over the world. It comes in a variety of styles from the single-legged (monopod) to multi-legged structures (tripod and quadpod).

Studies of the South Bering, the Norton Basin, and the North Aleutian Basin suggest that jacket structures could also be installed in the Bering Sea.

Technical Feasibility

Arctic Jacket Structure Design Considerations

For the design of a jacket structure it is important to take into account:

- Payload the jacket has to carry
- Foundation capacity
- Environmental loads (ice, waves and currents) the structure has to resist

If the jacket structure is located in ice covered waters also temperature loading, sea ice static loads and the accompanying vibration loads have to be considered.

Aside from the vibration problems, jackets used in sea ice have significant challenges with the protection of the conductor system. Options for protecting the conductors are to locate the system in the jacket legs or exterior to the legs in a separate ice reinforced enclosure (*IMVPA, 2008*).

In many cases, the sea ice static and vibration loads are the controlling factor either globally or locally in the sizing of the structure components, while temperature is generally the controlling factor in material selection.

Sea ice has varying geometry (level ice, ice floes, ridges and ice rubble), concentrations and mechanical properties. The structures have to be designed for the maximum ice load that results from three specific loading mechanisms.

- Momentum load is the load that results from the ice flow impacting the structure.
- Ridge building load is the pressure load the structure experiences as a ridge and rubble field builds.
- Pack-ice loading is the tangential frictional loading that results from the ice flow passing by the ridge and rubble field that has formed in front of the structure (*Cammaert and Muggeridge, 1988*).

The load impact to a structure by momentum, ridge building and pack ice loading in general relates to the width of the structure. In the case of a jacket structure, the load is a function of the jacket leg diameter (D) to distance between legs (W) ratio (D/W).

If this D/W ratio is maintained above seven, then *Sanderson (1988)* suggests that the legs of a jacket structure will behave independently and ice bridging will not occur between the jackets legs. However he does not indicate the maximum ice thickness for which the D/W-ratio value of seven is applicable.

When the legs of the jacket act independently, smaller global loads are experienced by the structure.
It is assumed that this D/W ratio is only applicable for non-rafted sea ice thickness of less than 1 m. It is strongly recommended to execute additional ice model testing when the ice is thicker than 1 m to determine what D/W ratio will produce independent behaviour of the jackets legs.

In addition to the impact caused by static sea ice loads, the jacket structure must handle the vibration loading resulting from the random ice edge hit, sudden ice load relaxation, nonsystematic ice load level variations and continuous repeating ice load failures (*IMVPA, 2008)*.

Ice reinforced jacket structures are more prone to vibrations than conventional jackets because they have less damping ability and tend to amplify vibrations similar to a portal frame.

The dynamic response of a jacket structure from sea ice is not fully understood. However, it is known that the vibration responses are proportional to the design static load and the thickness of the ice. There are a number of possibilities to reduce the vibration response:

- the foundation can be made as rigid as possible to minimize the displacement resulting from the dynamic loading.
- the structural mass and stiffness of the jacket can be changed to reduce the structures resonance.

For the development of future Arctic jacket structures the experiences and lessons learned from previous projects should be included:

- the use of low temperature steels to avoid brittle failures
- the use of double walled ice reinforced jackets to avoid local failures and protect interior members
- the location of leg bracing well below the sea ice flow. This prevents the collection of rubble and ice bridging under and in front of the structure, hence eliminating the possibility of ice damage to the bracing system and reducing global and local loading
- the use of X-bracing between jackets, rather then K-type bracing. The X-bracing jacket results in a safer design by increasing the redundancy of its components.

Jacket type structures could likely be installed in areas where first-year sea ice is predominant and water depths are less than 60 m. However, the jacket structure’s poor response to dynamic loading and the conductor system protection issues are a significant concern for application in the Navarin, St. George’s, North Aleutian and Norton Basins.

Current design practices and understanding of jacket design make their application unsuitable for the Beaufort Sea and Chukchi Sea, because the primary load case in both areas is ice.

The Beaufort Sea commonly experiences thick multi-year ice floes and the Chukchi Sea has been observed with enormous multi-year ridges. The thickness of the ice not only significantly increases the load on the structure, but it also creates problems with the location of the jacket bracing. The bracing should be located below the underside of any ice features which could interact with the structure. Thick ice features means that the effective length to radius of gyration ratio (KL/R) of the jackets would significantly increase. The only way to deal with this increase in the KL/R ratio is to use larger jacket legs.

However, if the leg diameter is increased to compensate for the greater unsupported column length, it will result in increased wave loads and drag on the structure. In consideration of the above, one comes to the conclusion that an alternative type of structure is more suitable to this scenario.

5.1.5 Gravity Base Platform (GBP)

Production with Gravity Base Structures (GBS) - Export via Shuttle Tankers

Presently, the permanent bottom-founded concrete structures employed in the North Atlantic Ocean offshore Newfoundland and Labrador are the GBS platforms Hebron and Hibernia (reference: *www.hibernia.ca*).

Example: GBS Project Hebron

Hebron is a heavy oil field estimated to produce more than 400 - 700 million barrels of recoverable resources. The field was first discovered in 1980, and is located offshore Newfoundland and Labrador in the Jeanne d'Arc Basin, in close proximity to the Hibernia, Terra Nova, and White Rose Developments, 350 km southeast of St. John's, the capital of Newfoundland and Labrador. It is approximately 9 km north of the Terra Nova project, 32 km southeast of the Hibernia project, and 46 km from the White Rose project. The water depth at Hebron is approximately 92 m (reference: *www.hebronproject.com*).

Although several options have been evaluated (e.g. subsea tieback, FPSO with subsea wells, new generation GBS, and FPSO with wellhead platform (*Department of Natural Resources, 2007*), the Hebron field development will be based on the use of a GBS similar to that of Hibernia The Hebron GBS, however, will be smaller then Hibernia, requiring less concrete and being easier to build (*The Telegram, 2007b*).

The Hebron co-venturers are:

ExxonMobil Canada Properties (36%)

Chevron Canada Limited (26.7%)

Suncor Energy Inc. (22.7%)

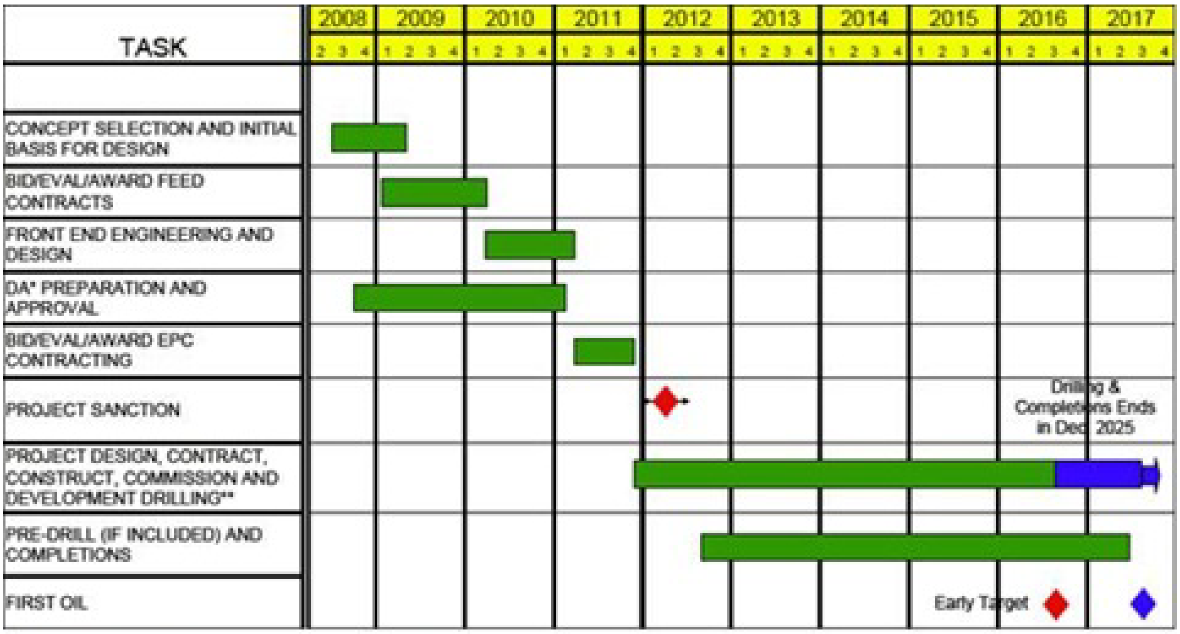
Statoil Canada (9.7%)

Nalcor Energy (4.9%).

ExxonMobil Canada Properties is the operator of the Hebron Project.

The timelines of the Hebron Project are given in *Table 8.* In *Figure 26* the GBS Hebron is illustrated.

Table 8 Timelines of Hebron Project



Source: Hebron Project

The concept selection and initial basis for design has started in 2008. In October 2012 the skirt installation began which is considered as officially starting GBS construction. In 2013 the fabrication of Topsides began. Construction and fabrication activities will proceed in parallel for several years. When the various Topsides components are complete, they will all come together at Bull Arm for integration, hook-up and commissioning. The Topsides and the GBS will then be connected and the complete platform will be towed to the Hebron field in the 2016-2017 time frame.

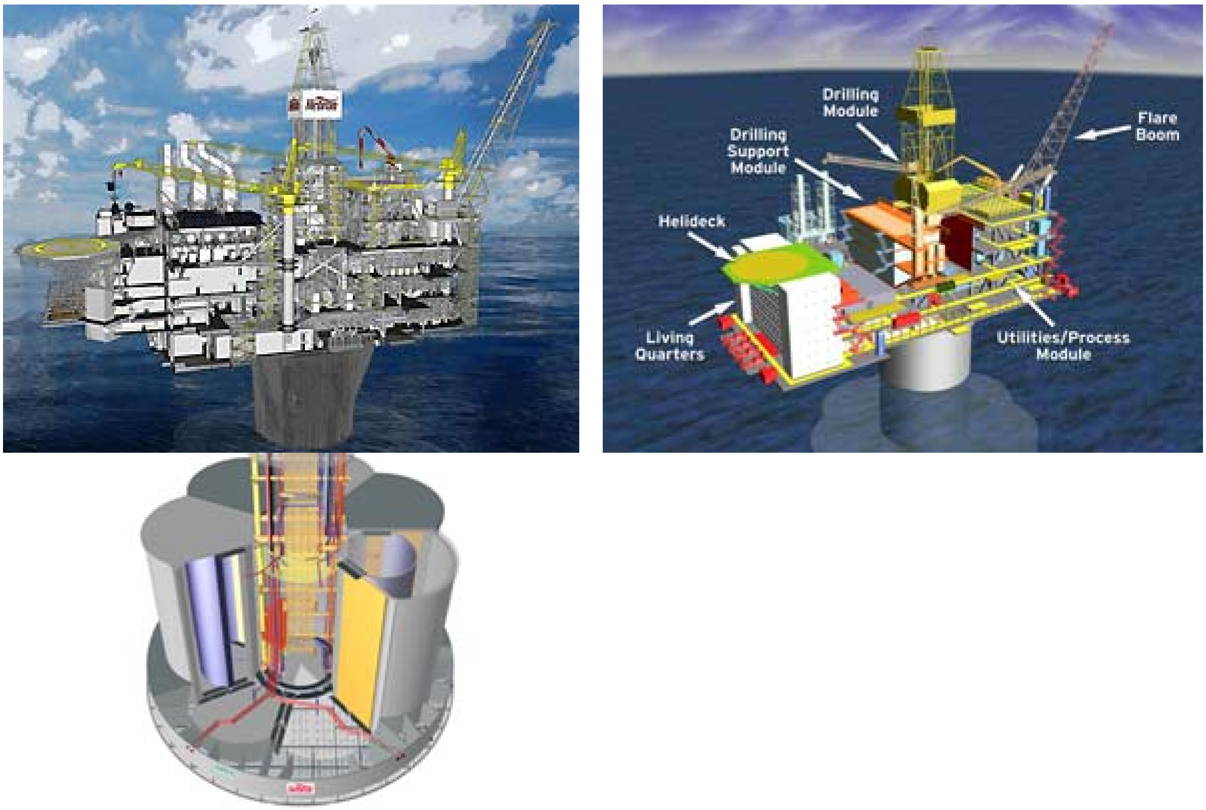
Key quantities of Gravity Based Structure

- Water depth - 93 m (Mean Sea level)
- Height of GBS - 120 m
- Diameter of GBS Base - 130 m
- Shaft diameter - 35 m
- Concrete volume - 132000 m^3
- Rebar - (density 300 kg/m3) approx. 40000 t
- Post tensioning steel - 3400 t
- Steel skirts - 400 t
- Mechanical Outfitting - 8000 t (piping systems & structural steel)
- Well Slots – 52

Key metrics of Topsides Key

- Length of Topsides - 158 m
- Width of Topsides - 64 m

- Height of Topsides (excluding derrick and flare) - 40 m
- Topsides Operating Weight - 65000 t
- Crude oil production - 150-180 1000's of barrels/day (kbd)
- Water production - 200-350 kbd
- Water injection - 270-470 kbd
- Gas handling - 215-300 million standard cubic feet/day
- Accommodations - Persons On Board (POB) – 220



Source: Hebron Project

Figure 26 Illustration of GBS Hebron Project (Canada)

Overall Hebron Platform Execution

Gravity Based Structure

- Gavity Based Structure (GBS) construction in dry dock including civil and mechanical outfitting (MOF)
- Tow out and installation at deep water site (DWS)
- GBS construction at DWS - civil and MOF including solid ballast

Topsides

- Utilities process module (UPM) transferred to topsides integration pier via heavy lift vessel
- Drilling support module (DSM) & drilling equipment set (DES) installed and integrated onto UPM
- Living quarters (LQ), helideck and west lifeboat station transferred to barge and installed onto UPM
- East lifeboat station and flare boom lifted and installed onto UPM
- Complete all module integration connections and commissioning
- Integrated topsides floated to the Bull Arm DWS for mating and hook-up with the GBS

Deep Water Site

- GBS towed out and topsides floated over; deck mating at deep water site
- Hook-up and commissioning topsides-GBS

Offshore

- Tow out and installation at offshore location, including grouting

Example: GBS Project Hibernia

The Hibernia platform is designed to resist the impact of sea ice and icebergs. It can withstand the impact of a one-million tonne iceberg with no damage. It can withstand contact with a six million tonne iceberg, estimated to be the largest that can drift into that water depth and only expected once in 10000 years, with repairable damage.

Because the Hibernia platform is located in relatively shallow water (80m water depth) the probability that a large iceberg ever hits the platform is extremely low. Located offshore east-southeast of St. John's, Newfoundland, Canada, the production platform Hibernia is the world's largest oil platform.

The platform has three separate components, the Topsides, the GBS and the Offshore Loading System (*Figure 27*). The Topside is composed of five super modules: Process (Module 10), Wellhead (Module 20), Mud (Module 30), Utilities (Module 40) and Accommodations (Module 50). For details reference is made to *www. hibernia.ca* .

The Topside is supported by the massive concrete GBS. The GBS, which sits on the ocean floor, is 111 m high and has storage capacity for 1.3 million barrels of crude oil in its 85 m high caisson. The GBS is specially designed to withstand the impact of sea ice and icebergs to allow for year-round production.

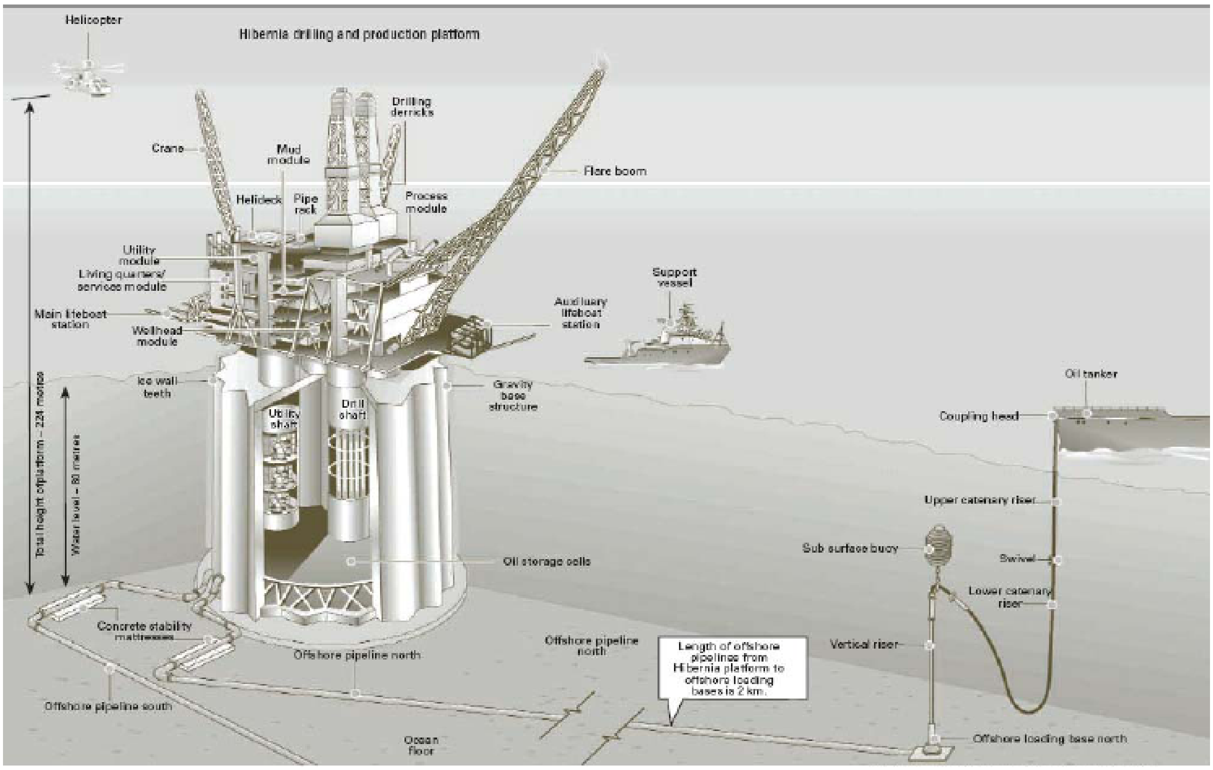


Figure 27 Hibernia Drilling and Production Platform with Offshore Loading System (OLS), (*Bott, 2004*)

Oil is exported from the Hibernia platform to shuttle tankers via a redundant Offshore Loading System (OLS). The OLS is comprised of a subsea pipeline, sub-surface buoy, and flexible loading hoses. As a measure of safety, the tanker loading point is located about 2 km away from the platform (*HMDC, 2007*).

Hibernia utilizes 3 custom-built shuttle tankers for oil transport – the *Kometik, Vinland,* and *Mattea*. These shuttle tankers have storage capacities of 850000 barrels, are double-hulled and have double bottoms with additional strengthening (particularly at the waterline). They are bow-loaded and are capable of quickly disconnecting from the OLS (*HMDC, 2007*).

The Hibernia platform has a total height of 224 m and weighs 1.32 million tons (1.2 million tonnes). Platform height is made up from the 85 m caisson, 133 m of topsides facilities, and 26 m from the shafts that protrude through the GBS roof to support the topsides (*Figure 28*).The four shafts (a utility, riser, and 2 drilling) each measures 17 m in diameter (*HMDC, 2007*).

The Hibernia GBS is constructed of high-strength reinforced and pre-stressed concrete, which is reinforced with steel (rebar steel) and pre-stressed tendons (*SPG Media Limited, 2007d*). The GBS caisson, which measures 106 m in diameter, consists of an exterior 1.4 m thick ice-wall with 16 teeth intended to distribute iceberg loads over the entire structure. Furthermore, the GBS has a 15 m thick ice-belt, which includes the ice-wall (*HMDC, 2007*).

Figure 28 Hibernia Platform (*HMDC, 2007*)

Main Characteristics of Hibernia Platform

The following are the key data of the Hibernia development:

Licensee/Operator:	ExxonMobil Canada (33.125% stake) Chevron Canada (26.875% stake) Suncor Energy (20% stake) Canada Hibernia Holding Corporation (8.5% stake) Murphy Oil (6.5% stake) Statoil Canada (5% stake)
Location :	315 kilometers east-southeast of St. John's, Newfoundland, Jeanne d'Arc Basin Expected field life: n/a

To allow year-round production, the Hibernia platform is uniquely designed to withstand impact from sea ice and icebergs (*HMDC, 2007*).

Specifically, the platform is capable of withstanding the impact of a 1.1 million ton (1 million tonnes) iceberg (1-in-500-year event) (*SPG Media Limited, 2007d*), without sustaining damage, and a 6.6 million ton iceberg (6-million tonnes iceberg) estimated to be the largest that can drift into that water depth and only expected once in 10000 years, with repairable damage. (*HMDC, 2007*). Due to the fact that the Hibernia platform is located in relatively 80 m deep shallow water, the probability of a large iceberg ever hitting the platform is extremely low (www.Hibernia.ca).

Although the probability of an iceberg colliding with the platform is low, because Hibernia still employs an ice management strategy (*HMDC, 2007*).

Icebergs that require intervention are tackled proactively by platform supply vessels while they are still 20 km or more away from the platform. The platform support vessels tow the iceberg into a different trajectory. It is not necessary to tow the iceberg widely, as already a change of direction can be achieved through pushing by supply vessels over a 20 km drift.

On the other hand, close encounters with icebergs could, however, force the platform to stop production and actual contact may require repairs afterward. As well, any bottom-scouring iceberg could potentially cause damage to the platform's Offshore Loading System (OLS), a network of oil transmission pipelines on the ocean floor. For this reason, the OLS pipeline has been encased in concrete for additional protection. A redundant OLS system is in place to serve as an auxiliary, in the unlikely event that the other system is damaged.

The following measures are taken to ensure a highest possible degree of safety:

- the International Ice Patrol of the US Coast Guard and the Canadian Ice Service of Environment Canada both provide airborne surveillance briefings
- data is gathered by satellite and radar technology, as well as Hibernia's own state of-the-art platform radar system, which can identify approaching icebergs up to 18 nautical miles away
- helicopters use radio signals to precisely pinpoint an iceberg's position
- platform support vessels are equipped with technology that allows them to collect ocean current information as they sail toward the iceberg and transmit it back to St. John's via satellite

- using side scan sonar, the vessels will go alongside the iceberg and record a detailed profile to measure its draught.

5.1.6 Other Proposed Grand Banks Structures

The Steel Stepped Gravity Base (SSGB) shown in *Figure 29* was developed for application on the Grand Banks of Newfoundland in water depths of around 100 m (*Fitzpatrick and Kennedy, 1997*). The SSGB concept represents a departure from traditional cylindrical concrete gravity base production platforms with respect to shape, material and method of construction.

The principal criteria affecting the design of an offshore platform in the Grand Banks environment is icebergs, waves and foundation strength parameters. The design iceberg for the Grand Banks is estimated at a mass of 4.4 million tons (4 million tonnes). An iceberg of this mass can lead to a shear force of 100000 tons (90000 tonnes) and a moment of 6.3 million tonne-m) into a gravity base structure. This ice load can be applied from any direction and at any elevation. A structure capable of resisting such an ice load has to be monolithic or non-wave-transparent.

Ideally the design wave load would be very close to the ice load. The SSGB achieves this by reducing the diameter of the structure as it progress upwards through the water column.

The stepping process reduces the wave shear force to 110000 tons (100000 tonnes) and a moment of 5 million tonne-m which is very close to the ice load (*IMVPA, 2008*).

In specific terms, the base of the SSGB must minimally have an area capable of resisting the shear and overturning moments created by the ice or wave loads. The foundation parameters in conjunction with the wave and ice load determine the necessary base area of the structure to be 13000 m^2. The SSGB has been reviewed for deployment at several locations on the Grand Banks. Parameters chosen for the foundation design are considered representative of some of the weaker strength sites. Thus, the structure base area is unlikely to increase no matter where the structure might be considered for deployment.

Figure 29 Steel Stepped Gravity Base Structure

By optimizing the SSGB's shape the designer has been able to:

- Converge the global loads
- Minimize material use to 93700 tons (85000 tonnes) of steel and a ballast weight of 220500 tons (200000 tonnes)
- Provide free storage capacity. The structure needs a minimum footprint and size to resist the applied loads. This minimum size provides "free space". This free space provides a storage capacity of 750000 to 1000000 bbls.
- Provide hydrostatic stability. Steel structures have a low vertical center of gravity (VCG) and the VCG of a steel pyramid shape can be further lowered by the use of solid ballast. This low VCG offers stability under towing and as a result the structure can be safely towed to site when loaded with up to 33000 tons (30000 tonnes) of topsides
- Minimize setup time. All solid ballast has been installed prior to tow out. Water ballast is added to hold the structure in place

The SSGB provides an economical solution to the challenges of exploration and hydrocarbon production in iceberg infested waters. (*IMVPA, 2008*)

Figure 30 shows another example of a gravity base structure (GBS) for an offshore platform in arctic regions protected by patent (*US Patent No. 5044830 A – 3 September 1991*)

The invention relates to a gravity base structure for an offshore platform in arctic regions, the structure comprising a monolithic concrete caisson closed by a top slab and by a bottom slab resting on the sea bed, the caisson exhibiting at its circumference a configuration of vertical teeth capable of withstanding icebergs colliding with it and absorbing the impact energy.

The invention resists the external forces by a different device, does not involve the internal walls in withstanding and transmitting of the forces, and consequently reduces the weight of the structure and improves its marine stability; it likewise reduces the effects of the high temperature of the oil to be stored upon the materials forming the walls of the tanks. Thus, an remarkable reduction in the quantities of the structural materials and the prestressing reinforcements can be achieved.

The structure incorporates at its circumference a double wall formed by two concentric walls mutually connected by vertical partition walls forming a lattice structure of triangular prisms, the outer concentric wall carrying the defensive elements.

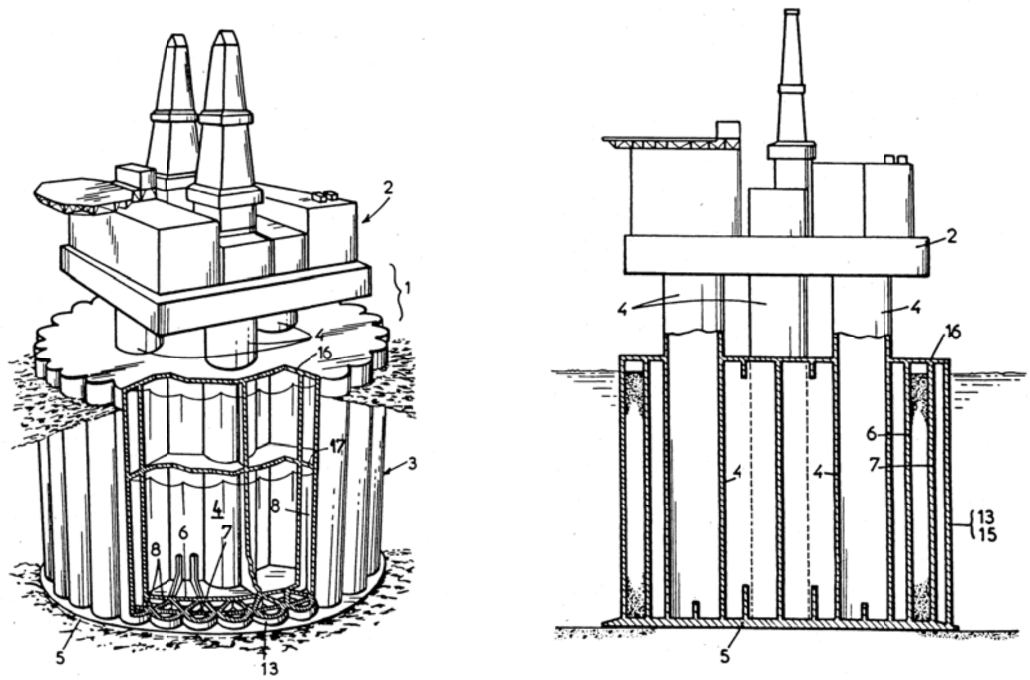


Figure 30 Monolithic concrete caisson for Arctic regions (US Patent 5044830 A)

Example: GBS Project Sakhalin II in the Sea of Okhotsk - Export via Pipeline

Production by means of a fixed Gravity Based Structure (GBS) and export via pipeline has been realized e.g. with the Sakhalin II development in the Sea of Okhotsk (reference: *www.shell.com*).

