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Writer: **Aryslan U. Biktiakov**	.... (Writer's signature)

Faculty supervisor: **Professor Ove Tobias Gudmestad (University of Stavanger)**
Professor Muk Chen Ong (University of Stavanger)

External supervisor(s): **Professor Anatoly Borisovich Zolotukhin (Gubkin University)**

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ABSTRACT

For a few last decades, the Arctic region is considered to be very wealthy in terms of oil and gas resources. Initial estimations show that roughly 100 billion tonnes of oil and gas reserves might be accumulated under the surface of the Arctic region *(Kontorovich, 2015)*.

Beginning with the general description of the most explored oilfields located in the southeastern part of the Barents Sea (Pechora Sea), the project comprehensively considers conceptual development of the Medynskoe-more oilfield by utilizing the IRGBS "Prirazlomnaya", in particular:

- development of the optimal oil production strategy for the oilfield;
- selection of the appropriate offshore structure;
- selection and justification of the possible oil transportation solution;
- design and construction of the subsea pipeline from the Medynskoe-more oilfield to the IRGBS "Prirazlomnaya";
- analysis of the processing, storing and offloading systems in the IRGBS "Prirazlomnaya".

Special emphasis is done on a detailed elaboration of a subsea pipeline that should be able to withstand harsh environmental conditions in the Arctic region, including ice presence (formation of stamukhas) and shallow waters (substantial hydrodynamic loads from wave and current). Aspects such as pipeline design, on bottom stability and pipeline trenching are reasonably considered.

Moreover, risk analysis procedure is provided by applying hazard identification method (HAZID) with the subsequent bow-tie diagrams construction for the most dangerous risks.

In order to evaluate the economic feasibility of the proposed project, the cost-effective analysis is fulfilled.

Eventually, a conclusion and recommendations for future work are presented based on the technical and economical results.

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Without whole time support, highly suitable recommendations and additional information from the Ralif R. Gil'fanov in Gazprom neft company, my work would not be totally finished. My work has become more mature because of his involvement in the project.

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LIST OF ABBREVIATIONS

API	*AMERICAN PETROLEUM INSTITUTE*
ARCO	*ARCTIC OIL*
BTOE	*BILLION TONNES OF OIL EQUIVIVALENT*
DNV-RP	*"DET NORSE VERITAS", THE NORWEGIAN VERITAS RECOMMENDED PRACTICES*
DP	*DYNAMIC POSITIONING*
FAR	*FATAL ACCIDENT RATE*
FPSO	*FLOATING, PRODUCTION, STORAGE AND OFFLOADING*
GBS	*GRAVITY BASED STRUCTURE*
GIR	*GROUP INDIVIDUAL RISK*
HAZID	*HAZARD IDENTIFICATION*
IR	*INDIVIDUAL RISK*
IRGBS	*ICE RESISTANT GRAVITY BASED STRUCTURE*
IRPA	*INDIVIDUAL RISK PER ANNUM*
LLC "GNS"	*LIMITED LIABILITY COMPANY "GAZPROM NEFT SHELF"*
MWL	*MEAN WATER LEVEL*
MTOE	*MILLION TONNES OF OIL EQUIVIVALENT*
NORSOK	*"NORSK SOKKELS KONKURRANSEPOSISJON"- THE NORWEGIAN INITIATIVE TO REDUCE COST ON OFFSHORE PROJECTS*
SMYS	*SPECIFIED MINIMUM YIELD STRENGTH*

LIST OF SYMBOLS

α_c	*CURRENT ANGLE OF ATTACK*
α_S	*WAVE ANGLE OF ATTACK*
B	*BUOYANCY FORCE*
f	*MOODY FRICTION FACTOR*
F_D	*DRAG FORCE*
F_I	*INERTIA FORCE*
F_L	*LIFT FORCE*
J	*MOMENT OF INERTIA*
K	*KEULEGAN NUMBER*
M	*RELATION BETWEEN U_c AND U_s*
r	*RELATIVE ROUGHNESS*
Re	*REYNOLDS NUMBER*
S_H	*HOOP STRESS*
S_L	*LONGITUDINAL STRESS*
T_n	*WAVE PARAMETER*
T_p	*PEAK PERIOD*
T_u	*ZERO-UP CROSSING PERIOD*
U_s	*SIGNIFICANT WATER VELOCITY*
V_e	*EROSION VELOCITY*
W_s	*SUBMERGED WEIGHT*

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1. INTRODUCTION AND OBJECTIVES

For decades, the main area for oil and natural gas production in Russia was the West Siberian region with its giant onshore fields. They contain enormous quantities of hydrocarbons with peak production rates taking place in the end of 1980's *(Heinkel, 1997)*. Because of intensive oil and natural gas production, hydrocarbon fields are being depleted. New areas of hydrocarbon reserves should be discovered in order to keep production rate at the required level. Exploration and production have been intensified during the last 10-15 years in offshore areas, leading to move into deeper waters and more environmentally severe conditions.

Russian Arctic is a good example of a zone with harsh environmental conditions. Initial estimations show that Russia poses tremendous reserves of hydrocarbons in the Arctic region and relying on up to date information reserves are equal to 100 billion tonnes of oil equivalents *(Kontorovich, 2015)*.

The most explored part of the Russian Arctic is the southeastern part of the Barents Sea. A lot of surveys were conducted in that area in 1980's *(Stoupakova, 2013)*. At that time, substantial deposits of oil were discovered in the Pechora Sea, including such perspective oilfields as:

- Dolginskoye, Prirazlomnoye, Medynskoe–more, Varandey–more as well as Vostochno-Gulyaevskoe and Severo-Gulyaevskoe oilfields.

Currently, only Prirazlomnoye oilfield is put in the production stage, by applying IRGBS "Prirazlomnaya" *(Digges, 2014)*. Concerning other mentioned fields, most of them are in the development stage now and effective development concepts are to be found.

The main objectives of the work are to analyze the technical possibility and economic feasibility of the Medynskoe-more oilfield development through the existent processing, storing and offloading capacities in the IRGBS "Prirazlomnaya".

The development strategy for the Medysnkoe-more oilfield is made taking into account the current processing, storing and offloading capacities of the Prirazlomnaya platform.

By taking into account the geographical and metocean conditions in the Medynskoe-more oilfield, the justified selection of the appropriate type of offshore structure is provided. Comprehensive consideration is paid to the design, construction and operation of the subsea pipeline that is implied to be laid on the trench on the seabed in order to connect two oilfields.

Risk analysis is carried out, with composing of bow-tie diagrams for most dangerous ones.

Moreover, the economic benefits are considered and recommendations for future work are given.

2. ENVIRONMENTAL CONDITIONS IN THE PECHORA SEA

2.1 Main parameters of the Pechora Sea

It is important to consider environmental conditions in the Pechora Sea region, according to them; special technical and technological solutions will be proposed and applied. The main environmental conditions are shown in Table 2.1.

Table 2.1 Main environmental conditions in the Pechora Sea *(*Gudmestad et al.,1999)

Parameter	Value
Latitude	70°N
Max. wind gust, m/s	41
Min. air temperature,°C	-48
Significant wave height, m (at 45 m water depth)	6.2
Currents velocity, m/s	1
Period of water freezing	Nov. (rarely Oct.) – Easter part of the Sea
Clearing	June
Average open water, days	110
Multi-year ice, %	-
Max. level of ice thickness, m	1.3
Rafted ice thickness, m	2,6 (double of ice thickness)
First-year ridge thickness, m	12-18
Multi-year ridge thickness, m	-

2.2 Metocean data

For more than 70 years metocean data and statistics of the Pechora Sea have been collected and analysed by several meteorological stations.

2.2.1 Air temperature and Wind

The air temperature for approximately 230 days is below 0°C while average annual temperature fluctuates from -2.9 to -5.6 °C, depending on the location within the Pechora Sea. The lowest temperature which has ever been recorded in Varandey is -48 °C, while the warmest month tends to be July with its maximum year temperature equal to +26°C (Gudmestad et al.,1999).

The wind conditions in the Pechora is not the same along the year and change with season. In the winter period, wind blows stronger and southwest direction is prevailed, whereas in the summer period, the wind is weaker and north, northwest directions are prevailed. According to the 50-years statistics, the wind can reach extreme values of 26 m/s with a duration of 6-7 hours (Gudmestad et al.,1999). It should be noted that, among the other Arctic seas, wind conditions in the Pechora Sea is the mildest.

2.2.2. Waves and currents

Wave conditions in the Pechora Sea are influenced by a few factors. The Pechora Sea is delineated by the Vaigach Island in the east, by the Kolguev Island in the west and by the Novaya Zemlya archipelago in the north, that eventually protect the area of the sea from very large waves. Shallow water depth also affects the wave conditions in the Pechora Sea.

In October-November, during storms season, waves come from the northwest direction and at their maximum values, they reach 11.5 meters wave height at regions with 20-30 meters water depth. Throughout the year, the mean value of wave height is 2-3 meters, with the mildest wave condition in the summer period of 1-2 meters wave height *(Subbotin, 2015).*

Considering 100-year wave conditions connected with the water depth, these data are given in Table 2.2.

Table 2.2 100-year (maximum) wave conditions in the Pechora Sea (*Barents Portal, 2014)*

Water depth, m	Hs, m	Tp, s
10	6.4	10.7
15	6.7	10.9
20	6.9	11

In the Pechora Sea, there are three main currents:

- Kalin
- Kolguev
- Litke

The velocity of the currents varies from 0.02 to 0.05 m/s. Moreover, current velocity affects the metocean and ice conditions inside the Pechora Sea. Commonly, tide currents are directed from the southeast to northwest and conversely during ebb tides. The 100-year velocity of the currents is 0.6 – 0.65 m/s (*Barents Portal, 2014*).

2.3 Soil conditions

The soil data is of great importance. The maximum loads on the seafloor created by GBS offshore structures or subsea pipelines due to weight and additional loads produced by waves; currents and ice can be estimated.

The major part of the Pechora Sea and the shoreline of the Novaya Zemplya archipelago have soft seabed soil covered by sandy-gravel mud *(Barents portal, 2014)*. However, concerning oilfields, it should be noted that in the area of the Prirazlomnoye and Dolginskoe oilfields, the seabed might be characterized as hard bottom, consisting of sand and muddy sand, while as the sea bottom in the area of Varandey-more and Medynskoe-more oilfields is soft and viscous. The seabed conditions in the Pechora Sea are shown in Figure 2.1.

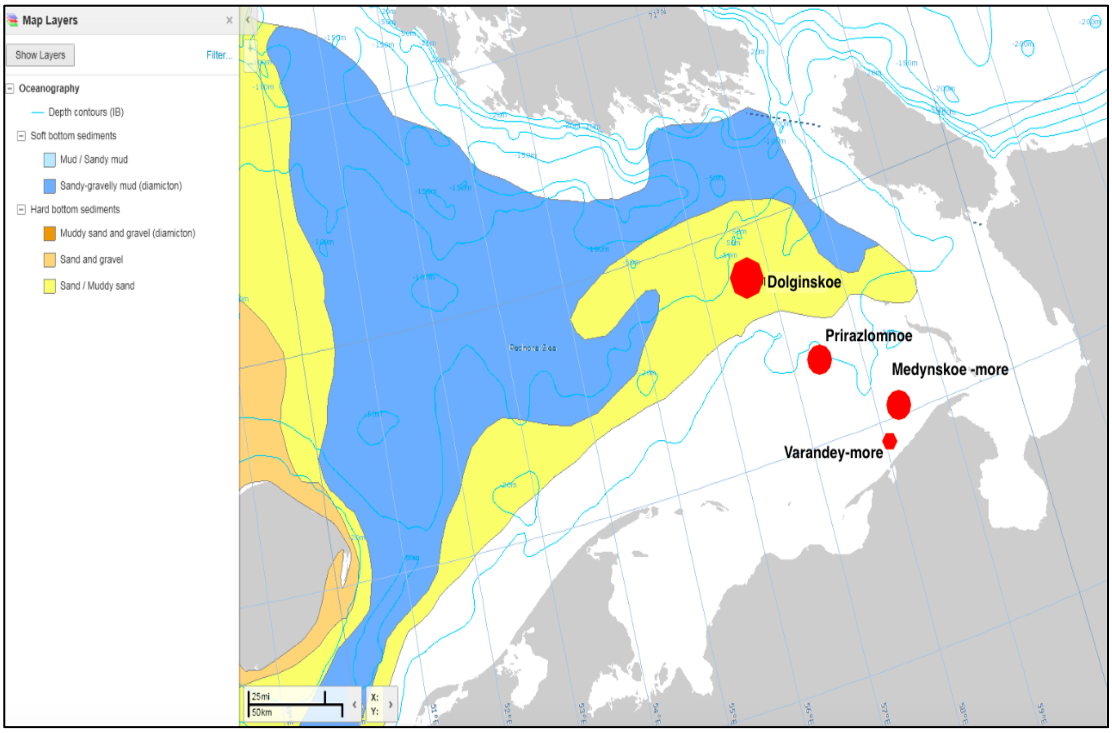

Figure 2.1 Seabed conditions in the Pechora Sea. ***(Barents Portal, 2014)***

2.4 Ice conditions

Considering the map of the ice presence with maximum and minimum ice extent, shown in Figure 2.2, it is clear that Dolginskoe, Prirazlomnoye, Medynskoe-more and Varandey-more oilfields are located in the areas which are covered with ice during the winter period. Averagely, the sea is free of ice approximately for 110 days.

Most of the ice located in the Pechora Sea is locally originated, but sometimes ice from Kara Sea might be found because of the ice exchange between the seas. Ice usually start to grow in October-November and grows until February, whereas the ice fracturing process begins in April-June depending on the location and eventually at the second part of June it is entirely broken *(Barents Portal, 2014)*

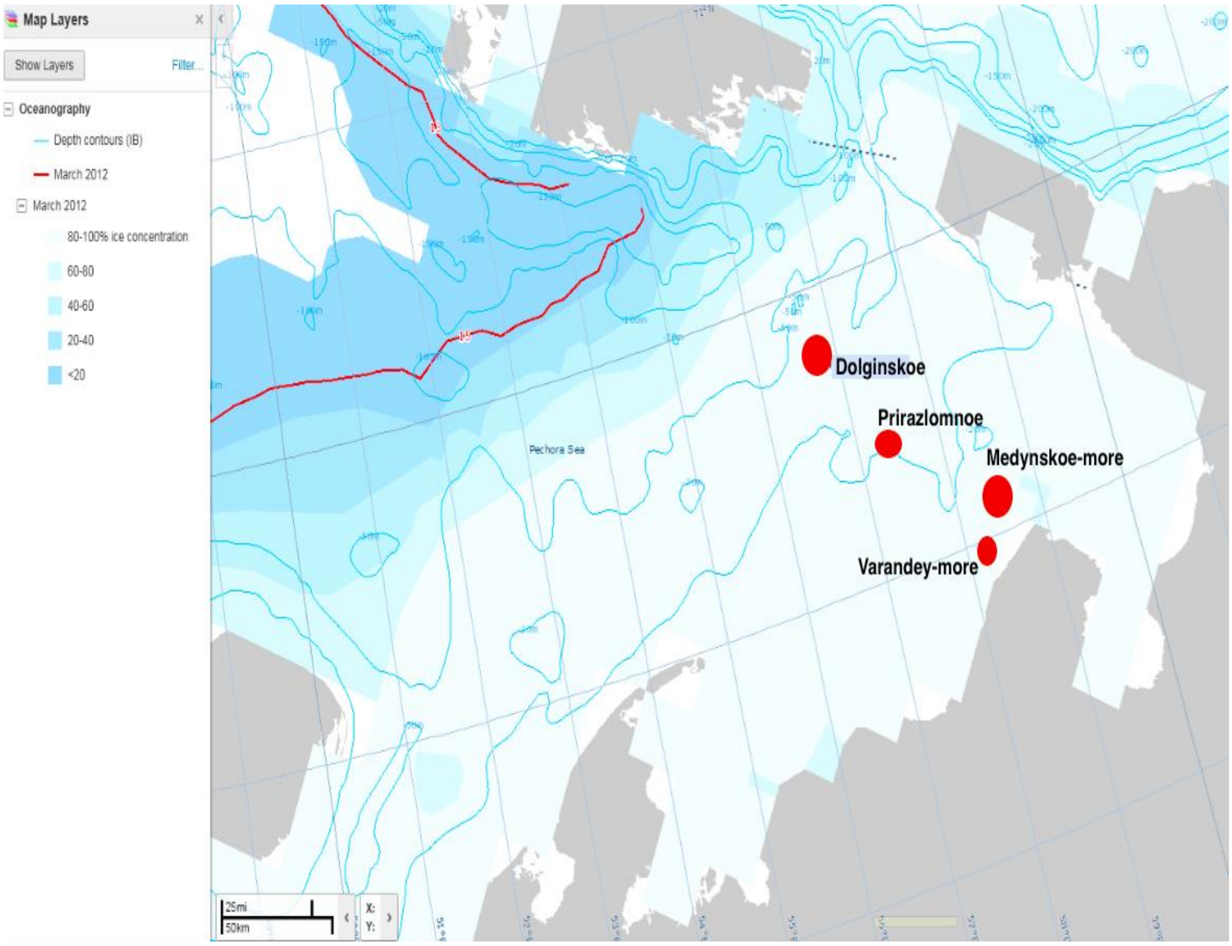

Figure 2.2 Ice arrangement in the Pechora Sea. ***(Barents Portal, 2014)***

3. OILFIELDS IN THE PECHORA SEA

3.1 Description of the oil fields

In the present chapter four oilfields located in the Pechora Sea, are going to be investigated generally:

- Prirazlomnoye oilfield;
- Dolginskoye oilfield;
- Medynskoe–more oilfield;
- Varandey–more oilfield.

The oilfields arrangement in the Pechora Sea is shown in Figure 3.1.

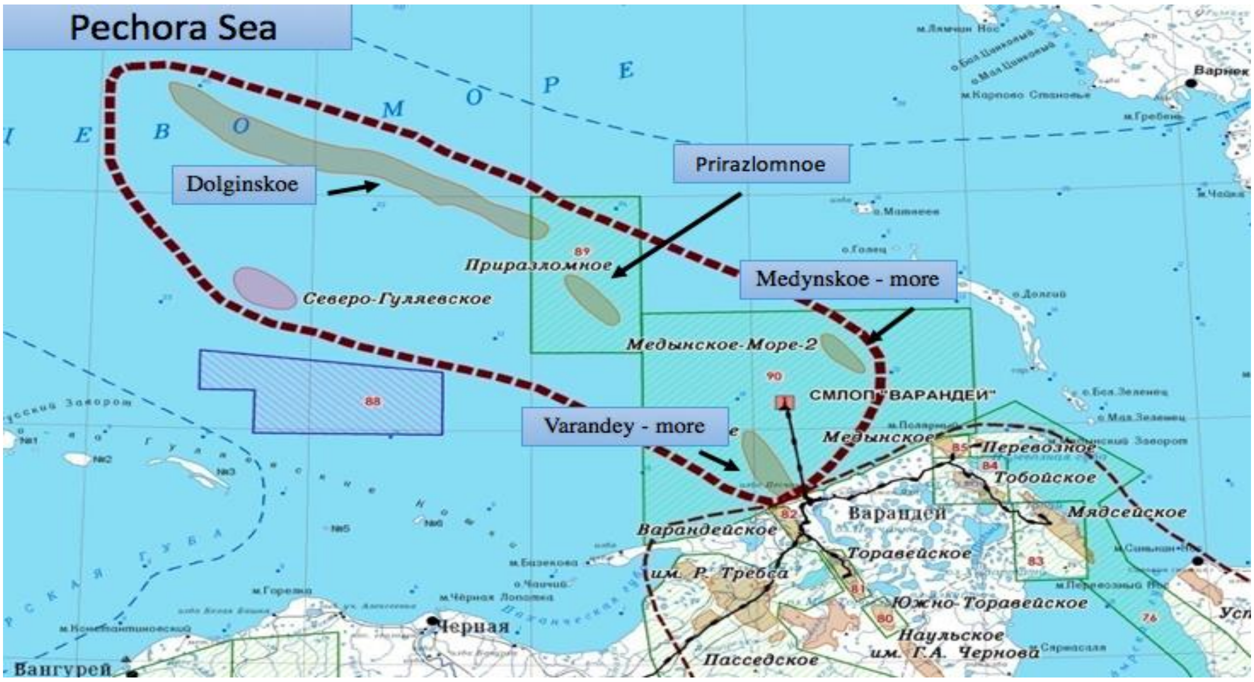

Figure 3. 1 The oilfields lay-out in the Pechora Sea (Oil and North, 2011)

All the mentioned oilfields are of great interest to the oilfields operators, as extractable reserves are estimated to be in a quite high level, varying from approximately 40 million tons of oil in Varandey–more up to 240 million tons of oil in the Dolginskoye oilfield *(Barents observer, 2010).*

Prirazlomnoye oilfield

The Prirazlomnoye oilfield is situated in the southeastern part of the Barents Sea. This area also called the Pechora Sea. The distance from the shoreline reaches 60 km. The closest big city is Naryan-mar, located at a distance of approximately 230 km away from the Prirazlomnaya platform. The oilfield was explored in 1989 and in 1993 the developing license was given to the Rosneft company. Later, by circumstances, the license was transferred to the Sevmorneftegas Company. Sevmorneftegas was renamed as LLC GNS and is belonging to the Gazprom Neft. The Prirazlomnoe oilfield is characterized by following features:

- Extractable oil reserves compose 72 million tons of oil
- Water depth is varying from 18 to 21 meters
- The pay zone formation is found in the depth of 2350 -2550 meters
- The oil density ranges from 910 to 955 kg/m^3 and is related to heavy oils
- Assumed amount of wells include 19 production and 16 injection wells.

It is important to mention, that currently Prirazlomnoye oil field is in production stage and an ice resistant gravity based structure was installed in order to produce oil from that field. The oil field development concept implies utilizing of IRGBS “Prirazlomnaya”, it was built in Severodvinsk shipyard manufactory, which is able to fulfil all necessary operations for current field exploitation and further field development. It is capable to carry out following operations:

- Drilling
- Production
- Processing
- Offloading

Oil is offloaded to specially constructed ice resistant shuttle tankers (IRST) named as “Mikhail Ul’yanov” and “Kirill Lavrov”. The deadweight for both tankers is equal to 70000 thousand tons *(Petrova, 2014).*

In October 2016 it was reported that 2.5 million tonness of hydrocarbons had been produced. There was a new type of oil named as ARCO. It is crucially important to mention that the Prirazlomnoye oilfield was the first Russian Arctic oilfield which came on stream *(Danichev, 2016).*

Dolginskoye oilfield

Currently, the Dolginskoe oil field tends to be the biggest oilfield in terms of hydrocarbon reserves in the Pechora Sea. The field is situated in the central part of the Pechora Sea with a distance to the continent equal to 110 km and to the opposite side 120 km to the Novaya Zemplya archipelago. The field was discovered in 1999 by implementing 2D and 3D seismic surveys as well as 3 exploratory wells have been drilled; one well in Yuzhno – Dolginskoe and two wells in Severo – Dolginskoe part. The following features characterize the Dolginskoe oilfield:

- Extractable oil reserves are reaching 235.8 million tons of oil

- The water depth in the area of the oilfield is varying from 45 to 60 meters
- The net pay zone is found between 3100 and 3300 meters
- The oil density ranges from 900 – 920 kg/m^3
- Assumed amount of wells is 90, with 68 production wells and 22 injection wells.

It should be noted, that oilfield is going to be second location in the Russian Arctic region, where production of hydrocarbons should begin *(Dolginskoye oilfield to open in Russian Arctic soon, 2016).*

Medynskoe-more oilfield

The field is located at a distance of approximately 30 km from the continental shoreline and at a distance of 50 km to the Varandey village. The oilfield was discovered in 1997 by means of drilling. Three exploratory wells were drilled by Arcticshelfneftegas and one exploratory well was drilled by Arcticmorneftegasrazvedka. Data received from the exploratory drilling have lead to resource evaluation, currently it is supposed to contain 516,6 million tons of oil implying C1 and C2 categories *(Barents observer, 2017).* The Medynskoe-more oilfield is characterized by following features:

- Extractable oil reserves are estimated to be equal 133.9 million tons of oil
- The water depth in the area of the oilfield ranges from 10 to 19 meters
- The net pay zones are located at the depth of, 1700 -2300 meters, 2360 – 2500 meters and 3045 – 3200 meters
- The oil density varies from 805 – 920 kg/m^3 (as a several pay zones exist)
- Assumed amount of wells are 42, with 27 production wells and 15 injection wells.

Varandey-more oilfield

The oilfield was discovered by Arcticmorneftegasrazvedka in 1995. The field is located in the Southern part of the Pechora Sea at a distance of approximately 15 km away from Varandey village The Varandey-more oilfield is characterized by following features:

- Extractable oil reserves are estimated to be 41.8 million tons of oil
- The water depth varies from 14 to 18 meters
- The net pay zone is found at a depth of 1780 – 1820 meters
- The oil density is ranged from 910 – 915 kg/m^3

- Assumed amount of wells – 23, with 13 production wells and 10 injections wells.

The summarized data about mentioned above oilfields in the Pechora Sea is given below in Table 3.1.

Table 3.1 Pechora Sea's oilfield characteristic

The name of the field	Reserves, million tons	Water depth, m	Distance from the shore, km	Net pay zone, m	Oil density, kg/m^3
Prirazlomnoye oilfield	72	18 - 21	60	2350 - 2550	910 -955
Dolginskoe oilfield	235,8	45 - 60	110	3100 - 3300	900 -920
Medynskoe-more	133,9	10 -18	50	1200 – 1600, 1700 - 2300	805 -920
Varandey - more	41,8	14 - 18	15	1780 - 1820	910 - 915

The area of the oilfields location is characterized as a remote area with entire lack of industrial infrastructure.

4 POSSIBLE OFFSHORE STRUCTURES FOR MEDYSNKOE – MORE OILFIELD DEVELOPMENT

For almost seventy years mankind have operated offshore (History of offshore, 2007), extracting hydrocarbons from offshore fields. Various structures may be utilized for oil and gas production, depending on a several parameters, like water depth, location, ice presence, icebergs and etc.

Concerning the Medynskoe – more oilfield, because of ice presence for approximately 250 days and harsh environmental conditions, selected offshore production facility should be able to withstand all possible ice loads.

According to the experience, received from the Arctic offshore oil and gas fields development, the most appropriate solutions are GBS (Gravity based structure) and artificial islands.

Good examples for the implementation of the mentioned approaches might be Northstar Island in Beaufort Sea and IRGBS Prirazlomnaya in the Pechora Sea shown in Figure 4.1 and Figure 4.2 respectively.

Figure 4.1 Northstar island in the Beaufort Sea (www.libertyprojectak.com)

Figure 4.2 IRGBS Prirazlomnaya (www.offshoreenergytoday.com)

However, prior to the selection of the offshore development facility, their advantages and disadvantages should be considered. Advantages and disadvantages of offshore structures are given in Table 4.1.

Table 4.1 Advantages and disadvantages of the offshore facilities (*Zolotukhin, 2015)*

Advantages	Disadvantages
FPSO	
• Disconnectable turret • Significant storage capacity • Mobility and rotationability • Ice vanning equipment • The possibility to reuse after decommissioning	• Not sustainable for significant ice hazardous, ice management should be provided • Substantial mooring forces and necessity to use DP • Open water riser, possibility of oil spills
GBS with vertical walls	
• Dry well heads • Significant storage capacity • Year round operability	• Suitable for shallow waters only (high cost) • Decommissioning problems, usually is not reused

• Risers inside the structure, low oil spill probability • Ability to withstand 100-year loads (ice, wave, wind, current)	• Lack of mobility
GBS with sloping walls	
• Dry well heads • Significant storage capacity • Year round operability • Reduced ice loads in comparison with GBS with vertical wall • Ability to withstand 100-year loads (ice, wave, wind, current) • Large site area	• Suitable for shallow waters only (high cost) • Decommissioning problems, usually is not reused • Wave and current loads are higher in comparison with GBS with vertical wall
Artificial island	
• Year round operability • Dry well heads • Large site area • High resistance to icebergs	• Suitable only for extremely shallow waters • In case of absence of building materials, difficult logistics needed to provide building material to the site of island construction • Sea spraying effect

The water depth in the Medysnkoe – more oilfield varies from 10 to 19 m, thus FPSO utilisation is problematic, resulting from FPSO's significant draught – usually more than 20 m (*http://www.ship-technology.com/projects/bonga-fpso/, 2017*). For artificial islands water depth of 19 m seems to be substantial, though ice loads will be estimated for both vertical/sloped wall GBS and artificial island.

