FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

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Abstract

The Master Thesis aims to develop a *cluster oil and gas fields development concept* in the Pechora sea and carry out an economic feasibility estimation of this concept.

The first chapter describes the climatic conditions of the Pechora Sea. The geographical characteristics and characteristics of hydrometeorological and ice conditions are under consideration.

The second chapter introduces the main challenges linked with offshore arctic oil and gas fields' development.

The third chapter presents the selection of a field-group for a cluster development consideration. After that, the design of the development concepts for the selected group of fields was carried out. The chosen fields are Dolginkoye, North-Gulyaevskoye and Pomorskoye oil and gas/condensate fields. The production profile for each field and the total production profile have been plotted.

The fourth chapter presents the infrastructure choice for the chosen cluster development concept: the choice of a gravitational-type platform design; selection of an LNG plant and natural gas liquefaction technology; selection of subsea production systems; choice of a loading and shipment method of carriers for transportation of extracted products.

In the fifth chapter, the concept's economic feasibility and the further selection of the most cost-effective concept was under consideration.

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Introduction

The Pechora Sea belongs to the Timano-Pechorskaya oil and gas province with a high density of initial geological hydrocarbon reserves. The sedimentary cover of the sea contains vast hydrocarbon reserves, the development of which is already started. The initial total oil and gas reserves in the Pechora Sea make up 8.1% of all oil and gas reserves located in the Russian seas (4th place), the initial oil reserves are 16.9% (2nd place) [1].

The first field developed in the Arctic is the Prirazlomnoye field. The location of this field is the Pechora Sea.

Currently, the question of continuing the development of the Pechora Sea is acute; there are a large number of deposits located here, the distances between which are quite small. The big and fundamental challenge is to find a way to start the cluster field development. This work aims to develop the concept of cluster field development and determine its profitability for a group of deposits of the Pechora Sea.

The Objectives of this work are:

1. Pechora Sea description;
2. Pechora Sea's oil and gas fields description;
3. Identification of the main challenges associated with the Arctic and Sub-Arctic offshore oil and gas field development;
4. Determination of oil and gas fields group for the further concept development;
5. Design of several development concepts for the determined group of fields;
6. Design of the development concepts’ infrastructure;
7. Concepts' economic feasibility analysis;
8. Determination of the best concept from an economic point of view.

1. The Pechora Sea description

1.1. Environmental issues of the Pechora Sea

1.1.1. Geographical description

The Pechora Sea is a part of the Barents Sea. However, it has its unique history of development, has a peculiar relief and sedimentary structure, and differs from the Barents Sea in its hydrological and ice regime. There are official borders of the Pechora Sea, adopted on November 28, 1935, by a resolution of the Central Executive Committee of the USSR. From the north-west, the Pechora Sea is limited by the line of the Kolguyev island - Chornyi cape in the Mezhdusharskiy Strait on Novaya Zemlya, and from the southwest by the line of the Kolguyev island - Svyatoy Nos cape on the Timan coast of the Malozemelskaya tundra (Figure 1.1) [2]. At the same time, the Kara Gates and Ugra Straits do not belong to the Pechora Sea. All shores washed by the sea belong to Russia (mainland coast, Kolguyev and Vaigach islands – Nenets Autonomous District, Novaya Zemlya archipelago – Arkhangelsk region).

The dimensions of the Pechora Sea are: in the latitudinal direction - from Kolguyev Island to the Kara Gate - about 300 km and the longitudinal direction - from Cape Russkiy Zavorot to Novaya Zemlya - about 180 km. The area of the sea is 81,263 km^2; the volume of water is 4,380 km^3.

Within the Pechora Sea, there are several bays: Ramenka, Kolokolkova, Pakhanskaya, Bolvan, Khaipudyrskaya, Pechora (the largest). The largest river flowing into the sea is the Pechora river.

The sea is shallow with gradually increasing depths in the meridional direction from the mainland coast. Along the southern coast of the Novaya Zemlya archipelago, there is a deep-sea trench with depths of more than 150 m [3].

Figure 1.1. Pechora Sea location on the map

1.1.2. Hydrological and meteorological description

Wind:

Repeatability of wind speed by rumbas (N, NO, O, SO, S, SW, W, NW), "wind rose" - this is one of the primary regime characteristics of wind speed. The initial data for the table below compiling was a data array with a 3 hours resolution in duration from 1949 to 2006.

Table 1.1 [4] shows the values of the wind speed ranked sample module quantile function x_p. The members of such a sample are called ordinal statistics and are quantile estimates x_p for a given p, and the serial number is defined as the integer part of the number $np + 1$.

The term p is a probability that should be understood as an estimate of the probability of the event. $p = 100\%$ and $p = 0\%$ in probability theory are impossible; in mathematical statistics, the ranked series are always of limited volume (sample size n), therefore, in the following tables, $p = 100\%$ and $p = 0\%$ is an abstraction, the extreme members of a sample x_i of volume n (x_{min}, x_{max}).

Table 1.1. Quantile function x_p of the wind speed absolute value [4]

p, %	x_p, m/s	p, %	x_p, m/s	p, %	x_p, m/s
100 (min)	-	75	5.8	20	11.7
99	1.7	70	6.3	15	12.5
97	2.5	60	7.2	10	13.6
95	3.0	50	8.1	5	15.3

Continuation of Table 1.1.

90	3.9	40	9.2	3	16.5
85	4.6	30	10.3	1	18.7
80	5.2	25	10.9	0 (max)	28.6

According to the table above, the quantiles $x_{0.7} = 5.8\,m/s$, $x_{0.25} = 10.9\,m/s$, the median $Me = x_{0.5} = 8.2\,m/s$, the highest value is 28.6 m/s, span $R = x_{max} - x_{min} = 28.6\,m/s$ since the smallest value is calm interquartile distance $Q = x_{0.25} - x_{0.75} = 5.1\,m/s$, "three-average" value $T = \frac{x_{0.25}+x_{0.75}+2x_{0.5}}{4} = 8.2\,\frac{m}{s}$. The indicator T shows a quantile estimation of the average sample value, and the indicators Q and R allow us to estimate the standard deviation σ.

Table 1.2 [4] shows the sample sizes n_i values of the wind speed absolute value conditional distributions by rumbas, five quantiles $x_{min}, x_{0.75}, x_{0.5}, x_{0.25}, x_{max}$ and the values of the indicators (Q, R, T).

Table 1.2. Quantile estimation of the sample average values [4]

Direction	n_i	x_{min}	$x_{0.75}$	$x_{0.5}$	$x_{0.25}$	x_{max}	Q	R	T
N	13836	0.50	5.30	7.40	9.80	22.70	4.50	22.20	7.48
NE	12864	0.60	5.20	7.20	9.40	22.40	4.20	21.80	7.25
E	14591	0.40	5.60	7.70	10.10	21.10	4.50	20.70	7.78
SE	13523	0.60	5.60	7.80	10.10	23.20	4.50	22.60	7.83
S	15406	0.50	5.90	8.30	11.10	28.60	5.20	28.10	8.40
SW	20520	0.40	6.70	9.60	12.70	27.00	6.00	26.60	9.65
W	18448	0.30	6.20	9.10	12.20	26.60	6.00	26.30	9.15
NW	15859	0.70	5.70	8.10	10.80	26.40	5.10	25.70	8.18

The mean value (average value of the wind speed vector) is 1.4 m / s, and the direction of this vector is 242°.

Waves:

The repeatability $p(h,\tau)$ and the significance $F(h,\tau)$ of average wave heights and periods, as well as the quantile functions h_p, τ_p of marginal distributions are presented in Table 1.3 and Table 1.4 [4].

Table 1.3. The repeatability $p(h,\tau)$ and the significance $F(h,\tau)$ of average wave heights and periods [4]

T_p		h_p						
		[0.0;0.5)	[0.5;1.0)	[1.0;1.5)	[1.5;2.0)	[2.0;2.5)	[2.5;3.0)	[3.0;3.5)
[1,2)	$p(h,\tau)$	5.6	–	–	–	–	–	–
	$F(h,\tau)$	100.0	–	–	–	–	–	–
[2,3)	$p(h,\tau)$	26.0	17.5	–	–	–	–	–
	$F(h,\tau)$	94.4	68.4	–	–	–	–	–
[3,4)	$p(h,\tau)$	0.5	21.5	11.1	–	–	–	–
	$F(h,\tau)$	68.4	50.4	28.9	–	–	–	–
[4,5)	$p(h,\tau)$	0.0	0.1	6.7	7.3	0.6	–	–
	$F(h,\tau)$	67.9	28.9	17.8	11.2	3.8	–	–
[5,6)	$p(h,\tau)$	0.0	0.0	0.0	0.1	2.1	0.8	0.1
	$F(h,\tau)$	67.9	28.9	11.2	3.8	3.1	1.1	0.2
[6,7)	$p(h,\tau)$	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	$F(h,\tau)$	67.9	28.9	11.1	3.7	1.1	0.2	0.2

The symbol "–" means that the corresponding values are absent in the sample or their probability is close to 0.

According to the above table, it can be found that the mean value of the wave height is approximately 0.78 m, and the mean value of the wave period is approximately 3.1 s.

Table 1.4. Quantile functions of average heights and wave periods [4]

p, %	h_p, м	τ_p, с	p, %	h_p, м	τ_p, с	p, %	h_p, м	τ_p, с
100 (min)	0.0	1.0	75	0.4	2.4	20	1.2	3.9
99	0.1	1.6	70	0.4	2.5	15	1.3	4.1
97	0.2	1.8	60	0.5	2.7	10	1.5	4.3
92	0.2	1.9	50	0.6	3.0	5	1.8	4.7
90	0.3	2.1	40	0.8	3.2	3	2.0	5.0
85	0.3	2.2	30	0.9	3.5	1	2.5	5.4
80	0.3	2.3	25	1.0	3.7	0 (max)	4.2	6.8

The shape of the coastline has a significant effect on the wave regime. The area is completely protected from the north, east and south, the water depth is relatively small. The highest waves have a north-west direction, and the intensity of the waves decreases from west to east. The storm season usually begins in October and at depths of 20-30 m. The presence of ice ultimately determines the wave regime in the winter and spring months. In summer, a calm surface prevails [5].

Air temperature:

The number of days with air temperatures below 0 °C is approximately 230 days per year. The coldest month is February, the average temperature in the Varandey region is -18.3 ºC, and the absolute minimum of the observed temperatures is -48 ºC. From December to March, the temperature change is insignificant. Figure 1.1 represents the difference between air temperatures from the west (North Kolguev) to the east (Varandey). The average annual temperature in the North Kolguev region is -2.9 ºC and in the Varandey region -5.6 ºC.

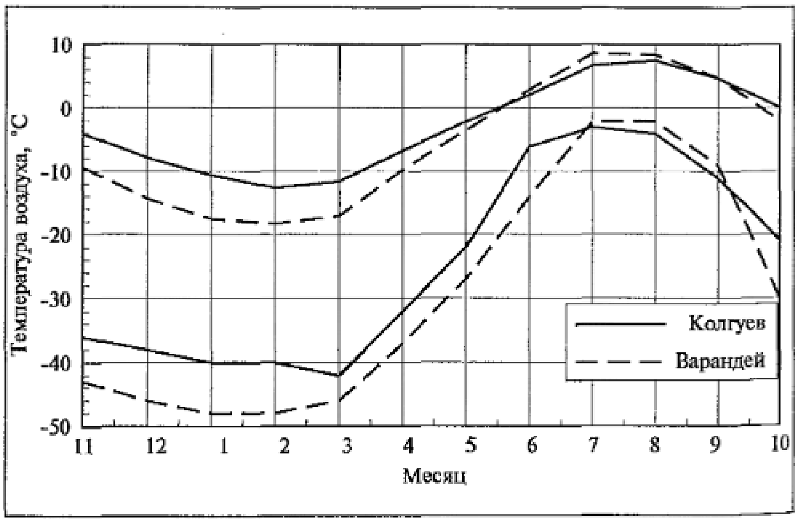


Figure 1.1. Average and extreme minimum air temperatures in North Kolguev and Varandey, Pechora Sea. Data refer to the period 1936-1979. for Northern Kolguev and 1940-1980 for Varandey [5]

Currents:

The entire range of seawater movements is presented in the Pechora Sea current system: quasi-stationary circulation, synoptic-scale currents (storm surges) and tidal currents. Quasi-stationary currents are represented by the Kaninsky, Kolguyevo-Pechora, Pechora currents and the Litke current flowing from the Kara Sea and spreading along the western coast of Novaya Zemlya. Their speed is low and usually does not exceed 0.2 m/s. The nature of the tidal current is semidiurnal, that is mean that the tidal wave makes a full movement in both directions for approximately 12 hours [6, 7].

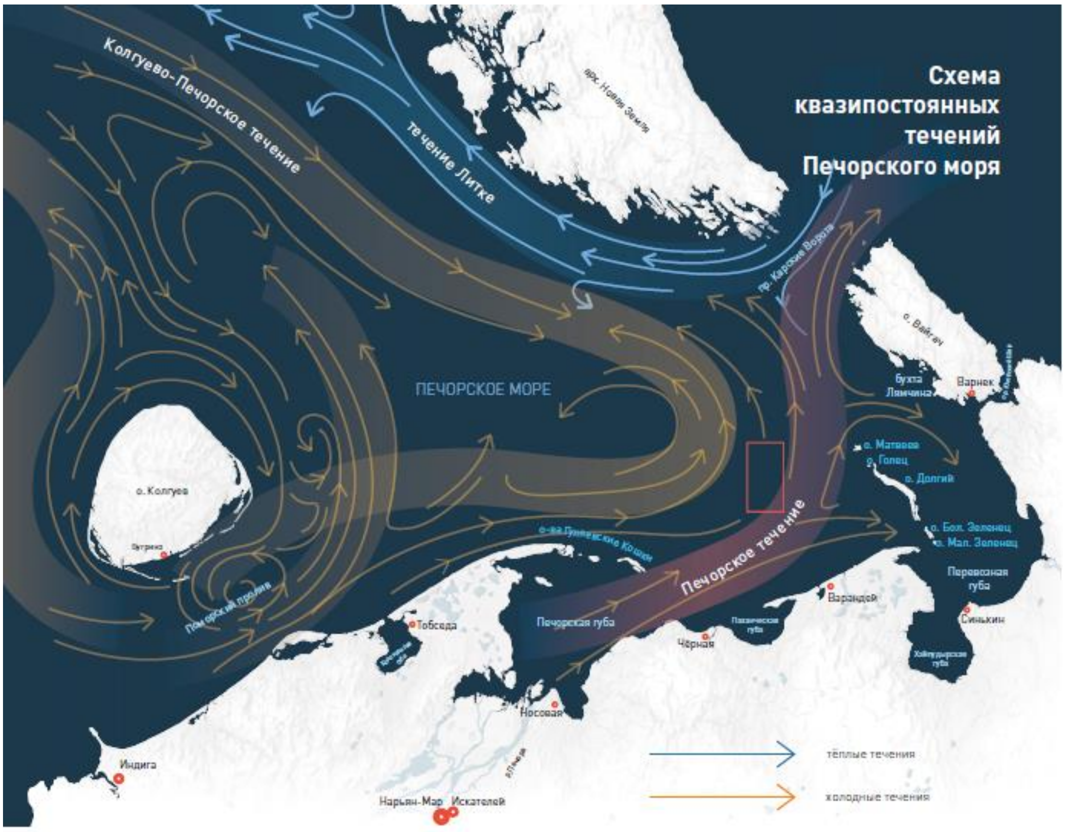


Figure 1.2 Scheme of quasi-stationary currents of the Pechora Sea [6]

The main direction of water masses movement (currents) during the tides is from the southeast to north-west (Figure 1.2). During low tide - on the contrary, the speed of the tidal current (in spring) can reach 0.4 m / s. The maximum speed of wind casting currents is 1 m/s [5].

1.1.3. Ice conditions

One of the most critical features of the Pechora Sea is the presence of one-year (in small amounts of multi-year) ice of local origin. Also, small amounts of ice from the Kara Sea (through the Kara Gate) and the White Sea (through the Pomeranian Strait) appears in the Pechora Sea.

The ice season in the Pechora Sea lasts on average from late October to late July. The peak of the ice cover is observed in March-April. During this period, the entire surface of the water in the Pechora Sea is covered with ice, Figure 1.3.

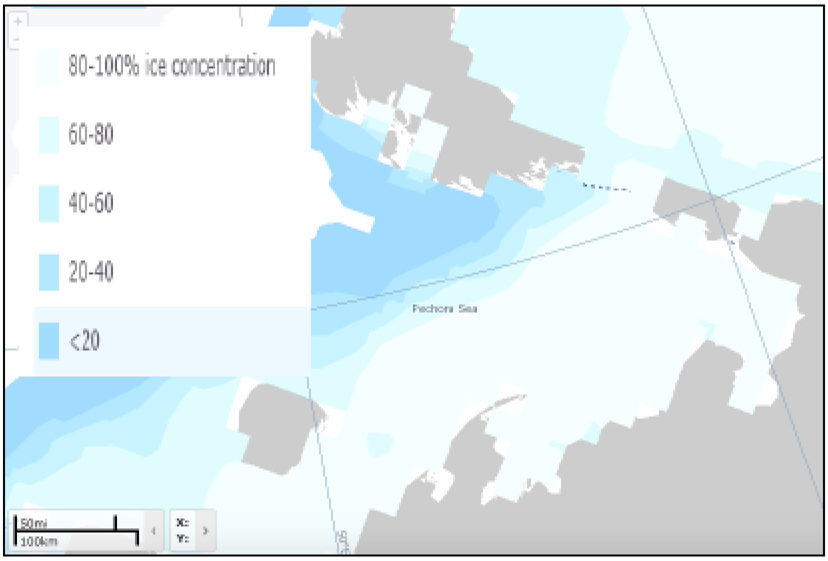


Figure 1.3. Ice concentration in the Pechora Sea (March 2012) [8]

The average duration of ice season lasts 185 days for the western part of the sea and 240 days for the eastern. The average free water period in the Prirazlomnaya platform's area is 110 days.

The Pechora Sea is characterized by intense ice drift. Ice drift is caused by the combined action of wind and current (including tidal currents). Due to the occurrence of such a phenomenon nature, the Pechora Sea ice drift is characterized by significant variability. The average ice drift velocity is 0.005 m / s, and the maximum is 0.05 m/s.

The maximum thickness of the sea ice is approximately 1.1 m. The layered ice formation with thickness up to 2.5 m is also possible. The ice structure is granular, ice salinity in winter is 5-6%, in spring 2.5-3%.

It should be noted that a large number of hummocks distinguishes the Pechora Sea. In the drift zone, hummocking can reach 3-4 points in February and 5 points in April. Typically, hummocks are composed of blocks 0.3–0.6 m thick. The keel draft is approximately 3–6 m but can reach 12–18 m [5].

1.2. Oil and gas fields in the Pechora Sea

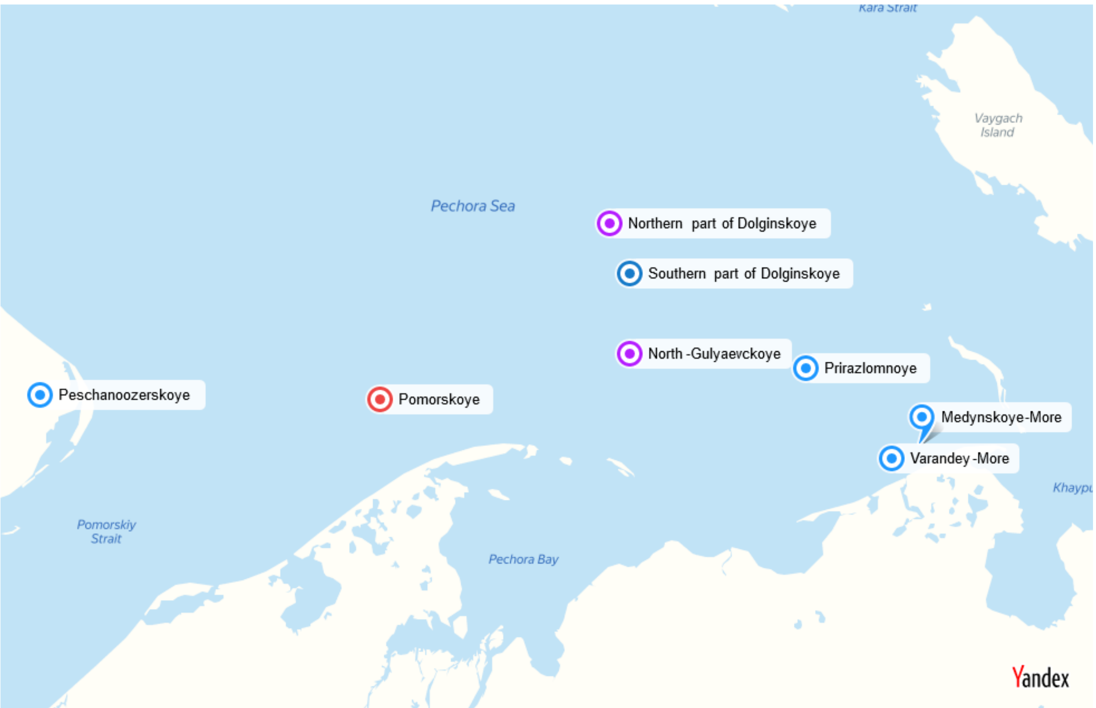


Figure 1.4. Oil and gas fields in the Pechora sea: red boundary – gas/condensate field; blue boundary – oil field; purple boundary – oil and gas/condensate field

The figure above represents oil and gas fields in the Pechora Sea [9]:

- Prirazlomnoye field;
- Dolginskoye field (Northern and Southern parts);
- North-Gulyaevskoye field;
- Medynskoye-More field;
- Pomorskoye field;
- Peschanooserskoye field.

The brief description for each field is presented below:

Prirazlomnoye field:

The Prirazlomnoye oil field is located in 55 km north from the Varandey village, 240 km northeast from the Naryan-Mar river port (Pechora River) and 980 km east from the Murmansk city. The water depth within the field does not exceed 19-20 meters. The soil of the sea bottom in the area of work is mostly represented by sand.

The field was discovered in 1989 by exploratory well No. 1, drilled in the arch part of the anticlinal fold to a depth of 3100 m. When testing the Lower Permian-

Middle Carboniferous limestones in the interval 2368-2438 m, an industrial oil flow was obtained with a flow rate of 393 m^3/day after acid treatment. 3D seismic work was performed at the field. The development of the field started in 2013. The operator of the field is the company Gazprom Neft Shelf.

Initial geological oil and associated gas reserves were approved by the Central Concern of the Russian Federation Ministry of Natural Resources (protocol No. 128 of 04/26/2001). The initial geological reserves in C_1+C_2 categories are 231.1 million tons, including the C_1 category - 153.4 million tons. The recoverable oil reserves of the productive horizon were approved by the State Reserves Committee of the Russian Federation for categories C_1 + C_2 in the amount of 69.3 million tons, including the category C_1 - 46 million tons. The oil recovery coefficient for the deposit was approved equal to 0.3. Due to the increase in the field cost-effective development period (oil price increasing), the total recoverable reserves were estimated to be 77.1 million tons (Approved by Protocol of the Central Commission for Development No. 3459 of 10.10.2005).

Initial geological resources of the associated natural gas in categories C_1+C_2 were approved by the Central Concern of the Russian Federation Ministry of Natural Resource in the amount of 10.4 billion tons.

Dolginskoye field:

The Dolginskoye field is located in the central part of the Pechora Sea, 120 km south from the Novaya Zemlya archipelago and 110 km north from the mainland.

It was discovered in 1999 during the Lower Permian-Carboniferous carbonate deposits testing with a well drilled in the crestal position of the South-Dolginskaya structure.

The dimensions of the Dolginskaya structure along its long axis, elongated along the Dolginsky fault in the elevated northern wing at different levels, ranging from 75 to 90 km. The height of the structure decreases upstream from 500 m and more in the carbonate part of the section to 250 m in the Lower Triassic sediments [10].

Water depth range from 15 to 62 meters in the field area. The average water depth is 39 m.

Currently, four exploratory wells have been drilled at the Dolginskoye field/

The oil potential at the Dolginskoye field was determined based on the drilling data from two wells: North-Dolginskaya-1 (completion of construction in 1998) and Yuzhno-Dolginskaya-1 (completion of construction in 1999), as well as based on seismic surveys conducted in 2006. Based on these data, the oil content of the Lower Permian-Carboniferous deposits was established, and the oil content of the Upper Permian deposits is assumed from the geophysical well logging materials.

For a long time, it was believed that the Dolginskoye field is an oil field with a small amount of associated gas. In 2014, during the drilling of the North-Dolginskaya-3 well, industrial gas inflow with a hydrogen sulfide content of up to 20% was obtained.

Taking this information into account, the reassessment of reserves has been done. Current estimation of reserves is 190 million tons of oil, 90 billion m^3 of gas and 15 billion m^3 of associated gas in the C_1+C_2 category [11, 12, 13].

North-Gulyaevskoe field

The North-Gulyaevskoye oil and gas/condensate field is located 50 km west from the Prirazlomnoye field within the Gulyaevsky shaft. One well was drilled at the field and two deposits discovered. An oil deposit is located in terrigenous deposits of the Upper Permian, and a gas condensate deposit is in the carbonates of the Lower Permian [14].

The North-Gulyaevskoye field was discovered in 1986. The field was discovered by Arktikmorneftegazrazvedka during geological exploration for oil and gas offshore. The depths of the sea range from 10 to 30 m. The average depth is 30 m. The North-Gulyaevskoye oil and gas condensate field in terms of hydrocarbon reserves refers to medium fields with oil reserves of C_1 + C_2 categories is 13 million tons, gas - 52 billion m^3 [15, 16].

Medynskoye-more field

The Medynskoye-More oil field was discovered in 1997 in the southern part of the Pechora Sea. It is located 40 km from the village of Varandey. The water depth within the field is 12-22 m. The average depth of the sea is 22 m.

