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ABSTRACT

As existing oil and gas fields' productivity is depleting, operators in the oil and gas industry are always searching for new prospects of reserves. Due to this reason, the Arctic shelf is becoming more important than ever, and it is believed to be a big pie for future development. However, the expansion of operations in the Arctic region requires the development of new technologies and solutions that can cope with harsh physical conditions. Leningradskoe field is located in the southwest of the Kara Sea. Even though existing severe arctic conditions indicate the high cost that might be involved in the field development, there is no scientific literature so far, disclosing a technical assessment of any sort carried out regarding the activity. Therefore, it is necessary to develop new technologies and concepts for Arctic offshore fields, including Leningradskoe field. Nowadays, some technology is sufficiently proven to have a high reliability and are ready for use in the freezing waters. At the same time, there are some technical problems associated with the adaptation of these technologies to the harsh conditions of the Arctic waters as well as the remoteness of the field. The Master's thesis focuses on the technology assessment of five major areas, which are all crucial to the development of Leningradskoe field. They are 1) drilling technical block, 2) reservoir engineering, 3) pipeline technical block, 4) production technical block and 5) technical block of logistics. This Master's thesis aims to contribute to the field development by providing a structured review of common technological problems; existing technologies, methods and best practices of work; and technology, the development of which is required for operations in Leningradskoe gas and condensate field. The evaluation of the most significant risks is performed in the form of Bowtie risk analysis. The results of the literature review, analysis of existing technology and research papers were synthesized by organizing the research and technical development (R&D) roadmap for the development of Leningradskoe field.

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«When you are grateful fear disappears and abundance appears» –
Tony Robbins, motivational speaker.

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NOMENCLATURE

ALARP – As Low As Reasonably Practicable

AUV – Autonomous Operated Vehicle

AMV – Annulus Master Valve

CIU – Chemical Injection Unit

CAPEX – Capital Expenditures

DEH – Direct Electrical Heating

FMECA – Failure Mode Effects Criticality Analysis

HVDC – High Voltage Direct Current

HMI – Human – Machine Interface

HPU - Hydraulic Power Unit

HSE - Health, Safety, and Environment

IM – Ice Management

IMR – Inspection, Maintenance, and Repair

LFAC - Low-Frequency Alternating Current

LNG – Liquefied Natural Gas

MCS – Master Control Station

MEG – Mono Ethylene Glycol

NPV – Net Present Value

PMV – Production Master Valve

R&D – Research and Development

ROV – Remotely Operated Vehicle

SPS – Subsea Production System

SPCU - Subsea Power and Communication Unit

SCU – Subsea Control Unit

SCSSV – Surface Controlled Subsurface Safety Valve

SCM – Subsea Control Module

TRL - Technology Readiness Level

TUTU – Topside Umbilical Termination Unit

TH – Tubing Hanger

HAZID - Hazard Identification

UPS – Uninterruptible Power Supply

VAR - Volt-Ampere Reactive

XT – Xmas Tree

CHAPTER 1. INTRODUCTION

1.1. Background and Objectives

As existing oil and gas fields' productivity is depleting, operators in the oil and gas industry are always searching for new prospects of reserves. Due to this reason, the Arctic shelf is becoming more important than ever, and it is believed to be a big pie for future development. However, the expansion of operations in the Arctic region requires the development of new technologies and solutions that can cope with harsh physical conditions. Leningradskoe field is located in the southwest of the Kara Sea. Even though existing severe arctic conditions indicate the high cost that might be involved in the field development, there is no scientific literature so far, disclosing a technical assessment of any sort carried out regarding the activity. Therefore, it is necessary to develop new technologies and concepts for Arctic offshore fields, including Leningradskoe field. There is no technical assessment of the development of Leningradskoe field in the scientific literature. This thesis aims to contribute to the field development by providing a structured review of common technological problems; existing technologies, methods and best practices of work; and technology, the development of which is required for operations in Leningradskoe gas and condensate field. Thus, the aim of this Master's thesis is to evaluate existing technology and define research and development (R&D) directions for the development of Leningradskoe field.

Therefore, the objectives of the Master's thesis:

1. It is necessary to analyze the geological data of Leningradskoe gas and condensate field. Then it is required to estimate the expected gas production rate to understand the potential productivity of the field.
2. The climatic and ice conditions of the southwestern part of the Kara Sea are to be analyzed. Moreover, the probability of icebergs' occurrence at Leningradskoe licensed area is needed to be studied.
3. It is required to assess the readiness of technology for the four main technical blocks, which are essential for the development of Leningradskoe field: drilling, transportation, production unit and marine operations. The readiness of the technology must be determined based on the classification of API RP 17N and the qualitative risk assessment.
4. The main challenges must be identified for each technical block. The risk assessment should be carried out by qualitative risk analysis.

5. It is needed to give the recommendations: what areas of research and technical development (R&D) have the highest priority for the development of Leningradskoe field.

1.2. The Scope of work

This Master's thesis focuses on the technology assessment of five major areas, which are all crucial to the development of Leningradskoe field. They are 1) drilling technical block, 2) reservoir engineering, 3) pipeline technical block, 4) production technical block and 5) technical block of logistics.

Chapter 1 (Introduction) explains the technology assessment approach, the evaluation of technology readiness, the procedure for the prioritization of research issues and technologies, and the methodology of risk assessment.

Chapter 2 (The geological information of Leningradskoe field) provides the existing geological information of Leningradskoe field. The evaluation approach of geological uncertainties is discussed.

Chapter 3 (Physical environmental conditions) gives an overview of the geographical location of Leningradskoe field; climatic, soil and ice conditions in the southwest of the Kara Sea. The occurrence of icebergs occurrence in Leningradskoe field is evaluated.

Chapter 4 (Drilling technical block) contains the study of the technology assessment of the drilling technical block in Leningradskoe field. Section 4.1 gives an overview of the drilling technical block. Section 4.2 compares all possible concepts of the drilling technical block. Section 4.3 contains the assessment study of the most important risks in the drilling technical block. Section 4.4 addresses the technology readiness and gives future recommendations for R&D directions in the drilling technical block of Leningradskoe field.

Chapter 5 (Reservoir engineering) estimates the potential gas production in Leningradskoe field. In Section 5.1, a gas production rate of a horizontal well is calculated. In Section 5.2, two possible development concepts are evaluated.

Chapter 6 (Pipeline technical block) addresses the study of the technology assessment of the pipeline technical block in Leningradskoe field. Section 6.1 contains an overview of the pipeline technical block. In Section 6.2, the following studies are carried out: the evaluation of shallow water area, the estimation of required pipeline burial depth, the simple calculation of hydraulic and thermal parameters in a trunk gas pipeline. A pipeline diameter of the trunk pipeline is estimated. Some aspects of shore erosion of a coastal zone are discussed. Moreover, possible technical solutions are considered. Furthermore, the challenges of flow assurance are discussed.

Section 6.3 provides the assessment of the most important risks in the pipeline technical block. Section 6.4 estimates the technology readiness and gives future recommendations for R&D directions in the pipeline technical block of Leningradskoe field.

Chapter 7 (Production technical block) contains the study of the technology assessment of the production technical block in Leningradskoe field. Section 7.1 gives an overview of the production technical block. Section 7.2 evaluates the key elements of the subsea production system that can be applied in Leningradskoe field. Section 7.3 assesses the most important risks in the production technical block. Section 7.4 evaluates the technology readiness and gives future recommendations for R&D directions in the production technical block of Leningradskoe field.

Chapter 8 (Technical block of logistics) assesses the technical block of logistics in Leningradskoe field. Section 8.1 provides an overview of the technical block of logistics. Section 8.2 comprises some of the most important aspects in the technical block of logistics. They are logistics and transport in and out of Leningradskoe field, infield logistics, and market. Section 8.3 comprises the study of assessment of the most important risks in infield logistics. Section 8.4 assess the technology readiness and gives future recommendations for R&D directions in the technical block oflLogistics of Leningradskoe field.

Chapter 9 (Economic discussion of the project) provides the discussion of the potential profitability of the Leningradskoe field development.

Chapter 10 (Conclusions and recommended strategy) provides conclusions of the project and illustrates R&D roadmap for the development of Leningradskoe field.

1.3. Technology assessment

Technology assessment is the study and evaluation of new technologies. A full range of available technologies is assessed against the criteria, in a four stages process. The process is illustrated in Figure 1.1.

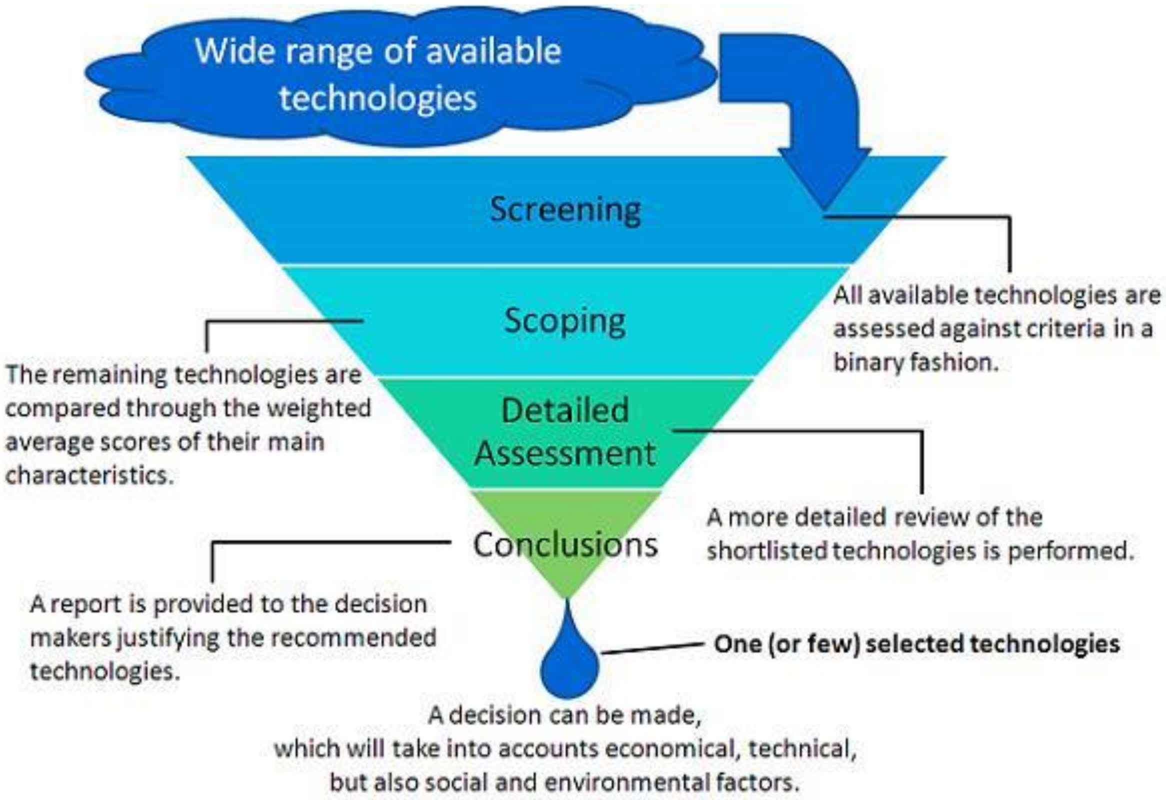

Figure 1.1. The stages of technology assessment [34]

Technology assessment is obliged to analyze and evaluate the desirable and the non-desirable consequences, the chances and the risks, of technologies, new techniques as well as established technologies.

At the screening stage, all available technologies that can be applied in each technical building block of Leningradskoe field are assessed.

At the scoping stage, the technologies are compared through one of the methods of multi-criteria decision making. For instance, it can be compared to the weighted average scores of their key features. The grid analysis considers options based on specified conditions. The total score of the option is calculated by taking the sum of the score of each parameter and multiplying it by the utility value (weight) then dividing the sum by the ideal rating. This is demonstrated by the following equations:

$$Ideal\ score = \sum_i^n weight_i \times \max score \tag{1.1}$$

Where i is parameter number, n is a total number of parameters, and the max score is 5.

$$Total\ score = \frac{\sum_i^n weight_i \times parameter\ score_i}{ideal\ score} \tag{1.2}$$

At the detailed assessment stage, a more comprehensive review of the shortlisted technologies should be performed. It is important to highlight limitations in the detailed assessment where the scope of the Master's thesis has been limited. Master's thesis focuses on a technical analysis that assesses the technical feasibility (technology readiness) and associated risks.

Technology Readiness Level (TRL) is a method of estimating technology maturity. That examines program concepts, technology requirements, and demonstrated technology capabilities. TRL is based on a scale from 0 to 7 with 7 being the most mature technology (see Table 1.1). The following definition relies on API recommended practice and is used in the oil and gas industry [36].

Table 1.1. The classifications of technology readiness levels

Technology Readiness Level	Description
TRL 0	**Unproven idea/proposal Paper concept.** No analysis or testing has been performed.
TRL 1	**Concept demonstrated**. Basic functionality demonstrated by analysis, a reference to features shared with existing technology or through testing on individual subcomponents.
TRL 2	**Concept validated.** Concept design or novel features of design validated through model or small-scale testing in laboratory environment. Shall show that the technology can meet specified acceptance criteria with additional testing
TRL 3	**New technology tested**. The functionality demonstrated through testing over a limited range of operating conditions.
TRL 4	**Technology qualified for first use.** Full-scale prototype built and technology qualified through testing in intended environment, simulated or actual. The new hardware is now ready for first use.
TRL 5	**Technology integration tested.** Full-scale prototype built and integrated into intended operating system with full interface and functionality tests.
TRL 6	**Technology is installed.** Full-scale prototype built and integrated into intended operating system. The technology has shown acceptable performance and reliability over a period.
TRL 7	**Proven technology integrated into intended operating system**. The technology has successfully operated with acceptable performance and reliability within the predefined criteria.

The prioritization of research issues and technologies can be considered to suggest future recommendations. To establish the priority ranking of the categorized issues, a priority ranking number P can be calculated [43, 57]. Hence, the value of P corresponding to the issue can be estimated using the following equation:

$$P = C \sum_{i=1}^{3} R_i \tag{1.3}$$

where, P – priority ranking factor;

C – industry relevance factor;

R_i – ranking factors.

The industry relevance factor (C) is used to reflect the importance of an issue to industry. The values used for this factor are:

- 0.5: identified from literature review, but not highlighted by industry;
- 1: defined as a relevant issue by several industry participants;
- 2: defined as an important issue by many industry stakeholders;

The ranking factors are R_1, R_2, R_3.

The factor R_1 (expected impact of R&D) is used to consider the probability of R&D making measurable progress regarding improving safety or reducing risks and costs [43]. The values used for the factor R_1 are:

- 1: small impact;
- 2: moderate impact;
- 3: high impact.

The factor R_2 (time to implementation) is used to reflect the timeframe in which benefits of this R&D will be available to industry [43]. The values used for the factor R_2 are:

- 1: < 5 years;
- 2: 5-10 years;
- 3: > 10 years.

The factor R_3 (state of knowledge) is used to consider the current state of knowledge and the relative size of the knowledge gap that the R&D will attempt to fill [43]. The values used for the factor R_3 are:

- 1: high level of understanding (small knowledge gap);
- 2: moderate level of knowledge (average gap);
- 3: low level of understanding (big knowledge gap).

Legislation for high-risk industries often requires that all hazards are to be identified [74]. HAZID is one of the best-known methodologies to determine potential hazards. It provides an approach to identify hazards, possible undesirable consequences and evaluate the severity and probability of what is identified. Risk identification is the process of finding, recognizing and describing risks [74]. The aim of this step is to generate a comprehensive list of risks. Risk matrices are probably one of the most popular tools for risk evaluation (see Appendix A). They are mainly used to determine the size of a risk and whether or not the risk is sufficiently controlled. There are two dimensions to a risk matrix: probability and severity. The combination of likelihood and severity will give any event a place on a risk matrix. It is necessary to understand that a risk matrix by itself makes for a poor decision-making tool. It is best suited for ranking events. However, decisions are to be based on an underlying analysis (for instance a Bowtie diagram). This information will make an informed decision possible [74]. The diagram is shaped like a bow-tie, while creating a clear differentiation between proactive and reactive risk management [35]. The power of a Bowtie diagram is that it gives an overview of multiple scenarios, in a single picture (see Figure 1.2).

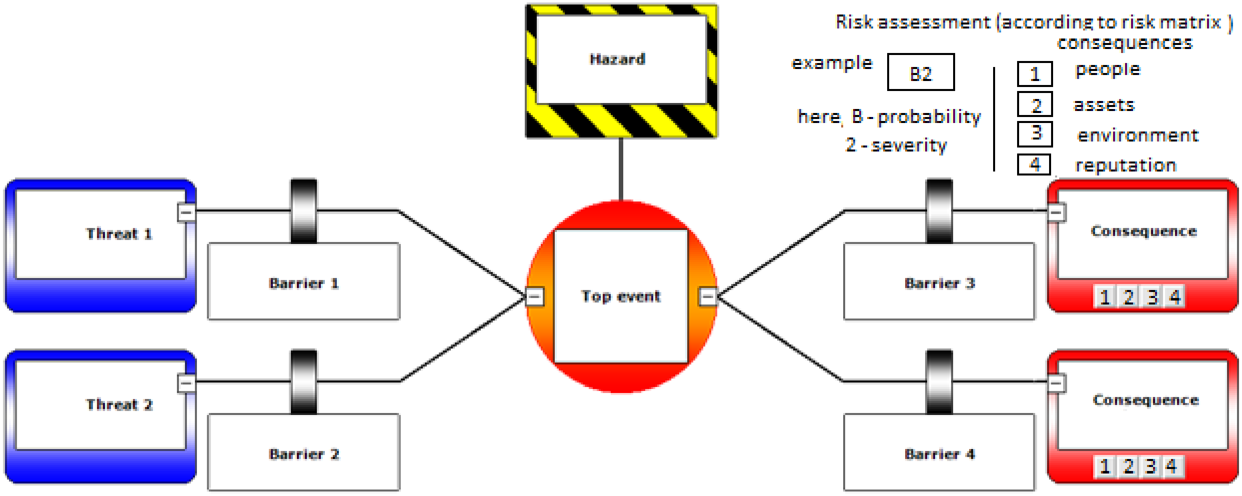

Figure 1.2. A Bowtie diagram

A Bowtie diagram does two things. First, a Bowtie provides a visual summary of all accident scenarios that might exist around a certain Hazard. Second, by identifying control measures the Bowtie displays what a company must do to manage those situations. Moreover, the Bowtie can be used effectively to assure that Hazards are managed to an acceptable level (ALARP).

Further, at the conclusion stage of the technology assessment, one or few technologies are to be selected. The decision should be made based on not only economic, technical, but also social and environmental factors. To ensure a technical focus is maintained, the information about local norms, environments or socioeconomic concerns is not analyzed. However, some economic and environmental concerns have been discussed and highlighted in the thesis.

CHAPTER 2. THE GEOLOGICAL INFORMATION OF LENINGRADSKOE FIELD

To this day, there is poor and highly non-uniform geological and geophysical knowledge regarding the shelf of the Arctic region. There are four oil and gas potential areas in the Kara Sea: Rusanovsko-Leningradskaya, Skuratovskaya, Matusevicha-Vilkitskogo, and Obruchevskaya. All of this areas are located in the zones of uplift with the same names (see Figure 2.1).

Rusanovsko-Leningradskaya area is characterized in the same age range of prospects as terrigenous Mesozoic sediments. In the same sediments, the hydrocarbon deposits on the adjacent land were identified. In addition to Mesozoic sediments, there are Cenomanian, Albian and Aptian sediments in Rusanovsko-Leningradskoe area. The productivity of the gas and condensate deposits in these sediments are characterized as unique [16].

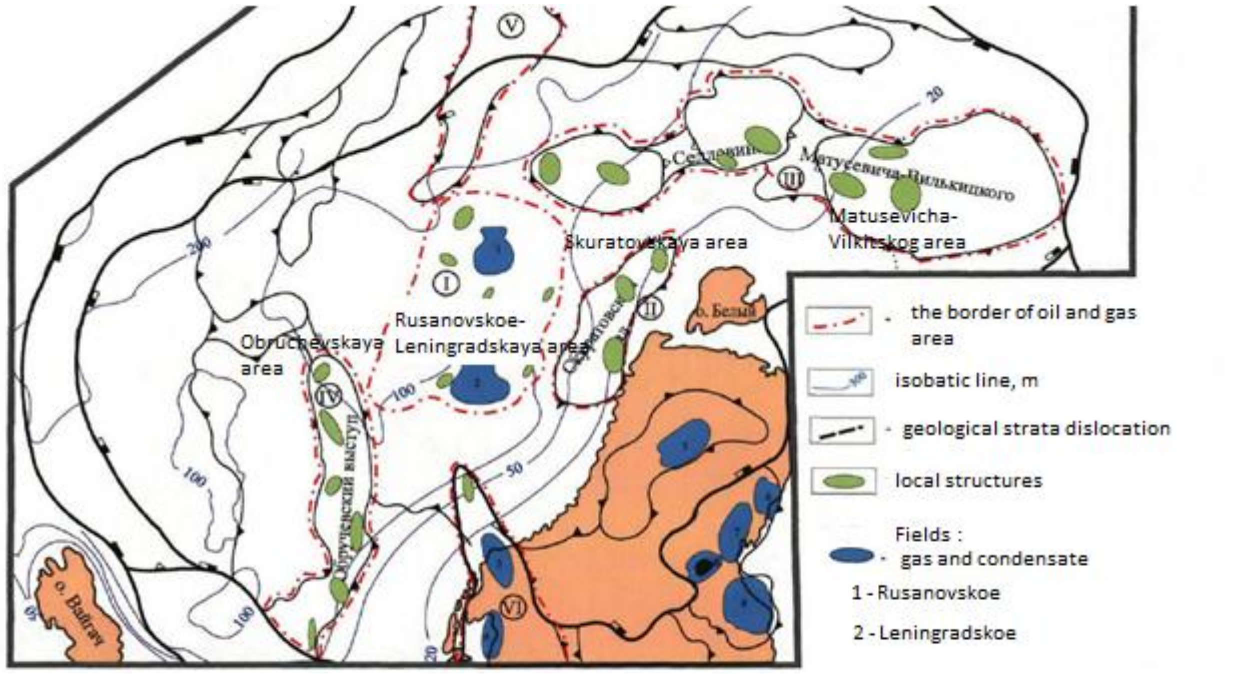

Figure 2.1. North part of West Siberian oil and gas province [16]

The ongoing study activities of the Kara Sea shelf began in the 70s of the twentieth century. In 1973, science and production association «Sevmorgeo» conducted aeromagnetic works on the scale of 1:500000 in the waters of the Kara Sea. As the results, the main tectonic elements of the southern shelf of the Kara Sea were highlighted. Moreover, the thickness of the sedimentary cover, as well as some local structures, were detected.

Then «Sevmorgeo» and scientific, technical association «Sevmorgeologiya» carried out seismic works in the area of the Kara Sea. Almost all area of the southwestern part of the Kara Sea was covered with a network of regional seismic profiles until 1990 year. The total volume of studies was more than 25 thousand linear kilometers. The study of the Kara Sea was not uniform.

The highest density of seismic focus was in the southern part of the area within Rusanovsko-Leningradskaya and Obruchevskaya areas (see Figure 2.2) [16].

The average density of seismic research is up to 0.8 km/km. In the southwest part of the Kara Sea, the drilling activity was conducted in Rusanovsko-Leningradskaya. As a result of geological and geophysical works, the structure of the sedimentary cover was determined. The depth of exploring was 11-17 km [16]. Moreover, the main tectonic elements were highlighted. There were over 60 local structures detected. In total, only four exploration wells were drilled in the southwest part of the Kara Sea. The length of the wells is around of 9.9 thousand meters. Two wells were drilled in Leningradskoe field and similarly, two wells were also drilled in Rusanovskoe field. These four wells discovered reserves of gas and condensate fields in the two mentioned fields.