5. ICE LOADS ON OFFSHORE STRUCTURES

5.1 Description of the ice actions

Generally, all offshore structures designed to work in the Arctic region should be capable to withstand harsh environmental conditions and particularly significant loads from all shape of ice. As it is shown above on the Figure 2.2 the area of the oilfield is covered by the ice for a significant part of the year, thus ice – structure collision is expected, therefore all ice actions, that have to be elaborated prior to offshore facility installation are shown in Figure 5,1.

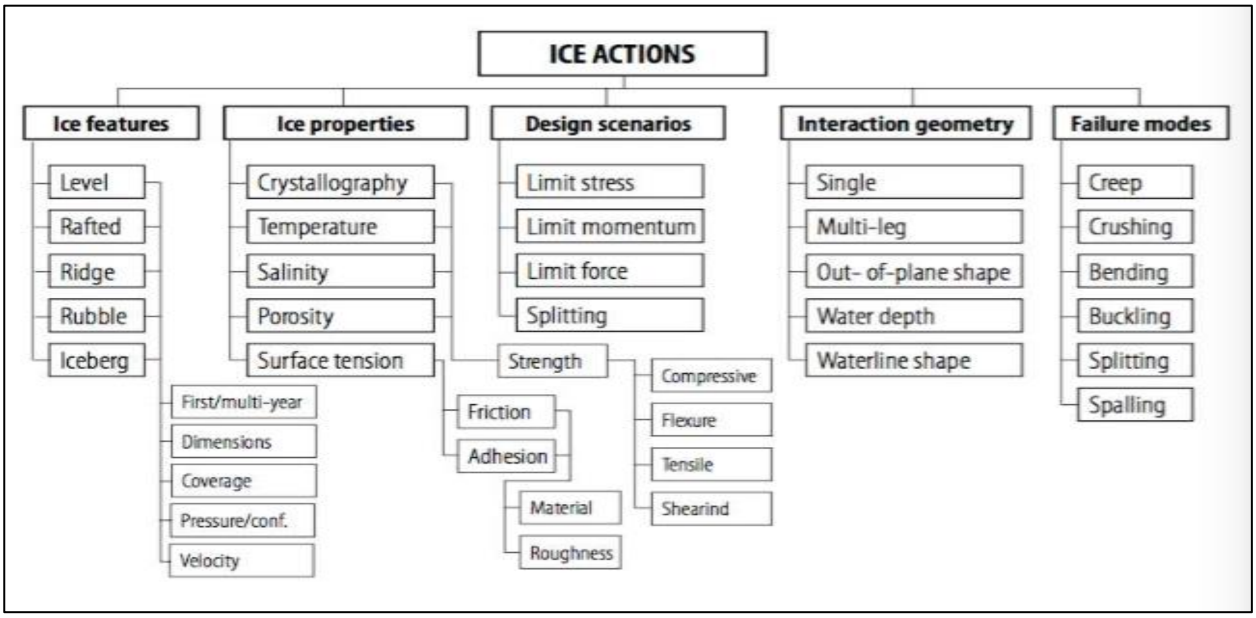

Figure 5.1 Different ice actions (Løset et al., 2006)

It should be noted, that all ice actions related to the ice – structure interaction can be divided into two groups:

- Global actions - actions exposed to the whole structure at any immediate time. Overall strength of the structure, horizontal stability and the overturning moment directly depend on global actions;
- Local actions - actions exposed to the limited section of the platform with average contact area equal to two meters. Structural local strength is in straight dependency of local actions.

The process of interaction mostly consists of crushing, creep and buckling failure modes, whereas the maximum ice loads are during crushing (*Croasdale et al., 2011)*.

The crushing failure mode takes place during high indentation rates of the ice and oppositely to the creep failure mode it is described by non-simultaneous partial interaction and locally concentrated pressure over the whole contact area. Thus, the ice affecting on the structure with vertical wall is failed due to compression failure, as depicted in Figure 5.2.

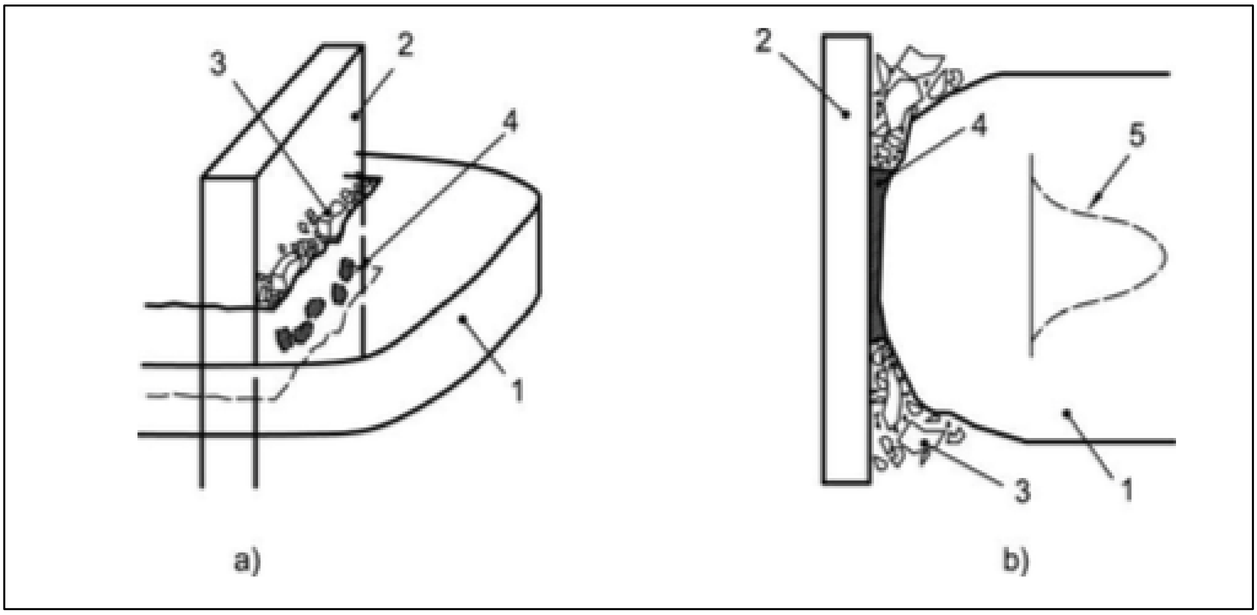

Figure 5.2 Schemes of compressive ice – structure interaction (*Sultabayev, 2014)*

Figure 5.2a shows the interaction of narrow plain structure with ice sheet, whilst Figure 5.2b shows the ice sheet – wide vertical structure interference, where digits mean:

- 1 – Ice sheet;
- 2 – Vertical structure;
- 3 – Wreckages;
- 4a – Zones with high pressure, 4b – High pressure zone with crushed ice;
- 5 – distribution of the pressure along the interaction surface.

It should be pointed, that the ice rubbles accumulated gradually in adherent to the offshore structure zone, may change prevailing failure mode from crushing to rubbling (*Croasdale et al., 2011*). In case of rubbling failure mode, ice loads on the structure is decreased as shown in Figure 5.3.

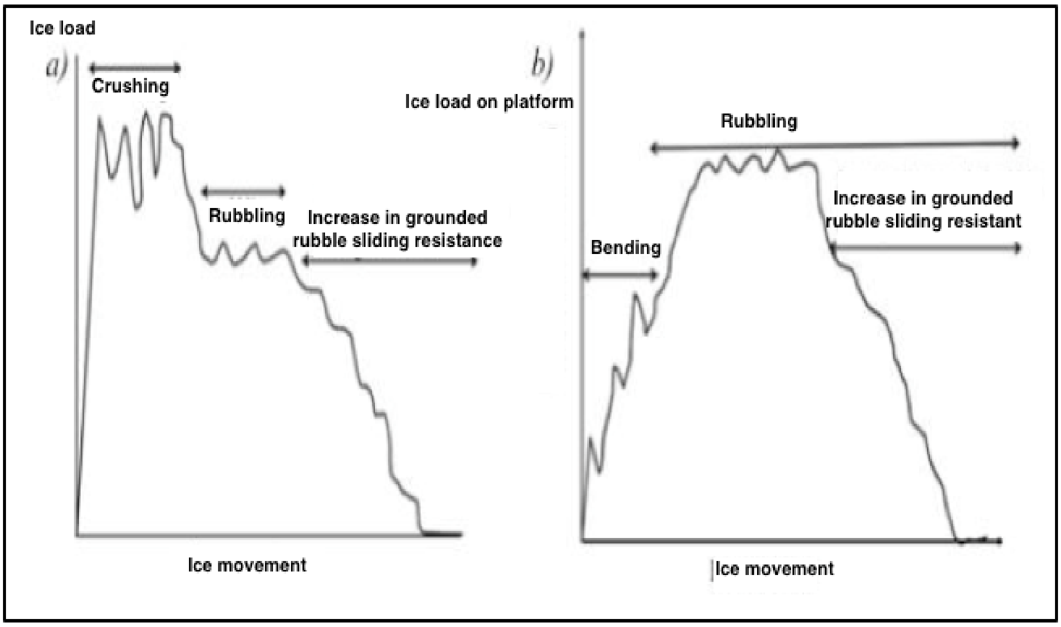

Figure 5.3 Ice loads distribution (*Palmer and Croasdale., 2012*)

According to Figure 5.3, the peak loads are expected at the initial stage of the ice – structure interaction, thus the limit stress scenario is most likely to happen when ice failure mode is crushing.

5.2 Ice loads on the vertical structures

There was a lack of data concerning ice properties in the Pechora (Barents) Sea, therefore experimental data were taken from the Arctic offshore engineering fieldwork and shown in Table 5.1 (*Study group AT-307, 2014).*

Table 5.1 Ice characteristics in the Pechora Sea

Parameter	Value
Uniaxial compressive strength, MPa	1.37 (average)
Flexural strength, MPa	0.52 (maximum)
Ice thickness, m	(100 year observation)

The shown values of ice properties in Table 5.1 are used in the calculation of ice loads.

5.2.1 Korzhavin's method

Korzhavin's approach seems to be advanced and accurate due to inclusion of some significant parameters *(Sultabayev, 2014)*.

$$F = I \cdot K_1 \cdot K_2 \cdot \sigma_C \cdot D \cdot h \qquad (5.1)$$

Where:

- I - indentation factor, taking into account stress – strain distribution within the ice field. It is equal to 2,47 when the ice width is 15D of structures diameter
- K_1 - contact factor, due to imperfectness of the ice – structure contact. Averagely it is equal to 0,4 – 0,7 in case of structure diameter equal to 3 – 10 metres
- K_2 - shape factor, mostly depend on cross – section form of the structure. For circular structures it is taken as 0,9, for flat structures 1
- h – ice thickness
- σ_C - uniaxial compressive strength
- D – diameter of the structure at the mean MWL

Equation 5.1 considers ice loads on the vertical wall structure, but by applying Korzhavin equation, overestimated results will be derived *(Løset et al., 1998)*. It is explained by the following factors*:*

- Korzhavin in his experiment has considered small diameter piles, which are a few times less than the diameter of existing offshore structures. Also, it is of great importance, that the average ice strength decreases when the magnitude of the structure increases, which also has not been covered in the experiment;
- Unconfined compressive strength does not completely reflect the total loads to the structure.

Calculation of ice loads on vertical structures according to the equation 5.1. Input data for calculation is defined in Table 5.2.

Table 5.2 Input data for the Pechora Sea

Parameter	Value
I	2,47
K_2	1
h	1,3

- h - ice height and average value for Barents Sea is taken (*Study group AT-307, 2014).*

Loads have been calculated for both GBS and artificial island with vertical walls. Contact factor K_1 – is not taken into consideration, as diameters of the GBS and artificial island are bigger than 3 – 10 m, assume K_1 = 1. Diameter of structures are assumed to be equal to (average among other offshore structures of the same type):

- GBS – 100 m;
- Artificial island – 140 m.

Ice loads on the mentioned structures are shown in Table 5.3 and Figure 5.4 respectively.

Table 5.3 Ice loads on vertical structures – Korzhavin's method

Parameter	GBS	Artificial island
Ice loads (Force), MN	439.91	615.87

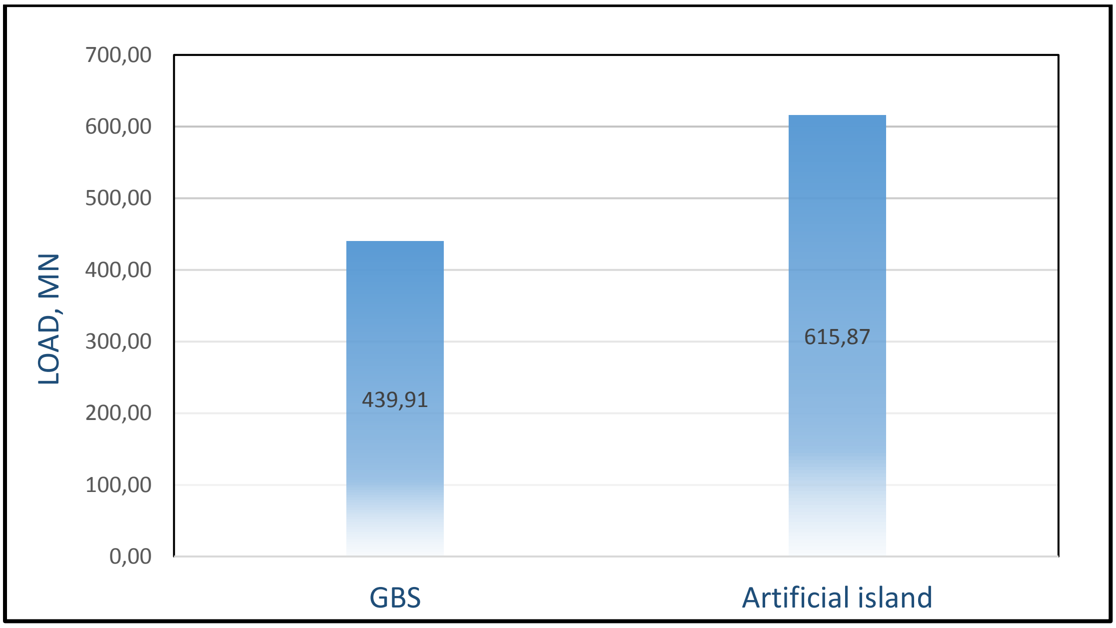

Figure 5.4 Ice loads on vertical structures – Korzhavin's method

5.2.2 ISO empirical correlation

There is an empirical correlation for the global ice acting pressure on a vertical structure *(ISO 19906, 2010)*.

$$F = p \cdot A \qquad (5.2)$$

where:

- p is the average effective pressure;
- A is the area of the contact between ice and structure (nominal).

Equation 5.2 is considered to be more appropriate for ice loads calculation. The average effective pressure might be represented as $\frac{F}{D \cdot h}$, thus it is able to elaborate all issues which have not been accounted by equation 5.1 (*Løset et al., 1998)*.

By implementing equation 5.2, results have been obtained. Table 5.4 and Figure 5.5 show ice loads on the GBS and artificial island.

Table 5.4 Ice loads on vertical structures – ISO's method

Parameter	GBS	Artificial island
Ice loads (Force), MN	178.1	249,3

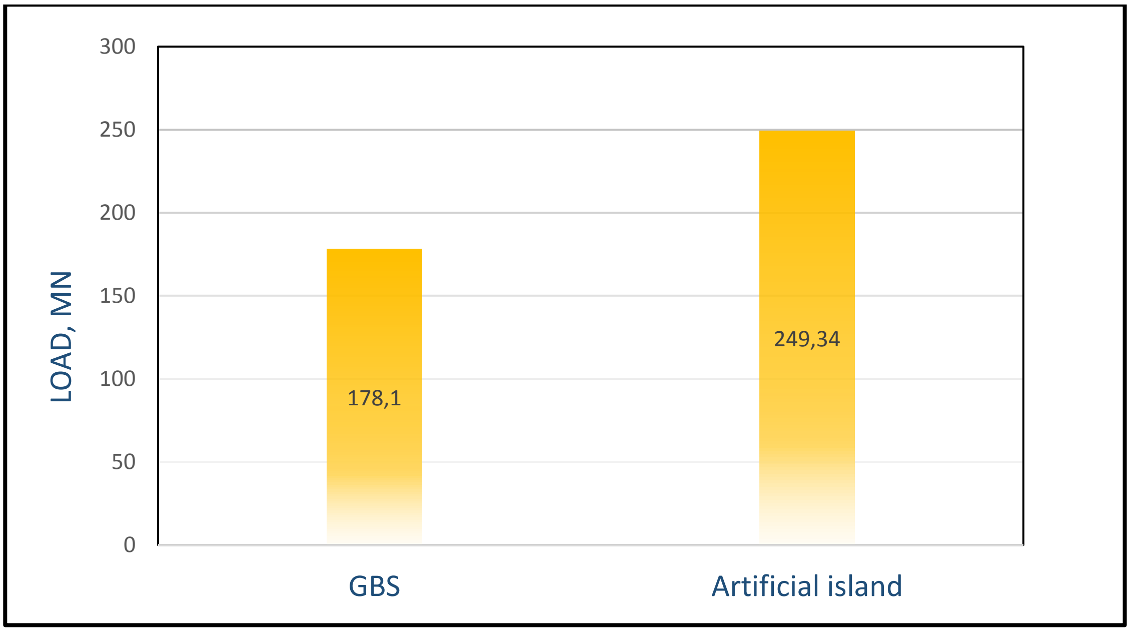

Figure 5.5 Ice loads on vertical structures – ISO's method

According to the obtained results in both approaches, it should be noted that, the wider offshore structures, the higher the ice load is. Thus, optimal width of the structure in terms of ice loads should be defined.

Ice loads in case of applying empirical ISO formula are lower and seems to be more realistic.

5.3 Ice loads on sloping structures

5.3.1 Description of the process

As the ice compressive strength is higher than ice flexural strength, structures with sloping walls are considered to be more efficient for reduction of ice acting forces. Ice acting on the sloping structure tend to fail in bending failure mode instead of in crushing failure mode, which is usual for vertical structures. There are upward and downward sloped structures shown in Figure 5.6, giving different compression and tension modes:

- Upward – the bottom surface of the ice sheet is subjected to the tension, while as top surface is compressed;
- Downward – the top surface of the ice sheet is tensioned, while as bottom surface is compressed.

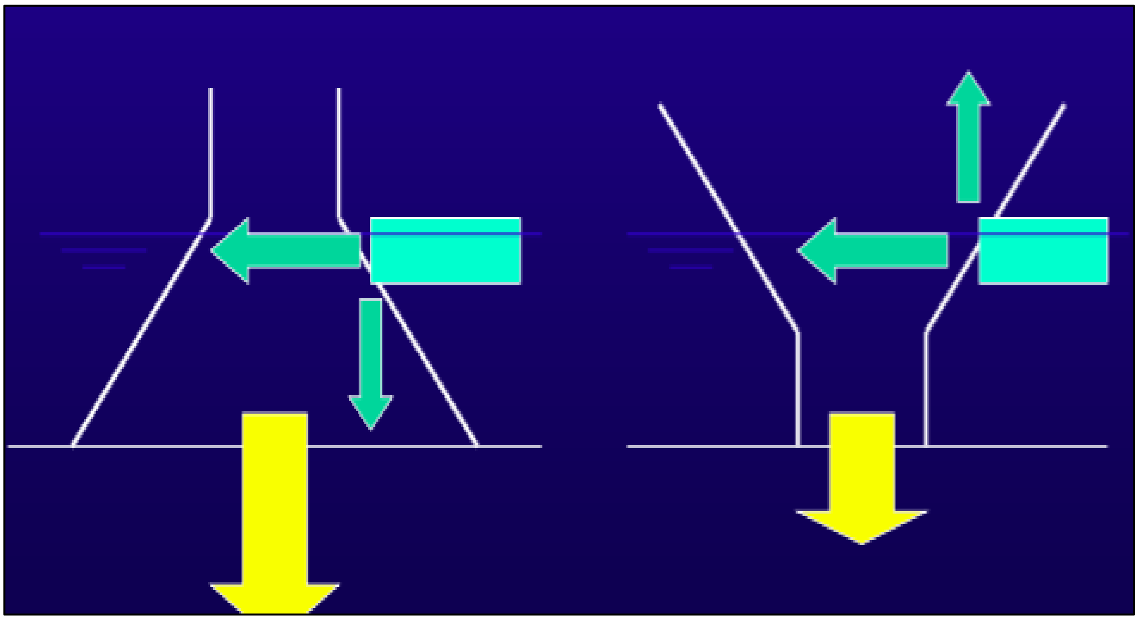

Figure 5.6 Upward and downward sloped structures (*Løset, 2016*)

As Medysnkoe – more oilfield is located in shallow water, it is crucially important to consider the stages of ice – sloping structure interaction in shallow water:

- The first phase reflects the process of initial ice sheet failing and subsequent riding – up on the sloping wall. Pieces of ice begin to accumulate on this sloping wall;
- In the second stage, the coming ice sheets push already accumulated ice rubbles, still fail in bending failure mode, and gradually ride up on the inclined surface. At the same time, the weight of the ice rubbles begins to act on the sloping wall and contributes to sliding resistance from ice rubbles;
- Eventually, the sliding resistance of the ice rubbles becomes so significant that the coming ice is not able to push existing rubbles further up on the inclined wall and breaks from collision with grounded ice rubble.

These stages are schematically shown in Figure 5.7.

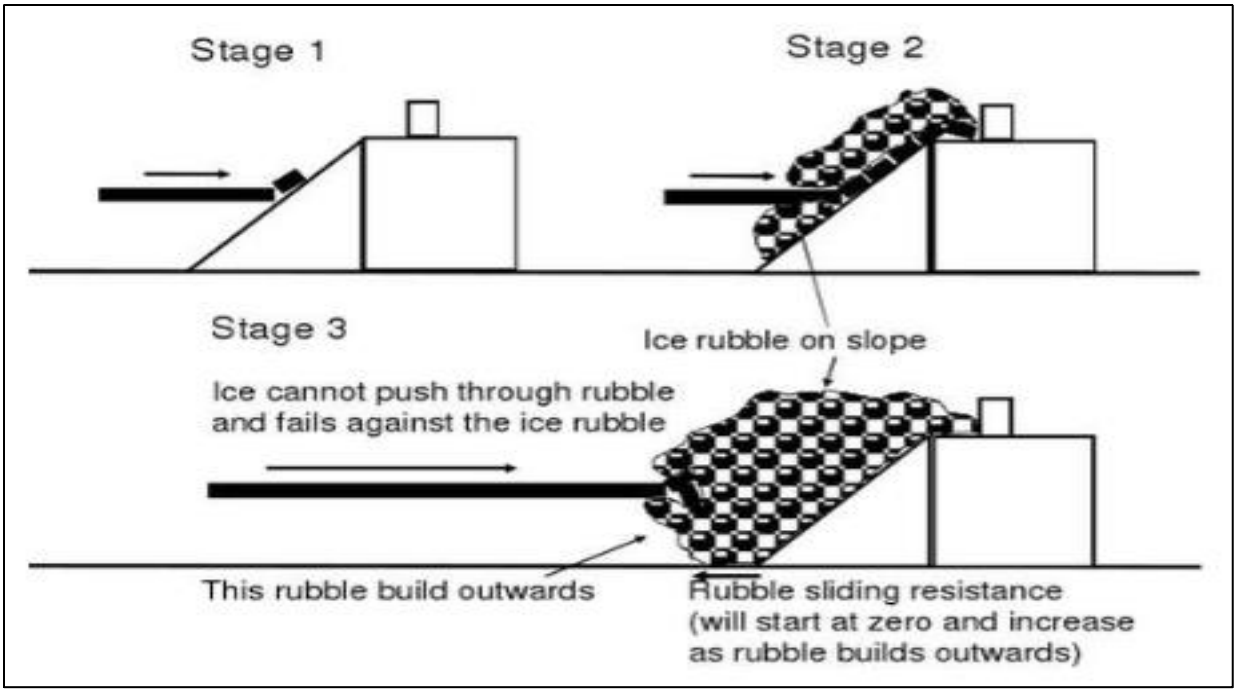

Figure 5.7 Ice – sloping structure interaction stages in shallow water (*Palmer and Croasdale, 2012*)

The described process of ice – structure interaction is observed in Figure 5.8.

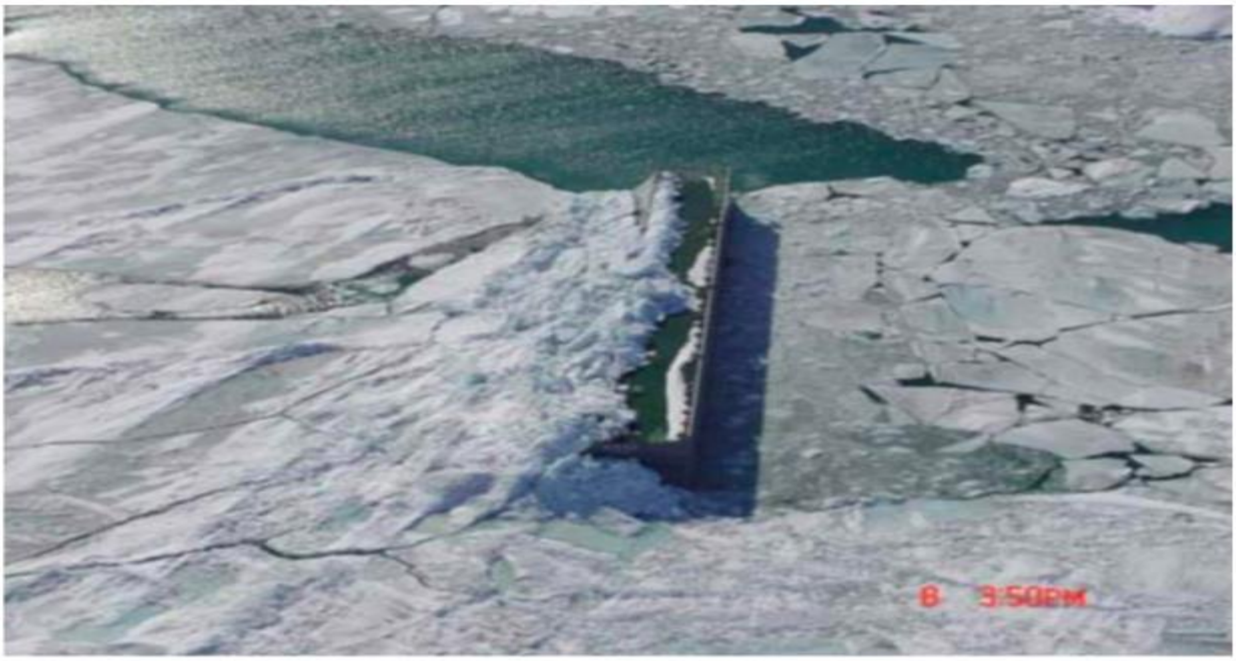

Figure 5.8 Accumulation of ice rubbles beside an ice barrier located in the Caspian Sea (*Croasdale et al., 2011*)

When the ice rubbles are accumulating beside the sloping structure, the ice loads from the coming ice are partially dissipated, due to impossibility of grounded ice rubbles to move further up. Hence, on the one hand, it is preferable to have ice rubbles in the vicinity of the structure; on the other hand, it is difficult to assess all loads from the rubbling due to the complexity of the phenomenon.