Four wells were drilled at the field. Arktikmorneftegazrazvedka drilled one well (No. 1) under a contract with Gazprom company, and wells (No. 2,3,4) - under a contract with Arktikshelfneftegaz company. Five deposits have been identified associated with carbonate deposits of the Lower Permian-Carboniferous and deposits of the Upper and Lower Devonian at this field. The field consists of two domed elevations (Medynskoye-More 1 and Medynskoye-More 2).

The deep drilling at this field was started in 1997. As it was mentioned above, four wells were drilled at the Medynskoye-More field. During the well No. 2 testing, heavy, viscous oil has been obtained from Lower-Permian sediments. The test of the second well results gave the light oil inflow (oil density is 810 kg/m^3) from Lower-Devonian sediments. The reservoir pressure is 45.75 MPa; the reservoir temperature is +72 ^{o}C at the reservoir depth 3060 m [5,6].

By the amount of recoverable oil reserves, the Medynskoe-More field is classified as large.

Varandey-More field

The Varandey-Sea oil field was discovered in the southern part of the Pechora Sea in 1995 by Arktikmorneftegazrazvedka. The average depth of the sea is 18 m.

The field is a part of the Medynsko-Varandey license area, which includes two fields: Medynskoe-More and Varandey-More.

According to Rosneft, recoverable oil reserves for open fields in category C_1+C_2 are Medynskoye-More – 97.4 million tons, Varandey-More – 5.8 million tons. Recoverable oil resources in category C_3 are 70.1 million tons, gas - 1 billion m^3 [14, 17].

Pomorskoye field

The Pomorskoe gas condensate field is located within the Kolvinsky megalithic banc, in 100 km west from North-Gulyaevskoye field.

The field was discovered in 1985 during offshore oil and gas exploration in the southern part of the Pechora Sea by Arktikmorneftegazrazvedka company. Within the field, the sea depth is in the range of 20-30 m. The average depth is 30 m. One well was drilled at the Pomorskoye field. The results of the well testing shown the presence of a gas-condensate deposit in the carbonate sediments of the Assel-Sakmara layer of the Lower-Permian.

The reservoir is represented by porous organogenic-detrital limestones. The cap is a thick (over 450 m) stratum of the Artinsky-Kungur mudstones. The Pomorskoye field contains reserves. In terms of hydrocarbon reserves classification, the Pomorskoye field belongs to medium fields with gas reserves in the C_1+C_2 categories of 20 billion m^3 [18].

Peschanoozerskoye field

Peschanoozerskoye oil and gas/condensate field is located in the eastern part of the Kolguyev island, and tectonic terms are confined to the Peschanoozersky upheaval. The field has a complex structure. It refers to the structural-lithological type, where hydrocarbon accumulations are controlled by structural and lithological factors. Open deposits of gas, condensate and oil have small reserves. However, the field has been producing oil since 1987, and at the moment it has been produced by approximately 75%. Production is planned to be carried out until 2033. At this field, production is carried out from the shore. Oil produced from the Peschanoozerskoye field is very light, similar in properties to the properties of condensates. The initial reserves of the Peschanoozerskoye field are estimated at 16 million barrels of oil equivalent [19, 20].

Since the production at the Peschanoozerskoye field is onshore, this field will not be considered below.

Intermediate conclusions:

Consolidated information for each of the Pechora Sea fields is presented below, Table1.5:

Table 1.5. Oil and Gas Fields of the Pechora Sea

Field	Type of production	Water depth	Location [8]		Operator
			Latitude	**Longitude**	
Prirazlomnoye	Oil	20	57.34	69.25	Gazprom Neft
The Northern part of Dolsginskoye	Oil	15-69	55,40	69,75	Gazprom Neft
The Southern part of Dolginskoye	Oil/gas		55,60	69,58	Gazprom Neft
Medynskoye-More	Oil	12-22	58,63	69,01	Rosneft/Arktikshelfneftegaz
Varandey-More	Oil	18	57,91	68,91	Rosneft/Arktikshelfneftegaz
North-Glyaevskoye	Oil/Gas/Condensate	10-30	55,60	69,30	Rosneft/Petrovietnam
Pomorskoye	Gas/Condensate	20-30	53,14	69,14	Rosneft

2. The main challenges linked with offshore arctic oil and gas fields development

2.1. The Arctic. General information

As climate change renders the Arctic increasingly accessible, there has been a substantial uptick in industry interest in the region. Climate change leads to a decrease in both the thickness and volume of ice. Because of this fact, the Arctic petroleum reserves becoming more and more accessible. New opportunities are opening up for industrial development and transportation of production to world markets, for example, via the Northern Sea Route. It is estimated that investment in the Arctic over the next decade could reach $100 billion. The Arctic contains vast reserves of oil and natural gas - according to the US Geological Survey, the Arctic may contain 22% of undiscovered technically recoverable resources. That estimation includes 47.3 trillion cubic meters of natural gas and 90 billion barrels of oil, which is 30% of the world's unexplored gas and 13% of the world's unexplored oil. More than three-quarters of these resources are located on the territories of the five coastal states of the Arctic Ocean: in the USA, Canada, Russia, Norway and Greenland. Of these countries, the first 4 are currently major oil-producing countries.

However, despite global climate change, the exploration and development of Arctic hydrocarbon resources require expensive, complicated technologies. That is because of very harsh climatic conditions. Harsh climatic conditions include extremely low temperatures lower than -50 °C, high ice concentration, long distances to infrastructure centres, almost complete darkness in the winter months, etc. In order to ensure the possibility of technically and economically feasible development of the Arctic shelf, a technological breakthrough is needed in many areas of science. Another factor that significantly increases the chances of success in the Arctic shelf developing is government support (especially regarding the tax regime) and cooperation between companies/Arctic countries.

Many ecological and social regulatory structures openly talk about the dangers and risks associated with the oil and gas potential of the Arctic development. Given the enormous problems associated with the elimination of oil spills in ice conditions, the most significant concern is the impact of such a disaster will provide on the fragile Arctic ecosystem. In order to avoid such a catastrophe, national regulatory structures introduce additional safety and environmental regulations. These regulations significantly increase additional time and financial costs and provide limitations to hydrocarbon resources access. Hence, only big companies with large production capacities and experience in the development and exploration of offshore fields can participate in the Arctic offshore fields development. A right solution could be to provide a joint-venture contract between international oil and gas companies and national oil and gas companies.

The Arctic represents the final frontier of conventional hydrocarbon development. Accessing these resources and bringing them to market could require another 20 years or more. Lining up these resources as the next major source of global energy supply will require substantial investment and relatively immediate and extensive expansion of exploration activity. [21, 22].

2.2. Arctic territory

The Arctic is often called a single region, but it is a large geographical area with about 4 million people living in it. The Arctic is divided by absolutely different eight countries.

For the clear understanding of the countries, that have an impact on the Arctic development, it is essential to look at the leading, controlling organization in the Arctic development field. One of the major organizations in the field of Arctic developments is The Arctic Council. The Ottawa Declaration lists the following countries as members of the Arctic Council: Canada, the Kingdom of Denmark, Finland, Iceland, Norway, the Russian Federation, Sweden and the United States.

Also, six organizations representing Arctic indigenous peoples have status as Permanent Participants. The category of Permanent Participant was created to provide for active participation and full consultation with the Arctic indigenous peoples within the Council. They include the Aleut International Association, the Arctic Athabaskan Council, Gwich'in Council International, the Inuit Circumpolar

Council, Russian Association of Indigenous Peoples of the North and the Saami Council.

Observer status in the Arctic Council is open to non-Arctic states, along with inter-governmental, inter-parliamentary, global, regional and non-governmental organizations that the Council determines can contribute to its work. Arctic Council Observers primarily contribute through their engagement in the Council at the level of Working Groups.

According to the Ottawa Declaration, there are eight arctic states: The Russian Federation; USA; Canada; Kingdom of Denmark; Finland; Iceland; Norway; Sweden.

However, not all those countries have access to the Arctic oil and gas field development. The following countries have such access: The Russian Federation; USA; Canada; Kingdom of Denmark (Greenland); Norway [22, 23, 24], Figure 1.2.

Figure 2.1. Circumpolar belt of hydrocarbon accumulation: 17 petroleum basins of Eurasia, North America and Greenland [25]

The largest number of people living in the Arctic is observed in Russia – approximately 2 million people. The second place is observed in the United States (Alaska) - approximately 650,000 people, in third place – Norway with a population of 469,000 people, in fourth place – Canada with a population of 120,000 people and in last place Greenland – 58,000 people. Approximately 10% of the Arctic population is indigenous. Many Arctic residents support a traditional lifestyle that combines hunting, fishing, reindeer herding with a nomadic lifestyle. Oil and gas activities affect the Arctic indigenous population. Such intervention can lead to land-use conflicts of interest. In the Arctic offshore oil and gas reserves concept developing, the interests of the indigenous population must be taken into account.

Currently, there is no single definition of the Arctic. Although usually, the Arctic is the territory beyond the Arctic Circle. It should be noted that such a definition excludes Iceland, which is located just below the Arctic Circle. Alternative definitions define the Arctic as a territory lying north of the trees line, that means the largest latitude where trees naturally grow. Another definition suggests that the Arctic territory is a territory where the average temperature in the warmest month of the year does not exceed 10 °C.

In some definitions, the territories with similar to Arctic climatic conditions (ice conditions, weather conditions) are included in the Arctic territories. A good example of such territories is the shelf of Sakhalin Island and the Caspian Sea. These territories are often included in the list of Arctic territories due to the similarity with the Arctic regions’ environment.

Valuable lessons can be drawn from Norway's experience in offshore mining and exploration, but the conditions in Norway cannot be classified as truly "arctic" because of the Norwegian and North Seas, as well as the Norwegian part of Barents Sea, are not covering by ice. Thus, during the development designing of Norwegian fields, one of the most dangerous and challenging features of the Arctic regions ice conditions are not taken into consideration.

Distribution of potential hydrocarbon reserves of the Arctic by countries is presented below:

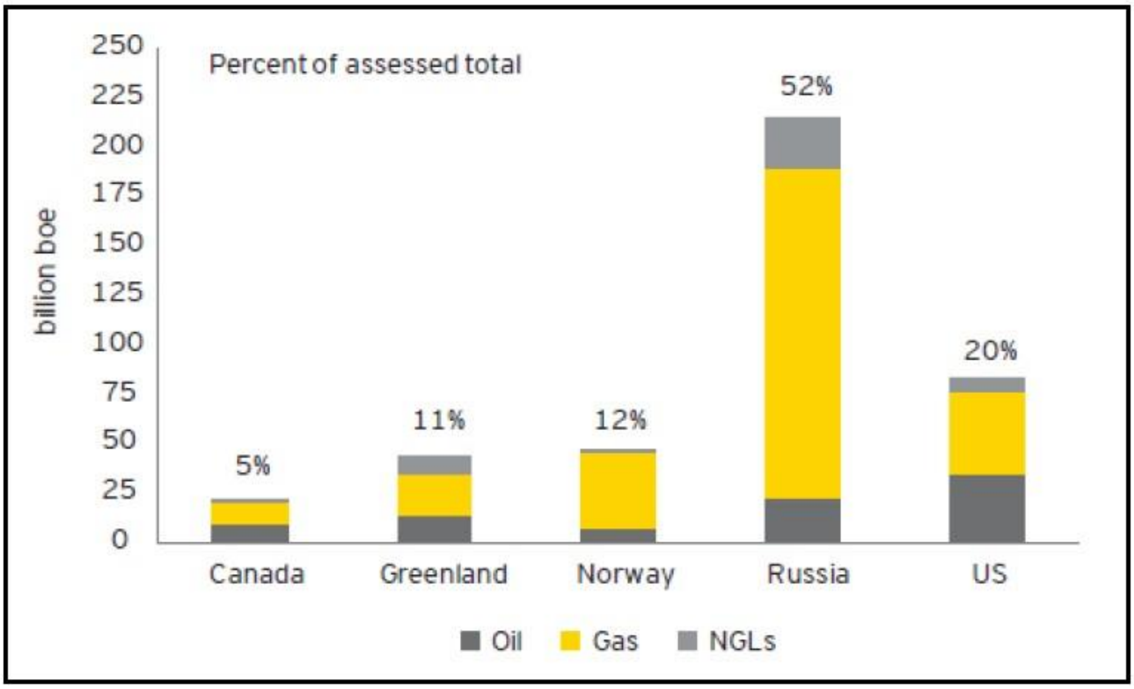


Figure 2.2. Distribution of potential hydrocarbon reserves of the Arctic by countries [21]

2.3. Development features of Arctic offshore oil and gas fields

Despite the vast amount of Arctic hydrocarbons resources and the tremendous potential benefit of developing these reserves, there are a lot of difficulties and limitations associated with the fact that development must be carried out at sea, as well as the fact that development must be carried out in harsh Arctic conditions.

Firstly, it is necessary to describe offshore oil and gas development features.

The main difficulty in offshore oil and gas fields development is the fact that the development objects (exploration, development, operation) must be designed taking into account the impact of three spheres: lithosphere, hydrosphere and atmosphere. Since onshore fields infrastructure is only influenced by the lithosphere and atmosphere, the design of infrastructure for offshore fields has many differences from the infrastructure design for onshore fields. The effectiveness of offshore development directly depends on the skilful and proper integration of all the influencing factors of the atmosphere, hydrosphere and lithosphere.

The main components of the atmosphere are wind, temperature and humidity; hydrosphere – current, wind waves, ice, icebergs, corrosion, etc.; lithosphere – geological structure, geotechnical, seismic and other conditions. The phenomenon of hydrosphere directly depends on the phenomenon of the atmosphere. This fact creates additional difficulties in assessing the development of oil and gas fields conditions.

Equipment for hydrocarbon production in the continental shelf and the production transportation to consumers should be created in offshore service, i.e. taking into account humidity and negative atmospheric temperatures, as well as the salinity of seawater, in which all technical equipment will be operated.

During the technological and drilling equipment arranging on land, there are almost no area restrictions. During the offshore oil and gas fields development designing, this factor is one of the most important and poses a global problem – creating the conditions for placing equipment necessary for drilling, production, and preparation/storage of extracted products.

Oil and gas transportation in offshore conditions is carried out by using subsea pipelines or bulk tankers. Exclusive technologies and tools are being created for pipelines laying. It should be noted that the calculation of offshore pipelines is a challenging task since it is necessary to take into account a large number of factors, including currents, waves, hydrostatic load, etc.

It should be noted that the conditions of freezing seas are significantly complicated in comparison with un-freezing seas due to the appearance of ice. Such a phenomenon as ice drift, icebergs, hammers, hummocks and so on have a significant impact on development infrastructure. Ice loads provide tremendous pressure on offshore development facilities, while hummocks and icebergs pose a real danger of development facilities destruction, which could lead to an environmental catastrophe and enormous economic losses [26].

Summarizing, the features of the development of offshore fields in Russia can be brought to the following list [27]:

- The location of the field is often outside the territorial waters of the country. At the same time, controversial issues arise regarding the delimitation of sea spaces and the ownership of shelf areas, as well as border and customs restrictions on the delivery of personnel, equipment and cargo.

- Seasonality of fieldwork;
- Special requirements for engineering surveys.
- The need to use special floating equipment for drilling, surveying, construction and installation works (construction and installation works) and field operation.
- The presence of marine equipment as a part of field development facilities requires the fulfilment of special requirements for the design documentation, as well as special requirements for the frequency of the technical inspections, including inspections in special docks.
- Sophisticated logistics for the delivery of people, machinery, equipment and materials.
- The need to attract highly qualified narrow-profile specialists for R&D, management of the most sophisticated technologies and equipment in the extreme climatic conditions of the Arctic region.
- High capital intensity and correspondingly high investment in offshore development projects.
- The specifics of the legislative framework governing the economic and financial relations of project participants.
- The availability of specific information related to national security, including exploration, hydrographic, oceanographic, etc.

The Pechora Sea is a freezing sea. In this regard, it seems necessary to describe in more detail the difficulties associated with the development of the offshore fields in the Arctic.

Additional difficulties are added that have a very significant impact on the choice of basic technical solutions in the Arctic conditions. The main challenges linked with arctic offshore field development are listed below:

- First- and multi-year ice;
- Ice drift;
- Icebergs;

- Hummocks and stamukhas;
- Seabed ice erosion;
- The icing of equipment;
- Permafrost soils;
- The short duration of the season of construction and installation works;
- Long distances to infrastructure centres;
- Polar night;
- Frequent magnetic storms and other natural phenomenon affecting the communication and stability of the navigation devices;
- Harsh climatic conditions (extremely low temperatures, wind, etc.).

Because of the listed above features, following technological and technical difficulties can be highlighted:

- The high cost of equipment in the Arctic;
- Logistic features;
- Lack of technology, experience, knowledge about the Arctic development;
- Lack of competent specialists;
- Significant and incompletely assessed environmental risks;
- Difficulties in emergency response;
- Shortened well drilling season. Wells' drilling is performed by using jackup drilling platforms - drilling is possible only during the ice-free period. Because of that, the construction of new wells is 2-3 times longer.

3. The choice of the development concept for the oil and gas fields cluster

3.1. Oil and gas fields choice for the development in cluster

The currently discovered oil and gas fields in the Pechora Sea are shown in Figure 3.1.

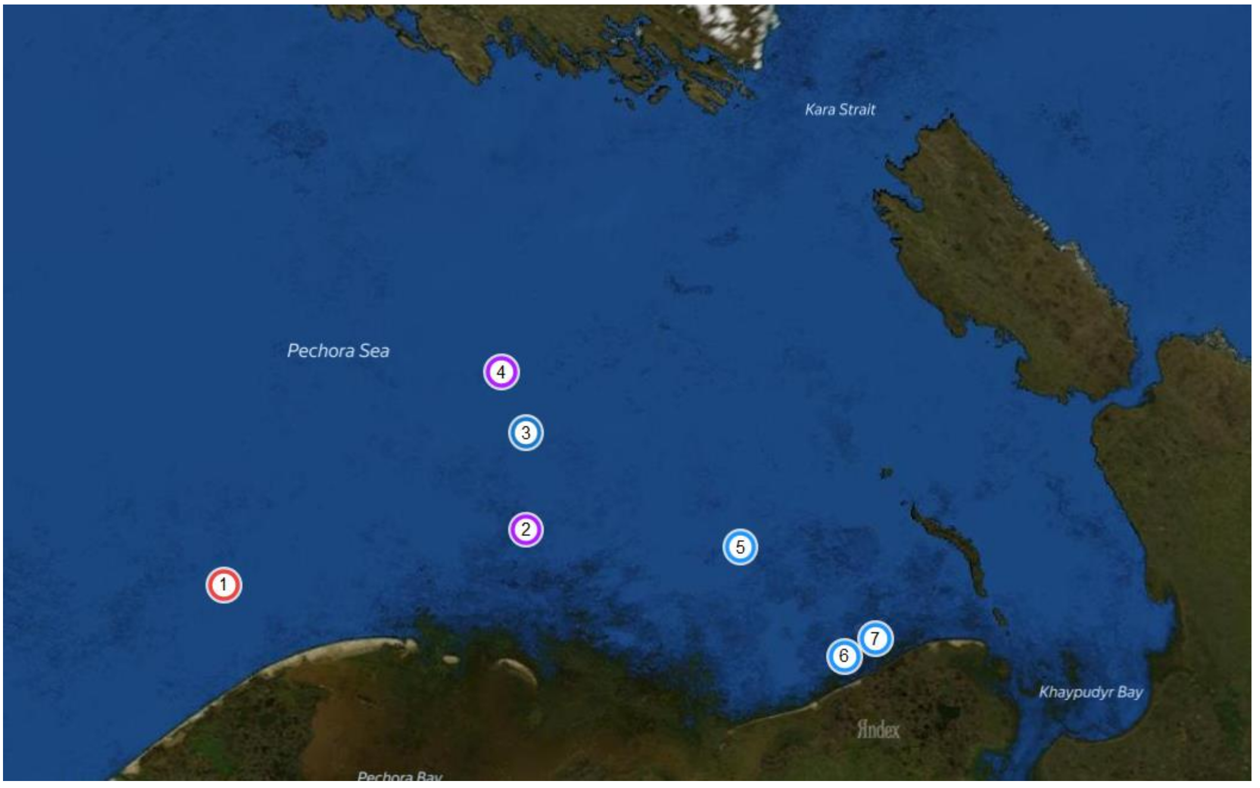


Figure 3.1. Oil and gas fields of the Pechora Sea (red boundary – gas-condensate field, violet – oil/gas-condensate, blue - oil):1 - Pomorskoye field; 2 - North-Gulyaevskoye field; 3 - the northern part of the Dolginskoye field; 4 - southern part of the Dolginskoye field; 5 - Prirazlomnoye field; 6 - Medynskoe-more field; 7 – Varandey-more field.

During the map construction, it was decided to divide the Dolginskoye field into two sections: Southern and Northern part of the Dolginskoye field. Such a division has been done due to the fact of the complex geological conditions in this field. These areas are very different. The difference can be found in the reservoir properties and the oil and gas reserves.

The figure above shows that the fields of the Pechora Sea can be geographically consolidated into two clusters.

The first cluster: Pomorskoye field, North-Gulyaevskoye, the northern part of the Dolginskoye and southern part of the Dolginskoye fields.

The second cluster: Medynskoe-more and Varandey-more fields.

Optionally, depending on the development conditions, the Prirazlomnoye field can be attached to any of these clusters. Moreover, since the Prirazlomnoye field is the only field at the stage of oil production, the infrastructure of this field can be used as a production centre. As far as the issue of expanding the production capacities of the Prirazlomnoye field is a complex task and is not the purpose of this master thesis, the Prirazlomnoye field is not included in the consideration.

Figure 3.2 shows the layout of the field in the selected groups.

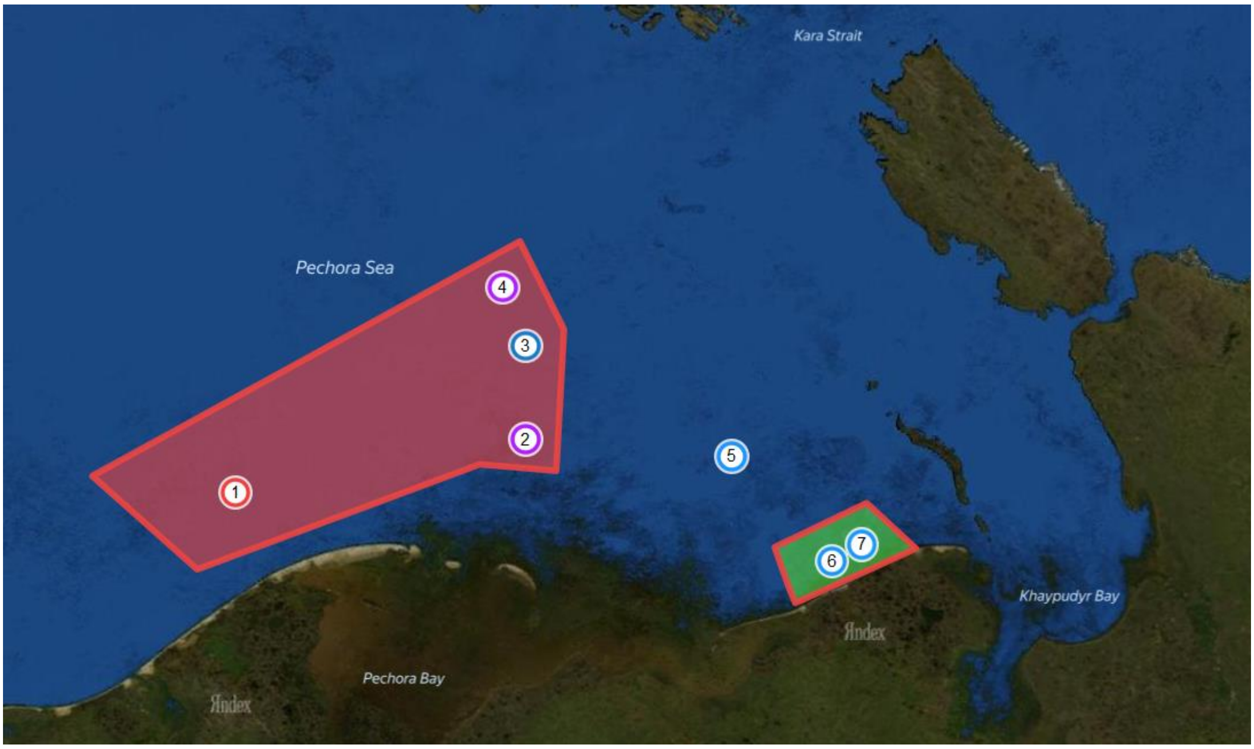


Figure 3.2. Divided into groups fields of the Pechora Sea (the red area – cluster 1, the green are – cluster 2):1 - Pomorskoye field; 2 - North-Gulyaevskoye field; 3 - the northern part of the Dolginskoye field; 4 - southern part of the Dolginskoye field; 5 - Prirazlomnoye field; 6 - Medynskoe-more field; 7 – Varandey-more field.

It should be noted that the first cluster includes gas-condensate and oil/gas-condensate fields. It is necessary to develop two development schemes: the oil production scheme and the gas production scheme. The development concept of the first cluster of fields is considered in this work.

3.2. Fields' cluster development concepts

Since both oil/gas-condensate and gas-condensate fields are presented in the cluster, as well as since gas-condensate deposit is isolated from oil deposit in the

North-Gulyaevskoye field, parallel design of the development concepts for the gas-condensate part and the oil part should be done.

3.2.1. Development concepts of the gas-condensate cluster's part

As far as gas reserves in all three fields are small, there is no point in developing these fields separately. Development in the cluster is the only way to make a production of gas from these fields economically feasible. Since there is no gas infrastructure in the region, the only option for developing gas condensate fields in the Pechora Sea is to liquefy the produced gas. In the concepts below, there are two options for installing a natural gas liquefaction plant.