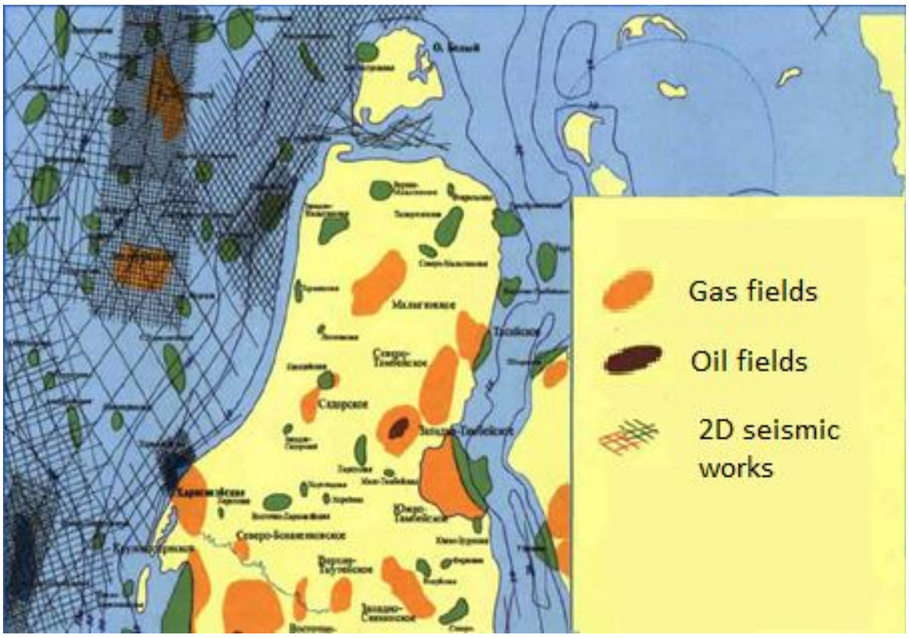

Figure 2.2. The map of seismic exploring of southern part of the Kara Sea [16]

Leningradskoe gas and condensate field was discovered in 1990. The water depth of the field is from 80 to 165 m, and its reservoir is a multilayer. The reservoir is large that the maximum area of the single layer is around 1180.2 km^2. The total area of productive layers is 3001.2 km^2. The first exploration well was productive. The production rate was 3.5 million m^3 per day. The second exploration well was not tested. However, it was also found out to be productive according to logging data. The first well has opened seven productive layers, meanwhile the second - only two (see Figure 2.2).

The Russian reserves system is only based on the analysis of geological attributes. Explored reserves are represented by categories A, B, and C_1; while preliminary estimated reserves are represented by category C_2; and potential resources are represented by category C_3; and forecasted resources are characterized by categories D_1 and D_2 [76].

In geological terms, the condensate field is located in the northern part of the West Siberian oil and gas province, within the South Kara petroleum region. The deposits are represented by alternating layers of sandstones, siltstones, and shales with high porosity (20%) and low and medium permeability [16]. The composition of the gas is mostly methane (91-99%). Therefore, the gas is almost dry (small amount of condensate). Category C_1 reserves are computed by results of geological exploration work [76]. In Leningradskoe field, the C_1+C_2 category of reserves (explored and preliminary estimated) was estimated by drawing the rectangular with 4 km in width and 13.2 km in length. According to C_1+C category, the initial reserves are 1.05 trillion m^3 of gas and 3 million t of condensate [3]. The percentage of C_1 reserves from the top layer to the bottom layer was estimated as 6.5% – 7.4% – 6.8% – 5.9% - 7.7 %. The average value is 6.8 %. The weighted average effective gas saturation thickness varies within 7.4 to 19.2 m; the sum of the thicknesses of all seven layers is 67.6 m [2]. The area of seven productive layers varies from 326.7 km^2 - to 1180.2 km^2; the depth is from 1099 m. to 1895 m [16].

The estimated average values of open porosity of reservoir rocks are from 24% to 27% in Leningradskoe field. The average permeability of the Aptian layers is around 3.3 mD, in the Albian layers is 1.6 mD, and in the Cenomanian layers is 0.6 mD (note: 1 Darcy = 1 μm^2). All productive strata are trapped by clay cover [16].

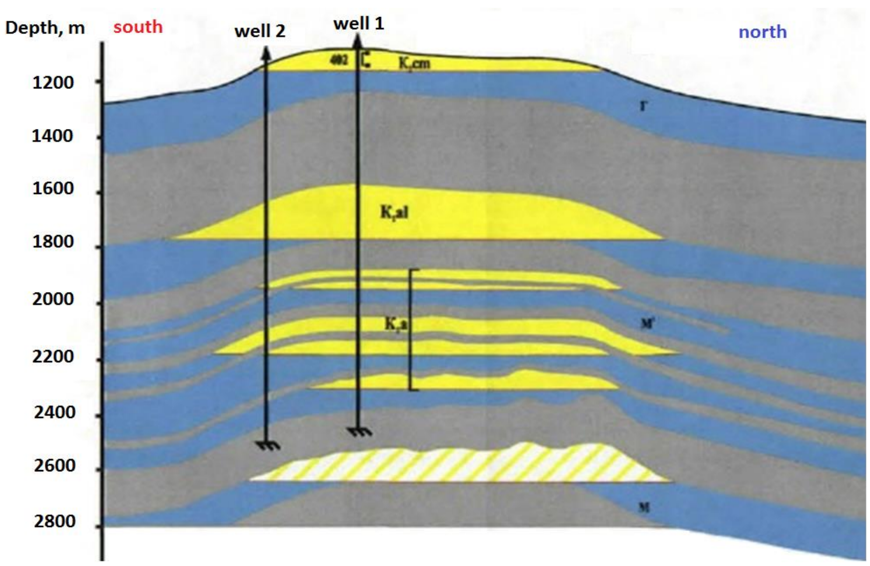

Figure 2.2. The geological profile of Leningradskoe field [16]

When receiving the license for oil and gas areas, it is necessary to assess the possible benefits or losses as well as to determine the degree of risks. Priority should be given to geological risk assessment. The probabilistic parameters of geological risk are directly related to the evaluation of calculated parameters. They are determined by three factors:

- The conformity of suspected or identified traps to existing (oil or gas-bearing areas, the reliability of reservoir traps);
- The adequacy of reservoir parameters of reservoir rocks (the effective thickness, open porosity);
- The presence of hydrocarbons and the adequacy of the phase state and the qualitative and quantitative composition of the hydrocarbon system (hydrocarbon saturation, gas and condensate factors, the composition of the mixture formation).

Quantitatively, the degree of uncertainty can be determined by the coefficient of variation of resources (reserves). This coefficient characterizes the ratio of standard deviation to the average estimate. For well-known geological structures the coefficient is low (0 - 0.3), for relatively well-known structures is average (0.3 - 0.5), and for poorly known structures is high (0.5 - 0.7) [16].

A conventional method for defining uncertain geological is to use the P10/50/90 framework, where the P10, P50, and P90 represent the 10th, 50th, and 90th percentiles of the ranges, respectively (see Figure 2.3) [75].

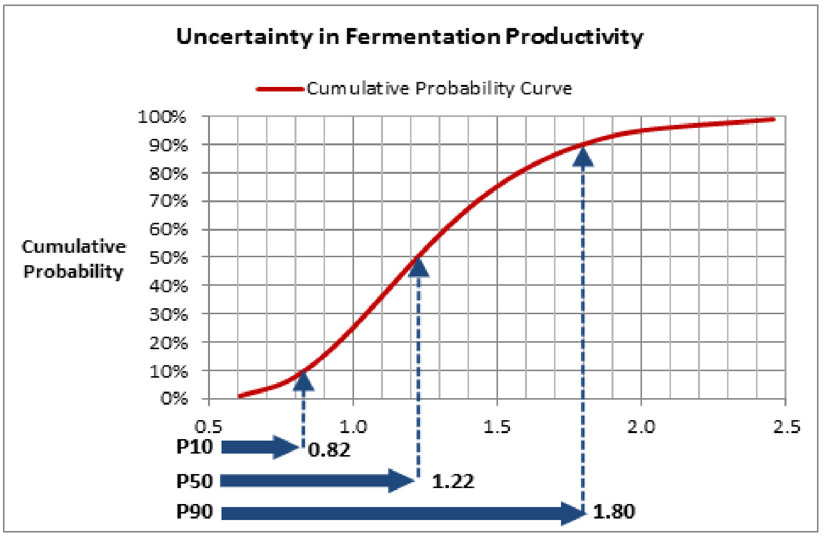

Figure 2.3. An example of how a P10/50/90 range is used to evaluate uncertainty [75]

Table 2.1 shows the results of probabilistic assessments for Leningradskoe field. Deposits are ranked with increasing uncertainty of the predicted reserves [16]. According to this table, the «threshold» assessment of resources was defined in Leningradskoe field: P90 (90%) is a minimum value, P50 (50%) is an optimal or base estimation, and P10 (10%) is a maximum value (see Figure 2.3).

Table 2.1. The initial total resources of Leningradskoe field taking into account the uncertainty and risk.

Field	**Geological risk factor** (the coefficient of variation)	**Probabilistic evaluation of gas, billion m^3**		
		P90 (90%)	P50 (50%)	P10 (10%)
Leningradskoe	0.22	1443	2010	2577

Note that the geological risk is associated with the uncertainty of the geological model. It does not depend on the absolute value of hydrocarbon resources. Thus, if the geological model is known exactly, the coefficient of variation and the local geological risk would be zero. However, that does not happen, even after the development of the field. The calculations and ranking in the degree of geological risk are conditional. Therefore, the ratio may vary in the future.

CHAPTER 3. PHYSICAL ENVIRONMENTAL CONDITIONS

3.1. Geographical location

The Kara Sea is part of the Arctic Ocean north of Siberia. The Kara Sea is an extension of the Arctic Ocean. It is separated from the Barents Sea (in the west) by the Kara Strait and Novaya Zemlya Archipelago - and the Laptev Sea (in the east) by the Taymyr Peninsula and Severnaya Zemlya [1]. Leningradskoe gas and condensate field is located in the southeast part of the Kara Sea (see Figure 3.1).

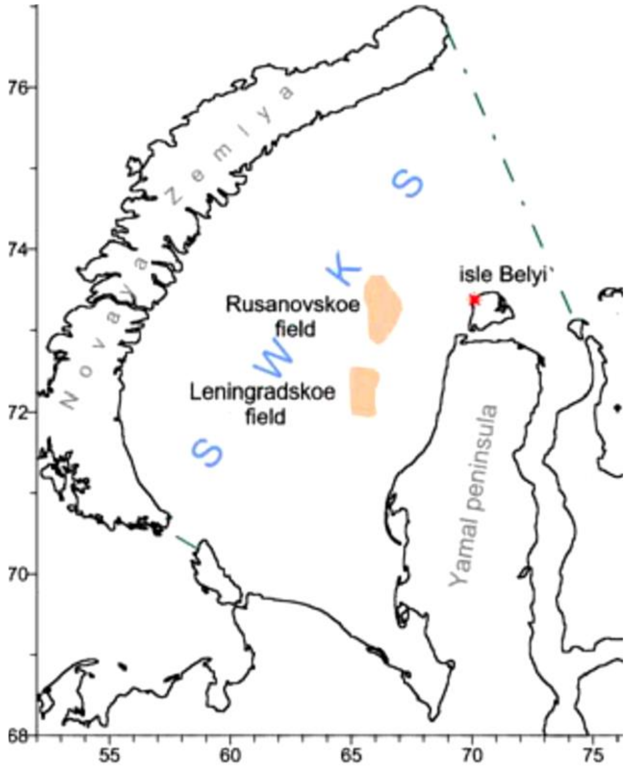

Figure 3.1. Southwestern part of the Kara Sea [1]

Leningradskoe field is located 150 km south of Rusanovskoe field. The distance from Leningradskoe gas and condensate field to the shore (Yamal peninsula) is 125 km. However, the distance to the nearest port, «Harasavay» (Yamal), is approximately 170 km.

3.2. The climatic conditions

The Kara Sea is characterized by a polar maritime climate. The weather in the Kara Sea can be different in two areas: southwest and northeast. Leningradskoe field is located in the southwest part of the Kara Sea. The average January temperature is about -20 to - 28 °C (minimum can reach -50 °C), July -6 to +1 ° C (maximum can reach +16 °C) [1].

The relative humidity is high throughout the year (80-85% in winter, 90- 95% in summer). Fogs over the sea occurs most frequenty in July and August. The number of days with storms is the 1-2 months in the summer months, and 6-7 in the winter. The system of currents in the Kara Sea is provided by circulating water of the Arctic Basin. The system of currents is characterized by a cyclonic circulation in the southwestern part.

Cold winds and currents come from the north to the south of the Kara Sea basin along the east coast of Novaya Zemlya archipelago. They are more or less confined by Novaya Zemlya and Yamal peninsula. In winter, low temperatures and wind cause problems for the working conditions in all types of operations. Frequent cases of polar depression are not expected.

Weather forecasts have a high degree of uncertainty, which may lead to the extension of «weather window», required before the start of the most significant operations. In general, there is a lack of long-term hydrometeorological and ice condition observations to create a sound basis for the design of ships and offshore structures.

The primary challenge that polar lows bring is the rapid change in the wind. Gale or storm force winds and seldom hurricanes are also possible. The problem is that polar lows are difficult to predict, and meteorologists cannot forecast them with reasonable accuracy for more than 9-12 hours [42].

3.3. The soil conditions

The soil in the Kara Sea is of various types, the most common being sand, clay, and silt. Permafrost is the special concern in this area [15]. Subsea permafrost derives its technical importance from current interests in the development of offshore petroleum and other natural resources in the continental shelves of the polar regions. The presence and characteristics of sub-sea permafrost must be considered in the design, construction, and operation of coastal facilities, structures founded on the seabed, subsea pipelines, and wells drilled for exploration and production. There is a clear relationship between soil strength and temperature [53]. However, it is not enough data to make a conclusion about the significance of the soil strength changes. Therefore, it should be noted that soil conditions are widely unknown in the Kara Sea.

3.4. The ice conditions

The Kara Sea is covered most of the time, from November to June, with a solid first-year ice, which can reach up a thickness of up to 2 meters with an average of 1.6 m. There are drifting ice floes and young ice in July – October. The open water period lasts from 3 to 4 months in the southeast part of the Kara Sea.

It is essential to provide the choice of criteria as well as the heaviest years with the uniform detailed description of each year's ice conditions. In the paper [1], the state of ice cover was estimated for each month by the following parameters: ice age, sizes of ice features, ice ridge concentration, the degree of melting, the amount of snow. The average parameters for ten previous heaviest years are presented in Tables 3.1 (3.2, 3.3).

Table 3.1. Age composition of ice in the region of Leningradskoe field (%) [1]

Age/Month	Oct	Nov	Dec	Jan	Feb	March
Thick	0	0	0	0	51	73
Medium + thin	20	20	33	55	39	22
Thin + nilas	42	98	67	45	10	5
Total concentration	44	100	100	100	100	100
Age/Month	**April**	**May**	**June**	**July**	**August**	**Sept**
Thick	90	90	90	86	55	4
Medium + thin	10	10	6	5	0	0
Thin + nilas	0	0	0	0	0	0
Total concentration	100	100	96	91	55	4

Table 3.2. Occurrence (%) of sizes of ice features in the region of Leningradskoe field [1]

Form/Month	Oct	Nov	Dec	Jan	Feb	March
Floes	40	75	100	100	100	100
Medium floes	10	12	67	50	10	20
Floe small/ ice cake	90	88	67	50	30	20
Pancake ice	90	88	100	100	70	60
Age/Month	**April**	**May**	**June**	**July**	**August**	**Sept**
Floes	100	100	100	80	40	0
Medium floes	0	30	60	80	90	20
Floe small/ ice cake	10	20	10	70	80	20
Pancake ice	30	40	20	30	10	0

Table 3.3. Ice ridges concentration (%), degree of melting (%) and amount of snow (%) in the region of Leningradskoe field [1]

Parameter/Month	Oct	Nov	Dec	Jan	Feb	March
Ice ridge concentration	0	6	20	20	21	20
Degree of melting	0	0	0	0	0	0
Amount of snow	-	-	20	20	22	20
Parameter/Month	**April**	**May**	**June**	**July**	**August**	**Sept**
Ice ridge concentration	22	18	19	22	20	0

Degree of melting	0	0	0.4	2.9	3.8	0.4
Amount of snow	20	25	10	0	0	0

Thus, ice formation starts in the middle of October; in November ice cover is presented by the nilas and young ice cakes (up to 30 cm). While the thickness is growing, the ice ridge concentration increases, ice floes start to prevail. Thin first-year ice and medium ice (30-120 cm) already dominates in January whereas floes of the thick first-year ice (more than 120 cm) are present from February to July [1]. Ice cover develops the most intensively in the period of April-May. The typical ice ridge concentration is about 20 percent, and the amount of snow is about 20-25 percent. The beginning of melting in June is accompanied by the decrease of ice cover level. Ice cake and cake forms of the thick first-year ice prevail. In August, the degree of melting reaches its seasonal maximum (about 40 percent). Ice with a thickness of less than 120 cm usually melts away. In September, the residual ice is crumbled significantly, and big ice floes are not observed. The duration of the ice period is usually more than ten months and can reach up to 11.5 months; it means that the permanent presence of ice cover is a special feature of the environmental conditions in the area of Leningradskoe field [1].

As far as the winter period is concerned, the statistically significant increased values of ice thickness are observed only in the second half of winter when ice cover thickness is close to or higher than 1 m. In this period ice thickness comprises about 1.5 m under medium conditions, 1.7 m under heavy conditions and about 2 m under extreme conditions. In the summer time, the largest deviations are observed when the average sea ice extent decreases down to 70% (beginning of August) and less (down to 15% at the end of September). In September, the sea ice extent amounts to 3-5% under medium conditions, about 15-25% under heavy conditions and 30-45% under extreme severe ones [1].

Ice gouging is the greatest threat to offshore pipelines in the shallow part near Yamal peninsula. The problem is caused by ice structures with deep keels moving in shallow waters, cutting deep gouges into the seabed. Ice ridges are the critical design factor in both pipeline design parameters and route selection. Ice conditions in the water area of Leningradskoe gas and condensate field are characterized not only by the presence of pack ice and ice hummocks but also grounded hummocks as known as «Stamukhas». Consequently, there is a danger of damage to offshore pipelines due to ice gouging seabed that poses a threat to the sites with a water depth of less than 25 m. Mainly, coastal sites of shore sea-gate require particular attention [39].

3.5. Icebergs

This section is focused on the study of the possibility of icebergs destroying subsea equipment that can be located in Leningradskoe field. First, the probability of an iceberg's occurrence is analyzed. Second, the study of the icebergs' draft within this area is performed.

On the map of the Kara Sea, it should be noticed that some islands partially consist of glaciers. These islands are possible places where icebergs can appear. Franz Josef Land and Severnaya Zemlya are highlighted as potential places where icebergs might be generated in the Kara Sea (see Figure 3.2).

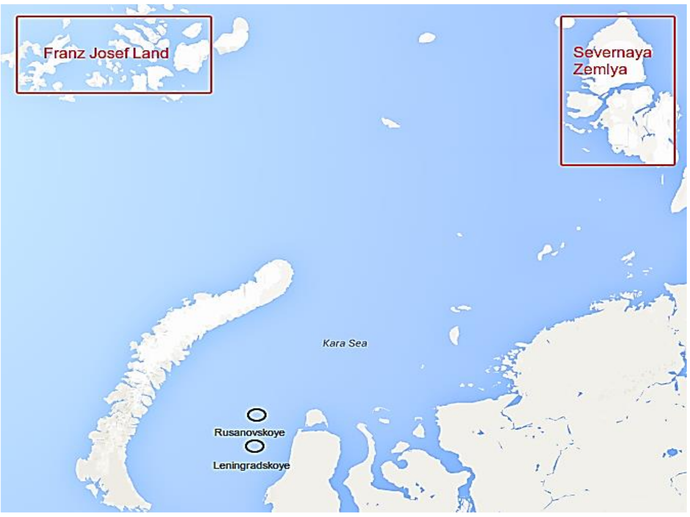

Figure 3.2. Potential places of icebergs' generation

The water depth in the areas where icebergs appear is deep (over 400 m). Therefore, icebergs might be large with a deep draft. However, bathymetric data in the direction of the Novaya Zemlya shows that the deepest draft of icebergs is about 250 meters in the north and the south of the Kara Sea (see Figure 3.3). Such large icebergs can travel to the southern part of the Kara Sea just along the east coast of Novaya Zemlya, as the central area of the Kara Sea is shallower. In general, icebergs are highly anticipated in the north part of the Kara Sea.

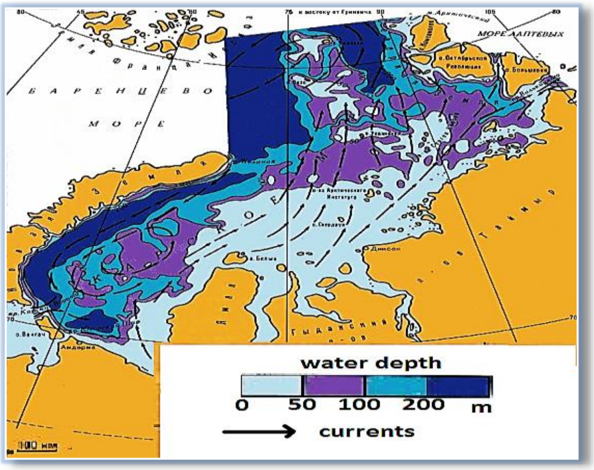

Figure 3.3. Bathymetric map of the Kara Sea [4]

According to the map of currents in the Kara Sea, icebergs travel from the north to south along the Novaya Zemlya. Therefore, there is a small probability that icebergs with a draft over 80 m can appear in the area of fields because of the depth and direction of currents.

Based on historical aviation research, which was conducted in the period of 1928 - 1991, the icebergs' occurrence in the Kara Sea can be observed [5, 6]. The southern border of the icebergs' presence according to this data is shown in Figure 3.4. According to this data, it can be concluded that the probability of occurrence of icebergs in Rusanovskoye field is high, while in Leningradskoe is low. Thus, the study of icebergs' occurrence is to be investigated.

Figure 3.4. Southern border of the icebergs' presence in the Barents and Kara seas, according to aviation research over the period 1928-1991 years [5, 6]

Rosneft and ExxonMobil have drilled an exploration well in the Kara Sea. The research about icebergs was conducted in the central part of the Kara Sea. Arctic and Antarctic Research Institute carried out an expedition to this area in 2013 [7]. It should be mentioned that icebergs are mostly concentrated near the north-eastern coast of Novaya Zemlya. East Prinovozemelsky 1st, 2nd and 3rd blocks in the Kara Sea are located in the northeast direction from Rusanovkoye field. Therefore, the size of icebergs is not that significant in Leningradskoe field.

In 2013, in the central part of the Kara Sea, the maximum depth of the sea, where gouging was found was 60 m (see Figure 3.5).