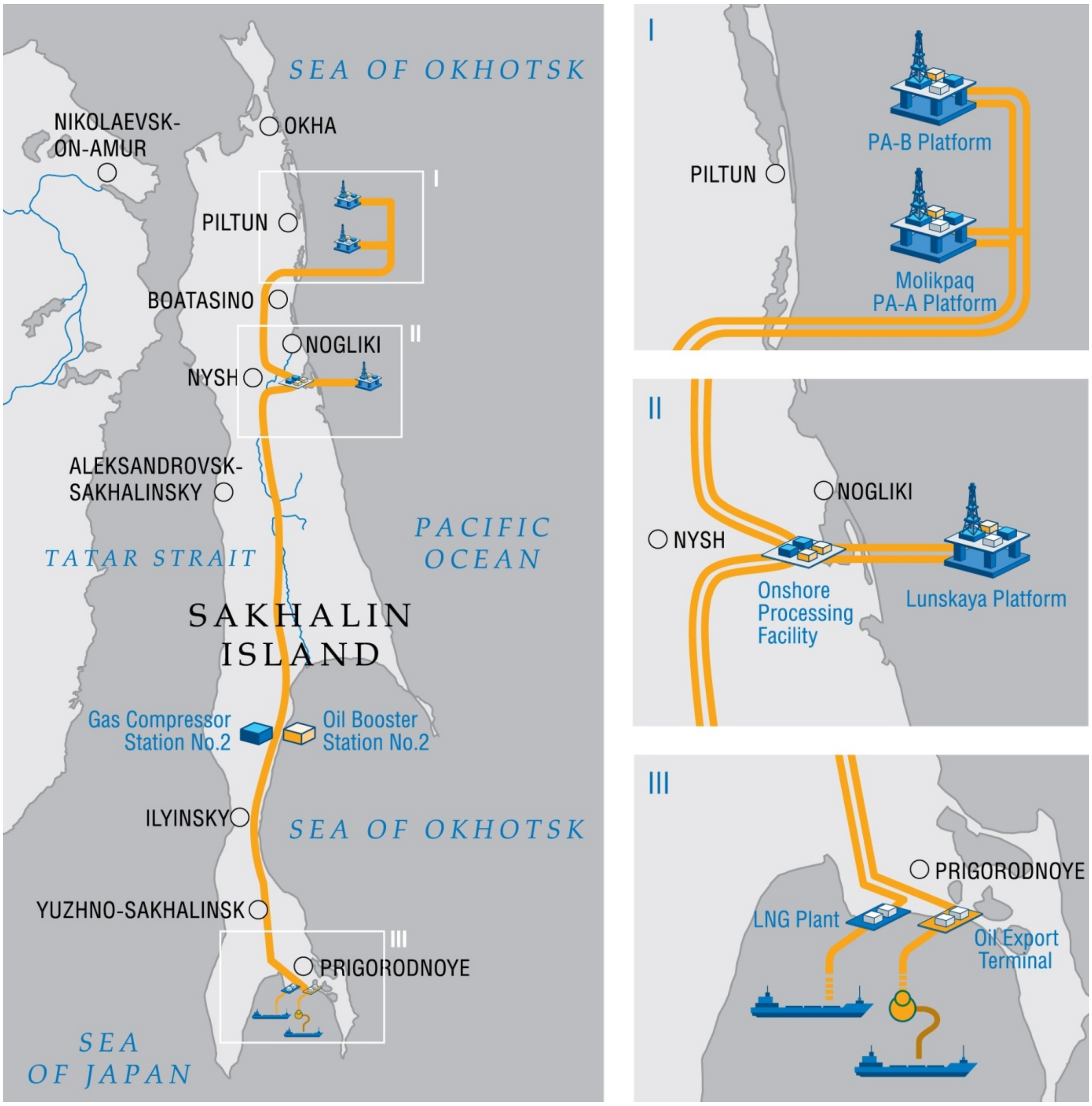


Figure 31 Sakhalin II Project

Located on the far eastern edge of Russia, offshore Sakhalin Island, near Japan, Sakhalin II is Russia's first offshore gas field brought into production (see *Figure 31*).

The project includes three large offshore production platforms in the north east of Sakhalin, an Onshore Processing Facility (OPF), Russia’s first natural gas liquefaction plant in the

south, an oil export terminal and a large onshore and offshore pipeline system to connect all these facilities.
The two-phase project incorporates the Lunskoye gas field, which was discovered in 1984, and the Piltun-Astokhskoye (PA) oil field, which was discovered in 1986. Together, these fields hold more than 1 billion barrels of oil and more than 500 billion m^3 of natural gas. At its peak it will produce some 395000 boe/day. The LNG plant will have a capacity of 9.6 mtpa from its first two trains.

The offshore oil platform Molikpaq (PA-A) was the first to be installed on the Russian shelf. The Lunskoye-A and Piltun-Astokhkoye-B (PA-B) platforms are also the first of their type to be installed with float-over technique on the shelf.

The first phase of development on Sakhalin II involved the installation of the Vityaz Production Complex on the PA oil field. Located in 30 m water depth in the Sea of Okhotsk, 16 km off the eastern coast of Sakhalin Island, Vityaz consists of a platform, mooring system and Floating Storage Offloading (FSO) unit. Produced oil is transported from Molikpaq via pipeline to the Okha FSO. The modified tanker Okha is a double-hulled vessel capable of storing up to 1 million barrels of oil. A single anchor leg mooring buoy system (SALM) is used to moor the FSO for offloading crude oil to tankers. Because of the arctic conditions at the complex, the FSO is only able to offload petroleum during the ice-free season, a six-month period year. Each production season, Vityaz produces some 85 million barrels of oil. During the ice season, the Okha FSO is leased out to work as a super tanker in the region, and the SALM system[12] is lowered into the water.

Main Characteristics

The following are the key data of the Sakhalin II development:

Licensee/Operator	Gazprom	(50% stake)
	Shell	(27.5% stake)
	Mitsui	(12.5% stake)
	Mitsubishi	(10% stake)

Location	Molikpaq	16 km offshore Sakhalin Island
	Lunskoye-A	15 km northeast offshore Sakhalin Island
	PA-B	
	Expected field life	$\geq$25 years

Discovery Lunskoye gas field: 1984
Piltun-Astokhskoye (PA) oil field: 1986

Start of production	Lunskoye gas field: 2008
	Piltun-Astokhskoye (PA) oil field: 1999

Water depth	Molikpaq	30 m
	Lunskoye-A	48 m
	PA-B	30 m

[12] SALM : Single Anchor Loading Mooring system

Platform type	Molikpaq	Monohull steel platform; FSO Okha		
	Lunskoye-A	GBS		
	PA-B	GBS		
FSO storage capacity:	1 billion barrel			
Platform dimensions:	Molikpaq	120 m wide, weight: 37,523t		
	Lunskoye-A	topside weight: 22.000 t		
	PA-B	topside weight: 28.000 t		
No. of Wells:	Molikpaq	>2		
	Lunskoye-A	27		
	PA-B	>2		
Estimated reserves:	natural gas:	500 billion m3		
	oil:	1-1.2 billion barrels		
Production:	Molikpaq	oil: 90000 bpd (barrels per day) natural gas: 2 MMcm/d (re-injected) (MMcm/d =million cubic meters per day)		
	Lunskoye-A	gas:	50 MMcm/d	
			condensate:	50000 bpd
	PA-B	oil:	70000 bpd	
	LNG plant		9.6 mtpa (million tons per annum)	
Export concept:				
	Molikpaq	via subsea pipeline to FSO Okha – via shuttle tanker to clients (from 2008 year round export via the new pipelines)		
	Lunskoye-A	2 pipelines (1x oil, 1x gas)		
	PA-B	2 pipelines (1x oil, 1x gas) pipelines total length: 300 km pipelines to LNG plant: 1600 km		
Personnel:	more than 25,000 jobs on the project (during construction) – 70% of them filled by Russian citizens;			
	Molikpaq	150		
	Lunskoye-A	126		
	PA-B			
	LNG plant:	300		
Training:	the consortium invests in several training, educational and social welfare activities in the Sakhalin area			
Services:	onshore support services spread in the Sakhalin area reducing unemployment rate from >6% to ~1%			

Example: Piltun-Astokhskoye-A platform (Sakhalin I project, Russia)

The Molikpaq drilling and oil production platform (Piltun-Astokhskoye-A platform) is an ice-resistant structure, originally built to explore for oil in the Canadian Beaufort Sea. It was taken out of operation in 1990, and was installed eight years later in the Astokh area of the Piltun-Astokhskoye field, 16 km offshore. The Molikpaq has a production capacity of 90000 barrels per day (14000 m^3/d) of oil and 1.7 million m^3 of associated gas.

Figure 32 The Molikpaq drilling and oil production platform (Piltun-Astokhskoye-A platform)

Figure 32 and *Figure 33* show the Piltun-Astokhskoye-A platform of the Sakhalin 1 project offshore Russia in winter after the Ice Breaking Supply Vessel *Pacific Endeavour* has been turning around clearing the ice away (ice management) to reduce ice loads and gain access to the platform for cargo discharge. (reference: *ww.oilrig-photos.com*).

Figure 33 Molikpaq production platform of the Sakhalin 1 project offshore Russia. (source: *www.oilrig-photos.com*)

Example: Piltun-Astokhskoye-B platform

The PA-B platform (see *Figure 34*) was installed in July 2007 in the Piltun area of the Piltun-Astokhskoye oil field, 12 km offshore. The PA-B has production capacity of 70000 barrels per day (11000 m^3/d) of oil and 2.8 million m^3 of associated gas.

Figure 34 Piltun-Astokhskoye-B platform (PA-B), [source: *Sakhalin Energy*]

Example: Offshore Lun-A platform

The Lunskoye field platform (*Figure 35*) was installed in June 2006 at the Lunskoye gas field 15 km offshore. It has production capacity over 50 million m^3 of natural gas, around 50000 barrels per day (7900 m^3/d) of peak liquids (associated water and condensate), and 16000 barrels per day (2500 m^3/d) of oil.

Figure 35 Concrete fixed 4-leg platform Lunskoye-A (Source: *Sakhalin Energy*)

Kashagan Project in North Caspian Sea

The Kashagan project is considered to be one of the most important field developments in the world. It is estimated to hold 38 billion barrels of oil-in-place, of which 16 billion are potentially recoverable reserves, and is considered to be one of the largest oil finds discovered in the past three decades.

Since its discovery, the project has faced several problems, including technical difficulties of extracting oil in a harsh climate, and the presence of sulphide in the associated natural gas. Because of this drawback, the original production date was planned for 2005, however postponed to 2012.

Located in the North Caspian Sea approximately 80 km offshore Atyrau, the Kashagan field is the most important field in the 11 offshore blocks in the North Caspian Sea Production Sharing Agreement. The area is about 5600 km^2 and includes four additional fields:

- Kalamkas
- Kashagan Southwest
- Aktote and
- Kairan.

A Production Sharing Agreement (PSA) was formed between the government of Kazakhstan and the Offshore Kazakhstan International Operating Company (OKIOC) in 1997.

The partners decided to create a consortium named Agip Kazakhstan North Caspian Operating Company N.V. (Agip KCO), and consists of:

- ENI (18.52 %)
- ExxonMobil (18.52%)
- Shell (18.52%)
- Total (18.52%)
- ConocoPhillips (9.26%)
- KasMunaiGaz (8.33%), and
- Inpex (8.33%).

Example: Drilling Rig Sunkar

A shallow draft barge rig was contracted to drill five exploration wells south of Atyrau in the Northern Caspian Sea (see *Figure 36*) in the first offshore drilling operation attempted in Kazakhstan. The rig "Sunkar", a floating production barge, was completed in 1999 and towed to its first location to perform the drilling program.

Owned by Parker Drilling, the rig was extensively modified not only to function in the extreme climate but also to keep up with the strict environmental codes since the field lies in a nature preserve.

The rig was adapted at the Astrakhan yard, and measures about 50 m by 82 m, weighs 6000 tons (5443 tonnes) and can accommodate a maximum of 100 people.

To protect the rig and in particular the steel tanks from drifting ice, 24 steel piles, each weighing 70 tons (64 tonnes), are driven into the ground on both sides of the rig (see *Figure 38*). The piles break up the drifting ice before it reaches the steel tanks.

In shallow water areas purpose designed permanent ice protection structures, so called ice barriers made from rock or concrete material are built to initiate ice rubble formation at a safe distance around drilling platforms our artificial islands.

For drilling exploration structures which usually have to change their location (e.g. drilling rig "Sunkar") ice barriers made from steel (e.g. barges) are the more favourable solution because they can be installed and de-installed more easily (*Berger, 2008*).

Figure 37 shows the drilling rig "Sunkar" with steel barges sat on ground as protection structures.

Figure 36 Satellite image from the Caspian Sea

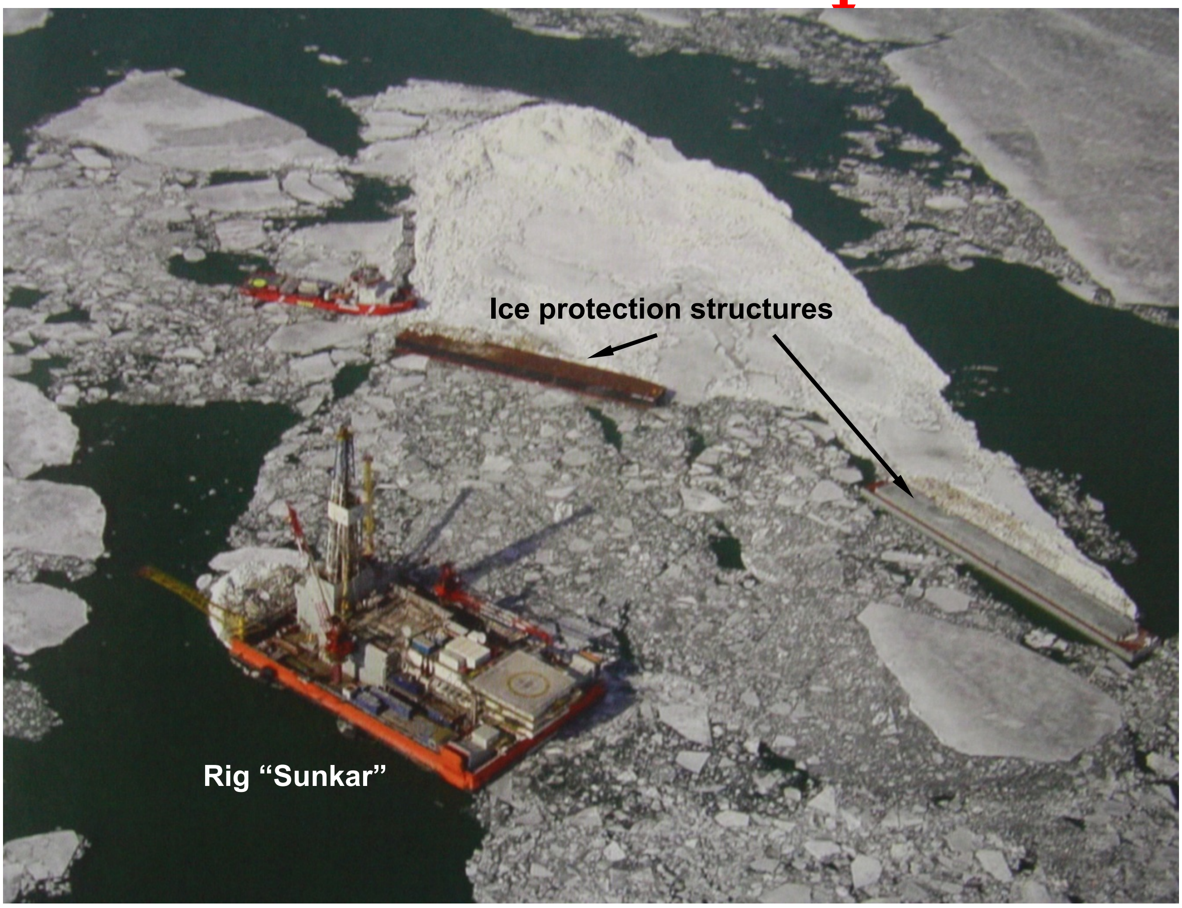


Figure 37 Drilling rig “Sunkar” surrounded by ice protection structures (grounded steel barges)

Figure 38 Drilling Rig "Sunkar" in shallow water of the North Caspian Sea

In 1998, ConocoPhillips acquired an interest in 11 blocks off the coast of Kazakhstan through the Republic of Kazakhstans NCSPSA. The drilling rig, Sunkar, drilled the first exploration well, Kashagan East-1. The well was completed as a discovery in 2000, when it was drilled in 3 meters of water and reached a total drilling depth of 5200 m. Subsequent exploration drillings revealed four more giant fields: the Kalamkas, Kashagan Southwest, Aktote and Kairan. Kashagan West-1 was the second discovery well.

Discovered in October 2001, the tests showed that the well flowed at a rate of 3400 bopd, while the oil gravity measured between 42 and 45 API.[13] The well was drilled to a total depth of about 5000 m.

Kashagan East-2 was discovered in late 2001 and was the third well drilled to a total depth of about 4150 m and with a flow rate of 7400 bopd[14].

The oil found is light and has a high gas-oil ratio. The field is heavily overpressured which presented a significant drilling challenge. The recovery factor is relatively low due to reservoir complexity, with between 4 and 13 billion barrels being the estimated ultimate reserve (reference: w*ww.subseaiq.com*).

Figure 39 and *Figure 40* show artificial islands located in the Kashagan field.

Figure 39 Kashagan – Artificial Island A (courtesy: *ENI*)

[13] API gravity is a measure of how heavy or light a petroleum liquid is compared to water. If its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks. The API scale was designed so that most values would fall between 10 and 70 API gravity degrees.
[14] bopd = barrels of oil per day

Figure 40 Kashagan – Artificial Island D surrounded by protection structures (ice barriers) [courtesy: *ENI*]

A development plan, adopted on February 2004, commenced operations in 2006, which calls for the field to be developed through three phases. In 2007, a revised Kashagan development plan and budget were submitted, which further delayed the development and production dates of the project. Finally, after government officials and the consortium came to an agreement, field development continued with the production date set for 2012.

The first phase of development, includes the construction of artificial islands for wells, processing facilities, living quarters and pipelines to carry products onshore to oil, natural gas and sulfur plants.

Four large rock structures, known as artificial or drilling islands were created for the Kashagan field, and two additional islands were formed for the Aktote and Kairan fields.

These six islands are linked between themselves and onshore operations by pipelines. The islands are used to collect and store oil, to ensure the initial separation of oil and gas and to maximize oil recovery and reduce sulphur production.

Oil and non-reinjected gas will be treated in the hubs and delivered through two separate pipelines to onshore treatment plants in Bolashak (Atyrau). At the treatment plants, the oil will be stabilized and purified; natural gas will be treated in order to remove hydrogen sulphide to be used as fuel for the production plants (reference: *www.subseaiq.com*).

Example: Gravity Based Platform Prirazlomnaya

Gazprom has started producing oil from the Prirazlomnoye field. It is the first Russian project for developing the Arctic shelf and the commencement of Gazprom's large-scale activities aimed at creating a large hydrocarbon production center in the region (see *Figure 41*).

The Prirazlomnoye oil field is located south of Novaya Zemlya in the Pechora Sea, 60 km offshore in shallow water of 20 m depth. This area is characterised by extremely low (-50°C) temperatures and strong ice loads. It is ice-free for about 110 days a year and the cold period lasts 230 days. The sheet ice thickness is up to 1.7 m.

It is reported that the platform will be able to safely resist the ice pressure generated by the ridge with a 3.5 m thick consolidated layer (*Central Design Bureau for Marine Engineering (Rubin), n.d.*)

The annual average temperature is -4°C and the temperature minimum is -50°C. Wind strengths reach up to 40 m/s and wave heights up to 12 m.

The field was discovered in 1989. The development license was granted to Rossneft in 1993 and transferred to Sevmorneftegaz in 2002.

The recoverable oil reserves amount to 72 million tons, projected oil production comes up to some 6 million tons a year, which is expected to be reached after 2020. The first oil shipment from Prirazlomnoye was conducted in the first quarter of 2014, and it is planned to produce no less than 300000 tons of oil throughout the year. Drilling plans envisage up to 40 directional wells (19 producing, 16 injection and five reserve). All wells will be drilled from the single rig on the platform, with simultaneous drilling and production. The production is expected to last for 22 years and th platform has a field life of 50 years.

The Prirazlomnaya offshore ice-resistant stationary platform secures every process operation in the field – drilling for oil, its production and storage, end product processing and offloading. It is for the first time in the world that hydrocarbons in the Arctic shelf will be produced by a stationary platform (*Offshore Technology, 2014*).

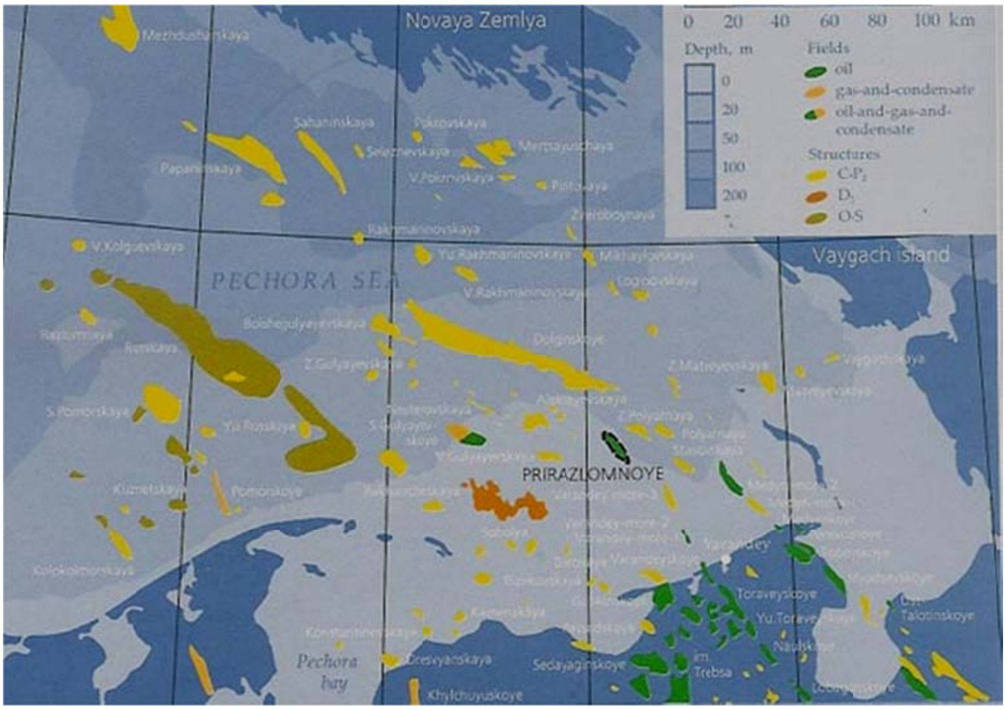


Figure 41 Map of the Prirazlomnoye field (source: *Offshore Technology*)

Prirazlomnaya is a GBP platform designed and constructed in Russia on Gazprom's request. This offshore fixed gravity platform is the first construction of its kind in Russia. It is designed for operation under extreme environmental and climatic conditions, meets the most stringent safety requirements and can resist high ice loads. Special alloys resistant to corrosion, low temperatures, high humidity and an aggressive marine environment were used during the platform construction. The platform is secured on the seabed by its own weight (506000 tons, including the stone berm artificially created for protection against scouring). A high-strength deflector secures the platform from wave and ice exposure (see *Figure 42*).

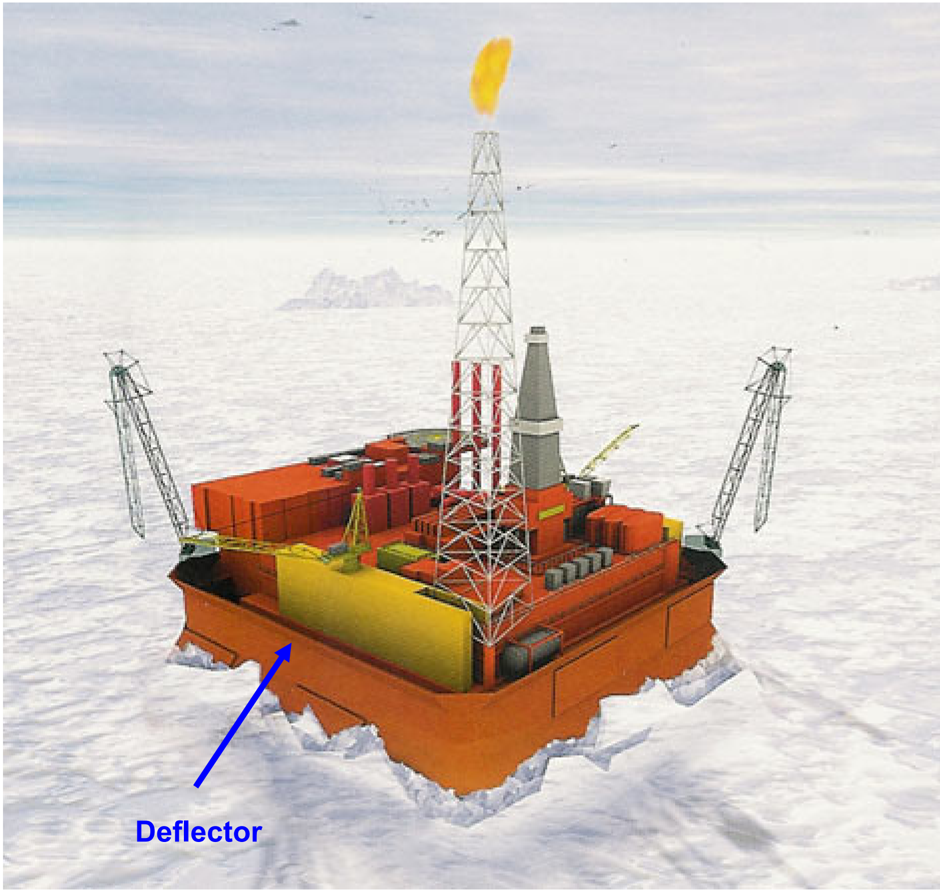


Figure 42 Artist's impression of the GBP Prirazlomnaya in the Pechora Sea (source: *Offshore Technology, 2014*)

The design features of Prirazlomnaya fully exclude any oil spills during its production and storage. All the wellheads are situated inside the platform. This way, its foundation serves as a buffer between the wells and the open sea (*Gazprom, 2014*).

Produced oil is stored in the caisson with three-meter-high concrete walls covered with two-layer corrosion- and wear-proof clad steel plate. The safety margin of the Prirazlomnaya caisson exceeds greatly the actual loads (*Gazprom, 2014*).

The topsides are based on the former UK North Sea Hutton tension leg platform, bought by Rosneft in 2002 and upgraded for its new work at the FSUE Sevmash military shipyard in Severodvinsk. The topsides were dismantled near Murmansk and towed to Severodvinsk. Meanwhile, the caisson was constructed by Sevmash as a number of caisson superblocks. The yard was also responsible for the offloading complex, platform towing and the accommodation module. Nearby, in the Severodvinsk yard of Zvyozdochka, superblocks 1 and 4 were constructed. The technological module was built in the Vyborg shipyard and other parts of superblocks and piping were built at the Tsentrenergomontazh facilities (*Offshore Technology, 2014*).