Concept №1:

Figure 3.3. Development concept of the gas-condensate cluster's part №1

The concept provides the following solutions:

- Installation of a gravity-based platform for the LNG plant (approximate water depth in the installation area is 20 m);
- Wellhead gravity-based platforms for gas and condensate extraction;
- Gas and condensate transportation to the platform through two-phase pipelines:
    - The approximate length of the pipeline from the Northern part of the Dolginskoye field to the platform is 70 km;
    - The approximate length of the pipeline from the North-Gulyaevskoye field to the platform is 35 km;
    - The approximate length of the pipeline from the Pomorskoye field to the platform is 65 km;
- Condensate storage and offloading are carried out on the platform.

<u>Concept 2:</u>

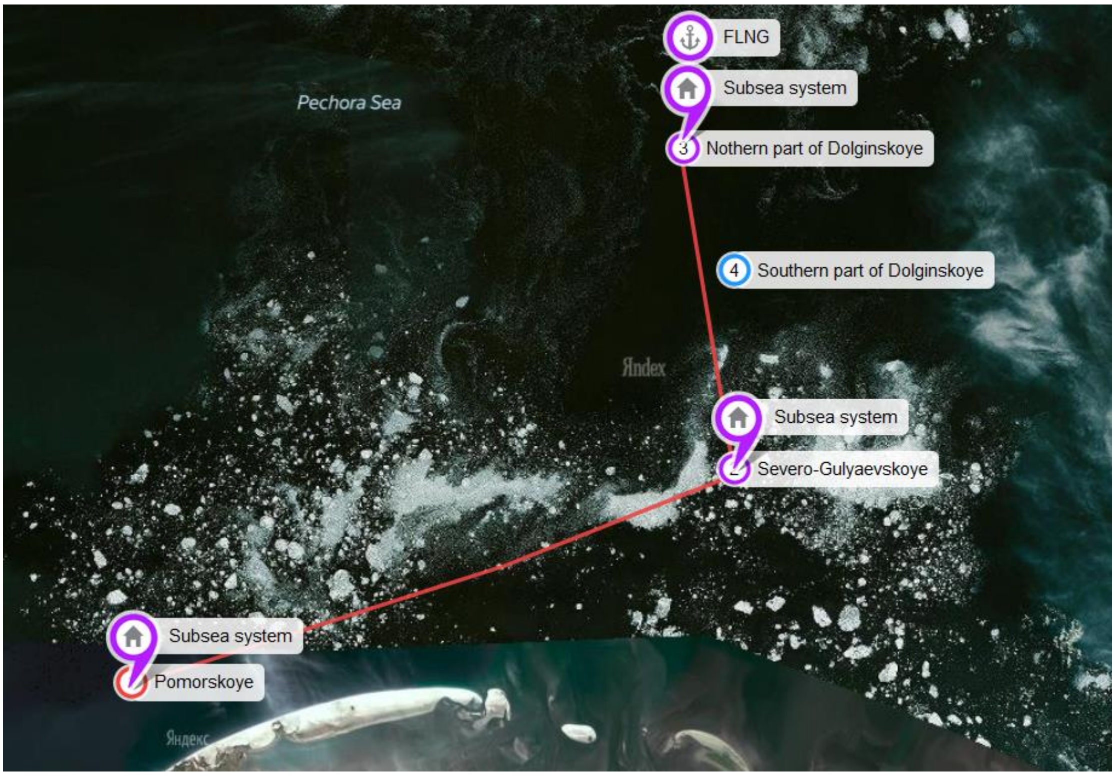


Figure 3.4. Development concept of the gas-condensate cluster's part №2

The concept provides for the following solutions:

- Installation of the FLNG close to the Northern part of the Dolginskoye field (approximate depth in the installation area is 70 m);

- Subsea production used for gas and condensate extraction;
- Gas and condensate transportation to the platform through two-phase pipelines:
  - The approximate length of the pipeline from the Pomorskoye field to the North-Gulyaevskoye field is 100 km;
  - The approximate length of the pipeline from the North-Gulyaevskoye field to the FLNG is 65 km;
  - Production from the Pomorskoye field is mixed with production from the North-Gulyaevskoye field and transport to the FLNG.
- Condensate storage and offloading are carried out on the FLNG vessel.

Concepts discussion

Concept 1 provides for the installation of an LNG plant on a gravity platform. This solution is technically feasible; there is rich experience in using gravity-type platforms in arctic conditions. Gravity-based platforms are considered resistant to ice loads and, as experience confirms, are the optimal solution for the conditions of the Arctic shelf. The water depth in the installation region allows designing a caisson type platform, monocone and monopod platform [28]. However, it must be realized that the topsides weight for an offshore LNG plant is indeed huge, possibly higher than 50.000 tonnes.

The critical disadvantage of the decision to install the LNG plant on a gravitational type platform is the immobility of such platforms. Considering the fact that vast gas reserves are expected in various fields in the Pechora Sea (according to some estimates, the reserves may contain up to 500-600 billion m^3) [13], it could be preferable to design a more mobile structure. So that after the development of the North-Gulyaevskoye, Pomorskoye and Northern part of the Dolginskoye fields is completed, it is possible to move the plant to another group of fields.

Moreover, the largest gas reserves are currently assumed in the North-West license section. Placing a plant on this site will enable the connection of new fields that can be discovered in the process of developing already discovered fields.

Concept 2 involve the using of a floating LNG plant. Installing a floating structure in ice conditions is a daunting task. Moreover, nowadays, there are no implemented projects of the FLNG installation in comparable conditions. However, active research and development of various concepts of Arctic LNG floating plants are currently underway. Heavy ice-management will be necessary to keep the floating plant stationary and, in some situations, it may be necessary to disconnect the plant from the producing wells to avoid overstressing of risers. The second concept also involves subsea systems implementation. It is necessary to test the feasibility of using such technology, taking into account the ice conditions in the Pechora Sea.

3.2.2. Development concepts of the cluster's oil part:

In the fields group which is under consideration, the North-Gulyaevskoye (geological reserves - 19 million tons) and Dolginskoye (geological reserves - 190 million tons) deposits have oil and gas potential. The centre of the oil development complex will be the southern part of the Dolginskoye field. In this zone, it is necessary to install a multifunctional ice-resistant platform. Also, since the Dolginskoye field has an elongated shape and vast oil reserves, the installation of a gravity-type satellite platform in the central part of the field is proposed. Oil production at the North-Gulyaevskoye field can be implemented on a satellite platform or using subsea production complexes, depending on the choice of concept for gas production part of the complex.

Intermediate conclusion

Two concepts for the Dolginskoye, North-Gulyaevskoye and Pomorskoye fields cluster development are formed.

The first concept involves the installation of wellhead platforms at the Pomorskoye field, the North-Gulyaevskoye field, in the Northern and Central part of the Dolginskoye field, as well as the installation of a multifunctional ice-resistant platform in the Southern part of the Dolginskoye field.

Figure 3.5. Development concept №1

The second concept involves the installation of subsea systems at the Pomorskoye field, the North-Gulyaevskoye field and in the Northern part of the Dolginskoye field, as well as the installation of a multifunctional ice-resistant platform in the Southern part of the Dolginskoye field and the wellhead platform at the central part of the Dolginskoye field.

Figure 3.6. Development concept №2

3.3. Oil and gas production profiles

First of all, it is necessary to make an approximate estimation of the geological and recoverable reserves of field. Based on this information, it will be possible to decide on the required number of wells and build estimated production profiles. It should be noted that the production profiles obtained in this way are exclusively estimates. The construction of such profiles is necessary for the initial selection of technological solutions for field development.

Due to the lack of data on condensate reserves, condensate is not estimated in this work. However, given that all deposits are considered gas-condensate, the gas pipeline should be designed as a two-phase gas pipeline.

Field reserves are presented in the table below. Due to the lack of sufficient data for calculations for each field, oil and gas recovery factors (ORF and GRF) were determined by the method of analogy based on the precise analysis of data, including internal materials of Gazprom Neft company and information from the website of the Norwegian Petroleum Directorate, which presents all the explored fields in Norway [13, 29].

Table 3.1. Oil and Gas fields' reserves

<table>
<tr><th rowspan="2"></th><th colspan="3">Dolginskoye</th><th colspan="3">North-Gulyaevskoye</th><th colspan="3">Pomorskoye</th></tr>
<tr><th>Geological</th><th>ORF/ GRF</th><th>Recoverable</th><th>Geological</th><th>ORF/ GRF</th><th>Recoverable</th><th>Geological</th><th>ORF/ GRF</th><th>Recoverable</th></tr>
<tr><td>Oil (the first concept)</td><td rowspan="2">190</td><td>0.34</td><td>58.71</td><td rowspan="2">13</td><td>0.35</td><td>4.50</td><td rowspan="2">—</td><td rowspan="2">—</td><td rowspan="2">—</td></tr>
<tr><td>Oil (the second concept)</td><td>—</td><td>—</td><td>0.29</td><td>3.78</td></tr>
<tr><td>Gas (the first concept)</td><td rowspan="2">90</td><td>0.80</td><td>72.06</td><td rowspan="2">52</td><td>0.79</td><td>40.82</td><td rowspan="2">20</td><td>0.77</td><td>15.42</td></tr>
<tr><td>Gas (the second concept)</td><td>0.73</td><td>66.04</td><td>0.75</td><td>38.87</td><td>0.75</td><td>14.99</td></tr>
</table>

Further, based on recoverable reserves data, it is necessary to estimate the number of wells for each field. The decision on how many wells to drill for each field was made based on a precise analysis of internal documents of Gazprom Neft company and information from the website of the Norwegian Petroleum Directorate, which presents all the developed fields in Norway. An analogy with similar reserves and geological conditions deposits was made [13, 29]. The information on the number of wells in each field is presented below.

Table 3.2. Number of wells at each field

The Dolginskoye field	Oil wells	32
	Injection wells	16
	Gas wells	12
The North-Gulyaevskoye field	Oil wells	2
	Injection wells	1
	Gas wells	10
The Pomorskoye field	Oil wells	6

The average oil flow rate of an oil well: 1450 t/day; average production rate of a gas well: 2000 thousand m^3/day (by analogy with the average production rate of wells in fields with similar geological characteristics).

The production profiles for each field for two options: with gravity-type platforms (well drilling from the platform simultaneously with production) and with subsea production complexes (well construction before production using Jack-Up drilling platforms) are presented below.

3.3.1. Production profiles at the Dolginskoye field

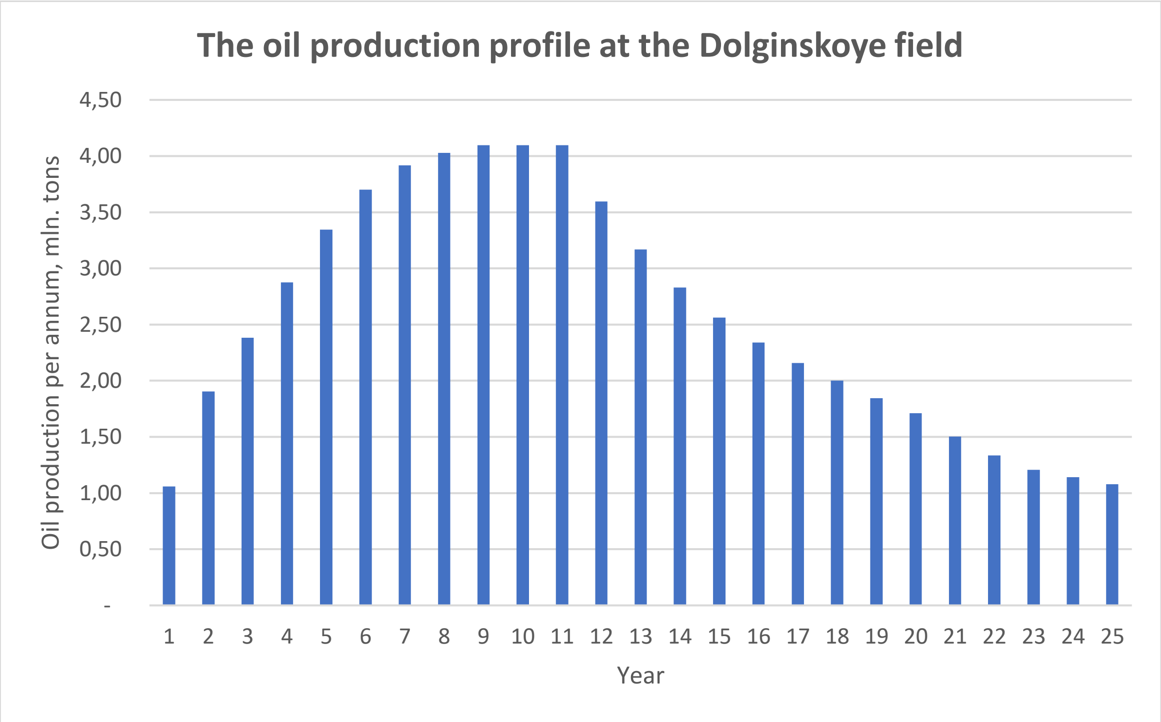


Figure 3.7. The oil production profile at the Dolginskoye field

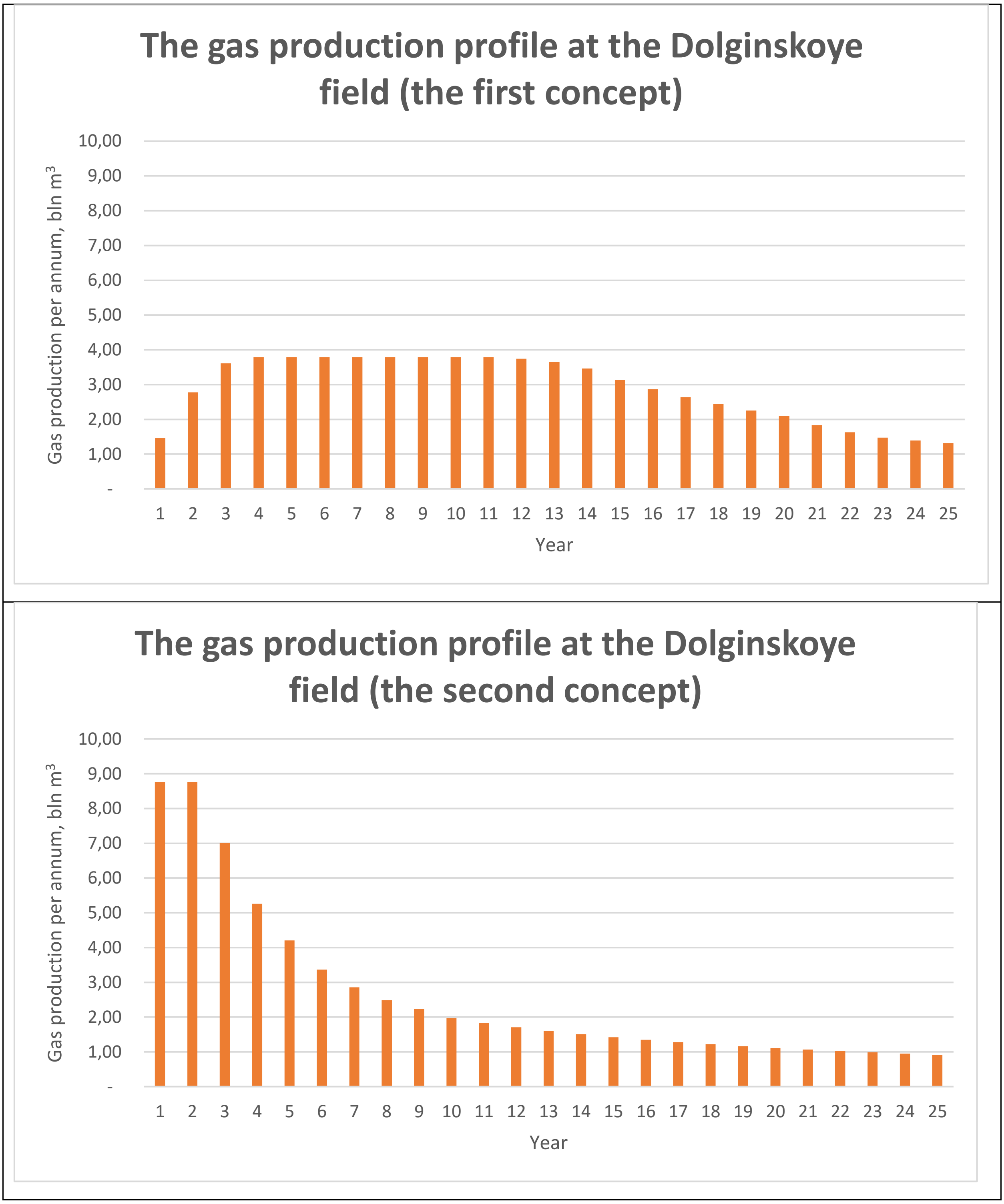


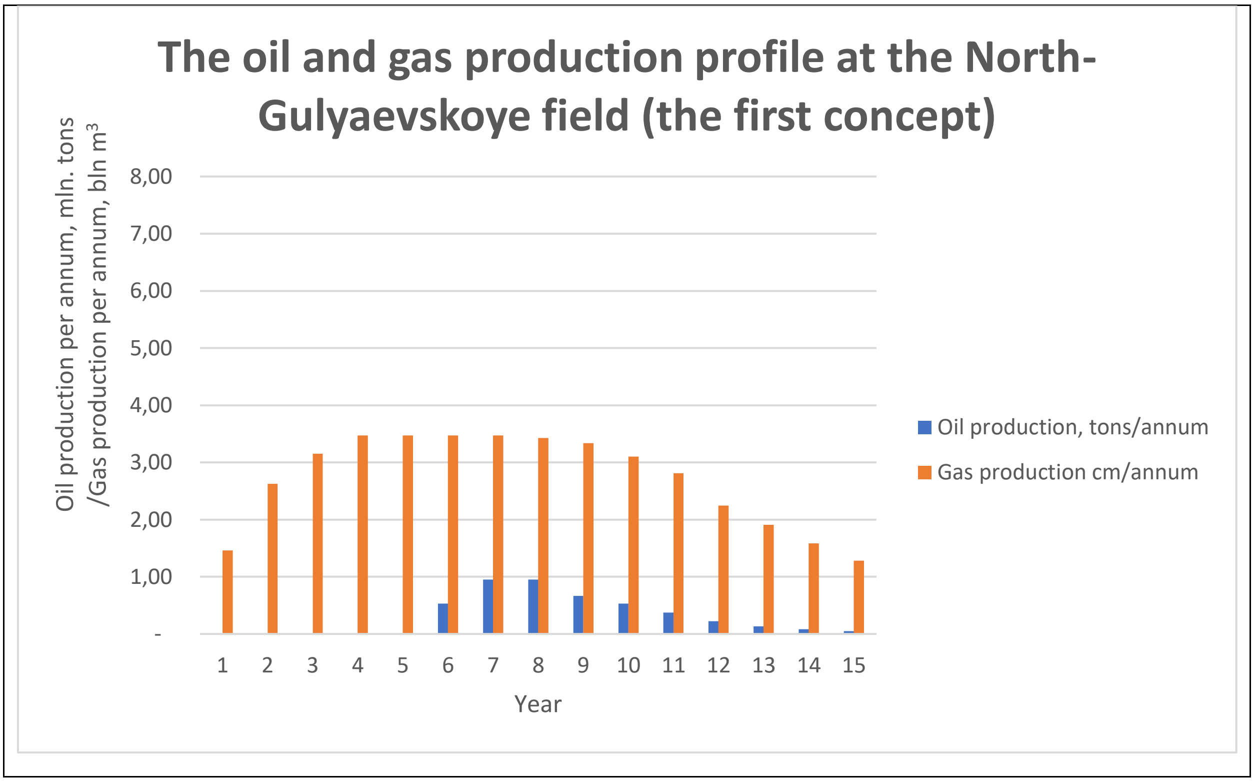
Figure 3.8. The gas production profile at the Dolginskoye field

It can be observed from the figure above, the gas production profile when using a subsea system (SPS) and the gravity type platform is different. In case of using SPS, because of the well drilling in advance by using Jack-Up platforms, production at all wells is started simultaneously. On the gravity type platform, a drilling rig is provided. This fact allows drilling wells, one after another. The drilling speed of such construction is taken to be 2-3 wells per annum. The capacity of the drilling rig makes it possible to drill 5-6 wells per annum; however, as experience shows, due to various complications and the need for scheduled and unscheduled well repairs, the actual drilling speed must be taken as 2-3 wells/year.

It should be mentioned that for the second concept (with SPS), due to intensive production in the first years of development, the GRF at the field will be slightly less than for the first concept (with gravity-type platforms).

3.3.2. Production profiles at the North-Gulyaevskoye field

Since the North-Gulyaevskoye field contains relatively low oil reserves and it is planned to produce oil and gas from one platform/one subsea production system, the profile of oil and gas production must be presented in one figure.



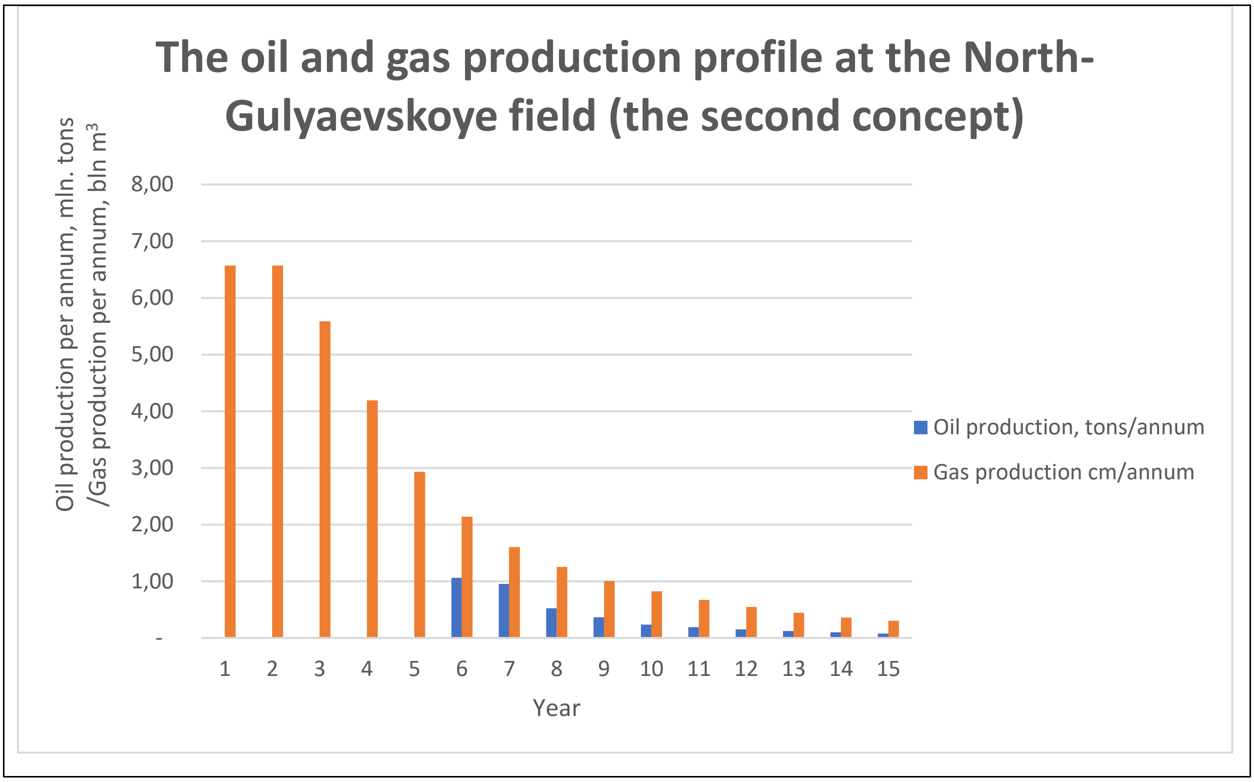
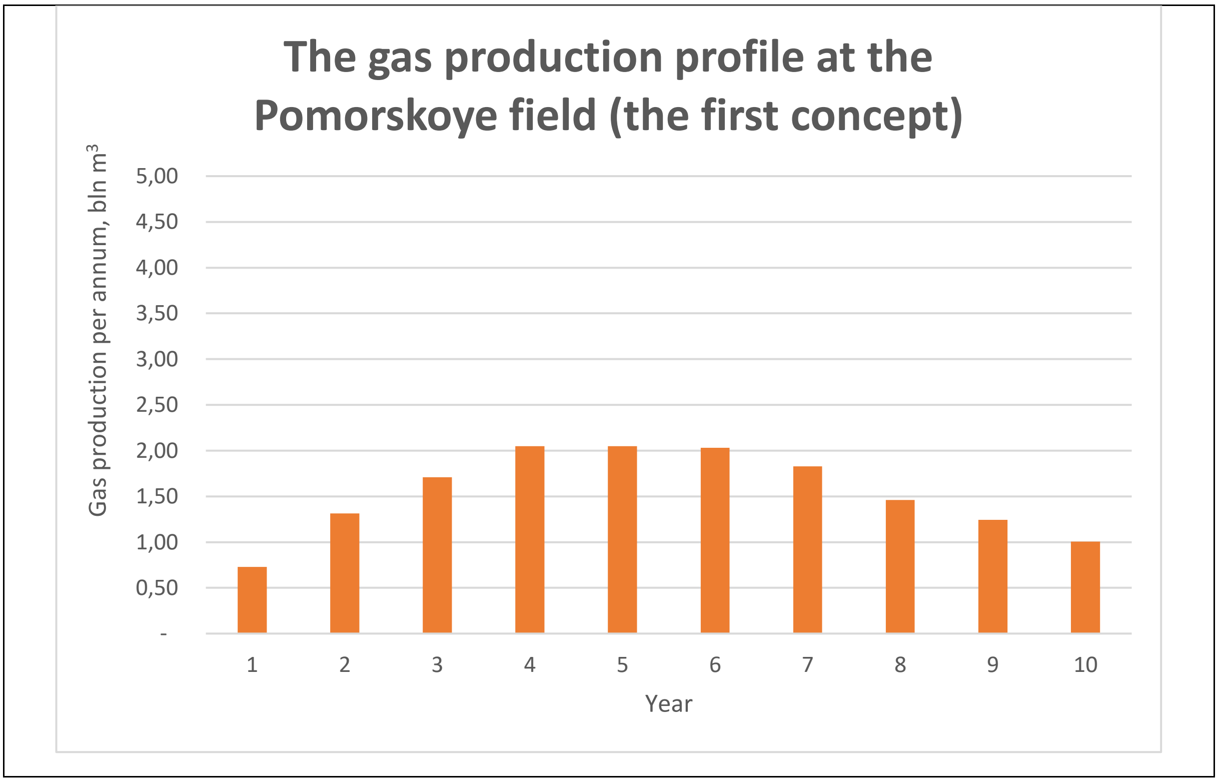


Figure 3.9. The oil and gas production profiles at the North-Gulyaevskoye field

As it can be observed from the figure above, the production in the oil part will be started at the 6-the year of the field development.