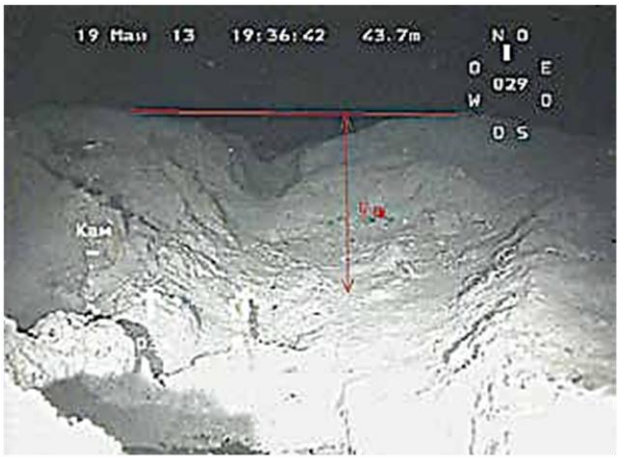

Figure 3.5. Gouging the seabed by icebergs in the Kara Sea [7]

Moreover, five icebergs were found drifting in the ice, including a giant iceberg of the size of a surface part 70 × 70 × 12 m and underwater depth up to 50 m (see Figure 3.6).

Figure 3.6. Giant iceberg in East Prinovozemelsky block, 2013 [7]

Based on another source [8], the probability of having the iceberg grounded within Leningradskoe field during the period 1987-2005 is low (see Figure 3.7). The depths of the sea within Rusanovskoye field change from 50 to 100 m. Meanwhile, the water depths within Leningradskoye field change from the northwest to the southeast between 80 and 165 m. The average height of subsea equipment is 10 m. Therefore, if the draft of icebergs is more than 70 m, then the subsea equipment should be located at deeper places of the field (more than 90 m). Otherwise, it must be protected from load of icebergs.

Moreover, there is a probability of iceberg grounding on the pipeline route. Therefore, the optimal pipeline route should be also chosen based on the drift of icebergs.

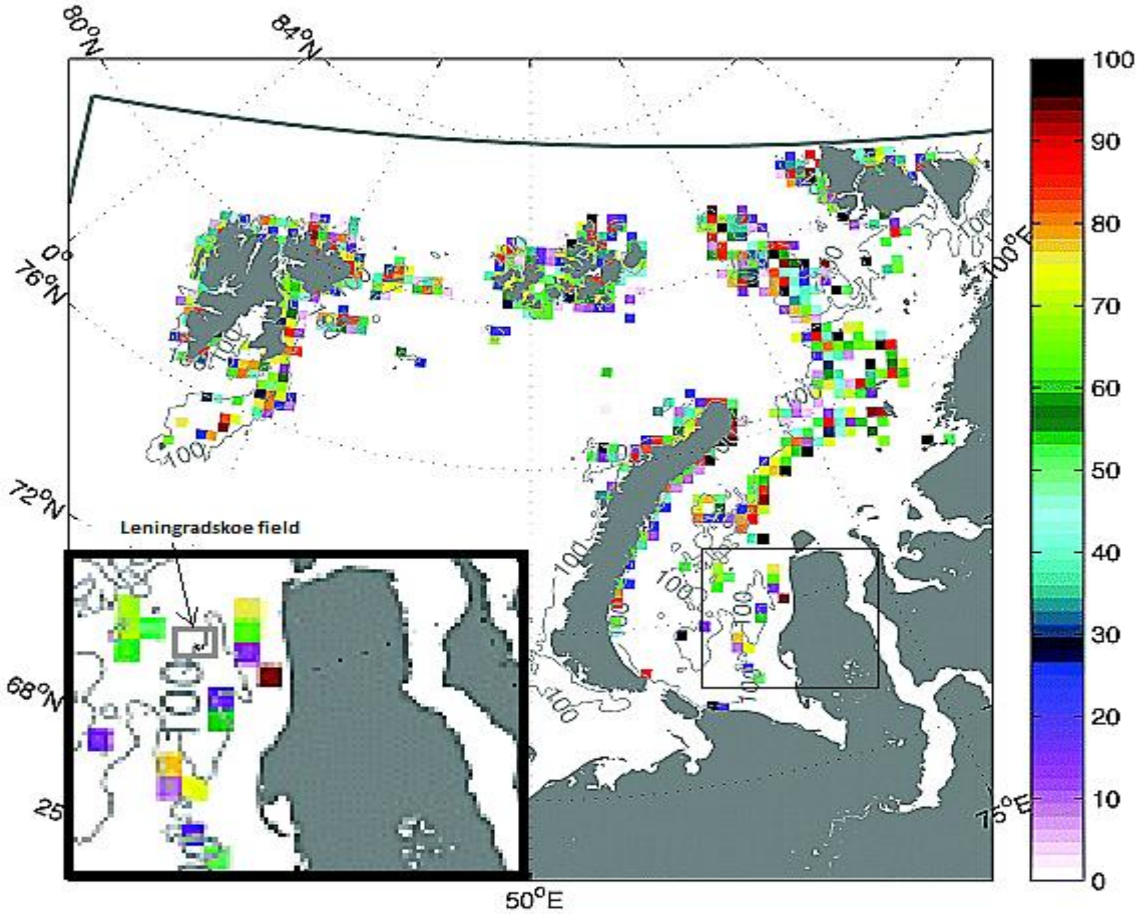

Figure 3.7. Probability (%) of having an iceberg grounded within a 25 × 25 km grid cell during the period 1987–2005 [8]

Therefore, it can be concluded that, based on current knowledge of iceberg presence, it is safe to locate subsea equipment in Leningradskoe field without ice-resistance protection when water depths are more than 90 m. If subsea equipment is going to be placed on the parts of Leningrdaskoe field where the water depth is less than 100 m, it is recommended to place subsea equipment in trenched holes (see Section 7.2.5). Meanwhile, in Rusanovskoe field, it is recommended to lay out the equipment in trenched holes. Another approach is to protect subsea equipment. Moreover, additional data regarding icebergs' occurrence is required to be gathered and analyzed.

CHAPTER 4. DRILLING TECHNICAL BLOCK

4.1. The Screening of the drilling technical block

The purpose of drilling is to explore and produce oil and gas resources. In such severe conditions that exist on the shelf of the Kara Sea, there is no experience of drilling wells. Some important factors that determine the feasibility of prospecting and exploration drilling are the presence of ice, the time of «weather window», weather severity, together with the availability of technical equipment, technology, production bases on the adjacent shore, and others.

The primary constraints to the drilling on the production stage are harsh climatic conditions, significant depths of resources and considerable depths of the shelf. However, the main challenge is constantly driving/ solid drifting ice fields. No structure that is capable of withstanding the natural forces, the pressure of the ice fields of the Kara Sea. The proper design of platforms and dynamic positioning system do not exist yet.

It is standard practice for Arctic field development to plan to drill only during the ice-free period from traditional drilling systems, such as jack-ups, semi-submersibles, and drilling ships. When compared with the North Sea, it must be noted that the North Sea has different environmental conditions. In the Kara Sea, there is long powerful sea glaciation that limits the possibilities of drilling. That is the main factor when considering the possible technological solutions for Leningradskoe field. The screening of the drilling technical block is illustrated in Diagram 4.1.

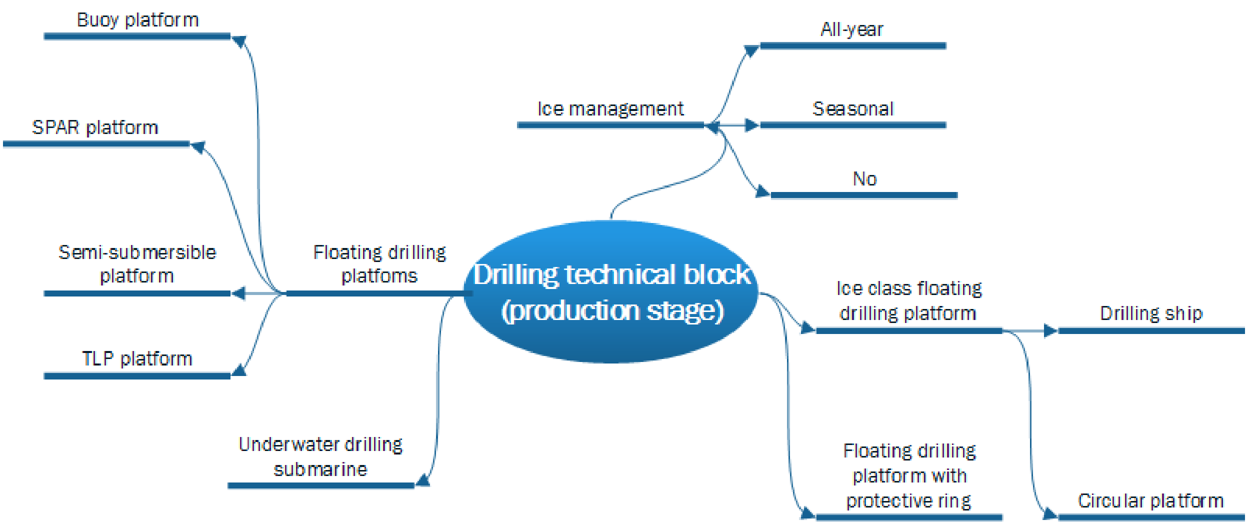

Diagram 4.1. The screening of the drilling technical block

There are key drilling characteristics:

- the risk of problems during well construction;

- the availability of existing drilling facility;
- ability to install several derricks on the structure;
- workover capability;
- the motion characteristics of a vessel.

It is not a good solution to use stationary types of drilling platforms in Leningradskoe field. One of the limiting factors is a depth that is more than 80 m. Therefore, it is better to apply a floating drilling platform or underwater drilling submarine.

The most important element of the floating drilling platform is a satellite navigation system that keeps the platform in a particular geographic location to do drilling activities. Drilling operations in Arctic areas are expected to be conducted primarily in «managed ice». Ice Management is the sum of all activities to reduce the risk of the ice loads on the offshore installations. Station-keeping can be done through dynamic positioning (DP) system in the deeper parts. As there is a lack of experience with drilling operations in heavy ice conditions with a floating drilling unit, in addition to the limited qualified rescue concepts in ice, it is believed that a heavy ice class floating drilling ship will not come into use for some years yet. The estimated period («weather window») of possible drilling with floating drilling platform is 3-4 months. According to this, nowadays the maximum number of drilled wells is two per year. Moreover, it is not possible to drill two wells simultaneously in such severe ice conditions.

To handle with severe climatic conditions and energy intensity of production, a subsea drilling concept can be suggested. Energy is produced in nuclear power installations. There are no ready-to-use subsea drilling systems in the world market. However, such developments are carried out. There is some success in exploring the concept of underwater drilling rigs [22].

Considering the climatic and environmental conditions of Leningradskoe field, it seems that submarine drill ships are a good technical solution for industrial drilling. To do maintenance works both the platform and the entire system of supply vessels, the modernization of existing technical equipment is required. This equipment must be capable of working independently while submerged for a long time. Therefore, to do the drilling activities, a large amount of energy is required.

The idea of subsea drilling design began in 2003 [22]. A schematic diagram of subsea drilling system is illustrated in Figure 4.1.

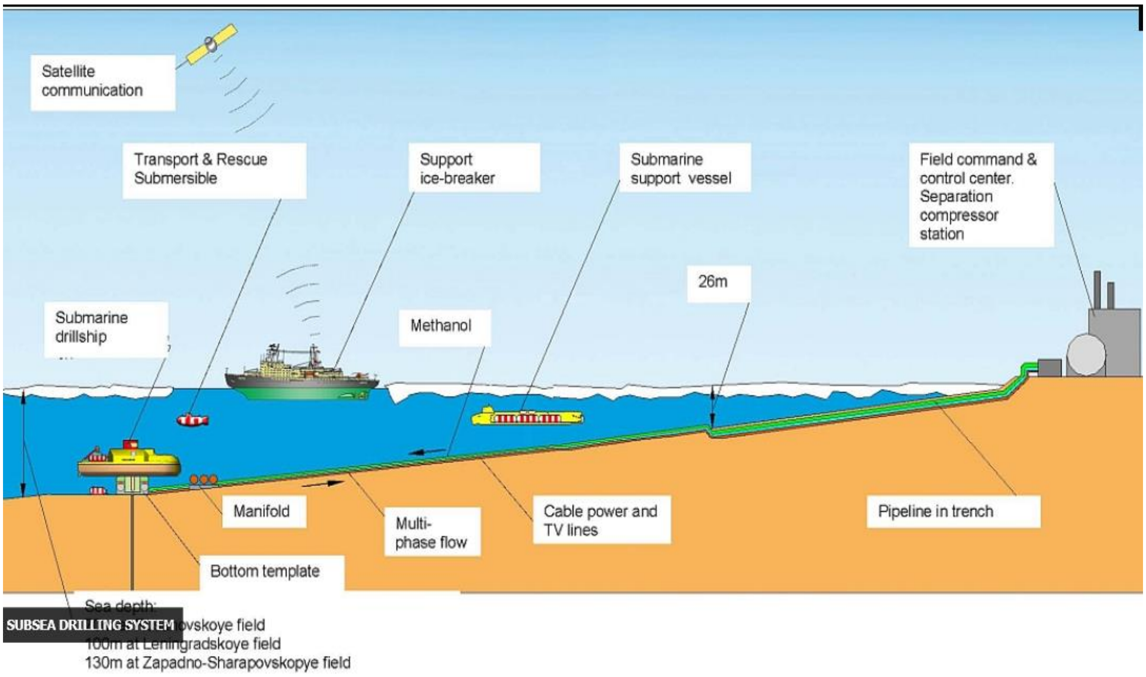

Figure 4.1. Subsea drilling system [70]

The subsea drilling system consists of a bottom base plate and an underwater drilling vessel (see Figure 4.2). There are a drilling rig and consumable materials that are sufficient for the drilling of one well on the board of the submarine drillship. For further drilling, the consumable materials are expected to deliver in containers. In the early stages of the project, the required power is supposed to transmit from the shore through the electrical cable. The latest design documentations refers to the use of nuclear power as a primary power source for submarines and surface vessels [22]. There is no experience in the implementation of such an ambitious program in the world. The use of nuclear energy for the field development in the Arctic will increase the risks of existing ones. It should be mentioned that in Norway they are extremely skeptical of using of nuclear-powered equipment in oil and gas business.

The bottom base plate is set permanently on the seabed. The function of the plate is to support the submarine. When well is completed, the production equipment is installed. The subsea drilling vessel is capable of drilling eight wells with a length of up to 3500 m each. The drilling can be performed at water depths of 70 to 400 m.

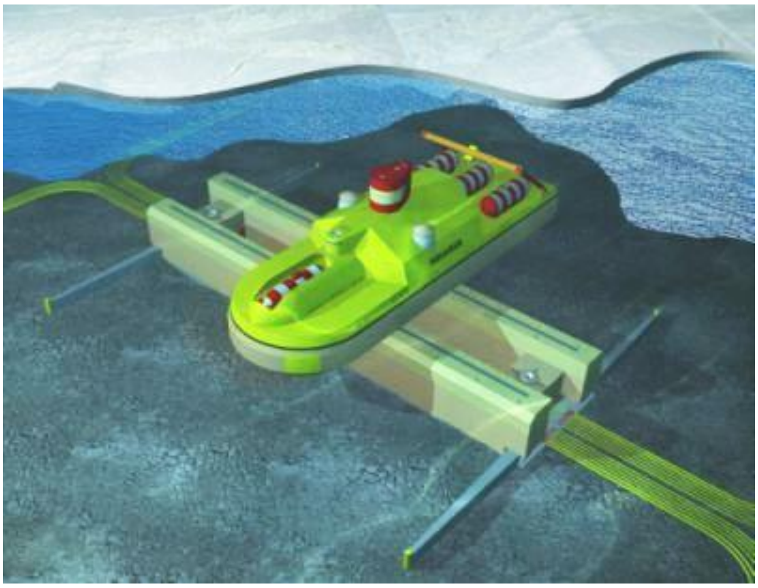

Figure 4.2. Nuclear powered underwater drilling rig [22]

4.2. The Scoping of the drilling technical block

To choose the best option of drilling concept, some important factors must be considered. They are technology readiness, the rate of drilling, resistant to environmental loads, the risk of problems during well construction, power consumption requirement, workover capability, operational window. The grid analysis of various technical solutions for the drilling technical block is shown in Table 4.1.

Table 4.1. Grid analysis for the drilling technical block

Selection criteria (scale 0-5)	Subsea drilling system	Floating drilling platform	Ice class drilling ship	Weight factor (scale 0-5)
Technology readiness	1	5	3	5
The rate of drilling	3	2	2	4
Ice management/ resistant to environmental loads	5	2	3	4
The risk of problems during well construction	2	4	4	3
Power consumption requirement	1	3	3	2
Workover capability	2	3	3	2
Operational window	5	2	3	5
Total score	0,423	0,429	0,423	Max score: 1

According to the multi-criteria decision making of four scenarios, it is not obvious to choose the best option. The main reason is that the technology readiness levels of the subsea drilling system and ice class floating drilling platform are extremely low. Meanwhile, floating drilling platform has many disadvantages to drill in the Kara Sea.

4.3. Risk assessment

The risk analysis provides input so that certain measures can be taken to reduce the probability of a risk event from occurring and reduce the consequences during drilling operations to sufficiently low levels. This type of analysis depends on the analyst's ability to identify and evaluate the risks. In the thesis, the following risks are considered to be the most important during drilling operations in Leningradskoe field: loss of well control, shallow gas-bearing zones, station-keeping failure and subsea drilling system failure. Loss of well control can lead to a blowout, which is an uncontrolled flow resulting from a failure of surface equipment or procedures. The possible consequences of loss of well control are gases, liquid hydrocarbons or mud spills, and loss of human life. Shallow gas-bearing zones are especially dangerous. Thus, when a shallow gas zone is first penetrated, a dramatic increase in pore pressure due to gas gradient can lead to underbalanced drilling. It can lead to fire or explosion on the drilling rig. Special considerations must be given to training, evacuation plan, seismic data, and drilling procedure. Station-keeping in severe ice conditions is supposed to be one of the main challenges when drilling using floating drilling platforms. The risk assessment is to be performed to understand the challenges associated with station-keeping. It can give an understanding of the required research works in this area. Ice management is one of the main barriers that can help to avoid a station-keeping system failure in ice conditions. Subsea drilling system is an innovative approach to drill wells. Moreover, the subsea drilling system is a promising direction in the development of Leningradskoe field. However, it leads to many possible risks that ought to be considered. Therefore, all defined dangers risks are considered in the thesis. The qualitative assessment of the risks in the form of bow-tie diagrams is shown in Appendix H.

4.4. Technology readiness and future recommendations

It can be concluded that the economic feasibility of the project is dependent on drilling a sufficient number of production wells. It is a particular challenge for deep water since year-round drilling from drill ships will be required. It is currently not possible; therefore, it is necessary to maximize uptime and ensure safe operations for drilling vessels. Therefore, developing technology to assist drilling vessel operators on deciding when to carry out disconnection is important. By doing this, it is possible to extend the drilling season. Another strategy is to develop technology in support of decreasing the time needed to drill a well through advances in drilling technology. For example, slimmer wells have the opportunity to reduce resupply requirements, the time required to drill as well as costs. The challenge is related to finding real solutions for drilling and completion equipment which combines lower cost while still maintaining the required well integrity. However, it may be more cost efficient to use large bore wells. Hence, the technology which combines slim wells with large through bore capacity would be beneficial. Furthermore, «new» technology such as dual gradient and riserless drilling as possible answers are needed to be investigated [46]. The duration of the drilling operation of a well should also be considered. Meanwhile, the technology solutions for protection of wellheads, including BOP must be developed [49].

Based on the analysis of the drilling technical block, the technology readiness levels of the key elements can be evaluated according to API RP 17N [36]. Therefore, the estimated technology readiness levels of the elements of the drilling technical block are shown below [36]:

- Ice Class Floating drilling vessel: TRL = 3;
- Subsea drilling system: TRL = 2;
- Combined slim and large holes drilling: TRL = 4;
- Riserless drilling: TRL = 5;
- Vessel Winterization for cold climate (cold, icing): TRL = 5;
- Station-keeping in severe ice conditions: TRL = 2.

Drilling technical block is not ready for drilling more than two wells annually. R&D is required taking into account all possible risks. Thus, R&D opportunities are identified to assist reduce drilling costs by increasing the number of wells that can be drilled in a season as well as extending the operational season.

There is a need for innovation and technology development:

- Ice mechanics and loading studies;
- Slim hole wells;
- Riserless drilling;
- Subsea drilling system;
- BOP protection (from icebergs);
- Stationing-keeping in severe ice conditions;
- A drilling vessel’s hull strength.

The calculation results of prioritization of research issues and technologies for the drilling technical block is shown in Appendix G.

CHAPTER 5. RESERVOIR ENGINEERING

5.1. Gas production assessment

The gas production can be estimated based on the data from two exploratory wells [16]. However, it is not enough. Therefore, the gas properties are assumed the same as in Yamburgskoe gas and condensate field [60]. The properties of gases are approximately similar because Leningradskoe field is situated in the northern part of the West Siberian oil and gas province as well as Yamburgskoe gas and condensate field. The Cenomanian, Albian and Aptian stages in the stratigraphic column were considered here.

In a (dry) gas field, the reservoir temperature is always larger than the critical temperature of the same gas. Therefore, the following initial condition is essential:

$$T_r > T_{crit} \tag{5.1}$$

If initial p-T conditions in the reservoir coincide with points located on the right-hand side of the dew point line in Figure 5.1 and gas recovery is performed in such a way that the dew point line will never be crossed then only dry gas will exist in the reservoir at any pressure. However, when producing the gas to the surface, both pressure and temperature will decrease, and the final state will be at a point within the two-phase envelope [38].

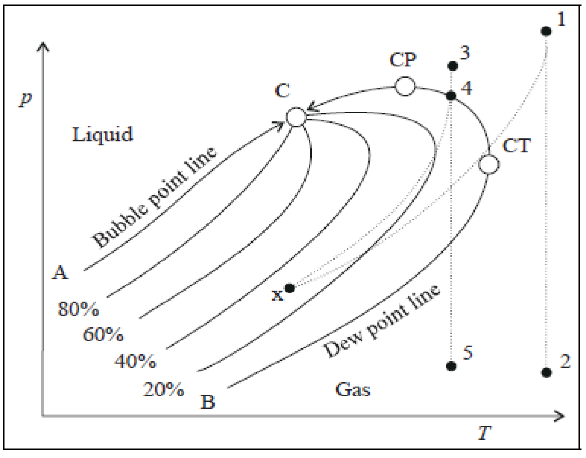

Figure 5.1. P-T diagram for a complex HC mixture [38]

The basis for all well-performance relationships is Darcy’s law, which in its fundamental differential form applies to any fluid—gas or liquid. However, different forms of Darcy’s law arise for various fluids when flow rates are measured at standard conditions. The different forms of the equations are based on appropriate equations of state for a particular fluid. In this Section, the dry gas inflow is assessed below.

It has been proposed to drill horizontal wells (see Figure 5.2). Horizontal well drilling provides powerful and attractive technology for hydrocarbon recovery due to the following features of horizontal wells:

- substantial length;
- infinite conductivity;
- the control of the geometry.