5.3.2 Load calculation on the sloping structure

In general, the global ice loads on a the sloping structure consist of the vertical F_V and horizontal F_H force components, which have the following relationship:

$$Fv = \frac{Fh}{\xi} \tag{5.3}$$

where:

$$\xi = \frac{sin\alpha + \mu cos\alpha}{cos\alpha - \mu sin\alpha} \tag{5.4}$$

where:

- μ – the friction coefficient of the ice – structure interaction;

- α – the sloping angle of the structure, that is shown in the Figure 5.9

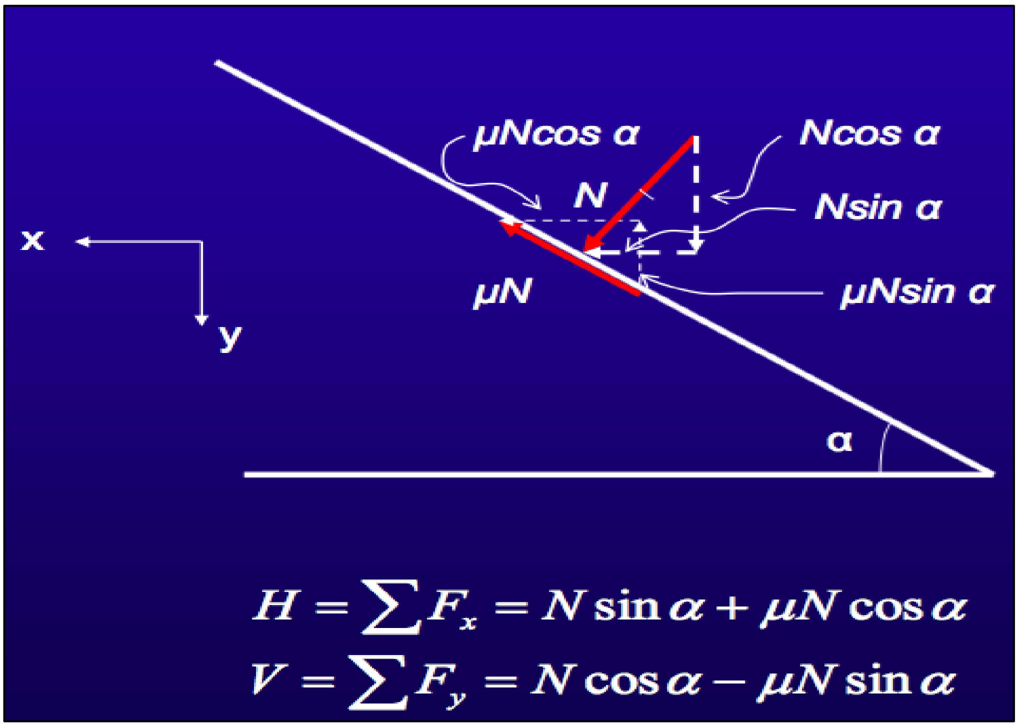

Figure 5.9 The sloping angle α of the structure (*Løset, 2016*)

The horizontal F_H component might be calculated from the model based on a semi-infinite beam on elastic foundations (*Løset et al., 2010*).

$$F_H = C_1 D\, \sigma_f \left(\frac{\rho g h^5}{E}\right)^{1/4} + C_2 D z h_i \rho_i g \tag{5.5}$$

where:

$$C_1 = 0{,}68\, \frac{\sin\alpha + \mu\cos\alpha}{\cos\alpha - \mu\sin\alpha} \tag{5.6}$$

$$C_2 = (\sin\alpha + \mu\cos\alpha) \cdot \left(\frac{\sin\alpha + \mu\cos\alpha}{\cos\alpha - \mu\sin\alpha} + \frac{\cos\alpha}{\sin\alpha}\right) \tag{5.7}$$

- σ_f – flexural strength of the ice;
- D – structure diameter – 100 m for GBS, 140 m for islands;
- ρ – density of the water - 1025 kg/m^3;
- ρ_I – density of the ice – 900 kg/m^3 (*Study group AT-307, 2014);*
- μ – friction coefficient. Put μ = 0,3 (*Løset, 2016*);
- z – height, showing how far the ice rides up on the inclined wall of the structure. Put z = 5 m (*Løset, 2016*).

Equation 5.5 consists of two terms. The first term describes the breaking of the ice due to the flexural failure and the second one is ride – up force.

Calculating the ice loads, through calculation of main acting – horizontal force (F_H) on both GBS and artificial island with sloping walls, varying the sloping angle from 20° to 70°, gives results as shown in Table 5.5 and Figure 5.10 respectively.

Table 5.5 Ice loads on sloping wall structures

Sloping angle, α	**C_1**	**C_2**	**Total horizontal force, F_H (MN)**	
			GBS, D=100 m	Artificial island, D=140 m
20	0.507	2.179	13.70	19.17
30	0.722	2.122	13.87	19.42
40	1.035	2.368	16.02	22.43
50	1.579	3.031	21.10	29.54
60	2.876	4.884	34.79	48.70
70	11.791	18.452	133.60	187.03

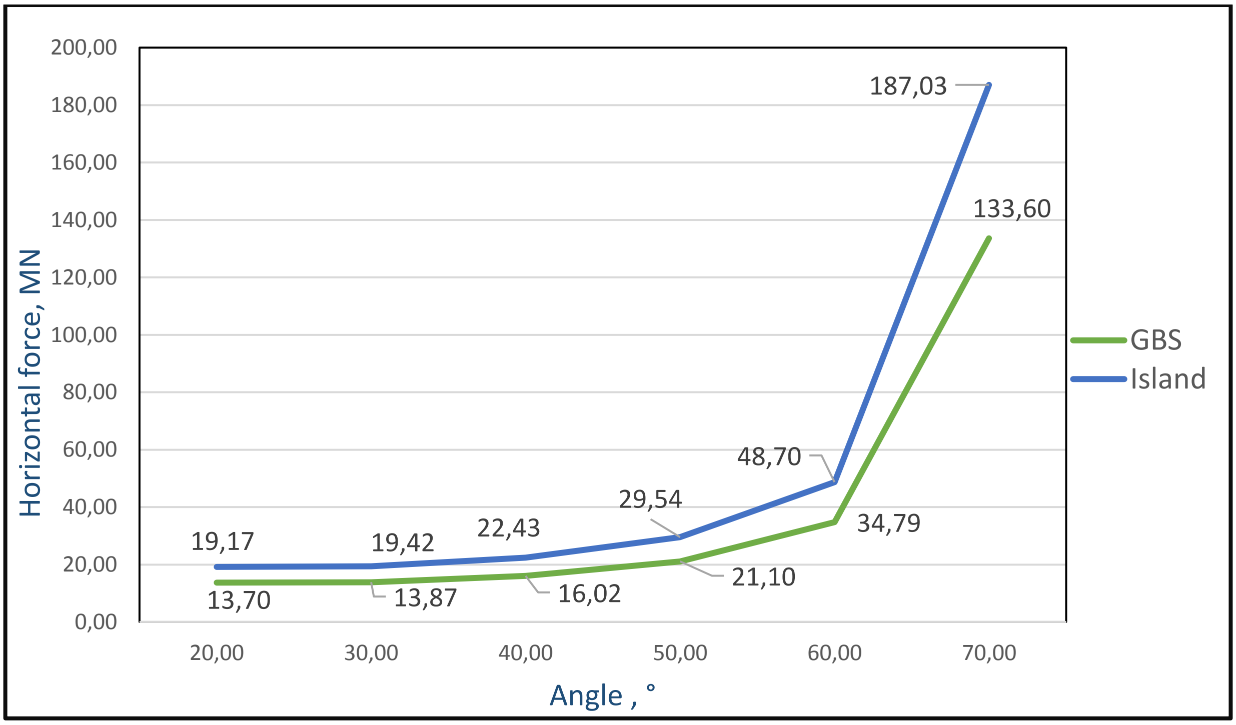

Figure 5.10 Ice loads on sloping wall structures

According to the obtained results, it might be pointed that the smaller the sloping angle, the lower ice loads on the offshore structure. The ice loads begin to grow substantially, if the sloping angle is higher than 60°. It is explained by changing in the failure mode from bending to crushing, which is inherent for steeper angles.

The friction coefficient μ is of great importance in order to keep the ice loads at a reasonable level, therefore smooth surface of the inclined wall should be provided.

The ice thickness, is considered to be the most significant parameter affecting for ice loads on structures (*Løset, 2016).*

6. ICE MANAGEMENT

Ice management is a complex approach to reduce or avoid any actions from all kind of ice. It includes the following components *(Eik K,2016)*:

- Indication and monitoring of the ice, ice ridges and icebergs;
- The estimation of the hazard;
- Utilizing of icebreakers and iceberg towing vessels;
- Disconnection capabilities for floating oil and gas production units.

A nuclear powered icebreaker is shown in Figure 6.1

Figure 6.1 A nuclear powered icebreaker
(*www.coolantarctica.com/Antarctica)*

The icebergs are considered to be the most dangerous ice formations for the offshore structures. Concerning the Medysnkoe – more oilfield, it should be noted that this area is free of icebergs for the whole year. (*Abramov, 1990*) as it is shown in Figure 6.2

So, any specific activities within the ice management are not required, implying that the offshore structure is able to withstand loads from any features of ice existing in the area of the oilfield.

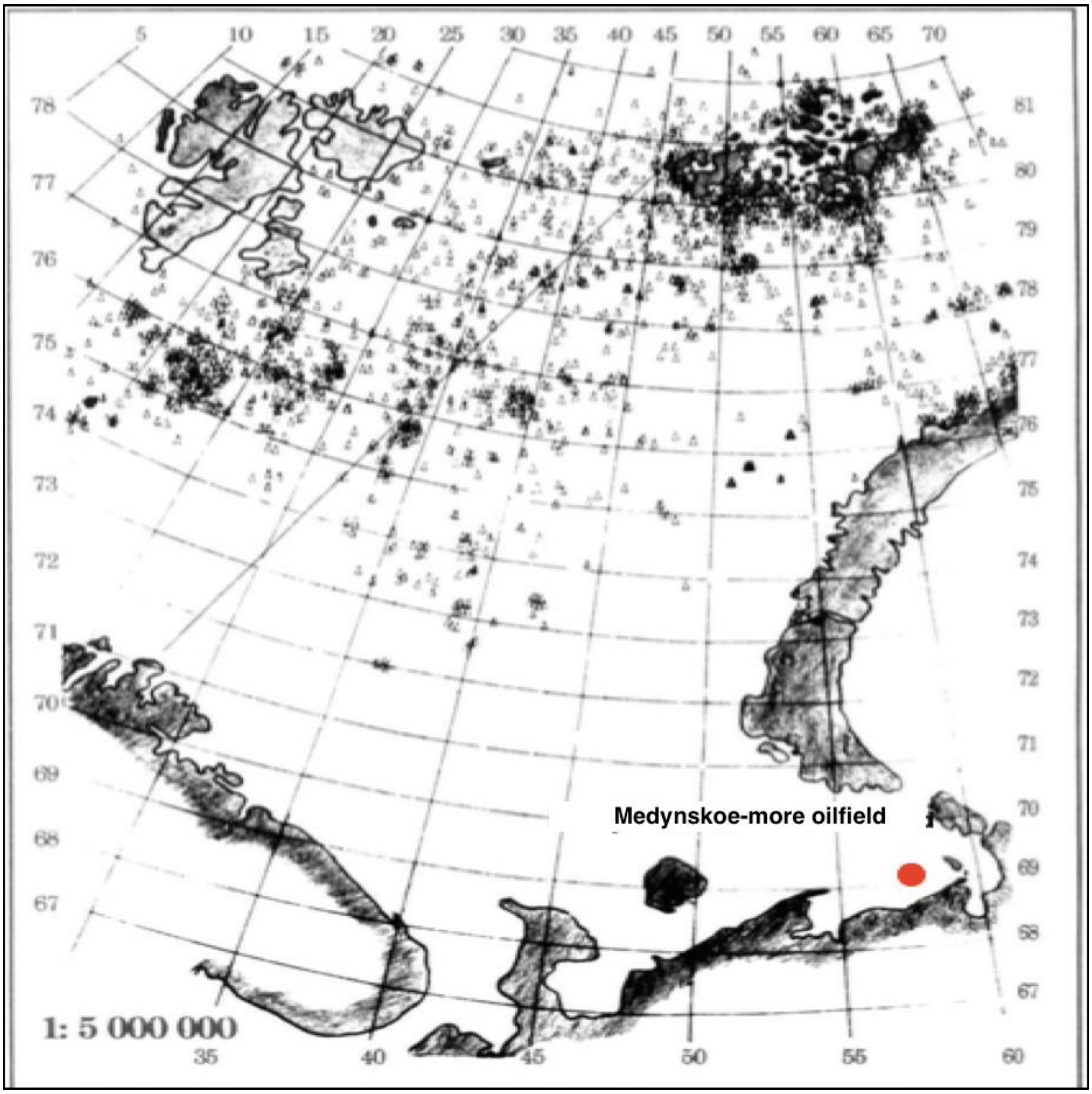

Figure 6.2 Russian iceberg observations in the Barents Sea in 1933 – 1990 (*Abramov, 1990)*

7. INTERMEDIATE CONCLUSION AND RECOMMENDATIONS FOR FURTHER WORK

In the previous chapters, selection of the most appropriate type of the offshore structure for the Medysnkoe – more oilfield has been conducted. GBS and artificial island have been selected as a competitive offshore structures for the installation on the Medynskoe – more oilfield.

The design and construction of both vertical and sloping wall structures are possible. Thus, the aim was to evaluate ice loads and choose the optimal solution.

Two approaches have been utilized to calculate the ice loads on vertical structures. During Korzhavin's approach, loads are overestimated - 439.9 MN and 615.8 MN for GBS and island respectively, while the ISO method showed reasonable values of ice loads - 78.1 MN for the GBS and 249.3 MN for an artificial island. The difference in ice impact on the structures is justified by the difference in diameter.

Concerning sloping wall structures, there is significant effect from the sloping angle of the structure. Elaborating results, it should be noted that a smoother angle gives less loads – from 133.6 MN in case of 70° to 13.7 MN for a GBS with heel angle of 20° for GBS, whereas for an artificial island the variation is from 187.03 MN during 70° to 19.17 MN in case of 20°.

Sharp increase of ice loads on the structure happened between 60° and 70° - explained by a change in the prevailing failure mode of ice, from bending to crushing.

The sloping angle of the structure should be less than 60°, in order to keep the ice loads at a reasonable level. Moreover, a particular attention to the smoothness of the inclined wall should be given, since it substantially affects to the ice loads.

Ice management has been elaborated implying that the area of the oilfield is free of icebergs. Design of the offshore structure against icebergs is not obligatory. However, if the iceberg will appear, it can be towed or destroyed by icebreaker.

Further considerations of wave and current loads on the sloping wall structures are necessary in order to derive the joint effect from changing of the sloping angle.

Sloping structures require more construction materials, therefore, economic analysis is required to evaluate the feasibility of the offshore structure installation in terms of economic efficiency.

8. SELECTION OF THE APPROPRIATE TYPE OF OIL TRANSPORTATION SYSTEM FROM THE MEDYNSKOE-MORE AND VARANDEY-MORE OILFIELDS

As mentioned above there are two ways of oil transportation from the offshore oil fields – subsea pipelines and shuttle tankers. Currently, the oil from Prirazlomnoye oilfield is offloaded to IRSTs "Mikhail Ulyanov" and "Kirill Lavrov" which have deadweight equal to 70 thousand tonnes each *(Kirill Lavrov,2017*). These tankers have 14 meters draft while the water depth in the Prirazlomnoye oil field is 20 meters; thus, there is no problem concerning seabed keel ploughing during oil offloading *(Aker Arctic, 2010)*.

8.1 Tankers

On one hand it is more beneficial to choose tankers as a transportation mean for Medynskoe-more oilfield, because significant experience is accumulated of tankers utilizing in harsh Arctic conditions (serve in Prirazlomnoye oilfield already for 3 years), but on the other hand the shallow water depth, shown in the Table 3.1, in the area of new oil fields does not allow to consider shuttle tankers as a transportation approach. Thus, the most appropriate type of oil transportation for these fields is utilizing of subsea pipelines. Figure 8.1 shows the IRST "Kirill Lavrov".

Figure 8.1 Ice resistant shuttle tanker "Kirill Lavrov" ***(20 Super tankers, 2012)***

8.2 Subsea pipelines to the shore

As mentioned above, Medynskoe-more oilfield is located not far from the shore, at a distance of 50 km. It results in the opportunity to transport the extracted oil from this offshore oilfield to the mainland and subsequently through the trunk pipeline to the nearest point with existing oil storing capacities which is located in Usa town. There is trunk pipeline from Usa to Uhta and it should be also noted that there is closest refinery located in Uhta which is 500 km from the Usa. In Figure 8.2 the assumed pipeline is shown.

Figure 8.2 Assumed onshore pipeline from Varandey village to Usa

A lot of challenges should be comprehensively considered in order to construct such an onshore pipeline:

- High cost;
- Environmental conditions (cold weather, irregular surface);
- Remoteness;
- Lack of infrastructure;
- The lack of capacity in the subsequent trunk pipelines and in the refinery (they are filled with existing onshore oil);
- Long distance.

The aforementioned challenges imply that this type of oil transportation can be applied but a lot of issues should be elaborated attentively. It should be noted, that most of the challenges are also related to offshore subsea pipelines.

8.3 Subsea pipeline to the IRGBS "Prirazlomnaya" and subsequent offloading to the shuttle tankers

Since two other approaches of oil transportation from Medynskoe-more oilfield have been considered, the third existing approach should also be elaborated. Produced oil from this oilfield might be transported through subsea pipelines directly to the IRGBS Prirazlomnaya.

This type of oil transportation is tending to be the most favourable, because:

- The area of Prirazlomnoye oilfield has sufficient water depth in order to offload to IRST like "Kirill Lavrov" and "Mikhail Ulyanov" with deadweight equal to 70 thousand tonnes.

These statements give us the opportunity to rely on the IRGBS Prirazlomnaya in terms of oil hub creation and subsequent oil transportation to the floating storing unit - vessel "Umba" which is located in the Kola bay and has deadweight equal to 300,000 thousand toe *(Oil tanker "Umba",2017)*. The assumed scheme of oil transportation is shown in Figure 8.3.

In the present work, subsea pipelines are considered as the approach for oil transportation from the Medynskoe-more and Varandey-more oilfields to the IRGBS "Prirazlomnaya".

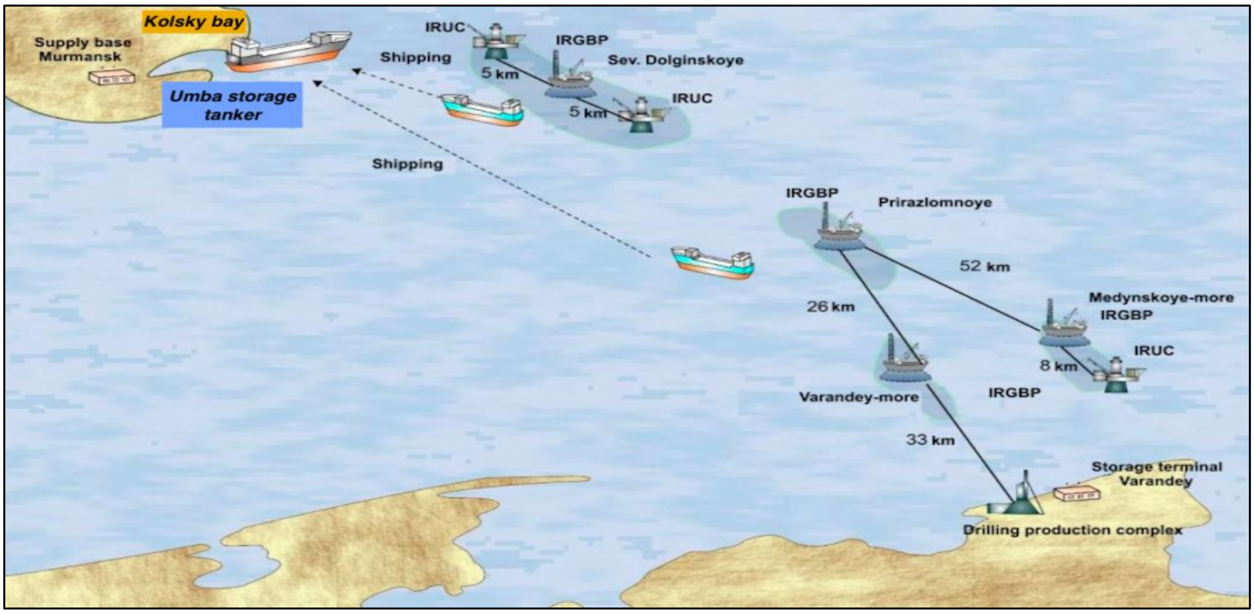

Figure 8.3 Scheme of oil transportation from the Medynskoe-more oilfield by using subsea pipelines to IRGBS Prirazlomnaya *(Bilalov, 2014)*

9. JUSTIFICATION OF THE DEVELOPMENT STRATEGY FOR THE MEDYSNKOE-MORE OILFIELD DEPENDING ON THE OIL PRODUCTION STRATEGY ON THE PRIRAZLOMNOYE OILFIELD.

As was aforementioned above, the Medynskoe-more oilfield is considered to be developed by utilizing the storing, processing and offloading capacities of the IRGBS "Prirazlomnaya". In order to realize that development scheme, mentioned above capacities of the platform should be estimated properly.

It should be noted, that all oil fields have approximately the same curve of oil production through the development period of the oilfield, which is shown in Figure 9.1. (*Mikael Hook, 2009*).

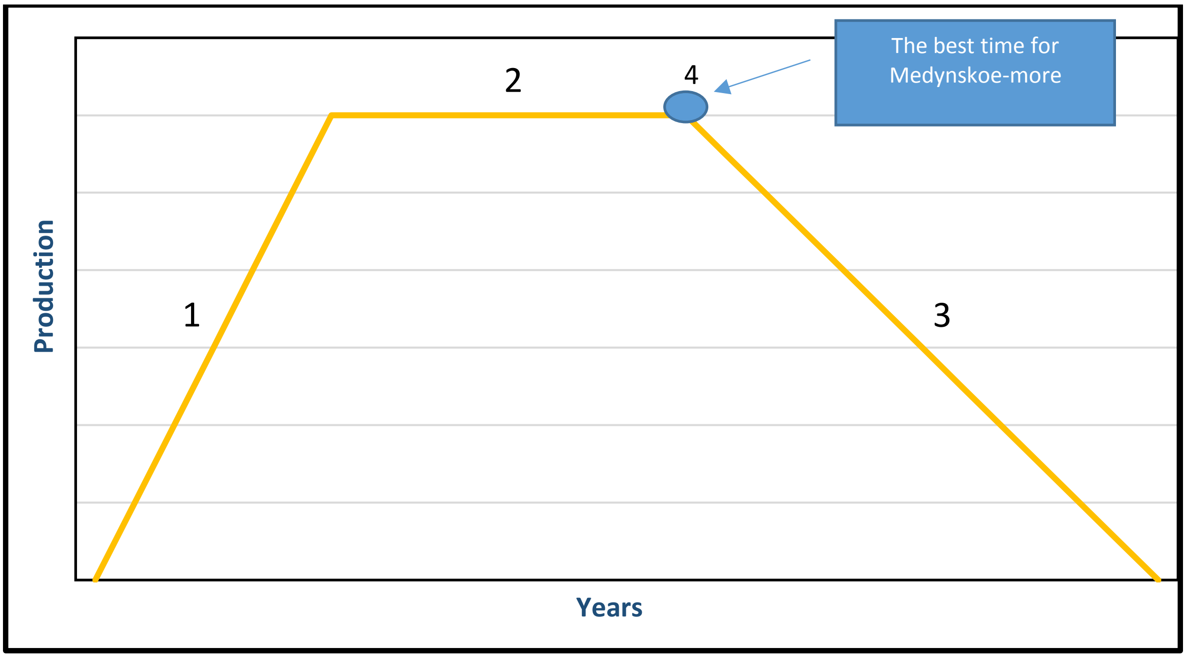

Figure 9.1 Typical oil production distribution through the lifespan of an oilfield

In the distribution shown in the Figure 9.1, it is possible to pinpoint three main stages:

- Stage 1 reflects the period of increasing production;
- Stage 2 reflects the period of high stable production;
- Stage 3 reflects the period of decreasing production.

The mentioned stages are integral parts of all oil fields that are developed commercially. During the first part of the curve, the oil production increases as new production wells are launching gradually. The second part, also known as "oil production plateau" depicts the stable production, when all planned wells are put in the working phase and give the maximum flowrate of the oil. At the third stage shown in the Figure 9.1, the oil extraction rate decreases as water cut increases, reservoir pressure decreases and total oil quantity of in the net pay zone is falling down.

Considering the curve shown in the Figure 9.1, it is reasonable to assume, that the best stage point for the subsea pipeline tying in from the Medynskoe-more oilfield to the host platform is point 4. Then, the oil extraction from the Prirazlomnoye oilfield begins to decline, thus storing, processing and offloading capacities become free for additional hydrocarbons from the neighbouring fields.

In order to create a mature development strategy for the Medynskoe-more oilfield, it is necessary to analyse the current oil production plan on the IRGBS "Prirazlomnaya" and evaluate the following parameters:

- The volume of liquid that might be processed per annum/day in the processing facilities of the Prirazlomnaya platform;
- The total volume of tanks in the platform that might be filled with oil, knowing the storing capacity of the Prirazlomnaya;
- The offloading capacity of the platform per annum/day. Two main factors should be elaborated – pumps capacity and weather condition, that also affect to the offloading process.

9.1 Current oil production strategy and processing capabilities on the IRGBS "Prirazlomnaya"

Prior to the development of any oilfield, it is inevitably important to have an oil production strategy. Depending on this strategy, the amount of wells and the order of it launching to the production stage might be defined. If at the very beginning of the oil production, there is prepared plan, it does not definitely mean that it will be used through the whole period of the production. During the production, there is an opportunity to update the plan depending on the new information about the physical properties of the reservoir and oil.

The approximate fluid, oil and water production on the Prirazlomnoye oilfield is depicted in the Figure 9.2

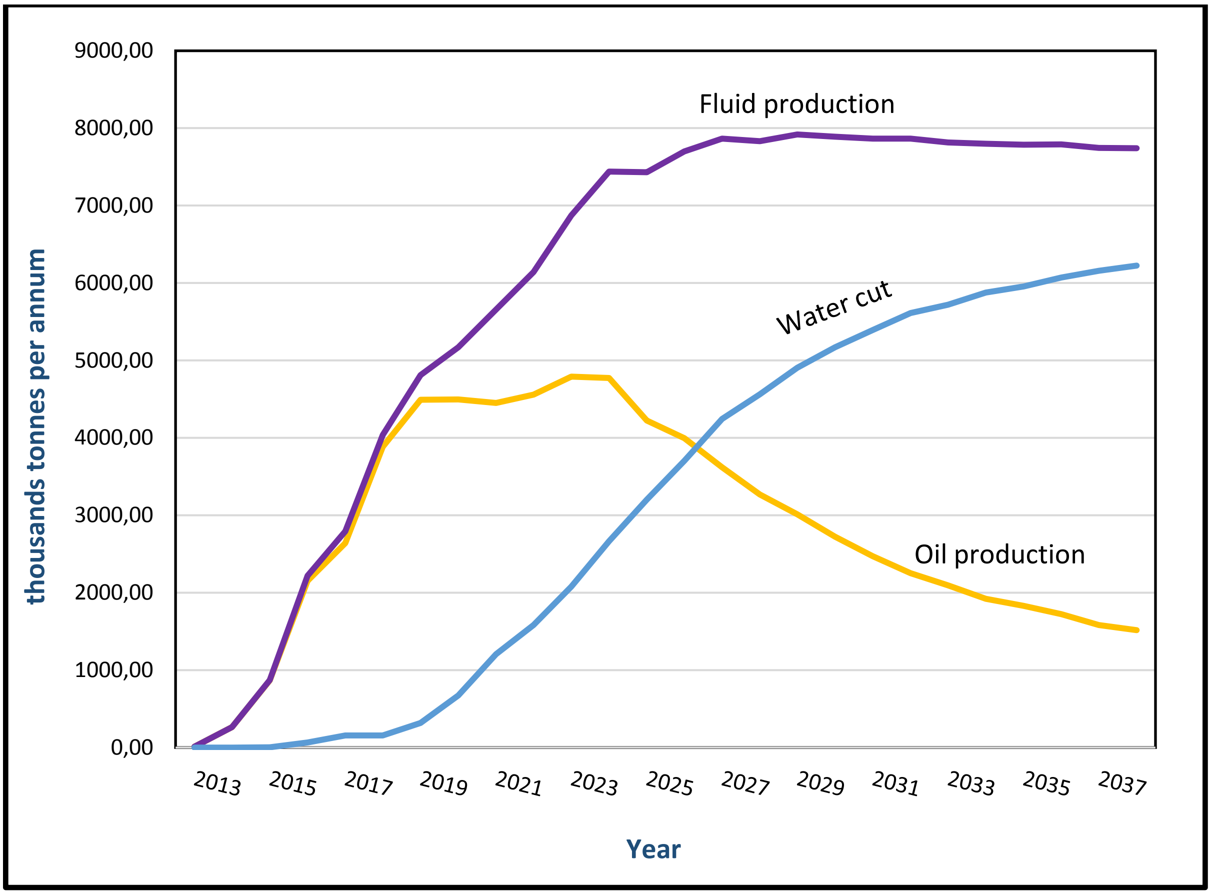

Figure 9.2 Approximate fluid, oil and water production on the Prirazlomnoye oilfield (*Gazprom neft, 2016*)

Considering the oil production curve in Figure 9.2, it is apparently that three phases of oil production mentioned above might be emphasized. Peak oil production level is expected to be in the year of 2023 with approximately 4,8 million tonnes of oil per annum. Thereafter, the oil production in the subsequent years will decline gradually. However, it does not mean, that processing facility will become free for additional quantity of oil, as water cut increases, resulting in a total increase of fluid production in the platform. In this term, it is visible that up to 2027 total fluid production will be increasing and from this year up to 2037 it will be stable.