3.3.3. Production profiles at the Pomorskoye field



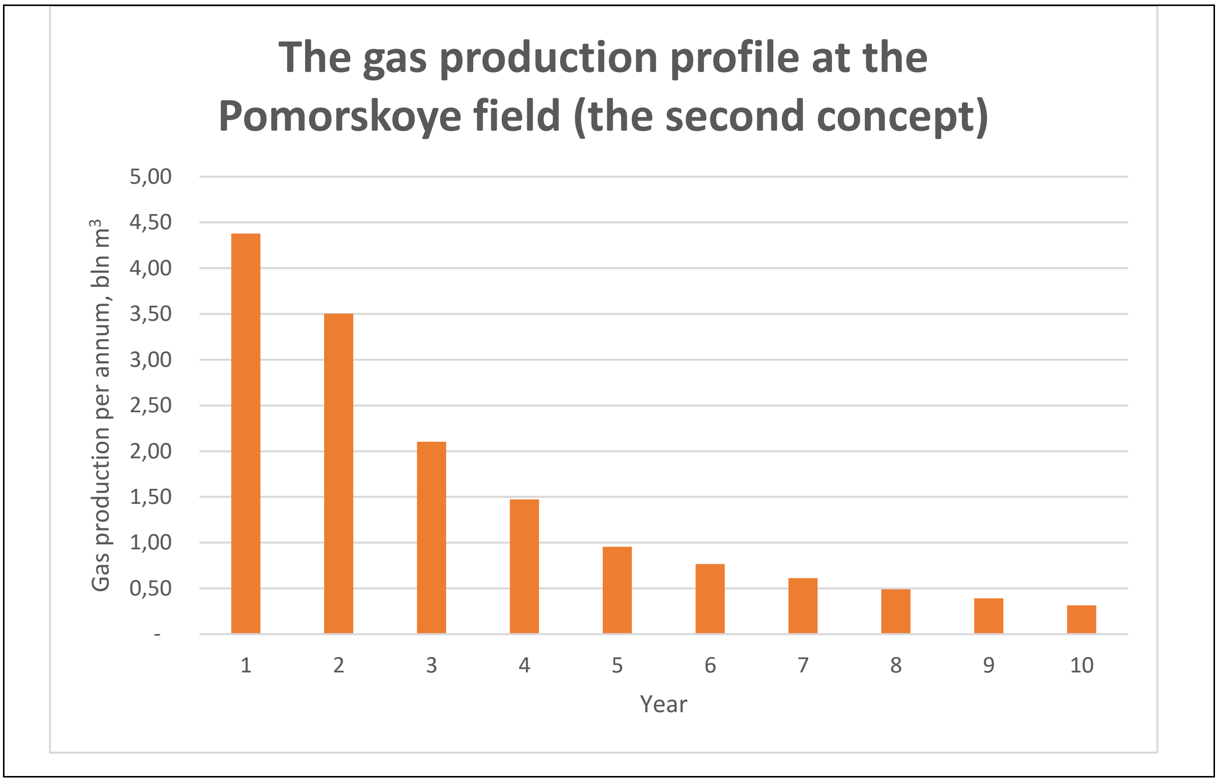


Figure 3.10. Production profiles at the Pomorskoye field

3.3.4. Total oil and gas production profiles

Two concepts are taken into account:

- The first concept with gravity-based platforms implementation;
- The second concept with subsea production systems implementation.

During the joint production profile building, special attention should be paid to the maximum annual gas production, since in case of the maximum annual production exceeds 9.52 billion m^3 (7 million tons of LNG) [30], the LNG plant's production capacity will be insufficient.

For a smoother production profile and to prevent too high annual production values, it is necessary to put fields into exploitation sequentially. Below is information on the fields' lifetime:

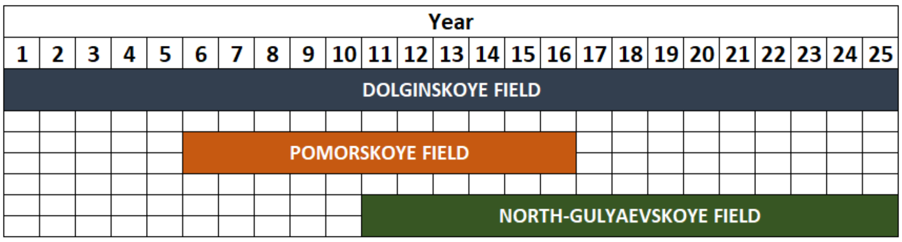
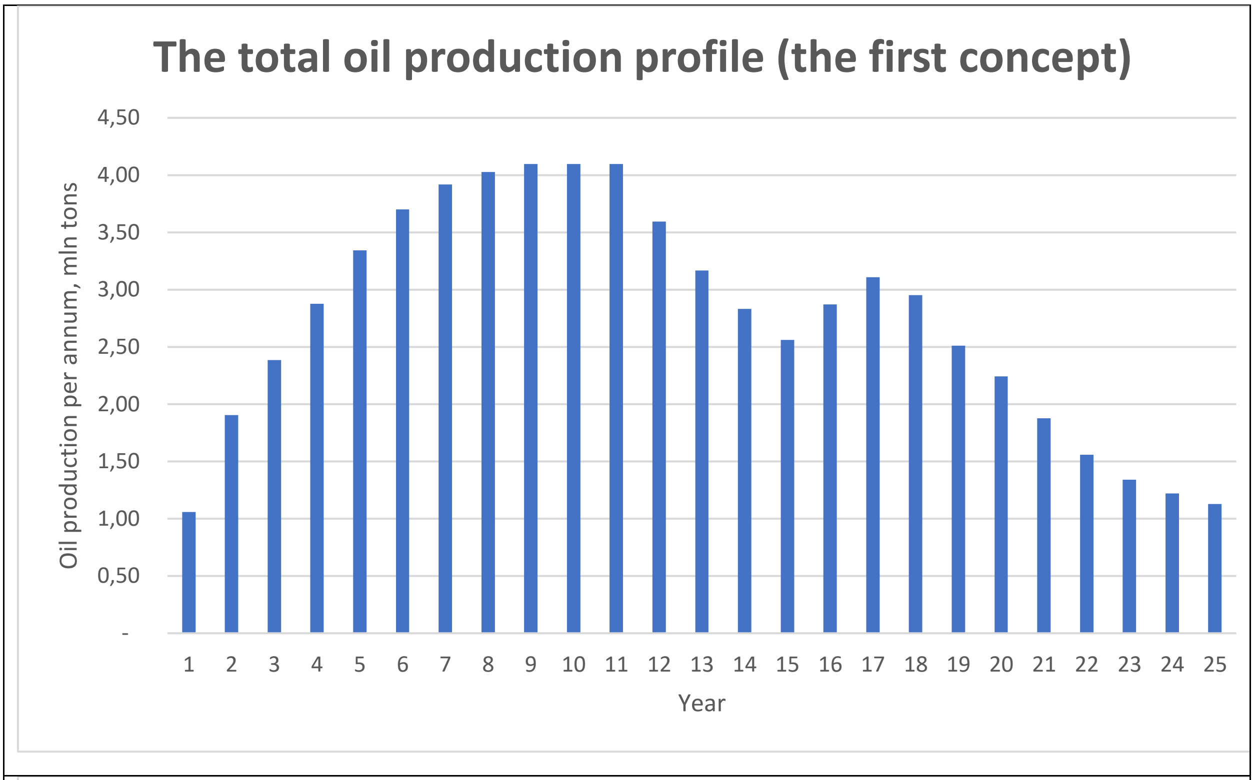


Figure 3.11. Fields lifetime

The total oil production profiles for the two concepts are presented below:



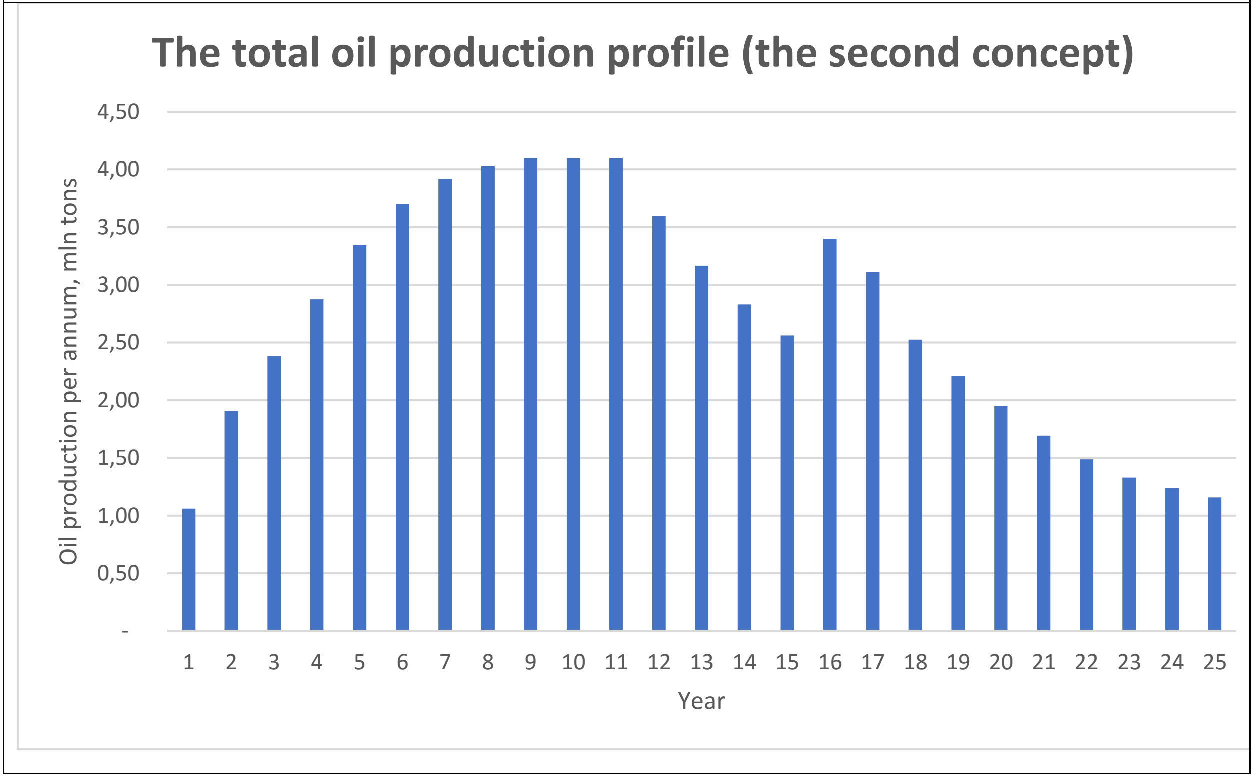
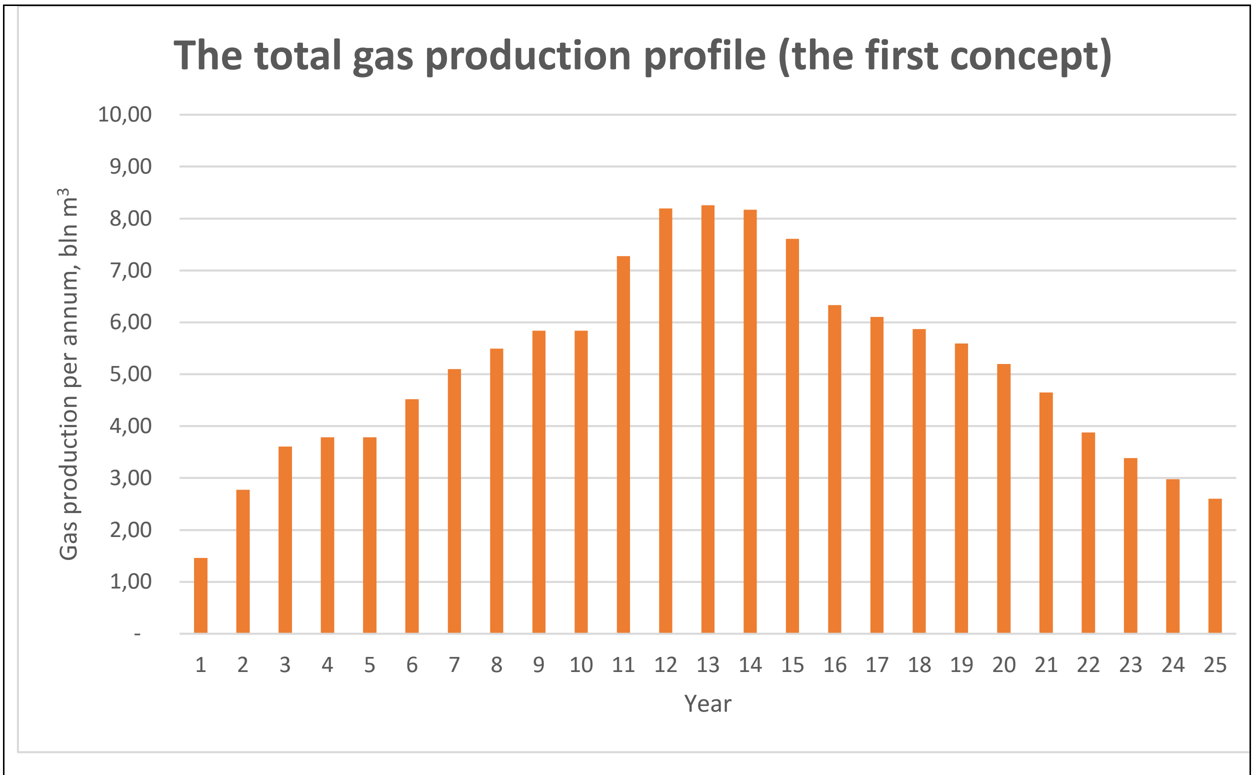


Figure 3.12. Total oil production profiles

The total gas production profiles for the two concepts are presented below:



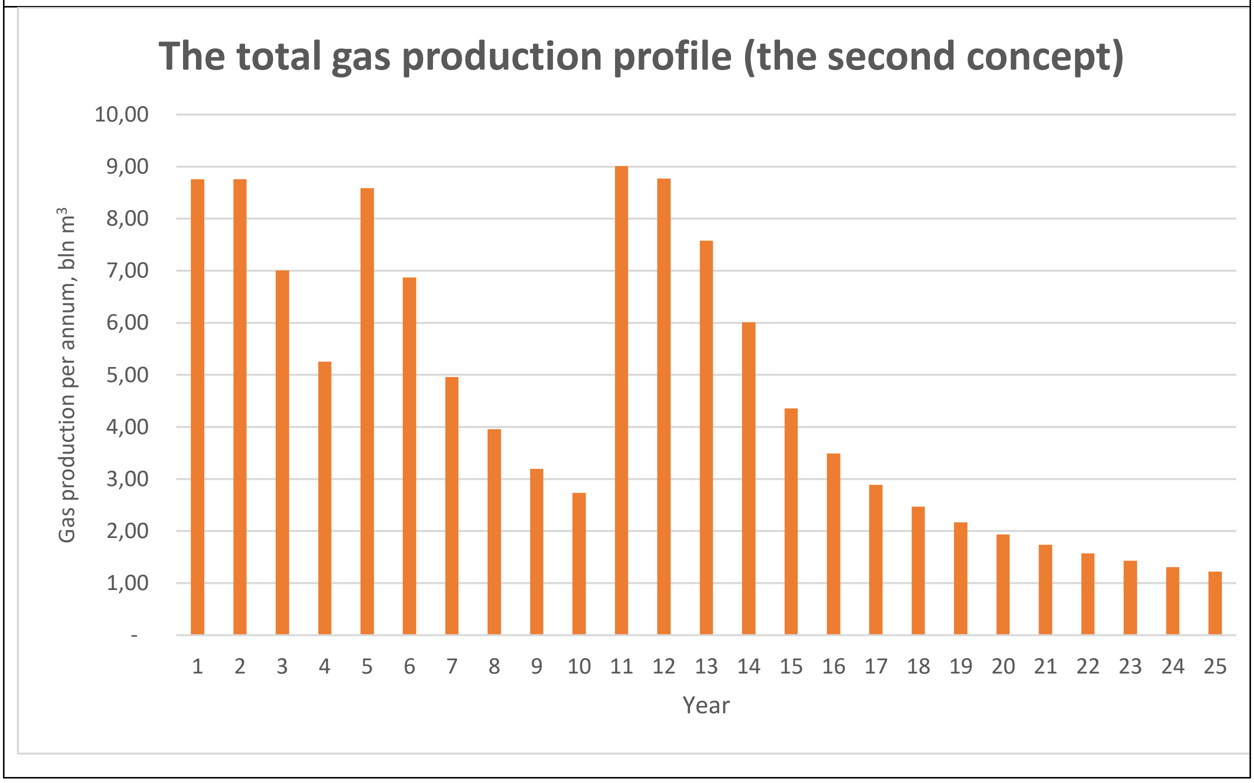


Figure 3.13. Total gas production profiles

Intermediate conclusions

The summary table on the maximum annual oil/gas production in the fields is presented below. This information is needed to evaluate the performance of the LNG plant and for the logistic suggestions.

Table 3.3 Summary table on the maximum annual oil/gas production

	Dolginskoye	North-Gulyaevskoye	Pomorskoye	Total
Oil (the first concept), mln tons/annum	4.10	0.95	—	4.10
Oil (the second concept), mln tons/annum	—	1.06		4.10
Gas (the first concept), bln m3/annum	3.79	3.47	2.05	8.26
Gas (the second concept), bln m3/annum	8.76	6.57	4.38	9.01

4. Design of the infrastructure in the cluster

4.1. Gravity-based platforms

4.1.1. Gravity-based platform variety:

Bellendir and Toropov presented in their report [28] possible types of arctic platform substructures for the installation in shallow areas. According to the report, these types of substructures are caisson type, monopod, monocone, multi-column and truss type structures. However, application of the truss-type substructure is limited by ice conditions. Truss-type substructures are not applicable in the multilayer ice conditions. It should be noted that the Pechora Sea is characterized by the existence of a small amount of multilayer ice [27].

Moreover, the Pechora Sea is characterized by intense ice drift. Under such conditions, there is a risk of ice accumulation in the grating spaces, which will lead to ice loads increasing, and will also lead to the support vessels approach limitation. This problem also occurs on platforms with a multi-column substructure. The problem of ice accumulation between columns is a complex issue that needs to be seriously studied and analyzed.

Taking into account all of these arguments, truss-type and multi-column platforms are not considered in the Thesis.

The substructure types description in a table view are presented below:

Table 4.1. Type of ice-resistant platforms

<table>
<tr><th>Type of structure</th><th>Water depth</th><th>Loading specific features</th></tr>
<tr><td>Caisson</td><td>Less than 30 m</td><td>The wall is almost vertical (angle α with the horizon > 60°). Extreme global ice load (4+5 MN per one linear meter) exceeds wave load. The effect of ice and wave impacts on soil foundation is comparable due to wave dynamic effect.</td></tr>
<tr><td>Monopod</td><td>Up to 50 m</td><td rowspan="2">The wall is inclined 45°> α >60 °. The values of extreme global and wave loads are comparable. Due to slamming, the integrated deck must be considerably elevated above MSL.</td></tr>
<tr><td>Monocone</td><td>Up to 50</td></tr>
</table>

For a reasonable substructure type choice for each platform of the cluster, it is necessary to clarify the installation water depth for each platform. Summary table showing the depths is presented below.

Table 4.2. Fields summary

Platform	Field	Water depth
DS	The southern part of the Dolginskoye field	25 m
DC	The central part of the Dolginskoye field	40 m
DN	The northern part of the Dolginskoye field	45 m
SG	Severo-Gulyaevskoye field	25 m
P	Pomorskoye field	25 m

Platforms with a caisson type substructure have a water depth limitation of 30 m. Hence, it is not possible to use caisson-type GBS for DC and DN platforms. In order to make the design and construction of platforms easier, it is preferable for the platforms of the same purpose to use platforms of the same type (N.B.: all the limiting conditions in each location must be taken into account). Thus, for satellite platforms, it is proposed to consider two single-support substructure types: monopod and monocone. For the DS platform, it is proposed to consider a platform with a caisson type substructure. This is due to the need for large oil storage for extracted products.

4.1.2. Design of the caisson type substructure:

Similar to the Prirazlomnaya platform, the size of the caisson for the DS platform will be 102x102x40.5 m.

An ice deflector is installed at the Prirazlomnaya platform. It is necessary to compare the loads that occur with the vertical walls of the caisson with the loads that occur when the ice deflector is installed. Also, it is necessary to determine the optimal angle of inclination of the deflector.

When the ice deflector is installed, the cross-section of the caisson at the sea level will be increased. The calculated data on the change in the side length of the caisson due to the deflector with different angles is presented below (the deflector rises above mean sea level by 4.3 m):

Table 4.3.Cross-section changing

Inclination, angle	Projected area
30	116.90
35	114.28
45	110.60
50	109.22
55	108.02
60	106.97

4.1.3. Design of the monopod and monocone substructures:

An example of DC platform design is presented below:

Design of the monopod substructure:

A schematic representation of a platform with a monopod substructure is presented below. [31].

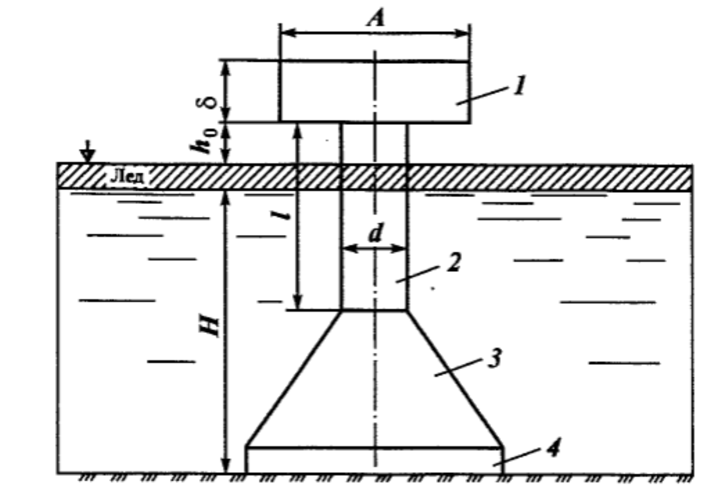


Figure 4.1. Monopod platform: 1 – top structure; 2 – column; 3 – support base; 4 – foundation [31].

Dimensional characteristics of the DC platform in case of monopod platform implementation:

- A = 102 m;
- h_0 = 20 m;
- l= 35 m;
- H=50 m;
- d = 21 m.

Design of the monocone substructure:

A schematic representation of a platform with a monocone substructure is presented below.

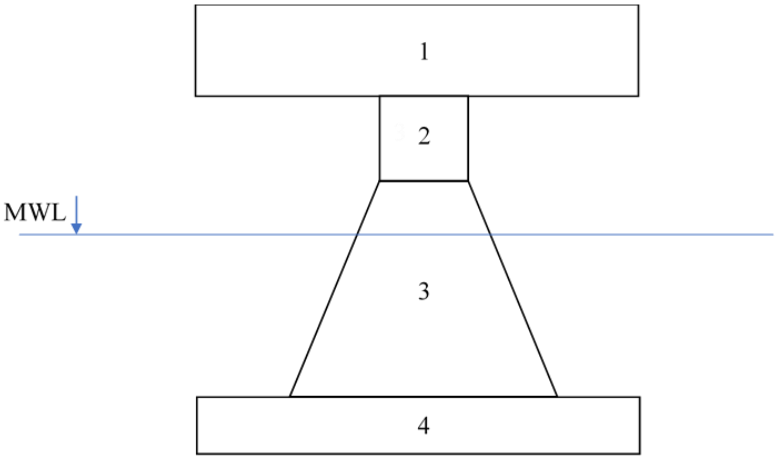


Figure 4.2. Monocone platform: 1 – top structure; 2 – column; 3 – cone; 4 – foundation.

Dimensional characteristics of the DC platform in case of monopod platform implementation:

- Foundation diameter – 125 m;
- Foundation height – 5 m;
- Column diameter – 21 m;
- Column height – 15 m;
- Cone height – 45 м;
- Cone height above the mean water level – 5 m;
- Cone diameter in the top – 21 m.

To determine the optimum angle of inclination of the cone, it is necessary to compare the loads acting on the structure with different angles of the cone inclination. The table below shows the estimated cone diameter at the bottom and cone diameter at mean sea level.