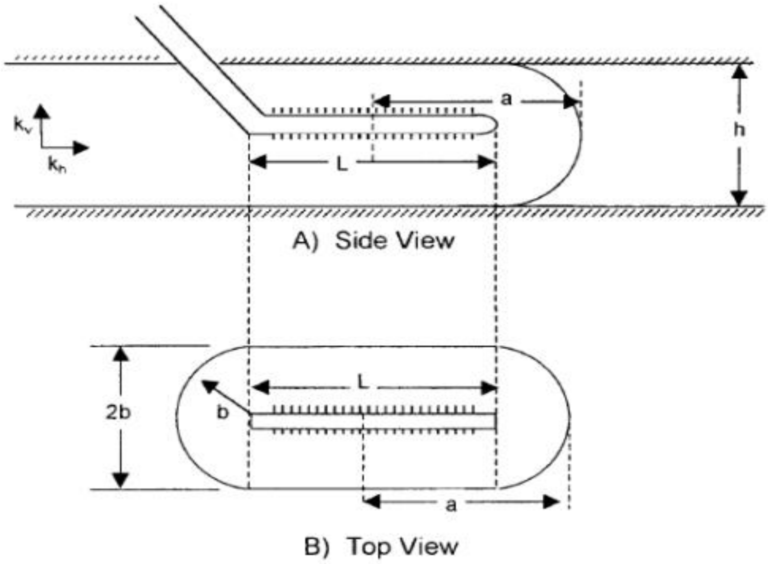

Figure 5.2. Horizontal well drainage area [64]

The horizontal well performance, penetrating a uniform deposit or layer can be determined by the formula [65]:

$$P_{res}^2 - P_{bot}^2 = a_g Q + b_g Q^2 \quad (5.2)$$

Where, P_{res} – reservoir pressure [MPa]; P_b – bottomhole pressure [MPa]; Q – gas production rate of a horizontal well [million m3/day]; ag, bg – the coefficients of filtration resistance (flow coefficients).

To predict the performance of horizontal wells as well as gas flow properties of each productive layer, it is necessary to know the values of the coefficients a_i and b_i of each layer. To determine the performance of horizontal wells and filtration properties of each layer, it is necessary to know the values of the coefficients a_{gi} and b_{gi} for each layer. It was established that the term $b_g Q^2$ is around 5-10 % of the right-hand side of the equation (5.2) [66].

Therefore, due to lack of information about the filtration and capacitive properties of each layer, the equation (5.2) can be rewritten as [67]:

$$P_{res}^2 - P_{bot}^2 = a_g^* Q \quad (5.3)$$

Here, the coefficient of filtration resistance a_g* is greater than a. It is determined by the equation [68]:

$$a_g^* = \frac{a^*}{2L_h}[\frac{2}{h_1}\left(h_1 + r_w ln\frac{r_w}{r_w+h_1}\right) + \frac{R_{ext}-h_1}{r_w+h_1} \tag{5.4}$$

$$h_1 = \frac{h}{2} - r_w \tag{5.5}$$

$$a^* = \frac{\mu z p_a T_{res}}{kT_{st}} \tag{5.6}$$

Where, μ – dynamic viscosity [mPa·s]; z – z-factor [-]; T_{res}- reservoir pressure [K]; r_w – well radius [m]; R_{ext} – the external boundary radius of a horizontal well [m]; k – the coefficient of permeability [Darcy]; T_{st} – gas temperature at standard conditions [K]; h – the thickness of a productive layer [m].

When determining the shape of the drainage area of the horizontal well productivity, the different shapes are possible to consider, for instance, a circle, ellipse or rectangle. In the present study, the rectangular shape is chosen (see Figure 5.3).

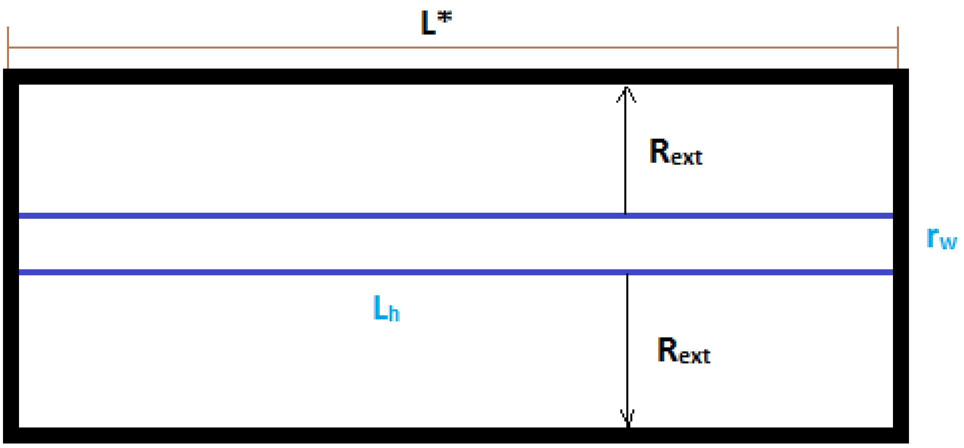

Figure 5.3. Top view of rectangular horizontal well drainage area

To determine the flow rate of Leningradskoe field, calculations were performed assuming the following initial data. The weighted average effective gas saturation thickness varies within 7.4 to 19.2 m; the sum of the thicknesses of all seven layers is 67.6 m [16]. In Leningradskoe field, one layer is Cenomanian; one layer is Albian, and five layers are Aptian (see Figure 2.2). The average permeability of the Cenomanian layers is 0.6 mD, the Albian layers is 1.6 mD, and the Aptian layers is around 3.3 mD [16].

The reservoir pressure is estimated as the hydrostatic pressure at the depth of 1750 m (the average depth of Leningradskoe field). That corresponds to 17.5 MPa. The bottomhole pressure is assumed to be equal to 12 MPa. The radius of the well is 0.1 m. The reservoir temperature is around 323 K [60].

The properties of gas are as follows [60]: z = 0.78; μ = 0.013 mPa·s.

In the study [65], it was established that the best length of the full penetration of the strip-like layer when $L^* = 2R_{ext}$. Here, L^* is a length of strip-like layer penetrated by a horizontal well (see Figure 5.3). If the well is fully penetrated and completed than $L^* = L_h$. It is determined by the minimum coefficient of filtration resistance and, consequently, the maximum flow rate at a given pressure drawdown. The external boundary radius of a horizontal well is unknown. However, the results of calculations are almost not dependent on L_h and R_{ext} when the ratio is the same. Therefore, assuming that the ratio is $L_h / R_{ext} = 2$, then the calculated gas rate of the well is equal to 3.22 million m^3/day (see Appendix C).

5.2. Development concepts

There are key factors, which influence the development of gas and condensate fields:

- field area (sweep efficiency);
- geological features;
- filtration-capacity properties of the reservoir;
- specification of the drilling on the Arctic shelf.

The nature of the principal indicators of the development is diverse. It primarily depends on the field itself and geological features of deposits. The implementation of the relevant technical solutions and roadmap are also important parameters for choosing the development production scenario. The main activities and milestones are shown in Figure 5.2. These activities are influencing the production profile.

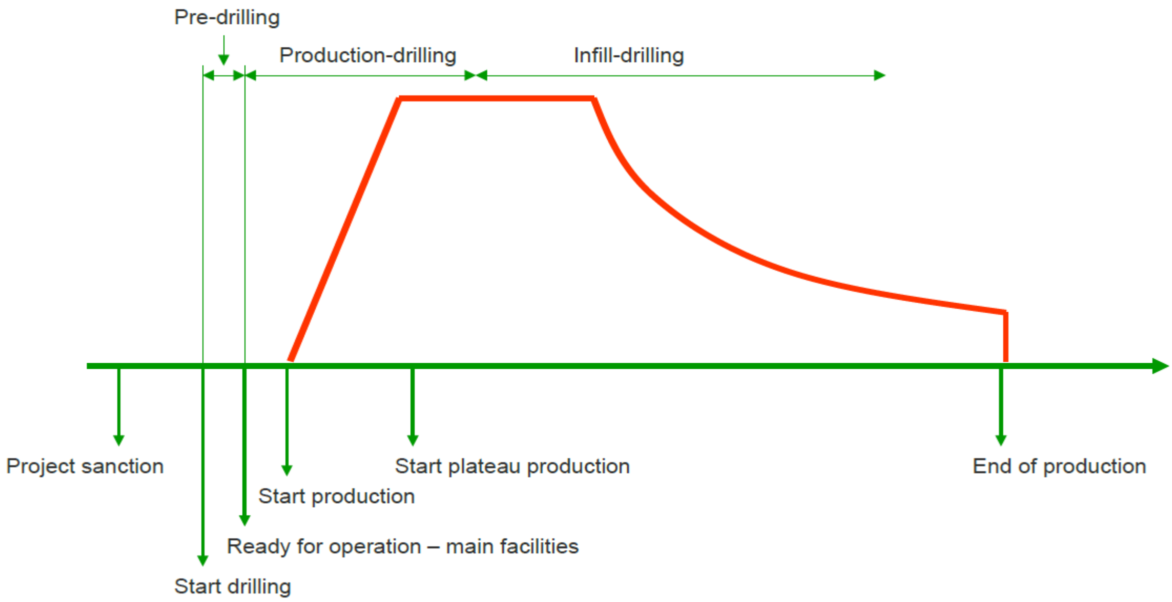

Figure 5.2. Gas production profile – activities and milestones

The production profile of a gas field can be divided into three stages. These stages are (see Figure 5.3):

- 1st stage – Build up. Here, gas production is increasing due to drilling new wells;
- 2nd stage – Plateau production. It is a period of relatively constant high production that is supported by additional drilling. Moreover, a pressure drop (drawdown) may be increased at this stage;
- 3rd stage – Decline. It is a period of intense production. The profile is decreasing due to depletion of the reservoir.

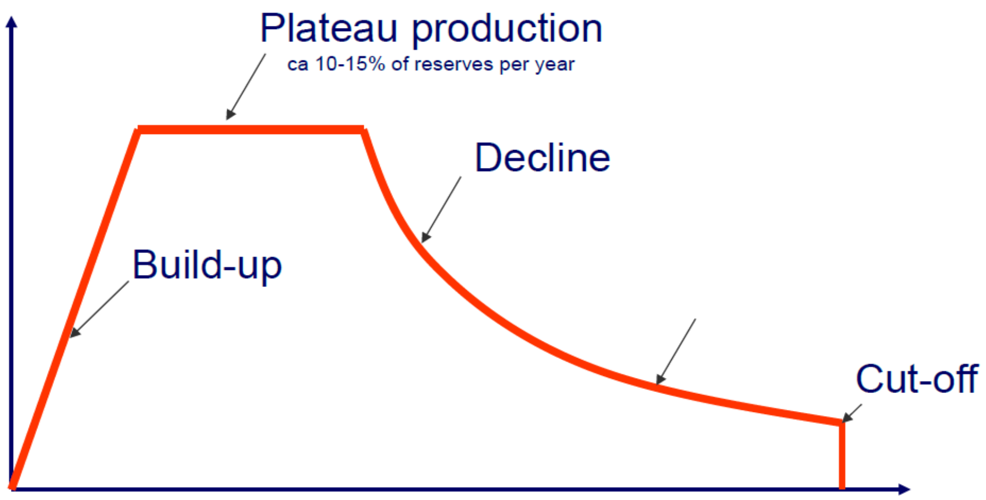

Figure 5.3. Gas production profile - periods

By analyzing the data from the production of another gas and condensate fields, some conclusions can be proposed [17]. The duration of the first stage of the field development depends on drilling speed. The duration of the second stage is from 4 to 10 years for large gas and condensate fields, while the average annual production at the second stage is about 10 to 15% of reserves. Most of the previous gas projects show that 40 - 70% of balance gas reserves are extracted by the end of the second stage. However, it is more realistic to extract 60-70% of gas reserves by the end of the second stage. At the third stage, 20 - 30% of the gas reserves are produced. It should be noted that the number of operating wells remains unchanged at the gas drive. Meanwhile, the number of operating wells are decreasing due to the decommissioning of flooded wells at elastic water drive. In the duration of the third stage, the rate of falling of gas production depends on the dynamics of the gas production that was in the first two stages. The third stage is finished when the project is approaching the minimum cost-effective production.

According to Mirzoev D.A. [40], a general view of a gas production profile of the cluster development of Leningradskoe and Rusanovskoe fields is shown in Figure 5.4. The red line is a production from fields. Meanwhile, the green line is a flow rate on the gas processing facility that is located on the shore.

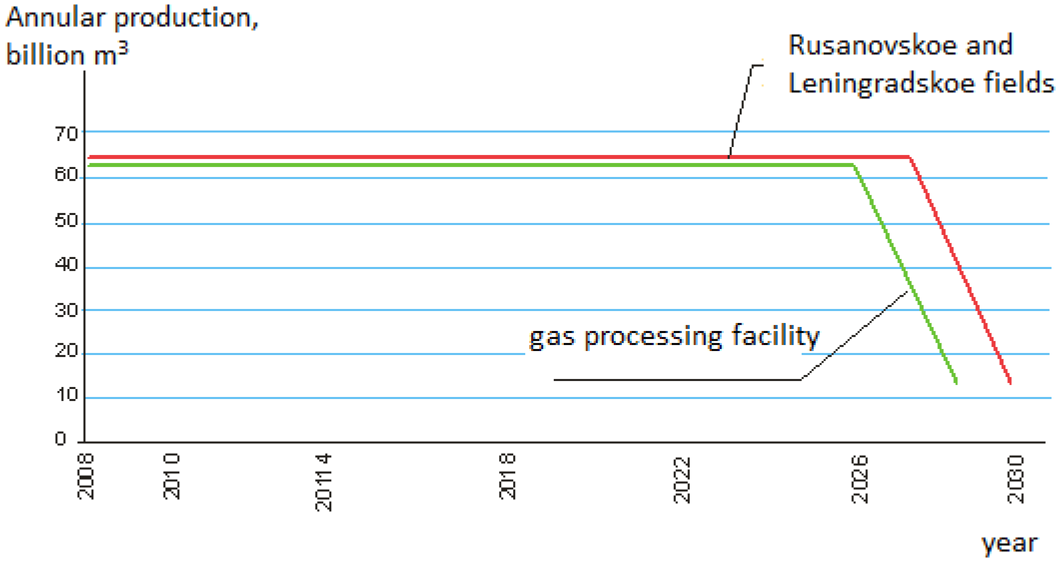

Figure 5.4. Theoretical gas production profile for the cluster development of Leningradskoe and Rusanovkoe fields [40]

It can be noticed that in the concept suggested by Mirzoev D.A., the first stage of the development is not shown. The main reason is that Mirzoev D. A. believes that the main challenge of the development of the southwest area of the Kara Sea is drilling [40]. If subsea drilling system could be applied, the first stage of the development would be short because of all-year drilling.

The development concept is dependent on production strategy. Meanwhile, the production strategy can be with a low level of production or with a high level of production. It is illustrated in Diagram 5.1.

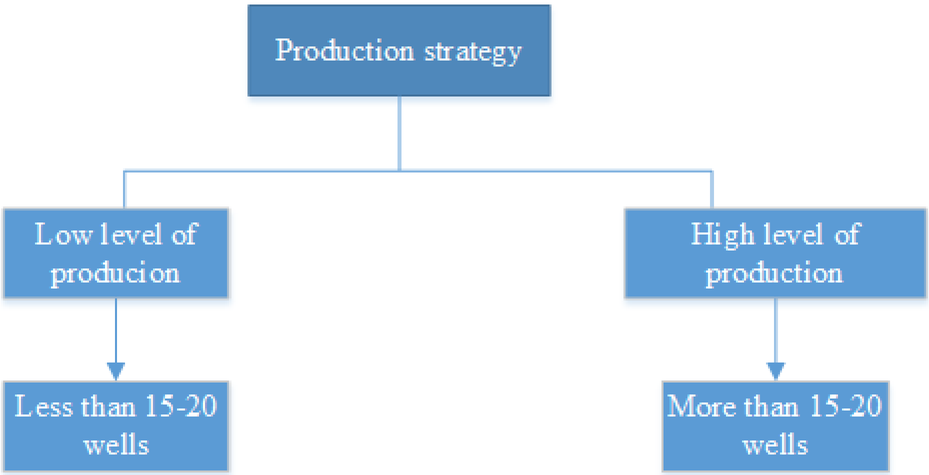

Diagram 5.1. The screening of the reservoir engineering technical block

The operating company sets the development schedule philosophy. The great production profile is governed by large investments associated with a majority of wells and equipment (high CAPEX and initial cash flow). It provides a better NPV and gets money back very fast; however the control of the reservoir is poorer.

Meanwhile, the scenario with the low level of production is governed by low CAPEX and moderate initial cash flow as well as longer time for production development. A low production profile is characterized by lower investments and good reservoir control, but it takes a long time to get the money back. This time is even longer in the context of offshore field development due to the period it takes to start the production. Both systems have benefits and drawbacks, but both investments reduction and good NPV performance are desirable [18].

It is possible for all-year drilling in the gas fields that are located on the land. However, the drilling in Leningradskoe field is dependent on the ice-free season. Therefore, the first phase of the Leningradskoe field development is much longer because the drilling in this license area is possible only for up to 3 months.

The grid analysis of various technical solutions for the development schedule selection is shown in Table 5.1. The considered selection criteria are CAPEX, OPEX, reservoir control, production time, operational risks (maintenance works).

Table 5.1. Grid analysis for the development schedule selection

Selection criteria (scale 0-5)	Low level of production	High level of production	Weight factor (scale 0-5)
CAPEX	5	3	5
OPEX	4	3	2
Reservoir control	4	3	4
Production time	2	4	4
Operational risks/ maintenance works	4	3	3
Total score	0,552	0,464	Max score: 1

According to the selection criteria, the best option is a low level of production. That is also dictated by reducing risks and uncertainties as well as drilling limitations in the Kara Sea.

To understand the maximum possible of the gas production per year, some assumptions are proposed. Thus, the recoverable gas reserves are 1.4 trillion m3 (P 90) [16]; and two production wells are drilled per year (see Figure 5.5). The calculated gas rate of the well is equal to 3.22 million m^3/day.

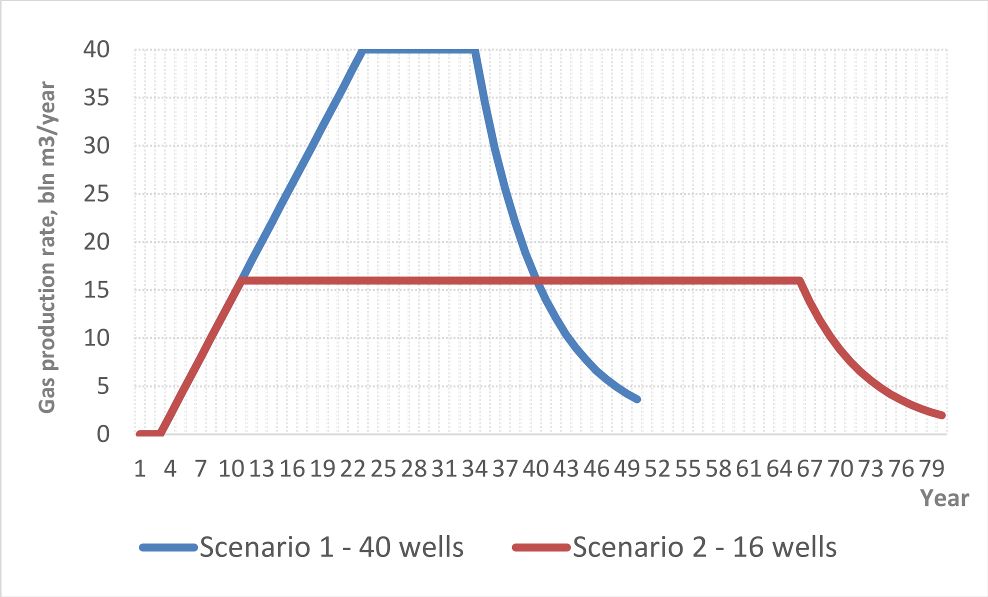

Figure 5.5. Theoretical gas production profile for Leningradskoe field

In the scenario with 40 wells, the maximum gas production rate is around 40 billion m^3 per year. The lifetime of the field development is about 50 years. Meanwhile, in the scenario with 16 wells, the maximum gas production rate is around 16 billion m^3 per year. The lifetime of the field development is about 80 years

CHAPTER 6. PIPELINE TECHNICAL BLOCK

6.1. The Screening and Scoping of the pipeline technical block

Subsea pipelines are expected to be one of the key building blocks in the development of Leningradskoe field because floating LNG vessel is unlikely to be used. The main reason is severe ice conditions. Pipelines are considered to be an effective way to transport gas to the onshore processing center as well as the storage facilities. The harsh environment and low temperatures put forward some additional requirements for the pipeline, both regarding manufacturing/construction, and concerning operation. The reinforced steel materials and coatings must be able to withstand low temperatures. As well as piping systems should be designed taking into account the potential stress caused by a direct or indirect influence of the ice features. The screening of the transportation technical block is shown in Diagram 6.1.

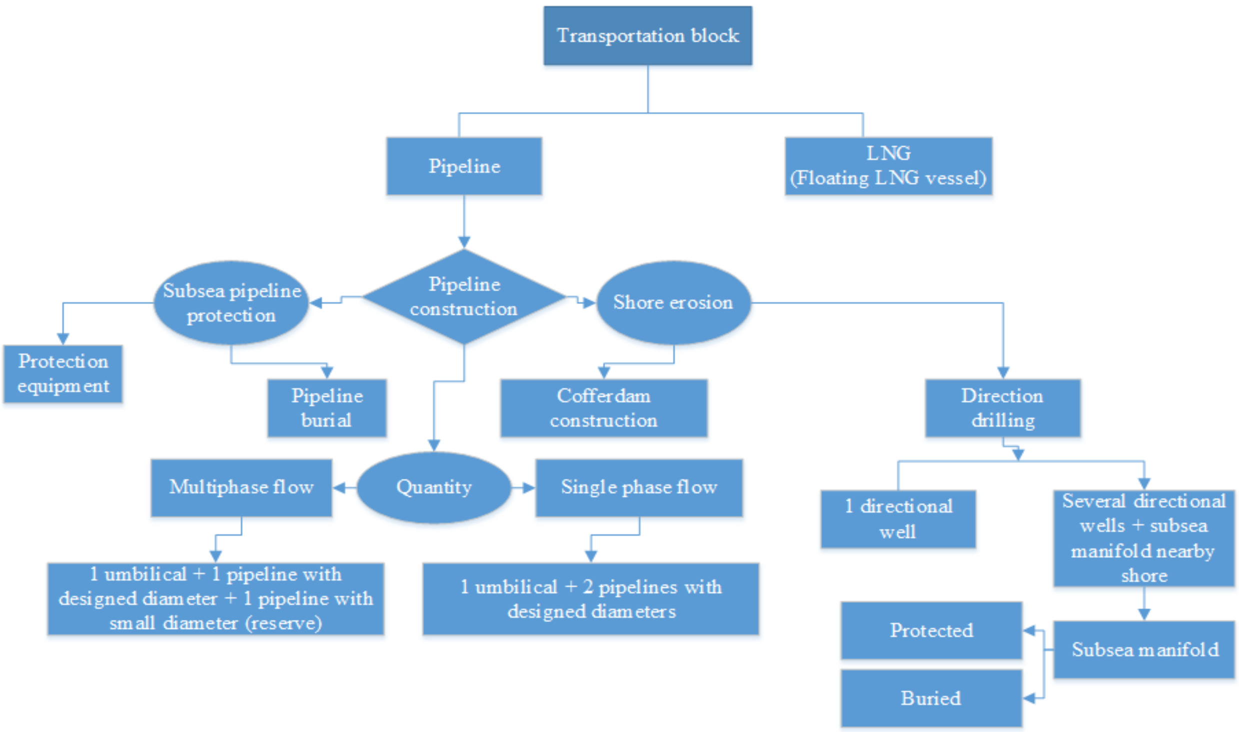

Diagram 6.1. The screening of the transportation technical block

Arctic waters bring many challenges for pipeline transportation. First, flow assurance issues should be considered very carefully for cold waters. High risks of plug formations require preventing measures, for example, chemical injection. Chemical injection requires additional pipeline installation as it was done on Ormen Lange and Snohvit fields. Moreover, pipeline gouging by ridges and icebergs is another severe issue that is relevant for Arctic region.