Considering capacity of the processing facility on the IRGBS "Prirazlomnaya", it should be mentioned that, it is more profitable to attach arriving oil from the Medynskoe-more oilfield to the second stage of separation as the processing capacity at this stage is higher than in the first stage. Major part of water is segregated on the first stage of separation, and subsequently is injected to the injection wells to boost the reservoir pressure, thus there are different processing capacities after each stage of separation (Gazprom neft, 2016) Processing volumes before both stages of separation are shown in Figure 9.3

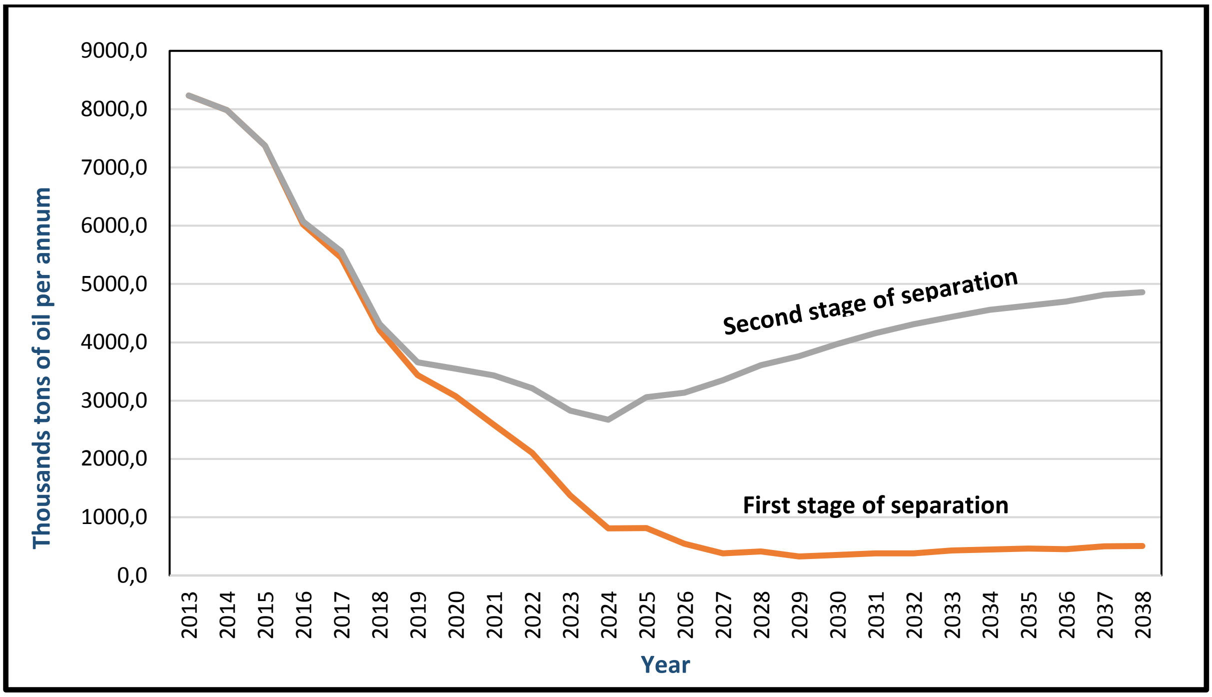

Figure 9.3 The amount of oil that might be attached to the first and second stages of separation in the IRGBS "Prirazlomnaya" (*Gazprom neft, 2016)*

According to the Figure 9.3, it should be pointed, that free processing volumes after both stages of separation are decreasing up to year 2024, resulting from that up to this period, both oil production and water cut are increasing. In year 2024, free processing volume before the second stage of separation begin to increase, as oil production begin to decrease and major part of the water is excluded from the reservoir fluid at the first stage of separation.

Thus, according to the Figure 9.3 and taking into account that maximum processing capacity of the equipment on the IRGBS "Prirazlomnaya" is 8.2 million tonnes per annum *(Gazprom neft, 2016),* the quantity of oil from the Medynskoe-more oilfield, that might be potentially taken and processed in the IRGBS "Prirazlomnaya" is shown in the Table 9.1

Table 9.1 The quantity of oil that potentially might be attached to the first and second stages of separation in the IRGBS "Prirazlomnaya"

Year	Free processing volume before the first stage of processing, million tonnes per annum	Free processing volume before the second stage of processing, million tons per annum
2013	8.2	8.2
2014	8.0	8.0
2015	7.4	7.4
2016	6.0	6.1
2017	5.5	5.6

2018	4.2	4.3
2019	3.4	3.7
2020	3.1	3.5
2021	2.6	3.4
2022	2.1	3.2
2023	1.4	2.8
2024	0.8	2.7
2025	0.8	3.1
2026	0.5	3.1
2027	0.4	3.4
2028	0.4	3.6
2029	0.3	3.8
2030	0.4	4.0
2031	0.4	4.2
2032	0.4	4.3
2033	0.4	4.4
2034	0.4	4.6
2035	0.5	4.6
2036	0.5	4.7
2037	0.5	4.8
2038	0.5	4.9

By taking into account the fact that free processing volumes before the second stage of separation begin to increase in year 2024, this year seems to be the most acceptable for attaching new oilfield in terms of processing capacities.

9.2 Storing and offloading capacities on the IRGBS "Prirazlomnaya"

Apart from the processing facilities on the IRGBS "Prirazlomnaya", storing and offloading capabilities should be taken into consideration. The oil is stored in the platform in a special tanks, which are located under the top side of the platform. There are twelve tanks with total storing capacity equal to 160 thousand cubic meters *(Gazprom neft shelf: Prirazlomnaya field development, 2015).* The arrangement of the tanks is shown in the Figure 9.4

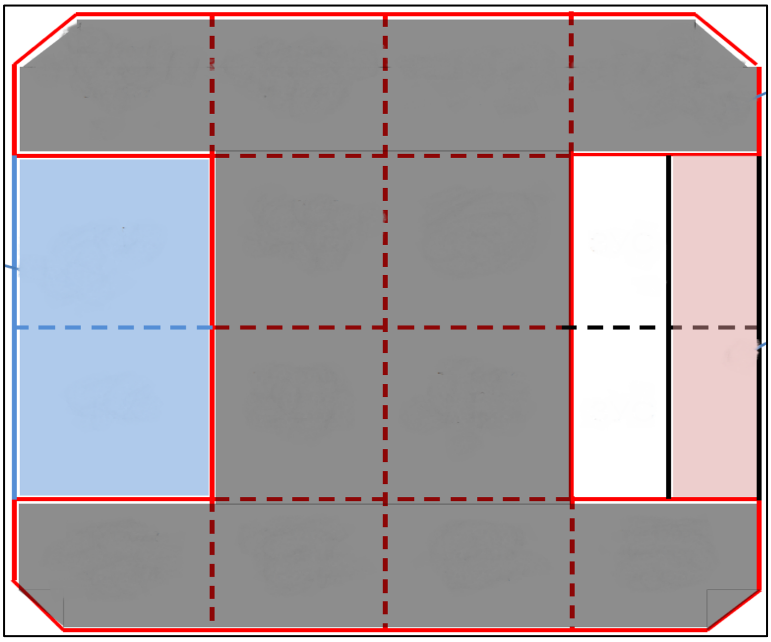

Figure 9.4 Oil tanks arrangement on the IRGBS "Prirazlomnaya"
(Gazprom neft shelf: Prirazlomnaya field development, 2015)

In order to prevent formation of the dangerous gaseous mixture, the oil in tanks is stored in combination with water, thus it allows to replace all oxygen from the tanks and to mitigate the probability of explosion *(Prirazlomnaya field, 2017).* Special emphasis should be done to the offloading system in the IRGBS "Prirazlomnaya" as it is determining the total capacity of oil that might be accepted to the platform. It should be pointed that stable transportation of oil from the Medynskoe-more oilfield to the IRGBS "Prirazlomnaya" can be provided just in case of reliable and sufficient working of the offloading equipment and shuttle tankers.

Offloading of the oil in the platform occurs by means of two "CUPON" systems, which are located in opposite sides – southwest and northeast. Two systems are needed to provide reliable offloading operations, taking into account that a several external factors such as ice floes drifting, change in wave and current direction may influence to the process of offloading. In case of necessity of fast disconnection, there is an emergency shut down system, that allow to eliminate oil spills to the open water (*Subbotin, 2015*).

The "CUPON" offloading system includes the following parts:

- Crane;
- Pipes for oil pumping;
- Special hose passing equipment;
- Platform – tanker tie in system;
- Controlling and monitoring system during offloading operations.

Schematically “CUPON” offloading system is shown in Figure 9.5

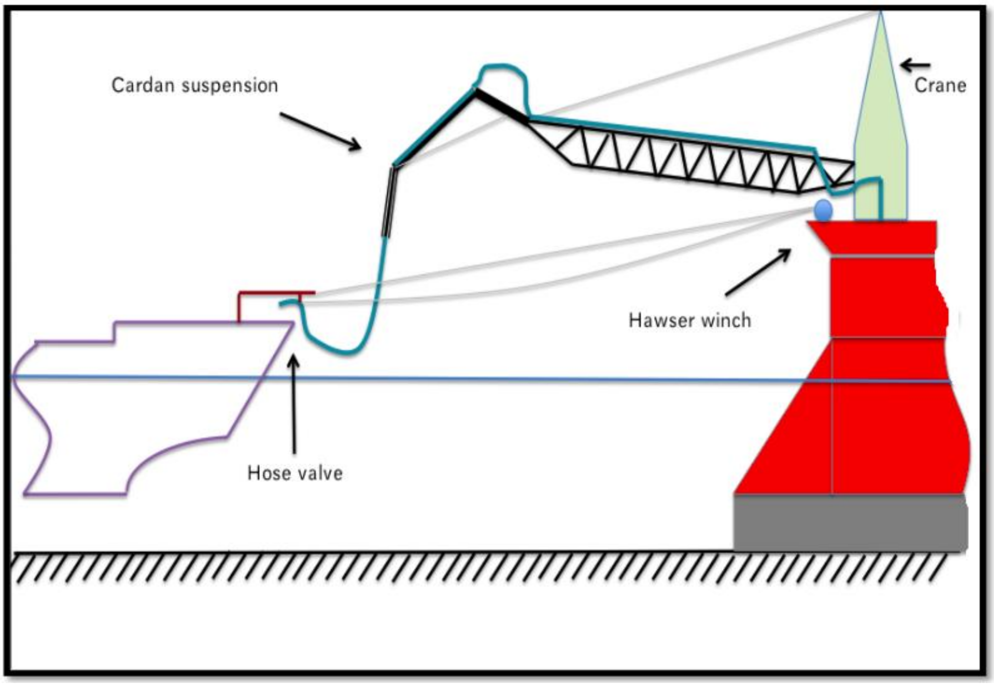

Figure 9.5 The scheme of the “CUPON” system (*Subbotin, 2015)*

At a peak offloading rates, pumps at the IRGBS “Prirazlomnaya” may reach 8750 m3/h (*Gazprom neft shelf: Prirazlomnaya field development, 2015)* what might be required at the peak oil production rates at the platform (Gazprom neft company

In order to estimate properly, the offloading capacity of the platform, not just the pumps capability should be taken into consideration as external factors, such as current direction, ice present and drift, wave height and etc., also affect to the process of oil offloading to the shuttle tankers. When some of the mentioned above external factors influence to the tanker stability, the offloading process cannot be totally finished per one attempt. Shuttle tanker must be disconnected from the platform and wait for the “weather window” in order to continue the offloading process.

Currently, there are two shuttle tankers that provide service to the Prirazlomnaya oilfield in terms of oil carrying from the platform to the floating storing unit “Umba”, which is located in the Kola Bay. It should be pointed that tankers should carry out several attachments to the IRGBS “Prirazlomnaya” in order to completely fill it tanks with oil. The statistical data that is shown below is based on the 40 oil offloading operations from the platform to the tankers (*Internal information of the Gazprom neft, 2016)*. Initially, the preliminary steps that have to be done during the platform – shuttle tanker connection in order to carry out the offloading operation are shown below:

- hose connection/disconnection;

- mooring tie-in/disconnection;
- hose flushing (before and after offloading);
- assembling and disassembling of green line;
- testing of the emergency shut down system (ESD);
- drawing up documents after the offloading process.

There is detailed analysis of mentioned above operations in terms of time:

1. Hose connection – the process of cargo systems connection between platform and shuttle tanker. The time needed for the cargo system connection is shown in Table 9.2, while the distribution of the time needed for the hose connection is shown in Figure 9.6.

Table 9.2 Time needed for the hose connection

Definition	Value
Average	38 min
Dispersion	192 min^2
The lowest	5 min
The highest	85 min

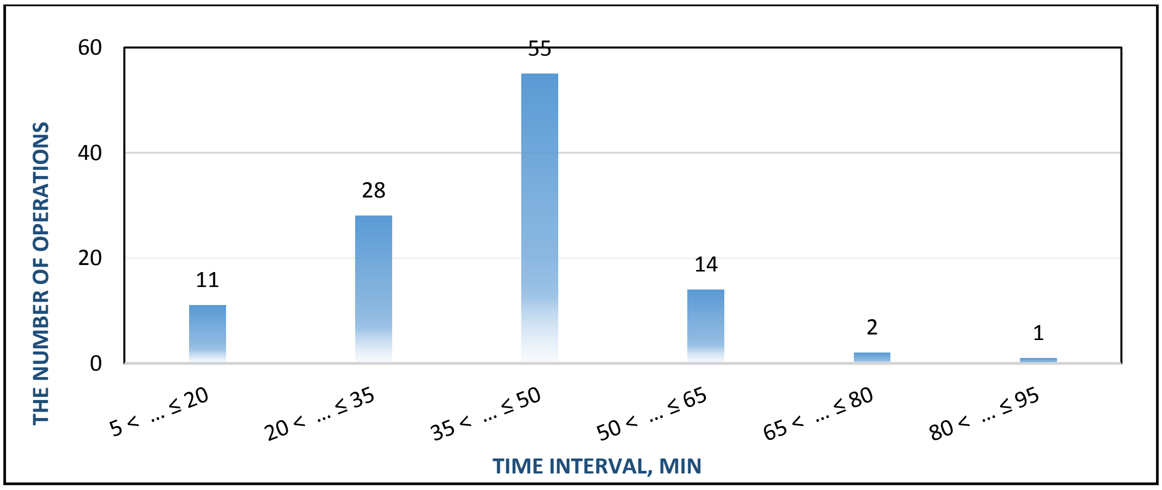

Figure 9.6 The distribution of the time needed for the hose connection

2. Hose disconnection - the process of cargo system disconnection between platform and shuttle tankers. The time needed for the cargo system disconnection is shown in Table 9.3, while the distribution of the time needed for the hose disconnection is shown in Figure 9.7.

Table 9.3 Time needed for the hose disconnection

Definition	Value
Average	27 min
Dispersion	190 min^2
The lowest	5 min
The highest	73 min

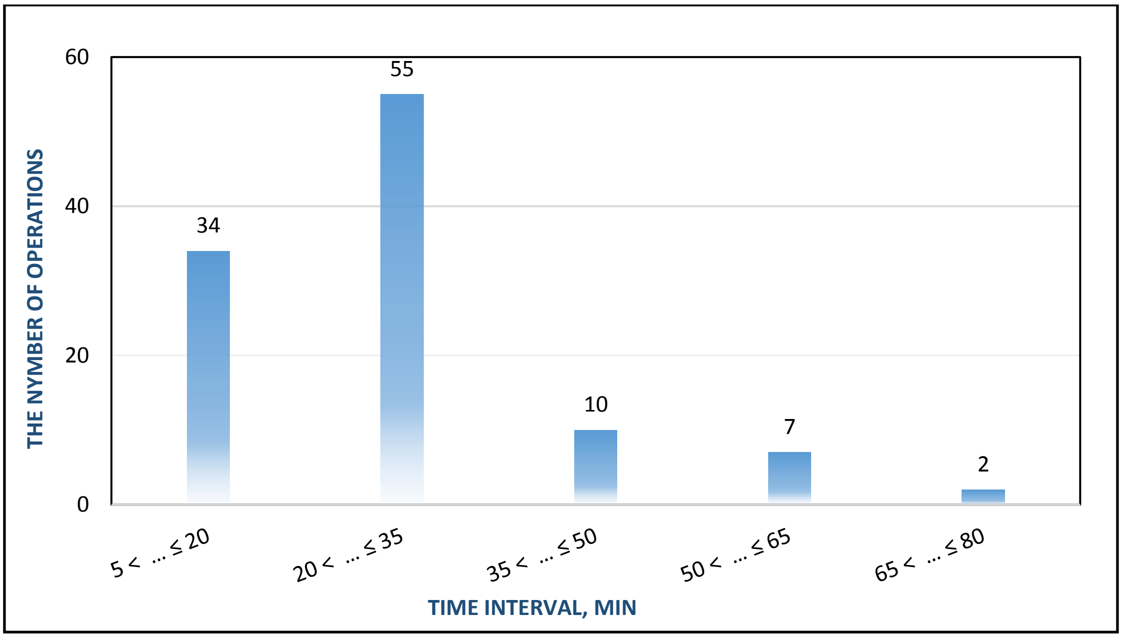

Figure 9.7 The distribution of the time needed for the hose disconnection

3. Mooring tie-in – the process of mooring lines connection between platform and tanker in order to provide stability of the vessel and the contact between offshore structures. The time needed for the mooring tie-in is shown in Table 9.4, while the distribution of the time needed for the mooring tie-in is shown in Figure 9.8.

Table 9.4 Time needed for the mooring line connection

Definition	Value
Average	40 min
Dispersion	193 min^2
The lowest	10
The highest	95

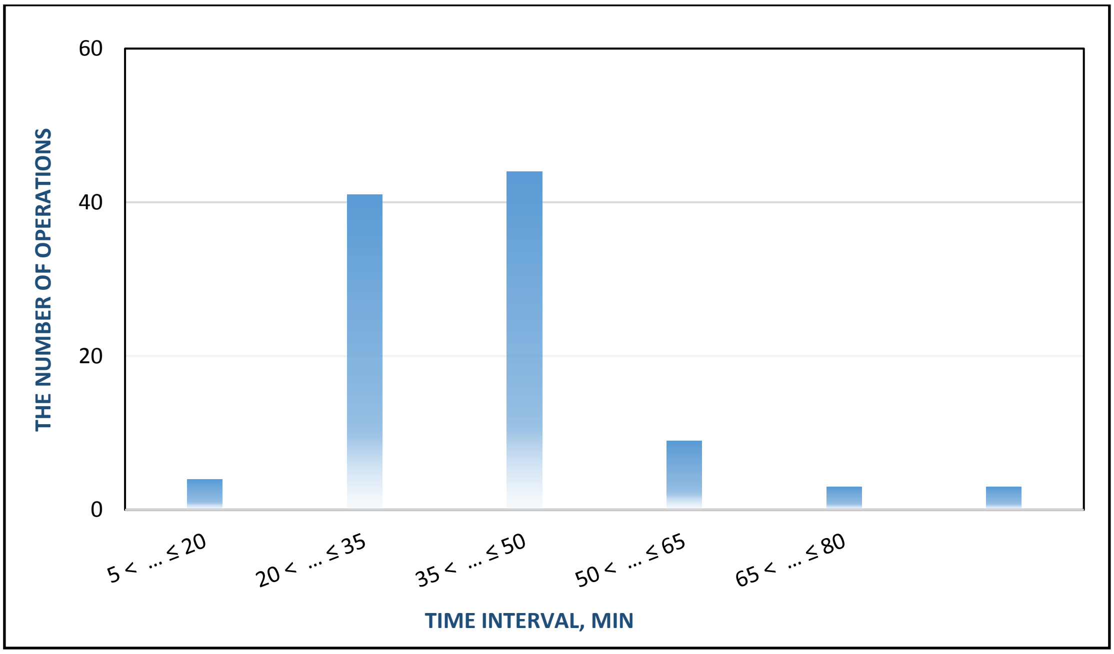

Figure 9.8 The distribution of the time needed for the mooring tie-in

4. Mooring disconnection – the process of mooring line disconnection between platform and tanker. The time needed for the mooring disconnection is shown in Table 9.5, while the distribution of the time needed for the mooring disconnection is shown in Figure 9.9.

Table 9.5 The time needed for the mooring disconnection

Definition	**Value**
Average	32 min
Dispersion	94 min^2
The lowest	10 min
The highest	66 min

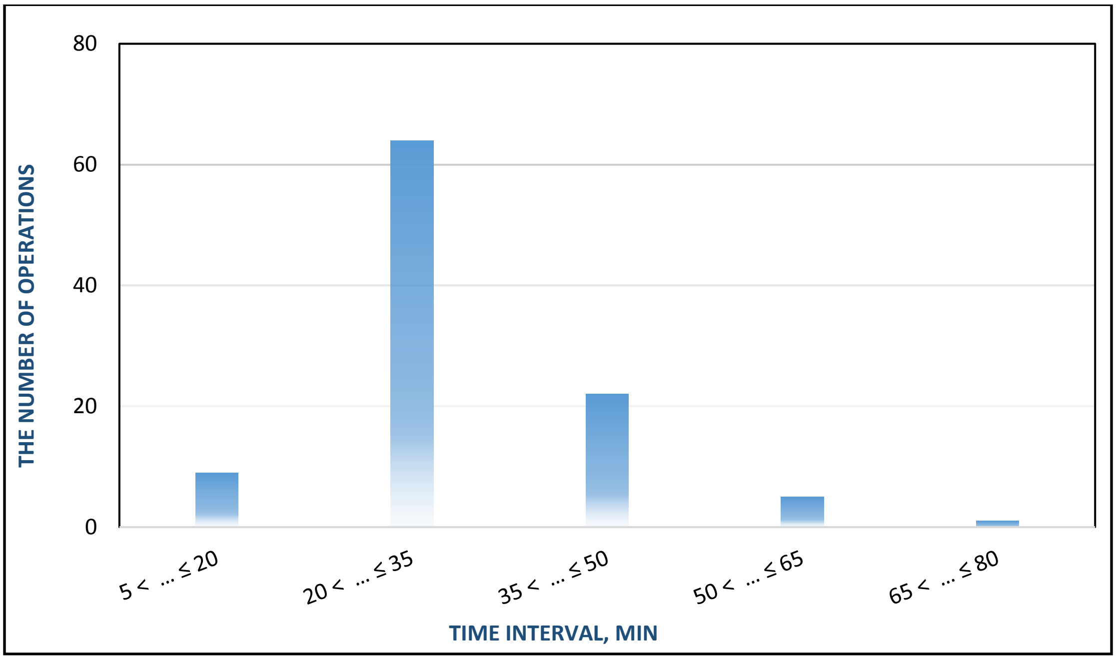

Figure 9.9 The distribution of the time needed for the mooring disconnection

5. Hose flushing – the cleaning of the connection hose between platform and tanker. The time needed for the hose flushing is shown in Table 9.6, while the distribution of the time needed for the hose flushing is shown in Figure 9.10.

Table 9.6 The time needed for the hose flushing

Definition	**Value**
Average	32 min
Dispersion	362 min^2
The lowest	5 min
The highest	78 min

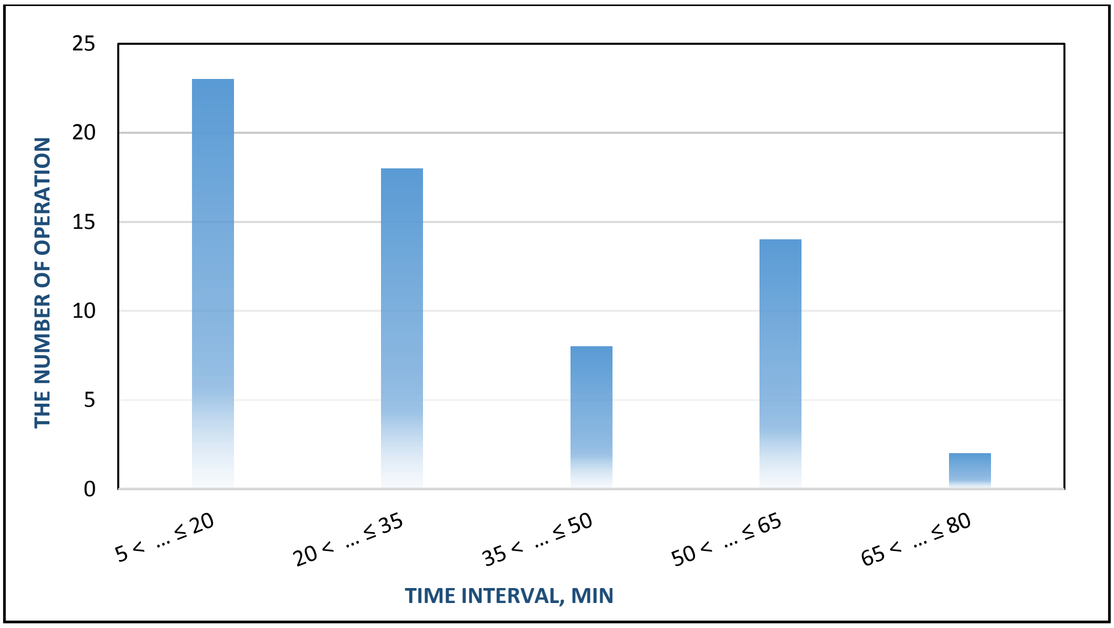

Figure 9.10 The distribution of the time needed for the hose flushing

6. Assembling and disassembling of green line; The time needed for the assembling and disassembling of the green line is shown in Table 9.7, while the distribution of the time needed for the assembling and disassembling of the green line is shown in Figure 9.11.

Table 9.7 The time needed for the assembling and disassembling of the green line

Definition	**Value**
Average	9,4 min
Dispersion	72 min^2
The lowest	1 min
The highest	28 min

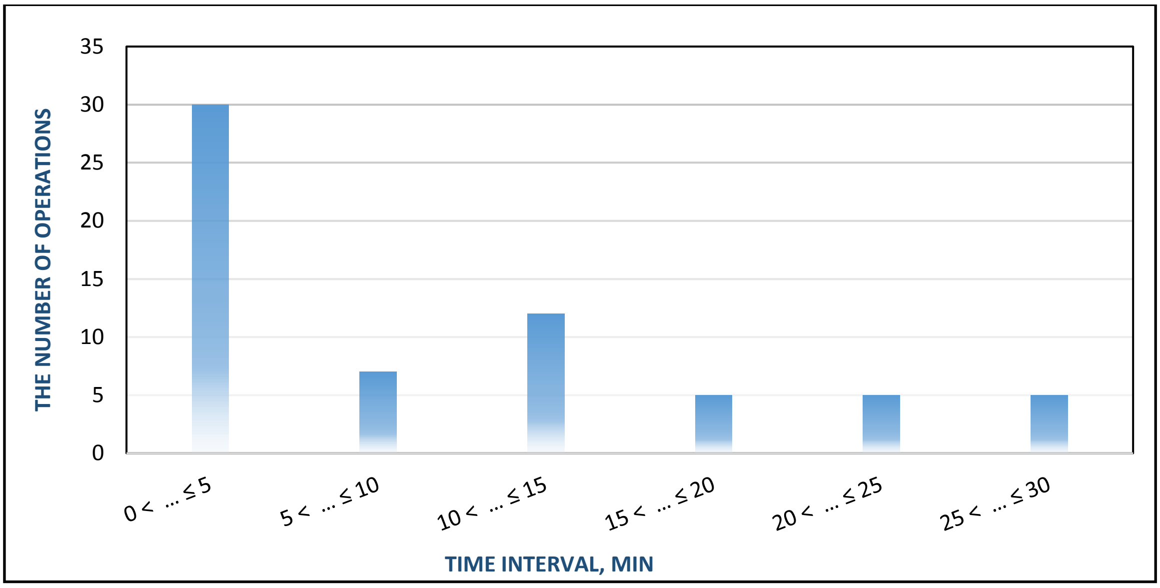

Figure 9.11 The distribution of the time needed for the assembling and disassembling of the green line

7. Testing of the emergency shut down system that ensure prevailing of any oil spills. The time needed for the testing of the emergency shut down system is shown in Table 9.8, while the distribution of the time needed for the testing of the emergency shut down system is shown in Figure 9.12.