Table 4.4. Cross-section changing

Cone inclination, angles	Cone bottom diameter, m	Mean sea level cone diameter, m
45	121	31
50	104.91	29.39
60	78.74	26.77

Wave loads

Theory [32, 33]**:**

In order to estimate wave loads, it is necessary to compute wave velocity and acceleration. Velocity can be expressed by the potential function $\varphi = \varphi(x, y, z, t)$. The partial derivatives of this function with respect to the directions will be equal to the velocities in these directions:

$$\nabla\varphi = \frac{\partial\varphi}{\partial x}\bar{\imath} + \frac{\partial\varphi}{\partial y}\bar{\jmath} + \frac{\partial\varphi}{\partial z}\bar{k} = \bar{U} \tag{4.1}$$

where $\frac{\partial\varphi}{\partial x} = \mathrm{u}$ – velocity in x-direction;

$\frac{\partial\varphi}{\partial y} = v$ – velocity in y-direction;

$\frac{\partial\varphi}{\partial z} = w$ – velocity in z-direction;

$\bar{U}$ – velocity vector.

In order to solve such equation, some assumptions should be made:

- Irrotational flow;
- Incompressible fluid.

Taking into account the assumptions presented above, eq (4.1) could be transformed:

$$\nabla \cdot \bar{U} = 0 \Rightarrow \frac{\partial u}{\partial x} + \frac{\partial v}{\partial y} + \frac{\partial w}{\partial z} \;\; \Rightarrow \frac{\partial}{\partial x}\left(\frac{\partial u}{\partial x}\right) + \frac{\partial}{\partial y}\left(\frac{\partial v}{\partial y}\right) + \frac{\partial}{\partial z}\left(\frac{\partial w}{\partial z}\right) = 0 \tag{4.2}$$

$$\Rightarrow \frac{\partial^2\varphi}{\partial x^2} + \frac{\partial^2\varphi}{\partial y^2} + \frac{\partial^2\varphi}{\partial z^2} = 0 \tag{4.3}$$

$$\Rightarrow \; \nabla^2\varphi = 0 \tag{4.4}$$

Hence, the Laplace equation has been obtained (4.4).

For the preliminary assessment of wave loads, it is sufficient to use the 2D model of wave propagation. Then the Laplace equation takes the following form:

$$\frac{\partial^2\varphi}{\partial x^2} + \frac{\partial^2\varphi}{\partial z^2} = 0 \tag{4.5}$$

We need these to understand the movement of the water particles in the sea, and not just the waves but also the forces of the waves in the sea. Derivation of this equation concerning direction will give us the properties of flow below the wave such as horizontal velocity, horizontal acceleration, vertical velocity, vertical acceleration, and so on.

In order to solve the Laplace equation, we will need boundary conditions, and also, we need to choose wave theory. The most common theories:

- Linear theory;
- 2-nd, 3-rd, 4-th и 5-th order Stoke's theory;
- Cnoidal theory;
- Standing wave theory.

In this Thesis, linear theory is applied. Such a theory is the most straightforward and most applicable. This theory is based on the assumption that the wave height is considered relatively small compared to the wave length. Therefore, when evaluating the boundary conditions, we can equate the wave height in the crest to the z = 0 level. Waves, in this case, have a sinusoidal form.

It is obvious that in real conditions it is almost impossible to meet sinusoidal waves (only swell in some cases). Waves in real conditions are irregular waves and consist of the sum of many sinusoidal waves in different phases and amplitudes. The analysis of such waves is carried out by Fourier analysis.

However, it is enough for a preliminary assessment to use linear theory.

Boundary conditions for the linear system:

- Bottom boundary condition (BBC): $\left.\frac{\partial\varphi}{\partial z}\right|_{z=-d} = 0;$
- Wall boundary condition (WBC): $\left.\frac{\partial\varphi}{\partial x}\right|_{x=a} = 0;$
- Surface boundary condition: $\frac{\partial^2\varphi}{\partial t^2} + g\frac{\partial\varphi}{\partial z} = 0$ for z=0.

By using boundary conditions eq. (4.5) the surface profile equation can be derived from the potential function:

$$\varphi(x,z,t) = \frac{\xi_0 g}{\omega}\frac{\cosh k(z+d)}{\cosh(kd)}\cos(\omega t - kx) \tag{4.6}$$

$$\xi = \frac{1}{g}\frac{\partial \varphi}{\partial t}\bigg|_{z=0} \tag{4.7}$$

$$\xi = \xi_0 \frac{\cosh k(z+d)}{\cosh(kd)} \sin(\omega t - kx) \tag{4.8}$$

where ξ_0 – amplitude, m;

ω – wave frequency, 1/s;

t – time, s;

k – constant, wave number, 1/m;

d – water depth;

x – a point at the horizontal axis.

Wave frequency can be obtained by the following:

$$\omega = \frac{2\pi}{T} \tag{4.9}$$

where T – wave period, s.

Wave number can be computed by the following iteration scheme:

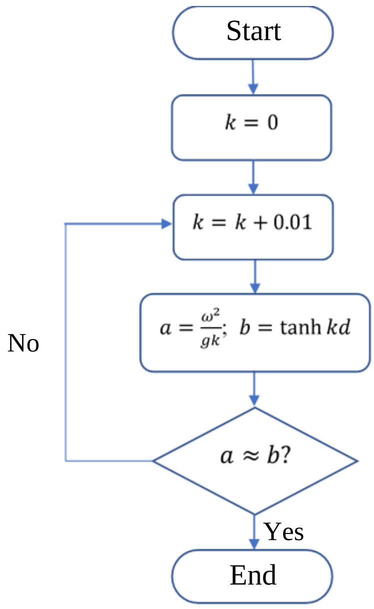


Figure 4.3. Iteration block-scheme

Wave length can be obtained by the following:

$$L = \frac{g}{2\pi} T^2 \tanh(kd) \tag{4.10}$$

Horizontal velocity can be obtained by the following:

$$u = \frac{\partial \varphi}{\partial x} = \frac{\xi_0 g}{\omega} \frac{\cosh k(z+d)}{\cosh(kd)} \sin(\omega t - kx) \tag{4.11}$$

Horizontal acceleration:

$$\dot{u} = \frac{\partial u}{\partial t} = \xi_0 g \frac{\cosh k(z+d)}{\cosh(kd)} \cos(\omega t - kx) \tag{4.12}$$

<u>Structures size classification:</u>

During the wave loads estimation, it is necessary to introduce structures size classification:

- Small bodies: $\frac{D}{L} < 0.2$;
- Large bodies: $\frac{D}{L} \geq 0.2$.

where D – diameter of the body, m;

L – wave length, m.

<u>Wave load at the small structures:</u>

The wave load on small bodies consists of two components: mass force and drag force. The wave load on small bodies at a specific depth can be calculated according to the Morison formula (an example is given for a cylinder, this formula can be used by analogy to calculate other forms, i.e. cube):

$$f(z,t) = f_M + f_D = \frac{\pi D^2}{4} \rho C_M \dot{u} + \frac{1}{2} \rho C_D D u |u| \tag{4.13}$$

where f_M –mass force, N;

f_D – drag force, N;

C_M – mass force;

C_D – drag force;

ρ – water density, kg/m^3.

Total wave load can be computed by the following equation:

$$F(t) = \int_{-d}^{surface} f(z,t)dz = \int_{-d}^{\xi} f_M(z,t)dz + \int_{-d}^{\xi} f_D(z,t)dz \tag{4.14}$$

Keulegan–Carpenter number:

$$N_{KC} = \frac{u_0 T}{D} \tag{4.15}$$

where u_0 – amplitude of the wave velocity, that is, the biggest water particle velocity under a wave crest, m/s.

Keulegan–Carpenter number is necessary for the dominating force determination:

- $N_{KC} \leq 5$, then inertia dominates;
- $5 \leq N_{KC} \leq 30$ there is both drag and inertia;
- $N_{KC} \geq 30$, drag dominates.

C_D and C_M constants determination:

According to NORSOK N-003 standard [34], constants can be obtained by the following:

$$C_D = \begin{cases} 1.05 - rough\ cylinder \\ 0.65 - smooth\ cylinder \end{cases}$$
$$C_M = \begin{cases} 1.2 - rough\ cylinder \\ 1.6 - smooth\ cylinder \end{cases} \tag{4.16}$$

Wave loads on the large structures:

Wave loads on the large structures can be obtained by the following:

$$f = \frac{\pi D^2}{4}\ \rho C_M \dot{u} \tag{4.17}$$

where C_M is a complex mathematical term depending on the ratio D/L.

It can be determined from the picture below.

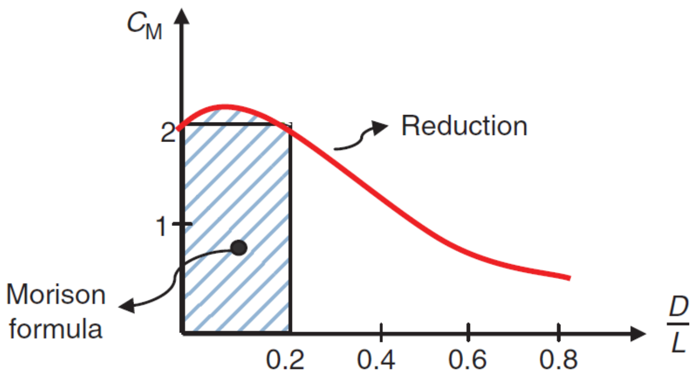


Figure 4.4. Plot for the C_M determination [32]

Initial data for calculations:

Table 4.5. Initial data for calculations

Platform	Substructure type	Cross-Section	Projected area, m	Water depth, m	Hmax, m	Tmax, s
DS	Caisson	Square	102	25	12.2	11.2
			116.9			
			114.28			
			110.6			
			109.22			
			108.02			
			106.97			
DC	Monopod	Circle	21	40	13.1	11.4
	Monocone	Circle	31			
			29.39			
			26.77			
DN	Monopod	Circle	19	45	13.2	11.4
	Monocone	Circle	29			
			27.39			
			24.77			
SG	Monopod	Circle	19	25	12.2	11.2
	Monocone	Circle	29			
			27.39			
			24.77			
P	Monopod	Circle	19	25	12.2	11.2
	Monocone	Circle	29			
			27.39			
			24.77			

Wave loads calculations:

Table 4.6. Preliminary calculations

Platform	Water depth, m	H_{max}, m	T_{max}, s	ω, 1/s	k, 1/m	L, m	Substructure type	D/L	Size	d/L	Water classification
DS	25	12.2	11.2	0.56	0.039	147.1	Caisson	0.69	Large	0.17	Intermediate depth
							Caisson with deflector	0.79	Large		
								0.78	Large		
								0.75	Large		
								0.74	Large		
								0.73	Large		
								0.73	Large		

Continuation of Table 4.6.

Platform	Water depth, m	Hmax, m	Tmax, s	ω, 1/s	k, 1/m	L, m	Substructure type	D/L	Size	d/L	Water classification
DC	40	13.1	11.4	0.55	0.0326	175.1	Monopod	0.12	Small	0.23	Intermediate depth
							Monocone	0.18	Small		
								0.17	Small		
								0.15	Small		
DN	45	13.2	11.4	0.55	0.0326	182.4	Monopod	0.10	Small	0.25	Intermediate depth
							Monocone	0.16	Small		
								0.15	Small		
								0.14	Small		
SG	25	12.2	11.2	56	0.039	147.1	Monopod	0.13	Small	0.17	Intermediate depth
							Monocone	0.20	Large		
								0.19	Small		
								0.17	Small		
P	25	12.2	11.2	56	0.039	147.1	Monopod	0.13	Small	0.17	Intermediate depth
							Monocone	0.20	Large		
								0.19	Small		
								0.17	Small		

In Table 4.6, preliminary calculations are given, based on which a further calculation plan is compiled.

Hence, the Morison equation can be applied in almost all cases for the platforms DC, DN, SG and P. For the DS platform, SG platform (with monocone substructure, cone angle – 45° and 50°) and P platform (with monocone substructure, the angle of the cone – 45°) it is necessary to use equation (3.17). For all platforms, the depth is intermediate. If for some of the platforms, the depth would be shallow or deep, this would simplify the equations for calculating the loads.

Since caisson is a large structure and caisson has a square cross-section, it is necessary to introduce equation of the wave loads for caisson:

$$f = a^2 \rho C_M \dot{u} \tag{4.18}$$

where a – caisson length.

C_M constant can be found by using Figure 4.4; acceleration can be found by using eq. (4.12).

Table 4.7. Calculation results

Object	Amplitude, m	ω, 1/s	k, 1/m	L, m	Substructure type	Size	Max. horizontal speed, m/s	Max. horizontal acceleration, m/c^2	N_{KC}	Dominating force	Projected area, m	C_M	C_d	F_{tot}, MN	Inclination, degree
DS	6.1	0.56	0.039	147.06	Caisson	Large	5.02	2.33	–	Mass	102	0.45	–	215.63	Vertical wall
					Caisson with deflector	Large					116.90	0.35		220.29	30
						Large					114.28	0.36		216.54	35
						Large					110.60	0.37		208.46	45
						Large					109.22	0.39		214.27	50
						Large					108.02	0.41		220.34	55
						Large					106.97	0.41		216.08	60
DC	6.55	0.55	0.0326	175.05	Monopod	Small	4.58	2.09	2.49	Mass	21.00	1.2	1.05	23.62	Vertical wall
					Monocone	Small			1.68	Mass	31.00			51.47	45
						Small			1.78	Mass	29.39			46.26	50
						Small			1.95	Mass	26.77			38.38	60
DN	6.6	0.55	0.0326	182.41	Monopod	Small	4.67	2.11	2.80	Mass	19.00	1.2	1.05	20.30	Vertical wall
					Monocone	Small			1.84	Mass	29.00			47.29	45
						Small			1.94	Mass	27.39			42.18	50
						Small			2.27	Mass	24.77			34.50	60
SG	6.1	56	0.039	147.06	Monopod	Small	5.02	2.33	2.96	Mass	19.00	1.2	1.05	15.67	Vertical wall
					Monocone	Large			–	Mass	29.00	1.8		54.76	45
						Small			2.05	Mass	27.39	1.6		32.57	50
						Small			2.27	Mass	24.77	1.2		26.63	60
P	6.1	56	0.039	147.06	Monopod	Small	5.02	2.33	2.96	Mass	19.00	1.2	2.05	15.67	Vertical wall
					Monocone	Large			–	Mass	29.00	1.8		54.76	45
						Small			2.05	Mass	27.39	1.2		32.57	50
						Small			2.27	Mass	24.77	1.2		26.63	60

During the analysis of the results, the following conclusions have been made:

- The minimum wave load on the caisson type base is observed at an inclination angle of the deflector equal 45°. The maximum load is observed at an inclination angle of 55°.
- The loads on the caisson-type substructure are significantly higher than the loads on the single-support type. However, since the mass of the caisson is very big, and the strength is high, this design is applicable, reliable, and is popular on the Russian Arctic shelf (including the shelf of Sakhalin Island).
- For single-support substructures, the minimum wave load is observed at a monopod (vertical wall), the maximum load is observed at the monocone with an inclination angle of 30°.
- With depth increasing, loads increase. However, an important point is the fact that structures that were small at deep water and were considered according to the Morison equation are taken large at a shallower depth and are considered according to formula (4.17). In this case, wave loads at a shallower depth may be higher than wave loads at a deeper depth.

4.1.4. Ice loads

Theory:

There are many methods for ice loads on a structure calculation. All of these methods are based on the determination of the minimum load at which ice will break under given conditions.

The action generated as a result of the ice floe impact against a structure depends on the mass, initial velocity and properties of the ice feature as well as on the environmental conditions and the structure's form and size. Different scenarios of interaction have to be considered.

The generally recognized scenarios are:

- limit stress;

- limit momentum;
- limit force;
- splitting.

Each of them corresponds to the situation when one of the parameters reaches the utmost value. These dominant variables should be treated probabilistically, where this is appropriate.

The Pechora Sea is characterized by a high concentration of ice. For high ice concentrations, the most appropriate way to assess ice loads is to use limiting force.

Ice loads are highly dependent on the wall profile. So, if the wall of the structure is inclined, the ice is destroyed due to bending. In the case of a vertical wall – the ice is crushing, under the influence of compression forces. Since ice has a lower bending strength than a compressive strength, ice loads on vertical walls are much higher than loads on inclined walls. This fact will be checked in the calculations below [35].

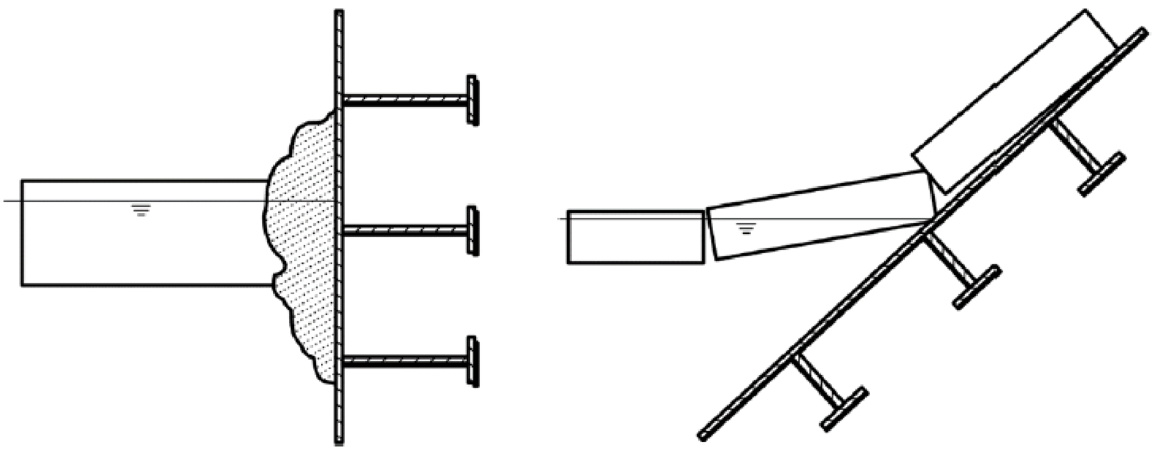


Figure 4.5. Destruction of ice on vertical and inclined walls [36]

Equations for ice loads on structures with vertical and inclined walls estimation are presented below.

Vertical wall:

There are several schemes for global loads on vertical walls calculations. Two equations are considered below: the Korzhavin equation and the equation presented in International Standard ISO 19906.

Korzhavin equation [35]:

$$F = IKm\sigma_c Dh \tag{4.19}$$

where I – indentation factor, takes into account the crystallographic structure of the ice, its properties, the correlation between the structure's diameter and the ice thickness (aspect ratio), the influence of the stress/strain field on strength (confinement). Depending on the different factors (aspect ratio, strain rate) and the internal ice structure (granular or columnar ice), the factor I varies between 3 and 4.5 for columnar ice, and 1.2–2.97 for granular ice.

K – contact factor, takes into account the imperfect contact between the ice sheet and the structure. It may be in the range of 0.3–1. Recommend the product IK = 0.45–0.55.

m – structure's in-plane shape factor. It varies in narrow limits between 0.9–1 where 0.9 corresponds to a cylinder and 1.0 to a flat contact surface.

D – diameter of the structure;

σ_c – unconfined compressive strength of ice;

h – ice thickness.

The indentation factor I can be computed by the following [37]:

$$I = \sqrt{5\frac{h}{D} + 1} \tag{4.20}$$

According to the equation presented in International Standard ISO 19906, global ice load can be computed by the following [36]:

$$F_g = p_G \cdot A_N$$

where p_G – is the ice pressure averaged over the nominal contact area associated with the global action;

$A_N = h \cdot w$ – is the nominal contact area;

w – width (diameter) of the structure.

The global ice pressure can be computed by the following:

$$p_G = C_R\left[\left(\frac{h}{h_1}\right)^n\left(\frac{w}{h}\right)^m + f_{AR}\right] \tag{4.21}$$

где h_1 – reference thickness of 1 m;

C_R – ice strength coefficient;

n – an empirical coefficient, equal to$-0.5\ +h/5$ for $h<1$ m, and $-0{,}3$ for $h\geq 1$ m;

m – an empirical coefficient equal to –0,16;

f_{AR} – an empirical term is given by:

$$f_{AR}=\exp-\frac{w}{3h}\cdot\sqrt{1+5\frac{h}{w}} \tag{4.22}$$

According to the International Standard ISO 199006, ice strength coefficient can be chosen from the following table:

Table 4.8. Regional values for ice strength coefficient [36]

C_R	**Region**
2.8	Arctic FY and MY ice
2.4	Subarctic (e.g. Okhotsk Sea — off northeast Sakhalin Island)
1.8	Temperate (e.g. Okhotsk Sea — Aniva Bay, North Caspian Sea, Cook Inlet, Baltic Sea, Bohai Sea)

The Korzhavin equation looks attractive since it is quite simple, but the great disadvantage of this equation is the fact that it is less accurate than the equation (4.21) [38].

Hence, equation (4.22) will be used to estimate ice loads.

Inclined wall

In the case when the ice field is in contact with inclined walls, as mentioned above, ice is destroyed due to bending forces.

Croasdale proposed a two-dimensional loading model on a plane slope. The model is based on analysis of a semi-infinite elastic beam on an elastic foundation. It also considers the force required to push broken ice blocks up the inclined slope. The equation for the horizontal component of the load was written in the form:

$$F_H=C_1D\sigma_f\left(\frac{\rho_w g h^5}{E}\right)^{0.25}+C_2Dh_rh\rho_i g \tag{4.23}$$

where C_1 and C_2 – coefficients depending on the slope inclination and the coefficient of the dynamic ice friction over the structure surface (μ),;

E – Young's modulus of ice;

h_r – height of rubble on the structure's slope;

ρ_w и ρ_i – water and ice densities;

g – acceleration due to gravity;

The coefficients C_1 and C_2 are given by:

$$C_1 = 0.68\xi_1/\xi_2 \tag{4.24}$$

$$C_2 = \xi_1(\xi_1/\xi_2 + \cot\alpha) \tag{4.25}$$

where

$$\xi_1 = \sin\alpha + \mu\cos\alpha \tag{4.26}$$

$$\xi_1 = \cos\alpha - \mu\sin\alpha \tag{4.27}$$

where α – wall inclination;

Later this method was modified by Croasdale and Cammaert into a 3D model [35, 36, 39]. This comprehensive solution takes into account many additional factors that influence the process.

The horizontal component of the total action F_H is presented as:

$$F_H = \frac{F_B + F_P + F_R + F_L + F_T}{1 - \frac{F_B}{\sigma_f L_c h}} \tag{4.28}$$

where L_c – total circumferential crack length: $L_c = w + \frac{\pi^2}{4} \cdot l_c$;

$l_c = \left(\frac{Eh^3}{12\rho_w g(1-\nu^2)}\right)^{0.25}$ – the characteristic length of an ice beam on an elastic foundation;

ν – Poisson's ratio is taken equal to 0,2;

F_B – the force which is needed to break the ice sheet by flexure is given by:

$$F_B = 0.68\xi\sigma_f L_c\left(\frac{\rho_w h h^5}{E}\right)^{0.25} \tag{4.29}$$

where $\xi = \frac{\sin\alpha + \mu_s \cos\alpha}{\cos\alpha - \mu_s \sin\alpha}$;

μ_s – ice-to-ice friction coefficient;

σ_f – flexural strength of the ice sheet;

F_P – *the* force needed to push the ice sheet through the rubble built up on the surface of the ice sheet is given by:

$$F_P = wh_r^2 \mu_i \rho_i g(1-e)\left(1 - \frac{\tan\theta}{\tan\alpha}\right)^2 \left(\frac{1}{2\tan\theta}\right) \tag{4.30}$$

where h_r – rubble height;

μ_i – the ice-structure friction coefficient is taken equal to 0.3;

e – porosity of the ice rubble, is taken equal to 0.4;

θ – angle the rubble makes with the horizontal;

F_L – the additional force necessary to lift and shear the ice rubble on top of the sloping surface before it can be pushed up to fail in bending is given by:

$$\begin{aligned} F_L = {} & 0.5wh_r^2 \rho_i g(1-e)\xi[(\cot\theta - \cot\alpha)(1 - \tan\theta\cot\alpha) \\ & + \tan\varphi\,(1 - \tan\theta\cot\alpha)^2] + \xi c w h_r (1 - \tan\theta\cot\alpha) \end{aligned} \tag{4.31}$$

where c – cohesion of the ice rubble, is taken equal to 4 kPa;

φ – friction angle of the ice rubble.

F_R – The force to push these ice blocks up the slope through the ice rubble is given by:

$$F_R = \frac{w\rho_i g h_r}{\cos\alpha - \mu_i \sin\alpha} P \tag{4.32}$$

$$P = 0.5(\mu_i + \mu_s)(1-e)h_r\left(\mu_i\left(\frac{sin\alpha}{\tan\theta} - \cos\alpha\right)\left(1 - \frac{\tan\theta}{\tan\alpha}\right) + h\frac{\sin\alpha + \mu\cos\alpha}{\sin\alpha}\right) \tag{4.33}$$

F_T – *the* force required to turn the blocks may read given by:

$$F_T = 1.5wh^2\rho_i g\frac{\cos\alpha}{\sin\alpha - \mu\cos\alpha} \tag{4.34}$$

Vertical and total ice loads on the structure can be computed by the following:

$$\mathrm{F}_V = \frac{F_H}{\xi} \tag{4.35}$$

$$F_{tot} = \sqrt{F_V^2 + F_H^2} \quad (4.36)$$

<u>Initial data for the calculations:</u>

The initial data for the calculations is presented in the table below. Data on the maximum ice thickness and ultimate unconfined compressive strength of the ice was taken following the textbook of O.T. Gudmestad, A.B. Zolotukhin, and others [5].