Figure 43 shows an artist's impression of the different Prirazlomnaya platform modules.

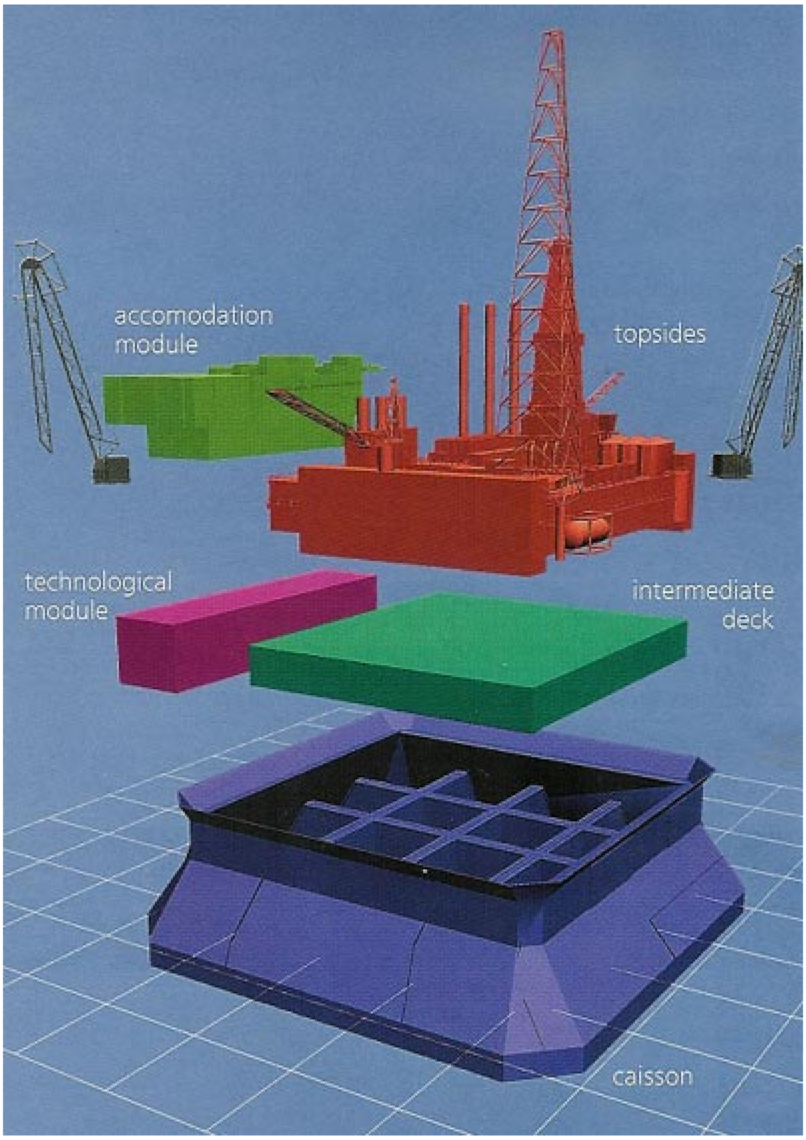
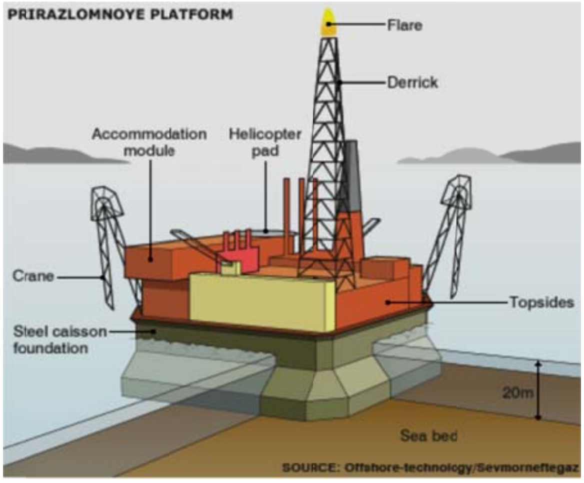


Figure 43 Artist's impression of the different platform modules (source *Offshore Technology, 2014*)

The topsides weight is 39000 tons and has a single derrick and 40 well slots. There are two oil offloading systems with capacities of up to 10000 m^3/hr. The topsides sit on a 126 m^2, 97000 tons caisson. It includes 14 oil storage tanks with a capacity of 113000 m^3, as well as two water storage tanks with a total capacity of 28000 m^3 (see *Figure 44*). The facility has an oil production capacity of 22000 tons/day, a gas production capacity of one million m^3/day and will inject water at 32000 m^3/day (*Offshore Technology, 2014*).

The superblocks were welded and installed in 2004 followed by the towing and installation the topsides and the concrete work. After a certain settlement period a safety berm was laid around platform.



(Source Offshore Technology)

Figure 44 Prirazlomnaya platform

A zero discharge system is employed at the platform. The system excludes the possibility of drilling and production waste getting into the sea. It will be pumped into special absorption wells or, if necessary, collected into tanks and delivered to the shore for further disposal. Reservoir and oil-contaminated waters will be pre-treated and also fed into the well.

In order to pump the end products into oil vessels, special equipment for direct oil loading was developed. The loading block system goes off in seven seconds at most, making it possible to avoid accidental oil spills.

Year-round product shipment is carried out in two stages. The 360000 tonnes FSO Belokamenka is installed in an ice-free part of Kola Bay, up to 1100 km away. Oil from Prirazlomnoye will be transferred to FSO Belokamenka near Murmansk by ice breaking shuttle tankers “Mikhail Ulyanov” and “Kirill Lavrov” super ice-class oil vessels with double hulls and capacity of 70000 dwt (*Figure 45* and *Figure 46*). The crude oil will then be exported by up to four 150000 dwt to 170000 dwt supertankers. On the platform site there are also two 16 MW multifunctional icebreakers for assisting the tankers as well as carrying out safety and environmental tasks (*Maritime Future, 2013; reference:www.gazprom.com*).

Figure 45 MT “Mikhail Ulyanov” approaches the Prirazlonaya platform (source: *Gazprom*)

Figure 46 Oil transfer from production platform to icebreaking shuttle tanker MT “Mikhail Ulyanov” (source: *Gazprom*)

Shtokman field

The project development has several sides and challenges – economical, technological, environmental and political. Discussion on a high level resulted in 2007 with signing agreements and establishment cooperation between Russian Gazprom, French Total, and Norwegian Statoil at the Phase 1 of the Shtokman field development. In 2008, the Shtokman Development Company was established with 51% shares of Gazprom, 25% of Total, and 24% of Statoil (*Bambulyak and Frantzen, 2011*).

The Shtokman field was identified in 1981 from offshore geophysical surveys performed by Sevmorneftegeofizika specialists on board the research vessel *Professor Shtokman*, which gave its name to the field. The geological study of the field was launched at the same time. In 1985 the structure was made ready for evaluation by drilling. In 1988 the first exploration well, with a design drilling depth of 4500 m, was drilled. Drilling was completed in July, 1988 at 3153 m. Well testing resulted in the discovery of two formations of free gas and gas condensate. Initial geological reserves estimated at 3.8 trillion m^3 of gas and 37 million tonnes of gas condensate (reference: *www.shtokman.ru*).

The field is located in the central part of the shelf zone in the Russian sector of the Barents Sea, about 600 km northeast of the city of Murmansk, where the water depth varies between 320 and 340 m.

The appearance of multi-year ice and icebergs weighing up to 4 million metric tonnes have been recorded on numerous occasions in the area (reference: *www.shtokman.ru*).
The Shtokman field development program encompasses the entire cycle of field development, from research to processing and transportation. A schematic scheme with the Floating Production Unit (FPU) and offshore installations of the Shtokman project is illustrated in *Figure 47*.

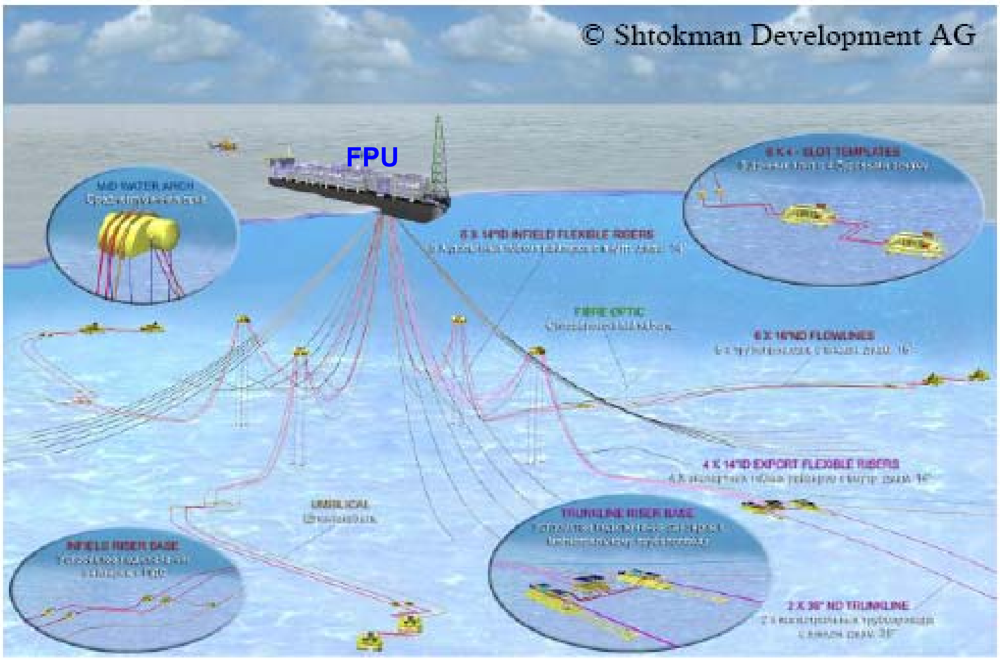


Figure 47 Schematic scheme of offshore installations of the Shtokman project (*Bambulyak and Frantzen, 2011*)

Annual gas production during the phase 1 of the project should be on the level of 23.7 billion m^3 of natural gas that will be split for producing 7.5 million tons of LNG, and piping 11 billion m^3 southwards. According to the new plans, agreed in 2011, the supply via the pipeline is to start in 2016, and LNG supply in 2017. The pipeline from Shtokman field will go to Teriberka, and then to Volkhov to join Nord Stream Gas pipeline. The LNG plant will be built in Teriberka, about 100 km east of Murmansk and the first LNG can be shipped in 2017 however Gazprom decided that pipeline gas deliveries from the Shtokman field to the European market would take priority over LNG shipments. (*Bambulyak and Frantzen, 2011*).

The Shtokman project will be developed in three phases – each for production of 23.7 billion cubic metres of natural gas per year. When the Shtokman project runs on a full scale, the yearly production at the field will be on the level over 70 billion m^3 of natural gas and 0.6 million tons of gas condensate.

The gas together with gas condensate will arrive from the offshore via double trunkline. The landfall will be located on the northern shore of the Kola Peninsula in Opasova bay near Teriberka. The onshore section of the trunkline between the landfall and the slug-catcher at gas treatment unit (GTU) will be buried underground and will be about 10 km long.

Downstream the slug-catcher the flow will be separated into two portions: half of the gas will go to GTU, the other to LNG plant for further processing and liquefaction.

The main purpose of the gas treatment unit (GTU) is to separate gas from condensate and treat it for transportation via main pipeline (reference: *www.shtokman.ru*).

The Russian gas will be transported via the Nord Stream gas pipeline to Europe as illustrated in *Figure 48* (*Bambulyak and Frantzen, 2011*).

Figure 48 Map of existing and projected pipelines from Shtokman Field

5.1.7 Export / Offloading terminals

General

The technical feasibility of marine terminals in arctic areas has been established through successful experience in a wide range of port facilities. A general review of experience in operation of high-latitude oil and gas marine terminals indicates that existing technology of port structures design and construction is sufficient to support operations in the Alaskan OCS.

While technically feasible, no tanker traffic has been proposed in the EIS for upcoming Beaufort or Chukchi lease sales. Regulatory requirements would require the use of pipelines (if economically feasible) rather than barging or tankering production to shore. An exception may be gas export by LNG[15] or CNG[16].

5.1.7.1 Prigorodnoye production complex and oil export terminal Aniva Bay

The Prigorodnoye Production Complex comprises a liquefied natural gas Sakhalin-2 LNG plant and an oil export terminal. The complex is located on the southern shore of Sakhalin island, alongside Aniva Bay, about 15 km to the east from Korsakov (*Figure 49* and *Figure 50*). Aniva Bay remains almost ice-free throughout the year and is a suitable place for oil and LNG deliveries as part of the Sakhalin-2 project.

The area of the complex measures about 4.2 km^2 (~420 ha). The LNG plant has two parallel process trains and general services facilities. Gas treatment and liquefaction are performed on the process trains. LNG is produced using “double mixed refrigerant” technology developed by Shell.

Shell developed this state-of-the-art technology for the Sakhalin LNG plant, to ensure maximum LNG production during severe Sakhalin winters. The production capacity of the plant is 9.6 million tonnes of LNG per year.

The plant has been designed to prevent major loss of containment in the event of an earthquake and to ensure the structural integrity of critical elements such as emergency shut down valves and the control room of the plant.

The LNG plant production capacity is 9.6 million tons of LNG per year. A special gas liquefaction process was developed by Shell for use in cold climates such as Sakhalin, based on the use of a double mixed refrigerant.

The LNG plant has two LNG double-walled, storage tanks with a capacity of 100000 m^3 each. LNG is exported via an 805 m long jetty in Aniva Bay. The jetty is fitted with four arms – two loading arms, one dual purpose arm and one vapour return arm.

The upper deck is designed for a road bed and electric cables. The lower deck is used for the LNG pipeline, communication lines and a footpath. LNG is pumped from the storage tanks into the parallel loading lines which are brought to the LNG jetty.

At the jetty head, the pipelines are connected with the jetty's four loading arms. The water depth at the tail of the jetty is 14 m. The jetty will serve LNG tankers which have capacities of between 18000 and 145000 m^3. (see *Figure 51* and *Figure 52*). Loading operations are estimated to take from six to 16 hours, depending on vessel size. The jetty will be able to

[15] LNG = Liquified Natural Gas
[16] CNG = Compressed Natural Gas

handle loading of around 160 LNG carriers per year. *Figure 50* shows the Sakhalin-2 LNG liquefaction plant.

Figure 49 Location of Prigorodnoye Production Complex (46°37'39.0"N 142°54'10.1"E) and LNG export terminal (source: *google maps*)

Figure 50 Sakhalin II LNG plant (commissioning date: February 2009), [source: *Sakhalin Energy*]

Figure 51 LNG tanker approaching the jetty head during ice-free season

Figure 52 LNG tanker approaching the jetty head with tug boat assistance in light ice conditions

The Oil Export Terminal (OET), including offloading pipeline and Tanker Loading Unit (TLU) for loading oil to the tankers, is located to the east from the LNG plant. The oil export terminal operations are managed in the control room, the supporting utilities are located on the territory of the LNG plant. Oil is transported from the Piltun-Astokhskoye and Lunskoye fields through the Trans-Sakhalin pipeline system to the oil export terminal. The oil is then mixed with a small amount of condensate recovered from the natural gas stream, and stored in two floating roof storage tanks each with a capacity of 95000 m^3.

Afterwards, the oil is transferred through the offshore pipeline to the 74 m high tanker loading unit, which is situated in a water depth of about 30 m, 4.8 km offshore. Oil tankers with a capacity from 40000 m^3 to 150000 m^3 can be loaded at the TLU (*www.sakhalinenergy.com*).

5.1.7.2 Trans-Sakhalin pipelines

The Trans-Sakhalin pipeline system is designed for transportation of hydrocarbons from the Piltun-Astokhskoye and Lunskoye fields in the North of Sakhalin Island to the onshore processing facility in the Nogliki district and to the LNG plant and the oil export terminal in Aniva Bay.

5.1.7.3 Arctic Tower Loading Unit (TLU) for the Sakhalin I, DeKastri Oil Export Terminal

De-Kastri oil terminal is an oil export terminal located 6 km away from the village of De-Kastri in Khabarovsk Krai, Russian Federation. It is one of the biggest oil terminals in the Far East that serves as a hub for crude oil deliveries to Asian markets.

The oil is transported to the terminal from the Sakhalin-1 onshore production facility northeast of Sakhalin Island via a 226-kilometer pipeline. One of the largest of its class, the single point mooring facility is being utilized to safely load the tankers in heavy ice conditions. The terminal is the first in Russia to successfully accomplish the year-round export of oil during severe arctic winter conditions using a specially designed fleet of double-hull Aframax class tankers. To ensure safe navigation through ice fields during severe winters, the tankers are escorted by ice-breaking vessels.

Since the start of operations in 2006, the terminal has offloaded 550 tankers with 51 million tons of Sakhalin-1-produced oil, which makes De-Kastri one of Far East Russia's largest ports (*www.sakhalin-1.com/Sakhalin/Russia*).

The terminal which started operations in 2006 belongs to the Sakhalin-I consortium led by Exxon Neftegas Ltd which also includes 20% stake held by Russian affiliates of Rosneft: Sakhalinmorneftegas-Shelf and RN-Astra. The overall capacity of the export terminal is approximately 88 million barrels per annum (~1.2 ×107 tonnes/a) of oil. Tanker loading capacity is suitable for Aframax tankers up to 110000 dwt. The five Aframax tankers servicing the terminal are purpose-designed double-hull ice class vessels. The area of the terminal covers nearly 256000 m^2. The construction of the terminal started in 2003 and was completed by August 2006. (*http://en.wikipedia.org/wiki/De-Kastri_terminal*)

Figure 53 Oil export terminal DeKastri

Figure 54 Oil export terminal DeKastri surrounded by level ice

The Tower Loading Unit is designed to moor a dedicated 110000 dwt, Aframax class tanker all year round in ice conditions with temperatures as low as –35° Celsius. The unit is provided with an off-loading arm to prevent hose contact with water or ice at all times. In addition to a bow loading system, the unit is capable of offloading via a floating hose system for midship loading during the summer months.

The terminal consists of a fixed vertical tower structure, piled into the seabed with a rotating head on top of the substructure. The tanker connects to the rotating head via a hawser arrangement. A slew bearing allows the rotating head to turn relative to the substructure, ensuring that the tanker can weathervane freely and take up the position of least resistance to the prevailing weather at all times.

The rotating head position, control of the winches for the hawser and loading hose, and the operation of valves etc. can be controlled remotely from the tanker as well as from the shore base.

Comprehensive ice model tests have been carried out at Krylov Ship Research Institute (KSRI) and the Hamburg Ship Model Basin (HSVA) in level ice conditions to establish the design loads. In order to withstand the harsh 100-year ice conditions, the tower is equipped with an ice breaking cone. The cone and structure are able to resist ice thicknesses of 2.0 m (consolidated layer thickness in ridged ice) or 1.5 m level ice. During operations, with the tanker attached, the system can withstand drifting ice floes of approximately 60 m in size with thicknesses of up to 0.55 m.

The structure has also been designed to resist fatigue during its design life caused by waves and the alternating ice loads of drifting ice-floes and to withstand earthquakes.

The challenging seabed conditions consisted of very soft soil in the top 5 m, and weathered rock between 12 and 16 m below the seabed. Therefore a special foundation was designed for the 'in-place condition' as well for the 'un-piled condition'.

Arctic tower loading details

Designed and built by:	Bluewater Energy Services BV
Client:	Exxon Neftegas Ltd., Russia
	Project Sakhalin I, DeKastri Oil Export Terminal
Completed.	2005
Location:	Offshore DeKastri on the Siberian side of the Tatar Strait
Water depth.	21.5 m
Off loading capacity.	8,000 m^3/hr
Tanker size.	110 000 DWT
Design temperature:	-35 °C
1/100 year ice thickness:.	2.0 m (consolidated layer in ridged ice)
1/100 year ice thickness:	1.5 m (level ice)
1/100 year wave height:	10.9 m
Operational ice thickness:	floe size 60 m, level ice thickness 0.55 metres
Peak ground acceleration:	2.0 m/s
Number of piles:	2 x 8 (pile in pile system)
Pile diameter:	72 inch sleeve pile, 56 inch insert pile

Overall length rotating head: 74 m

Elevation off-loading arm: 61 m above waterline

Riser diameter: 48 inch

5.1.7.4 Snøhvit LNG Export Terminal, Melkøya Island, Norway

The Snøhvit LNG project was constructed to exploit the resources of three gas fields in the Barents Sea: Snøhvit, Albatross and Askeladd in water depth between 250 m to 345 m, which lie about 140km northwest of Hammerfest in Norway (see *Figure 55*).

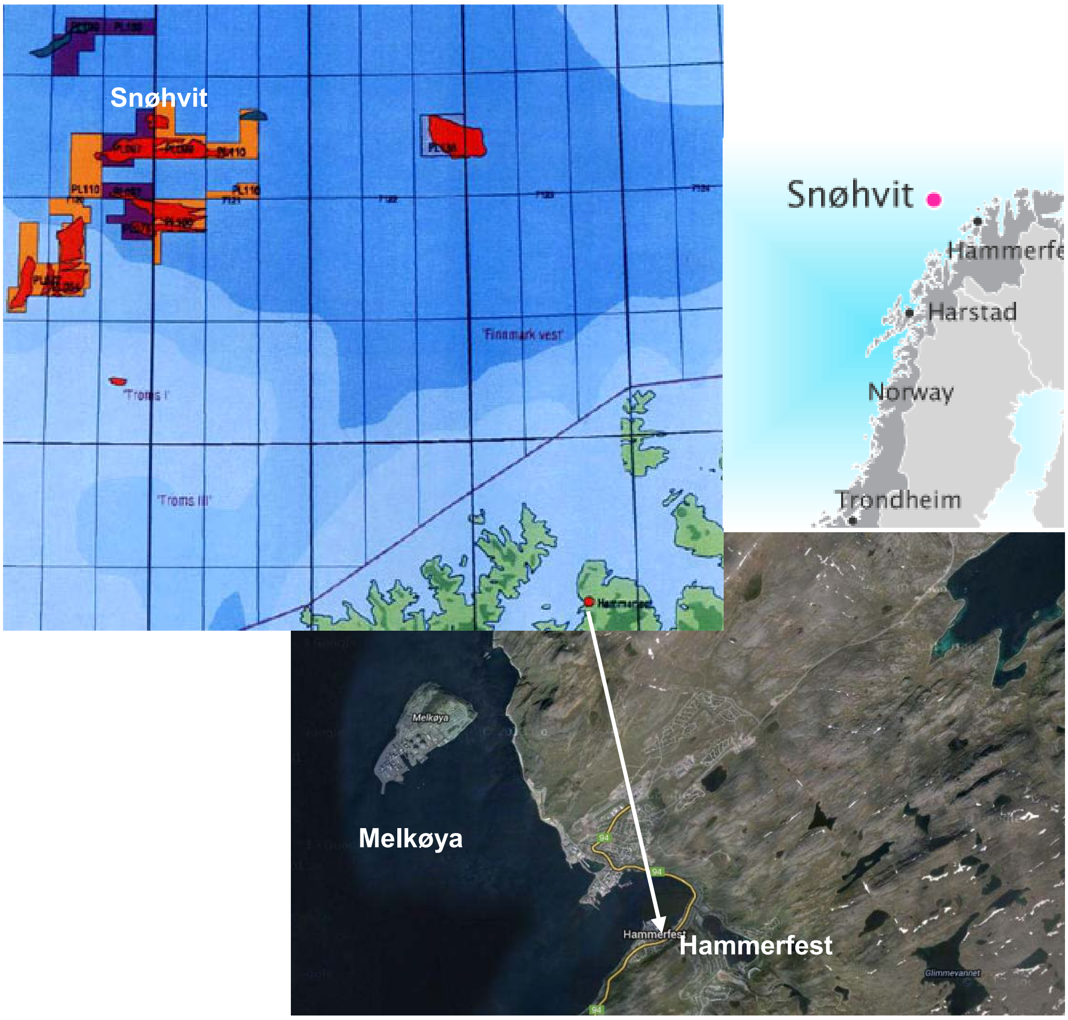


Figure 55 **The Snøhvit LNG project on Melknøya Island has estimated recoverable reserves of 193 billion m^3 of LNG, 17.9 million m^3 of condensate and 5.1 million tonnes of natural gas liquids (NGL).**

These fields, which were first discovered in the 1980s, have estimated reserves of 193 billion m^3 of LNG and 17.9 million m^3 of condensate and 5.1 million tonnes of natural gas liquids (NGL). The Snøhvit and Albatross fields came onstream in 2007, while the Askeladd is due to come onstream in 2014-15.

The gas production system is one of the first in Europe to use a subsea production platform, which feeds gas via 143 km of pipeline with multiphase flow to a 4.2 million tonnes a year LNG processing plant on Melkøa Island near Hammerfest. The project also has a carbon dioxide capture and storage facility located 2.6 km beneath the seabed of the Snøhvit field and a 153 km pipeline for reinjection. The facility can store 700000 t of carbon dioxide annually (*www.hydrocarbons-technology.com)*.

The project was led by Statoil as part of a consortium of eight companies.

The consortium consists of:

Statoil (33.53%),

Petoro (30%),

TotalFinalElf (18.4%),

Gaz de France (12%),

Amerada Hess (3.26%)

RWE-DEA (2.81%).

Construction on the project began in late 2003. The facility started production in September 2007 and will be used until 2035 (see *Figure 56*).

Figure 56 The Snøhvit gas production system was one of the first in Europe to use a subsea production platform

Snøhvit production capacity

The production capacity of the new single train facility is 4.3 million tonnes per year (equivalent to approximately 5.6 billion m^3 of LNG). Supply contracts were agreed with customers in the US east coast (El Paso) and Spain (Iberdrola), accounting for four million tonnes per year (the remaining capacity and any future expansion will go to Gaz de France).

The production capacity of Snøhvit is 4.3 million tonnes per year.

The unprocessed gas arriving at the LNG processing facility contains between 5% and 8% carbon dioxide. This is separated out at the processing and liquefaction facility and returned via a separate 160 km pipeline for storage / sequestration beneath the seabed (2600 m below the sea bed on the edge of the reservoir in the 45 m to 75 m thick Tubasen sandstone formation), thus preventing undue pollution and allowing Norway to adhere to the Kyoto treaty.

The energy efficiency of the liquefaction facility is 70%, which is the best yet achieved in any plant of this kind across the world (the compressor operates with an efficiency of 230 kWh per ton of LNG).

Liquefication / process barge

The heart of the Snøhvit LNG facility, the liquefaction plant, was borne and operated on a gas liquefaction barge, which was constructed at the Spanish shipyard group Izar Construcciones Naval (Dragados yard) in Cadiz.

The process barge measures 9 m ×154 m ×54 m. This process barge approach was chosen because it greatly reduces the need for steelwork on Melkøya Island, necessitates a compact efficient design, allowed prefabrication of modular components off-site in a convenient dry-dock situation and, most importantly, gives cost savings as well as higher productivity compared with constructing the plant on site. Following completion of the barge in May 2005, it was towed to an outfitting yard where 24000 t of process equipment for the gas liquefaction plant was installed on the deck.

The barge was then transported to Melkøya Island in July 2005 on a heavy-lift vessel and installed in a custom-built dock. The completion work for the barge on the island was completed by the end of August 2006 (*Figure 57* and *Figure 58*).

Figure 57 Dragados Offshore began construction of the 33,000-ton processing plant producing liquefied natural gas in June 2003 On 13 July 2005, the system was put in place in the dock at Melkøya outside Hammerfest (source: Statoil).