Table 9.8 The time needed for the testing of the emergency shut down system

Definition	**Value**
Average	9,4 min
Dispersion	72 min^2
The lowest	1 min
The highest	28 min

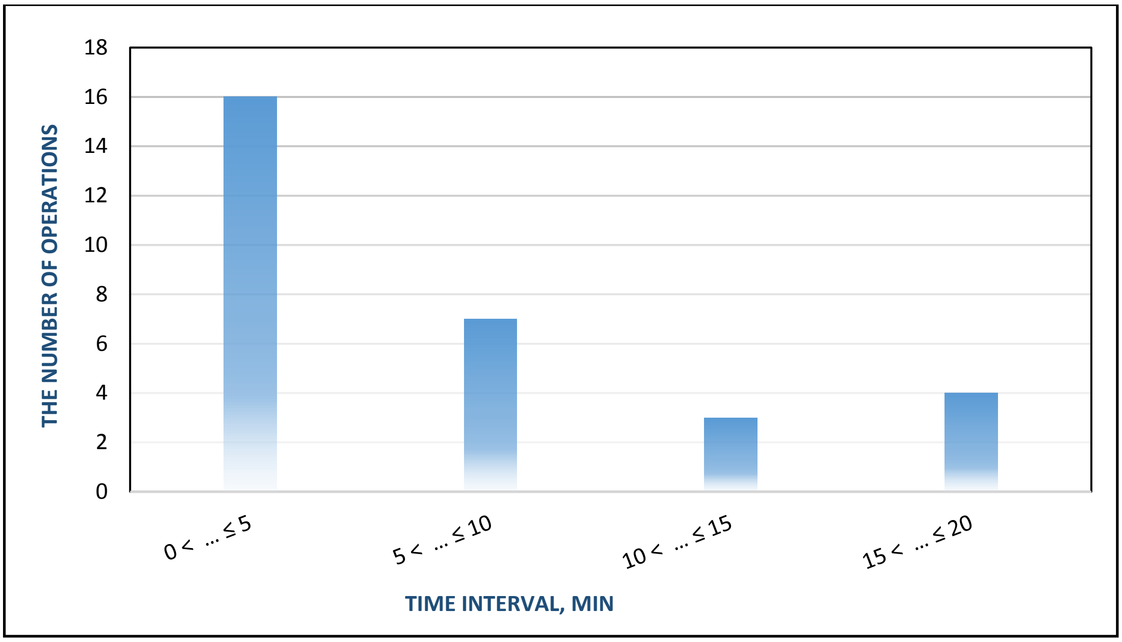

Figure 9.12 The distribution of the time needed for the testing of the emergency shut down system

8. Oil offloading operations – the main aim of all previous steps. The time for oil offloading operations per one approach is down in Table 9.9, while the output distribution of the oil offloading pumps in m^3/hour per offloading operation shown in Figure 9.13.

Table 9.9 The time for oil offloading operations per one approach

Definition	**Value**
Average	4,8 hours
Dispersion	4,95 $hours^2$
The lowest	1,4 hours
The highest	15,6 hours

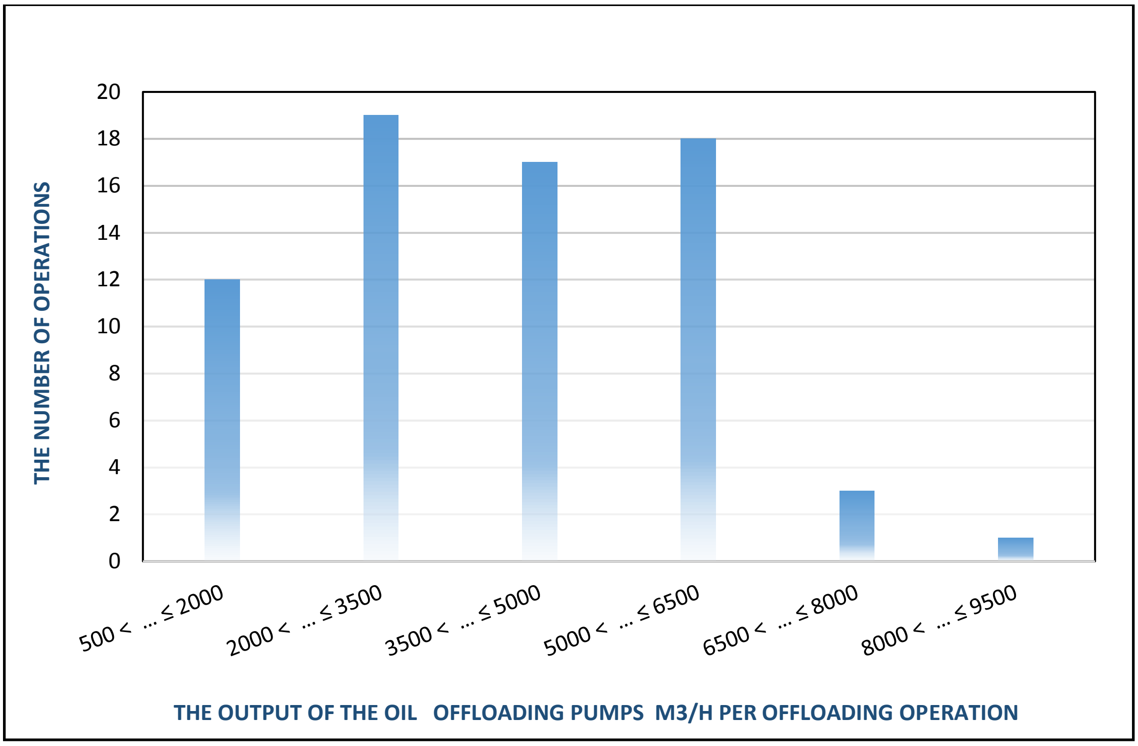

Figure 9.13 The output distribution of the oil offloading pumps m3/h per offloading operation

According to the Table 9.9, the average time of offloading operation per one approach is 4,8 hours, it means that per one connection to the platform the shuttle tanker is filling for 4,8 hours. Averagely, after that time tanker is disconnected and moved away not far from the platform, it is usually caused by weather conditions. Both shuttle tankers are equipped with dynamic positioning system, however it does not provide whole time stability at one particular point (*www.gazprom-neft.ru,2017*). According to the Figure 9.13, it might be pointed that most (19) of the oil offloading operations have been carried out with capacity of 2000 – 3500 m^3/hour out of maximum potential of 8750 m^3/hour. It is mainly justified, that the oil pumps are reaching their maximum offloading capacity gradually, therefore as offloading operations usually interrupted in some point, pumps are not able to reach their maximum capacity. At the same time, 18 operations have been carried out with 5000 – 6500 m^3/hour. In order to estimate average offloading capacity within mentioned 40 offloading operations, the weighted mean value of the capacity of the oil offloading pumps might be calculated:

Initial data:

- Number of approaches – 70;

Calculation:

The weighted mean value of oil offloading capacity per one approach of the tanker according to the Figure 8 = $\frac{500+2000}{2} * \frac{12}{70} + \frac{2000+3500}{2} * \frac{19}{70} + \frac{3500+5000}{2} * \frac{17}{70} + \frac{5000+6500}{2} * \frac{18}{70} + \frac{6500+8000}{2} * \frac{3}{70} + \frac{8000+9500}{2} * \frac{1}{70} = 3907$ m^3/hour.

The information, concerning the productivity of the oil offloading pumps in the IRGBS "Prirazlomnaya" during the offloading operations from the platform to the shuttle tanker is shown in the Table 9.10, while the precise productivity of the oil offloading pumps per each offloading attempt is shown in Figure 9.14.

Table 9.10 The productivity of the oil offloading pumps in the IRGBS "Prirazlomnaya"

Definition	**Value**
Average	3907 m^3/hour
Dispersion	3384029 m^3/hour
The lowest	518 m^3/hour
The highest	8077 m^3/hour

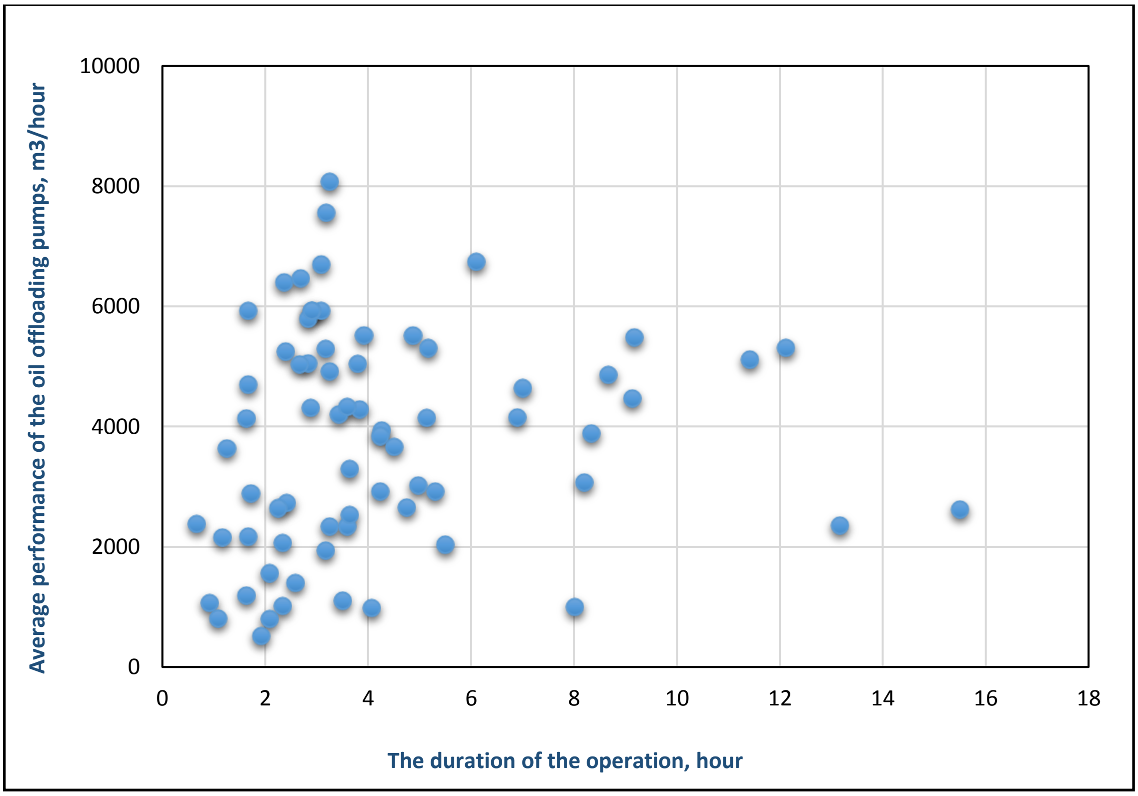

Figure 9.14 Precise productivity of the oil offloading pumps per each offloading attempt

It is of great importance, to consider the time, which is needed to fill whole effective volume of the shuttle tanker. As was mentioned above, the maximum capacity of the oil offloading pumps is 8750 m^3/hour. However, considering the statistical data given above, it is obvious that in fact the offloading capacity is much less. It is connected with several factors, where the major one is that the pumps reach their maximum offloading capacity gradually and often pumps are not able to reach their peak offloading values, as "weather windows" quite short.

As mentioned above, the shuttle tankers which provide service for the Prirazlomnaya platform, have deadweight equal to 70 000 tonnes, thus there is an opportunity to calculate time which is needed to fill up the volume on the tankers.

The average oil density in the Prirazlomnoye oilfield is 0.920 kg/m^3, thereafter, the average oil offloading capacity might be defined:

- $m = V * \rho = 3907\ m^3/hour * 0.920\ kg/m^3 = 3594.44$ tonnes/hour

In order to fill up the shuttle tanker fully, it is needed:

- Time = $\frac{70000}{3594.44} = 19.5$ hours

However, the duration of one connection between the tanker and platform does not reach that 19,7 hours, as according to the Figure the maximum duration was 15,7 hours, with average duration of connection equal to 4,8 hours, therefore to fill the effective volume of tanker several approaches of the tanker are needed.

The average amount of approaches might be estimated:

Number of approaches $= \frac{19.5}{4.8} = 4.06$

Usually disconnections happened because of weather conditions, thus in order to continue offloading operation, appropriate "weather windows" should exist. According to the internal statistic of the Gazprom neft shelf company, inappropriate weather conditions averagely lasts approximately for 7 hours.

Calculation of the total time needed to fill the shuttle tanker fully:

Time per one approach (averagely from the statistic above):

- $T_{per\ approach}$ = 38 min (hose connection) + 40 min (mooring line connection) +32 min (hose flushing) + 9.4 min (green line assembling and disassembling) + 288 min (the process of oil offloading 4.8 hours) + 27 min (hose disconnection) + 32 min (mooring disconnection) = 466.4 min = 7.8 hours is needed to realize one approach.

  As, there are 4.06 approaches, the total time that is needed to fill whole shuttle tanker is = 4.06·7.8 hours = 31.7 hours for one tanker.

Even, if there is maximum possible oil production in the IRGBS "Prirazlomnaya" of 22.5 thousand tonnes per day, taking into account that part of the oil comes from another platform to the second stage of separation. In order to provide oil for the shuttle tanker, platform should work for 3.11 days.

Resulting from the comprehensive consideration of the factors which affect to the volume of liquid that might be transported from the Medynskoe-more oilfield to the IRGBS “Prirazlomnaya”, the development strategy the oilfield might be considered.

9.3 Oil production strategy for the Medynskoe-more oilfield

Resulting from the proposed conception, that the Medynskoe-more oilfield should be developed by utilizing the processing, storing and offloading capacities of the IRGBS “Prirazlomnaya” leading to necessity to define the order of well drilling in new oilfield in order to comply with the capabilities of the platform, that have been comprehensively considered in previous chapter. The amount of oil that might be attached to the platform at the first and second stages of separation in thousands tonnes per day, is shown in the Figure 9.15.

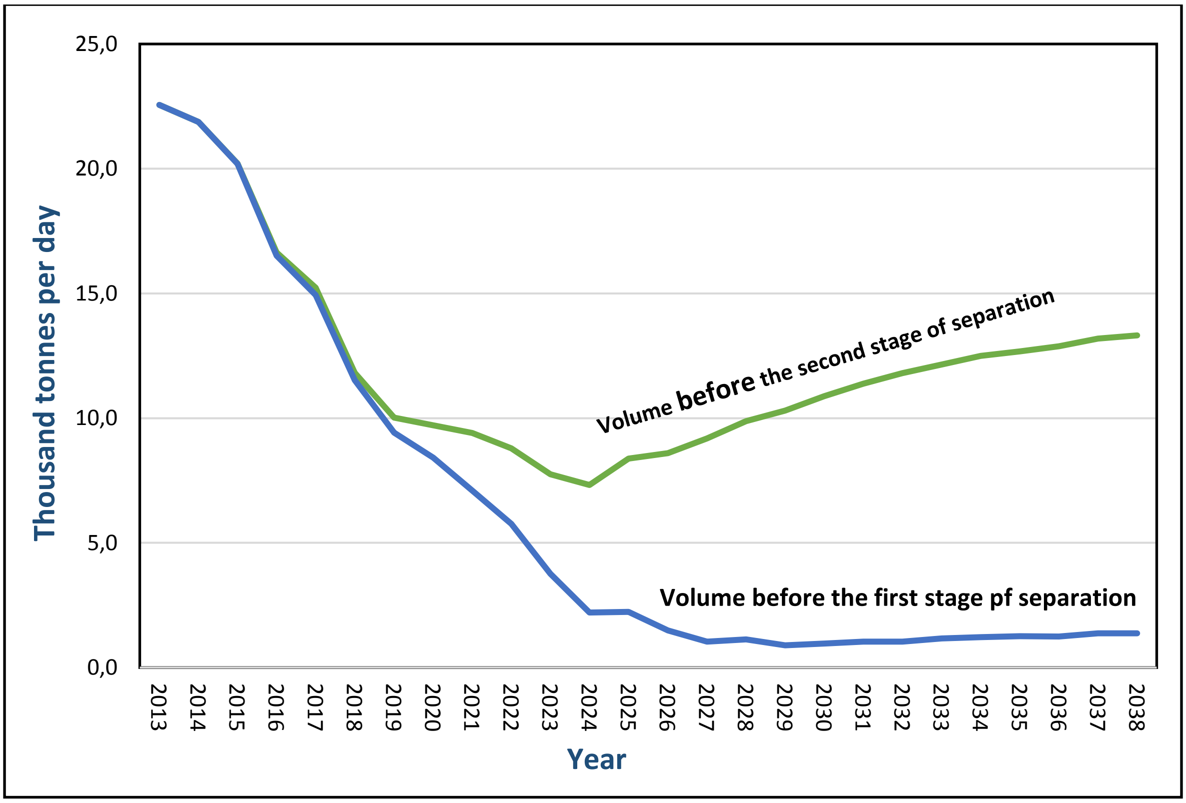

Figure 9.15 The amount of oil that might be attached to the platform at the first and second stage of separation, thousands of tonnes per day (*Internal information of the Gazprom neft, 2016)*

According to the Figure 9.15 it is apparently, that it is more beneficial to attach the up-coming oil to the second stage of separation, as the capacity is higher. Therefore, the first stage of separation is presumed to be installed on the Medynskoe platform, as in the future, water from the first stage of separation will be used for water injection wells, while as the associated gas will be used for electricity generation purposes on the new platform.

As there is lack of geological information concerning the Medynskoe-more oilfield, the following assumptions have been made in order to make oil development strategy on the oilfield:

- The reservoir properties in both oil fields are the same, as the net pay zones of the oil fields are laying at about the same depth (2350 – 2550 meters at Prirazlomnoye and 2360 – 2500 meters at Medynskoe-more oilfield), thus the assumption is allowable, therefore the oil production rates are approximately the same. Put 1300 tonnes/day from the production well in the Medynskoe – more oilfield, as in the Prirazlomnoye (Current average production rate the Prirazlomnaya);
- For the development of the oilfield, it is needed 27 production wells and 15 injection wells (*Bilalov,2014*);
- Concerning current oil prices and experience in the construction of such a huge oil platform (Example: IRGBS "Prirazlomnaya" have been constructed for roughly 10 years), production at the oilfield might be started not earlier than year of 2030.
- Oil production strategy in the Prirazlomnaya oilfield is implied that oil production will be continuing up to year of 2038, therefore after this year, the processing, storing and offloading capacities will be totally free (*Internal information of the Gazprom neft, 2016*).
- Beginning from the second year of production, it is necessary to abandon all oil production and well drilling activities for one month, in order to carry out maintenance of the processing, storing and offloading equipment;
- The IRGBS "Prirazlomnaya" is capable to work up to 2060, totally 50 years of working. (Assumption, according to the internal documents);

Taking into account these assumptions and the Figure 9.15, where the oil processing capabilities in the Prirazlomnaya platform is shown, the oil production and well drilling strategy for the Medynskoe-more oilfield might be proposed. In the Table 9.11, the oil extraction strategy is shown, implying that new oil stream is attached to the second stage of separation and new wells are launching in a specific order to meet the processing capacities in the IRGBS "Prirazlomnaya", to boost the reservoir pressure by water injection.

Table 9.11 The Medynskoe-more oilfield development strategy

Year	Total amount of drilled wells	Production wells	Injection wells	Oil production,		Accumulated production, Million tons	Processing capacity in the second stage of separation in the IRGBS "Prirazlomnaya"
				Thousand tonnes /day	Million tonnes /year		
2030	4	3	1	3,9	1,42	1,42	10,9
2031	4	3	1	7,4	2,48	3,91	11,4
2032	4	2	2	9,3	3,11	7,01	11,8
2033	4	2	2	10,9	3,67	10,68	12,1
2034	4	2	2	12,4	4,17	14,85	12,5
2035	4	1	3	12,5	4,19	19,04	12,7
2036	4	1	3	12,6	4,21	23,24	12,9
2037	2	1	1	12,6	4,22	27,46	13,2
2038	1	1		12,6	4,23	31,69	13,3
2039	2	2		15,2	5,10	36,79	22,7
2040	1	1		15,6	5,23	42,02	22,7
2041	1	1		15,6	5,24	47,27	22,7
2042	1	1		15,7	5,25	52,52	22,7
2043	1	1		15,8	5,29	57,81	22,7
2044	1	1		15,8	5,30	63,11	22,7
2045	1	1		15,9	5,34	68,45	22,7
2046	1	1		15,9	5,32	73,77	22,7
2047	1	1		15,7	5,25	79,02	22,7
2048				15,2	5,09	84,12	22,7
2049				14,7	4,94	89,06	22,7
2050				14,3	4,79	93,85	22,7
2051				13,9	4,65	98,50	22,7
2052				13,5	4,51	103,01	22,7
2053				13,1	4,37	107,38	22,7
2054				12,7	4,24	111,62	22,7
2055				12,3	4,12	115,74	22,7
2056				11,8	3,95	119,69	22,7
2057				11,3	3,79	123,48	22,7
2058				10,9	3,64	127,12	22,7
2059				10,4	3,50	130,62	22,7
2060				10,0	3,36	133,97	22,7

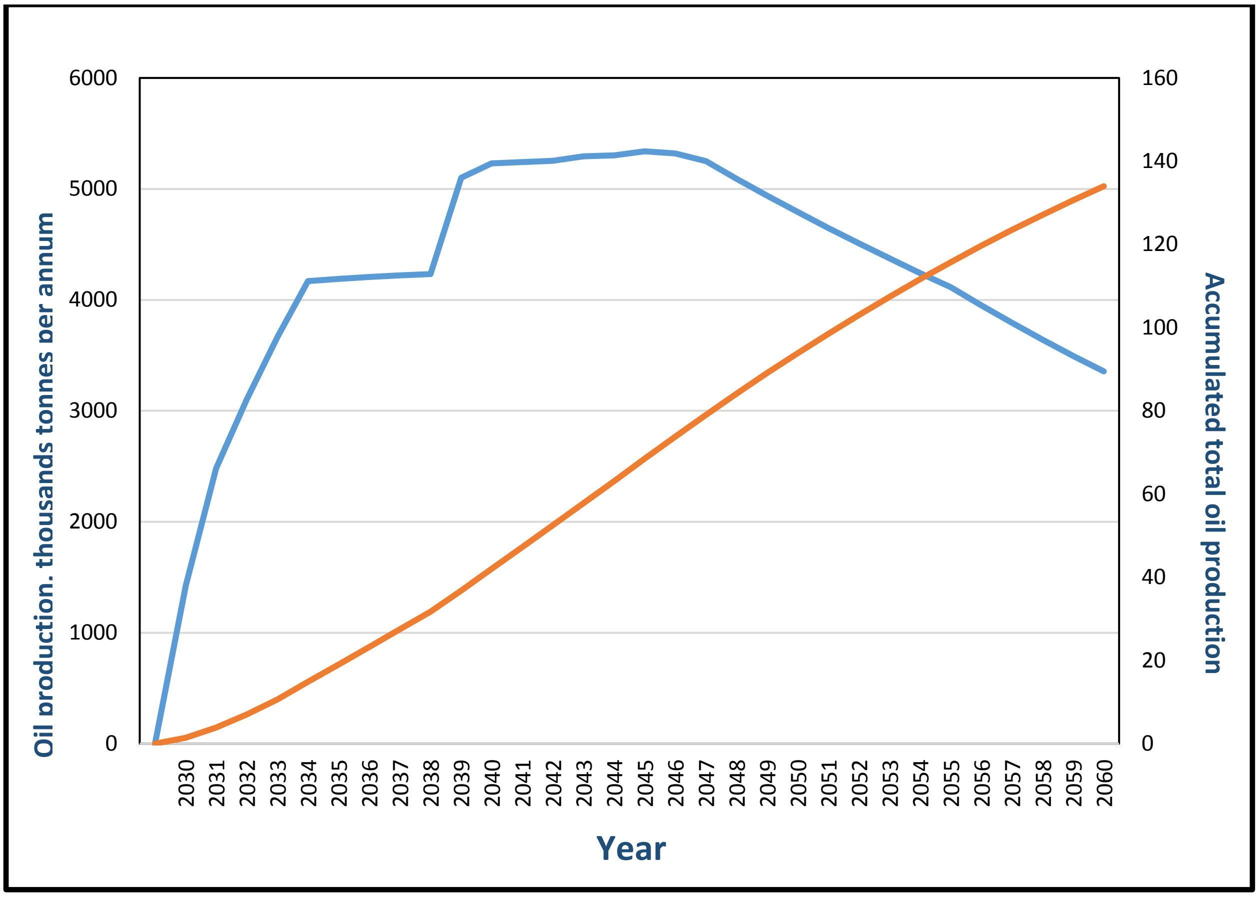

Figure 9.16. Oil production per annum and the total accumulated oil production from the Medynskoe-more oilfield up to year 2060

According to the Figure 9.16, it might be pointed, that the oil production curve does not precisely correspond to that is shown in Figure 9.1, but in generally they coincide. Concerning the curve shown in Figure 9.16, there are two oil production plateaus. First one is connected with the limited processing capacity at the IRGBS “Prirazlomnaya”, thus until own oil is produced in the Prirazlomnoye oilfield, just limited amount of additional oil might be attached, second one is explained by the development strategy. As the Prirazlomnaya platform is presumed to be able to operate up to year of 2060, the accumulated oil production is also considered up to 2060.

10. SUBSEA PIPELINES DESIGN AND CALCULATION

10.1 Subsea pipelines design approach

Subsea pipelines design is a complicated task, moreover it becomes even more complex when we deal with harsh environmental conditions in the Arctic region.
The pipeline design consists of the following steps, depicted in Figure 10.1. Beginning with the pipeline route selection and ending by freespan and correction analysis.

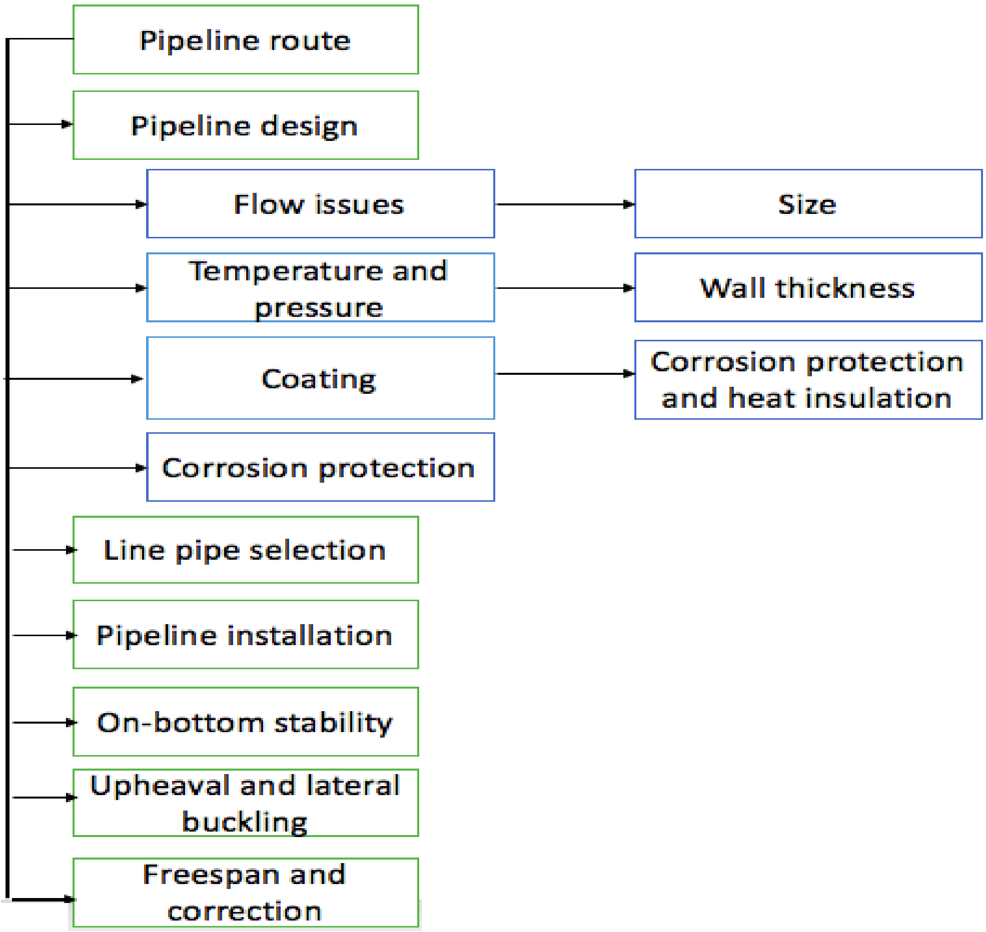

Figure 10.1 The pipeline design steps

10.2 Subsea pipelines calculation for the Medynskoe-more oilfield

These stages embrace all parts of subsea pipelines design and calculations.
In our case as it mentioned above, there is Medynskoe-more oilfield that should be tied to the IRGBS “Prirazlomnaya” by utilizing subsea pipeline.