6.2. The detailed assessment of the pipeline technical block

6.2.1. Subsea pipeline

Leningradskoe field is located at 125 km from the shoreline. However, there is no infrastructure there. Therefore, it is recommended to lay the pipeline to the nearest port (see Figure 6.1). The pipeline route should be optimized; therefore, the shortest distance must be considered and the elevation difference must be minimal. In shallow water area of the route, it is required to bury pipelines and umbilical.

Figure 6.1. The pipeline route: Leningradskoe field – Harasavay port

«Harasavay» port is located at 170 km from Leningradskoe field. The construction of the «Harasavay» port started in 2007 (see Figure 6.2). Dredgers have been carrying out the land reclamation and the deepening of water area to construct the port [58]. The company «IHC Holland» has already built most of the machines working in the area of the Yamal Peninsula.

Figure 6.2. «Harasavay» port [13]

Further, the study of the shallow water area of the pipeline route has been performed based on the maps [9]. Two sections were chosen to analyze the water depth in the area (see Figures 6.3, 6.4).

In the first section, the water depth is more than 25 m there. Therefore, the pipelines on this route are not necessary to protect from ice ridges. However, there is a probability of pipeline's damage by icebergs. The length of the pipeline where the water depth is less than 80 m is around 15 km. Therefore, it is recommended to study the icebergs' occurrence in this area. It will minimize the length of the pipeline where trenching is required. Thus, the costs of pipeline installation will be reduced.

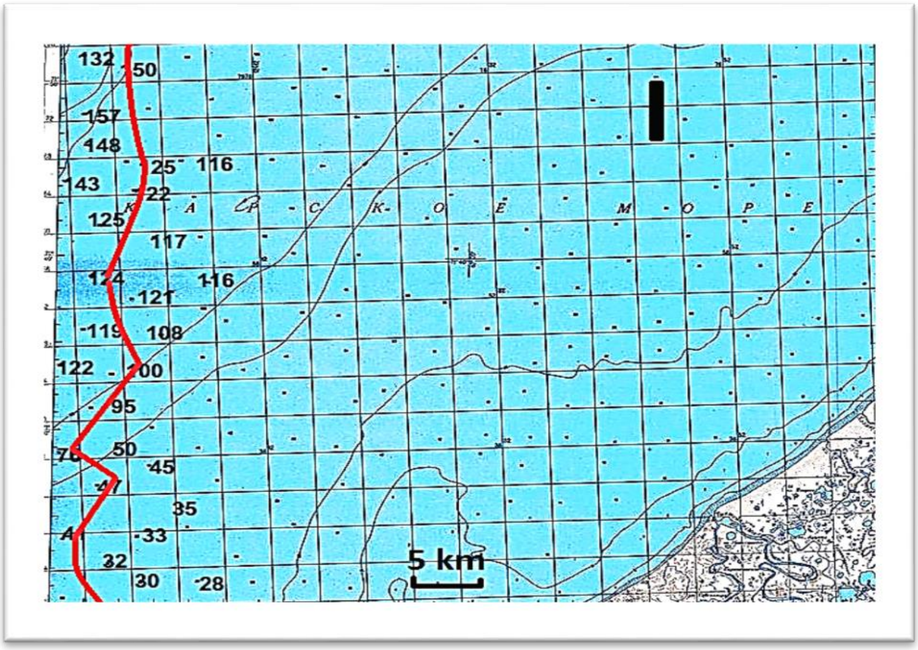

Figure 6.3. The pipeline route in the first section shown in the bathymetric map

The second section is the shallow water area with a length of 31 km. The damage to the pipeline by ice ridge keels is possible here. Therefore, it is recommended to bury the pipeline on all route of the pipeline in the second section.

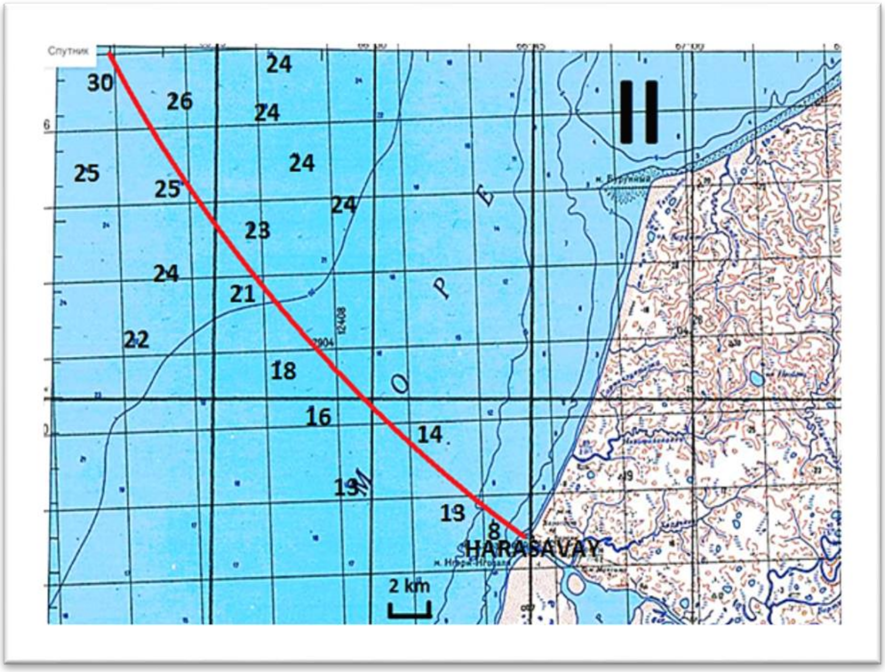

Figure 6.4. The pipeline route in the second section (shallow water) shown in the bathymetric map

The pipeline laying in a straight line can not be the best solution. If it is possible, the pipeline should be laid avoiding landslide areas, canyons, rock outcrops. The route should not impose the restrictions on future development of the field. Moreover, by adding a predetermined curved path sections, the expansion/contraction of the pipeline can be compensated. The connection point of the pipeline system is essential for the correct alignment of the connecting elements and the placement of the required equipment.

The piping systems must be designed when taking into account the potential load actions from the direct or indirect effects of the ice. That is especially relevant in the shallow areas with ice hummocks, coastal and land zones with permanent or temporary ice conditions.

6.2.2. Ice Ridge Scouring

Ice conditions in the water area of Leningradskoe gas and condensate field are characterized not only by the presence of pack ice and ice hummocks but also by grounded hummocks as known as «Stamukhas». Consequently, there is a danger of damaging offshore pipelines due to ice gouging seabed that poses a threat to the sites with a water depth of less than 25 m. On several occurrences, coastal sites of near shore sea-gate require particular attention.

The pipeline on the seabed may not be able to withstand the ice load and usually, should be buried below the projected depth of the keel (see Figure 6.5). Subsea pipeline protection equipment is very costly to use in case of long sections of a pipeline. Therefore, the special equipment that could protect a subsea pipeline is not considered in the thesis.

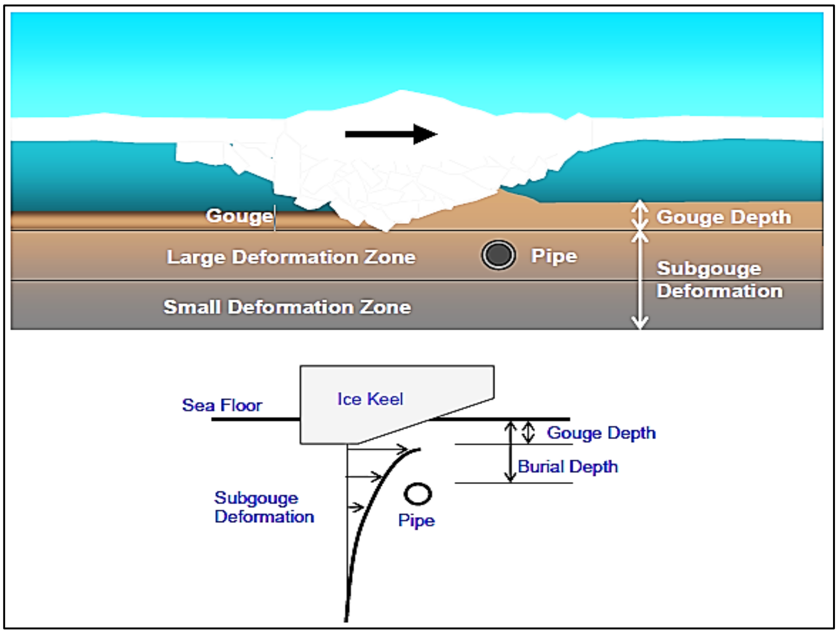

Figure 6.5. Sub-gouge deformation [10]

The conventional approach to study the required burial depth is:

1. evaluate the extreme maximum depth of gouging;
2. add the estimated amount of subgouge deformation;
3. add a margin of safety;
4. require that the top of the pipe in the trench is below this depth.

To study the required depth of the pipeline's burial, the environmental data, ice data, soil data must be collected in the southwest part of the Kara Sea. In this section, the basic calculations of ice scouring are performed. The main objective is to understand the minimum burial depth of the pipeline in the Kara Sea. Some data was approximated, and an averaged values were taken by using the data available from other nearby locations. The environmental data is shown in Table 6.1 (Appendix D) [7]. The ice data of the southwest part of the Kara Sea is shown in Table 6.2 (Appendix D) [1, 7].The soil data is shown in Table 6.3 (Appendix D) [14, 15]. The two scenarios have been proposed: clay and sand. The reason is that in some parts of the route there is a clay type of the soil. Meanwhile, in other parts of the route, there is a sand type of the soil. The present study does not take into account the permafrost to simplify the calculations. However, at the end of this chapter, the different scenarios with various soil densities were analyzed.

Then, it is required to analyze the ice ridges' properties. The geometrical ice ridge parameters are illustrated in Figure 6.6.

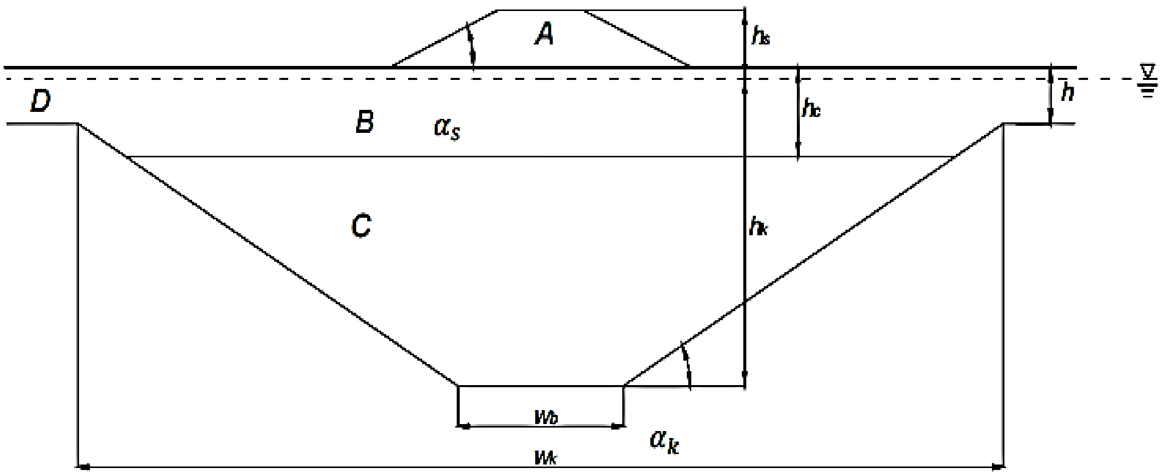

Figure 6.6. Geometrical parameters for typical first-year ice ridge. A – sail; B – consolidated layer; C – keel; D – level ice [11]

The algorithm for calculating the ice ridges' parameters is shown in Appendix D (equations (6.1) - (6.6)). The calculation results of the ridge features are shown in Table 6.4 (Appendix D).

Vershinin et al. [12] has established several design models, determining the behavior of ice ridge when contact with soil occurs. These models are as follows:

1) Force model – analysis of static forces equilibrium;

2) Energy model – based on kinetic energy dissipation through the soil friction.

Here, the force model of ice gouge estimation is implemented. The introduced model is based on the expectations that the friction forces are dependent on the scour depth. The more the soil in the front face, the greater is the friction. At the maximum depth of the ice ridge's keel, the resistant forces are in balance with drag forces.

Some assumptions must be made to apply this simplify model. Assumptions of the model are [12]:

- The bottom of ice ridge keel has an infinite strength;
- Ridge is assumed to be initially motionless such that all forces exert their maximum values;
- Ice ridge is a rigid body with negligibly small elasticity;
- The seabed has no inclination.

The critical gouge depth is relevant when the following force system exists in equilibrium:

In vertical direction:

$$F_b - W - F_c \cdot \sin \alpha_k + N = 0 \quad (6.7)$$

In horizontal direction:

$$F_{dw} + F_{dc} + F_i - F_a(d) - F_{cx}(d) = 0 \quad (6.8)$$

The force system acting on the ice ridge is illustrated in Figure 6.7.

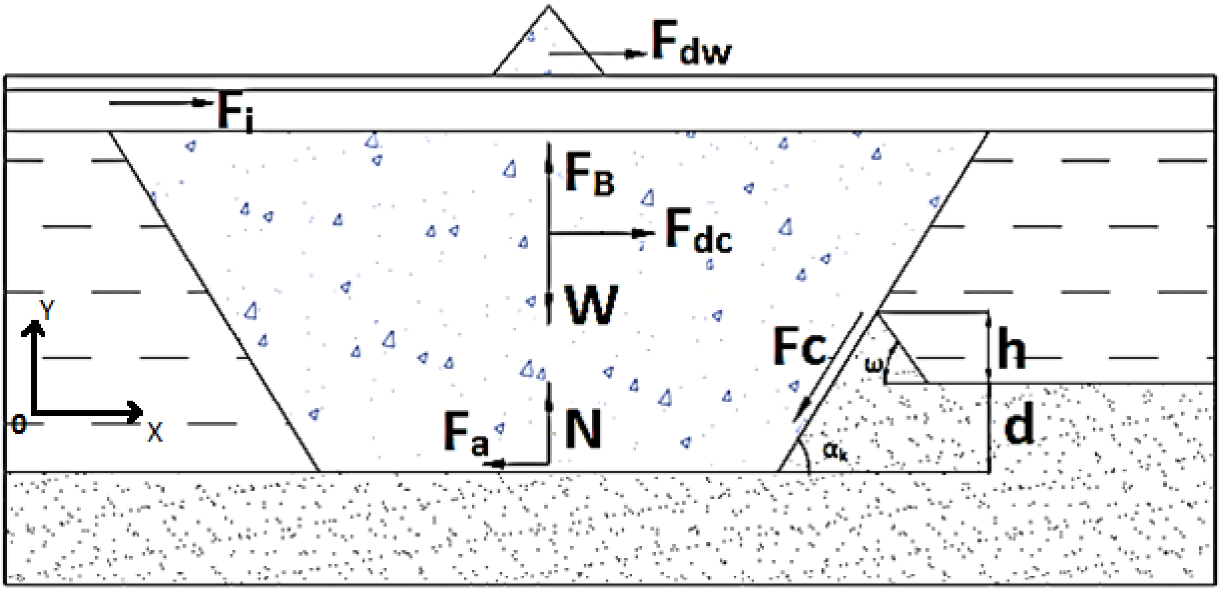

Figure 6.7. Forces on the ice ridge [12]

The algorithm of forces' calculations on the ice ridge is shown in Appendix D (equations (6.9) - (6.21)). The results of calculations of force actions are shown in Table 6.5 (Appendix D). Finally, the calculated ice gouge depth is shown in Table 6.6 (Appendix D).

There were many uncertainties in the initial data when the gouge depth was calculated. Therefore, the various scenarios were considered to understand the sensitivity of the results. In these scenarios, the unknown parameters have been changing.

First, the dependence of gouge depth from the keel breadth was analyzed. It must be noted that the bigger keel breadth is, the more projection area of the ice ridge has, therefore, the larger forces due to ice action, current and wind drags. The results are shown in Figure 6.8.

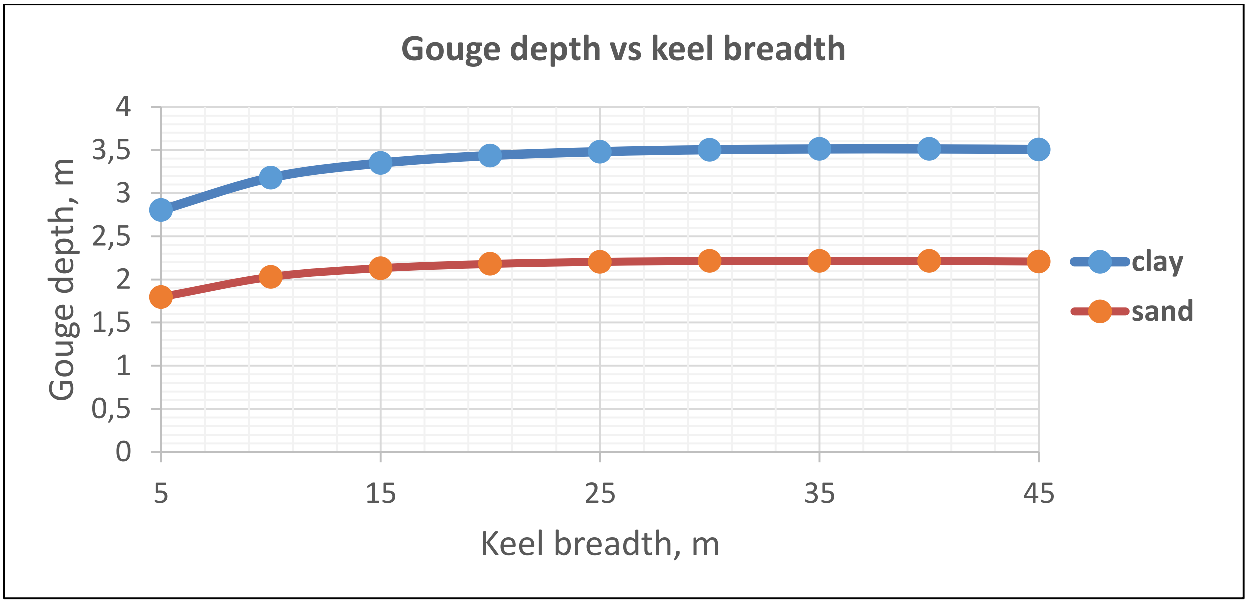

Figure 6.8. Gouge depth vs. keel breadth

Based on the results, it can be concluded that there is an increasing of gouge depth when the keel breadth is going up to 25 m. Then, the graph is constant, and there is no influence of the keel breadth on the gouge depth.

Then, the ice thickness influence on the gouge depth has been studied. It is obvious that the pipeline burial has to be designed in a pessimistic way. Here, the worst conditions in wintertime, where the maximum ice thickness is up to 2 m. In Figure 6.9, the gradual increase in the gouge depth can be noticed.

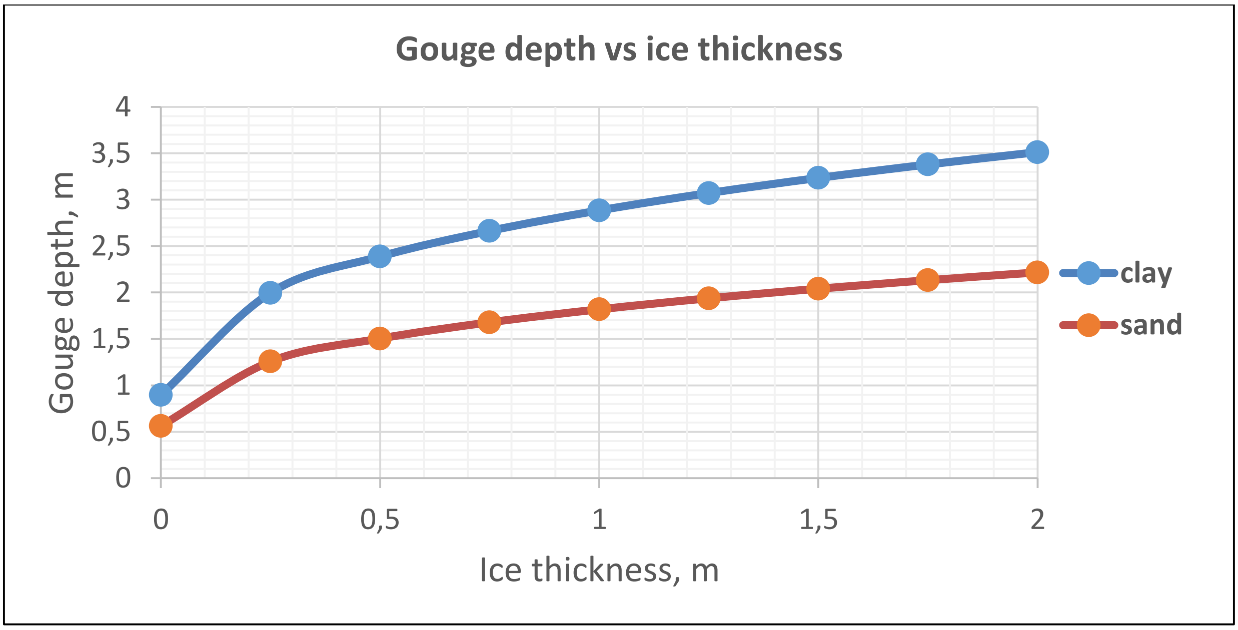

Figure 6.9. Gouge depth vs. ice thickness

The different geometrical parameters (length and angle) give different results. Therefore, it is recommended to study the dependence of the results on the keel angle and the height of a sail (keel depth).

Keel angle is an unknown parameter. Therefore, it is a good idea to check the sensibility of the dependence of gouge depth on the keel angle. In Figure 6.10, it is observed that the maximum gouge depth is around 4 meters when the keel angle ranges from 25 to 30 degrees.

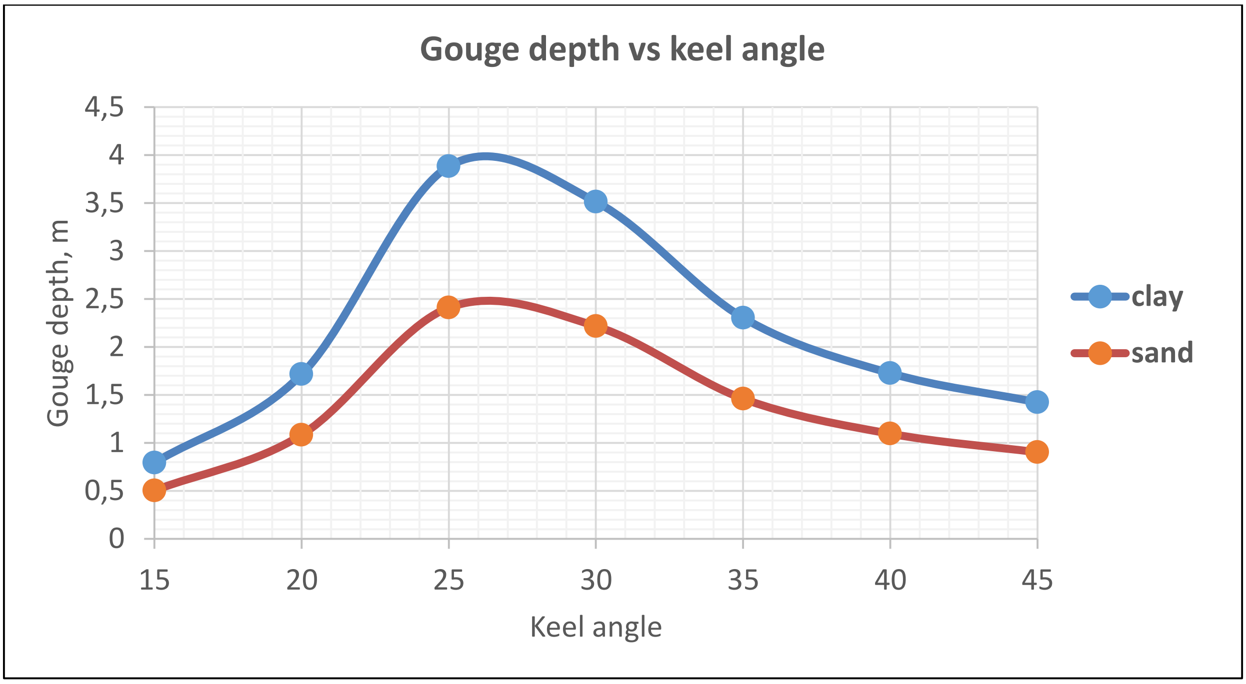

Figure 6.10. Gouge depth vs. keel angle

The height of a sail (keel depth) is also the geometrical parameter that influences the gouge depth. The maximum value of the gouge depth has been investigated here. It can be concluded that the maximum gouge depth is 4.1 meters (see Figure 6.11).