Figure 58 Snøhvit (Statoil LNG Plant 24.000 t (2005), (source: Dragados Offshore)

Instrumentation components and sub-systems

Parker Instrumentation supplied all of the instrumentation components and sub-systems for the Snøhvit LNG project. They provided over 1000 H-series manifolds, 20 km of conventional and heat race tubing and many thousand twin-ferrule A-LOK compression tube fittings.

The components were supplied fabricated in 316 grade stainless steel and, for areas where corrosion is a major problem (sea water cooling systems), in 6% Molybdenum steel. Parker also used its Supracase process to harden the ferrules of the fittings and avoid the affects of corrosion. The instrument enclosures provided by Parker are weather proof and equipped with antifreeze systems to allow them to operate at temperatures below -25°C.

LNG, condensate and LNG exports

The consortium needs four 145000 m^3 capacity carriers to deliver the LNG to receiving terminals in the US and southern ports of Europe.

Snøhvit annual exports are estimated to be 5.75 billion m^3 of LNG, 747000 t of condensate and 247000 t of LPG.

Arctic Princess (launched in April 2007) delivered the first 145000 m^3 LNG cargo from Snøhvit to southern Europe in October 2007.

Arctic Discoverer docked at the Cove Point gas import terminal in the state of Maryland, south of Washington DC, after a 12-day voyage across the Atlantic in July 2008.

It is estimated that 70 cargoes of LNG per year will be shipped out from the Melkøya facility. The annual exports are estimated to be 5.75 billion m^3 of LNG, 747000 t of condensate and 247000 t of liquefied petroleum gases (LPG).

Construction of the LNG tanks

The Snøhvit project required the construction of two LNG tanks, one condensate tank and one LPG tank at the gas processing complex on Melkøya Island. The respective tanks have the following capacities and dimensions:

- two LNG tanks 125000 m^3, diameter 74 m, height 48.70 m
- one condensate tank 75000 m^3, diameter 60 m, height 42.30 m
- one LPG tank 45000 m^3, diameter 50 m, height 37.90 m

DYWIDAG Systems International (DSI) was responsible for the supply and installation with stressing and grouting of a total of 1650 t horizontal and vertical DSI post-tensioning tendons with accessories in the construction of the tanks to allow them to withstand the extreme conditions.

The weather conditions during the construction were of an extreme Arctic nature. The tank walls were constructed by means of a slip formwork with a performance of two metres per 24 hours within a few weeks.

A particular challenge was the installation of the vertical tendons with 12 strands. The vertical tendons of the tanks are typical U-shaped or loop tendons. A loop tendon consists of two vertical tendons, which are connected at their bottom ends in the foundation by a 180° arc. Despite a maximum tank wall height of 40 m and an arc radius of only one metre the installation of the loop tendons by pushing single strands was carried out without any problems (*www.hydrocarbons-technology.com)*.

Problems at Snøhvit

The Snøhvit LNG plant at Melkøya had a troubled start-up period that saw it shut down four times after it came onstream in September 2007. StatoilHydro shut down the production from the field from June 2009 to November 2009 for repair and upgrades of the onshore plant cooling system.

A closure on 7 November 2007 was caused by a sea-water leak in a heat exchanger in the cooling system of the Melkøya liquefaction plant. The plant then resumed production in mid-January but was closed again in March 2008 for cooling system difficulties and then reopened in July 2008 (*www.hydrocarbons-technology.com*).

5.1.7.5 Offshore `Mooring Bay' concept developed by IMPaC

General

Gas transport by LNG tankers (Liquefied Natural Gas) can be an alternative to the use of pipelines. Each decision for a solution depends on several technical and economic factors with the distance to the client receiving facility being very relevant. In order to achieve economically reasonable transportation, the natural gas (mostly methane) is cooled down to -162 degrees C, whereby it is liquefied and reduced to 1/600th of its original volume.

Recently a ´Mooring Bay`concept was developed by IMPaC Offshore Engineering GmbH, Germany, allowing mooring of the vessels in tandem configuration and simultaneous handling and operation of up to six flexible transfer pipes in full aerial mode.

The new offshore LNG transfer system is outlined to operate with flexible transfer lines with 16-inch inner diameter like the newly designed and certified corrugated pipes. The mooring concept and its major subsystems have proven their operability by means of extensive numerical analysis, model tests and a professional ship handling simulator resulting in an overall transfer solution suitable to be used safely and reliable especially in harsh Arctic conditions.

State-of-the-art technology allows loading/offloading in moderate seas by means of articulated arm technology adapted from onshore technique. Nevertheless, the increasing loading capacity of LNG carriers (up to 266000 m³) creates a new market for fast and safe loading/unloading concepts for operations in rough seas and even in Arctic conditions.

Studies show that none of the ‘conventional’ vessel mooring configurations and transfer techniques can easily be adapted to meet the requirements of offshore LNG transfer, especially when dedicated for use in environmental conditions with significant wave heights up to e.g. 5.5 m at zero-up-crossing periods between 8 and 12 seconds or in ice conditions combined with significant wind and current loads and overall operation durations (incl. mooring, transfer and departure) of 18-24 hours (*Hoog et al., 2012*).

An innovative offshore-loading system MPLS20 (Maritime Pipe Loading System 20“) was developed by Brugg and Nexans for LNG (Liquefied Natural Gas) consisting of a flexible corrugated pipe made of stainless steel, an approaching- and handling system and the connection- and coupling technique considering the prevailing standards and safety regulations.

The unique selling point is the flexible corrugated pipe, which will compensate the dynamic caused by the offshore application and the innovative mooring system, which allows a close tandem mooring of the two ships. The system is certified by Det Norske Veritas (DNV); (reference : *www.mpls20.de*).

The overall system is based on IMPaC's patented offshore 'Mooring Bay' concept -certified by Germanischer Lloyd (GL) allowing safe and reliable mooring of the shuttle carriers to the FLNG and simultaneous handling and operation of up to six transfer pipes in aerial mode

System set-up

The mooring concept utilizes a unique tandem configuration for the LNG terminal (the FLNG) and the shuttle carrier (LNGC, see *Figure 59*). To meet the needs for Arctic application the initial design and the vessels have been adapted, resulting in icebreaking abilities, a new mooring concept for the barge and a modified concept for approach of the new I(ce)-LNGC to the mooring bay at the aft end of the new I(ce)-FLNG.

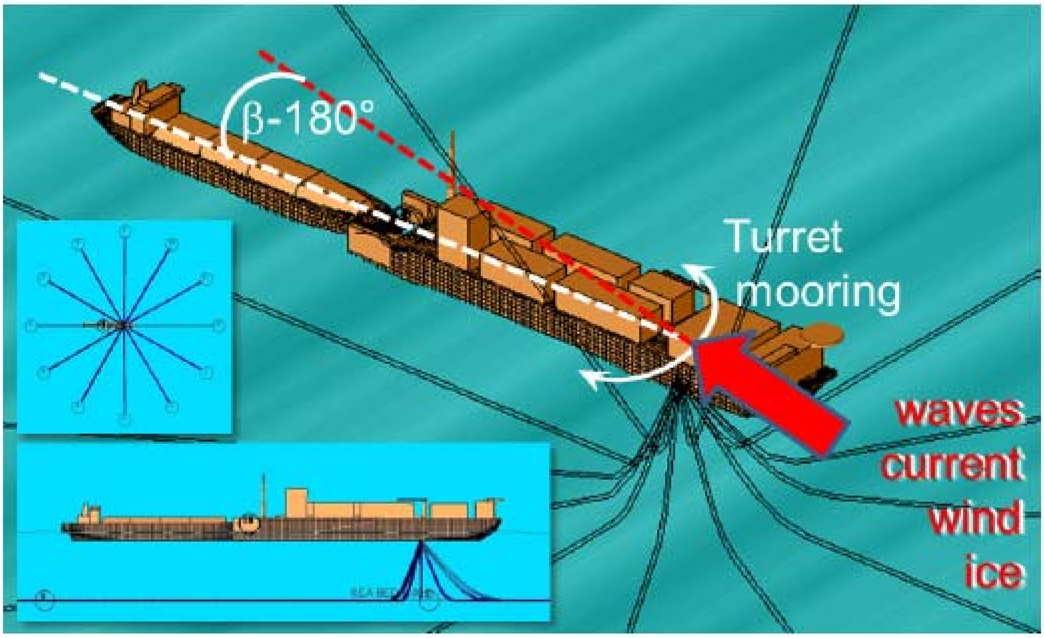


Figure 59 The turret mooring concept allows weathervaning as response to changing load directions (*Hoog et al., 2012*)

Mooring of the I(ce)-FLNG is realized by an internal turret mooring system using a submerged production buoy allowing coping with drifting ice. Up to sixteen segmented mooring lines are employed (depending on site specific environmental loads) to fix the buoy at location allowing weathervaning of the moored vessels in 360°.

Although the main focus of the development lies on the Mooring Bay and the cargo loading concept the hull design of both vessel types I(ce)-FLNG and I(ce)-LNGC is important for the concept, in particular in view of operation in ice conditions.

To reduce the response forces of the mooring lines to ice loads the terminal barge bow has been modified to improve the icebreaking capability. As result the bow shape of the I(ce)-FLNG can roughly be characterized as a flat spoon with about 30° stem angle and flared frames in the icebreaking zone allowing combining the required buoyancy and loading capacity with sufficient icebreaking capability (compare *Lundamo et al., 2008*).

A wedge-shaped plough at the bow of the barge serves as an ice clearing system reducing the amount of ice reaching the turret mooring system below the hull bottom.

The I(ce)-LNGC is a double acting vessel with azipod drives allowing the ship to pass level ice with thickness up to 1.5 m in backward direction (comparable hull designs are approved and operating) and with optimised behaviour in open water and reduced ice thickness in forward direction.

Relevant geometric parameters of the generic terminal barge and the carrier are given in *Table 9.*

Table 9 Main geometrical features of the LNG terminal and the LNG carrier (*Hoog et al., 2012*)

Item	Terminal (I-FLNG)	Carrier (I-LNGC)
Length (LOA) [m]	**360 (+ 40 Mooring Bay)**	**282**
Length (LPP) [m]	**347.7**	**257.4**
Width [m]	**65**	**42**
Draught [m]	**12**	**12**
Height [m]	**33**	**26**
Displacement [m^3]	**~253 000**	**~104 000**
LNG Loading capacity [m^3]	**250 000**	**138 000**

Offshore LNG Transfer Concept

The concept features the generic I(ce)-FLNG design with the so called `Mooring Bay´, double acting shuttle carriers and the handling system for a set of up to six flexible LNG/LPG transfer pipes (see *Figure 60*). The I(ce)-FLNG is of barge type providing a cargo loading capacity for LNG up to 250000 m^3 in five independent SPB tanks (Self-supporting, Prismatic, IMO Type B) which are sloshing-proof and provide a flat deck (reference: *www.mpls20.de*). By-products like LPG and condensate are stored in dedicated tanks with capacity up to 25000 m^3 each.

The employed I(ce)-LNGCs are ice going vessels with quasi standard dimensions and functionality but equipped with an additional receiving manifold at the bow deck space. This manifold completely enters the `Mooring Bay´when the carrier is pulled and moored to the cargo transfer position. The resulting distance between the loading flanges at the terminal and the receiving manifold at the carrier is thus minimized achieving a total length of less than 40 m for the transfer pipes.

The `Mooring Bay´ is built of two so called ‘mooring wings’, which are structurally part of the terminal’s aft end at starboard and port side, respectively, reducing the risk of ice inflow between both vessels (see *Figure 60*). For safety reasons any remaining ice in the `Mooring Bay´can be pushed out of way by means of dedicated thrusters at the aft end of the barge prior to the approach of carriers.

The mooring arrangement for the I(ce)-LNGC to the `Mooring Bay´ results in a symmetrical arrangement of six moorings each operated by load adequate winches and heave compensation systems at the I(ce)-FLNG. This arrangement provides a unique solution to actively pull in and stop the incoming vessel in a controlled manner at the required position right below the loading bridge. The moorings are temporarily fixed to quick release hooks (QRH) which can be remotely activated for safety reasons.

The cargo transfer flanges are located in a sheltered position within the loading bridge structure high above the wings weather decks so that handling, draining and purging of the flexible pipes can be carried out in a safe, efficient and reliable way as shown in *Figure 61* (*Hoog et al., 2012*).

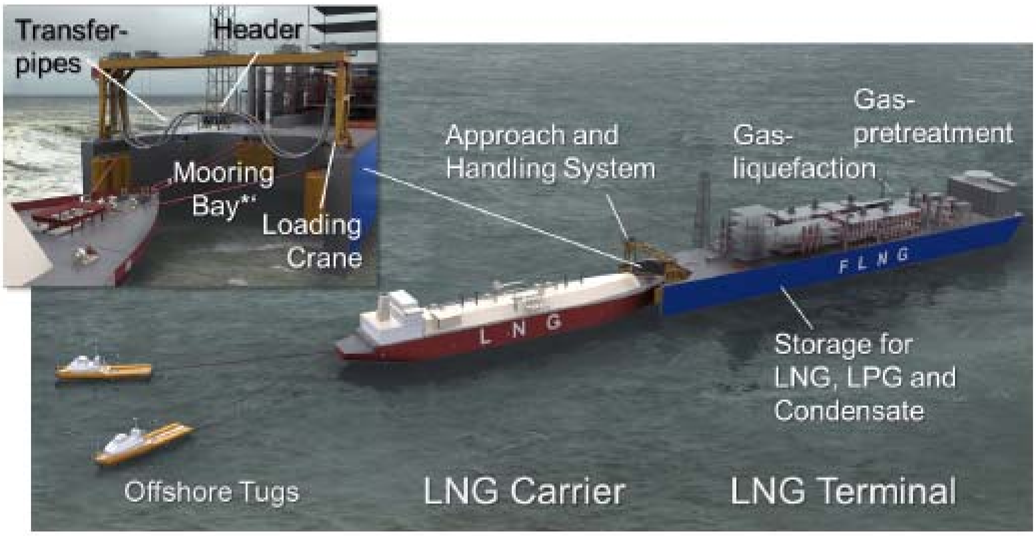


Figure 60 Main components of the MPLS20 concept (*Hoog et al., 2012*)

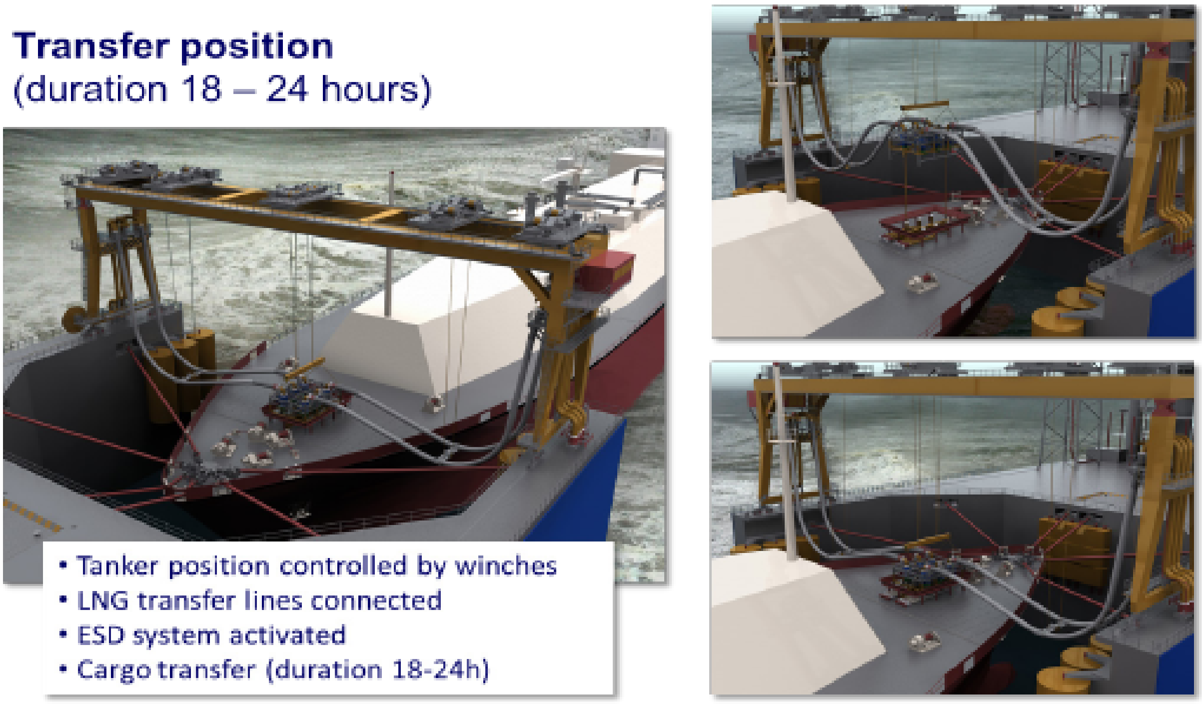


Figure 61 **Safe and reliable handling of the flexible pipes for cargo transfer and in ESD[17] situations (*Hoog et al., 2012*)**

Flexible LNG Transfer Pipes

Vacuum insulated pipes are common in all kinds of cryogenic application. Nevertheless, the developments of Nexans and Brugg are based on their flexible vacuum insulated pipe system CRYOFLEX for offshore LNG loading applications considering the code EN1474-2, (for details refer to *Frohne et al.,2008*).

These pipes provide a double containment system - the 'Pipe in Pipe' technology - having advantages in terms of leak detection and risk assessment of the installations with best thermal insulation properties.

A corrugated double wall pipe of stainless steel 316L is insulated by a super insulation and a vacuum space between these two pipes. A stainless steel braiding on the inner pipe bears the end cap load of the pipe. For mechanical protection an outer sheath of Polyethylene (PE) or Polyamide (PA) can be applied.

The vacuum does not need active pumping during operation for more than 15 years. The pipe structure offers leak detection in the vacuum space, giving a signal to the system if the vacuum degrades due to a leak in either the inner or the outer pipe. Nevertheless, in case of a problem the gas cannot escape to the environment because of the double containment system (*Hoog et al., 2012*).

[17] ESD = Emergency Shut Down

Maneuvering in Ice

The approach of the I(ce)-LNGC follows several clearly defined steps (see *Figure 62*):

The first step is the far field approach of the carrier with ice breaking in backward drive. This step is characterized by the entering of the carrier into the terminals ice free wake (Phase I). One of the waiting tugs moors to the aft end of the carrier allowing controlling of the alignment of both vessels. The carrier proceeds driving with very slow speed in forward direction to the Mooring Bay until mooring lines are deployed from the terminal to the QRH[18] at the carrier taking over speed control (Phase II). The final approach starts by the gentle and controlled pull-in of the carrier into the Mooring Bay until the receiving manifold has reached the exact position right under the loading bridge which is standby and ready for coupling of the header to the manifold as shown in *Figure 61* and *Figure 62* (Phase III).

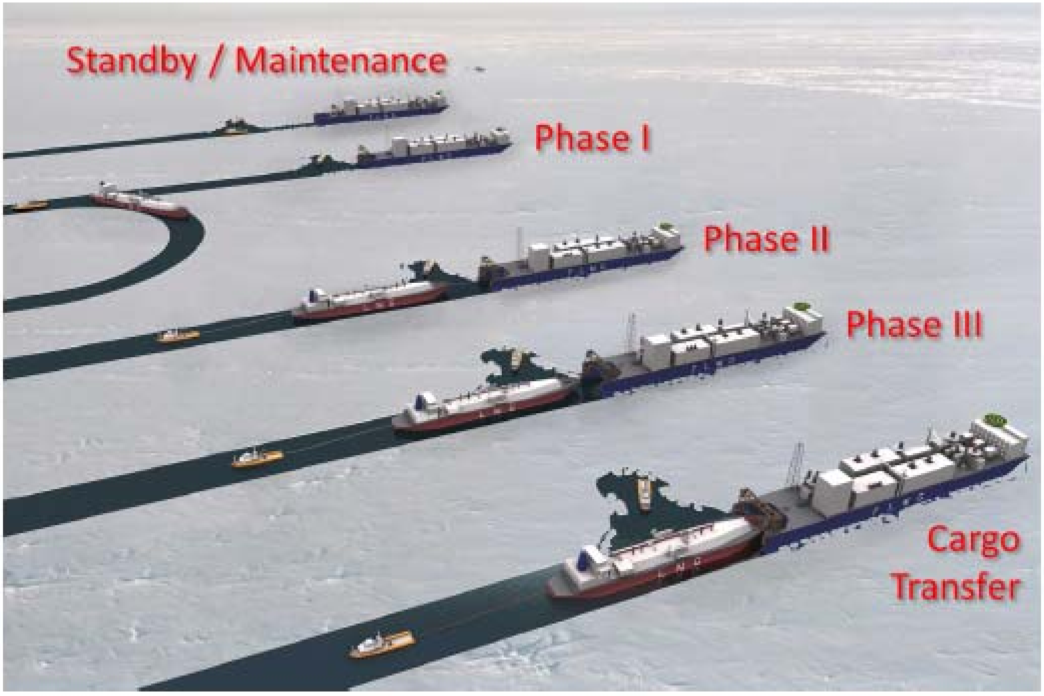


Figure 62 Steps of approach and pull-in of the carrier to the 'Mooring Bay' and cargo transfer in ice conditions (*Hoog et al., 2012*)

Connection of Transfer Lines

When the carrier/manifold is located in the right position two lines are released from the header and hooked-in in dedicated docking cones at the manifold. Active winches allow safe pull-in of these lines for the final approach of the header to the manifold (see *Figure 51*). The header carries the complete set of up to six transfer pipes (max. 4 for LNG, max. 2 for vapor return) each equipped with its QCDC[19] and ERC[20] couplings. After touchdown of the header the QCDC couplings are closed and the cargo transfer, which alone can last up to 18 hours,

[18] QRH = Quick Release Hook
[19] QCDC = Quick Connect/Disconnect Couplers
[20] ERC = Emergency Release Couplings

can be started. According to international requirements the transfer capacity is outlined to reach at least 10000 m^3 per hour (*Hoog et al., 2012*).

It is important to note that this concept provides a fully aerial solution which means that no cargo carrying component touches the sea surface (or sea ice) in any regular phase of operation or even in ESD situation.

After completion of the cargo transfer this sequence is followed vice-versa so that the header remains permanently under control until it has been fully retrieved from the carrier deck/manifold.

Emergency Shut Down (ESD) situation

The handling of LNG transfer lines in emergency situations is a very critical part of related risk assessments. Here, the MPLS20 system has proven especially good performance as the developed aerial solution provides full control of every single step of operation. If for example a critical situation (e.g. loss of a mooring) results in excessive vessel relative motions and the reaching or exceeding of the pre-defined working envelope within the \`Mooring Bay´, the cargo pumps are stopped (phase ESD 1) or even all ERCs are opened followed by the departure of the carrier from the \`Mooring Bay´ (phase ESD 2), respectively. This situation can be carried out in a safe and reliable way and without disturbances due to environmental constraints, which has been approved in principle by Germanischer Lloyd (GL).

Motion Analysis

To study the motion behaviour of the system numerical calculations are conducted by means of the two software systems WAMIT and ANSYS AQWA, both “Potential Theory” approaches.

While the specially adopted radiation-diffraction panel code WAMIT[21] (Wave Analysis at Massachusetts Institute of Technology) is able to take inner free liquid surfaces into account (sloshing), ANSYS AQWA considers wind and current, providing results in frequency domain as well as time series for ship motions and mooring forces of the multi-body system.

During the cargo transfer period free fluid surfaces occur in the cargo tanks of the LNGC. This leads to a significant decrease of the initial intact stability and altered motion behavior (for details refer to *Frohne et al., 2008*). While the FLNG unit is equipped with sloshing-proof SPB[22] tanks, the LNGC selected for the investigations features standard prismatic tanks without internal partitions. This type of tank is prone to resonant free surface motions that are induced by the ship moving in waves.

The sloshing analysis has been carried out in frequency domain with WAMIT. Calculations with water in the tanks have been carried out and compared with model tests in order to validate the numerical setup (*for details refer to Frohne et al., 2008*). Subsequent calculations with LNG tank filling provide the real motion behaviour of the system with partially filled tanks (*Hoog et al., 2012*).

Ice Load Analysis

Numerical calculations have been carried out to determine specific loads from drifting ice to the moored multi-body system. For this purpose the above described generic I-FLNG hull with ice breaking capabilities has been analyzed with the software ANSYS AQWA. Two

[21] WAMIT = Wave Analysis Code developed at Massachusetts Institute of Technology
[22] SPB = Self-supporting, Prismatic-shaped IMO Type B

different mooring configurations (see *Figure 63*) with a) equidistant attachment of the lines around the circumference of the mooring buoy and b) a 4 times 3 lines configuration (centered each 90°) have been considered and the resulting equilibrium positions and load in the lines are calculated. It should be noted that the mooring line assemblies are the same for both configuration very basic designs in order to achieve suitable solutions. They have to be subject of detailed investigations for each discrete development and location (*Hoog et al., 2012*).

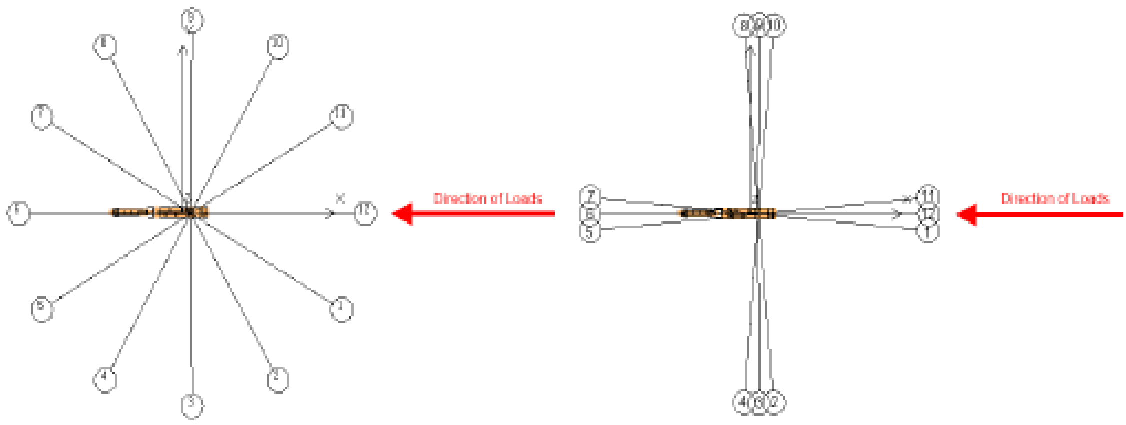


Figure 63 The analyzed mooring line configurations: 12x1 (left), and 4x3, with angle of attack 180° at each (*Hoog et al., 2012*)

Waves with significant height H_S = 5.5 m, wind with max. velocity 15 m/s, current with velocity 1.0 m/s and two different ice coverages at the I-FLNG bottom (A=70% coverage and B=30% coverage due the wedge-shaped plough) have been considered.

The ship shape modification like the wedge-shaped plough significantly contributes to reduce the ice induced effects on the coupled multi-body system (*Hoog et al., 2012*).