- Medynskoe-more oilfield $\xrightarrow{52\text{ km}}$ IRGBS “Prirazlomnaya”

According to the preliminary estimations, the recoverable oil reserves in Medynskoe-more oil field will be equal to 133.9 million tonnes.. According to the development strategy of the Medysnkoe-more oilfield, the maximum flow rate to the IRGBS "Prirazlomnaya" through the subsea pipeline is expected in year of 2045 and equal to 5,34 million tonnes per annum, at the same time annual production rate might be taken in a range of 5 – 8 % of recoverable reserves *(Aliev & Bondarenko, 2002).* Thus, in would be reasonable to take 5 %, as it is complying both criterion and provide certain reserve in subsea pipeline capacity. Therefore, annual and daily oil production in the oilfield is the following:

- **Medynskoe-more** – 133.9 · 0.05 = 6.7 million tons of oil per year
  The daily production: $\mathrm{Qd} = \frac{8700000}{365} = 18356\ \frac{tons}{day}$
  The production in m^3:
  - $\frac{18356}{0.920} = 19952\ \frac{m3}{day} => \frac{199526}{86400} = 0{,}23\frac{m3}{second}$

As a reference document API 5L might be utilized in order to choose pipeline parameters and properties of the material. Pipe properties are given in Table 10.1, X65 steel properties are considered in Table 10.2, while as initial data concerning the pipeline and additional parameters are considered in Tables 10.3 and 10.4 respectively.

Table 10.1 pipe properties *(API 5L, 2005)*

Pipe diameter (nominal)	10'	12'	14'	16'
Pipe outside diameter	273.1 mm	323.9 mm	355.6 mm	406.4 mm
API 5L standard wall thickness	9.3 mm - 11.1 mm 12.7 mm 14.3 mm 15.9 mm 18.3 mm	9.5 mm 10.3 mm 11.1 mm 12.7 mm 14.3 mm 15.9 mm 18.3 mm	9.5 mm 10.3 mm 11.1 mm 12.7 mm 14.3 mm 15.9 mm 18.3 mm	11.9 mm 12.7 mm 14.3 mm 15.9 mm 17.5 mm 19.1 mm 20.6 mm

Table 10.2 X65 steel properties *(APi 5L, 2005)*

Parameter	SI Units
SMYS	448 MPa
Thermal coefficient for steel expansion	1.17E-5 °C
Poisson's ratio of steel	0.3
Young's Modulus of steel	210 GPa

Table 10.3 Initial data about the pipeline

Pipe Data	SI Units
Nominal Wall thickness, t_w	14,3 mm (Initial assumption)
Nominal pipe diameter, D_o	406,4 mm (Initial assumption)
Pipeline Length, L	52 km
Internal roughness, k	0.05 mm
Flowline well head pressure	450 bar
Minimum arrival pressure at the IRGBS "Prirazlomnaya"	350 bar
Constant Operating temperature	65 deg Celsius
Installation temperature	5 deg Celsius

Table 10.4 Additional parameters

Operating Data	SI Units
Flow rate, Q m3/s	0.23
Dynamic Viscosity	2.590E-3 Pa*s
Contents Density	920 kg/m^3

10.2.1 Calculation of the pressure drop throughout subsea pipeline

The aim is to find the diameter of the pipeline which will provide the required arrival pressure conditions. As the pipeline has a quite long distance of 52 km, at the beginning 406.4 mm nominal diameter of the pipeline with a wall thickness equal to 14.3 mm is taken. We should check for the pressure drop inside pipeline throughout whole distance and compare it with limit value, if it does not respond to the requirements, calculations should be revised with another diameter and in some cases with another wall thickness.

1. We choose initial pipeline diameter and wall thickness according to the table:

D_O = 406.4 mm and t = 14.3 mm

2. Calculation of the pipeline internal diameter

$D_i = D_O - 2 * t = 406.4 - 2 * 14.3 = 377.8$ mm

3. Calculation of the erosion and flow velocity

At the beginning it is necessary to calculate erosion velocity (Ve) in order to compare it with the actual flow velocity (V) in the pipeline:

$$\mathrm{Ve} = \frac{122}{\sqrt{\rho}} = \frac{122}{\sqrt{920}} = 4\ m/s$$ - erosion velocity

Calculation of the actual flow velocity in the pipeline:

$$\mathrm{V} = \frac{\mathrm{Q}}{\mathrm{S}} = \frac{4*\mathrm{Q}}{\pi*\mathrm{Di}^2} = \frac{4*0{,}31}{3{,}14*0{,}3778^2} = 2{,}05\ m/s$$ – actual flow velocity

So, V < Ve => actual flow velocity is accepted.

4. Calculation of the Reynolds number:

$$\mathrm{Re} = \frac{\mathrm{v}*\mathrm{D}*\rho}{\mu} = \frac{4*\mathrm{Q}*\mathrm{Di}*\rho}{\pi*\mathrm{Di}^2\mu*} = \frac{4*0.31*0.3778*920}{3.14*0.3778^2*3.092*10^{-3}} = \frac{290{,}3}{6.2*10^{-7}} = 2{,}75 * 10^5$$

Based on the Reynolds number, we can define the flow regime:

- Laminar – when Re < 2300
- Transient – when 2300 < Re<4000
- Turbulent – when Re > 4000

According to the Reynolds number – the flow is turbulent – $2.75*10^5 > 4000$

5. Calculation of the relative roughness of the pipelines (r):

$$\mathrm{r} = \frac{\varepsilon}{\mathrm{Di}} = \frac{0{,}05}{377.8} = 1.32 * 10^{-4}$$

According to the Moody diagram, it is possible to define the Darcy-Weisbach friction factor f. A Moody diagram is shown below in the Figure 5.1.

6. Calculation of the actual pressure drop which consists of two parts – head loss due to friction in the pipeline and hydrostatic pressure head:

$$\Delta p = \frac{f*\rho*v^2*L}{2*Di} + \rho * g * h = \frac{0.015*920*2.05^2*52000}{2*0.3778} + 920 * 9.81 * 50 = 4.45\ MPa$$

Δp = 4.45 MPa = 44.5 Bar – pressure drop throughout pipeline

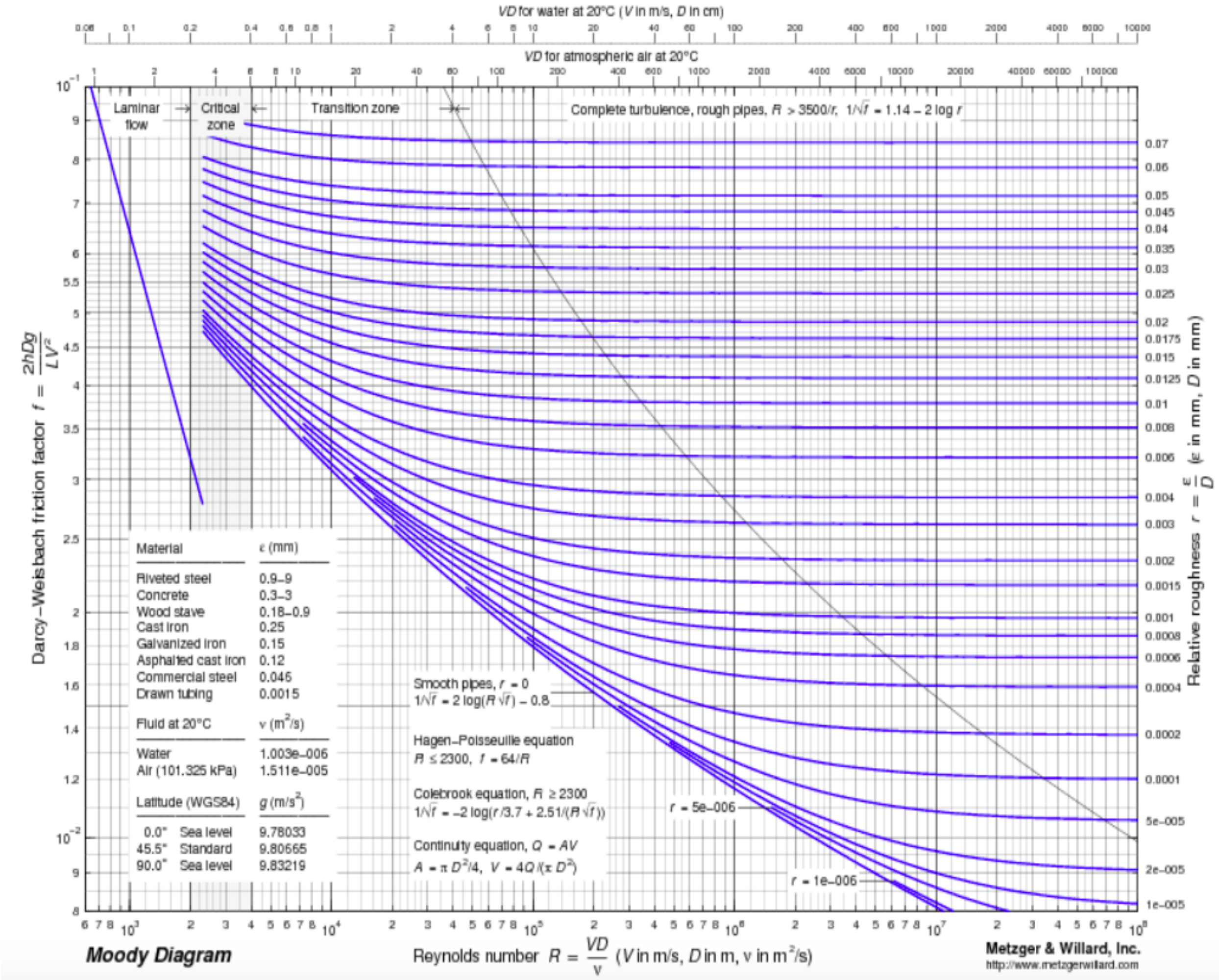

Figure 10.2 Moody diagram *(Karunakaran, 2014)*
Determination of the Darcy – Weisbach friction factor

According to the Figure 10.2, the Darcy – Weisbach friction factor is equal to 0.015 which has been used in the pressure drop calculation.

7. Comparing the actual pressure drop and allowable pressure drop requirements:

$P_{WH} - \Delta p > P_{MIN}$

where:

- P_{WH} – flowline well head pressure, MPa
- P_{MIN} – minimum arrival pressure at top of the platform, MPa

45 MPa – 4.45 MPa > 35 MPa – thus, the diameter is appropriate to this pipeline, there is no need to change pipeline diameter and the wall thickness.

10.2.2 Optimization of the subsea pipeline wall thickness *(Karunakaran, 2014)*

The wall thickness of the pipeline should be optimized based on the hoop stress value. Therefore, the following equation for the hoop stress is applied:

1. Hoop stress $= \frac{Pi*Di-Po*Do}{2*t} = \frac{45*10^6*0.3778-1025*9.81*50*0.4064}{2*0.0143} = 587 \text{ MPa}$

   S_H = 587 MPa

According to API 5L, SMYS for X65 steel is 448 MPa. Design factor of 0.8 has to be used in order to ensure safety margin.

SMYS design factor = 448 ∗ 0.8 = 358.4 MPa

In order to provide safety, the following expression should be utilized:

SMYS∗design factor > S_H, so putting values we can see,

322 MPa < 587 MPa => it is not acceptable; the wall thickness should be optimized.

1. The wall thickness of the pipeline should be optimised:

New wall thickness is: t = 27 mm, in this case we have new internal diameter:
$D_i = D_o - 2 * t = 0.4064 - 0.027*2 = 0.401$ mm

$$S_H = \frac{Pi*Di-Po*Do}{2*t} = \frac{45*10^6*0.401-1025*9.81*50*0.4064}{2*0.027} = 330.3\ MPa$$

Let's check:

SMYS∗design factor > S_H => 358.4 MPa > 330.3 MPa. therefore it is appropriate wall thickness.

10.2.3 Calculation of the Von Mises criteria *(Karunakaran, 2014)*

We assume that there is one span throughout subsea pipeline. The pipeline is subjected to a residual axial tension of 150 KN and a bending moment of 50 KN. We have to use Von Mises criterion to estimate stresses and for safety margin design factor of 0.8 is taken.

Von Mises criterion = $\sigma_{eq} = \sqrt{\sigma_h^2 + \sigma_l^2 - \sigma_h * \sigma_l}$

9. Moment of inertia

$$J = \frac{\pi}{64} * (D^4 - (D - 2 * t)^4) = \frac{3.14}{64} * (0.4064^4 - (0.4064 - 2 * 0.027)^4)$$

$= 5.81 * 10^{-4}$

10.Bending stress

$$\sigma_{bending} = \frac{M}{J} * \frac{D}{2} = \frac{50*10^3}{5.81*10^{-4}} * \frac{0.4064}{2} = 17 \text{ MN}$$

11.Longitudinal stress

$$\sigma_{longitudinal} = \sigma_{axial} \pm \sigma_{bending} = \frac{4*Faxial}{\pi*D^2} + \sigma_{bending} = \frac{4*100*10^3}{3.14*0.4064^2} + 17 = 18.25 \text{ MN}$$

12.Hoop stress

$$\sigma_H = \frac{Pi*Di - Po*Do}{2*t} = \frac{45*10^6*0.401 - 1025*9.81*50*0.4064}{2*0.027} = 303.3 \text{ MPa}$$

13.Von Mises criterion

$$\sigma_{eq} = \sqrt{330.3^2 + 18.25^2 - 330.3 * 18.25 =} \; 321.5 \text{ MPa}$$

14.Let's check the acceptance of this value.

SMYS*design factor = 448 * 0.8 = 358.4 MN

So, SMYS*design factor > σ_H => 358.4 MN > 321.5 MN, so it is accepted.

11. SUBSEA PIPELINES ON-BOTTOM STABILITY ANALYSIS

11.1 Description of the on-bottom stability analysis *(DNV-RP-E305,1988)*

After the subsea pipeline diameter, the wall thickness and material quality are established, on- bottom stability design should be conducted in order to provide stability of the subsea pipeline, due to exposing loads from waves and current. DNV-RP-E305 is taken as a reference document for vertical and lateral stability analysis of the pipeline. On-bottom stability consideration, aiming to prevent vertical and lateral motions include the following main motions:

- Sinking
- Floating
- Horizontal movement

In accordance with the latest codes, beginning from 1988, small horizontal displacements of the pipeline are allowed. Concerning this issue, there are three design methods:

- Dynamic lateral stability method
- Generalized lateral stability method
- Absolute lateral stability method

In the following chapter, just absolute lateral stability analysis of the pipeline is conducted, based on the static equilibrium of forces in order to provide sufficient resistance against hydrodynamic loads.

11.2 On bottom stability analysis *(DNV-RP-E305,1988)*

In order to carry out calculations, input data should be given. Pipe data, environmental data and soil data should be considered. Relevant data is given in tables 11.1, 11.2 and 11.3.

Table 11.1 Pipe data

Parameter	Value
Steel pipe outer diameter, D	406.6 mm
Wall thickness, t_s	27 mm
Steel pipe density, ρ_s	7850 kg/m^3

External corrosion coating thickness, t_{cc}	5 mm
External corrosion coating density, ρ_{cc}	1400 kg/m^3
Internal corrosion allowance	0
Pipe content density, ρ_i	920 kg/m^3
Seawater density, ρ_w	1030 kg/m^3
Concrete coating density, ρ_c	2932 kg/m^3
Concrete coating thickness, t_{conc}	85 mm
Water absorption for concrete	3 %

Table 11.2 Environmental Data

Parameter	Value
MSL, d	10 m
Significant wave height, Hs	6.7 m
Spectral peak period, Tp	10.9 s
Current velocity, Ur at 1 m above the seabed	0.6 m/s
Height of measured current, Zr	1 m above the seabed
Angle of attack – wave, α_s	90° (critical)
Angle of attack – current, α_c	90°

Table 11.3 Soil data

Parameter	Value
Soil type	Sand
Roughness of sand, z_0	0.02083 mm
Coefficient of friction	0.7

Now, calculations might be fulfilled (*DNV-RP-E305,1988)*

1. Find wave parameter, Tn

$$\mathrm{Tn} = \sqrt{\frac{\mathrm{d}}{\mathrm{g}}} = \sqrt{\frac{10}{9.81}} = 1.009\ \mathrm{s}$$

2. The ratio of Tn to Tp

$$\frac{\text{Tn}}{\text{Tp}} = \lambda = \frac{1.009}{10.9} = 0.092$$

3. Defining the U_s^* the significant water velocity.

Parameter $\frac{Us*\text{Tn}}{Hs}$ might be defined by using two methods – calculation and graphical

a) First method – calculation

- $\frac{Us*Tn}{Hs}$ = 0,5 if $\lambda = 0$
- $\frac{Us**Tn}{Hs}$ = 0 if $\lambda \geq 0, 5$
- $\frac{Us*Tn}{Hs}$ = $(80.052\lambda^5 - 141.85\lambda^4 + 90.988\lambda^3 - 22.782\lambda^2 + 0.3772\lambda + 0.4967)$ if λ has another value – it is our case.

So we have:

$\frac{Us*Tn}{Hs}$ = $(80.052 * \lambda^5 - 141.85 * \lambda^4 + 90.988 * \lambda^3 - 22.782 * \lambda^2 + 0.3772 * \lambda + 0.4967)$

$= (80.052*0.092^5 - 141.85*0.092^4 + 90.988*0.092^3 - 22.782*0.092^2 + 0.3772*0.092 + 0.4967) = 0.399$

b) Second method – graphical

We know the relation $\frac{\text{Tn}}{\text{Tp}}$, so we can define $\frac{Us*Tn}{Hs}$ according to the Figure 11.1:

Peakedness = 1 (assumption)

So, $\frac{Us*Tn}{Hs}$ is approximately equal to 0.4, what generally, coincide with value 0.399.

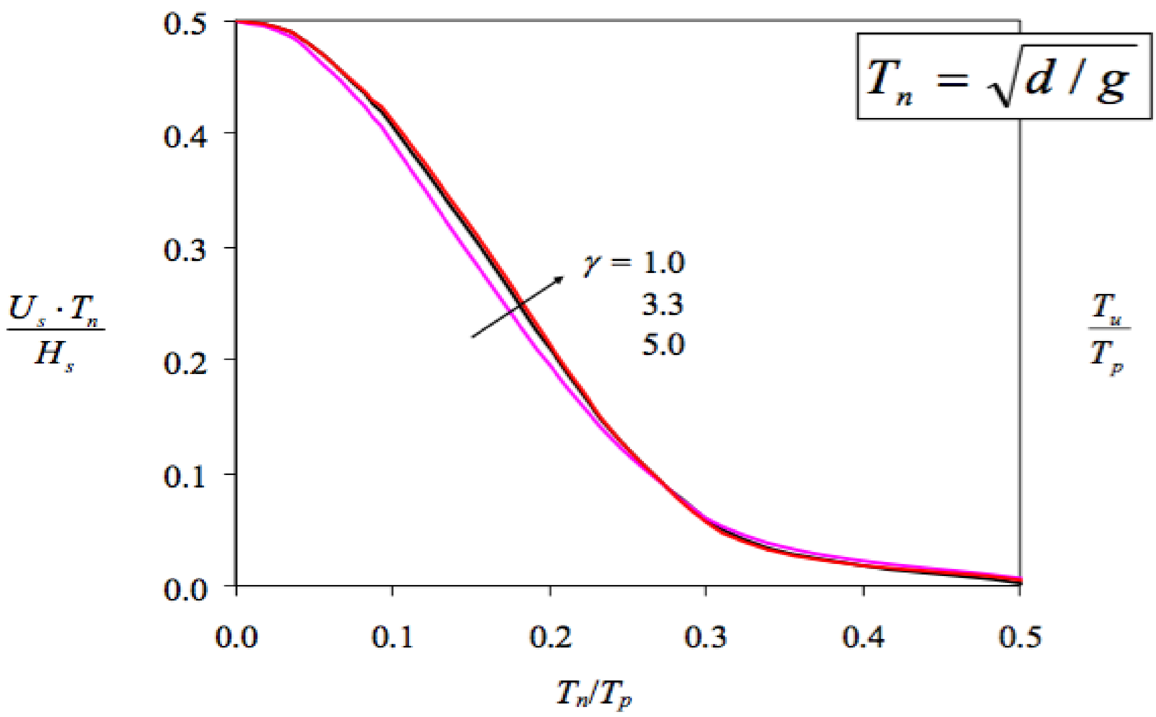

Figure 11.1 Significant water velocity ***(DNV-RP-E305,1988)***

Now, the significant water velocity can be calculated,

Us = $\frac{Hs*0,399}{Tn} = \frac{6.7*0.399}{1.009} = 2.65$ m/s at 90° to pipeline axis.

4. Defining the near bottom velocity perpendicular to pipeline:

Us = 2.65 ∗ sin90° = 2.65 ∗ 1 = 2.65 m/s

5. Defining the zero-up crossing period, T_u

Parameter $\frac{Tu}{Tp}$ might be defined by using two methods – calculation and graphical methods

a) First method - calculation

- $\frac{Tu}{Tp} = 0.71$ if $\lambda = 0$
- $\frac{Tu}{Tp} = 1.41$ if $\lambda \geq 0,5$
- $\frac{Tu}{Tp} = (14.491\lambda^4 - 16.788\lambda^3 + 5.5237\lambda^2 + 1.0172\lambda + 0.7116)$ if other value

Our value of λ is equal to 0.092, so we are using the following formula:

$\frac{Tu}{Tp} = (14.491\lambda^4 - 16.788\lambda^3 + 5.5237\lambda^2 + 1.0172\lambda + 0.7116) = (14.491 * 0.092^4 -$
$-16.788 * 0.092^3 + 5.5237 * 0.092^2 + 1.0172 * 0.092 + 0.7116) = 0.839$

So, now zero-up crossing period can be found:

$\frac{Tu}{Tp} = 0.839 \Rightarrow \text{Tu} = 0.839 * 10.9 = 9.15$ s

b) Second method – graphical method

We know that $\frac{\text{Tn}}{\text{Tp}} = 0.092$, so according to the Figure 11.2 $\frac{\text{Tu}}{\text{Tp}} = 0.84$

So, from $\frac{\text{Tu}}{\text{Tp}} = 0.84$, up-crossing period Tu might be deduced:

Tu = 0.84 ∗ Tp = 0.84 ∗ 10.9 = 9.156 s

The results from both methods coincide,

Up-crossing period - Tu equal to 9.15 s

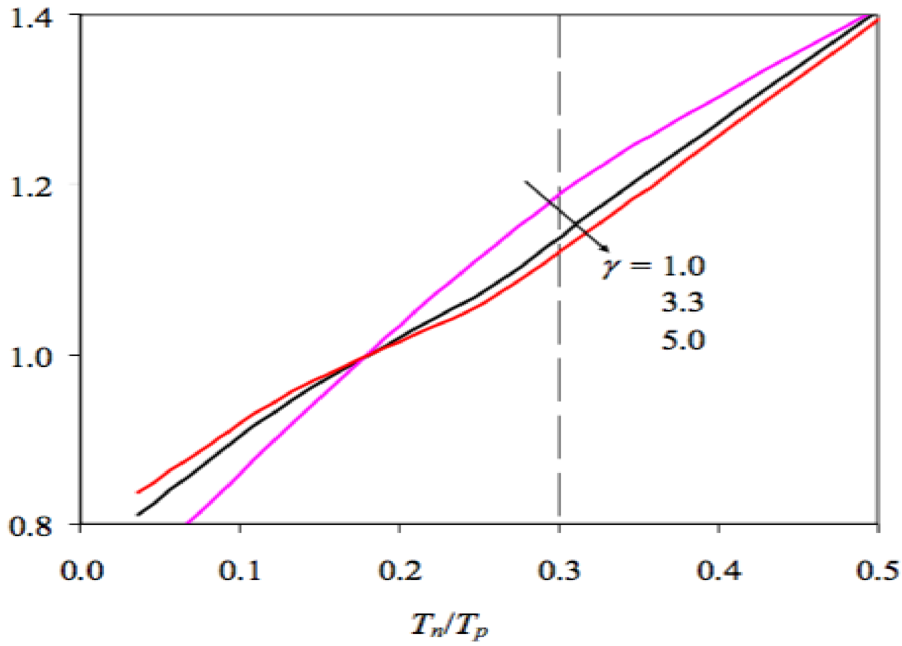

Figure 11.2 Zero-up crossing period *(DNV-RP-E305, 1988)*

Current

Average current velocity over pipe diameter. Using 80 mm concrete coating and 5 mm corrosion coating

Overall Pipe Diameter = Ds + 2t_{CC} + 2t_{CONC} = 406.6 + 2*5 + 2*85 = 586.6 mm

Now, the current velocity perpendicular to the pipeline should be calculated:

$$U_D = Ur * \left[\frac{1}{\ln\left(\frac{Zr}{Zo}+1\right)}\right] * [\left(1 + \frac{\text{Zo}}{\text{D}}\right) * \ln\left(\frac{\text{D}}{\text{Zo}} + 1\right) - 1]$$

$$= 0{,}6 * \left[\frac{1}{\ln\left(\frac{1000}{0.02083}+1\right)}\right] * [\left(1 + \frac{0.02083}{586.6}\right) * \ln\left(\frac{586.6}{0.02083} + 1\right) - 1]$$

$= 0.5147$ m/s

So, current at 90° is equal to:

Uc = 0.5147 $*$ sin 90° = 0.5147 $*$ 1 = 0.5147 m/s

6. Pipe weight calculation $W_{con,}$ with 85 mm of concrete coating and 5 mm corrosion coating thickness:

- Steel pipe weight = π $*$ (0.4066 – 0.027) $*$ 0.027$*$7850 = 252.76 kg/m
- Corrosion coating weight = π $*$ (0.4066 + 0.005) $*$ 0.005 $*$1400 = 9.05 kg/m
- Concrete coating weight = π $*$ (0.4066 + 0.010 + 0.085) $*$ 0.085 $*$ 2932 $*$ 1.03 = 404.5 kg/m
- Content weight $= \pi * \frac{(0.4066 - (2*0.027))^2}{4} * 920 = 89.8$ kg/m

By summarizing these values, we will get the total dry pipe weight:
Dry pipe weight = (252.76 + 9.05 + 404.51+89.8) * 9.81 = 7417.83 N/m

7. Pipe buoyancy calculation

Pipe buoyancy= $b = \frac{\pi * D^2}{4} * 1030 * 9.81 = (\frac{\pi * 0.5866^2}{4} * 1030 * 9.81) = 2730.74\ N/m$
So, submerged pipe weight = Dry pipe weight - Pipe buoyancy = 7417.83 – 2730.4 = 4687.43 N/m

8. Applying simplified static stability method

Friction coefficient for sand is 0,7

The relation between Uc and Us is following:

$$\mathrm{M} = \frac{\mathrm{Uc}}{\mathrm{Us}} = \frac{0.51}{2.65} = 0.19$$

Now, the Keulegan number is calculated:

$$K = \frac{\mathrm{Us} * \mathrm{Tu}}{\mathrm{D}} = \frac{2.65 * 9.15}{0.5866} = 41.33$$

Calibration factor might be defined by calculations and by using Figure 11.3 below

a) Calculation

There are the following formulas:

Fw1

- Fw1 = 1.0 if K ≤ 5.5, otherwise:

- Fw1 = 1.2 if M ≥ 0.8
- Fw1 = [1.3 – (M – 0.7)] if 0.6 < M < 0.8
- Fw1 = 1.4 if 0.4 ≤ M ≤ 0.6
- Fw1 = [1.5 – (M- 0.3)] if 0.2 < M < 0.4
- Fw1 = 1.6 if M ≤ 0.2

Fw2

- Fw2 = (0.03 * K + 0.85) if 5.5 < K ≤ 2, otherwise we take Fw1

Fw

- Fw = Fw2 if Fw2 ≤ Fw1, otherwise we take just Fw1, Fw = Fw1

In our case:

Our M = 0.19, so our Fw1 = 1.6

b) Second method – graphical

So, by using Figure 11.3, calibration factor Fw = 1.6

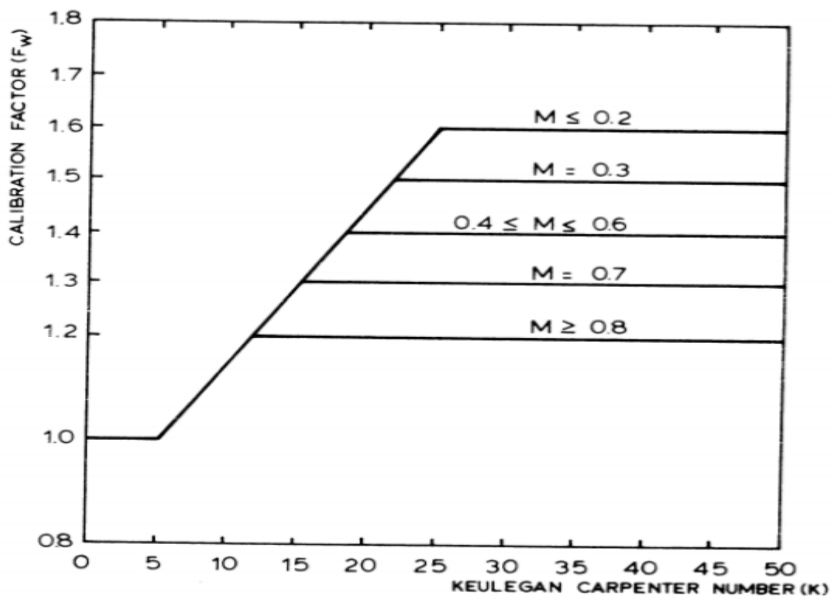

Figure 11.3 Determination of the calibration factor Fw *(DNV-RP-E305,1988)*

So, the values of calibration factor in both methods are the same Fw = 1.6

9. Calculation of Drag, lift and inertia coefficients

Firstly, there is calculation of the Reynolds number:

$$Re = \frac{(Uc + Us) * D}{\nu} = \frac{(0.5147 + 2.65) * 0.5866}{1.17 * 10^{-6}} = 1.58 * 10^{6}$$

In accordance with DNV-RP-E305 (page 28) if Re > 3 $*10^5$, then coefficients have the following values:

- $C_D = 0.7$ – drag coefficient
- $C_L = 0.9$ – lift coefficient
- $C_M = 3.29$ – inertia coefficient

10. Stability Criteria (Simplified Static Stability Analysis)

There is formula:

$(\frac{Ws}{Fw} - F_L) * \mu \geq F_D + F_I$, where

- F_D = Drag Force per unit length = $\frac{1}{2} * \rho_W * C_D * D * (U_S \cos\theta + Uc)|U_S \cos\theta + U_C|$
- F_L = Lift Force per unit length = $\frac{1}{2} * \rho_W * C_L * D * (U_S \cos\theta + Uc)^2$
- F_I = Inertia Force per unit length = $\frac{1}{4} * \pi * \rho_W * C_M * D^2 * a * \sin\theta$, where

a = water particle acceleration normal to pipe axis = $\frac{2*\pi*Us}{Tu} = \frac{2*\pi*0,6}{9.15} = 0.41\ m/s^2$

θ - wave phase angle

Now, rearranging stability criteria, we have:

$Ws = (\frac{(FD+FI+FL*\mu)}{\mu}) * F_W$

Now, by iterating wave phase angle, we can find the maximum required Ws, the results are shown in Table 11.4 below:

Table 11.4 Results of the iterations in order to find maximum required Ws

Phase angle θ (°)	Drag Force, F_D (N/m)	Lifting Force F_L (N/m)	Inertia Force F_I (N/m)	W_s (N/m)
10	2064.39	2654.22	289.39	3760.47
15	1998.80	2569.88	431.33	**3775.93**
20	1909.43	2454.98	569.99	3748.93
25	1798.65	2312.55	704.30	3680.12
30	1669.39	2146.36	833.26	3575.98
35	1525.04	1960.77	955.88	3440.59
40	1369.39	1760.64	1071.22	3279.51
45	1206.45	1551.15	1178.41	3098.81

50	1040.41	1337.67	1276.63	2904.83
55	875.46	1125.60	1365.14	2704.03
60	715.72	920.21	1443.25	2502.78
65	565.05	726.50	1510.38	2307.13
70	427.04	549.05	1566.02	2122.67
75	304.81	391.89	1609.75	1954.34
80	200.97	258.39	1641.21	1806.30
85	117.58	151.17	1660.18	1681.77
90	56.02	72.03	1666.52	1583.00

According to Table 11.4, the maximum required weight of the subsea pipeline Ws is equal to 3775,93 N/m,

Thereby, 406,6 mm pipeline with 85 mm concrete coating thickness will give a submerged weight of 4687,4 N/m which is greater than the Ws required, thus there is sufficient weight for short term stability of the pipeline (installation conditions).

Now, safety factor for operational conditions should be checked.

Calculation of the safety factor:

By using formula below, safety margin for operational conditions might be checked:

$(\frac{Ws}{Fw} - F_L) * \mu \geq F_D + F_I$, so, we put $F_D + F_I = 1$

$\frac{(\frac{Ws}{Fw} - FL)}{FD+FI} * \mu \geq 1$, sufficient safety factor will be provided, if the left part of the equation will be bigger than one.

Checking:

$\frac{(\frac{4687,4}{1,6} - 2569,88)}{1998,8+431,33} * 0,7 \geq 1$ => 0,10 is not bigger or equal to 1, thus the subsea pipeline is considered to be unstable in operation conditions (long term). Shallow waters can explain it, where high waves and current effects still exist.

In order to get sufficient safety factor value, concrete coating might be increased, however, this will lead to enormous financial expenditures. In this case, in Arctic shallow waters, pipeline should be laid down into a trench, that eventually give the opportunity to take out some of the concrete coating and thus to mitigate expenditures to it, at the same time the expenditures will be increased, as the pipeline trenching is considered to be very expensive. In chapter 12, there are discussions devoted to the subsea pipeline trenching in Arctic conditions and trenching technology selection for the Pechora Sea.

12. PIPELINE TRENCHING JUSTIFICATION

According to the calculations, provided in Chapter 11, a conclusion might be drawn. Shallow water conditions along the subsea pipeline route, lead to high loads from the waves and the current, which cannot be handled by the proposed subsea pipeline during operating stage. There are two approaches to solve this issue:

- To make the subsea pipeline heavier, by putting more concrete coating;
- To conduct trenching.

More concrete can be used, resulting in higher expenditures, but it will not solve the problem entirely, because of the possibility of ice ridges formation in the Pechora Sea. As a result, subsea pipelines can be ruptured in case of collision with grounded ice ridges, also known as stamukhas. Ice ridge schematically is shown in Figure 7.1. By fulfilling trenching for the subsea pipeline, the necessity to put on concrete coating will be limited as well as collision with the ice ridge will be excluded. Trenching in the Arctic region is considered in chapter 8.

Ice ridges are usually situated in the water depth up to 20 meters and usually, they are made of consolidated layer and unconsolidated ice blocks with porosity of 30-35 %. The sail height might reach 12 m, whereas the surface length varies from 30 to 150 meters. In Figure 12.1 the ice ridge scheme is shown

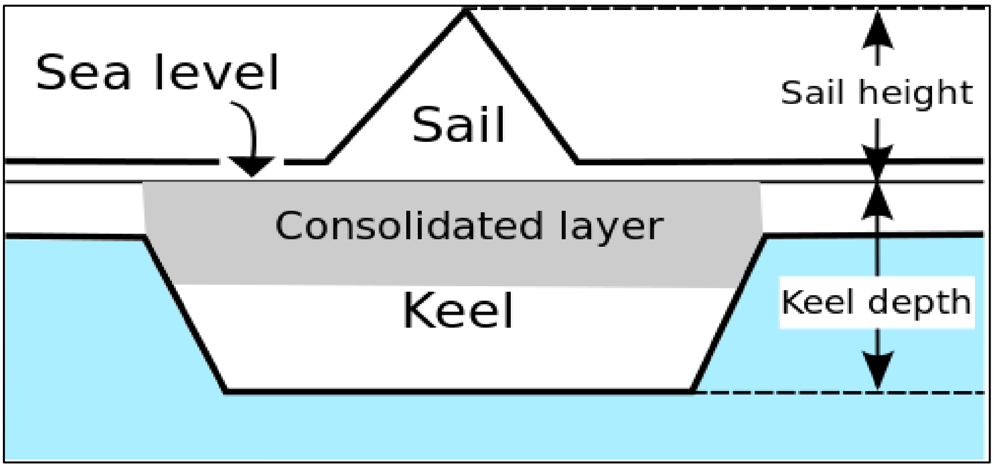

Figure 12.1 Scheme of the ice ridge *(Pressure ridge (ice), 2015)*

13. CONSIDERATION OF THE SUBSEA PIPELINE TRENCHING PROCESS

In shallow Arctic waters, subsea pipelines protection should be provided, where the seabed trenching is considered the most effective solution. Subsea pipeline trenching is an enormously expensive operation. Moreover, it should be highlighted that in Arctic conditions, with a short ice-free period, remoteness, limited logistics and cold weather, expenses will even increase.

There are a few main parameters which define trenching:

- The trench depth and width;
- Soil characteristic, boulders should be also considered;
- Equipment for the trenching, with trench speed as the main characteristic;
- The shape of the trench – box shape and V-shape *(Vaartjes et al., 2013).*

V-shape trench schematically is shown in Figure 13.1.

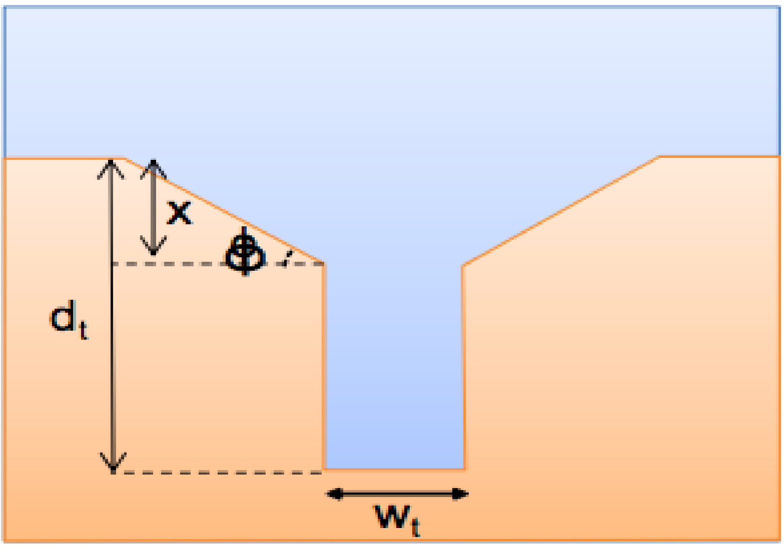

Figure 13.1 Scheme of the V-shape trench ***(Vaartjes et al., 2013)***

13.1 The trench depth

The trench depth is of great importance. Proper trench depth ensures the subsea pipeline stability, whereas the wrong design of the trench will lead to its instability. Usually, stamukhas (grounded ice ridges) can grow down to the water depth up to 20 meters. Concerning subsea pipeline from the Medysnkoe-more oilfield to the IRGBS "Prirazlomnaya", it should be pointed, that the water depth along the pipeline varies from 10 to 20 meters, resulting in possibility of damages by the stamukhas. Many estimations have been provided relatively to the secure trench depth, currently it is believed that to bury the pipeline to the depth of 5 meters is reliable and safe (*Vaartjes et al., 2013).*

13.2 Soil type

There are a lot of seabed areas in the Arctic with remoulded soil. Prior to the subsea pipeline installation, soil surveys should be carried out in order to estimate soil type and choose appropriate trencher. Because of remoulded soil inappropriate type of trenching equipment might be taken, which is capable to dig just the top layers. The existence of boulders on the subsea pipeline route should also be taken into account. In some cases, this will require additional estimation in terms of trenchers ability to destroy them.

13.3 Trenching strategy

It is known that in most of the Arctic areas, the ice-free period lasted up to 150 days, resulting in necessity to plan and provide all operations connected with pipe laying within this period. There are the main following steps:

- Mobilization of the pipe laying vessels (≈ 10 - 15 days)
- Seabed trenching
- Pipe laying
- Demobilization of the vessels (≈ 10 - 15 days)

Time left to the seabed trenching and pipe laying is approximately equal to 120 – 130 days. The whole operation should be comprehensively planned and fulfilled during one free ice season. Relatively to that time, sufficient speed of trenching should be provided. The whole process of the subsea pipeline burying into the trench, might have different sequences of the operations.

There are two main modes of subsea pipeline trenching:

- Pre-trenching
- Post-trenching

They define the time of the trenching relatively to subsea pipelines laying. Advantages and disadvantages of each method are considered in Table 13.1.

Table 13.1 Advantages and disadvantages of trenching approaches *(Jukes et al., 2011)*

Trenching type	Advantages	Disadvantages
Pre trenching	• Excavation provided easier • No intersection between trenching equipment and pipeline • Possibility to carry out trenching in two seasons (separately) • Trenching equipment more diverse	• Trench might be filled with soil again, between trenching and pipe laying operations • Strict accuracy requirement, no deviation from the planned route is allowed
Post trenching	• More flexibility for the pipe installation vessel • Less trenching is needed. No necessity to dig more amount, visual control of the pipe	• Trenching operation should be fulfilled within one ice-free season, as subsea pipeline already laid on the seabed • In case of inaccuracy, pipeline might be damaged

According to Table 13.1, the main disadvantage of the pre-trenching method seems to be undeliberate backfilling of the trench during a short period of time, when the trencher goes up and the subsea pipeline is lowered. It may result in necessity to provide trenching operation again in case of soft soil thereby expenses will be increased. The trench width should be bigger in pre-trenching approach reaching 3 – 5 meters, providing tolerance margin, whilst during post-trenching the trench width inconspicuously overcome the subsea pipeline diameter. The significant disadvantage of the post-trenching, is that if the subsea pipeline has been lowered to the seabed, trenching operations should be carried out at the same free ice period, while the as pre-trenching approach does not necessarily require it *(Vaartjes et al.,2013)*.

13.4 Trenching equipment (*Jukes et al.,2011)*

Currently, four main types of trenching equipment might be pinpointed. There are:

- Ploughing equipment
- Jetting equipment
- Mechanical equipment
- Dredging equipment

Nowadays, neither of mentioned above equipment is capable to conduct the trenching operation alone. There are some limitations for each of them in terms of water depth, reliability and power ability; however, they are able to fulfil trenching operations in the Arctic region. The trenching process in the Arctic region could be divided into three stages with existing equipment:

1) Ploughing is used to remove soft top layers;
2) Mechanical equipment is assumed to use secondly to trench bedrocks;
3) Jetting is applied to flash out debris and cuttings prior to subsea pipe lay.

In case of joint work of the equipment, the 5-6 meters trench depth might be reached.

13.5 The trench main parameters consideration

The expenditures to seabed trenching are evaluated to be enormously high. Therefore, all parameters, such as trench depth and width and the slope angle of the trench walls, are crucially important and should be defined.

These are the following main parameters of the trench:

- The trench depth should include the total external diameter of the pipeline and the potential gouge depth of the stamukha;
- After the subsea pipeline is laid in the trench, it is firstly covered with recommended soft clay and then with in-situ sand to the level of the seabed;
- The width of the trench should be double of the relative pipeline-soil displacement, otherwise, the neighbouring sand might expose unacceptable loads when the clay layer settles;
- The trench walls should be declined.

Buried pipelines, as a rule, are less corroded and have no significant displacement due to current and buoyancy *(Jukes et al., 2011).*

In Figure 13.2, a typical cross section of a buried pipeline is shown.

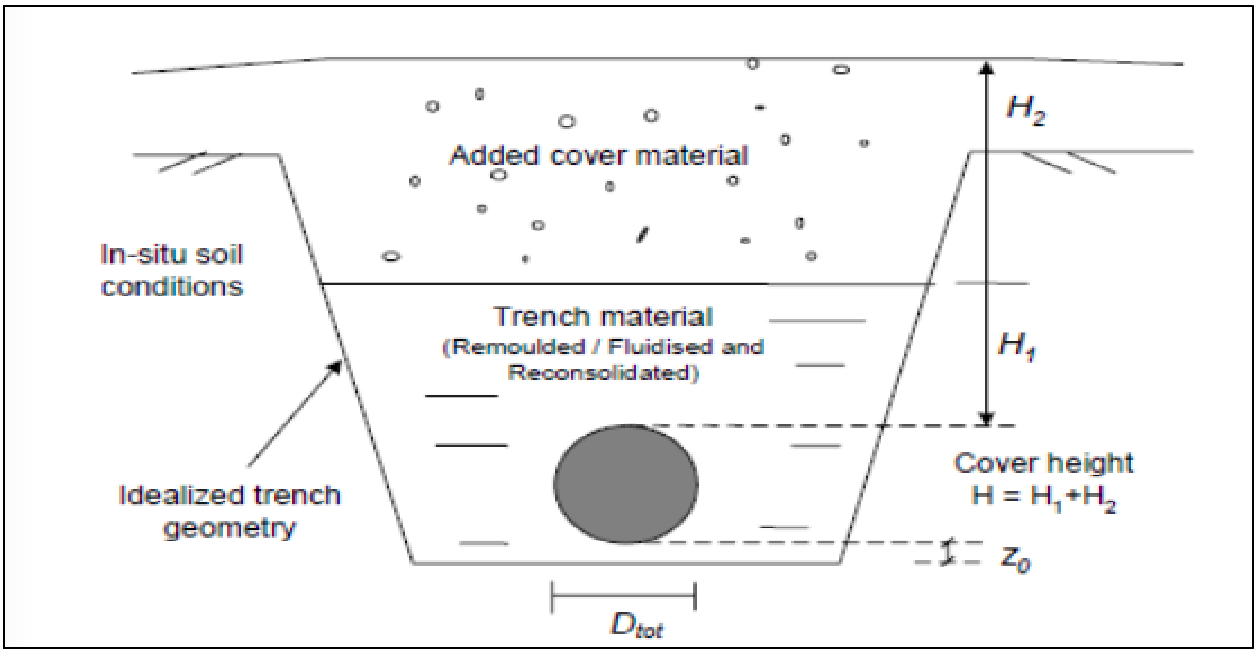

Figure 13.2 Trench parameters (*Duplensky, 2012)*

14. RISK ANALYSIS

14.1 Risk analysis description

A risk evaluation procedure is an integral part of a comprehensive project evaluation and it is especially important for the oil and gas industry. A full risk assessment procedure is conducted in order to identify probabilities of risk occurrence and evaluate possible consequences. Risk is defined as probability × consequence and generally might be arranged in three to five groups of risk:

- Low;
- Medium;
- High.

Concerning medium and high risks, there are government regulations, national and international standards, rules etc. which define risk acceptance criteria. A risk acceptance criteria is a criterion which is utilized to take a decision about risk acceptance *(DNV-RP-H101, 2003)*. Risk acceptance criteria might be qualitative and quantitative.

Risk assessment should be provided for a several main categories:

- Risk to people;
- Risk to the environment;
- Risk to the company – assets and reputation.

As mentioned previously, risk = probability × consequence and in accordance with acceptance criteria, several categories of probabilities and consequences should be outlined.

The frequency of hazards occurrence is the basis for probability categories. There are the following categories (Efimkin, 2015).

- Rarely occurred;
- Happened several times per year in industry;
- Happened at least once in operating company;
- Happened several times per year in operating company;
- Happened several times per year in the location.

Whereas for consequences, there are different categories, shown in Table 14.1:

Table 14.1 The range of consequences *(Efimkin,2014)*

Consequences	People	Environment	Assets
Negligible	Negligible damage	Insignificant damage	Insignificant damage
Low	Minor damage	Minor damage	Minor damage
Medium	Medium damage	Moderate damage	Moderate damage
High	One fatality	Considerable damage	Considerable damage
Very high	Several fatalities	Serious damage	Serious damage

Concerning quantitative analysis, the safety of people can be estimated by using FAR, GIR, IR or IRPA *(NORSOK standard z-013, 2010),* the environmental impact can be assessed as function of the toxicity, whereas the assets will be estimated by the level of lost money.

It should be noted, that there is a special HAZID technique for the hazards and weaknesses identification, associated with the operation under elaboration. As a hazard, the physical object (e.g. subsea pipeline), an activity (e.g. subsea pipeline installation) or a material (e.g. transported oil in the subsea pipeline) might be considered.

In order to evaluate risk through the probability and consequence approach, risk matrices should be implemented. 5×5 matrices are normally used, which contain 25 cells. This approach is used to evaluate the risks in the following chapter.

14.2 Qualitative accept criteria and risk matrices

At the present paragraph, there is comprehensive consideration of the risk in terms of Hazid analysis for:

- subsea pipelines;
- offshore structure;
- shuttle tankers.

As it was mentioned above, the matrices should be constructed. There are three different zones according to the probability and consequences analysis of the risk. There is green zone – risk can be easily accepted, yellow zone – risk can be taken in case of fulfilling reasonable preventing measures and red zone – risk cannot be accepted. The matrices is shown in Figure 14.1 .

Probability		1 Very unlikely	2 Unlikely	3 Possibly	4 Likely	5 Very likely
Consequences	Very high					
	High					
	Medium					
	Low					
	Negligible					

Figure 14.1 Risk probability – consequences matrices ***(Gudmestad lectures UIS,2016)***

14.3 HAZID analysis

14.3.1 HAZID for subsea pipeline exploitation in the Arctic region

In order to ensure secure exploitation of the subsea pipeline, hazards identification procedure should be conducted in order to make preventive measures for main hazards.
Typical subsea pipeline, located on the seabed is shown in Figure 14.2

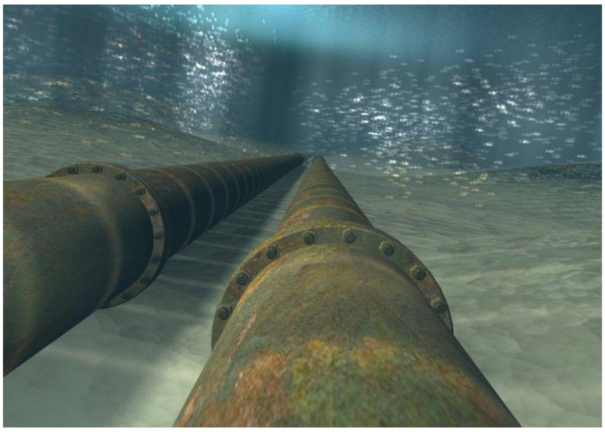

Figure 14.2. Subsea pipeline (subseaworldnews.com/tag/pipeline)

Main hazards for subsea pipeline:

1. Bursting, collapsing, significant lateral and vertical displacement of the pipeline;
2. The appearance of significant fracks and holes on the pipeline;
3. Subsea pipeline destroying by ice ridges (stamukhas);
4. Wax deposition inside the subsea pipeline
5. Accidental contact with some external objects (trawl, trawl-acoustic survey, anchors etc.)

In compliance with list of hazards above, a HAZID analysis table is provided below in table 14.2.

Table 14.2 HAZID analysis for subsea pipelines

№	Causes	Hazard	Consequences	Preventive measures
1	• Improper design and calculations of the hydrodynamic loads • Lack of input data about waves, current and soil • Inadequate knowledge of the procedure • Non-expected loads • Non-use of safety factors	Bursting, collapsing, significant lateral and vertical displacement of the pipeline	• Oil spill in the open sea, significant damage to the fragile flora and fauna • Problems with oil spill elimination, as the sea surface varies (water, ice) • Suspending of the production • Damage to the reputation of the company, punishment and fees from the regulators	• Following to the instructions and procedures • Rechecking for the data and extreme loads • Using of skilled specialists (experienced) • Using of safety factors
2	• Lack of experience of anti-corrosion methods implementation in Arctic conditions • Un-skilled specialists • Non-use of safety factors • Low steel quality • Insufficient control procedures during steel quality checking and fabrication	Initial material defects or appearance of significant fractures and holes on the pipeline during exploitation	• Oil spills in the open sea, significant damage to the flora and fauna • Problems with oil spill elimination, as the sea surface varies (water, ice) • Production suspending • Reputation damage to the company, punishment from the regulators • Necessity to fix the pipeline – extremely difficult in Arctic	• Choosing of appropriate type of corrosion protection system • Steel quality sending out checking test • Periodical subsea pipeline monitoring
3	• Ice covering of the sea for the most part of the year with subsequent ice ridges	Subsea pipeline destroying by ice ridges (stamukhas)	• Oil spills in the open sea, significant damage to the fragile flora and fauna	• Proper design • Appropriate depth of the trenches for

	and stamukhas formation • Shallow waters • Improper routing of the subsea pipeline • Improper prediction of ice ridges formation • Lack of subsea pipeline protection		• Problems with oil spill elimination • Production suspending • Reputation damage to the company, punishment from the regulators • Necessity to fix the pipeline – extremely difficult in Arctic	subsea pipelines • Utilizing of protection coating • Proper routing • Destroying of the ice ridges formation in advance
4	• The production of waxy crude oil • Cold environment (low water temperature) • Lack of insulation and coating for the pipeline	Wax deposition inside the subsea pipeline	• Decreased flowrate of the oil • Possible production suspension • Hard to remove from the pipelines wall	• Implementation of the subsea pipeline insulation techniques • Pipeline coating • Applying of electrical heating
5	• Subsea pipeline is not pointed in the international water map • Careless actions of the vessel crew	Accidental contact with some external objects (trawl, trawl-acoustic survey, anchors and etc.)	• Significant and insignificant subsea pipeline damage • Possible oil spills in the open sea, significant damage to the flora and fauna • Necessity to fix the pipeline – extremely difficult in Arctic.	• Mark the pipeline on the international water maps • Accurate behaviour of the vessel crew

Main hazards for the subsea pipeline construction and exploitation in the Arctic conditions are elaborated above, thus there is the opportunity to evaluate probability and consequences of the hazards in a matrices form in Figure 14.3, mentioned above.

Probability		1 Very unlikely	2 Unlikely	3 Possibly	4 Likely	5 Very likely
Consequences	Very high		3			
	High		2,1,5			
	Medium			4		
	Low					
	Negligible					

Figure 14.3 Risk matrices for the subsea pipeline construction and exploitation in the Arctic

According to the Figure 14.3, the most dangerous hazard is the ice gouging of the subsea pipeline by ice ridges (stamukhas), so that a bow-tie diagram will be used in order to provide a comprehensive evaluation of the risk.

14.3.2 HAZID for the offshore structure and shuttle tankers exploitation in the Arctic region

Offshore structures for oil and gas fields development serve as a huge construction that might provide safe execution of numerous operations, such as:

- Hydrocarbon production;
- Hydrocarbon processing;
- Drilling;
- Hydrocarbon storing;
- Oil offloading.

Therefore, it must very robust. Concerning harsh Arctic conditions, offshore structures have to be even more reliable and be able to withstand serious ice loads.

Considering the shuttle tankers for Arctic region, they ensure connection between the place of production with the place of refining and subsequent consumption.

Main hazards for offshore structure and shuttle tankers are considered below:

6. Platform destroying resulting from the collision with huge pieces of ice (icebergs);
7. Platform – shuttle tanker interaction;
8. Oil spills during the process of oil offloading;

9. Ice – shuttle tanker collision causing the appearance of the hole in the hull;
10. Impossibility to offload produced oil.

Hazid analysis for the platform and shuttle tankers are shown in Table 14.3.