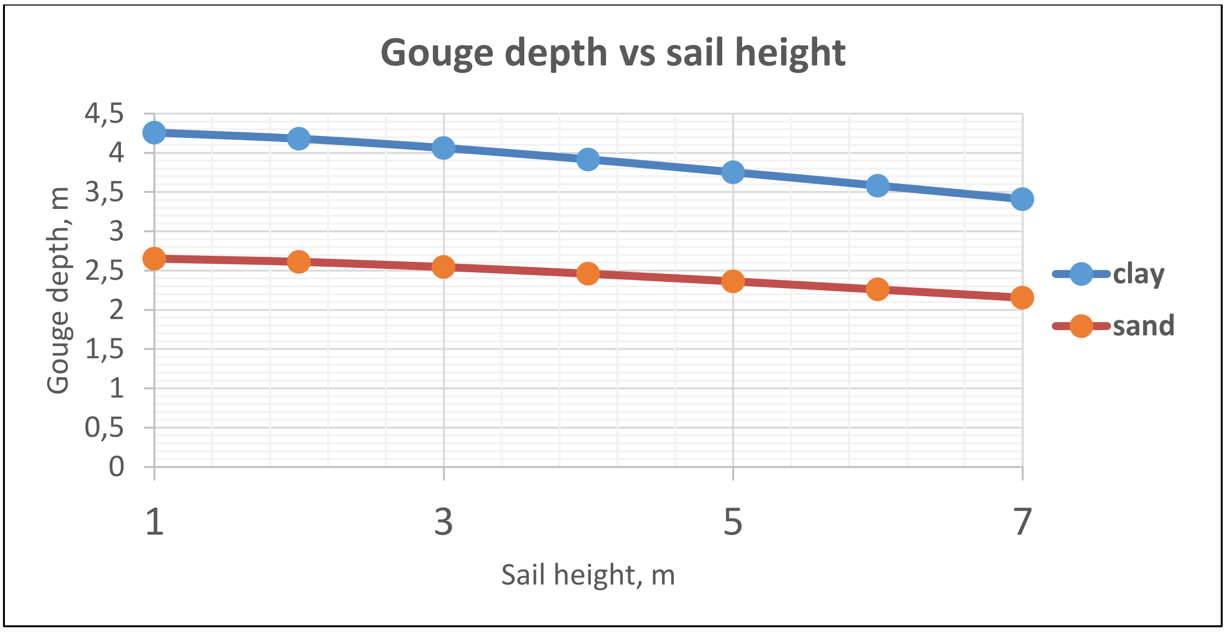

Figure 6.11. Gouge depth vs. sail height

Soil properties are not well known in the shallow west part of Yamal peninsula. Therefore, the various scenarios with different soil densities are to be analyzed in the present study. Here, the maximum value of gouge depth is 3.8 m (see Figure 6.12). It should be noted that permafrost is not considered here. Therefore, the further study of the properties of frozen soil is recommended.

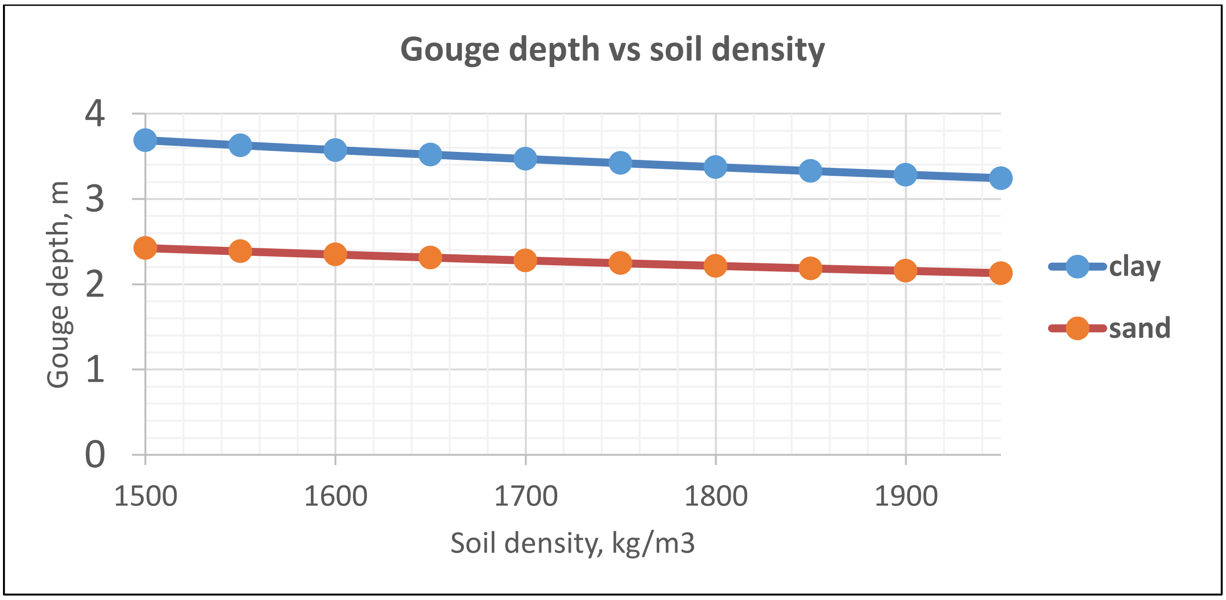

Figure 6.12. Gouge depth vs. soil density

The results show that the gouge depth becomes larger when the density of soil is less.

Thus, it can be concluded that the extreme maximum depth of gouging is 4.1 m. The subgouge soil deformations transmit substantial loading to the buried pipeline that can stress it beyond the allowable strength. There are many factors influencing subgouge deformation. In a rough estimation «Russian Maritime Register of Shipping – Rules of classification and construction of subsea pipelines» gives the recommendation that the subgouge deformations are accounted by supplemented 0.4 m of extra soil thickness [31]. A safety factor of 5% of the extreme maximum depth of gouging and subgouge deformation is assumed. Thus, the safety factor is equivalent to additional 0.23 m. The estimated pipeline diameter is 1.28 m (see Section 6.2.3). To ensure the safety of the pipeline design, the pipeline must be buried below the seabed at a depth of 4.1 m + 0.4 m + 0.23 m + 1.28 m = 6.01 meters. Therefore, dredging and trenching issues are identified as being of high priority. A key issue is the design and development of improved dredging and trenching technologies capable of operation in the Kara Sea. Another major issue is the high costs associated with dredging and trenching operations. It is required to find a conceptual solution for deep (6 m) and fast trenching. The digging is a great challenge for pipeline installation because of high operational costs with current technology. In the paper [59] it has been proposed to use the bucket ladder dredging as a solution for the trenching challenge in the Arctic region (see Figure 6.13).

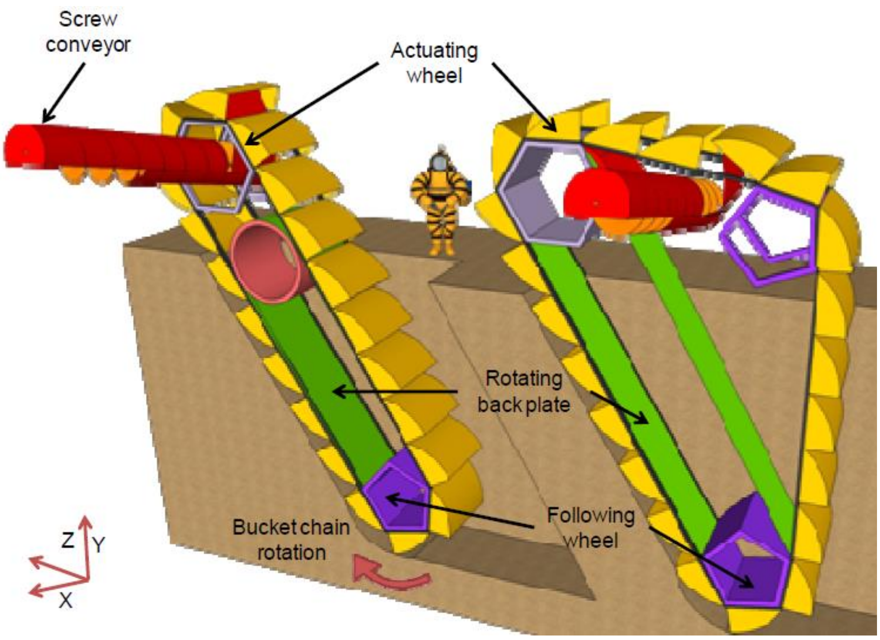

Figure 6.13. Two potential arrangements for the bucket ladder and spoil transportation system. Left: compact ladder concept. Right: triangular ladder concept [59]

It was established that the bucket ladder dredging has an excellent potential for successful trenching in the Arctic. However, some uncertainties remain. Therefore, the concept is under development.

Further, an improved understanding of iceberg scours patterns, frequencies and loads is identified as one of the main areas of research that could help reduce burial depth requirements.

6.2.3. Hydraulic and thermal calculations

The objectives of the section are: to give an understanding of what diameter is required to transport the maximum gas production from the large gas field (Leningradskoe field); to establish the pressure and temperature profiles. The profiles are critical to evaluating the flow conditions in the pipeline.

The pipeline inner diameter should be selected based on:

- flow rate;
- minimum pressure drop.

The sizing should be carried out on the plateau production. Here, the single-phase flow hydraulic theory could be applied with a certain level of confidence. This theory is well understood, and analytical models may be used. The basis for the pressure drop and the temperature profile calculation is the conservation of mass, momentum and energy of the flow. In the standard of Gazprom [21] the expression depicting the gas flow is given by the flow rate:

$$q = 3{,}32 \cdot 10^{-6} \cdot d^{2{,}5} \sqrt{\frac{p_1^2 - p_2^2}{\lambda \gamma_a z_a T_a l}} \tag{6.22}$$

where,

q – gas flow rate [$MMsm^3$/day];

p_1 – pressure inside the pipe at the beginning of trunk pipeline [MPa];

p_2 – minimum delivery pressure [MPa];

l – pipeline length [km];

T_a – average gas temperature [K];

λ – hydraulic friction coefficient [-];

γ_a – specific gravity (gas – air density ratio) [-];

z_a – average compressibility factor [-];

d – inner diameter [mm];

Here is the equation on the minimum inner diameter:

$$d = \sqrt[5]{q^2 \cdot 9.07 \cdot 10^{10} \cdot \frac{\lambda \gamma_a z_a T_a l}{p_1^2 - p_2^2}} \tag{6.23}$$

The hydraulic friction coefficient depends on Reynolds number and relative roughness. It could be determined by the Moody diagrams or by empirical relationship. The gas flow is always in the quadratic friction mode (turbulent flow). Therefore, there is only one formula for friction coefficient in gas pipelines:

$$\lambda = 0.067 \cdot (\frac{158}{Re} + \frac{2k}{d})^{0.2} \quad (6.24)$$

where, k - pipe roughness [mm]; Re – Reynolds number in given dimensions.

$$Re = 17.75 \cdot 10^3 \frac{q\gamma_a}{\mu_g d} \quad (6.25)$$

where, μ_g – dynamic viscosity [Pa·s];

It is well seen that equations written above are interdependent, which means that some iteration is required. The assumptions and approximations were proposed in Appendix E.

The average temperature is a logarithmic average of value T_1 and T_e;

$$T_a = \frac{T_1 - T_e}{ln\frac{T_1}{T_e}} \quad (6.26)$$

where, T_1 – inlet temperature [K], T_2 – environment temperature [K];

The average pressure is expressed as follows:

$$p_a = \frac{2}{3}(p_1 + \frac{p_2^2}{p_1 + p_2}) \quad (6.27)$$

Because of lack of the data, the parameters were assumed based on the data of the nearby shore gas and condensate field (Yamburgskoe gas and condensate field) [60]. Leningradskoe field is located in the northern part of the West Siberian oil and gas province as well as Yamburgskoe gas and condensate field. Therefore, it is possible to assume that the properties of gases are similar. The maximum production rate is calculated in Section 5.2.

Thus, the calculated minimum allowable inner diameter for the given conditions is 1154 mm (see Table 6.7 (Appendix E)). Meanwhile, the minimum standard inner diameter is 1220 mm [32]. That corresponds to 1284 mm standard outer diameter, having assumed that wall the thickness is 32 mm.

This information can be used to estimate the required depth of trenching on the shallow part of the route. Moreover, it gives an understanding that one trunk pipeline is enough to allow the high production rate. However, in a case of one trunk pipeline is laid, the reserve pipeline with a smaller diameter is necessary to install.

Pressure distribution can be calculated as:

$$p = \sqrt{p_1^2 - \frac{9.07 \cdot 10^{10} \cdot q^2 \lambda \Upsilon_a z_a T_a x}{d^5}} \quad (6.28)$$

A possible pressure distribution profile along the trunk pipeline is illustrated in Figure 6.14.

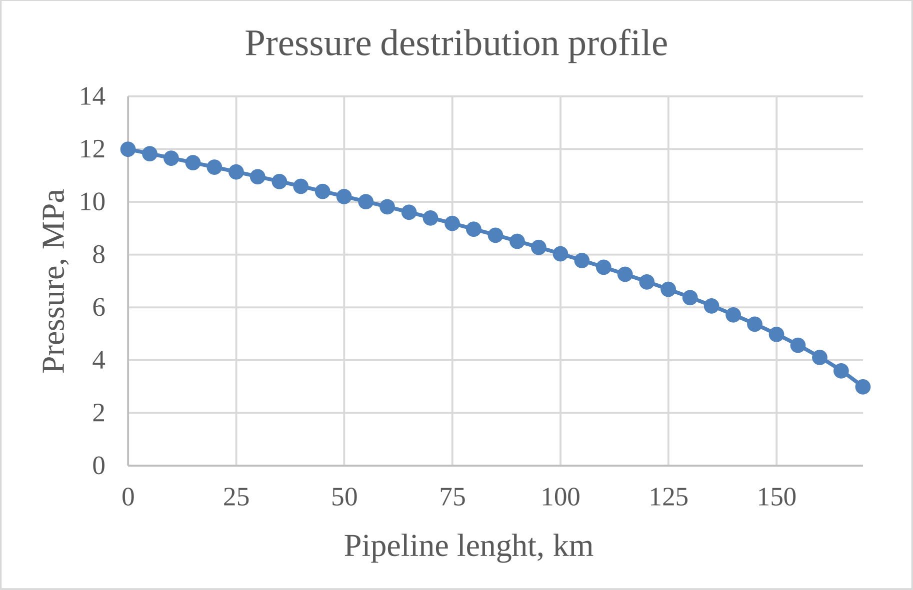

Figure 6.14. Pressure distribution profile

Thermal parameters are especially important for the gas flow, where it is necessary to keep the temperature above the hydrate formation and dew point values. Moreover, these parameters are influencing the pressure drop, and, consequently, the final decision upon the flowline diameter.

A temperature profile along the trunk pipeline could be described by the equation (6.29) at every point x, km [21]:

$$T = T_e + (T_1 - T_e)e^{-ax} - D_i \frac{p_1^2 - p_2^2}{2alp_a}(1 - e^{-ax}) \tag{6.29}$$

This equation accounts either for the heat loss to the environment and Joule-Thompson effect. The parameter *a* is given by:

$$a = 225.5 \frac{k_a D}{q\gamma_a c_p \cdot 10^6} \tag{6.30}$$

Where, c_p - isobaric heat capacity [W/m^{2}K]; D – outside diameter of the pipe [mm].

Assuming that the gas temperature is uniform inside the pipe, and there is no insulation, the heat transfer coefficient is calculated for the subsea pipeline from equation:

$$\frac{1}{k_a} = \frac{t}{\lambda_t} + \frac{t_c}{\lambda_c} + \frac{1}{\alpha} \tag{6.31}$$

Where, *t* – pipeline wall thickness [mm]; t_c – corrosion coating thickness [mm];

λ_t, λ_c – wall thermal conductivity for pipeline steel and coating respectively [W/m·K];

α - heat transfer from the pipe surface to water (or to the soil for a trenched section) [W/m^2·K].

For heat transfer to water:

$$\alpha_w = 0.26(\frac{u_r D \cdot 10^{-3}}{\nu_w})^{0.6} Pr_w^{0.37} \frac{\lambda_w}{D \cdot 10^{-3}} \quad (6.32)$$

Where, u_r – the current speed at the seabed level [m/s]; ν_w – kinematic viscosity of water [m/s^2]; c_{pw} -isobaric heat capacity for water [J/K]; λ_w – thermal conductivity of water [W/mK]. Pr – Prandtl number for water:

$$Pr_w = \frac{\nu_w \rho_w c_{pw}}{\lambda_w} \quad (6.33)$$

For heat transfer for soil:

$$\alpha_s = \frac{2\lambda_s \cdot 10^3}{D \cdot \ln[\frac{2d_b}{D \cdot 10^{-3}} + \sqrt{(\frac{2d_b}{D \cdot 10^{-3}})^2 - 1}]} \quad (6.34)$$

Where, λ_s – soil conductivity; d_b – depth of pipeline burial [m].

Such data as initial temperature, heat transfer coefficient for soil, the thermal conductivity of coating, pipeline wall thickness, corrosion coating thickness, heat transfer to soil, gas heat capacity, Joule-Thompson coefficient, and average pressure were assumed. Further study of the shown parameters is required. The calculation results are shown in Table 6.8 (Appendix E). The temperature distribution profile along the trunk pipeline is illustrated in Figure 6.15.

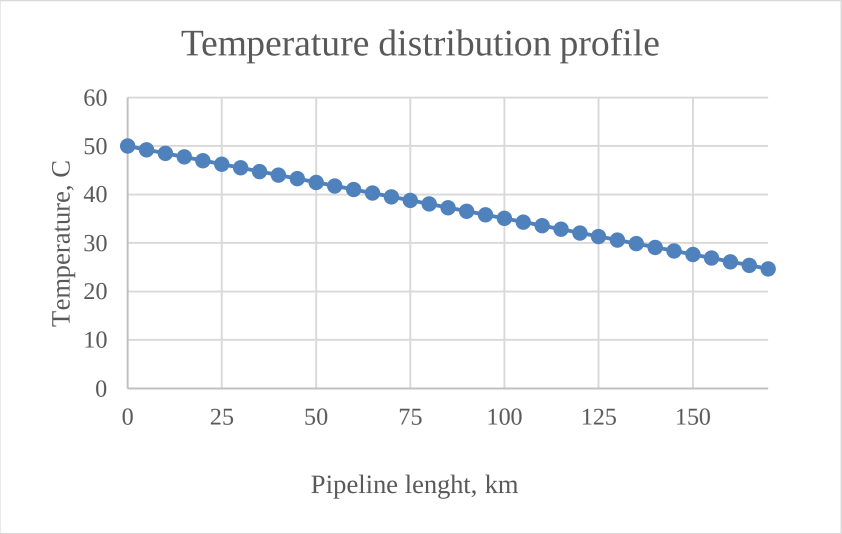

Figure 6.15. Temperature distribution profile

It can be concluded that the temperature distribution profile is almost linear. The temperature drop is around 25 ^oC. It is rather a large temperature drop. Therefore, it gives an understanding that it is necessary to inject gas hydrate inhibitors (for example MEG) to prevent the gas hydrates precipitation. The main reason for the temperature drop along the pipeline is Joule-Thompson effect. Meanwhile, the heat transfer from the surface of the pipe to water or soil is not the main concern. However, the permafrost is not considered here as well as the seabed elevation profile. Therefore, it is recommended to improve the study with more proper data as well as taking into account the permafrost of seabed soil, the seabed elevation profile, and multiphase flow.

6.2.4. Coastal zone

It is required to store, process and transport the extracted resource. Therefore, the coastal base is needed to be constructed on the shore. Meanwhile, the port must be modernized. The greatest technical complexity is a coastal zone. There are some features of the shore [52]:

- permafrost is from 20 to 55 m below seabed;
- shore erosion;
- ice gouging;
- salted rocks;
- «Stamukcha», hummocks;
- the different direction of currents.

The western landfall and coastal areas of Yamal peninsula consist of continuous and discontinuous layers of frozen soil. Meanwhile, the erosion processes expose the shore area. Therefore, the erosion of shore is the main engineering and technical challenge of the pipeline laying. To respond to the changing conditions of the sea ice, coastal erosion and discontinuous thickness of the frozen soil, a solution is required for the design of the pipeline laying on the coastal zone.

To solve this challenge, an innovative solution is proposed which is the drilling of a directional well from the land (see Figure 6.16). The pipeline is supposed to be laid through this well. At a distance from the coast, the pipeline is connected to the subsea pipeline section using welding and installation of the coupling. Thus, the pipeline would be outside of the active coastal processes. Several wells can be drilled to simplify the drilling activity. In this case, it is required to install a subsea manifold nearby the shore. It is important to highlight that the subsea manifold must be protected or buried. Otherwise, the mechanical interaction with ice ridges is probable.

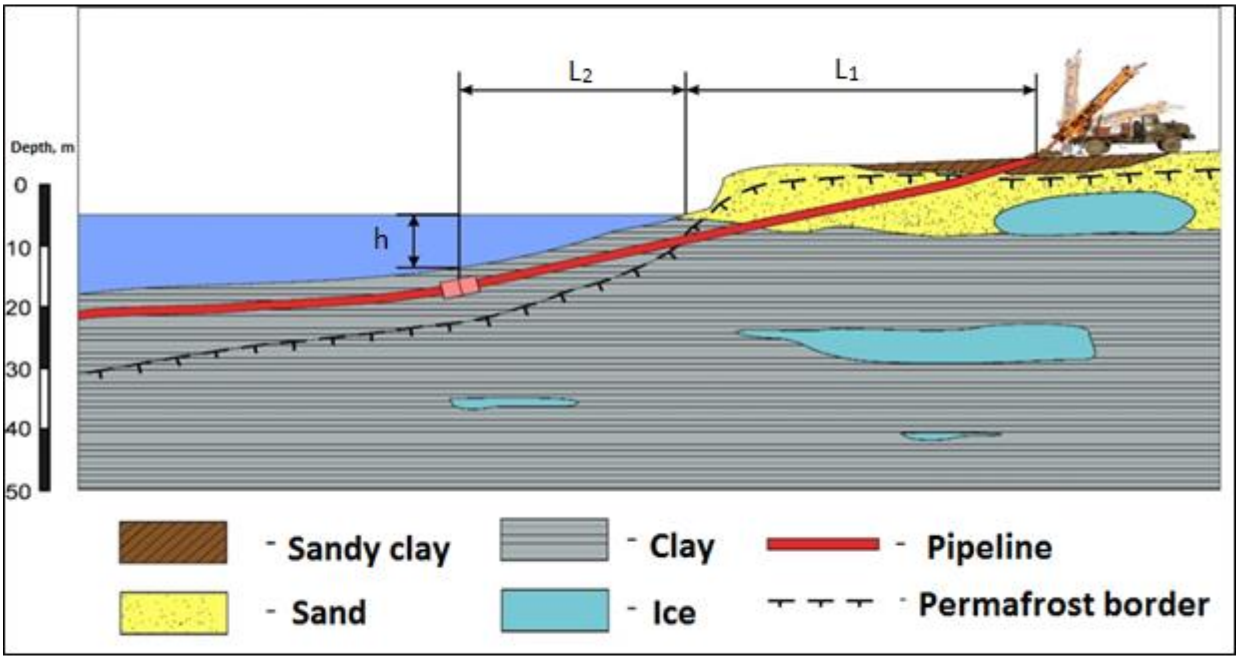

Figure 6.16. The concept for drilling a directional well

Another possible solution is to build a «cofferdam». On the transition zone, the technology «cofferdam» with cross-protective structures can be applied (see Figure 6.18). A «cofferdam» is a construction within the coastal zone. The laying of pipelines is carried out using the trenching technique. Meanwhile, the pipelines are laid along the axis of the cofferdam. The special works of filling of the boulders are necessary to strengthen the shore from the thermal and abrasive impacts. Therefore, the facility serves as an obstacle to the longshore sediment transport. This solution was applied in Sakhalin Island [62]. However, the shore erosion process there is not so severe as in the west part of Yamal peninsula. Moreover, there is no permafrost in Sakhalin Island.