As reported by Hoog et al. (2012) the project with respect to the development of a completely new mooring concept for large vessels and a handling and approach system for a bundle of flexible transfer pipes in aerial mode was successful. However there are still general investigations required with respect to

- Verification of application in (specific) ice conditions
- Verification of appropriate barge hull form (ice tank tests)
- Concept for winterization e.g. of the transfer system
- Application of the transfer system in harsh conditions (snow and ice)

5.2 Floating Structures

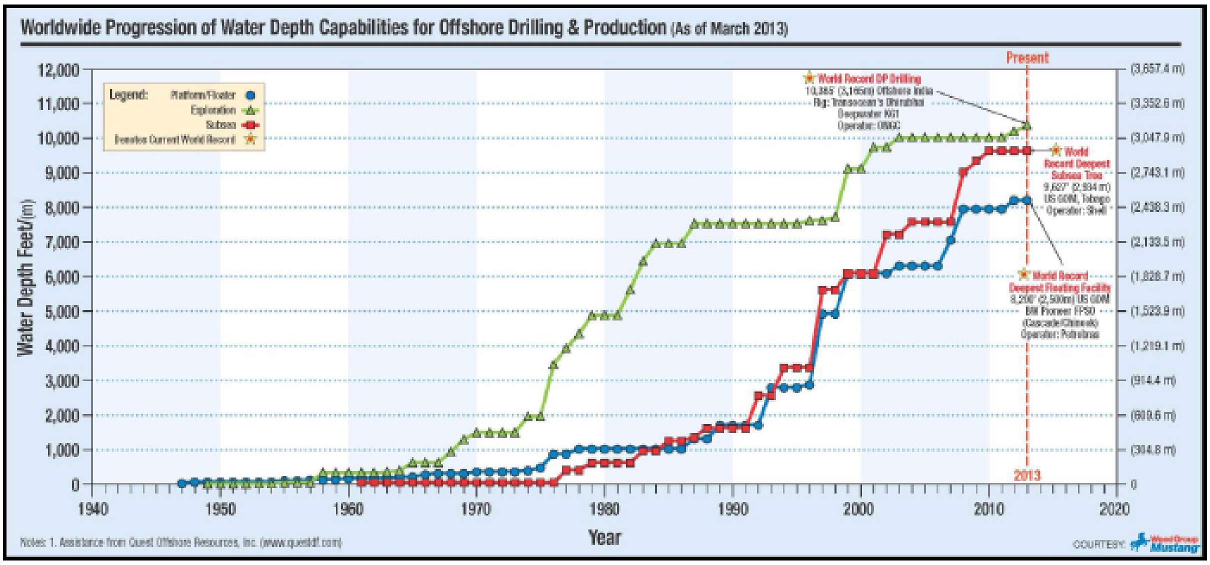
General

There is only a limited number of floating exploration or production structures that have been used in ice environments. Seasonal exploration can be carried out in the Alaskan OCS using drillships and drilling barges and, in areas without multi-year ice, semisubmersibles or a TLP[23]. However, for exploration, the only location that a floating structure might be capable of staying on station year-round might be the Bering Sea under light ice conditions. A Semi-rigid Floater structure might work year-round under first-year ice conditions but would need to have the ability to disconnect and leave station in the event of potentially higher loads.

Floating production systems for the Beaufort Sea, Chukchi Sea and North Bering Sea are not considered to be technically feasible, even with continuous ice management. No floating production structures could be economically designed to stay on station with multi year ice loads found in the Beaufort and Chukchi Seas, and possibly northern Bering Sea depending on local ice conditions. However, floating systems may have some merit in southern Alaskan OCS areas (*IMVPA, 2008*).

The development of oil and gas fields offshore in Arctic and sub-Arctic regions has received increased attention because of the huge potential of the hydrocarbon resources. The change of climate conditions, i.e. melting of ice in the Arctic, has increased the open water area and opened shipping and transportation routes, which provides an opportunity for development of these fields. These developments are in deeper water depths of 300 to 3000 m, which exceeds the limits for the installation of fixed base or bottom founded platforms. Therefore floating systems are being considered as practical solutions, which have been used as installations during the past 20 years in deepwater worldwide (*Aggarval and D'Souza, 2011*).

The worldwide progression of water depth capabilities for offshore drilling and production is shown in *Figure 64.*



Source: Mustang Engineering

Figure 64 Worldwide progression of water depth capabilities for offshore drilling and production in the period from 1947 to 2013

[23] TLP = Tension Leg Platform

In general the designs of alternative floating systems are available for their application in deep Arctic waters, but there technical feasibility, operability and cost-effectiveness depend on specific conditions in the Arctic and Sub-Arctic. These areas are subjected to harsh metocean conditions, extreme temperatures and severe ice conditions.

Figure 65 shows as an example floating drilling system for offshore drilling in the Arctic.

(a) (b) (c)

Figure 65 Floating systems for offshore drilling in the Arctic: (a) drilling rig Kulluk, (b) drillship Stena DrillMax ICE and (c) semi-sub rig designed by Moss Maritime

These drilling units are designed specifically to operate in ice conditions and can be disconnected as protection against large drifting ice features like pressure ice ridges, multi-year ice floes and icebergs.

Different floating production platform categories that have been proven in service and are considered as appropriate technologies for development of deepwater and ultra-deepwater hydrocarbon fields in water depth up to 3000 m. However only few of these design categories (FPSO, TLP, SPAR, Semi-sub and Buoy shaped) have been used due to specific demands and constraints associated with field development in each region (*Aggarval and D'Souza, 2011*) *Figure 66* and *Figure 67* show different platform designs for deepwater drilling and production.

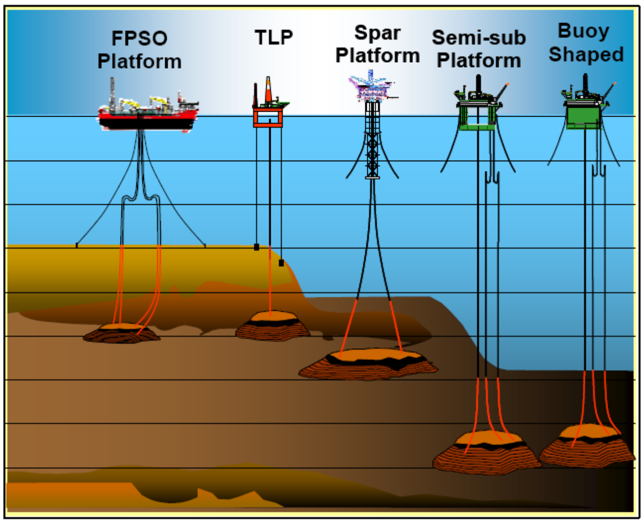


Figure 66 Alternative floating platform designs in deepwater

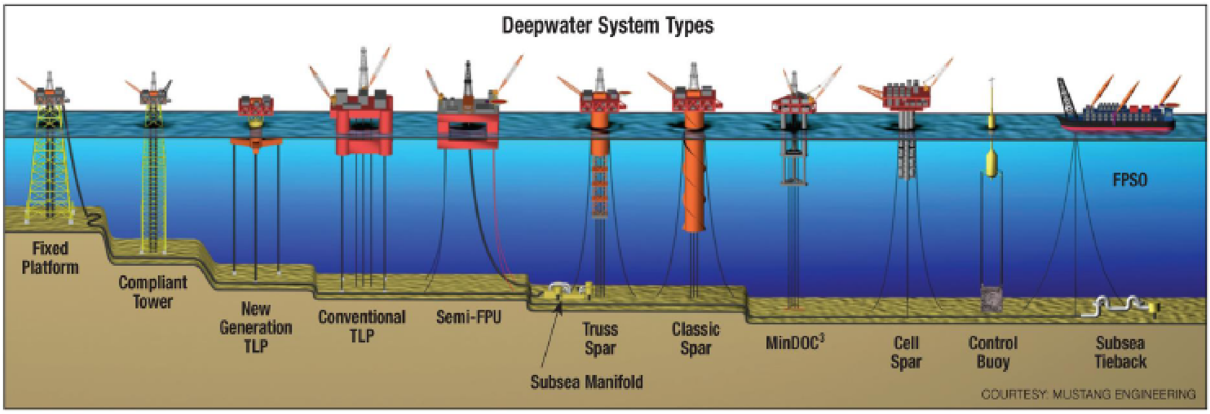


Figure 67 Deepwater system types (source: *Mustang Engineering*)

5.2.1 Conventional Floating Exploration Structures

Conventional floating exploration structures, drillships and semi-submersibles, have been used in areas subject to seasonal/marginal ice cover including the east coast of Canada, offshore Greenland, the Russian Arctic, and offshore Sakhalin Island. Drilling with these structures is generally carried out during summer months when seas are ice free. However, there are drilling units which are ice strengthened/classed for operation in light/managed ice cover. Furthermore, there are other drilling units, such as the Vidar Viking, which have shown that drilling in ice well beyond light/managed ice is possible (*IMVPA, 2008*).

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5.2.1.1 Floating Production, Storage and Offloading (FPSO)

General

Floating Production Storage Offloading (FPSO) vessels are ideally suited for development of remote-region projects, because tankers and onsite storage are needed to transport crude oil to markets. Even for the basins where pipelines are eventually built, an FPSO can still serve as an early production system to reduce project risk and improve project cash flow. Therefore, an FPSO offers an attractive solution to deepwater fields in the Arctic where fixed platforms are not feasible from either technical or commercial perspectives (*Li, 2012*).

The technical feasibility of an arctic FPSO depends on ice and iceberg conditions. In iceberg infested waters, the FPSO for the Arctic needs to be disconnectable to avoid collisions with incoming icebergs. Even without the presence of icebergs, an Arctic FPSO may need to be disconnectable due to the limits of stationkeeping capacity of its mooring system. Design of a disconnectable mooring system becomes significantly more challenging than a permanent one, because of the additional requirement of load transfer, disconnected subsea system, disconnections and reconnections. These requirements often conflict with the ones of flow assurance, topside layout, ventilation and fire protection (*Li, 2012*)

Terra Nova Field

The Terra Nova field, discovered in 1984 by Petro-Canada, is currently the 2nd largest producing field off the east coast of Canada. Furthermore, the Terra Nova was the first 'harsh environment' development in North America to utilize a FPSO vessel (*Petro-Canada, 2007a*). The field is located approximately 350 km eastsoutheast of St. John's. The Field water depths range from 90 to 100 m (*SPG Media Limited, 2007e*).

The production from Terra Nova project began in January, 2002 (*Bott, 2004*). Field recoverable oil reserves have been estimated at 440 million barrels and life of field is estimated to be about 20 years (*Petro-Canada, 2007a*).

Through an integrated subsea and topside production system, oil is produced, stored, and subsequently offloaded to shuttle tankers. The production from subsea wells/trees is gathered by subsea manifolds and conveyed topside (to the FPSO) via flexible flowlines and risers.

More then 40 km of flexible flowlines, control umbilicals, and dynamic risers were required for the project (*Furlow, 1998*). Flowline and riser inner diameters ranged between 125 and 250 mm, while the umbilicals used were the largest ever manufactured at the time, with an outside diameter of 265 mm (*Cottrill, 2000*).

To protect against potential iceberg gouging, subsea equipment is located in excavated seafloor pits, called open glory holes as shown in *Figure 68*. Glory holes used for the project are approximately 11.5 m deep and base dimensions range from 16 m x 16 m to 56 m x 16 m (*Furlow, 1998*). Excavation of the glory holes was carried out by a giant trailer suction dredger, the Queen of The Netherlands (*Cottrill, 2000*).

Although considered sacrificial and equipped with "weak links" to protect wellhead equipment, flowlines were trenched and buried in the seabed to provide stability, insulation, and afford some measure of protection from iceberg gouging. The initial plan was to provide 1.5 m of cover, however, due to trenching difficulties some flowlines were rock-dumped instead (*Cottrill, 2000*).

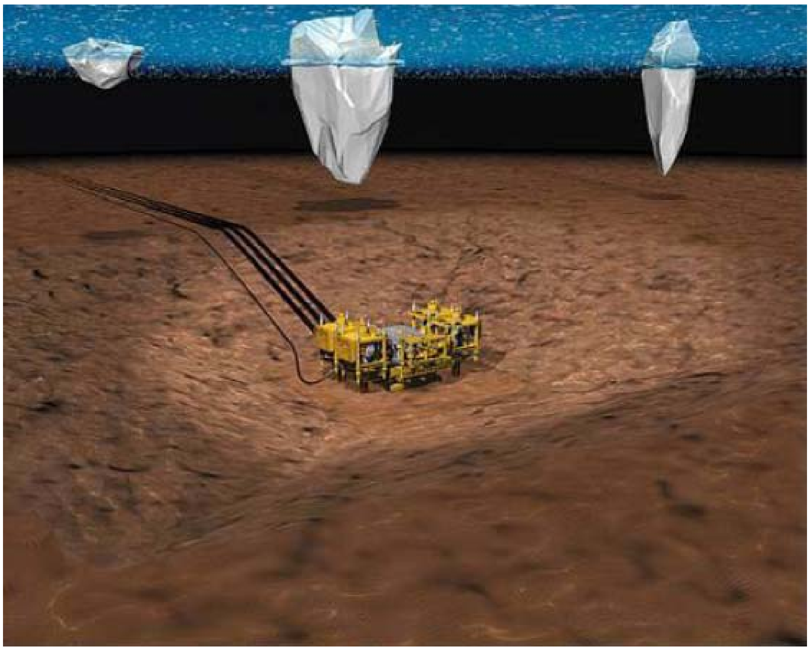


Figure 68 Open Glory Hole (*Petro-Canada, 2007a*)

Example: Terra Nova FPSO

The core of the development and production system is the Terra Nova FPSO one of the largest FPSO vessels ever built, shown in *Figure 69.* The Terra Nova measures 292 m long by 45.5 m wide. The height from the keel to the helideck is about 55 m. During operation, it has a draft of approximately 13 to 19 m and a maximum displacement of 194000 tonnes (*Fletcher and Clark, 2001*). The Terra Nova has a production rate of 180000 bpd[24] (*Howell, 2007*) and an integrated storage capacity of 960000 barrels of oil.

The hull is designed for multi-year ice pressures and impacts of 100000 metric tonnes iceberg at 0.5 m/s (1 knot) drifting speed and for 3000 metric tonnes bergy bits at 5 m/s (10 knots). In comparison to the non-arctic hull design, this means an additional demand of about 12% steel (*Aggarval and D'Souza, 2011*).

Stationkeeping is made possible by means of thruster assisted mooring with 9 chain mooring lines. The disconnectable turret/spider buoy with supporting mooring lines and risers and umbilicals adds 4000 metric tonnes to the FPSO, and the buoy is desined to drop 35 m. The planned disconnection time for normal operation is about 4 hours and in emergency case the buoy can be disconnected in 15 minutes.

The *Terra Nova* FPSO was designed for the environment in which it operates. A double-hulled, ice-reinforced vessel, it has five thrusters (two forward and three aft) and a global dynamic positioning system (DP), an automated system that allows the vessel to maintain its headings. The same system reduces the impact of waves by allowing the FPSO to change to more favourable headings in high winds and storms.

An ice management program allows *Terra Nova* personnel to monitor and deflect icebergs when required. Support vessels can encircle an iceberg with a cable or net and change its direction. Water cannons or the wash from a vessel's propellers can be used to nudge the iceberg along a different course (reference: *www.suncor.com*).

To avoid collision with icebergs and severe sea ice conditions, the Terra Nova FPSO is equipped with an internal disconnectable turret system. During a disconnection, the spider buoy, along with its attached risers and moorings, is released allowing the FPSO to move off station and sail out of harms way. Once released, the spider buoy sinks to a mid-water equilibrium depth of 35 m (*Cottrill, 2000*).

A planned disconnection, which entails well shut-in, depressurization, flowline flushing, etc., can be executed in less than 4 hours, while in an emergency situation, disconnection can be achieved in approximately 15 minutes (*Sofec, 2007*). Up until the final moment of disconnect (i.e. prior to mechanical connector release), the sequence is reversible. The turret system is designed to reconnect in a matter of hours with normal operations support (*Furlow, 1998*). Reconnection can be accomplished in up to 2.1 m significant wave heights (*Cottrill, 2000*).

In June 2007, the Terra Nova FPSO underwent its first planned disconnect when it left the field to undergo several months of maintenance work in the Keppel Verolme shipyard in Rotterdam, the Netherlands. The Terra Nova arrived back in the field on September 25th and was reconnected to it's moorings on October 1st (*Petro-Canada, 2006*).

There were a number of design challenges for the Terra Nova disconnectable turret system; severe weather and storm conditions, relatively shallow water, a large vessel, a significant number of risers, a heavy mooring system and the ability to disconnect/reconnect. At time of design, the Terra Nova turret was quoted "as the most sophisticated and complicated turret ever" to be constructed (*Furlow, 1998*).

[24] bpd = barrels per day

Figure 69 Terra Nova FPSO (source Petro-Canada)

The connection between the FPSO and the subsea flowlines is the spider buoy (the lower portion of the turret). The spider buoy is the mooring point for the FPSO, and the pathway for oil and fluids that flow to and from the FPSO and reservoir (*Figure 70*). The spider buoy has a quick-disconnect feature, allowing the FPSO to safely disconnect and leave the area in an emergency situation.

Figure 70 Illustration of pathway for oil and fluids that flow to and from the FPSO and reservoir (source: *Suncor*)

5.2.1.2 Drillships

A drillship is a maritime vessel that has been fitted with drilling apparatus. It is most often used for exploratory drilling of new oil or gas wells in deep water or for scientific drilling. The drillship can also be used as a platform to carry out well maintenance or completion work such as casing and tubing installation or subsea tree installations. It is often built for oil production companies and/or investors design and specifaction but it can also be a modified tanker hull and outfitted with a dynamic positioning system to maintain its position over the well. The greatest advantages of these modern drillships is their ability to drill in water depths of more than 2500 m and the valuable time saved sailing between oilfields worldwide and they are completely independant compared with Semi-submersibles and jack-up barges (reference: *www.oil-rig-photos.com*)

Starting in the mid 1970s, Dome Petroleum (Canmar) deployed floating drillships during the summer months. These were moored on site during the summer (open water) months. They encountered relatively light ice conditions, and there are no recorded ice loading events for these floating structures (*Timco and Johnston, 2002*).

In 1983, Gulf Canada Resources Ltd. designed and built an inverted-cone shaped floating structure (the “Kulluk”) that allowed drilling later into the winter season. This structure was exposed to moving pack ice. Active ice management around the Kulluk ensured that the ice conditions were not severe. This structure was instrumented to measure mooring line forces. *Wright (2000, 2001)* summarized the measured forces on the Kulluk. Measured loads were up to 4 MN depending upon the ice thickness, floe size and ice concentration.

The ice class drillship “Explorer II” and “Kulluk” (see *Figure 71* and *Figure 72*) were used in the Beaufort or Chukchi Seas for water depths of more than 30 m in the 1980’s and 1990’s. To the south, in Navarin Bay and St. George Basin, semi-submersibles were used extensively due to the relatively ice-free environment for most of the year. The first drilling operations undertaken by drillships in ice-infested waters were primarily intended for open water use, and normally drilled during the Beaufort or Chukchi’s summer and early fall seasons. However, with icebreaker support, they soon developed the capability to maintain position in a variety of pack-ice conditions. This extended their operating season beyond the open water period, although they did not work extensively in heavy ice. The Northern Explorer II is a Donheiser Marine, Super Class 1AA design. Its mooring system is an eight point wire design and had a variable load capability of about 5800 metric tonnes).

(Timco and Johnston, 2002)

Figure 71 "Northern Explorer II" (formerly the CANMAR Explorer II and Explorer II) , (*IMVPA 2008*)

Figure 72 Ice management operations around the moored Kulluk structure in the Beaufort Sea (*Timco and Johnston, 2002*)

The Kulluk was designed as a second generation drilling system that was purpose built to significantly extend the open water season, by beginning drilling operations in the spring break-up period and continuing until early winter. As a result, the Kulluk operated in a greater and more difficult range of pack-ice conditions than drillships. In addition, "in-ice performance information" was systematically obtained during its operations. Because of this, the Kulluk's experience base provides the best source of data for most considerations related to moored vessel station-keeping operations in various pack-ice conditions (*IMVPA, 2008*).

In the early 1980 extensive model tests in ice tanks were performed among others at the Hamburg Ship Model Basin (HSVA) to develop an appropriate hull form, which resists the corresponding ice loads and allows a safe operation in the Arctic.

The Kulluk (shown in

Figure 73 and *Figure 74*) was designed with a variety of features to enhance its performance capabilities in ice. Some of the primary technical challenges that were considered and accommodated in the Kulluk's design are highlighted as follows:

- Minimizing the icebreaking and clearance forces that the vessel would experience from any direction, by providing it with an "omni-directional capability" to resist ice action

- Developing a hull form that would "minimize" icebreaking forces, enhance ice clearance, and reduce the possibility of ice moving down the hull and under the vessel, where it could interfere with the mooring and riser systems, and enter the moonpool area

- Providing a strong mooring system that could resist the "high" load levels associated with heavy pack-ice conditions during extended season operations, with acceptable mooring line tensions and vessel offsets

- Developing a submerged mooring system that would "eliminate" the problem of ice interaction with mooring lines at (or near) the waterline

- Configuring an ice management system that would be capable of "protecting" the Kulluk in the more difficult ice conditions expected in the Beaufort's extended drilling season.

Typically, the Kulluk was supported by two to four CAC 2 icebreakers[25] during its operations in heavy pack-ice conditions. Although the vessel occasionally operated in unbroken ice, it normally worked in managed ice conditions, where the oncoming pack-ice cover had been pre-broken into relatively small fragments by the support icebreakers as shown in *Figure 72.*

[25] CAC : Canadian Arctic Category

Figure 73 Drilling barge "Kulluk" ; stacked at Tuktoyuktuk (courtesy of *Beaudril*)

Figure 74 The Kulluk - Operations with Icebreaker Support (courtesy of *DC Marine*)

Example: Drillship Vidar Viking

The Swedish Vidar Viking is an diesel-electric ice breaking anchor handling, tug and supply vessel (Class DNV IBICE10, 1.3 m ice) complete with a full dynamic positioning system.

The vessel was outfitted with a moonpool and a compact drill rig for deep sea drilling in summer of 2004. This upgrade was performed to allow the Vidar Viking to serve as the drilling vessel for the scientific Arctic Coring Expedition (ACEX) project. In the summer of 2004 as part of the ACEX, the Vidar Viking successfully gathered cores from under the central polar ice pack. Ocean floor core sampling was carried down to the full target depth, to bedrock on the Lomonosov ridge (Laptev Sea), at about 450 m of core length (*Keinonen et al., 2006*). Prior to this date no core drilling had taken place under the central polar ice pack.

Moran et al. 2006 report that at the drill site, temperatures were near 0°C and occasionally dropped to –12°C. Ice floes 1–3 m thick covered 90% (i.e., >9/10 ice cover) of the ocean surface, and ice ridges, several meters high, were encountered where floes converged. The ice drifted at speeds of up to 0.3 knots and changed direction over short time periods, sometimes within 1 hour.

Two other icebreakers, a Russian nuclear vessel, the *Sovetskiy Soyuz,* and a Swedish diesel-electric vessel, the *Oden* protected the *Vidar Viking* by circling "upstream" in the drifting sea ice, breaking the floes into smaller pieces that would not dislodge the drilling vessel more than 75 m from a fixed position. Despite thick ice cover, the ice management teams successfully enabled the drilling team to recover cores from three sites. Ice conditions became unmanageable only twice, forcing the crew to retrieve the pipe and move away until conditions improved. *Figure 75* shows the convoy of involved vessels.

Figure 75 **The Expedition 302 fleet during the transit north, the *Sovetsky Soyuz* leading, the *Oden* following, and the drillship *Vidar Viking* in the rear (Photo:Sven Stenvall)**

Example: Drillship Stena DrillMAX ICE

The Stena DrillMAX ICE (*Figure 76*) is the most expensive drillship ever built. The extremely high cost of similar drillships and their accompanying icebreakers, makes it unlikely that two companies would concurrently decide to acquire such vessels for use in the Beaufort Sea. A more likely scenario is that the first drilling system would be acquired and a successful deep-water well drilled, before a second drillship and its icebreakers are commissioned (*Callow, 2012*).

Figure 76 Drillship Stena Drill MAX ICE (courtesy Stena)

As the world's first dynamically positioned, dual-mast drillship with ice-class certification, the Stena DrillMAX ICE represents a large and important investment for Stena Drilling Ltd., a wholly owned subsidiary of Stena. The Stena DrillMAX ICE is an extremely specialized and expensive vessel, which makes every hour of operation crucial.

Stena decided to install a ballast water treatment system before regulations are in place, as this would mean taking the drillship out of service and placing it back in the dry dock. In such an event, the cost of the retrofit would be not only the cost of the equipment, but also the cost of the downtime.

The ice-strengthened hull unit has been optimised for Arctic conditions. Six ice-classed 5.5 MW azimuth thrusters provide maximum manoeuvrability. Below the deck escape ways on port and starboard side connect the aft engine rooms with accommodation. Moon pools on port and starboard allow for installation of two separate ROV[26] systems.

Anti-icing equipment protects the unit's anchors, deck piping, lifeboat escape exits, scuppers and drains while enhanced de-icing machines keeps decks, gangways, and handrails clear.

Steam heating coils warm the ballast tanks and drill water tanks and windwalls and cladding offer enhanced protection to the drill floor and dual mast derrick (reference: *www.dnv.com*).

Operating in ice-infested seas and at low temperatures, which can drop to more than –20°C degrees in the Arctic in summer, is challenging. Icebergs and extreme cold represent a risk in the Arctic, but there is less of a threat from storms and heavy seas.

The drillship is able to break the ice, although it is not a typical icebreaker. When operating in the Arctic the drillship will be escorted by icebreakers and/or icebreaking Offshore Supply Vessels (OSV) for ice management purpose.

When the drillship is operating in other areas like North Sea or Gulf of Mexico there might be a threat due to frequent storms and heavy seas with large waves, however the DrillMAX ICE can survive waves up to 30 m height.

The drillship's hull form is based on Stena's proven DrillMAX design, some topside modifications were included. Because the drillship is likely to operate in the environmentally sensitive Arctic region, space was created on deck for an extra six-RAM blowout preventer (BOP), providing critical redundancy.

The drillship is also equipped with DP3 station-keeping and related automation systems provided by Kongsberg for operating in ice conditions, Knuckleboom deck cranes are designed for temperature conditions of -30°C.

In early 2011 Stena Rederi AB performed a series of model tests in the ice tank at the Hamburg Ship Model Basin (HSVA). For the first time a model test in ice conditions was performed with a DP-system specifically configured for operations in ice in order to cope with the expected large variations in ice drift forces (see

Figure 77), (*Haase and Jochmann, 2013*).

The major purpose of the tests was to assess the operational limits of Stena DrillMAX ICE for operation in ice drift conditions. A secondary goal was to evaluate the performance of the specially tuned DP-system in order to be prepared for full scale operations (*Hals and Efraimson, 2011*). Stena Rederi AB worked closely with DNV to achieve ICE 10 Certification, among other notations.

[26] ROV: Remotely Operated Vehicle

Figure 77 Ice model tests with Stena DrillMAX ICE model in managed ice

5.2.1.3 Semi-submersible floating structures

A semi-submersible floating structures is a conventional floating exploration structure which consists of a top side deck that comes in several designs. It is typically stabilized by columns with submerged lower hulls which are semi-submerged to a predetermined draft during operations. Compared to a FPSO the semi-submersible has a small water plane area. In general, harsh environment winterized semi-submersibles have been used considerably in the south Bering Sea (*IMVPA, 2008*).

Example: Semi-submersible Ocean Odyssey

An example of a previously used semi-submersible; the *Ocean Odyssey* (*Figure 78*) was an advanced super-class unit designed to operate in Arctic environments (*OSTI, 2007*).

The Odyssey was capable of operating in winds greater than “100 knots (51.4 m/s) with its 4100 tonne deck-load without de-ballasting from its 24.4 m operating draft” (*OSTI, 2007*). Further, the Odyssey was constructed with reinforced columns and was equipped with a caged riser (*Oil Rig Disasters, 2007*).

The semi-submersible rig was completed in March 1983 by Sumitomo Heavy Industries in Japan for ODECO, the Ocean Odyssey was one of the most advanced semi-submersibles of its day and was designed to work on high pressure wells in harsh environments, such as offshore Alaska and the North Sea. The rig was in operation from April 1983 to September 1985 off the coasts of Alaska and California before being stacked for two years in Seattle, WA. The rig was then contracted to ARCO and shipped to the North Sea by February 1988.