Table 14.3 Hazid analysis for the platform and shuttle tankers

№	Causes	Hazard	Consequences	Preventive measures
6	• Wrong design parameters • Low construction material quality • Tremendous peace of ice (has never been observed before)	Platform destroying resulting from the collision with huge pieces of ice (icebergs)	• In case of wrong evacuation actions, the possibility of employee's death • Oil spill in the open sea, significant damage to the fragile flora and fauna • Problems with oil spill elimination, as the sea surface varies (water, ice) • Suspending of the production • Damage to the reputation of the company, punishment and fees from the regulators	• Precise and proper design calculations (have to rely on reliable initial data) • Utilizing of ice management, including ice – towing vessels. Permanent monitoring of huge ice pieces movement, attempts to predict the way of ice moving
7	• Broken dynamic positioning system • During the oil offloading operations, appearance of strong waves and current • Inaccurate actions by the crew members in terms of tanker ruling	Platform – shuttle tanker collision	• Oil spill in the open sea, significant damage to the fragile flora and fauna • Problems with oil spill elimination, as the sea surface varies (water, ice) • Possible production abandonment, as there will be the lack of ice resistant shuttle	• Often maintenance of the dynamic positioning system • Reliable weather forecast data • Accurate maneuvering near to the platform

			tankers to remove the oil from the platform • Suffering of the reputation	
8	• Broken dynamic positioning system • During the oil offloading operations, appearance of strong waves and current • Inaccurate actions by the crew members • Hose collapse	Oil spill during the process of oil offloading	• Oil spill in the open sea, significant damage to the fragile flora and fauna • Problems with oil spill elimination, as the sea surface varies (water, ice) • Suffering of the reputation	• Before beginning of the offloading operations, check the integrity of the CUPON system in common and hose integrity in particularly. • Provide proper working of the emergency shut down system (ESD)
9	• Tremendous size of iceberg, unexpected. • Low material quality of the tanker • Absence of ice – management operations	Ice – shuttle tanker collision, causing the appearance of the hole in the hull	• Oil spill in the open sea, significant damage to the fragile flora and fauna • Problems with oil spill elimination, as the sea surface varies (water, ice) • Suffering of the reputation • Possibility to lose the tanker, as it can sink	• Proper ice management activity • Tanker's road monitoring for the existence of tremendous icebergs and ice floes • Design the tankers with load and material reserve coefficients
10	• Significant oil production from the Prirazlomnaya oilfield at peak period and additional oil from the Medynskoe-more oilfield	Impossibility to offload produced oil to the tankers (potentially)	• Necessity to suspend the oil production at the IRGBS "Prirazlomnaya" • Reduction of the oil transportation from the	• Oil offloading process – accumulation of the experience • Building of new shuttle tanker

	• Short "Weather windows" for oil offloading		Medynskoe-more oilfield	

Hazards from the Table 14.3 are put into the matrices form, in order to define their hazardous. Matrices with hazards are shown in Figure 14.4

<table>
<tr><td colspan="2" rowspan="2">Probability</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td></tr>
<tr><td>Very unlikely</td><td>Unlikely</td><td>Possibly</td><td>Likely</td><td>Very likely</td></tr>
<tr><td rowspan="5">Consequences</td><td>Very high</td><td>6</td><td></td><td></td><td></td><td></td></tr>
<tr><td>High</td><td>9</td><td>7,8,10</td><td></td><td></td><td></td></tr>
<tr><td>Medium</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Low</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Negligible</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

Figure 14.4 Risk matrices for the offshore structure and shuttle tankers exploitation in the Arctic region

14.4 Bow-tie diagram risk analysis

The utilizing of bow – tie diagram is a very convenient approach for the risk evaluation. In bow – tie diagrams, the hazard (the initiating event) should be positioned in the middle, all threats should be located on the left-hand side, while as in the right-hand side consequences of the risk occurrence are shown. Between the threats and hazard – there are barriers, which should decrease the probability of occurrence of the event, while as between the hazard and consequences – the mitigation measures of the consequences are shown.

We have considered the risk with the highest probability of happening with the most significant consequences for the environment and reputation of the company. Despite the fact that people do not directly suffer from ice ridging, still the damage for the environment and company make this risk very important. It also should be noted that, in Arctic conditions where there is lack of infrastructure, experience and rescue vessels along with ice presence for almost 250 days this risk management become even more important.

The bow – tie diagrams are given in the appendixes for:

- Subsea pipeline destroying by ice ridges is shown in the Appendix A;
- Platform – shuttle tanker collision is shown in the Appendix B;
- Impossibility to offload produced oil to the shuttle tankers is shown in the Appendix C;
- Impossibility to utilize the subsea pipeline is shown in the Appendix D.

Bow – tie diagram gives an opportunity to prepare a risk evaluation procedure and implement risk preventive measures along with the possibility to diminish risk consequences in case of occurrence.

15. COST ANALYSIS

Current oil prices lead to necessity to provide comprehensive consideration of all projects which potentially might be realised and seems to be profitable from the technical point of view. Even more attention should be paid to the offshore projects, as it always requires more investments.

The proposed development scheme, when the oil from the Medynskoe-more oilfield is transported to the IRGBS "Prirazlomnaya" for oil processing and transportation has to be considered from the economic point of view. As other projects, this one should be evaluated taking into account several main parameters for project estimation, there are (*Efimkin, 2015*):

- Net present value (NPV);
- Internal rate of return (IRR);
- Profitability index (PI);
- Net profit margin.

Even if there is no possibility to calculate IRR, PI and net profit margin, the decision relatively the project realization might be taken according to the NPV parameter. Description of the NPV is shown in the Table 15.1

Table 15.1 NPV parameter characteristic ***(Net present value method, 2017)***

NPV value	What does it mean	Decision relatively the project
NPV > 0	Expenditures is less than earnings (gain additional value)	There is economic point of project realization, project should be accepted
NPV = 0	Expenditures is the same with the earnings	There is no economic point of the project. Investments might be done if it lead to satisfying of some other aspects
NPV < 0	Expenditures higher than the earnings	There is no economic point of the project. Project should not be accepted.

The proposed conception for the development of the Medynskoe-more oilfield is seems to have two main economic advantages:

- The additional oil at the Prirazlomnoye oilfield, that comes from the Medynskoe-more oilfield, will increase the amount of oil that is processed and exported from the IRGBS "Prirazlomnaya", what eventually will make additional value to the platform and also it will prolong the effective utilizing time of the platform;
- The CAPEX to the development of new offshore oilfield is decreasing, it is even more important in such unfavourable environment, such as low oil prices.

In order to estimate the economic practicability of the proposed project, it is necessary to compare it with the current development strategy. The following parameters should be defined:

- The capital expenditures (Capex);
- The operational expenditures (Opex);
- Amortization – it may be calculated as the 2 % of the total initial investments (assumption, relying on the internal conversation in the Gazprom neft company);
- The tax on income. According to the Russian law, it is 20 %. It is calculated as: Tax on income = 0,2· (Revenue – Opex);

The calculation of the $NPV = \sum PVi$ should be carried out in the following way:

1. Calculation of the cash inflow:

Cash inflow = revenue = $(Q \cdot P_{bbl})_I$, where Q – produced quantity of oil in barrels, P_{bbl} – price per barrel. Price per barrel is taken equal to 60 $/barrel.

2. Calculation of the cash outflow:

Cash outflow$_i$ = Capex $_i$ + Opex $_I$ + Amortization $_i$ + Tax;

Capex = 800 million dollars to the platform construction (http://www.offshore-technology.com/projects/prirazlomnoye/) capex is separated evenly through the 9 years, as the construction of the platform began in 2002 and the frilling operations on the oilfield location commence in 2013.(https://en.wikipedia.org/wiki/Prirazlomnoye_field)

- e – discount rate, %. Discount rate is utilized in order to transfer future value of money to current day. Assume 10 %.
- t – the numerical order of the year.

There is NPV parameter comparison for the Prirazlomnoye oilfield. Two scenarios are taken into account:

- Base scenario, without Medysnkoe-more oilfield
- Proposed scenario, the Medynskoe-more oilfield is connected to the IRGBS "Prirazlomnaya". Prirazlomnaya will get additional 18 $ for each processed,

stored and offloaded barrel of oil (the assumption got from the conversion with co-workers in Gazprom neft company).

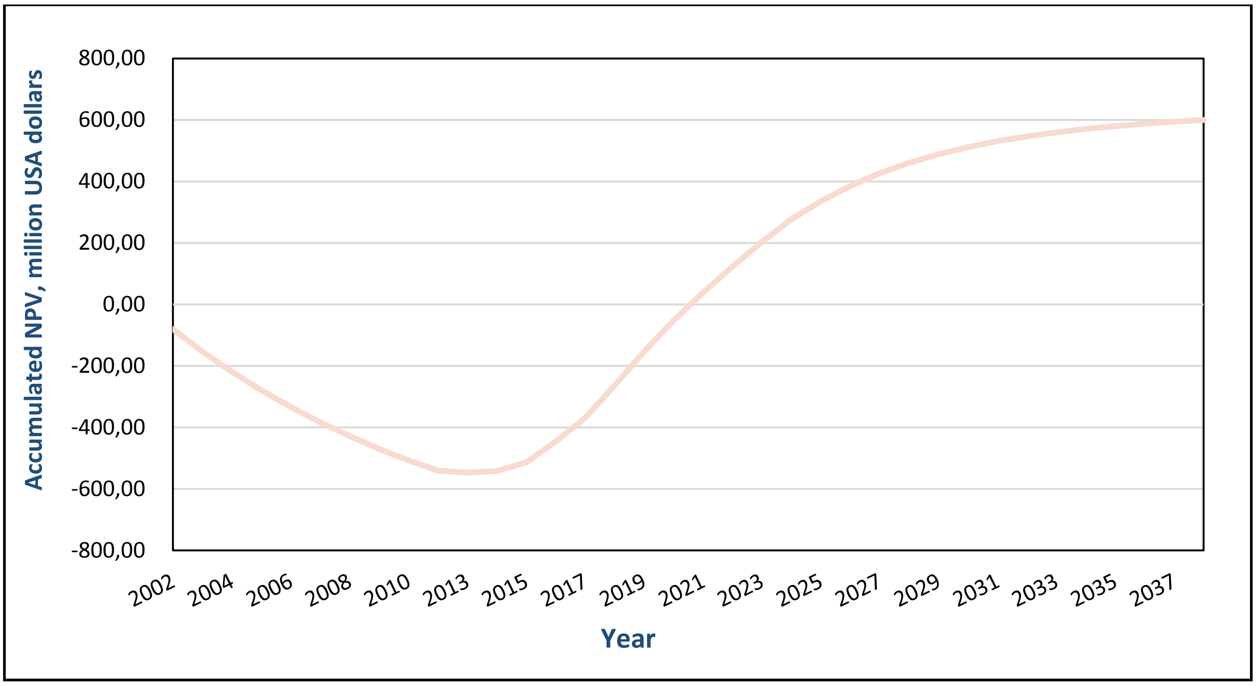

Figure. 15.1 NPV. Basic scenario of the Prirazlomnoye oilfield development

The additional NPV in case, when the Medynskoe-more oilfield is attached to the IRGBS "Prirazlomnaya" is shown in Figure 15.2

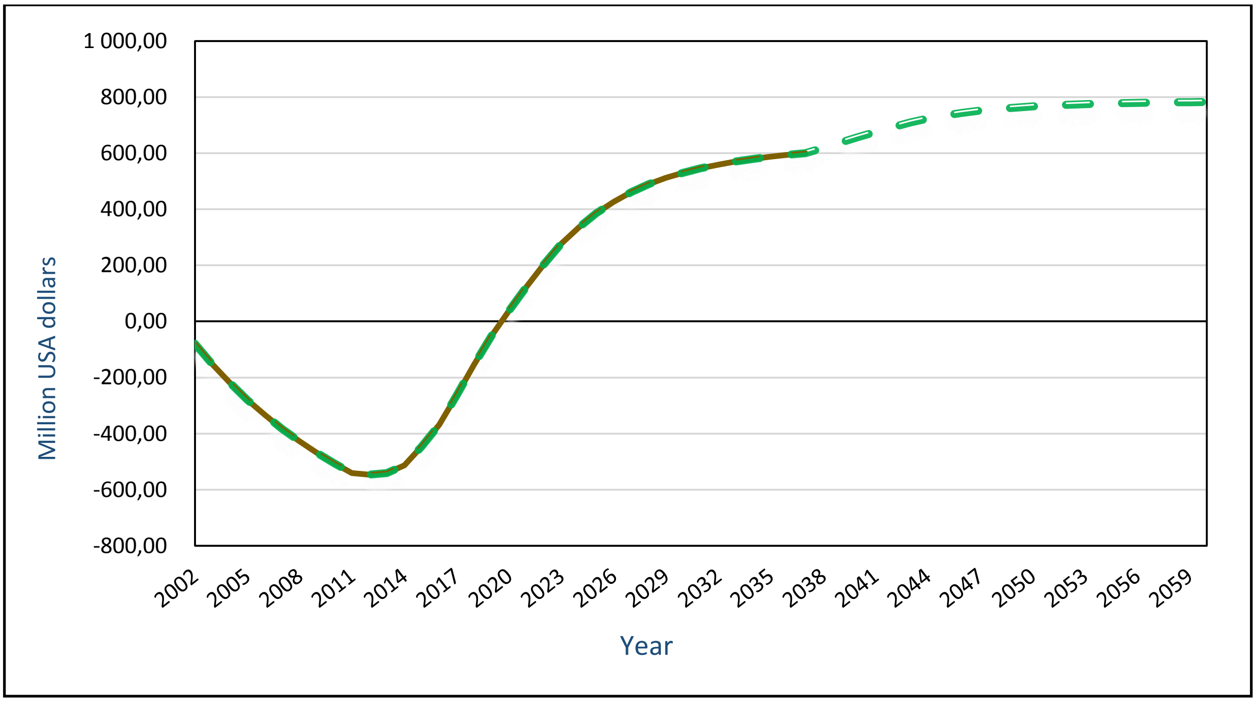

Figure 15.2 NPV. Scenario with the oil from the Medynskoe-more oilfield

According to the Figure 15.2, it is obvious that additional NPV of two hundred million dollars will be gained. That income comes as additional and preliminary have not been considered, therefore the total economic effectiveness of the Prirazlomnoye oilfield development rise significantly.

Moreover, except additional NPV for the Prirazlomnoye oilfield, the initial investments (Capex) and operational expenses (Opex) for the personnel, maintenance of the equipment - will decrease substantially. Mentioned above points, make proposed scheme of development quite attractive from the economical point of view.

The consideration of the total economic effect of the Medynskoe-more oilfield development through the IRGBS “Prirazlomnaya” is consist of two main parts:

- The additional income to the platform on the Prirazlomnoye oilfield;
- Significant money saving on Capex and Opex during the Medynskoe-more oilfield development.

If the Medysnkoe-more oilfield will be developed by utilizing own platform with complete production chain , it would approximately cost 800 million dollars, as Prirazlomnaya platform costs (http://www.offshore-technology.com/projects/prirazlomnoye/).

If there will be combined development, when IRGBS is planned to be installed in the Medysnkoe-more oilfield without storing, processing and offloading capacities and the water depth in the area of the oilfield is equal to 10-11 meters (what is less than in Prirazlomnoye – 19 meters), the platform cost can be estimated as 0,3 from the IRGBS “Prirazlomnaya” total cost (assumption according to the co-workers in the Gazprom neft company), Therefore 240 million dollars will be spend to the platform construction and installation. Additional Capex will be spending to the subsea pipeline construction. There is no precise information about the cost of subsea pipeline trenching and laying, as there is no absolutely the same projects. The cost of kilometre is taken according to the brief information gained from the representative of the oil and gas companies in the science conference, 1 km ≈ 500 million rubbles, (8,3 million dollars).

Also, it is of great importance to consider Opex during both type of development. Opex is calculated relatively to the production of one barrel of oil,

In case of development without Prirazlomnaya platform, the Opex is estimated as 45 $/barrel, whereas in case of combined development the Opex is estimated to be 33 $/barrel, what includes 15 $/barrel as margin cost of production and 18 $/barrel is paid to the Prirazlomnaya platform for storing, processing and offloading. The Capex and Opex (the whole period of production) during both approaches for the Medynskoe-more oilfield development are shown in Figure 15.3 and Figure 15.4 respectively. It should be pointed that:

- A – The Medynskoe-more oilfield development without IRGBS "Prirazlomnaya"
- B – The Medysnkoe-more oilfield development with IRGBS "Prirazlomnaya"

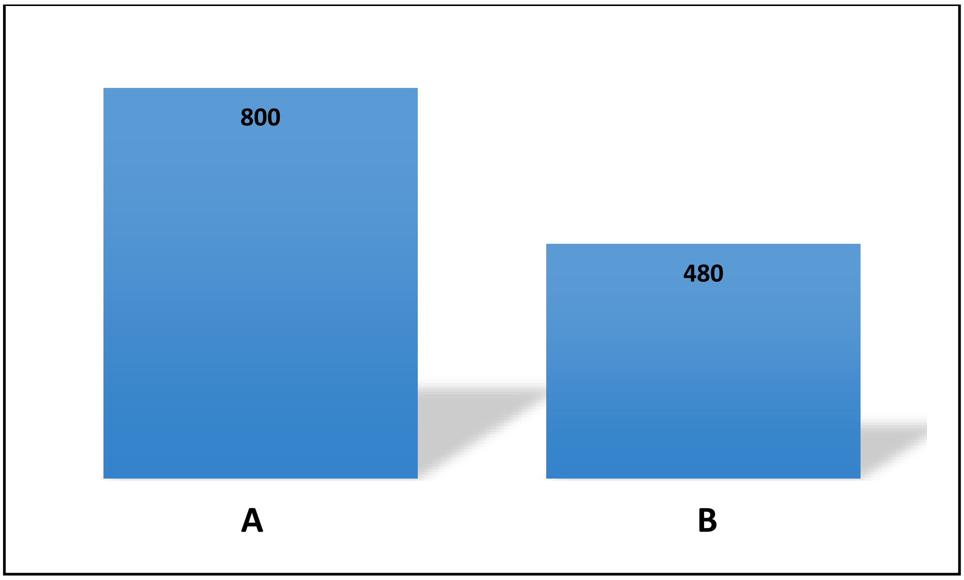

Figure 15.3 The comparative of Capex during A and B scenarios, mln. $

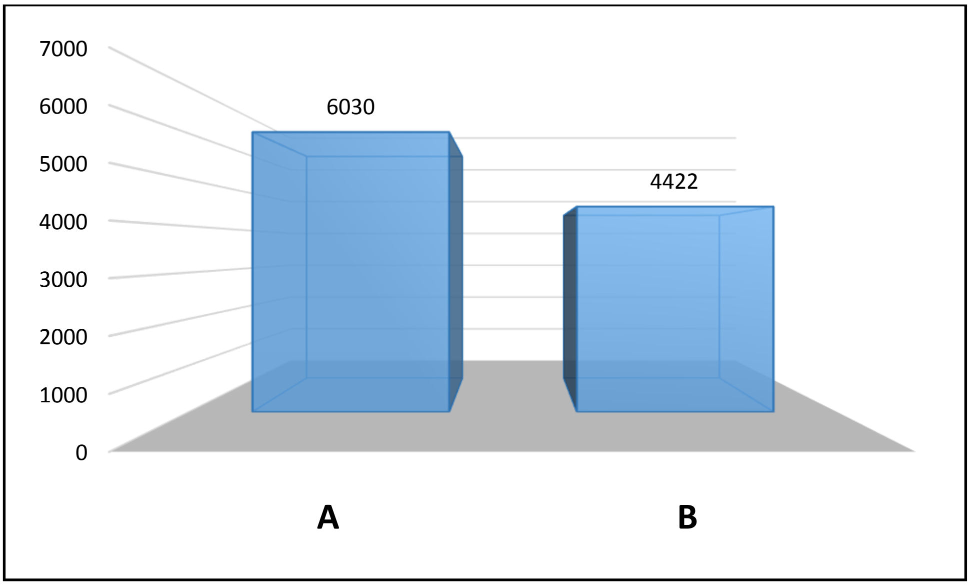

Figure 15.4 The comparative of Opex (whole period of production) during A and B scenarios, mln. $

Thus, the economic effect in case of Medynskoe-more oilfield development through the IRGBS "Prirazlomnaya" might be estimated as:

- Capex – 800 – 480 = 320, mln. $
- Opex – 6030 – 4422 = 1608, mln. $
- The additional NPV to the Prirazlomnaya platform is 200, mln. $

Therefore, the total economic benefit from the proposed scheme of development is $320 + 1608 + 200 = 2128$ mln. $.

16. CONCLUSION

In current situation with unstable oil and gas prices, new approaches for the offshore oilfields development should be found.

The present work covers all aspects of conceptual consideration of offshore oilfield development through the IRGBS "Prirazlomnaya" including:

- Environmental conditions;
- Selection of the appropriate type of the offshore structure for the Medysnkoe-more oilfield;
- Selection of the optimal oil transportation system, including detailed consideration of the subsea pipeline design and construction;
- Comprehensive risk analysis;
- Cost effective analysis of the proposed scheme of the Medynskoe-more oilfield development.

Considering mentioned above points in details, it should be pointed that the best offshore structure for the Medynskoe-more oilfield development is GBS with 60 degree sloping angle, as it allows to optimize the loads from ice and waves.

For the oil transportation just subsea pipelines might be used, as the water depth in the area of the Medynskoe-more oilfield does not allow to utilize the shuttle tankers with 70 thousand tonnes deadweight, as their draft overcome the water depth (14-15 m draft, 10-12 m water depth). Moreover, the pipeline cannot be installed directly on the seabed, as hydrodynamic loads are high and in the operational conditions pipeline will float, as well as stamukhas might plough the subsea pipeline on the shallow waters, therefore trenching is proposed.

Comprehensive risk analysis is provided, especially Hazid is applied in order to estimate potential risk and measure that might diminish these risks. For the most dangerous risks, bow –tie diagrams are constructed.

Cost effective analysis is provided in order to asses to economic feasibility of the proposed concept. The total economic benefit is calculated as 2128 mln. $.

As technical solutions are found and proposed and economic feasibility of the project is shown, the future work should be dedicated to the additional and comprehensive evaluation of the cost of GBS and subsea pipeline construction. Moreover, particular attention should be paid to the oil price, as it is the most important parameter which defines the future of the Medynskoe-more oilfield. The higher the oil price, the higher probability that is field will be developed.

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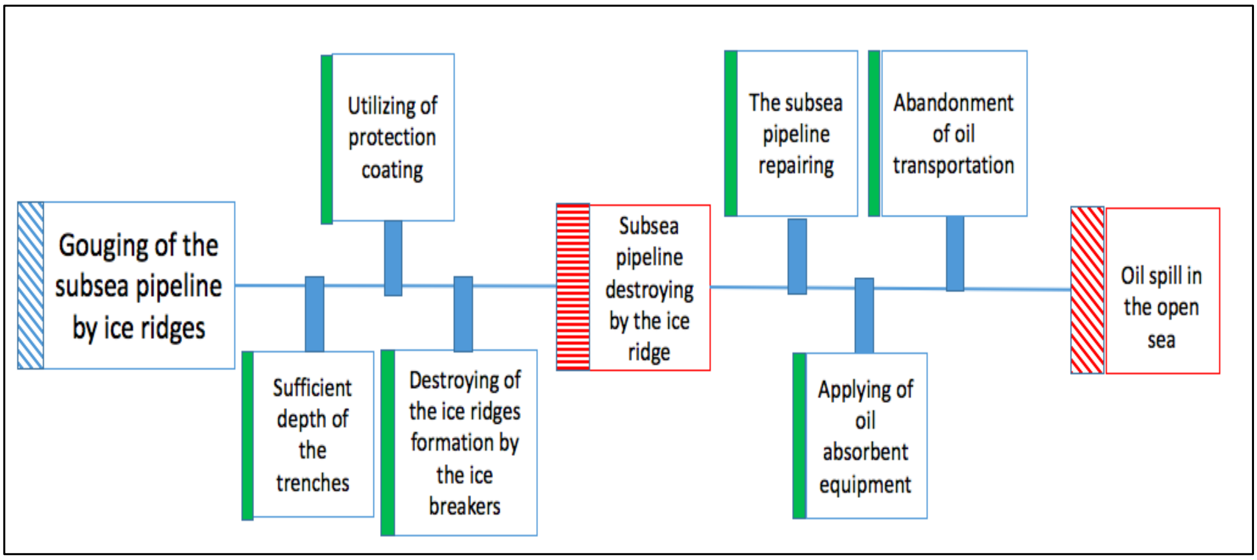
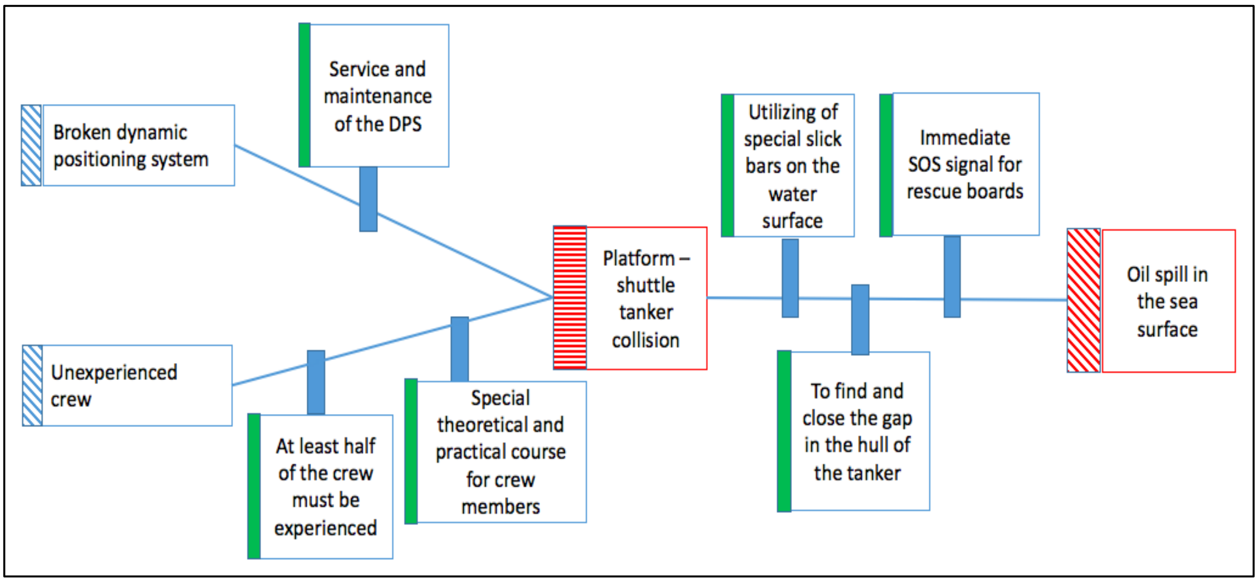
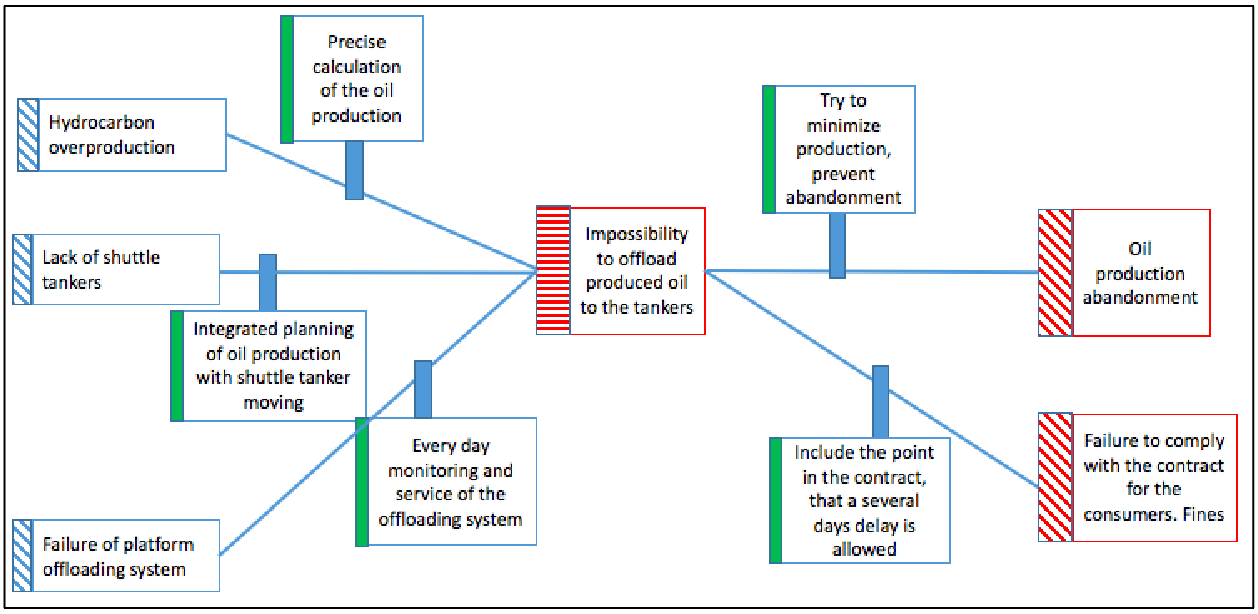
APPENDIX A. BOW-TIE DIAGRAM FOR SUBSEA PIPELINE DESTROYING BY THE ICE RIDGES (STAMUKHAS)



APPENDIX B. BOW-TIE DIAGRAM FOR THE PLATFORM – SHUTTLE TANKER COLLISION



APPENDIX C. BOW-TIE DIAGRAM FO THE IMPOSSIBILITY TO OFFLOAD PRODUCED OIL TO THE SHUTTLE TANKERS



APPENDIX D. BOW-TIE DIAGRAM FOR THE IMPOSSIBILITY TO UTILIZE THE SUBSEA PIPELINE