The bending strength can be calculated following the Russian standard SNiP 2.06.04-82 * "Loads and effects on hydraulic structures" [40]:

$$\sigma_f = 0.4 \cdot \sigma_r \quad (4.37)$$

Table 4.9. Initial data for the calculations

Parameter	Value	Units
h	2.5	m
n	-0.3	–
m	-0.16	–
C_R	2.8	MPa
E	8700	MPa
ρ_w	1025	kg/m^3
ρ_i	900	kg/m^3
g	9.81	m/c^2
σ_r	2.1	MPa
σ_f	0.84	MPa
e	0.4	–
θ	42	^{o}
φ	45	^{o}
c	4	kPa
μ_s	0.2	–
μ_i	0.3	–

<u>Calculation results:</u>

The results of ice loads calculations on vertical and inclined walls are presented in Table 4.10:

Table 4.10. The results of ice loads calculations

Platform	Wall inclination	Structure width, m	F_H, MN	F_V, MN	F_{tot}, MN
DS	Vertical	102	—		308.34
	30	116.90	184.80	190.19	265.19
	35	114.28	149.30	132.68	199.73
	45	110.60	154.26	102.84	185.40
	50	109.22	186.08	106.96	214.64
	55	108.02	240.46	118.15	267.92
	60	106.97	327.88	135.76	354.87
DC	Vertical	21.00	—		94.00
	45	31.00	48.70	32.47	58.53
	50	29.39	56.55	32.51	65.23
	60	26.77	91.46	37.87	99.00
DS	Vertical	19.00	—		87.58
	45	29.00	46.05	30.70	55.34
	50	27.39	53.31	30.64	61.49
	60	24.77	85.58	35.44	92.63
SG	Vertical	19.00	—		87.58
	45	29.00	38.62	25.75	29.00
	50	27.39	48.21	27.71	27.39
	60	24.77	83.16	34.44	24.77
P	Vertical	19.00	—		87.58
	45	29.00	38.62	25.75	55.34
	50	27.39	48.21	27.71	61.49
	60	24.77	83.16	34.44	92.63

By analyzing Table 4.10, it can be observed that the maximum loads occur with an angle of inclination of 60^0 (inclined wall). The minimum loads are observed with an angle of inclination of 45^0 (inclined wall). It should be noted that the minimum and maximum loads are very different. Thus, when using platforms with a wall angle of 45^0, loads can be reduced by up to 52% (in the case of a caisson-type platform).

4.1.5. Intermediate conclusions:

A summary table with the calculated wave and ice loads is presented below:

Table 4.11. Environmental loads summary table

Platform	Wall inclination	F, MN	
		Wave loads	Ice loads
DS	Vertical	215.63	308.34
	30	220.29	265.19
	35	216.54	199.73
	45	208.46	185.40
	50	214.27	214.64
	55	220.34	267.92
	60	216.08	354.87
DC	Vertical	23.62	94.00
	45	51.47	58.53
	50	46.26	65.23
	60	38.38	99.00
DS	Vertical	20.30	87.58
	45	47.29	55.34
	50	42.18	61.49
	60	34.50	92.63
SG	Vertical	15.67	87.58
	45	54.76	55.34
	50	32.57	61.49
	60	26.63	92.63
P	Vertical	15.67	87.58
	45	54.76	55.34
	50	32.57	61.49
	60	26.63	92.63

During the analysis of the obtained results, it can be observed that ice loads in the Pechora Sea are dominant in most cases. Hence, it is necessary to choose a platform design in which ice loads can be minimized. Although at an angle of inclination of the platform wall of 45^0, wave loads in most cases are maximum, ice loads are minimal. With this design, waves and ice introduce approximately the same action on the platform.

A table with the final choice of foundation for each gravity-based platform is presented below:

Table 4.12. Platform type choosing

Platform	Type of the platform	Wall inclination	F, MN	
			Wave loads	Ice loads
DS	Caisson	45	208.46	185.40
DC	Monocone	45	51.47	58.53
DN	Monocone	45	47.29	55.34
SG	Monocone	45	54.76	55.34
P	Monocone	45	54.76	55.34

4.2. LNG plant

4.2.1. Brief technologies and world experience overview:

Liquefied natural gas (LNG) is natural gas in liquid form, which is obtained by cooling and condensing of natural gas.

According to experts, LNG is preferable to pipeline gas according to economic and environmental indicators. However, it should be mentioned that the economic advantage of LNG is achieved in the case of LNG transportation over long distances.

During liquefaction, its volume decreases 600 times. Another advantage of LNG is its flexibility in terms of product delivery to consumers. Unlike piped gas, LNG can be delivered to different markets at different times. There is always the possibility of revising the supply chain, its expansion or re-profiling. It should also be noted that gas fields with vast reserves are often located too far from the market or in regions with no infrastructure (for example, the Pechora and Barents Seas, the Nenets Autonomous Okrug), in such a case, liquefying of natural gas is the only possible way to obtain some production from such fields. Another one advantage of the LNG is that natural gas in liquified form is not a flammable and non-toxic product. Such a strong environmental advantage significantly increases the value of LNG. However, it must be mentioned that under atmospheric conditions, LNG is converted into natural gas, which is both toxic and explosive/fire hazardous. In connection with this fact, it becomes evident that, despite the relative safety of LNG, the leakage of LNG is inappropriate.

LNG should be stored under slight over-pressure and at a temperature of approximately -161^0 in special containers with thermal insulation.

Nowadays, LNG is imported by more than 30 countries with the appropriate infrastructure. The leading LNG importers in the European zone are Spain, the UK and France. Spain in terms of imported LNG ranks third in the world after Japan and South Korea. Russia is currently in the top ten LNG exporting countries. Today, the LNG market is rapidly transforming from a narrow-profile direction of several regional markets into a huge developing industry, which in the future may come first in supplying the world gas market.

Currently, natural gas liquefaction plants are mainly installed on land (for example, the LNG plant as a part of the Sakhalin-2 project). However, it has already been proven that floating land plants are a real alternative to onshore LNG plants. A critical advantage of floating plants is that such plants can be easily liquidated or relocated after depletion of the field-natural gas provider reserves.

In Russia, LNG is produced only from onshore plants. However, NOVATEK is already developing a new LNG-2 project that focuses on the use of LNG plant on a floating basis. A similar approach was adopted in the Pechora LNG project, which was implemented by Rosneft. Unfortunately, the Pechora LNG project has been suspended for political and economic reasons. Despite the great work done, it is not yet known when this project will be implemented.

The concept of LNG production during the development of offshore gas and gas-condensate fields can be realized through the use of floating LNG plants (FLNG).

FLNG is a technological vessel that interfaces with wells/gas pipelines, is equipped with:

- a gas treatment system,
- a gas liquefaction plant,
- an LNG and condensate storage facility,
- an offloading system.

The advantages of FLNG include relatively short construction periods and the possibility of their use at other points, which makes it possible to distribute their cost between several projects.

These advantages are especially relevant for the conditions of the Pechora Sea since the Pechora Sea has vast potential gas reserves. Currently, one oil and gas condensate and two gas condensate fields have been discovered [41, 42, 43].

A table with the already started FLNG projects is presented below.

Table 4.13. Ongoing FLNG at the moment [42, 41]

Name of the project	Project status	LNG performance, mln tons/annum	Operator	FLNG dimensions /storage capacity	Shipyard	Liquefaction technology
 «Prelude»	Started at 2019	3,6	«Shell»	488x74x43 / 220	Samsung, Korea	DMR («Shell»)
 PFLNG1 «Satu»	Started at 2016	1,2	«Petronas»	365x60x33 / 177	Daewoo, Korea	Nitrogen expansion (AP-NTM)
 «Hilli Episeyo»	The first FLNG converted from a gas carrier	2,4	«LNG Golar»	294x62,6 / 125	Keppel, Singapore	«PRICO» («Black& Veatch»)
 «Caribbean FLNG»	First FLNG - dumb barge	1.6	«Exmar»	140x32x20 / 0.55	Wison, China	«PRICO» («Black& Veatch»)

It should be noted that all already built factories were built for conditions in which there is no ice; hence, it is impossible to use only the experience of such projects.

The current project information for offshore LNG projects in Russia is presented below [42, 44, 45]:

Table 4.14. Russian offshore LNG Projects

Project	Operator	LNG performance, mln tons/annum	Resource potential	Project status	Planned infrastructure
Arctic LNG-2	Novatek	19.8	Deposits of the Gydan Peninsula, Yamalo-Nenets Autonomous Area	Final Investment Decision (FID) made in September 2019	Gravity-based platform
Pechora-LNG	Rosneft/Altech	4.3	Kumzhinskoye and Korovinskoye fields of the Nenets Autonomous Okrug (geological reserves – 165 billion m^3 and 5.6 million tons of condensate)	Project suspended for political reasons indefinitely	Gravity-based platform or FLNG
–	Rosneft VNIPIneft	n/d	Based on the resource base of the Company	Feasibility study	n/d
–	Lloyds Energy	2,5	Pipeline Gas / Far East	n/d	Dumb barges

The objectives of the Pechora LNG project are very similar to the task of this Master's Thesis:

- The Kumzhinskoye and Korovinskoye fields are also located in the Timan-Pechora oil and gas province.
- The total gas reserves of the Dolginskoye, Pomorskoye and North-Gulyaevskoye fields are close to the total reserves of the Kumzhinskoye and Korovinskoye fields.
- The marine conditions for the LNG plant installation are the same as the conditions discussed in this dissertation.

Hence, the only difference, in terms of design conditions, is the depth of the sea. The depth at the plant installation site according to the Pechora LNG project is 19 m. At the plant installation site, according to the materials of this Master's Thesis, the depth is approximately 70 m (for the second concept) and 20 m (for the first concept).

While the installation of a floating plant is not possible for the Pechora LNG project (only the installation of a gravity-type platform is possible), for higher depths the possibility of installing floating plants opens up. However, during the pre-design work on the Pechora-LNG project, the option of a floating LNG plant was also considered.

During the LNG plant design choosing, an analogy with pre-design materials of the Pechora-LNG project was made (including the issues of LNG storage and holding the plant in place system features) [42].

4.2.2. LNG plant design

The required volumes of LNG storage are 260-270 thousand m^3, condensate 30-60 thousand m^3. Space is also needed for storing diesel fuel, refrigerants, sea water, etc.

The right decision is to design the storage in the lower part of the structure. Taking into account the required storage volumes, two types of plant construction can be applied: the ship's hull shape and buoy hull shape.

Type 1:

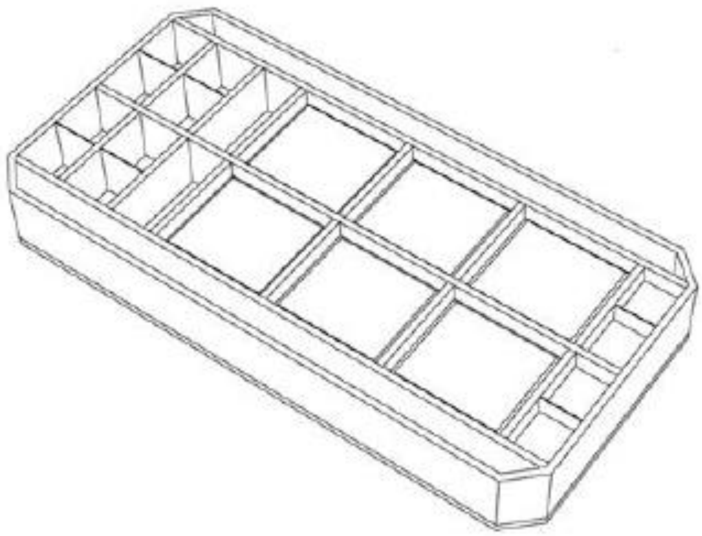


Figure 4.6. Ship's hull shape. Dimensions: 300x100x40 m [42]

Demonstrative examples of such shape are the Prelude, PFLNG1 Satu, Hilli Episeyo, Caribbean FLNG plants (see Table 4.13). Obviously, in the case of using a ship's hull shape, it is necessary to strengthen the hull and apply an advanced and reliable positioning system. Even taking into account amplification and a reliable positioning system, this form may not be reliable under the conditions of the Pechora Sea, since the direction of ice drift is unstable.

Type 2:

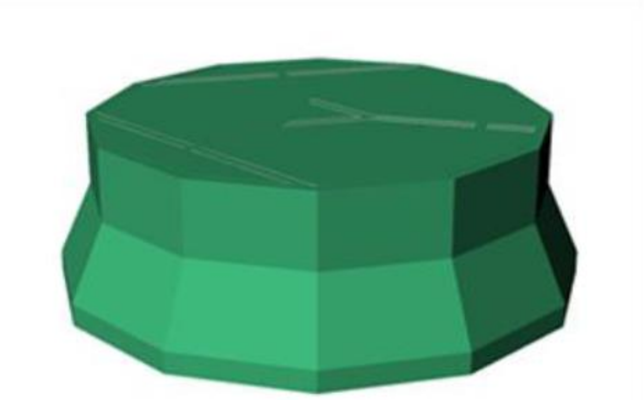


Figure 4.7. The buoy hull shape. Dimensions: 140x46 м *[42]*

A striking example of a buoy hull shapes the projects of the company "Sevan SSP". A successful project to implement such design is the FPSO Goliat, launched in 2016 in the Norwegian part of the Barents Sea.

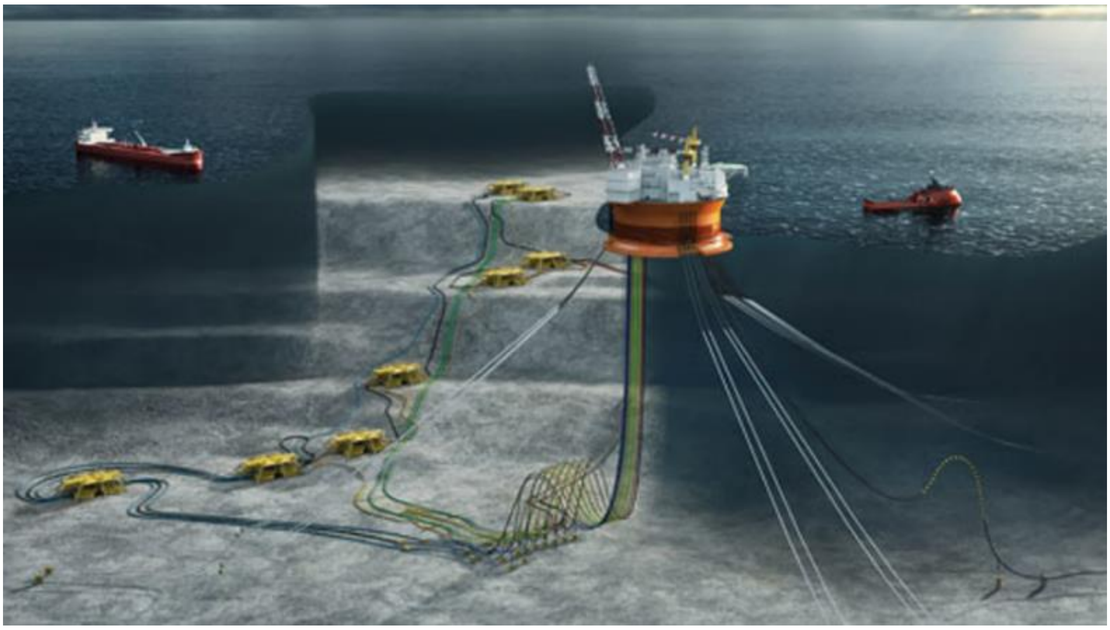


Figure 4.8. FPSO Goliat [46]

This platform is installed in the ice-free part of the Barents Sea, and therefore the vertical walls of the platform are a right solution.

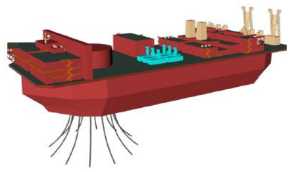
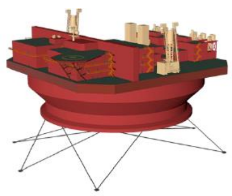
In order to install such type of platform in the ice conditions of the Pechora Sea, a structure with a walls inclination of approximately 45^0 and with an enhanced positioning system is required.

Sevan SSP is currently developing a floating LNG plant. The company identifies the following benefits of using such technology [47]:

- No need for Turret/Swivel;
- Capex and Opex savings;
- Low Complexity;
- Large deck area capacity;
- Spread mooring;
- Applicable for different liquefaction technologies.

Concepts of the FLNG with station-keeping systems consideration is presented below [42]:

Table 4.15. Concepts of the FLNG with station-keeping systems consideration [42]

Ship's hull shape		Turret Dimensions of a hull: 292x94x38, draft – 15 m, mass – 185 ths tons
		Cross-anchor station-keeping system or spreading anchor mooring system Dimensions of a hull: 292x94x38, draft – 15 m, mass – 180 ths tons
Buoy hull shape		Cross-anchor station-keeping system or spreading anchor mooring system, top diameter – 188 m, waterline diameter – 150 m. draft – 23 m, mass– 180 ths. tons

Following the Rubin design bureau calculations, in the Pechora Sea conditions, the ship's hull shape FLNG anchor mooring system cannot ensure safety in case of ice floe moving in the stern direction. This problem can be solved in two ways [42]:

- Use of icebreakers to break the ice;
- Using a turret system in which a ship can rotate around a turret. In this case, the vessel can turn in the direction of ice drift [48].

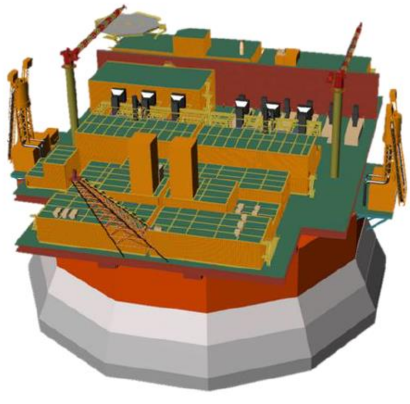
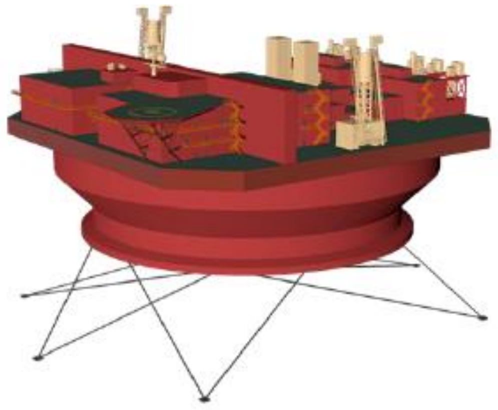
Both of these methods can be successfully implemented, however, since the direction of ice drift in the Pechora Sea is very inconsistent, the implementation of such solutions may be too expensive and not feasible from the economic point of view.

The Rubin design bureau concluded that of all types of floating units, only buoy hull shape FLNG with a powerful spreading anchor mooring system (32 large-diameter links) can be used in the ice conditions of the Pechora Sea.

Restrictions on the depth for buoy hull shape FLNG: not less than 45 m [42].

Considering all the information above, a buoy hull shape FLNG is decided to be used as an LNG plant for the second development concept. For the second concept, it is proposed to consider a gravity-type platform with a shape close to a circle. The topside diameter of such a platform should be 188 m and diameter of 188 m, and the waterline diameter is proposed to be 140 m. 45 degrees inclined walls should be used in the gravity-based platform:

Table 4.16. LNG plant concepts [42]

Concept 1	Concept 2
	

4.2.3. Anchor system for LNG plant type 2

A spread anchor mooring system with 32 large-diameter links was proposed for the floating LNG plant. The main challenge for such a platform is to keep the positions under the tremendous unstable ice loads linked with the unstable ice drift.

The best practice of the buoy-shaped hull platforms construction belongs to the Sevan company. This company designed many buoy-shaped cylindrical platforms for different conditions, including Brazil's offshore and Norwegian's part of the Barents Sea. Although there are no platforms designed by Sevan company for the harsh ice conditions, some analogies can be made.

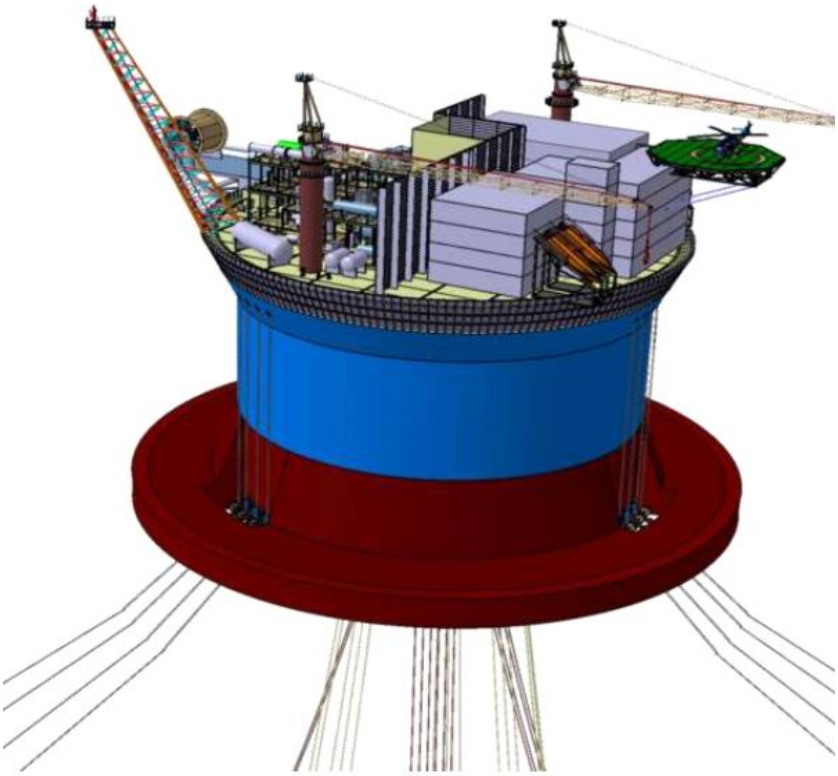


Figure 4.9. Sevan Hull [49]

The most reliable hull construction developed by the Sevan company is presented above. It can be observed that the mooring system, in this case, is started at the topside of the platform and lowering along the hull wall. At the bottom of the hull – lines are lowered to the seabed in approximately 45^0 angles.

For the proposed FLNG, the same system can be used with some changes (additional mooring defense from the ice rubbles, 32 mooring lines – eight clusters of four lines each, etc.).

The reliable line configuration for a permanent mooring system could be following: anchor to chain to polyester rope to chain [50, 51, 52]. Such a system is expected to be the most reliable and efficient from the weight reduction point of view.

Different grades of the mooring chain are presented in the table below [53]:

Table 4.17. Mechanical properties of offshore mooring chain and accessories [53]

Grade	Yield stress N/mm^2 min	Tensile strength N/mm^2 min	Elongation % min	Reduction of area % min	Charpy V-notch impact tests		
					Test temperature °C	Average energy J min	Average energy flash weld J min
R3	410	690	17	50	0 -20	60 40	50 30
R3S	490	770	15	50	0 -20	65 45	53 33
R4	580	860	12	50	-20	50	36
R4S	700	960	12	50	-20	56	40
R5	760	1000	12	50	-20	58	42
R6	900	1100	12	50	-20	60	46

According to the table above, the most reliable mooring chain grades are R5 and R6. Moreover, it is using at the most challenging projects with harsh environmental conditions so that the best mooring chain grade for the Pechora Sea conditions is R5 or R6 grade.

However, as it can be observed from the table above, the test temperature is -20 ^{0}C. According to the Global Maritime Summary Guidance Document GMH-8500-3122, it is a great problem during the material choice for the Arctic conditions. It is recommended to provide testing of the chosen for the project grade at the -50 ^{0}C temperature before the final decision [54].

The nominal diameter for the mooring chain and polyester rope should be defined during the ice, waves, and wind loads modelling. For sure, the nominal diameter should be large enough to withstand all the loads which influence the structure. Such modelling and diameter choosing is not considered in this Thesis and is recommended to be provided in the future works.

Considering the approximate line angle, a draft of the FLNG and water depth, the approximate length of the line from the platform bottom to the seabed can be computed: line length is equal to 68 meters.

The main anchor types are presented below [52]:

- Fluke anchor;
- Plate anchor;
- Anchor piles;
- Suction anchors;
- Gravity anchors.

It seems that the most conservative and reliable anchor system is a plate anchor system.

Plate anchors are anchors that are intended to resist the applied loads by orienting the plate approximately normal to the load after having been embedded. The embedment of the plate anchor maybe by dragging (like a fluke anchor), by pushing, by driving or by use of suction [52].

For the anchor system considered in this master thesis, plate anchor with the suction embedment is proposed.

It is, however, suggested that the concept is tested in an ice tank to document its feasibility in the Pechora Sea ice conditions and actual water depth prior to further engineering analysis.

4.2.4. Plant equipment

Currently, several different technological processes for the liquefaction of the natural gas are used, but all of them are based on the same principle: the cooling and condensation of natural gas in a heat exchanger is carried out by one or more refrigerants. Refrigerants circulate in closed thermodynamic cycles in which the processes of compression in a compressor, cooling with air or water, expansion and heating with cooled natural gas follow one after another. Nowadays, C3-MCR and DMR technologies provide the best efficiency for offshore large-capacity LNG production plant [42]. Consideration of both technologies is presented below [43]:

C3-MCR technology:

The technology is based on the mixed refrigerant and propane pre-cooling system implementation.

The C3-MCR process designed by the APCI (Air Products & Chemical, Incorporated) is the most common. In 2012, it was used to liquefy approximately 54% of worldwide LNG production, while 81% – in a total number of LNG trains. At the beginning of 2013, the unit production of each train varies between 2.5 and 4.9 MTPA (million tons per annum) [43].