By September 1988 the rig was drilling in the Central Graben of the North Sea when a blowout occurred. After this accident the Odyssey was berthed at Dundee docks in the UK for some time before being redeveloped as an ocean-going satellite launch pad by a joint four-company consortium which included Boeing and Kvaerner.

The Ocean Odyssey is now used as a mobile spacecraft launch platform. The company Sea Launch has successfully launched the Intelsat 21 satellite aboard a Zenit 3SL launch vehicle from the Odyssey mobile platform, in the equatorial Pacific Ocean. (reference: *www.aerospace-technology.com*).

Figure 78 Semi-sumersible rig Ocean Odyssey (*NationMaster, 2005*)

Example: Sakhalin III Semi-submersible

The Sakhalin shelf is one of the main sources of gas supplies to consumers of the Russian Far East. Gazprom operates in three blocks within the Sakhalin III project:

- Kirinsky
- Ayashsky and
- Vostochno-Odoptinsky.

The Kirinsky block includes the Kirinskoye field and Gazprom also discovered there the Yuzhno-Kirinskoye and Mynginskoye gas and condensate fields.

The Kirinskoye gas and condensate field is located 28 km off the coast at a water depth of 90 m. Geological exploration operations were completed at the field in 2011. All reserves are within the C1 category and total 163 billion m^3 of gas and 19 million tons of gas condensate.

The Yuzhno-Kirinskoye gas and condensate field's C1+C2 reserves amount to 564 billion m^3 of gas and 72 million tons of gas condensate.

The Severnoye Siyaniye (Northern Lights) semi-submersible drilling rig (SSDR) as shown in *Figure 79* has been delivered to the Yuzhno-Kirinskoye field in the Sakhalin shelf. The Polyarnaya Zvezda (Polar Star) SSDR (see *Figure 80*) was the first to arrive in the Kirinskoye field. Polyarnaya Zvezda will continue the construction of production wells. It is projected to finalize the second well with a depth of over 3600 m in a three-and-a-half month's period during the 2013 season. This drilling rig will also build the third well (reference: *www.gazprom.com*).

Figure 79 Sakhalin III Project - Severnoye Siyaniye (Northern Lights) semi-submersible drilling rig (SSDR), Yuzhno-Kirinskoye field (source: *Gazprom*)

Figure 80 Semi-submersible floating drilling rig Polyarnaya Zvezda (Polar Star) drilling in Kirinskoye field (Sakhalin III Project), [source: *Gazprom*]

5.2.1.4 Floating Production Storage Offloading Vessel (FPSO)

The FPSO is a floating, production, storage and offloading ship-shaped vessel. FPSO concepts have frequently been based on converted tankers. Production facilities are mounted on raised supports above the vessel deck. Reservoir fluids pass from subsea production wells, via flowlines and risers, up into the turret and then to the production facilities (see *Figure 81* and *Figure 82*). The produced oil is stored in the vessel cargo tanks and periodically offloaded onto a shuttle tanker via a loading hose in areas where a pipeline to transport oil to shore is not available.

FPSO design has shown a fast evolution in recent years. The concept is more and more frequently used for deepwater solutions and in addition new design concepts are being considered with respect to operate FPSOs in ice covered waters at higher latitudes.

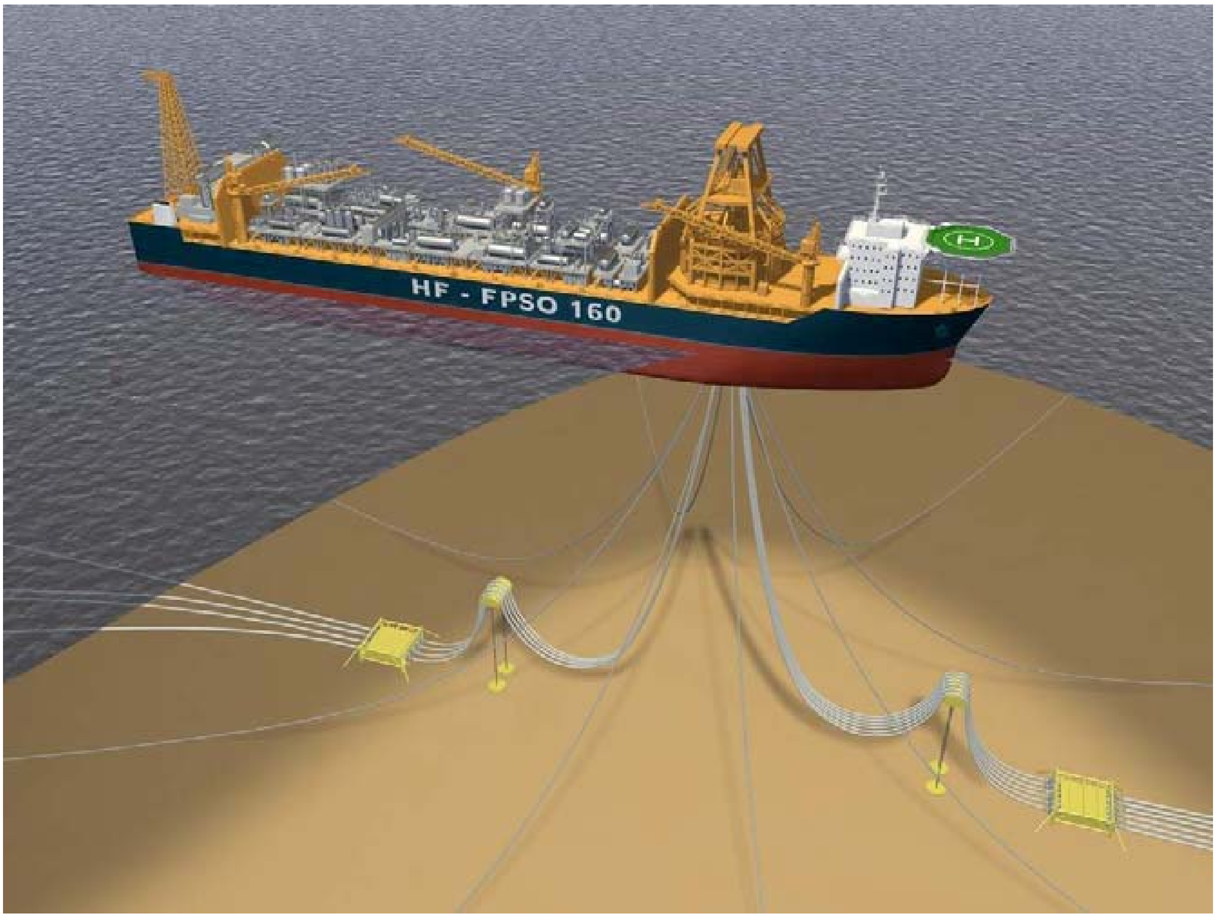


Figure 81 Illustration of Floating Production Storage and Offloading (FPSO) with flowlines and risers (source: *corrosion-doctors.org*)

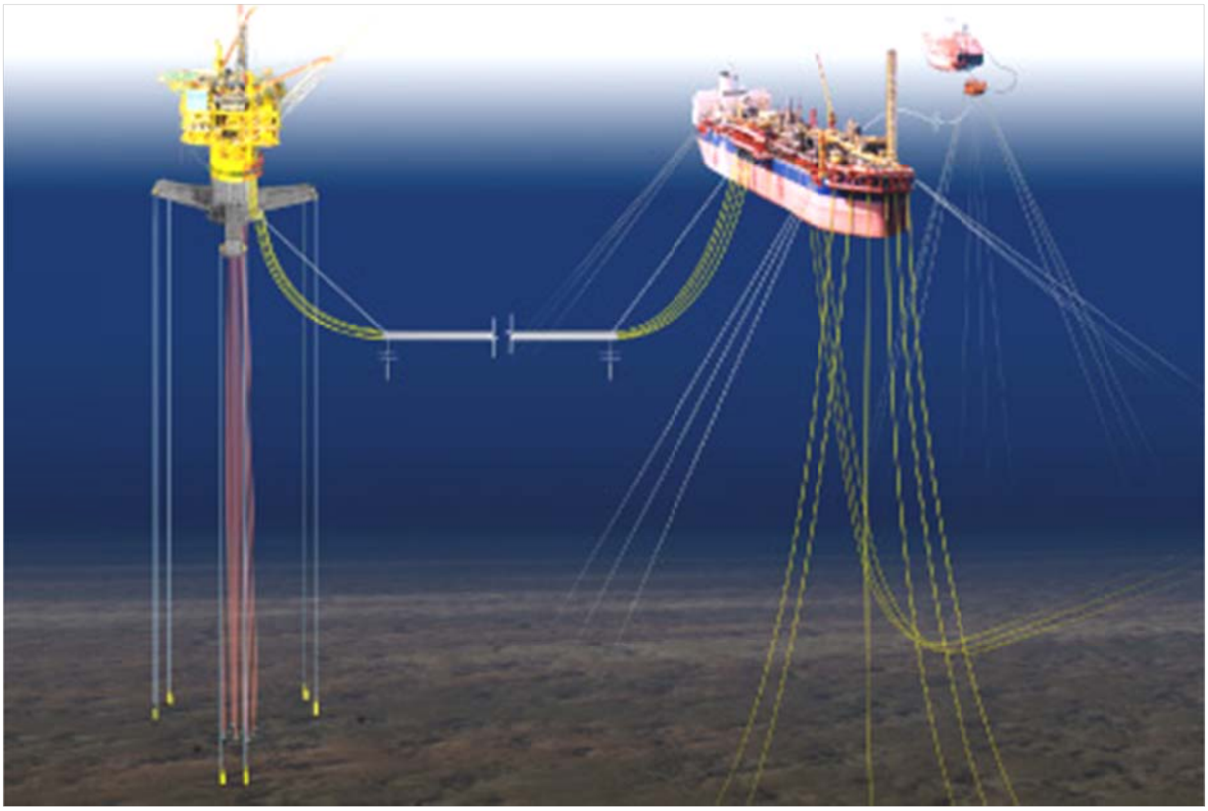


Figure 82 Illustration of TLP and FPSO with multiple riser [27] configuration

Other acronyms related to FPSO are:

- FSU : Floating Storage Unit
- FPU : Floating Production Unit
- FPSU : Floating Production & Storage Unit
- FSO : Floating Storage & Offloading
- FPSO: Floating Production, Storage and Offloading
- FDPSO : Floating Drilling Production Storage & Offloading
- FSG : Floating Storage of Gas
- FGSO : Floating Gas Storage Offloading
- FPSG : Floating Production Storage of Gas

[27] Risers: Similar to pipelines or flowlines, risers transport produced hydrocarbons, as well as production materials, such as injection fluids, control fluids and gas lift. Usually insulated to withstand seafloor temperatures, risers can be either rigid or flexible

5.2.1.5 Tension Leg Platform (TLP)

General

A tension-leg platform (TLP) or extended tension leg platform (ETLP) is a vertically moored floating structure normally used for the offshore production of oil and/or gas, and is particularly suited for water depths between 300 m and 1500 m.

The platform is permanently moored by means of tethers or tendons grouped at each of the structure's corners. A group of tethers is called a tension leg. A feature of the design of the tethers is that they have relatively high axial stiffness causing low elasticity, such that virtually all vertical motion (heave) of the platform is eliminated. This allows the platform to have the production wellheads on deck (connected directly to the subsea wells by rigid risers), instead of on the seafloor. This makes a simpler well completion possible and gives better control over the production from the oil and gas reservoir, and easier access for downhole intervention operations (reference: *http://en.wikipedia.org/wiki/Tension-leg_platform*).

TLPs have been in use since the early 1980s. The first tension leg platform was built for Conoco's Hutton field in the North Sea in the early 1980s. The hull was built in the dry-dock at Highland Fabricator's Nigg yard in the north of Scotland, with the deck section built nearby at McDermott's yard at Ardersier. The two parts were mated in the Moray Firth in 1984.
The Hutton TLP was originally designed for a service life of 25 years and had 16 tension legs. Its weight varied between 46500 and 55000 tons when moored to the seabed, but up to 61580 tons when floating freely.The total area of its living quarters was about 3500 m^2 and accommodated over a 100 cabins though only 40 people were necessary to maintain the structure in place.
(reference: *http://en.wikipedia.org/wiki/Tension-leg_platform*)

Larger TLPs will normally have a full drilling rig on the platform with which to drill and intervene on the wells. The smaller TLPs may have a workover rig, or in a few cases no production wellheads located on the platform at all.

The deepest (E)TLPs measured from the sea floor to the surface are:

- Magnolia ETLP (depth 1425 m)
- Marco Polo TLP (depth 1300 m)
- Neptune TLP (depth 1300 m)
- Kizomba A TLP (depth 1177 m)
- Ursa TLP (depth 1200 m)
- Allegheny TLP (depth 1020 m)
- W. Seno A TLP (depth 1000 m)

Figure 83 shows a schematic diagram of tension-leg platform (gray) under tow with seabed anchors (light gray) held up by cables (red) on left-hand side; the platform with seabed anchors lowered and cables lightly tensioned on right-hand side and (b) the TLP (gray) free floating on left-hand side; the structure is pulled by the tensioned cables (red) down towards the seabed anchors (light-gray) on right-hand side (very simplified, details of temporary ballast transfers are omitted).

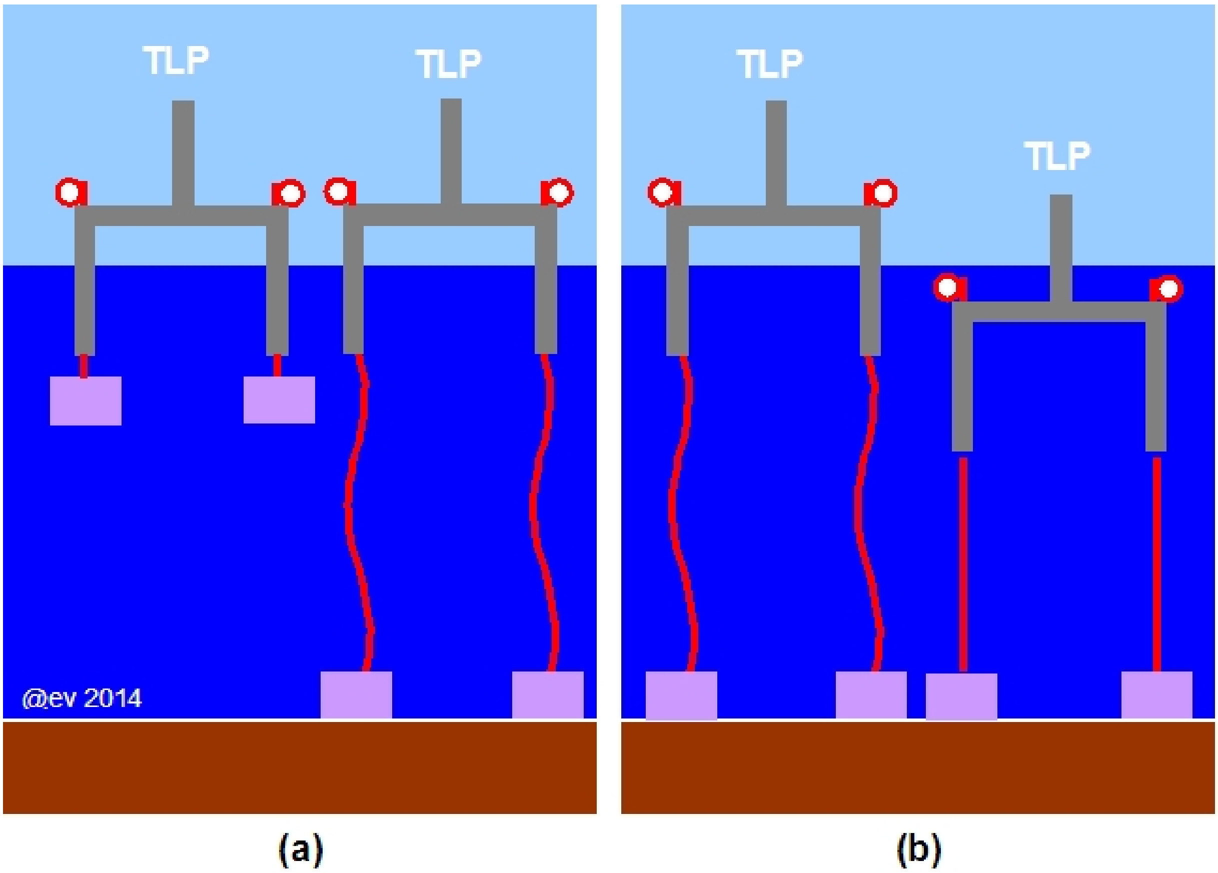


Figure 83 Schematic diagram of (a) tension-leg platform under tow with seabed anchors held up by cables on left-hand side; platform with seabed anchors lowered and cables lightly tensioned on right-hand side. (b) TLP free floating on left-hand side; structure is pulled by the tensioned cables down towards the seabed anchors) on right-hand side

Examples of various TLP's are shown in *Figure 84* through *Figure 87*.

Figure 84 TLP Nanhai Tiao Zhan (previously Stadrill), (Photo: *Nick Cregan, 2013*)

Figure 85 Njord Plaform, Statoil, Norway (Photo: *Jon King, 2011*)

Figure 86 Snorre A Platform (courtesy Statoil)

Figure 87 Snorre B Platform (*courtesy Statoil*)

Snorre is an oil and gas field in the Tampen area in the southern part of the Norwegian Sea and in operation since August 1992. It was the first field developed by Saga petroleum. The sea depth in the area is 300 to 350 m.

Snorre A platform in the south is a floating steel facility for accommodation, drilling and processing. Snorre A has also a separate process module for production from the Vigdis field. A subsea template with ten well slots, Snorre UPA, is located centrally in the field and connected to Snorre A. Oil and gas from Snorre A is piped to the nearby Statfjord A platform for final processing.

Snorre B platform is located in the northern part of the field and is a semi-submersible integrated drilling, processing and accommodation steel facility. Oil from Snorre B is piped 45 km to Statfjord B platform for storage and export.

The Snorre field is operated by Statoil. In 2009, Statoil started a project to upgrade the offshore production complex. The Norwegian Petroleum Directorate requested Statoil to build a new platform at the field. (reference: *http://en.wikipedia.org/wiki/Snorre_oil_field*).

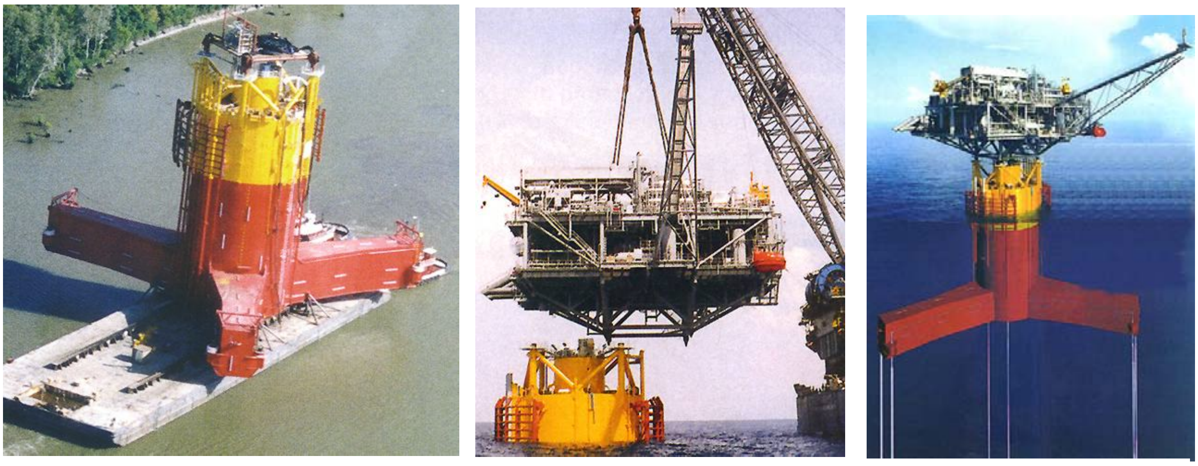
Example: Morpeth TLP

The Morpeth field is located in about 520 m water depth, in the Gulf of Mexico Ewing Bank (EW) blocks 921, 964 and 965, offshore of Louisiana.

Since the tension-leg mooring suppresses heave motions and reduces excursions, the performance requirements of the risers are reduced, in comparison with a catenary-moored platform. In the case of the Morpeth, the platform supports four satellite subsea oil and gas wells, each approximately 1000 m from the platform. The oil and gas flow through individual flexible flowlines, to the platform.

Processed crude oil and natural gas is exported from the Morpeth platform via a 30.5 cm oil-export line and a 20 cm gas-export line to the Grand Isle 115 platform. The Grand Isle 115 platform lies in 112 m of water near the continental shelf margin, about 35 km from Morpeth (reference: *www.offshore -technology.com*).

Figure 88 shows the towing of the Morpeth SeaStar TLP hull, from Houma to the Morpeth field in the Gulf of Mexico (a) and the installation of topsides (b).



(a) (b) (c)

Figure 88 (a) Towing of the Morpeth SeaStar TLP hull, from Houma to the Morpeth field in the Gulf of Mexico.
(b) Installation of the topsides. The topsides have a full processing capability.
(c) Artist's impression of the Morpeth tension leg platform (TLP). Tendon separation is a result of the base pontoons, with a platform displacement of 10000 tons, (source: www.offshore-technology.com)

5.2.1.6 Single Point Anchor Reservoir (SPAR)

General

A Single Point Anchor Reservoir (SPAR) is a type of floating oil platform typically used in very deep waters, and is moored in place vertically. The SPAR production platforms have been developed as an alternative to conventional platforms that can support drilling, production and storage operations, the SPAR consists of a large vertical cylinder bearing topsides with equipment. Similar to an iceberg, the majority of a SPAR facility is located beneath the water's surface, providing the facility increased stability (reference: *www.rigzone.com)*.

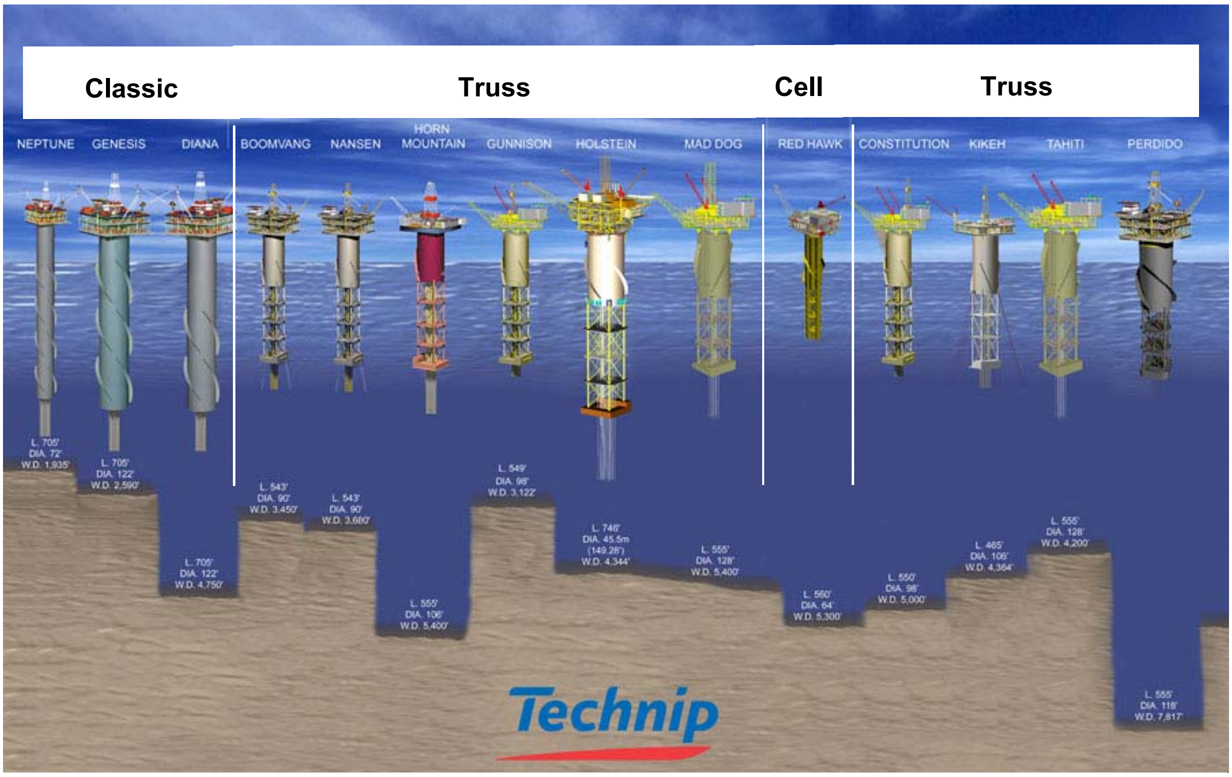
SPAR's are anchored to the seabed by means of a spread mooring system with either a chain-wire-chain or chain-polyester-chain composition.

There are three primary types of SPAR's:

- the classic SPAR
- the truss SPAR
- and the cell SPAR

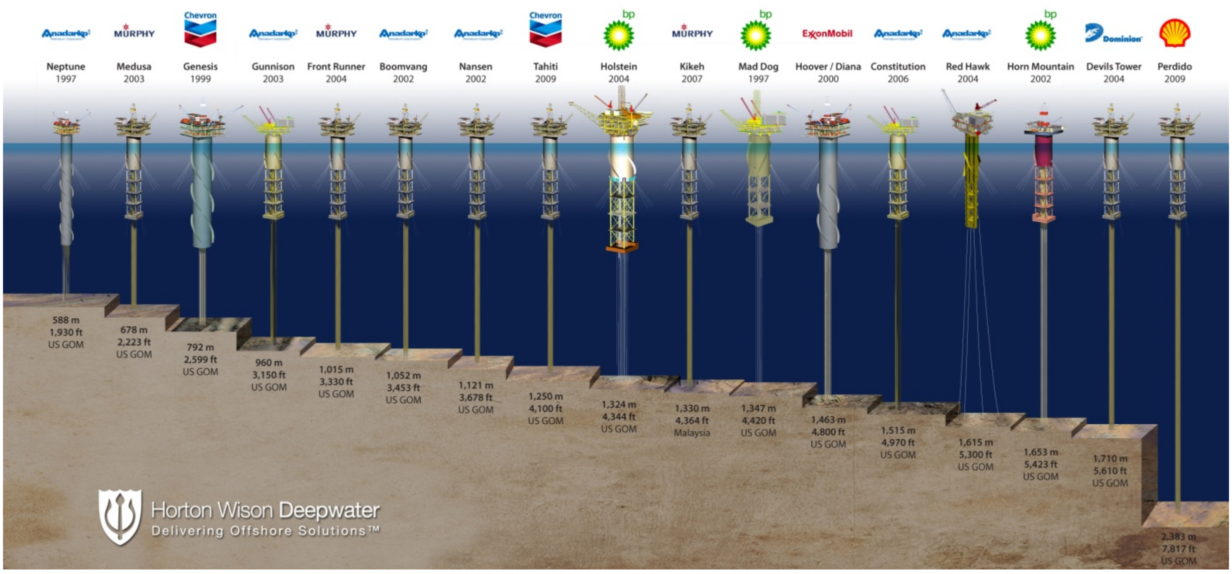
The *classic SPAR* consists of the cylindrical hull noted above, with the heavy ballast at the bottom of the cylinder.

A *truss SPAR* has a shorter cylindrical "hard tank" than a classic SPAR and has a truss structure connected to the bottom of the hard tank. At the bottom of the truss structure, there is a relatively small, square shaped "soft tank" that houses the heavy ballasting material. The majority of SPARs are of this type. In *Figure 89* and *Figure* 90 different SPAR buoy types are shown.