Therefore, it is necessary to modify this approach. In this Master's thesis, the concept of keeping soil temperature below the melting point is proposed. The suggested concept is shown in Figure 6.18. Here, the atmospheric pipe-still technology keeps the soil temperature below the melting temperature. The energy of condensate is supposed to supply the power for the atmospheric pipe-still. The required facilities are gas processing facility, manifold, stabilizer and storage reservoirs.

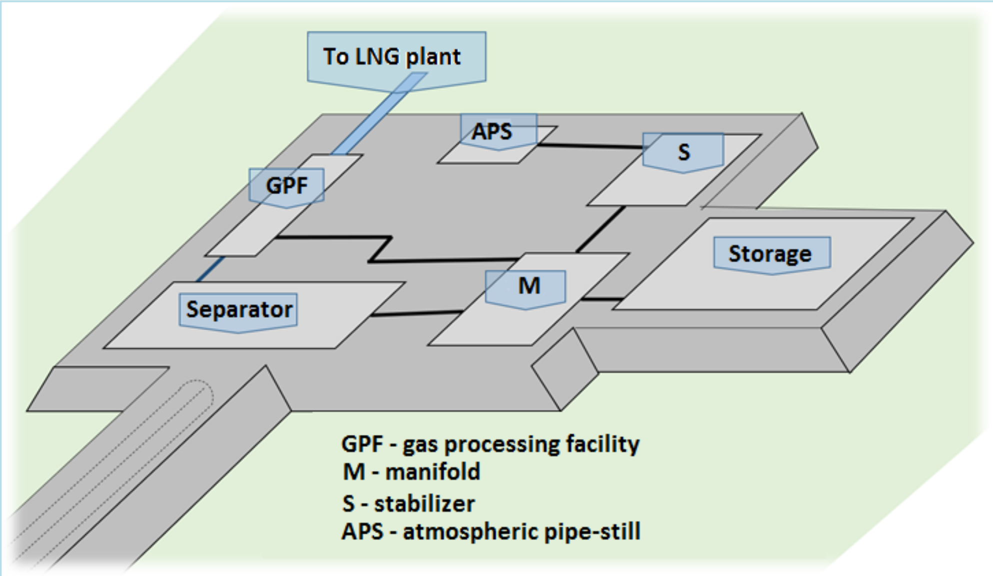

Figure 6.17. The concept of cofferdam

6.2.5. Flow assurance philosophy

Flow assurance is one of the most critical aspects that should be specified for the appropriate subsea production. The flow is subjected to pressure and temperature variations that might cause fluid to be unstable and create flow assurance. The main challenge for the field is the accurate prediction of pressure drops along the pipelines, properly considering fluid properties into account. Several challenges connected with the flow assurance may occur. They are slugging, hydrates, scale formation (in late stage development), corrosion and erosion [77]. They are described below:

1. **Slugging**

A flow of gas and condensate may occur in some parts of the pipeline system. Simultaneous flow of gas and liquid means that multiphase flow in a wellbore, flowlines, processing facilities, in all subsea production system.

Problems: damage to the equipment (due to vibrations); enhanced corrosion; separation facilities disturbances; different compressor loads; frequent shutdowns.

Mitigation scenario:

- The aim is to «understand» the flow, as well as the changes of the velocities; that is why multiphase flow meters are used for that purpose;
- Active-controlled choke must be implemented: sensors are to provide pressure reading across the slugging zone. The information is analyzed and applied for choke valve activation to get stable flow.

2. **Hydrate formation**

Hydrate formation may occur, because of high pressure and low temperatures.

Problems: that becomes a big challenge, resulting in plugs that can adhere to the pipe walls.

Mitigation scenario:

- Use of chemicals. They can shift hydrate equilibrium conditions to lower temperatures and higher pressure. Inhibitors are also solution of the problem;
- Insulation of the lines;
- Heating of the lines and other equipment;
- Operating conditions changes;
- DEH (direct electrical heating) is used to keep the temperature above the HET (hydrate equilibrium temperature). The principle lies in sending an electric current through the pipe wall, after that the heat is generated. The current is fed through two electric cables, connected to the ends of the flowline. The cable is located inside the flowline protection structure to protect it from trawl impact. Protection structure is made of PP (polypropylene). There is no pollution while DEH using.

3. **Scale formation**

Hydrocarbon reservoirs usually contain saturated water with dissolved salt. Year by year the content of water is growing. Changes in pressure and temperature cause supersaturated water, and salt precipitations may occur. Thus, there is a serious issue with the scaling formation.

Problems: high consequences for the SPS; problems with the reservoir productivity; system pressure drop; corrosion.

Mitigation scenario:

- Squeezing of the inhibitor into the formation to prevent or delay scaling in the area near wellbore;
- Injecting of the inhibitor into piping systems to prevent scale formation in the equipment. The injection can be done at the X-mas tree or downhole. This mitigation scenario is widely used due to precise control of injected chemicals.

4. **Corrosion and erosion**

There is a possibility of corrosion environment as well as sand particles presence in the flow from wells of Leningradskoe field.

Problem: Corrosion environment (CO_2 and H_2S acids) leads to corrosion of the downhole completion, subsea production system, and flowlines. Besides, the erosion damages may occur due to the production of sand.

Mitigation scenario:

- The techniques such as ultrasonic instruments may be used to measure wall thickness loss in metal structures. The solution is based on application of corrosion-erosion monitor (CEM);
- Adding of corrosion inhibitors in the flow;
- Use of corrosion resistant alloys;
- Improvement of erosion resistance;
- Erosion risk management – choose the correct material in critical wear parts.

The ability to accurately predict the behavior of multiphase is critical for subsea production in Arctic conditions, especially in the hundreds of kilometers away from remote fields to shore base. There are several commercially available simulators such as OLGA® and LedaFlow® on the market. There, the models of multiphase flow are applied. These programs make it possible to predict the problems with the flow assurance. For instance, hydrates precipitation, liquid accumulation, the formation of plugs, sand accumulation. These software tools are the main tools used by engineers involved in the flow assurance and the design of multiphase pipeline systems. Improved models for multiphase flow, with enhanced capabilities to predict flow instability, slugging and liquid accumulation will facilitate the development of Leningradskoe field.

6.3. Risk assessment

In the section, the following challenges are considered to be the most important in the pipeline technical block. They are dredging/ trenching, pipeline installation and operation. Thus, dredging must be performed in the operational «weather window». However, threats can lead to the failure of dredging. The threats are the wind, cold temperature; ice loads; lack of power in new ice; trenching is less than 6 m; environmental pollution. To avoid the possible consequences of the dredging failure, the qualitative risk analysis is to be performed. It can help to establish sufficient barriers to avoid the potential undesirable consequences. Pipeline installation and operation is one of the main concerns for the development of Leningradskoe field. Special attentions must be drawn to pipeline design, pipeline operation, frozen soil, free spans and the potential pipeline damage by ice ridge or iceberg keel gouging. The detailed qualitative assessment of the defined risks is presented in Appendix H.

6.4. Technology readiness and future recommendations

Based on the analysis of the pipeline technical block, the technology readiness levels of the key elements can be evaluated according to API RP 17N [36]. Therefore, the estimated technology readiness levels of the elements of the pipeline technical block are shown below [36]:

- design, installation, and operation of pipelines: TRL = 4;
- dredging and trenching: TRL = 4;
- the technology for coastal transition zone: TRL = 5;
- flow assurance: TRL = 6.

The installation of the subsea pipeline is not ready for the development of Leningradskoe field. The main challenge is trenching of 6 m depth in an «operational window». There is a need for innovation and technology development:

- the improvement of installation and operation of pipelines;
- the enhancement of dredging and trenching technique;
- the pipeline protection from shore erosion;
- the improvement of pipeline inspection.

The calculation results of prioritization of research issues and technologies for the pipeline technical block is presented in Appendix G.

CHAPTER 7. PRODUCTION TECHNICAL BLOCK

7.1. The Screening of the production technical block

The ice cover and remoteness are the main factors limiting the effective economic activity in the Arctic. The choice of optimum technical solutions and technologies in freezing seas, where significant oil and gas reserves have been found, are two of the most important challenging tasks among others, for the development of an energy production facility. Floating production systems are a common solution for deep waters. However, subsea technologies may offer a significant advantage in field development cost, under the freezing sea environment.

The effectiveness of the development of Leningradskoe field is highly dependent on the choice of gas production facilities, which are of main importance for offshore fields. The decisions depend on the completeness and reliability of the technology, engineering, geological, meteorological, industrial and environmental factors. The screening of the production block is shown in Diagram 7.1.

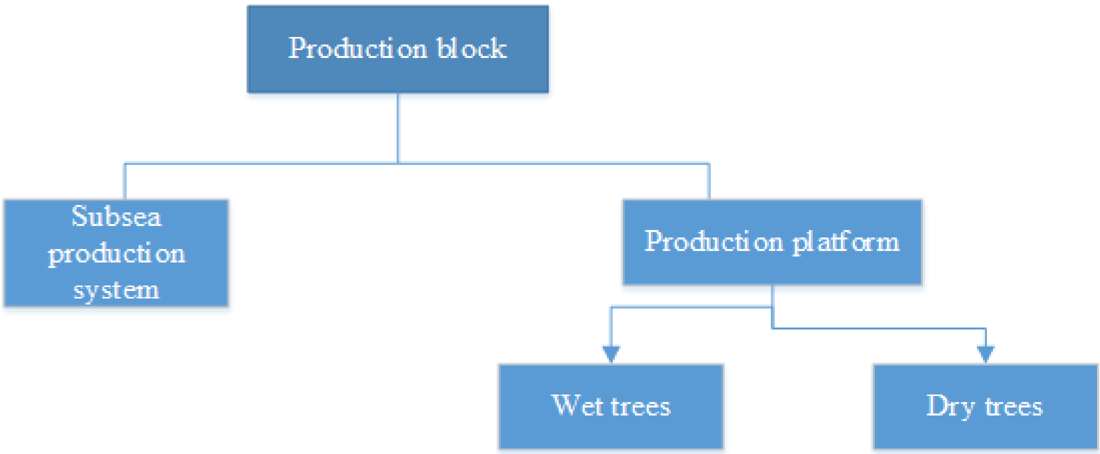

Diagram 7.1. The screening of the production block

The floating production platforms are unlikely to be applied in Leningradskoe field because of harsh ice conditions. Subsea production is the most promising direction in the development of deep-water fields, both regarding freezing and non-freezing seas. It is based on the use of so-called subsea well completion systems, whose Xmas trees are located on the seabed. There are well production systems, subsea pipelines, power, communication and control systems.

The method of a subsea production system is the most promising direction in the development of the deep-water fields in the Russian Arctic shelf. Subsea production systems have been widely accepted for gas and liquids production in freezing seas since such systems offer a significant reduction in capital costs involved in field facility construction.

Subsea production system is completely autonomous. Subsea well completion systems have many advantages over traditional methods of development in which the wellhead is located on the platforms. For example, subsea production technologies are more flexible. There is a possibility of a quick-change in production as well as the year-round field development, where the field is located in the severe Arctic conditions.

Subsea technology makes it possible to improve the economy of Arctic projects by reducing CAPEX, reducing topside facility, environmental impact, and development costs. The screening of the subsea production block is shown in Diagram 7.2.

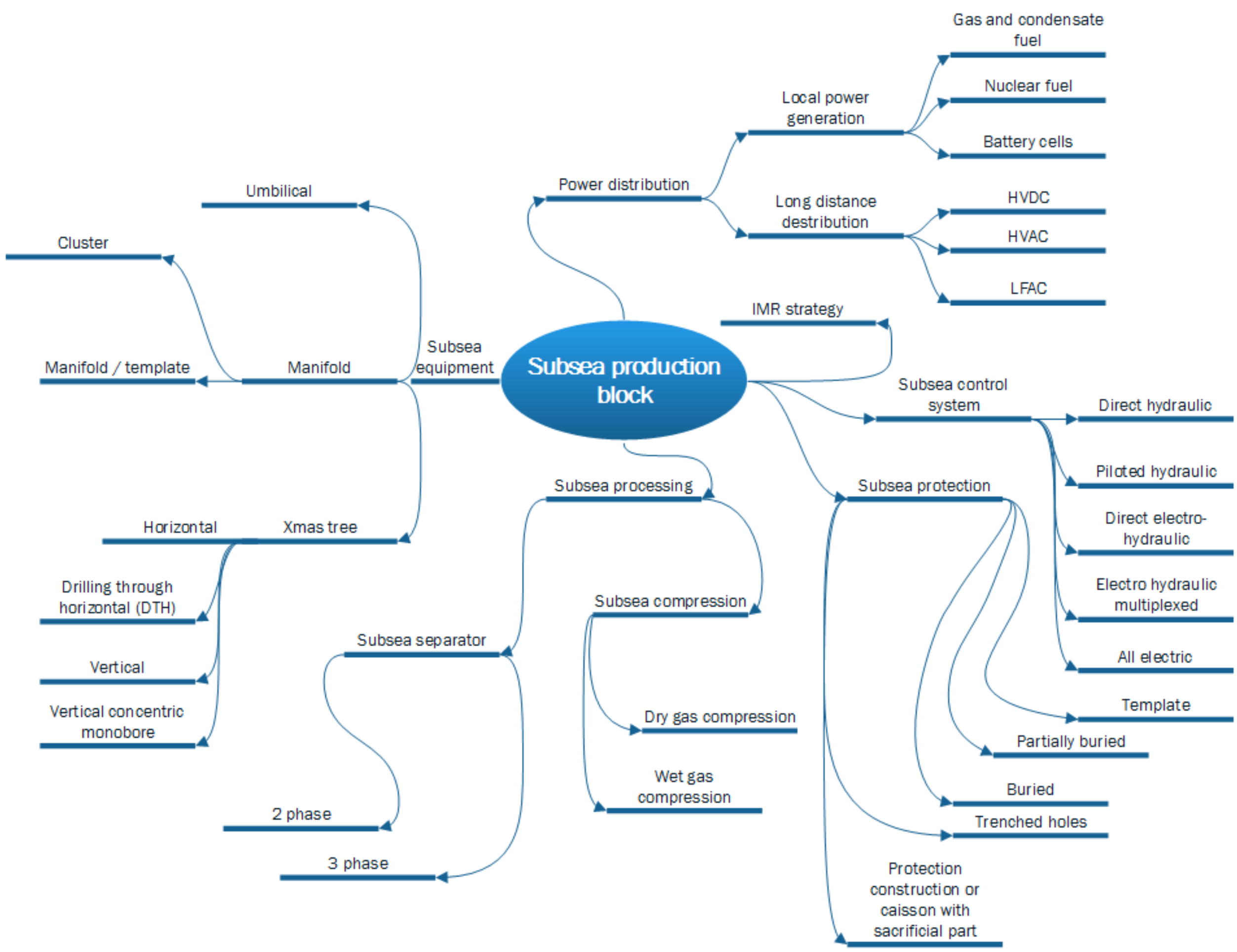

Diagram 7.2. The screening of the Subsea production block

Subsea technologies have been developed, qualified and modernized over the last fifteen years significantly; for instance subsea processing, AUV/ROV, subsea equipment, control systems and power transmission. Moreover, some new subsea technology can appear in the next ten years on the global market. For example, 3-phase and compact separation, gas compression, and distribution/ power conversion system.

At first glance, it seems that subsea concept is suitable for Leningradskoe gas and condensate field. Subsea production system is a good solution for Leningradskoe field for the following reasons:

- the water depth is from 80 to 165 m;
- the ice-free period is less than two months;
- the thickness of ice is up to 2 m.

According to Mirzoev D. A. [40], a cross section scheme of a subsea concept for Leningradskoe and Rusanovskoe fields is shown in Figure 7.1. It is proposed to apply subsea drilling. Moreover, it is suggested to use Gravity Based Structure (GBS) to control the fields, where GBS is to be located in the shallow water area.

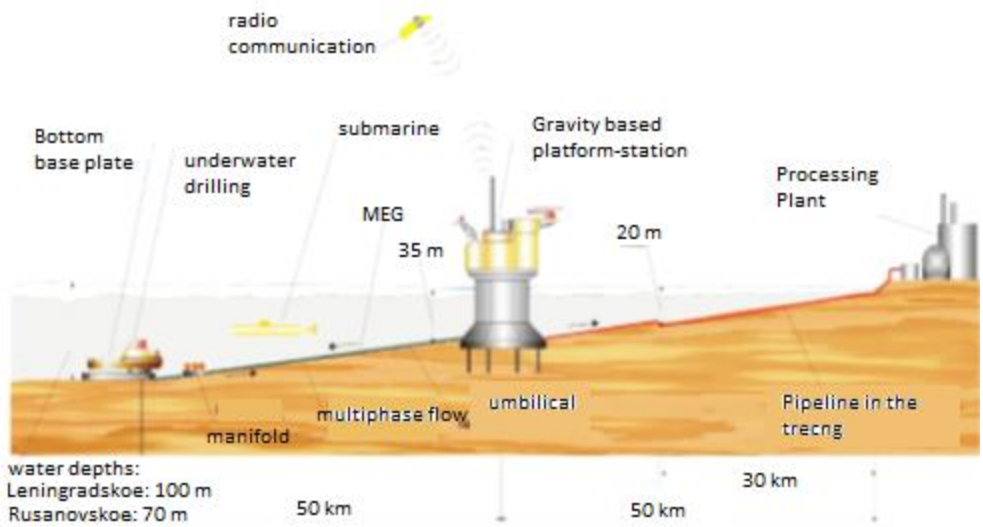

Figure 7.1. A cross section scheme of a subsea concept of Leningradskoe and Rusanovskoe fields [40]

The choice of the optimum field architecture must address and balance the competing requirements of reservoir engineering, drilling program and schedule, early production (if applicable), acceptable well trajectories, flowline and pigging requirements, subsea well control, installation strategies and intervention plans. The field architecture must address the sites for drilling centers and the number of wells at each center, with the objective of adequately draining the reservoir. These drilling centers will also serve as the key nodes in the architecture of the field [61].

The pipeline transportation of gas from the field can be a multi-phase flow in a single pipeline. Otherwise, gas and condensate are transported through the separate pipelines. Here, the processing of gas is required.

Applying the surface facilities for gas separation and processing is challenging in the existing ice conditions. It requires the creation of innovative technical means that are capable of resisting horizontal loads from the powerful ice formations. The transportation of gas and condensate in the individual pipelines is profitable with the large volume of condensate. However, it is supposed that it is not profitable to build a separate pipeline as well as install subsea separators. However, the multiphase flow causes the challenges related to flow assurance at large distances with uneven seabed elevations and condensate presence.

7.2. The Scoping of the production technical block

7.2.1. Subsea equipment

The subsea equipment is required to be installed to implement the subsea layout of Leningradskoe field; for example, Xmas trees, prefabricated manifolds, infield gas gathering system, export pipelines to onshore facilities, control umbilicals, power supply, a supply of chemicals and other equipment (see Figure 7.2).

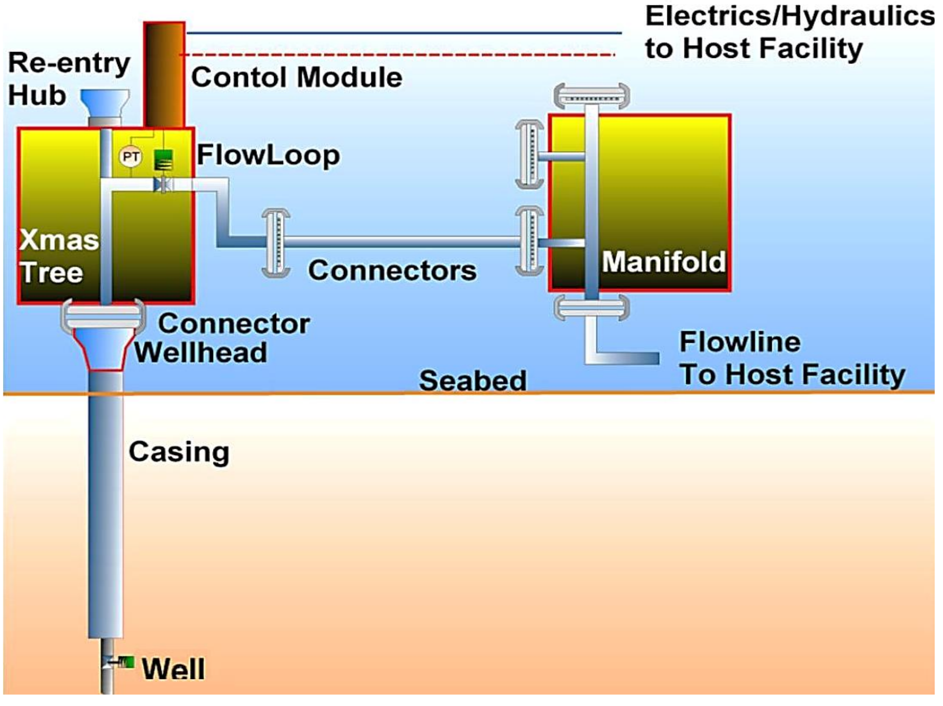

Figure 7.2. The principle of subsea production system [69]

The challenges are an installation of subsea technologies, subsea compression, operation and maintenance of the equipment. The short navigation period would require a high degree of elaboration of construction and installation works in the water area. Most of the year, the Kara Sea is covered by ice; therefore, the high operational reliability of the diving equipment and connecting nodes is required.

Three main factors are governing the selection of Xmas tree: water depth, Blow-Out Preventer (BOP) tripping time, and marine riser tripping time. The deeper the water depth, the more expensive to run the BOP and the longer time it takes for marine riser installation. Two Xmas tree solutions are available: Vertical Xmas Tree (VXMT) and Horizontal Xmas Tree (HXMT). VXMT is the conventional solution whereas HXMT is relatively newer than VXMT. The main difference between VXMT and HXMT is the master valve flow path: in a vertical and horizontal direction respectively. One governing design driver is well maintenance and intervention. HXMT allows the intervention without the removal of it, whereas VXMT needed to be removed to proceed well intervention.