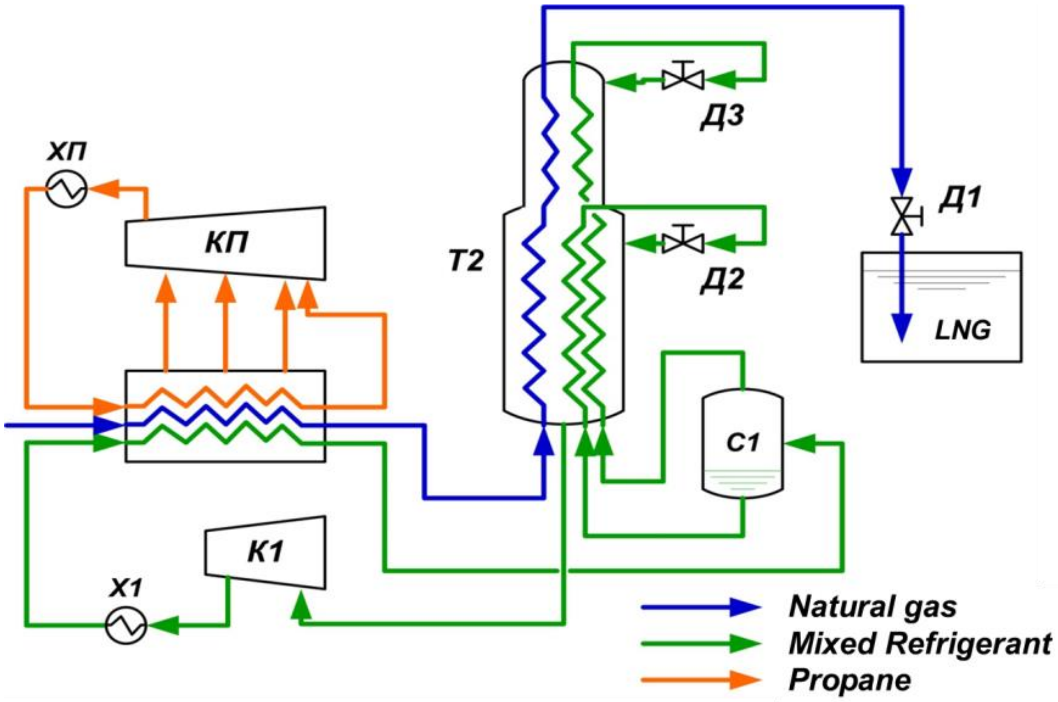


Figure 4.10. C3-MCR technological scheme [43]

The APCI C3-MR process has two cooling cycles. One is a series of heat exchangers using propane to pre-cool the natural gas. The three or four heat exchangers (the kettle type) in the series (not sown on the scheme) each have propane at a different pressure: high pressure, medium pressure, and low pressure. The different pressures used to allow the propane to be cooled to different temperatures to allow the natural gas to be cooled to an initial temperature before it enters a spiral wound heat exchanger that accomplishes most of the cooling.

The mixed refrigerant used is composed of methane, ethane, propane, butane, and nitrogen.

At output from the liquefaction exchanger, the LNG is still pressurized at 40/45 bars.

The make-up hydrocarbons are supplied by the fractionating unit. One of the strong points of APCI is its ability to supply both the process license and the primary cryogenic exchanger SWHE (Spool Wound Heat Exchanger), that the company manufactures.

Advantages of APCI C3MR process are:

- The process is applied for natural gas with various structures;
- Minimal number of units;
- Efficiency;
- Operative flexibility;
- Reliability.

One of the main disadvantages of the C3-MR process is its high equipment cost. With the use of the propane exchangers, there is a high utility cost associated, as well as the high cost of the spiral wound heat exchanger. The amount of work required by the compressor is huge, which also increases the cost of the processes. A large compressor or multiple numbers of compressors are required to compress the amount of refrigerant in the process [43].

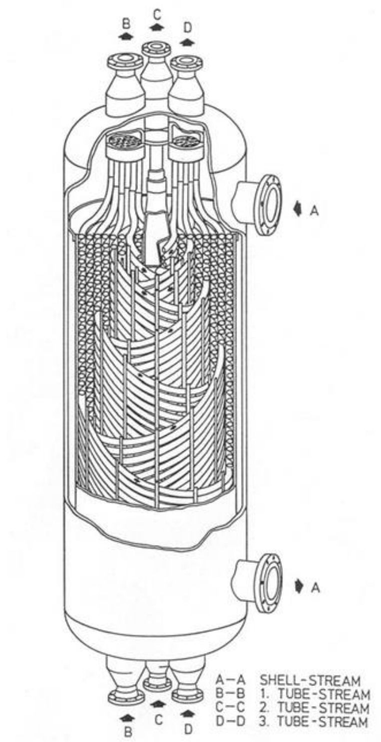


Figure 4.11. The spiral wound heat exchanger [43]

DMR technology

Such technology was developed by the Shell company. Process configuration is similar to the propane pre-cooled mixed refrigerant process, with the pre-cooling conducted by a mixed refrigerant (made up mainly of ethane and propane) rather than pure propane. Another main difference is that the pre-cooling is carried out in SWHEs rather than kettles. The pre-cooling and liquefaction SWHEs were supplied by Linde [43].

By using DMR technology, 7 MTPA production can be obtained (i.e. "Scarborough FLNG").

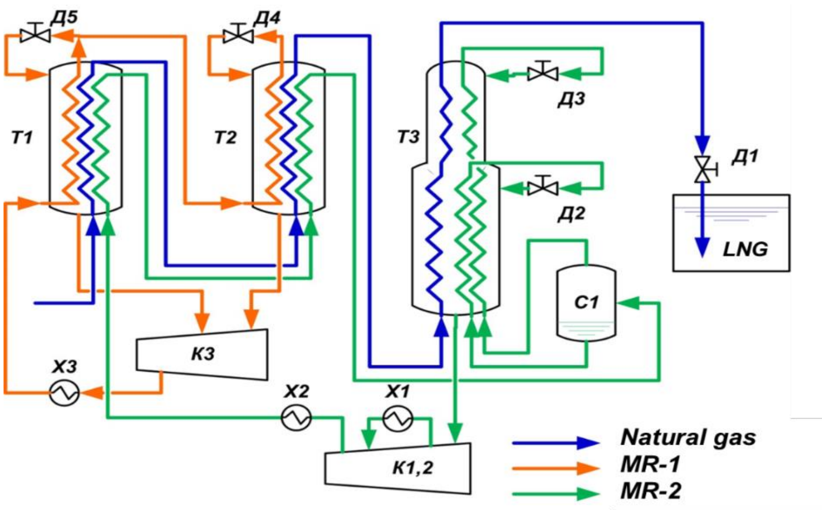


Figure 4.12. DMR technological scheme [43]

Technologies comparison

The effectiveness of liquefaction technology is characterized by the specific energy consumption required to produce one kilogram of LNG. With the temperature decreasing, the energy consumption for LNG production decreases. The comparison of specific energy consumption between DMR and C3-MR technologies is presented below:

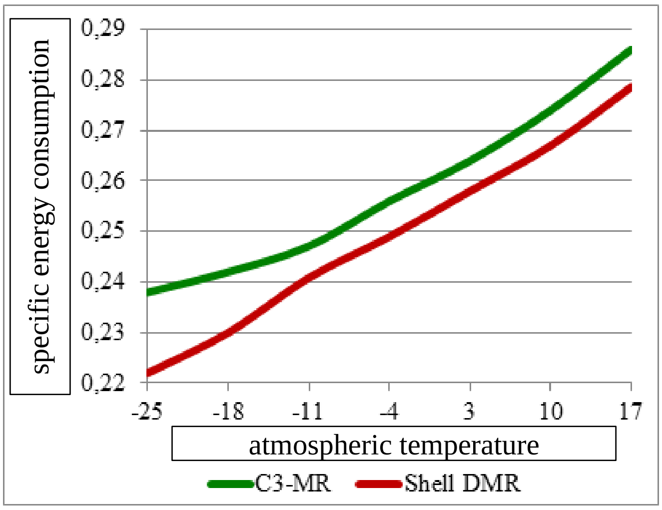


Figure 4.13. Dependence of specific energy consumption of natural gas liquefaction processes on changes in atmospheric temperature [55]

As far as in Arctic LNG plants heat removal in refrigeration cycles is possible at very low ambient temperatures, regardless of the technology chosen, the total amount of circulating refrigerant in the pre-cooling cycle is reduced, which leads to a reduction in compressors energy consumption.

However, the energy consumption reduction in the cycle with propane does not occur linearly. Approximately to a temperature of minus 10 °C, the decrease in the specific energy consumption in both technological processes occurs at the same rate. Further, the reduction in energy consumption in the C3-MR process is lower than in the DMR process. This fact occurs since the temperature of pre-cooling with pure propane at atmospheric pressure is limited by temperatures of minus 30 °C - minus 35 °C. With a decrease in external temperature, a decrease in energy consumption in the pre-cooling cycle occurs due to a decrease in propane consumption. However, the flow of propane through the compressor has a minimum value, followed by surging. In order to keep the compressor within operating parameters (to avoid surging), the propane flow rate in the cycle is kept constant, even with a further decrease in air temperature. A further decrease in specific energy consumption occurs due to an increase in the efficiency of gas turbines. At the same time, LNG production can be kept almost constant throughout the year.

The using of propane with ethane or ethylene mixture in the pre-cooling cycle instead of pure propane reduces the temperature of natural gas at the outlet of this cycle but requires constant control of the mixture composition. As the ambient temperature decreases, the ratio of propane and ethane in the mixture changes in favor of ethane, which causes a decrease in the outlet gas temperature. The dependence of the natural gas cooling temperature on the ethane content is presented below [56]:

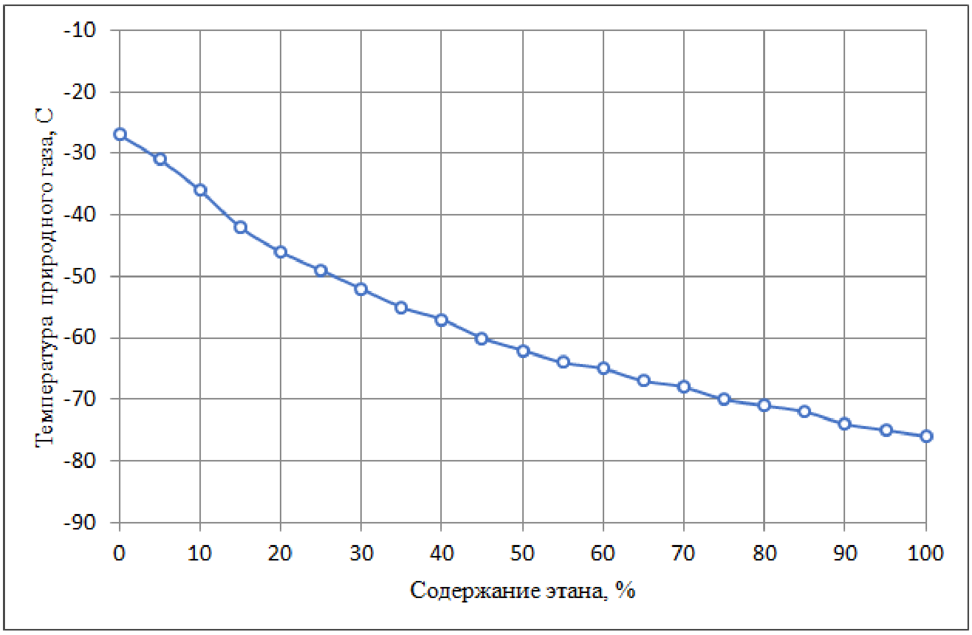


Figure 4.14. Dependence of the natural gas cooling temperature on the ethane content [56]

Reducing the pre-cooling temperature allows redistributing the load between pre-cooling and liquefaction, thereby reducing the load on the main cryogenic heat exchanger and increasing the productivity of the production line. An example is the LNG plant on Sakhalin Island. Although this plant is not located in the Arctic zone, monthly average winter temperature is minus 20 ° C. The Shell DMR liquefaction technology implemented at the plant with a design capacity of 9.6 million tons per year allows reaching a production level of more than 10 million tons annually.

Although the mixture refrigerant system is more complicated than a single-component cooling system, it provides additional flexibility, since the composition of the mixture can be adjusted in accordance with seasonal changes in the atmosphere temperature to minimize energy consumption [56].

Based on the analysis presented above, the DMR system is taken as a technology for the LNG plant.

4.2.5. Equipment layout at the platform

The space area on the upper deck on which the equipment will be installed is approximately 28 thousand m^3.

Since there are no detailed data on the area occupied by the equipment, an analogy method must be used to estimate the required space. The V.S. Nikitin's et al. article [41] provides a summary table for all LNG floating plants. In this table, there is a description of the project "Bonaparte FLNG". A floating plant for this project is planned to be installed offshore Australia. The dimensions of the deck for this floating plant are 400x70. Therefore, the deck area is 2800 m^3. Natural Gas Liquefaction Technology - DMR.

The area and technology of Bonaparte FLNG coincide with the area and technology of liquefaction for the plant considered in this Master Thesis. Hence, we can conclude that the area of the upper deck of the platform in question should be sufficient to accommodate all the equipment. Obviously, with a more detailed design of the platform, more accurate analysis of the area occupied by the equipment should be done, but as an initial assessment, such an analogy seems to be sufficient.

According to Dr Mokhtab [57], the weight of the upper deck for large-scale production can have a mass up to 70 thousand tons.

Thus, the total mass of the platform will be 250 thousand tons.

4.2.5. Determination of the natural period in heave for an FLNG:

In order to avoid the resonance of the vessel in the waves, it is necessary to calculate its eigen period.

A vessel can move in 6 degrees of freedom, and for movement in each degree of freedom, it is necessary to calculate its natural period. However, in case the vessel is moored by a spreading anchor mooring system, the heave motion is the determining movement.

The natural period in heave can be determined by the following equation:

$$T_{heave} = 2\pi \sqrt{\frac{M_a + M}{\rho g \frac{\pi D^2}{4}}} \tag{4.38}$$

where M_a – added mass;

ρ – water density;

D – waterline platform diameter.

Added mass can be determined following the DNV-RP-C205 standard [58]:

$$M_a = \rho C_A A_R L_W \tag{4.39}$$

where C_A – added mass coefficient;

A_R – cross-section area;

According to the calculations, $T_{heave} = 12.2\ s$.

The maximum wave period in the Pechora Sea is 11.4 s. Therefore, the design of the platform seems reliable from the preventing resonance point of view.

4.3. Subsea production system

4.3.1. The main subsea production system components

The main components are:

- Subsea wellhead;
- Manifold;
- Template.

Subsea wellhead performs the same functions as a wellhead for surface wells. However, the design of the subsea wellhead is very different. Subsea wellhead should be designed to withstand large loads created by hydrostatic pressure, waves, flow and so on. Moreover, such subsea wellheads should be able to provide remote control by using ROV. Images of subsea wellhead are presented below [59]:

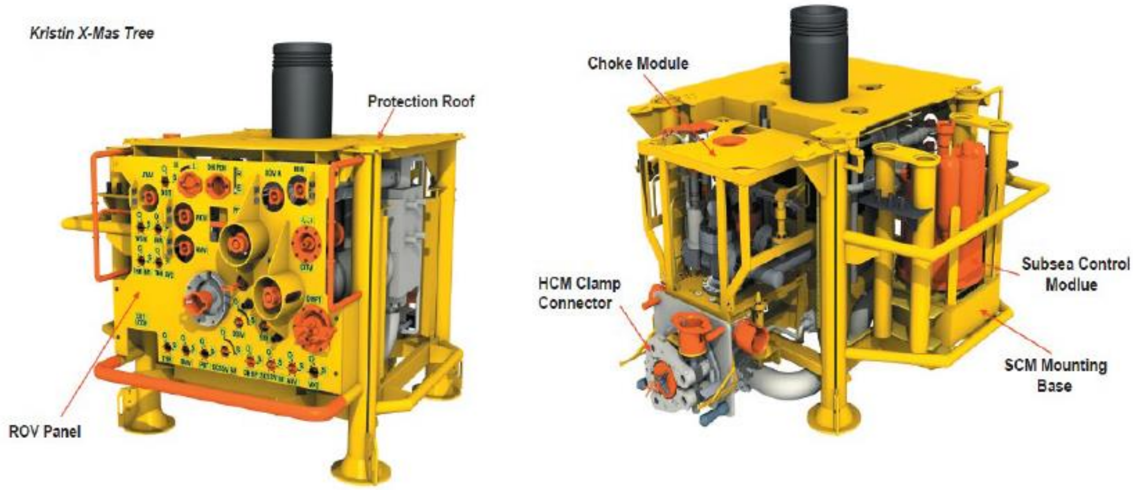


Figure 4.15. Subsea wellhead [59]

A manifold is a system that can be used to collect production from several production wells, as well as to distribute an injection agent before injection into the reservoir. An image of the manifold is presented below [59]:

Figure 4.16. Manifold [59]

The template provides the protection of the manifold and the wellheads from objects that may fall on them, as well as the protection from environmental influences.

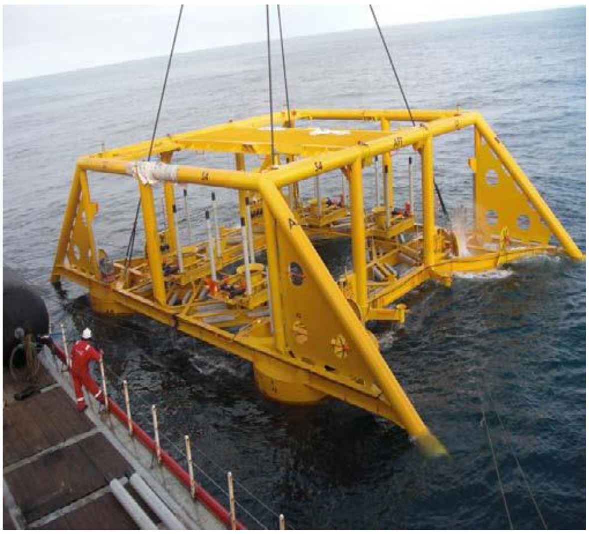


Figure 4.17. Template [59]

It is common to consider template and manifold as one structure, as far as the manifold is inserted into the template and together they can represent a single structure necessary for the collection and distribution of products, as well as protection from environmental influences on wellheads. That term calls integrated production template (IPT).

Figure 4.18. Integrated production template [59]

The approximate dimensions of the integrated 4-slot template [59]:

- Template height - 10 m;
- Template width - 20 m;
- Template length - 20 m.

4.3.2. Subsea production system choosing

In the case of the second development concept consideration, SPS should be chosen.

Dolginskoye field

At the Dolginskoye field, twelve subsea wells should be drilled.

The installation of three 4-slots IPT is proposed in this field.

Since the water depth at the SPS, installation site is approximately 45 meters, and the maximum thickness of hummocks in the Pechora Sea is 18 meters [5], the layout of ITS will be safe from the ice loads point of view.

North-Glyaevskoye field

At the North-Gulyaevskoye field, it is necessary to build ten subsea gas wells, two subsea oil wells and one subsea injection well.

The following SPS layout is proposed:

- The installation of three 4-slots IPT for ten subsea gas wells;
- The installation of one 4-slots IPT for two subsea oil well and one subsea injection well.

The extra slots in the IPT presence make it possible in the future, in case of increase in recoverable reserves, to drill additional wells.

Since the average water depth at the SPS installation site is approximately 30 meters, and the maximum thickness of hummocks in the Pechora Sea is 18 meters, the layout of ITS will be safe from the ice loads point of view.

Although the maximum water depth in the North-Gulyaevskoye field is 30 meters, there is a risk of the impossibility of the whole SPS equipment installation as far as in some locations water depth varies from 20 to 30. In that case, glory holes shall be implemented.

Pomorskoye field

At the Pomeranian field, six subsea gas wells should be drilled.

The installation of two 4-slots IPT for six subsea gas wells is proposed.

The sea depth in the installation area is the same as in the North-Gulyaevskoye field. Therefore, the installation of SPS is possible.

Although the maximum water depth in the North-Gulyaevskoye field is 30 meters, there is a risk of the impossibility of the whole SPS equipment installation as far as in some locations water depth varies from 20 to 30. In. In that case, glory holes shall be implemented.

4.3.3. Glory holes

A Glory hole – is housed within a buried protection structure to prevent ice keel and soil intrusion into the IPT. The protection structure has been designed to be made from either all steel materials or a combination of reinforced concrete and steel [60].

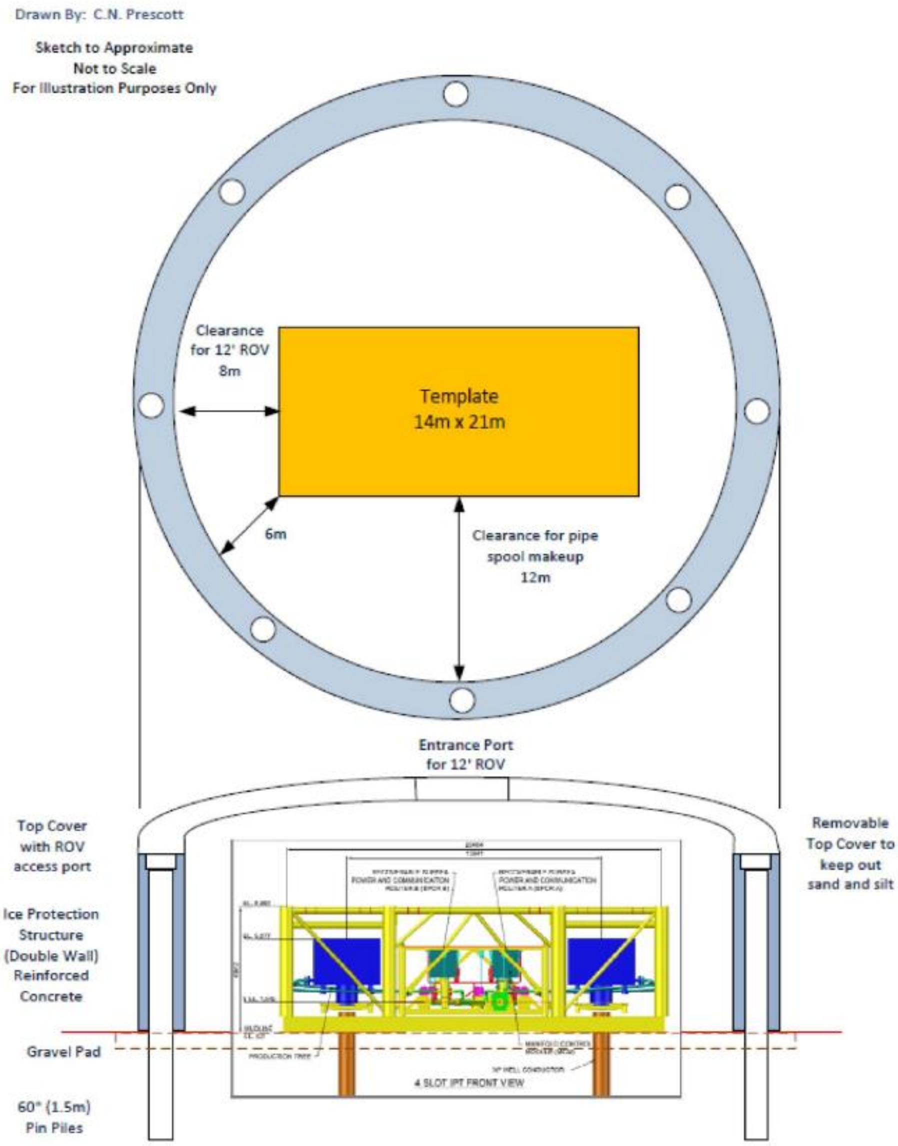


Figure 4.19. Slot Integrated Production Template enclosed within a Buried Protective Structure [60]

4.4. Offloading and transportation

4.4.1. LNG offloading and transportation

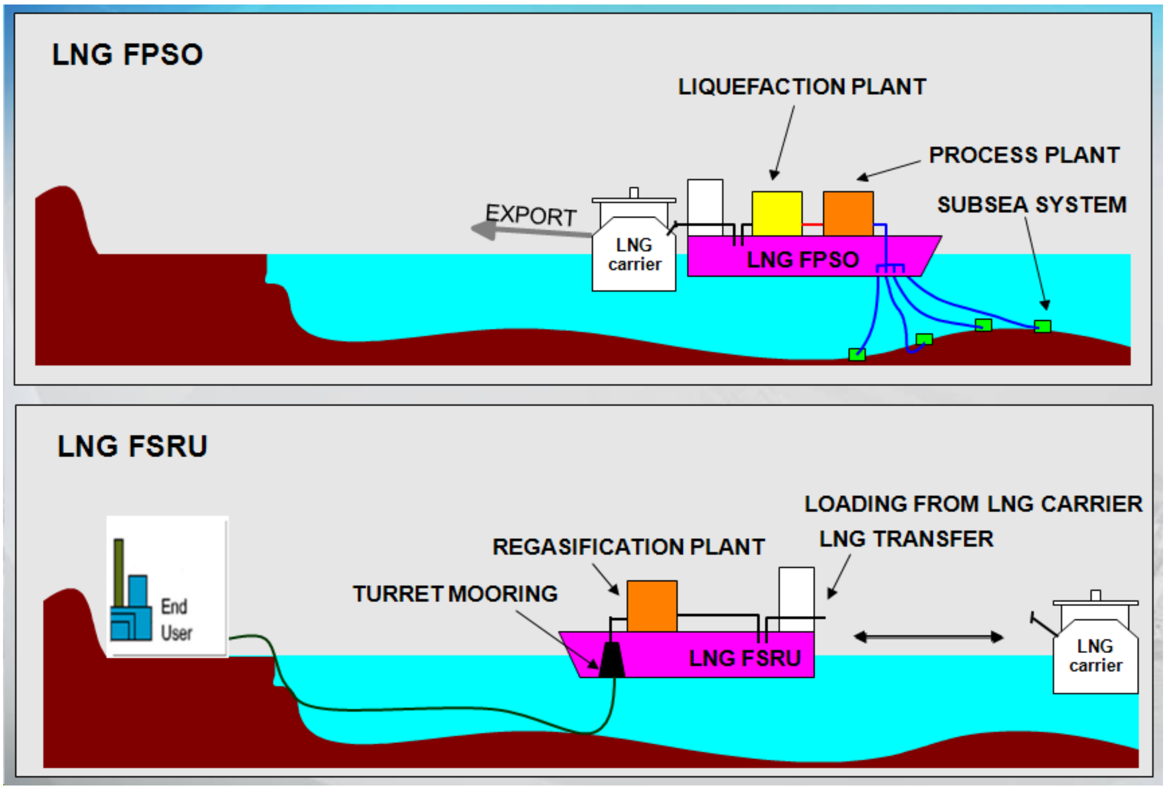


Figure 4.20. Logistic scheme of the FLNG [61]

The most common logistics concept for FLNG is presented above. Liquefied at an FLNG gas is stored in its storage facilities. Further, LNG is regularly shipped to carriers that export it to the point of sale where a regasification platform can be installed. After regasification, gas is piped to the shore and from there is transporting to end consumers.