(source : http://subseaworldnews.com)

Figure 89 Different SPAR types (Classic SPAR – Truss SPAR – Cell SPAR)



(source: http://www.hortonwison.com/wp-content/uploads/2011/01/spars.jpg)

Figure 90 Compilation of SPAR buoys operated by various oil companies in 600m to 1700 m water depth

Example: "Arctic SPAR" Concept (developed by Aker Solutions, Norway)

The SPAR is considered a technically viable solution for deployment in arctic regions where it has to contend with loads from level ice, ice ridges and icebergs in addition to other environmental loads of wind, waves and currents. The Arctic SPAR design is characterized by a conical section at the waterline to reduce omni directional ice loads which are ultimately transferred to the passive mooring system.

The shape of the cone is optimized to suit the design ice load conditions by altering the slope of the cone surface, the height of the necked section and its diameter. Structures can be strengthened locally to withstand loads up to a limit. Above these limiting cases, it is not practical to design the Spar to withstand the loads from the ice and therefore it is released from its moorings and riser systems and moved away from the threat. Subsequent to disconnect, the moorings and riser systems must be recovered and reconnected after the threat has passed (*Murray et al. 2009*).

Aker Solutions has designed a SPAR platform for the Eastern Barents Sea to operate in first-year ice conditions. In case of multi-year ice or iceberg occurrence the design allows that the riser and mooring system can be disconnected and the platform can move off location (*Bruun et al. 2009*).

Comprehensive ice model tests of the concept were performed to verify its ice and mooring load capabilities, and the hull capability of ice transport around the hull avoiding rubble accumulation. In the first campaign ice model tests with a conical shaped structure were carried out investigating the conical shaped structure in level ice and ridges in fixed mode, i.e. the model was rigidly fixed to the towing carriage (*Bruun et al. 2009*).

In this context the concerns are:

1. The ice load could be affected by:

- The platform pitch motion increasing the angle of interaction with the cone and therefore reducing the efficiency in breaking the ice in bending.
- The platform set down (due to vertical mooring tension increase under large offset) increasing the water plane area diameter and therefore potentially the ice load.

2. The mooring load could be significantly different from the ice load due to inertia load resulting from the platform acceleration induced by the ice action.

The Arctic Concrete SPAR hull sizing is based on provision of the total operating topside weight with corresponding centre of gravity and layout for wind area considerations. The governing parameter for the hull sizing was the required metacenter height (major contribution from vertical distance between overall centre of gravity and centre of buoyancy) for the open water draught of the platform which in turn determines the overall hydrostatic stability and natural periods in pitch and heave. It was important to increase the metacenter height to a level which reduces the natural pitch period below the region with dynamic wind excitation and well below the double value of the heave motion natural period where the Mathieu instabilities may occur.

Other key parameters for the hull sizing are:

- hull storage/ballast requirements

- hull optimization for ice loads
- heel angles due to ice loads
- motion characteristics in storm conditions
- hydrostatic stability criteria

The hull is designed with a 45 degree downward ice breaking cone (upper cone) in the ice waterline (see *Figure 91*) allowing the level ice to fail in a flexural mode, and to further transport the broken ice pieces around the hull downstream. For an ice ridge interaction the hull is designed to break the consolidated layer downwards in a flexural mode. The hull diameter below the waterline (vertical neck and lower cone) is reduced as much as possible to generate a load as low as possible from the failing of the keel rubble, and allow for transportation of both failed consolidated layer pieces and keel rubble fragments around the hull. This will avoid ice accumulation which would cause a larger effective diameter.

The mooring system is designed to resist the 100-year return period of a first year ice ridge without the need for ice management; however, multi-year ridges and icebergs will have to be handled by active ice management or by disconnection of the hull from the mooring and risers. The mooring system consists of 20 lines (see *Figure 92*) and is designed for operation loads up to 60 MN in first-year ice ridge. The configuration of each line is given by a chain-wire-chain system with a given pretension. Spring buoys with buoyancy are attached to each line.

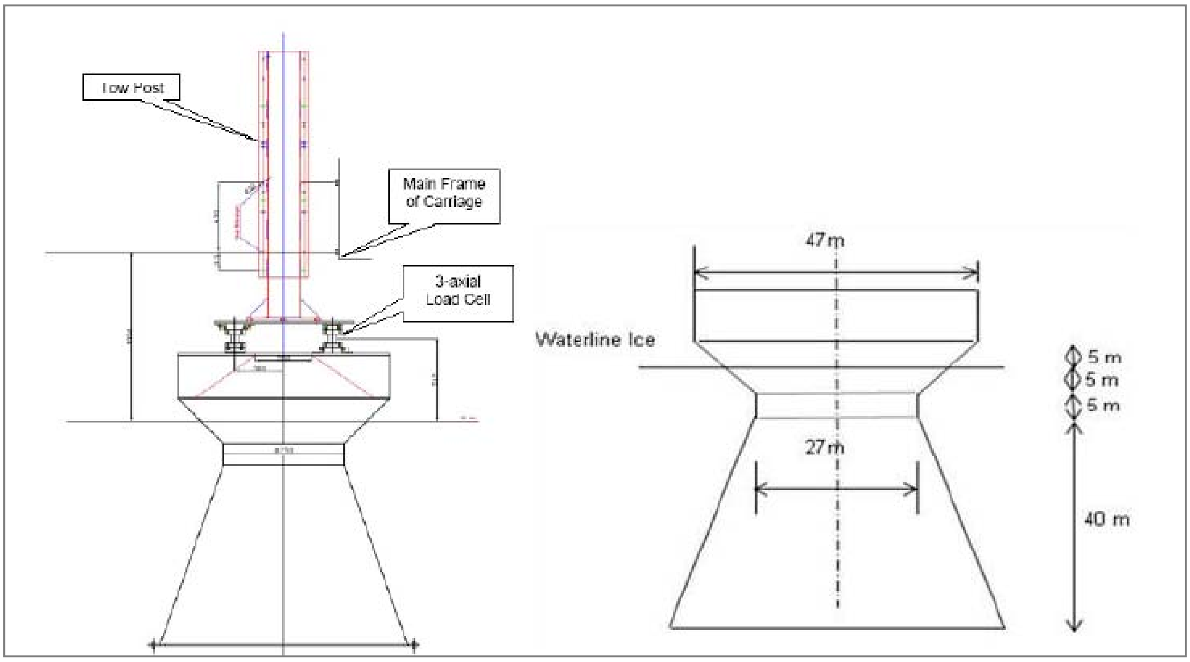


Figure 91 Fixed model set-up and geometry, representing the upper part of the SPAR (*Bruun et al., 2009*)

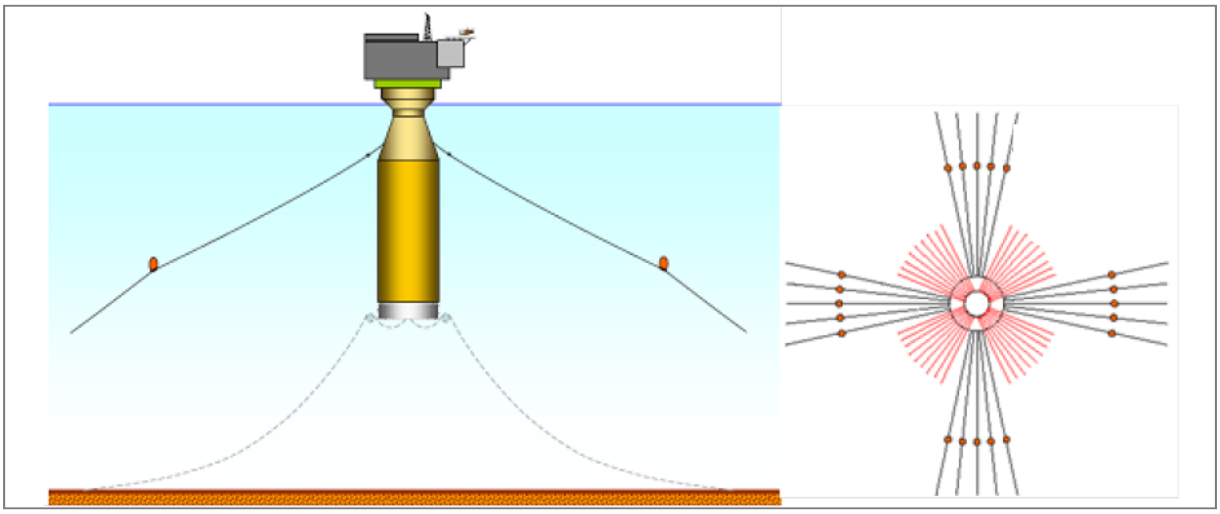


Figure 92 Vertical plane view of mooring lines (left) and horizontal projection of 20 lines mooring system in 4 groups with 5 lines in each group (right), [*Bruun et al. 2009*]

In a second testing campaign the SPAR model was free floating and moored to the bottom of the ice tank to investigate the ice-hull interaction significantly influenced by the dynamic behaviour of the floater (*Bruun et al. 2009*).

Due to ice basin limitations an equivalent truncated mooring system set-up was designed. Each of the four mooring line groups consisting of 5 lines was simulated in the test by a single mooring line (see *Figure 93*).

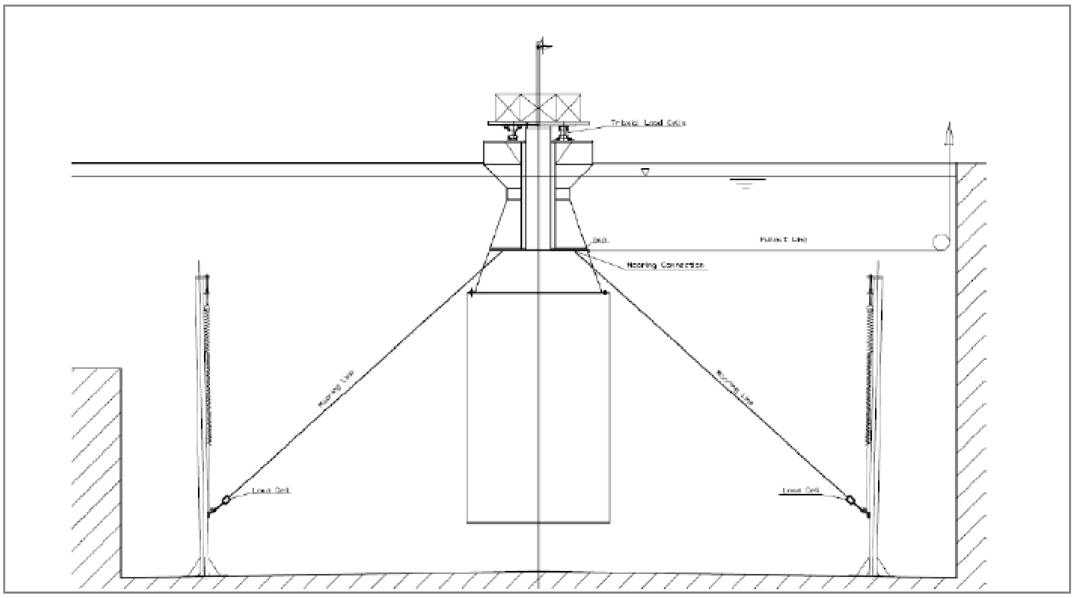
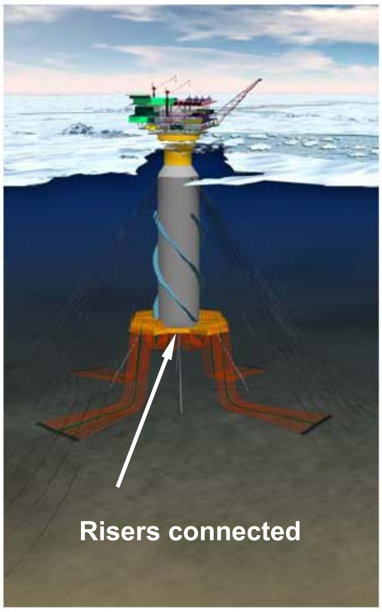


Figure 93 Schematic diagram of mooring system (*Bruun et al., 2009*)

A basic design of the Arctic SPAR design is illustrated in *Figure 94.*



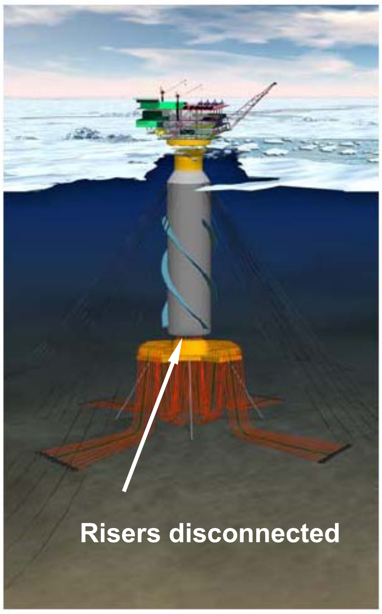


Figure 94 Artist's cut-away of the Arctic Spar with risers connected (left) and disconnected (right), (*after Ghoneim, 2011*)

The hull is composed of three main components; the hard tank, the midsection and the soft tank. The hard tank, located in the upper sections of the hull, provides most of the required buoyancy to support the intended payload and hull weight. The midsection is flooded with seawater. On a Truss Spar this section is an open truss possibly exposing the risers to ice. However, on the Arctic design the enclosed midsection is better suited to follow the "Classic Spar" design. The soft tank, located at the keel of the hull, holds the fixed ballast to lower the center of gravity. The Spar also has a conical section at the waterline to reduce ice loads resisted by the hull and mooring. When the Spar is disconnected from its moorings, riser systems must also be detached and reconnected after the threat has passed (*Murray et al. 2009*).

Figure 95 shows a schematic diagram of SPAR components.

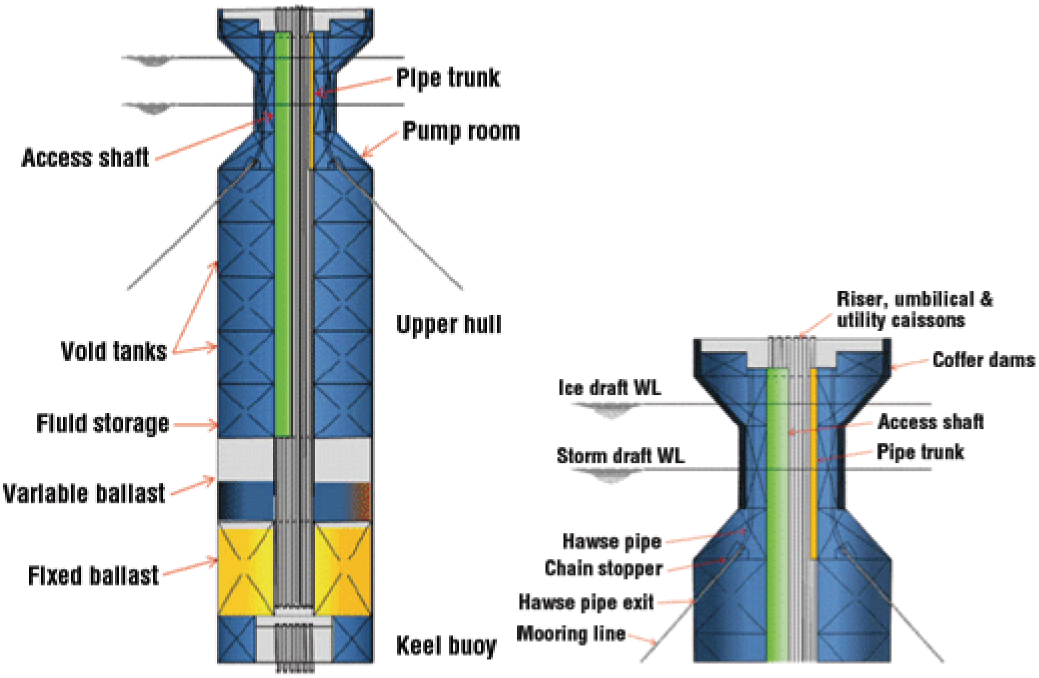


Figure 95 Schematic diagram of SPAR components (*Ghoneim 2011*)

The world's deepest production platform is *Perdido,* a truss SPAR in the Gulf of Mexico, operated by Royal Dutch Shell.

The *Perdido* (see Figure 96) is located in the Perdido fold belt which is a rich discovery of crude oil and natural gas that lies in water that is about 2450 m deep. The platform's peak production will be 100000 barrels of oil equivalent per day. With 267 m, the *Perdido* is nearly as tall as the Eiffel Tower in Paris. (reference: *http://en.wikipedia.org/Perdido_(Oil_platform)*).

Figure 96 SPAR platform *Perdido (left*) with SSCV[28] *Thialf (right*) in the Gulf of Mexico in 2450 m waterdepth (source *Wikipedia*)

[28] SSCV : Semi-Submersible Crane Vessel

5.2.2 Assessment of Floating Structures

There is only a limited number of floating exploration or production structures that have been used in ice environments.

During exploration in the Canadian Arctic in the 1980's, floating vessels (drillships) were used successfully with the support of icebreaking ships for ice management. In particular, the Kulluk, a round conical drilling unit purpose built by Gulf Oil, Canada to the Arctic Class IV specification, roughly equivalent to the modern IACS Polar Class PC4[29], operated in the Canadian Beaufort Sea. This vessel could operate through the open water season until early December (at the latest) with intensive ice management support (*IMVPA, 2008*).

On the Grand Banks of Newfoundland, FPSOs (Floating Production, Storage and Offloading) have been the choice of floating production vessels under potential sea ice (first-year) and iceberg conditions. The hulls of both of the Grand Banks FPSOs (Terra Nova and White Rose) are designed to continue operations with light to moderate first-year pack ice (5 to 8 tenths ice coverage) and can maintain their moorings in heavy first-year pack conditions (8 to 9 tenths ice coverage). It is assumed that this ice cover would not have significant pressure ridges, nor would multiyear ice be present. The FPSO hulls are designed to withstand the energy from a strike by a 100000 tonnes iceberg moving at 1 knot. This is an impact event and not a sustained load as might be found in the Beaufort or Chukchi Seas. In heavy pack ice conditions, or in the event of the approach of an unmanageable iceberg, the FPSOs are designed to disconnect from their moorings and an emergency disconnect can be effected in approximately 15 minutes.

Modified SPAR, TLP and semi-submersible designs have also been proposed for ice environments, although none have been built for applications in the Beaufort and Chukchi Sea (*IMVPA, 2008*).

FPSO's proposed for ice/iceberg areas are typically designed to be disconnected from their moorings in case of emergency and are operated in managed ice conditions. The ability of floating platforms to leave station allows the vessels to avoid extreme ice loads and also provides the capability for operations on a seasonal basis.

In ice-covered waters or regions with icebergs, the geometry and hull form of the vessel must be chosen to handle ice loads. Any vessel will also need a mooring foundation design capable of handling environmental loads. Moored floating structures are typically used in water depths greater than 30 m. However, yoke-moored FPSO's have been used also in shallow water of about 20 m in light first-year ice conditions in Bohai Bay, China.

5.2.2.1 Technical Feasibility

Seasonal exploration can be carried out using drillships and drilling barges and, in areas without multi-year ice, semi-submersibles or a TLP. However, for exploration, the only location that a floating structure might be capable of staying on station year-round might be for example the Bering Sea under light ice conditions. A semi-rigid floating structure like the "Eirik Raude" that is a 5th generation harsh environment, dynamically positioned semi-submersible could work year-round under first-year ice conditions (loads ~ 180 MN), but

[29] IACS = International Association of Classification Societies; Polar Class PC 4: Year-round operation in thick first-year ice which may include old ice inclusions

would need to have the ability to disconnect and leave station in the event of potentially higher loads (*IMVPA, 2008*).

Economically considered no floating production structure can be designed to stay on station and resist approximately 750 MN to 1000 MN multi-year ice loads found in the Beaufort and Chukchi Seas, and depending on the ice conditions possibly in the northern Bering Sea.

Due to the fact that in any design, an adequate factor of safety must be applied to the design load yielding an ultimate design load for the structure and moorings in the order of magnitude of 1000 MN to 1500 MN.

In the southern Bering Sea, under light or moderate ice conditions, a floating structure might be feasible.

Ice conditions in the Grand Banks are similar to operating conditions that predominate in the Bering Sea, particularly south of approximately 57° north latitude. North of 57° latidude, pack ice concentrations tend to be greater than on the Grand Banks. In addition, the Bering Sea, due to the higher general ice concentration, has pressure ice ridges, which are not present on the Grand Banks, which would need to be considered.

5.2.2.2 Design Philosophy

According to ISO 19906 the design philosophy and operational approaches for floating structures include the following:

- potential to suspend operations and move off location, to avoid any interactions with extreme or abnormal ice features;
- ice management support techniques to actively modify ambient ice conditions and thereby mitigate potential adverse ice actions.

The design and operational components of a floating installation and its subsea components shall be treated jointly as a system, including ice management support.

5.2.2.3 Ice loads

Floating offshore structures that are deployed in ice covered waters are often supported by ice management vessels. These vessels have the task to modify the local ice environment, reducing ice load levels on the structure and enhancing ice clearance around it.

The type of ice management system used can have a significant influence on the design approach taken for a floating structure. This influence depends upon the expected ability to consistently detect potentially adverse ice conditions (icebergs or fragments of thick sea ice features) and successfully manage them before they interact with the structure.

According to *ISO 19906* the following design and operating approaches may be used for floating petroleum installations in ice-covered waters:

- passive: no move-off capability, withstand interaction with all anticipated ice conditions, no ice management capability

- semi-active: withstand most environmental conditions , move-off capability, no ice management capability
- active: move-off capability, ice management capability, use of ice capable ships to break-up ambient ice conditions into small floes or rubble, or by means of towing, divert large ice features from the operating area

For active and semi-active operating approaches, design values of ice actions on a floating installation can be considerably less than for a fixed installation.

Any mitigation measures (i.e. ice management and move-off strategies) that are intended to ensure appropriate levels of safety should be properly identified, considered and quantified, along with expected levels of reliability.

When unmanageable ice features are approaching the structure, the production platform or vessel would need to disconnect from its moorings and leave station to avoid contact with these large features. If disconnection is required, the production platform will need to remain off station until ice conditions improve sufficiently for reconnection.

As an example, this approach is used in Sakhalin for offloading, where the SALM[30] offloading buoy remains in operation in the early winter with active ice management. When ice management is no longer possible, the buoy is laid into a trench on the sea-floor and operations are suspended until the spring. *Figure 97* through *Figure 99* shows photos of the SALM buoy on Sakhalin 2.

Figure 97 Icebreaker „Smit Sibu“ providing ice management operations for SALM buoy lay down operations on Sakhalin (courtesy of Don Conelly)

[30] SALM = Single-Anchor Leg Mooring

Figure 98 SALM Offshore Sakhalin Island with Molikpaq , Spring 2002 (courtesy of *Canatec*)

Figure 99 SALM Offshore Sakhalin Island, de-icing measures, December 2004 (courtesy of *Canatec*)

There is no known precedent for a moored structure operating in unmanaged continuous heavy ice conditions, but a wide range of model test experiments have been conducted to evaluate this scenario (*Comfort et al., 2001, Bruun et al., 2009, Evers and Jochmann, 2011*).

Figure 100 shows for various structure types (FPSO, Semi-submersible, Kulluk and CANMAR drillship) the peak loads in managed ice depending on ice concentration. In particular for semi-submersibles there is a clear trend that peak loads increase with increasing ice concentration.

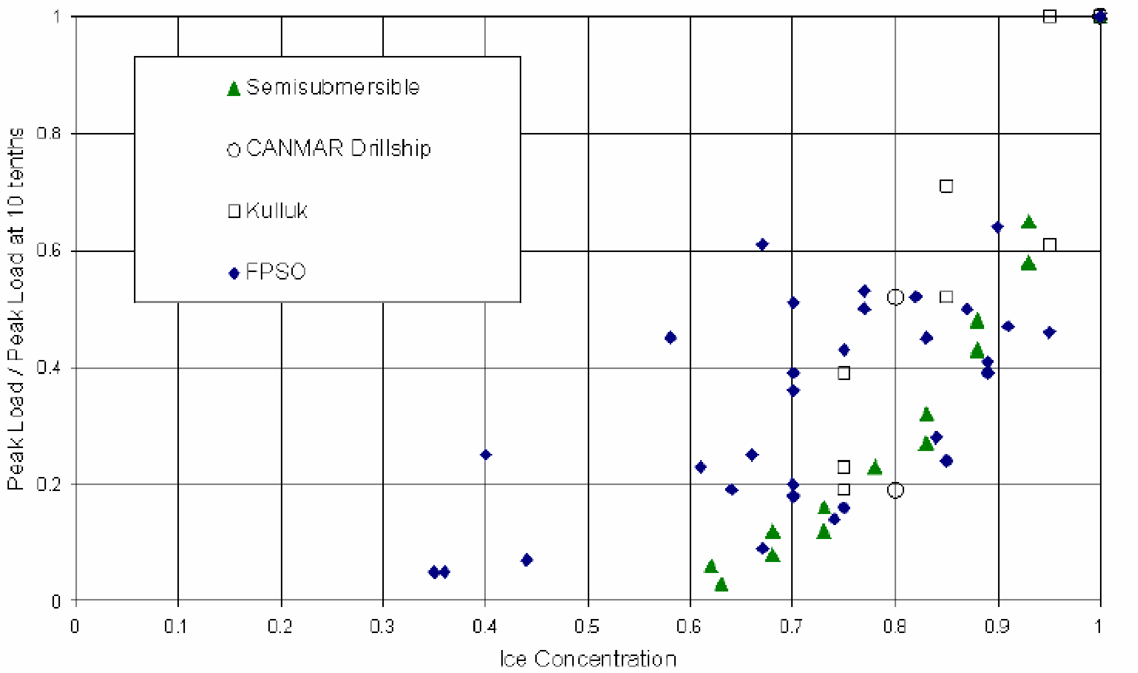


Figure 100 Peak loads in managed ice – effect of ice concentration on various structure types (reproduced from *Comfort et al., 2001*)

In general, ice loading will be greater in unmanaged ice than in managed ice. The ice thickness and drift speed become important factors in the ice loading in unmanaged ice, primarily due the need of the structure to break, as well as clear the ice sheet. In particular, multi-legged semi-submersibles can experience loads disproportionate to the size of the individual column sizes if ice jams in between the legs of the structure occur (*IMVPA, 2008*).

Another significant potential issue with respect to the use of a floating structure in severe ice conditions (coverage greater than 8/10) is the behavior of the ice as it interacts with the structure. If ice floes are submerged and forced under the vessel, interaction with the mooring and riser systems might be problematic. This situation has been investigated in a wide range of ice model test experiments.

5.2.2.4 Wave Loads

The 100 year return wave conditions for various geographical locations in the Arctic are shown in *Figure 101*. It can be generalized that the intensity of the design wave condition decreases from south to north.

Wave loading on SPAR, semi-submersible or TLP designs tend to be lower than those acting on an FPSO design, due to reduced waterplane area causing greater wave transparency and by the nature that the natural response frequencies of these designs tend to be outside (faster or slower) the wave frequencies.

Figure 101 illustrates the approximate design wave loads for a FPSO with 194000 tonnes displacement based on the environmental conditions given in *Figure 102*.

An FPSO in the southern parts of the Bering Sea would be subject to lower wave loads than those encountered on the Grand Banks of Newfoundland.

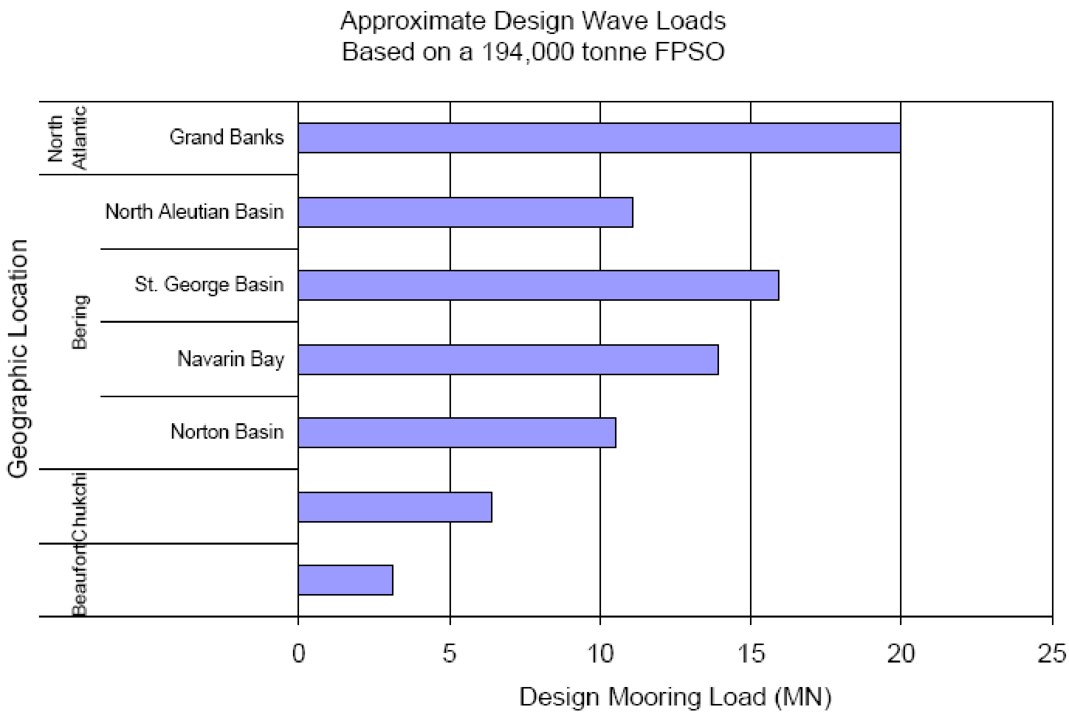


Figure 101 Approximate design wave loads – FPSO basis (note: wave loads for the Beaufort and Chukchi Sea are for summer conditions and are not meant to imply year round FPSO operations), (*IMVPA, 2008*)

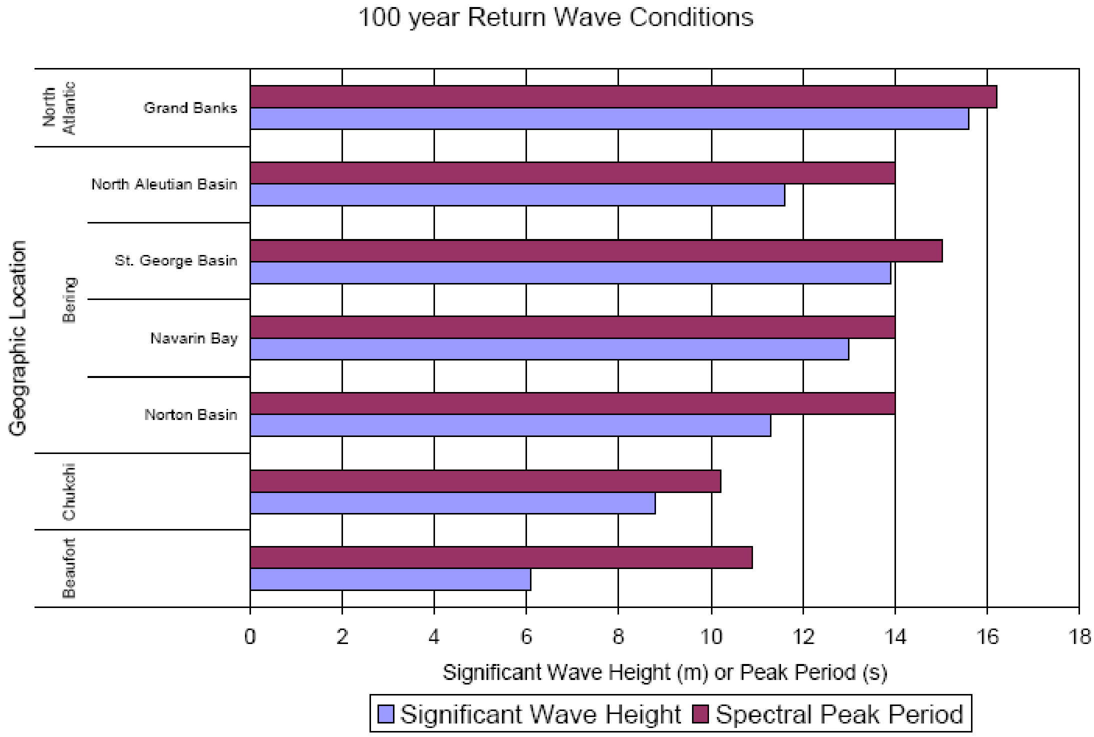


Figure 102 100-year return wave conditions in Arctic seas (*IMVPA, 2008*)

5.2.2.5 Dynamic Positioning – Station Keeping

Dynamic positioning is typically used by vessels acting for exploration, e.g. drillships and semi-submersibles, but dynamic positioning thrusters have also been used to supplement passive moorings on production platforms in marginal ice areas, e.g., Terra Nova on the Grand Banks.

The dynamic positioning systems installed in deepwater exploration vessels require significant thrust availability for sea-keeping in waves. These systems may also provide sufficient thrust for station keeping in broken first-year light ice conditions. There is the additional requirement that the vessel hull must be sufficiently reinforced for operation in ice covered waters (*IMVPA, 2008*).

As a example of the technical feasibility of exploration at high latitudes, an Arctic Coring Expedition was conducted in 2004 in the high-arctic where, with the ice management support of two icebreakers (Swedish icebreaker "Oden" and Russian nuclear icebreaker "Sovetskiy Souyuz", the dynamically positioned drillship *Vidar Viking* successfully maintained station for up to 8 days while drilling at 88° latitude in 2.5 to 3.5 m thick old ice at coring site. Up to 10 m thick ridges were observed and ice concentration of old ice was 7 to 8/10. The drillship Vidar Viking operated in floes of about 300 to 500 m in diameter before they were managed by the assisting icebreakers (*Keinonen et al., 2000*).

5.2.2.6 Mooring Systems

Modern mooring systems can provide extremely robust anchoring systems for floating structures. In most areas of application, mooring systems for floating structures are governed by wave loading.

In the Beaufort Sea and Chukchi Sea, unfactored loads from first-year ice acting on a fixed structure will be on the order of 200 MN while unfactored loads from multi-year ice acting on a fixed structure can approach 1000 MN.

One can generally consider that the maximum ice loads in these areas are in the range from 20 to 100 times the wave loads.

In light first-year ice, e.g. in the southern Bering Sea, it is possible that the dominant design criteria of the vessel mooring system could be wave loading, depending on the mooring stiffness. However, this would need to be confirmed in a site specific detailed evaluation process. For comparison purpose the amount of restoring force provided to a moored vessel, the approximate design mooring force for a selection of FPSO's and drillships with two icebreaking ships is plotted in *Figure 103*.

The thrust or mooring system resistance available from such vessels is considerably less than forces from design ice conditions for both year-round exploration (20000 tonnes) and production (100000 tonnes) conditions (*IMVPA, 2008*).

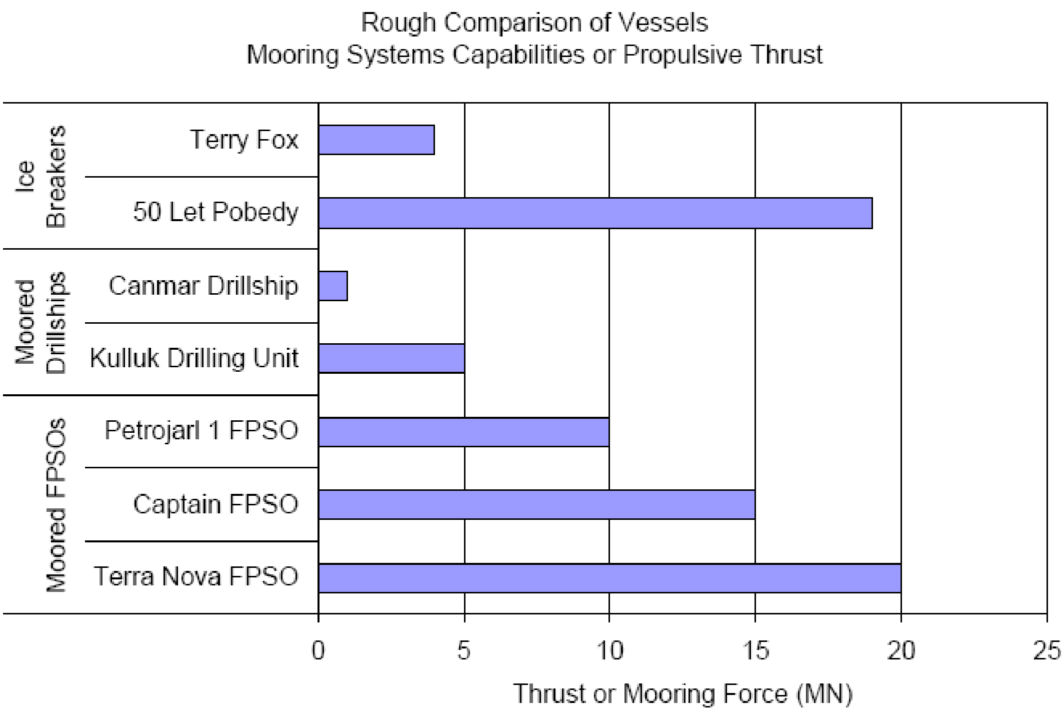


Figure 103 Comparison of selected vessel mooring systems; with selected icebreaker bollard thrust (*Comfort et al., 2001*)

If ice and environmental conditions become worse, alert and ice management procedures can cause a production shutdown. Under planned conditions, this includes a complete flushing of all necessary systems. If the ice conditions continue to worsen, the mooring system and product lines shall be released in a controlled manner.

If the design and operating scenarios involve cases of rapidly worsening or emergency conditions, the mooring system and product lines shall be designed for quick disconnection according to ISO 19906.

5.2.2.7 Seismic

Moored floating structures are not generally critically affected by seismic activity. The vessels will respond to pressure waves from nearby seismic events, but the frequency of seismic-induced pressure waves are such that the ship will not respond with large motions, and so these pressure waves will not constitute a design condition. There may be some foundation considerations with respect to seismic events.

Tsunami induced waves offshore are of low amplitude and long wavelength, and again will not induce significant motions or loads of a moored structure in deep water (*IMVPA, 2008*).

6 Summary and Conclusions

In the study, different types of fixed and floating structures for the exploration, production and transportation of oil and gas in Arctic regions have been described substantially. The choice of the types of structures depends on various parameters at the planned location. Decisive factors are the predominant on-site water depth, soil conditions, distance from the coast line and environmental conditions (e.g. ice conditions, wind, waves and currents). The first major exploration and production ice covered seas were conducted in the Beaufort Sea by American and Canadian oil companies since 1980. Generally, these are technical solutions that have proven themselves over the years.

The group of "Fixed Structures" include the types of structures:

- Artificial Islands (gravel / ice islands)
- Gravity based structures (steel /concrete)
- Jacket & Jack-up structures
- Export/loading terminals

6.1 Artificial islands and fixed structures

6.1.1 Artificial islands - Gravel islands

Gravel islands do not belong to the category of "high-tech"-technology. Nevertheless, this type of structure has been used successfully in the Beaufort Sea for decades and can continue to be used for exploration and production, as the example of "North Star" shows. Based on the proven technology and due to relatively short construction time, the gravel islands are an economical alternative for low water depths to about 20 m. With rising oil prices at the time, it is also conceivable that this type of structure in the future for something deeper water can be used despite increased material and manufacturing costs application.

Landfast ice thickness usually up to 2 m comprises the nearshore Beaufort Sea for about nine months of the year and has a significant impact on island design and construction methods.
In deeper water, the occurrence of multi-year ice and increased sea ice drift is taken into account. A primary requirement is that the island has a sufficient lateral stability to the ice and wave loads. This is generally provided by the geometry of the island.

Ice ride-up is constrained by the sloped island sides due to friction and plowing forces and/or, in some cases, by discontinuity in slope.

Waves begin to break as they reach the sloped island sides, i.e. energy is dissipated before they reach the working surface. Wave overtopping can be avoided by placing the working surface above the design wave height or by placing a barrier around the working surface perimeter.

6.1.2 Artificial islands - Ice islands

Grounded ice islands have been used successfully for exploration drilling structures in nearshore areas (shallow water) of the U.S. and Canadian Beaufort Sea.

The water depth is a fundamental factor that must be considered when assessing the feasibility of the grounded ice island structures. The technical requirements for the structure generally increase as the water depth increases associated with an increase of construction costs and construction time.

An ice island must be thoroughly founded on the seabed to resist ice loads, which may act through the surrounding ice sheet. This requirement is important because a significant movement of the island during the drilling process can lead to damage to the drill rods.

Ice loads acting on an ice island depend on the ice failure mode, rather than on the driving force of the ice sheet. Ice crushing failure of the surrounding ice sheet limits the upper bound of these loads.

Assuming that the shear capacity of soil beneath the island is less then than the shear capacity of the ice island core, global ice island resistance will be governed by its sliding resistance (lateral stability).

In practice ice islands have been used in water depths of up to about 7.5 m in the Beaufort Sea. Based on a study of C-Core (2005) and ice islands could be built up to a water depth of up to 12 m.

When planning ice islands, however, the ice dynamics of the surrounding ice cover and the duration of the winter season has to be considered in any case, which often do not allow the construction of ice islands.

6.1.3 Gravity Based Structures

Exploration drilling for oil and gas in the Beaufort Sea started from gravel islands in shallow Alaskan State waters in the late 1960’s and similarly in the Canadian Beaufort Sea in the early 1970’s. With time the activities were focusing on deeper waters.

In 1976, ice reinforced drillships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system.

Although referred to as "mobile" structures, the caisson structures were not really mobile offshore drilling units (MODU’s).

The Single Steel Drilling Caisson (SSDC) was the first MODU-type structure in the Beaufort Sea, coming into service in 1982 and, with the addition of the MAT in 1985, remains the only active bottom-founded exploration structure in the Arctic offshore.

What global size, structure cost and geometry concerns, there is only little difference between dedicated exploration platforms and dedicated production platforms. In fact, an arctic mobile drilling structure is often more expensive than a production platform, because it must cater to a range of water depths, rather than a known set-down depth like a production platform.

A mobile platform needs to be able to operate in a range of different foundation conditions. With production platforms, foundation characteristics are known and top weak layer(s) can be excavated. However this is often not practical in the case of short-term mobilization of an exploration structure.

In areas where substantial multi-year ice can encounter the structure, the ice impact loads become the primary design criteria. Where multi-year ice prevails wave loads are small and do not have a real effect on the design. However in southern areas where only first-year ice occurs (e.g. Bering Sea) the platform is primarily governed by wave load that has to be taken into account. In these regions it is required to install monolithic type structures, because ice loads are locally too high to allow the installation of jacket type structures. However the use of solid structures to mitigate local ice load effects, ice bridging and structure vibration results in relatively high wave loads.

Other parameters that have a significant effect on the global structure size optimisation are water depth and foundation conditions. As a matter of fact multi-year ice loads increase with increasing water depth. However deeper water means higher horizontal ice loads and a higher structure associated with higher costs. The foundation conditions can range from “totally inadequate” to “strong enough”.

If the foundation conditions are “totally inadequate” lateral relocation, dredging and /or replacement will be required. If the foundation is “strong enough” the structure can set-down directly on the seabed without any preparations.

In general the foundation requirements for an exploration structure are significantly less than those for production structures operating permanently with respect to the design ice loads, i.e. first-year ice vs. multi-year ice loads.

In multi-year ice areas, there are gravity base structures (GBS), solutions that are considered safe and economical up to around 75 m water depths when foundation properties are good, and up to around 60 m water depths when foundation properties are relatively weak.

There are no known bottom-founded platform design solutions for water depths greater than 100 m that could be considered as workable or proven for multi-year ice areas. In the more southern areas, where multi-year ice is not present and only first-year consolidated ridge loadings are possible, bottom-founded solutions out to 130 to 150 m water depths are potentially viable (*IMVPA, 2008*).

6.1.4 Jacket and Jack-up Structures

The jacket structure is the most commonly used fixed offshore platform. It was first used in the Gulf of Mexico and has since been adapted and modified for use around the world. There are a number of structure types from the single-legged to multi-legged structure. The ice-strengthened jacket platform was first used successfully in sea ice in the mid-1960s for Cook Inlet, Alaska Development. Conventional jacket designs were modified to make them suitable for sea ice environments.

An important criterion for the design of a jacket structure is the payload that has to be carried by the structure, the capacity of the foundation and the external environmental loads (e.g. ice, wind, waves etc.) must resist the structure.

The loads Arctic offshore structures are temperature loading, static sea ice loads and the accompanying loads due to ice-induced vibrations. In many cases, the static and vibration loads are the controlling factor (either globally or locally) in the sizing of the structure components. Temperature is generally the controlling factor in material selection.

The load acting on a structure by momentum, ice ridge building and pack ice loading relates to the width of the structure. If the jacket legs are within a certain distance of each other, ice bridging can occur between the legs and higher ice loads will be experienced by the structure compared to the case where the legs are loaded independently (e.g. larger leg to leg distance).

In addition to static sea ice loads, the jacket structure must be able to absorb the vibration. Ice-reinforced jacket structures are more prone to vibration than conventional jackets, because they have less damping capacity and tend to amplify vibrations.

In view of the jacket failure in the Gulf of Bohai and the malfunction of another jacket structure as a result of ice-induced vibrations, jacket platforms do not seem to be particularly practical.

Further development work regarding alternative damping techniques is necessary to reduce ice-induced vibrations on the jacket

A variety of exploration and development options have been employed or considered for use in the Arctic and other cold regions. These options are summarized in *Table 10*.

Table 10 Summary of Arctic and Cold Regions Exploration and Development Options

Region	US Beaufort Sea	Chukchi Sea	Bering Sea	Cook Inlet	Can. Beaufort Sea	Can. High North	Can. East Coast	Offshore West Greenland	Barents Sea	Kara Sea (Gulf of Ob)	Pechora Sea	Baltic Sea	Sakhalin Island
Bottom-Founded & Fixed Type Structures													
GBS	X	X	X		X		X			X	X		X
Mobile Bottom-Founded	X				X					X			
Barge			X		X								
Jacket/ Monopod			X	X			X						
Jack-up			X	X			X						X
Gravel Island	X				X								
CRI					X								X
Ice Island	X				X								
Floating Structures													
FPSO/FSO			X				X	X					
SPAR							X		X				
TLP							X		X				X
Semi			X	X			X	X					X
Drillship	X	X		X	X		X	X					
Floating Ice Pad						X							
Export and Infrastructure													
Offloading Buoy/ Terminal			X				X				X		X
Export Terminal		X	X			X	X		X		X	X	X
Pipeline	X	X	X		X	X	X		X			X	X
Subsea/ Flowlines	X	X	X		X	X	X	X	X				X

6.2 Floating Structures

There are only a limited number of floating exploration or production structures that have been used in ice environments.

During exploration in the Canadian Arctic in the 1980's, floating vessels (drillships) were used successfully with the support of icebreaking ships for ice management, e.g., CANMAR "Explorer III" drillship and CANMAR "Kigoriak" icebreaker. In particular, the conical drilling barge "Kulluk", purpose built by Gulf Canada, operated successful in the Canadian Beaufort Sea. This vessel could operate through the open water season until early December (at the latest) with intensive ice management support.

On the Grand Banks of Newfoundland, FPSOs (Floating Production, Storage and Offloading) have been the choice of floating production vessels under potential first-year sea ice and iceberg conditions.

The hulls of both of the existing Grand Banks FPSOs "Terra Nova" and "White Rose" are designed to operate in light to moderate first-year pack ice and can also maintain their moorings in heavy first-year pack conditions (*IMVPA, 2008*).

The ice conditions in Grand Banks are different from those in the Alaska Outer Continental Shelf , because no significant pressure ice ridges are embedded in the ice cover.

Additionally, the hulls of the FPSO's are designed to withstand the energy from a strike by a 100000 tonnes mass iceberg moving at 1 knot. This is an impact event and not a sustained load as might be found in the Beaufort or Chukchi Seas.
Modified SPAR, TLP (Tension Leg Platform) and semi-submersible designs have also been proposed for ice environments. Floating structures have been and will continue to be used for seasonal exploration. A Semi-rigid floater type structure could be considered for year-round exploration, if disconnects is permissible under extreme loading events.

Recently FEED[31]-studies have been carried out and ice model testing in various ice tanks were executed to validate the feasibility of newly developed designs for future operations in high latititudes in the Arctic.

Floating production platforms proposed for ice/iceberg areas are typically designed to be readily disconnected from their moorings and operated in managed ice conditions. The ability of these floating platforms to leave station would allow the vessel to avoid extreme ice loads and also provide the capability for operations on a seasonal basis. The amount of time that it might take any particular floating vessel to reconnect back on station will be a significant consideration in concept selection for any production site (*IMVPA, 2008*).

6.3 Export / Loading Terminals

A marine export terminal is defined as a complex of structures and equipment for loading of hydrocarbon products, either pumped to a tanker from a storage facility located onshore or directly from a processing facility.

In most cases, marine transportation of hydrocarbon products starts with large storage facilities located onshore. The land-based components of these facilities (tank farms, loading pump stations, treatment plants, etc.) in the Arctic are basically the same as those in moderate climates (*IMVPA, 2008*).

[31] FEED = Front End Engineering Design

The main difference is primarily in providing the conditions and the process equipment to allow continuous operation under harsh environmental conditions (e.g. low temperatures, icing and snowfall conditions).

Flow assurance is a critical consideration for arctic and sub-arctic locations. Consequently, to ensure smooth operations, an important aspect of any terminal concept is the need for proper insulation and heat-tracing technology on piping and pipelines.

Alternatively, hydrocarbons may be loaded on tankers at sea or in the vicinity of production platforms, either from the platform storage tanks or from a FSO (Floating Storage and Offloading) vessel. The FSO may also be used in the nearshore for temporary storage or trans-shipment loading.

Particularly challenging in the Arctic is the offloading of products to tankers. This operation would need to be conducted in floating ice if year-round operations are going to be carried out. In this case ice management has to be provided by assisting icebreakers or icebreaking supply vessels. Support is necessary because otherwise the ice loads on the FSO may be so large that a safe off-loading operation can not be guaranteed.

The technical feasibility of export/loading terminals for oil and gas in arctic areas has been documented in a wide range of port facilities:

- Nome (Alaska, Beaufort Sea)
- Cook Inlet (Alaska)
- Anchorage and Valdez (Alaska)
- Godthab and De Long (Greenland)
- Nanisivik (North Baffin Island, Canada)
- St. David de Levis and Caps Noirs (Quebec, Canada)
- Norwegian and Russian ports in the Barents Sea (Murmansk, Arkhangelsk)
- Magadan and Petropavlovsk (Okhotsk Sea, Russia)

The most recent examples are the large oil terminal in DeKastri and the LNG terminal in Prigorodnoye (Sea of Japan), Russia., LNG terminal Aniva Bay (Sakhalin, Russia), oil loading terminal Varanday (Russia), oil loading terminal Primorsk (Russia)

The main challenge of the above mentioned ports and terminals is that these marine structures are to be managed, operated and maintained under adverse conditions (remote area, undeveloped infrastructure, harsh environment and severe ice conditions).

In particular for fixed offshore and floating terminals there is a high risk that these marine structures experiences high lateral ice loads. Floating ice does not only affect the marine structure but also often complicates vessel operations. Additional uplift forces and compression loads on structures may be generated by tidal change due to adfreeze to the structure.

The loads generated through ice/structure interaction, in most cases, govern the design of arctic ports and terminal structures.

A general review of experience in operation of high-latitude oil and gas marine terminals indicates that existing technology of port structures design and construction is sufficient to support operations in the Alaskan Outer Continental Shelf.

While technically feasible, no tanker traffic has been proposed in the Environmental Impact Statement (EIS) for upcoming Beaufort or Chukchi lease sales. Regulatory requirements would require the use of pipelines (if economically feasible) rather than barging or tankering production to shore. An exception may be gas export by LNG or CNG (*IMVPA, 2008*).

Conclusion

Worldwide, there are currently around 790 offshore drilling rigs (jack-ups, semisubmersibles, drillships and barges), and 8,000 fixed or floating platforms. Of these, 116 rigs and more than 1,000 fixed or floating platforms are in European waters (*Sandrea and Sandrea, 2007*). Many offshore installations are likely to be constructed in the near future as explorations in nearly all sea areas. Some of the projects under development concern deepwater exploration activities, particularly in the Northern North Sea, the Black Sea and the Mediterranean Sea. The shelf of the Barents Sea off northern Norway and Russia is also subject to intensive exploration. A substantial increase in offshore activities related to offshore oil and gas exploration is expected in this area in the coming years.

Fixed offshore structures are a family of technological solutions which are well established and proven since tenth of years. A number of realized examples for fixed structures show a variety of technological solutions for very shallow water, shallow water and water depths up to 300 m. Suitable production facilities are installed on artificial islands and concrete or steel made Gravity Base Structures (GBS).The most concepts include Offshore Loading Systems (OLS) or loading facilities on moles or jetties and have to be designed for harsh open water conditions (waves) but also to withstand loads from drifting ice.

As fixed structures have technically drawbacks when the water depth increases and in the case when sea ice occurs, alternative techniques and structure types have been developed. Differences can be found in the individual product export means, such as pipelines or shuttle tankers. The produced volume of oil or gas, the water depths or the distance to shore or the related receiving plant as well as the chosen strategy to reach the next market access point together with the expected field life are influencing the decision for the most favorable offshore structure type solution. For this reason, there is no preferred type of structure that can be used anywhere.

The first family of alternatives belongs to floating surface offshore structures which can be developed, built and tested at invulnerably locations or comparably cheap construction sites before moving to the offshore site and which can be removed with low effort to other places when the field life has reached its end.

New technology developments are required regarding shipping operations, primarily by providing the highest level of safety of tanker operations in ice-infested waters and by maximizing the efficiency of ice management systems.

It is suggested that FPSOs operating in ice covered regions should adapt features of icebreaker designs, such as icebreaking bow, reamers or inclined sidewalls in the waterline to resist ice loads, and azipod drives to be able to manoeuvre efficiently in harsh ice conditions.

Active ice management, a tactical procedure to break the ice around the platform or moored FPSO by icebreakers or icebreaking supply vessels is strongly recommended to enable align FPSO with prevailing ice drift direction by weathervane due to turret and swivel systems. The subsurface buoy is designed to fit into a specially configured compartment in the hull of the FPSO, housing the swivel and bearing around which the FPSO can rotate.

Winterization aspects have to be considered because the FPSO superstructure is also sensitive to atmospheric and sea spray icing and requires necessary measures with respect to winterization of the facilities (*Evers and Richter, 2014*). Significant advantages of moored ship shaped FPSOs are single point disconnection using turret and the ability to self-manoeuvre after disconnection from the mooring lines. The type of an appropriate mooring system varies with water depth and expected response forces respectively mooring line loads due to ice.

The most modern strategy of hydrocarbon production belongs to the subsea production facilities. These facilities are installed completely at the seafloor by means of heavy duty construction vessels. The facilities are permanently connected via export pipelines to a related onshore receiving plant Remote control takes place via multipurpose umbilicals with high bandwidth from the onshore plant and even from all over the world via the Internet. Although fully submerged from time to time these facilities need work over drilling; service requires free access of remotely operated vehicles (ROV) or autonomous underwater vehicles (AUV).

The experience of the past few decades with the installation, operation of offshore exploration and production structures, as well as transportation systems in the Arctic are a solid basis for future developments of innovative technologies, that enable year-round drilling and production with a high level of reliability.

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