Due to the uncertainty of the end LNG from the Pechora Sea consumers (it could be Spain (or another European country) or Asian countries via Northern Sea Route), it is not possible to consider the full supply chain in this work. Hence, only the first part of this chain is considered. That is the determination of the method of LNG shipment from the plant to the tanker; and determination of the type of tanker. The cost of the tanker will not be included in the economic assessment in the chapter below since the needed tankers number is unknown. The number of tankers can be determined after determining the LNG market for the Pechora Sea and determining the distance that each tanker will cover.

LNG shipment:

There are two main ways to transfer LNG:

- Side-by-side offloading;
- Tandem offloading system.

Side-by-side offloading uses Loading Arm facility for offloading operation to a ship alongside FLNG. Since two floating vessels are very close during offloading operation, it is crucial to control relative motions between the two vessels with state-of-the-art position monitoring systems to monitor both the position and the velocity of the LNG carrier. In order to ensure the possibility of safe using this type of shipment, the wave height should not exceed 1-3 meters.

Tandem offloading system allows an FLNG-to-LNG carrier transfer of LNG in a tandem configuration. By utilizing Dynamic Positioning system on the LNG carrier and heading control on the FLNG, the LNG transfer operation can be carried out even in harsh weather conditions. Hydrodynamic analysis tools are used for a set of environmental load cases to verify feasibility. Since by using of such the distance between LNG carrier and FLNG can be 45-80 from the plant, tandem offloading allows offloading to LNG carrier in more rough sea conditions and offloading operation is permitted for significant wave height up to 4-5m [61].

For the LNG plant considered in this work, it is proposed to use the tandem shipping system proposed by Bluewater. When using such a system, the tanker is attached to the plant by using a steel rope. LNG is shipped via special flexible cryogenic pipes. In addition to holding the vessel with a steel rope, the vessel is also holding in place by using a Dynamic Positioning System. Such a system guarantees the safety of the shipment process. During shipment, the tanker is located at a distance of 80 meters from the plant. This fact allows shipment at a wave height of up to 5.5 meters [62].

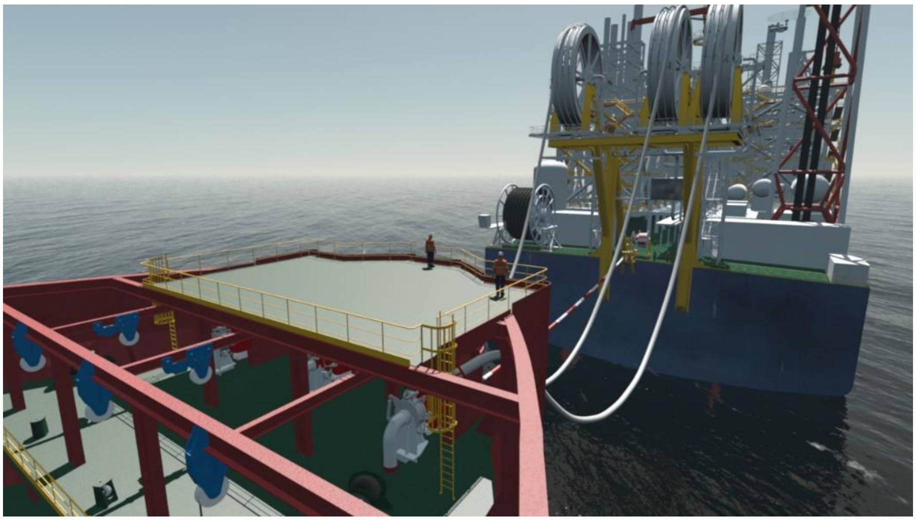


Figure 4.21. Tandem offloading system, designed by the Bluewater company [62]

LNG transportation

To transport LNG, an Arctic vessel that can move in harsh weather and ice conditions is required. For the LNG transportation in this work, the Yamalmax tanker developed for the Yamal-LNG project is proposed. Such a tanker is an ARC7 ice-class tanker (according to the Russian classification), which allows year-round navigation without icebreaking assistance. The development of the Arctic tanker was attended by Russian and foreign classification societies, leading design and engineering institutes, shipyards and ship-owners.

The main characteristics of the tanker are:

- Cargo capacity is approximately 170 thousand m^3 of LNG;
- Power plant capacity of 45 MW;
- Speed in open water - 19.5 knots;
- Speed during the course in the ice with a thickness of 1.5 meters - 5.0 knots;
- The main type of tanker fuel is LNG;
- A dual-fuel diesel-electric propulsive system with three Azipod units.
- A dual-action system is applied - the front part is adapted for navigation in open water and thin ice conditions, and the stern is optimized for independent navigation in severe ice conditions.

Figure 4.22. The model of the proposed carrier [63]

The maximum gas production in the fields cluster is 9 billion m^3/year.

This value corresponds to the average daily production of 24 million m^3/day of natural gas. If we assume that during liquefaction natural gas is compressed 600 times, the average daily production of LNG is 41,095 m^3/day.

With such a rate of LNG production and using the proposed carrier, offloading should be made once in four days.

The storage volume is 260 thousand m^3. Such storage volumes will make it possible to store LNG in the case of unforeseen logistical circumstances (for example, a carrier breakdown).

4.4.2. Oil offloading and transportation

Oil offloading

By analogy with the Prirazlomnaya platform, two CUPON devices (a complex device for direct oil offloading), located on the north-eastern and south-western parts of the platform, can be installed on the DS platform for oil offloading. Oil is shipped through one of the devices, depending on the direction of external loads (wave, ice drift, currents, wind). To prevent an oil spill during the offloading operation, the shipping line is equipped with a stop emergency system and close emergency system.

Before the start of offloading operations, carriers equipped with a bow loading system carry out non-contact mooring. To exclude an involuntary collision with the platform, they are equipped with a dynamic positioning system.

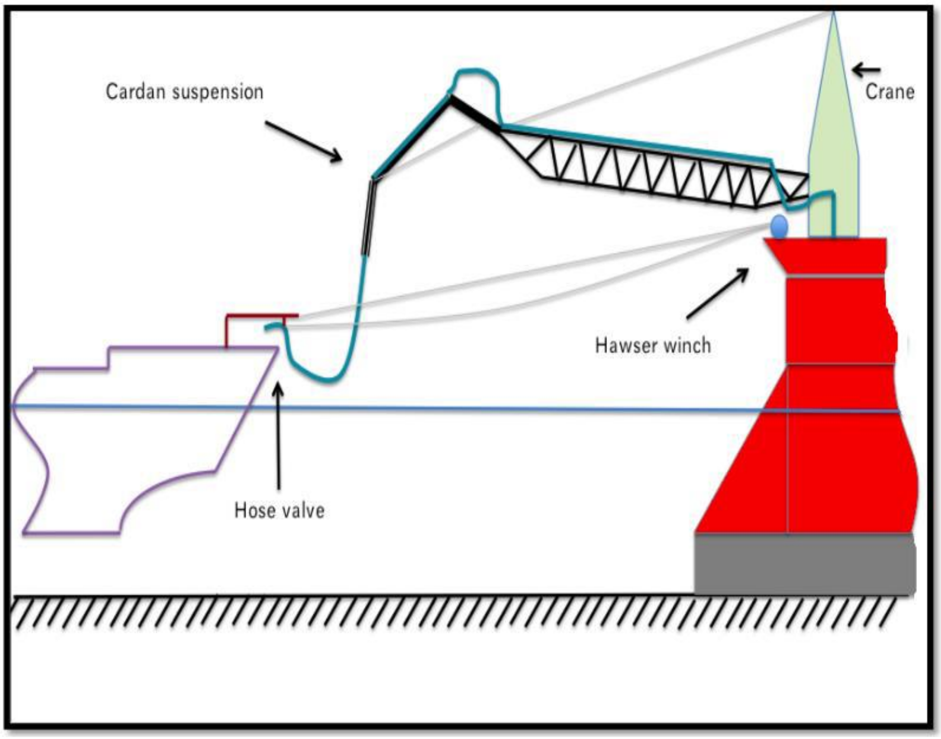


Figure 4.23. CUPON [64]

<u>Oil transportation</u>

A PANAMAX class tanker with a deadweight of 100,000 tons is proposed for the transportation of oil.

Tanker characteristics:

- Speed in open water - 30 knots;
- Speed during the course in ice - 7 knots;
- Draft – 6 m.

With maximum oil production of 4.1 million tons/year (11,232 tons/day) and using the proposed tanker, offloading should be done once in nine days.

For icebreaker tanker assistance, the use of the Taimyr class nuclear-powered icebreaker is proposed.

5. Economic assessment of the concepts' feasibility

5.1. Theory

In order to assess the economic viability of concepts and choose the most appropriate concept, the evaluation of the net present value (NPV), profitability index (PI) and profit margin are necessary.

5.1.1. Net present value

Net present value is the primary indicator of project performance that investors are interested in. In contrast to the payback and profitability periods, it gives the absolute value of the potential profit, which means that it is not related to other values. Its value lies in the simplicity of calculations and easiness in understanding.

In general order, the value of the net present value is determined as the sum of all the discounted values of the future payment flows reduced to today and is determined as follows [65]:

$$NPV = -I + \sum_{t=1}^{N} \frac{CFt}{(1+r)^t} \tag{5.1}$$

where I – initial investments;

CFt – cash flows, which are the sums of cash inflows and outflows in a period t = 1..N;

r – discount rate.

Depending on this indicator value, the investor evaluates the attractiveness of the project.

If:

- $NPV > 0$, then the investment project is profitable;
- $NPV = 0$, then the project will bring neither profit nor loss;
- $NPV < 0$, then the project is unprofitable and promises losses to the investor.

5.1.2. Profitability index

According to the American professor Anthony Atkinson, the profitability index (PI) is a variation of the net present value method, which is calculated as the ratio of the sum of the discounted cash flows to the discounted value of the outflows. The profitability index can be calculated as follows [66]:

$$PI = \sum_{t=1}^{N} \frac{NCF}{I} \quad (5.2)$$

где NCF – Net cash flow.

Profitability Index is a more accurate and conservative measure of project profitability than NPV. This assessment is especially useful for projects with a large number of investments [66].

If:

- $PI > 1$, then the project is acceptable;
- $PI < 1$, then the project is unacceptable;
- $PI = 1$ then the project is neutral.

5.1.3. Profit margin

Profit Margin is a profitability ratio calculated as the ratio of net income to all sales revenues or the ratio of net profit to revenue. Profit margin is a handy indicator, especially during the projects in similar conditions comparison. A higher profit margin indicates a more profitable project. Profit margins are usually indicated as a percentage [67].

Profit margin can be calculated as follows:

$$PI = \frac{Revenue - OPEX - CAPEX}{Revenue} \quad (5.3)$$

5.2. Initial data for the calculations

Two development concepts of the Dolginskoye, North-Gulyaevskoye and Pomorskoye fields are considered.

5.2.1. The first concept

- Installation of five production GBS platforms: one platform is the centre of production, the technological complex and oil storage are installed on it, and four platforms are satellite platforms without storage and the technological complex. Satellite platforms are installed on the base of the monopod type.
- Installation of an LNG plant on the GBS platform.
- Pipelines with a total length of 213.5 km.

A drilling schedule is presented below:

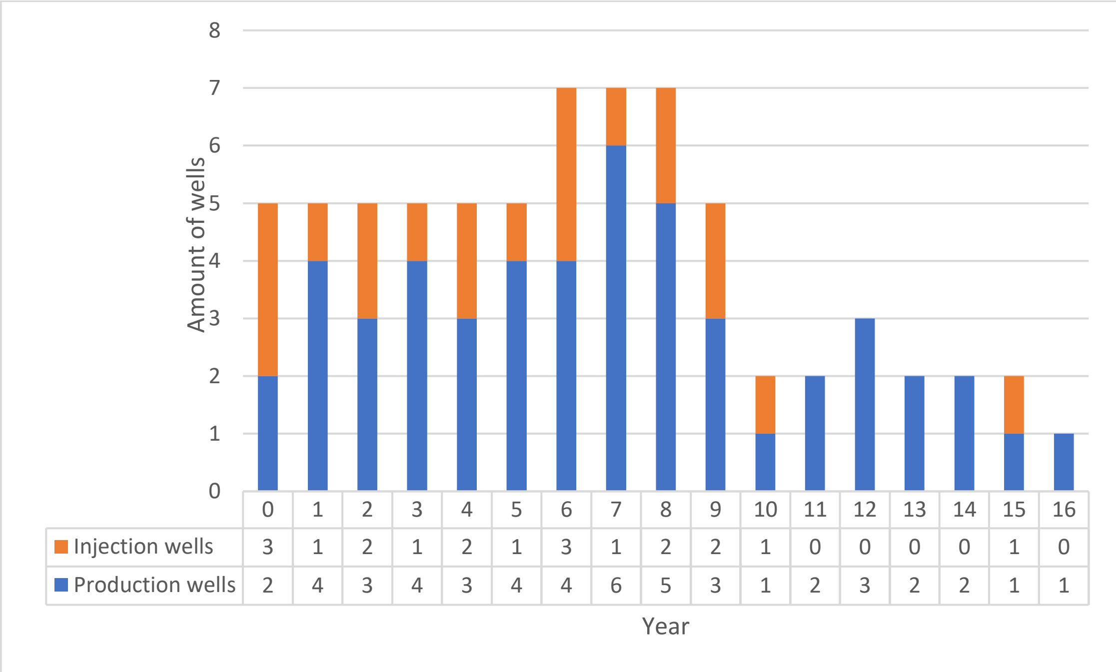


Figure 5.1. Drilling schedule, the first concept

Revenue was calculated based on production profiles obtained in the chapter "Oil and gas production profiles".

Table 5.1. Initial data [13, 20, 30, 42, 48, 68]

Initial data		
Discount rate	12	%
Income tax rate	20	%
Property tax rate	2.20	%
MET rate (oil)	43	$/tons
MET rate (gas)	3	$/ths m^3
Depreciation rate	3	%
Oil barrel price	70.00	$
Investments	6 308	mln $
Oil OPEX	37	$/tons
Gas OPEX	43	$/ths m^3

Continuation Table 5.1.

Producing well cost	19	mln $
Injection well cost	17	mln $
DS topside cost	650	mln $
Sattelite topside cost	436	mln $
LNG topside cost	1071	mln $
Monocone GBS cost	130	mln $
Caisson GBS cost	250	mln $
1 km pipeline cost	1.14	mln $

5.2.2. The second concept

- Installation of two GBS platforms: one platform is the centre of production, the technological complex and oil storage are installed on it, and one platform is satellite platforms without storage and the technological complex. Sattelite platform is installed on the base of the monopod type.
- Installation of FLNG at the approximate water depth of 70 m;
- Nine ITS installation.
- Pipelines with a total length of 193 km.

A drilling schedule is presented below:

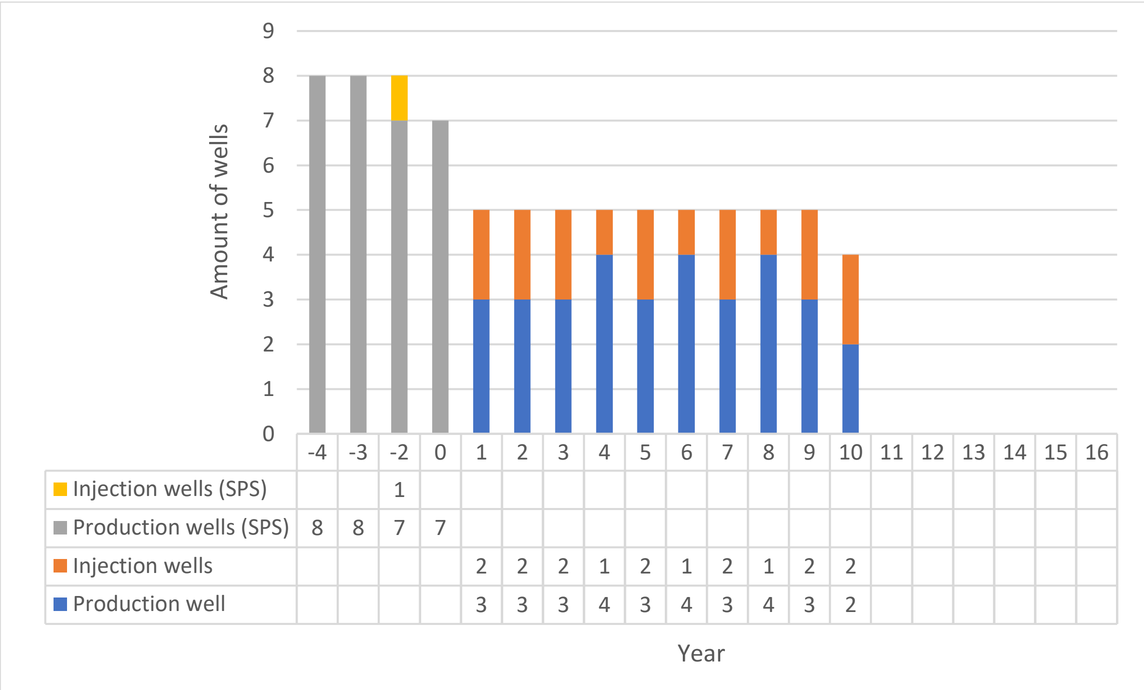


Figure 5.2. Drilling schedule, the second concept

Additional initial data should be introduced for the second concept:

Table 5.2. Additional initial data [13, 20, 30, 42, 48, 68]

Production subsea well cost	12	mln $
Injection subsea well cost	11	mln $
FLNG hull cost	286	mln $
SPS cost	103	mln $
Jack-Up platform cost	100	ths $/day

5.3. Calculation results

The calculation results for both concepts are presented below:

Table 5.3. Calculation results

Value, mln $	Concept 1	Concept 2
Revenue	**51094**	**49200**
CAPEX	**6308**	**4105**
Topsides	3464	2021
Platform bases	1260	657
Drilling	1339	1206
Pipelines	244	221
OPEX	**20174**	**19253**
Production operational cost	8059	7502
Taxes	12115	11751
NPV	3161	4945
IRR	**17%**	**21%**
PI	**0.4**	**1.2**
Profit margin	**48%**	**53%**

During the analysis of the table above, it can be observed that the second concept is much more profitable.

Although the NPV in both concepts is positive, the profitability index for the first concept is less than one. This means that this concept requires too much investment.

The oil price indicator's sensitivity analysis for NPV and PI is presented below:

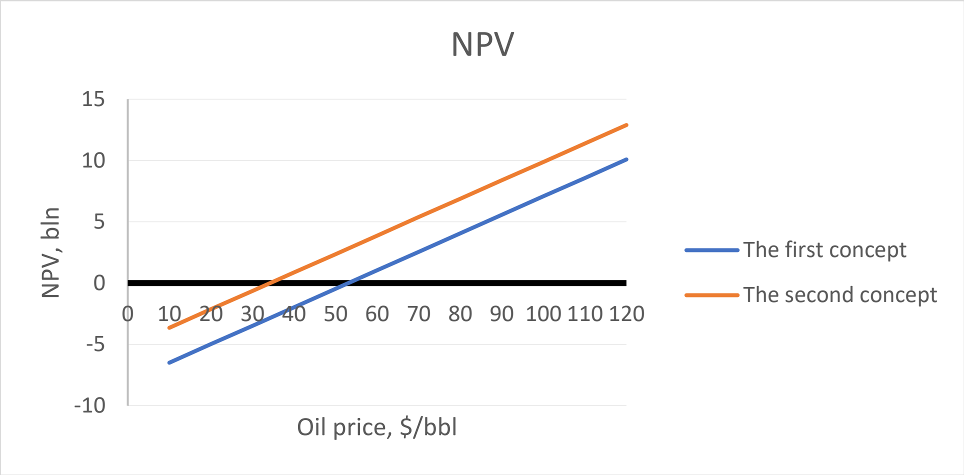


Figure 5.3. The oil price indicator's sensitivity analysis for NPV

It can be seen that the break-even price for the first concept is 52.5 $ per barrel. The break-even price for the second concept is 35 $ per barrel.

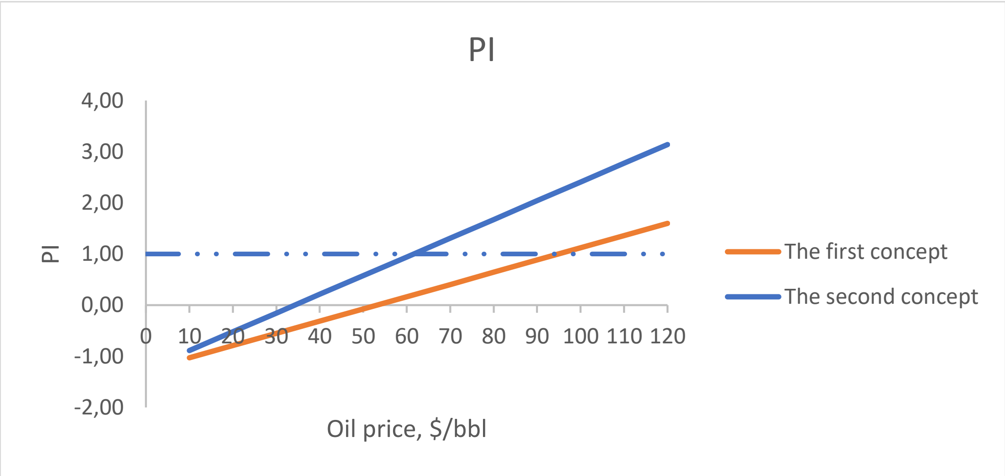


Figure 5.4. The oil price indicator's sensitivity analysis for PI

Profitability index is greater than 1 with oil prices above 95 $ per barrel for the first concept and with oil prices above 60 $ per barrel for the second concept.

Intermediate conclusions

Based on economic analysis, it becomes evident that the second concept is much more profitable. It can be explained by the fact that for the second concept, it is not necessary to install a large number of expensive GBS platforms. Moreover, subsea well drilling is cheaper due to the simplification of a well design. Thus, capital investments are significantly reduced. Also, since in the second concept, the ORF and GRF are lower, revenue is reduced, but OPEX is reduced, which also plays a role in the resulting economic factors.

Conclusions

In the course of this Master Thesis, a development concept for the group of the following fields was designed:

- Dolginskoye field;
- Severo-Gulyaevskoye field;
- Pomeranian field.

According to the designed concept:

- The total recoverable oil reserves in the group of fields are 63.21 million tons;
- The total recoverable gas reserves in the group of fields are 119.9 billion m^3.

The concept provides the following infrastructure solutions:

- Installation of two platforms: one platform is the centre of production, the technological complex and oil storage are installed on it, and one platform is a satellite platform without storage and the technological complex. The satellite platform is installed on the base of the monopod type.
- Installation of a buoy-type FLNG at the approximate water depth of 70 m in the northern part of the Dolginskoye field.
- Installation of subsea production systems at the North part of the Dolginskoye field (three 4-slots ITS), Pomorskoye (two 4-slots ITS) and North-Gulyaevskoye fields (four 4-slots ITS).
- Pipelaying of five pipelines with a total length of 193 km.

The calculations of ice and wave loads on GBS platforms (caisson, monopod and monocone) type were carried out. According to the calculations, in order to minimize the environmental loads, it is necessary to use a caisson-type platform for the DS platform with a wall inclination of 45^0 and a monopod type platform with a wall inclination of 45^0 for the DC platform. Loads are presented below:

Table 6.1. Wave and Ice loads on the chosen platforms

Platform	Platform type	Wall inclination	F, MN	
			Wave loads	Ice loads
DS	Caisson	45	208.46	185.40
DC	Monocone	45	51.47	58.53

Due to the lack of infrastructure for gas transportation in the region of the Pechora Sea and the Nenets Autonomous Okrug, it is proposed to install a buoy-type FLNG. It is proposed to use an Arc7 Yamalmaks ice-class tanker for the further transportation of LNG. Such design of the FLNG was chosen since it has sufficient characteristics for operation in the Pechora Sea ice and wave conditions (following the calculations of the Rubin design bureau). A spread anchor mooring system with 32 large-diameter links was the proposed station-keeping system.

DMR technology was chosen as the liquefaction technology. Such technology allows the production of LNG in large volumes. Moreover, the Arctic conditions expand the capabilities of the plant due to the low average atmospheric temperature.

The tandem technology developed by Bluewater was chosen for LNG offloading.

By analogy with the Prirazlomnaya platform, the CUPON system was chosen as the offloading system.

The PANAMAX tanker was chosen for oil transportation. Icebreaking assistance is required in winter periods. A Taimyr-class nuclear-powered icebreaker was chosen as a vessel for icebreaking assistance.

The results of the economic assessment showed that decisions are economically feasible.

Recommendations for the future works

This Master Thesis is a preliminary assessment of the proposed concept implementation possibility, which describes the most critical aspects of the development. In the future works, it is necessary to conduct a detailed analysis of each of the aspects to approve the decisions made.

Special attention is recommended to be paid to the following issues:

- Field development simulation in specialized software packages;
- A detailed description of the logistics chain, including an analysis of potential sales markets;
- Detailed calculation of multiphase pipelines;
- Clarification of the subsea production system with appropriate calculations.

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