There are some important features for Leningradskoe field case:

- Poorly explored reservoir because an exploration drilling is costly in Arctic region;
- High production rate;
- Production method is natural flow with/without subsea compression;
- Smaller Xmas tree is preferable to mitigate the risk of iceberg gauging;
- Larger completion size is better to install screens due to soft formation nearby wellbore zone;
- Capex should be minimal to reduce investments in project;
- Smart well completion is recommended to implement (remotely located field);
- Emergency disconnect time has to be reduced;
- Drilling and completion time due to a limited operational window in Arctic have to be reduced.

The different parameters must be taken into account to choose the best option. Here, a set of criteria is aggregated into a single principle of choice. Here, ω_i – weighting coefficients, reflecting the importance of the i-th parameter P_i in the total estimate. It is estimated that the weighted arithmetic value is larger with Drilling through Horizontal XT for Leningradskoe field (Table 7.1). The description of selected Xmas tree is shown in Figure 7.3.

Table 7.1. Multi-criterion assessment of Xmas trees. Decision making.

Selection criteria (scale 0-3)	Horizontal	Drilling through Horizontal	Vertical	Vertical Concentric Monobore	Weight factor	Imortance ranking (max 5)
Flexibility to adopt to reservoir uncertainty	3	3	1	1	0,114	5
CAPEX/ Cost and less number of BOP trips	1	2	3	3	0,091	4

OPEX/ technique of tubing replacement	3	3	1	1	0,068	3
Small size of Xmass tree	3	3	2	2	0,046	2
Flexibility of design to accommodate gaslift, injection	3	3	1	1	0,091	4
High production wells	3	3	1	2	0,091	4
Large completion size	3	3	2	2	0,068	3
Intervention works	3	3	1	2	0,068	3
Suitability for smart completion	3	3	0	1	0,068	3
Environmental safety/ no potential leak paths below the BOP	1	1	3	3	0,091	4
Reduced wellhead loading	1	1	3	3	0,023	1
Seal wear	1	1	3	2	0,068	3
Emergency disconnect time	2	2	3	3	0,114	5
Weighted arithmatic value	2,341	2,432	1,818	1,977	1,000	44

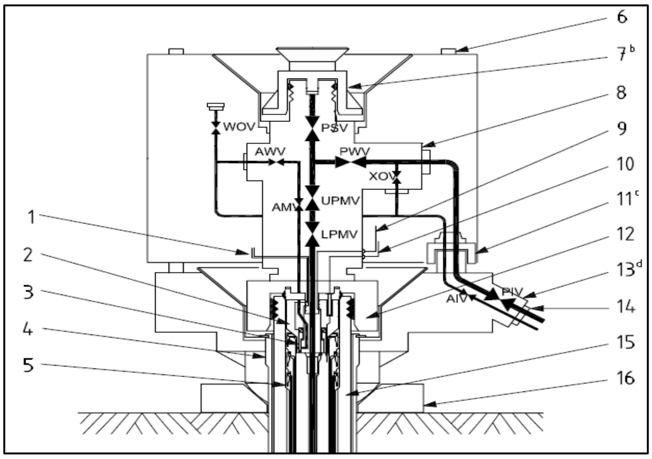

Figure 7.3. Drilling through Horizontal Xmas Tree [20]

Where,

1 - annulus access shift valve control line;
2 - tubing hanger (TH);
3 - annulus access sliding sleeve;
4 - conductor housing;
5 - casing hangers and seal assemblies;
6 - guideposts (optional);
7 - XT cap;

8 - Xmas tree (XT);
9 - monitoring line;
10 - SCSSV control line;
11 - flowline connector;
12 - XT connector;
13 – guidebase;
14 - flowline/tie-in spool connector;
15 – wellhead;
16- drilling guidebase or template slot.

Subsea Drill Through Horizontal Christmas Trees were first used in Dalia project in 2011 (company is «Total») [71]. When BOP is installed and the production bore is protected by removable wear bushing, it is possible to drill the well to be drilled through the tree. Therefore, it leads to the opportunity for minimizing the number of BOP runs (from two to one BOP trip). It should be noted that time-saving in drilling riser deployment is an important factor in the well drilling program of Leningradskoe field.

A well barrier is an envelope of one or several dependent barrier elements preventing fluids or gases from flowing unintentionally from the formation into another formation or to surface. A well barrier element is an object that alone cannot prevent flow from one side to the other side of itself. In the production wells, well barrier elements are shown in Table 7.2 and Figure 7.4 [21].

Table 7.2. Well barrier elements [21]

Primary Barrier		
No.	Component	Function
1	Subsurface safety valve (SSSV)	Preventing hydrocarbon/fluid flow to the tubing
2	Completion string (production tubing and 9 5/8” casing)	Providing a conduit for formation fluid from reservoir to surface or vice versa
3	Production packer	Providing a seal between production tubing and the casing (9 5/8”) and preventing flow to and from above the packer element
Secondary Barrier		
4	Component	Function
5	Tubing hanger plug	Providing a pressure well barrier in the bore through the tubing hanger
6	Horizontal Xmas Tree (AMV)	Stopping the flow of hydrocarbon/fluid from tubing to the subsea and surface lines
7	Horizontal Xmas Tree (PMV)	
8	Tubing hanger	Preventing flow from the bore and to the annulus and providing seal towards wellhead
9	Wellhead	Preventing flow from the bore and annuli to formation or the environment

10	Casing	Act as an obstacle to uncontrolled flow of formation fluid/injected fluid between the bore and back-side of the casing
11	Casing cement	Providing a permanent and impermeable hydraulic seal along the casings

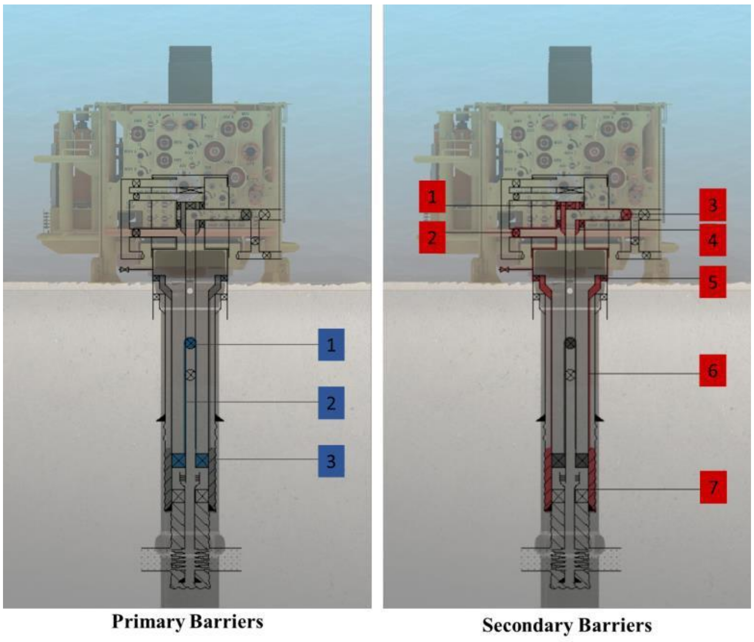

Figure 7.4. Barriers in subsea production well with horizontal Xmas tree [21]

Perhaps, it is more cost effective to use a borehole with a larger diameter bore for a large gas field, because of larger production rates. It follows that technology that combines a small-diameter hole as well as a large diameter will be the most favorable since it would reduce the number of wells required for the gas field.

The bottom site of Leningradskoe field is irregular. Moreover, the damage of equipment by icebergs is probable. Therefore, it is obvious that reducing the number of units installed on the seabed as well as limiting the physical footprint allow for a cost effective protection design: modular manifold/ template solution.

It leads to several functions that the manifold/template shall achieve such as [25]:

- A bottom foundation structure to carry the weight of the manifold module;
- High integrity pressure protection system (HIPPS);
- Provide guide and hang-off of the conductors and wellhead to support drilling of the wells;
- Support tie-in of umbilical and export pipeline;
- Support subsea distribution unit and control system hydraulic accumulators: distribution of hydraulic pressure, chemicals, and annulus service lines for each well;
- Support for manifold control module: control production.

Modular design allows to reduce design and manufacturing time and thus results in shorter delivery and installation time. It will enable drilling to start earlier for the operator thus allowing multiple activities to go on at the same time. Moreover, modular design also makes the manifold relatively efficient to retrieve if this should be required.

It is advisable to apply dual header manifolds connected to two parallel pipelines. Such a configuration allows production to continue while performing pipeline maintenance. Moreover, a pigging loop will be able to launch/receive the pig. It makes the pigging operation much more efficient and less costly.

An umbilical system serves for conveying hydraulic fluid under high pressure and low pressure, chemicals, hydrate inhibitors, power and electrical signals. The transfer process must be carried out without leakage or electrical noise. The main umbilical is one-piece construction with its section. Infield umbilical has the same cross-sectional design. Steel pipes provide axial strength. Pipes have high impact strength and do not require any additional reinforcement to withstand axial loads and to prevent damage from falling objects.

An umbilical can provide a hydraulic and electric power to the control system, chemicals for injection into well or production system, electric or optical fiber communication, electric power for pumps or gas for gas lift (see Figure 7.5).

Tube material for shallow water can be thermoplastic which has excellent fatigue resistance, short delivery time and is low cost. On the other hand, it has the limitation when it comes to chemical compatibility and uses in deeper water. Since the development is moving in the direction of deeper water and higher pressure and temperatures, steel tubes are now dominating. Therefore, in Leningraskoe field, it is recommended to use 25Cr duplex stainless steel that is the most common material used for fabrication of umbilical tubes. This material has excellent corrosion properties, high strength, and good fatigue properties.

- Steel tubes
- Hydraulic supply lines
- Chemical injection
- Fiber conductors
- Power conductor**s**

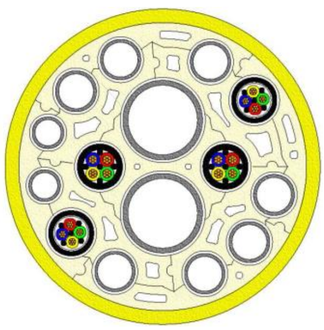

Figure 7.5. Cross section of umbilical [24]

The conditions of the Kara Sea require there to be developed new technologies and solutions capable of handling severe physical conditions, for instance, sea ice, seabed ice scouring, and permafrost. There are changing soil conditions due to the potential presence of frozen soils (permafrost), gas hydrates or a combination of these [55]. Therefore, there are challenges related to the design of wellheads, Xmas trees, manifolds, and templates. The most significant challenges for subsea equipment are changing soil conditions. It is especially challenging to the design of wellheads, Xmas trees, manifolds, and templates).

7.2.2. Subsea processing

The term «subsea processing» contains a variety of technologies to make processing of oil and gas on the seabed before transport. Objects include the separation, booster, power and control systems. Subsea processing can improve the economic component of the Arctic offshore oil and gas fields by increasing the rate of production solutions to ensure flow conditions, reduce restrictions topsides, reduce environmental impact and reduce development costs. In some cases, the processing technology can afford to develop earlier inaccessible resources.

Many of the elements of the subsea processing technology have been developed, qualified and established over the last fifteen years. Subsea processing may help to increase a life of production. Furthermore, producing fields with low reservoir pressures might become feasible if installing subsea processing equipment. Subsea processing represents a set of subsea building blocks that will simplify field operations and improve and increase field production rates.

Tordis (2007) was the world's first full-scale commercial subsea separation, boosting and injection system. It was designed to remove water and sand from the well stream and re-inject it into a nearby formation [25].

The Perdido (2010) and Pazflor (2011) fields were the first full field subsea separation and pumping systems in their respective regions. Both involve vertical gas/liquid separation units. Nowadays, there are two major projects ongoing with subsea compressor stations (Gullfaks and Asgard). Those units will by far push the limit of complexity of equipment and systems to whatever have been installed on the seabed before. They are all being installed on mature fields with the purpose of increasing the production [25].

Subsea compression is a solution to compensate the reservoir pressure drop in the future. Subsea compressor unit can be placed after collecting manifold, in front of the transport system. It will improve the key production parameters by increasing available pressure in the pipeline.

Asgard compressor station has three production lines with a capacity of 11.5 MW, one of which is a backup [54]. In the design, particular attention was paid to the issues of installation and maintenance of equipment. Broken components are expected to be extracted and replaced by new ones. Meanwhile, repair is performed at the coastal base. The expected availability of the facility is 96%. Thus, subsea compressor technology will play a significant role in setting up offshore gas fields soon. The use of such equipment will not only increase the rate of extraction of gas but will also involve the development of previously unavailable fields or at least increase the development margin.

These technologies can be widely used in the future on the Russian shelf. One of the potential installation sites of subsea compressor station can be Leningradskoe gas and condensate field. The benefit of subsea compression will increase with increasing tie-in distance. Compression at the wellhead will reduce pressure drop in pipelines compared to compression on receiving end and give a lower ultimate abandonment pressure, while being more energy efficient. For large fields, sophisticated systems including gas scrubbing upstream of centrifugal compressors are being employed.

Subsea compression will reduce the minimum reservoir pressure; ensures the uninterrupted flow of production wells. Moreover, it will increase a gas recovery factor of the field. Subsea compressors are necessary to use after some years of gas production when the reservoir pressure decreases up to a critical point. At this point, the reservoir pressure is not enough to push the fluid to the shore base. It seems relevant in the framework of the improvement of technical and technological parameters of Leningraskoe field. Subsea compression is increase of gas well stream pressure using a compressor:

- to enhance reservoir recovery by reducing the back pressure on the reservoir;
- to enable transport of well stream over long distances;

It must be noted that the implementation of such a solution will require a modernization of the existing schemes of arrangement and a certain number of operations at sea. Moreover, it will be necessary to involve craft and underwater remote control vehicles to do maintenance works.

According to preliminary estimates made in the development of Leiningradskoe field development, at least the first ten years of gas will be transported to onshore facilities under the reservoir pressure. Then, subsea compressor station ought to be used to compensate the decreasing of production [19]. Based on the data of Ormen Lange and Asgard subsea gas compression projects, the compressors are to be commissioned after 10, 15 and 20 years of the production because the depletion of the reservoir.

The main disadvantages of the subsea compression are insufficient reliability and high cost. Moreover, there are relevant issues such as:

- power transmission (in a case of power supply from the shore there are significant losses);
- no management experience of subsea compression.

Based on the existing experience of the petroleum industry, it is possible to install subsea separator and subsea compression station in Leningradskoe field. Leningradskoe field has a long step out of the field (approximately 170 km to port). Therefore, if the content of liquid or mechanical particles is large in the gas flow, it is necessary to apply subsea separators to sustain flow assurance.

Subsea compression requires technology and infrastructure for the generation and transmission of large amounts of electricity (over 25 MW) over long distances. It will be followed by an underwater energy distribution and (or) the conversion of this energy to meet the requirements of underwater electricity consumers (compressors, pumps, management system).

Two types of subsea compression systems have been developed and qualified over the past fifteen years [55]:

- Dry compression gas, where liquid and gas are separated in a scrubber. Gas is compressed using a high-speed centrifugal compressor. Fluid pressure is increased by a hydraulic pump. Further, gas and liquid streams are recombined and transported through the main multiphase pipeline. This technology is based on the already proven compression technology on the topside facility. Sealed centrifugal compressor with active magnetic bearings is adapted underwater conditions. Compression engine compressors are qualified for the power of up to 12.5 MW. It should be noted that the compressors are designed for continuous operation at the low liquid content in the gas stream (up to 20-30% by weight) with emergency conditions.
- Wet gas compression - multiphase flow is compressed using a compressor for operation. These system does not require separation of a multiphase flow. This technology is based on the multiphase pump technology, i.e. axial impeller adapted to liquids with a high gas fraction. It uses two rotors rotating in opposite directions. Wet gas compressors are qualified for the motor power of up to 5 MW.

The main advantage of the technology for wet gas compression is its simplicity and compactness. Because it eliminates the need for many components required to compress a dry gas, for example, a separator, a pump surge control. The main advantage of the dry gas technology is more power compression achievable for each compressor. That makes it more suitable for large deposits. It can be assumed that the average time between failures will be 4-5 years for both types of compressors. These theoretical assumptions are based on operating experience. It should be noted; that dry gas compression is more suitable to use in Leningradskoe field. The reasons for this are high production rate and relatively small amount of produced condensate.

7.2.3. Subsea control system

The main shore facilities to control subsea production system comprise the following components [27]:

- Uninterruptible Power Supply (UPS) system
- Master Control Station (MCS);
- Subsea Power and Communication Unit (SPCU)
- Topside Umbilical Termination Unit (TUTU)
- Hydraulic Power Unit (HPU);
- Subsea Data Processing Unit (SDPU);
- Chemical Injection Unit (CIU) system.

Umbilical contains the necessary supply, signal, hydraulic and injection lines. Hydraulic lines provide low and high pressures.

The uninterruptible power supply (UPS) system is a safeguard against immediate loss of power supply.

MCS provides control and monitoring of subsea wells. MCS includes processors A and B with redundant lines. MCS configures the management and control of subsea equipment. MCS may include control and monitoring of basic parameters of HPU and SPCU such as voltage, current, resistance. In many production systems, additional remote workstations can be connected to the production controls using satellite communications systems [27].

SPCU performs the management and control of subsea equipment after receiving control messages from the MCS. SPCU should return a functional state, the values of the process monitoring and system status. The unit distributes power from the UPS to a subsea control module (SCM) and provides a link between MCS and SCM [73].

Topside Umbilical Termination Unit (TUTU) connects the subsea umbilical line with the relevant coastlines. The panel is equipped with the control and measuring panel of the hydraulic system. Sensors and shut-off valves allow for testing and flushing of the fluid lines. There are electrical junction boxes for coupling subsea cable with a topside cable system. The electric and hydraulic power generated topsides, along with control signals are transmitted to the subsea network after joining up at the topside junction box and passing through the umbilical termination unit (TUTU) [73].

The hydraulic power unit (HPU) is designed to be used in the production control system. HPU supplies the hydraulic power through the umbilical to the subsea equipment system. The HPU is required to deliver hydraulic power to the rest of the control system during normal operation of the control system [72]. The hydraulic accumulators that are located topside have to operate in conjunction with the HPU to deliver the required hydraulic power to the control lines. Master Control Station provides the control for HPU. However, HPU has a local control panel that provides an opportunity to start/ stop the pumps. HPU pumps are connected directly to the motor control box. The primary function of HPU is to provide fluid under low pressure (LP) and high pressure (HP). Therefore, it is possible to control the pressure in the wells with a help of control modules.

Subsea Data Processing Unit includes:

- Personal computer for flow data;
- Personal computer for data acquisition.

The chemical injection unit (CIU) system is used to inject the corrosion inhibitor. Chemicals are needed to be injected to ensure a more safe and reliable production from hydrocarbon reservoirs. It consists of chemical injection pumps, reservoirs that store the chemicals that are used. The well stream is analyzed using flow metering devices that will show flow conditions. In the case of emergency, the gas and water mixture is relieved through the reverse line of the main umbilical. Then, it is burned on a horizontal burner [73].

The production control system is responsible for valve control and monitoring of the XT production parameters. Typical parameters that are measured using the XT production control system sensors are production pressure, choke downstream pressure, annulus pressure, manifold pressure, production temperature, manifold temperature. Moreover, gas leak detection, tree valve position, production choke position, production choke differential pressure, sand detection, down-hole monitoring, multiphase flow, corrosion monitoring and pig detection. There are different possible subsea control systems: direct/piloted hydraulic, direct electro-hydraulic, electro-hydraulic multiplexed, all electric. In Leningradskoe field, the electro-hydraulic multiplexed system is preferable (see Figure 7.6).

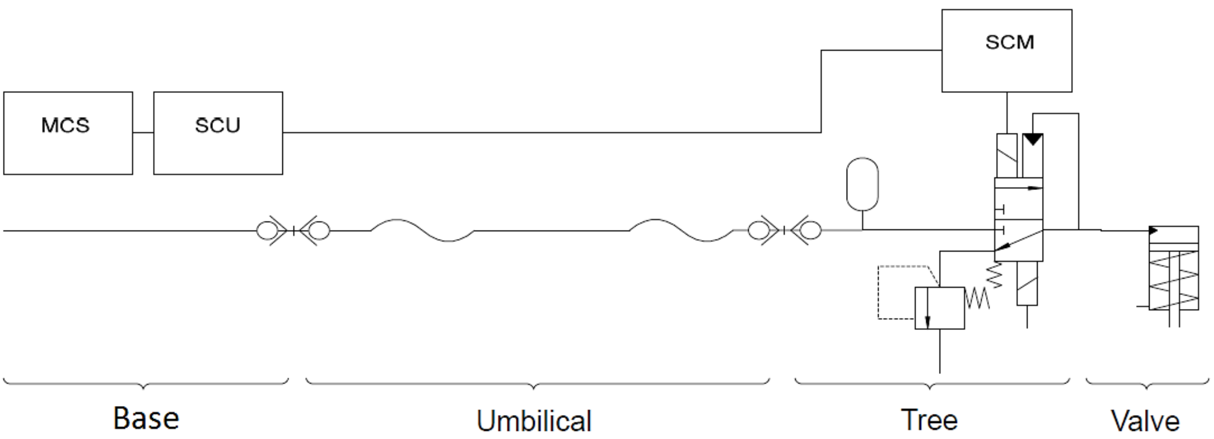

Figure 7.6. Electro Hydraulic multiplexed system [27]

The features which influence a choice of the subsea control method:

- long step out;
- Arctic region: high reliability, environmentally friendly, fast to respond, expandable system;
- long production lifetime;
- subsea compression.

In an electro-hydraulic system, an electric motor with a local reservoir is used instead of a hydraulic pump to act as a driver. It creates the hydraulic force which enables a hydraulic motor to perform as an actuator. This system eliminates the hydraulic connection requirement of the simple hydraulic system, reducing the weight and the possible sources of hydraulic leaks in the system. Multiplexing is a method by which multiple analog or digital signals are combined into one signal over a shared medium [63].

The advantages and disadvantages of chosen system are shown in Table 7.2.

Table 7.2. Pros and cons of electro-hydraulic multiplexed system

Benefits	Drawbacks
Long step out and deep water	Increased number of subsea electrical connections
Faster response	Higher voltage connections
Simplified umbilical	More complex subsea components
Capable of complex control	More difficult to support
Improved surveillance	High cost

7.2.4. Remote source of electrical power

The uninterruptible power supply (UPS) system is a key factor in the development of the field. It must provide the required level of reliability while providing acceptable initial and operating costs. The analysis of energy demands shows that electrical equipment and power transmission technologies developed and used in international practice are not adequate for the development of highly remote fields.

In general, the electrically controlled equipment can be divided into the following groups:

a) Subsea control system:

- valve actuators;
- control and measuring apparatus;
- subsea control modules.

b) Power blocks:

- pump units (pumps, compressors);
- injection units (pumps for the injection of inhibitors);
- direct electrical heating (DEH) of pipelines.

To select the type of power supply for subsea production system (SPS), subsea systems can be classified into the following two groups [55]:

- SPS with low power consumption, which includes the equipment for a gathering of gas production as well as the control system with a total energy demand of 10 kW;
- SPS with high power consumption, which includes the equipment for a gathering of gas production, the control system as well as the equipment for processing and transport of the fluid (separators, multiphase pumps, injection pumps, compressors) with a total energy demand of 250 MW.

The problem with low-power supply has been solved. However, the choice of power supply system depends on the management plan of the field. The costs of electrical equipment are relatively small and almost the same in both cases. Besides, the capital costs (CAPEX) will depend on the length of the cable line.

For SPS with a high energy demand, the transmission of power can be as long power distribution or local power generation concept.

The first approach is long power distribution. The most appropriate distance of power supply is up to 200 km. Traditional 50 Hz alternating current (AC) in combination with subsea variable speed drives (VSD) can cover step-outs in the range 200-350 km.

The transmission of power on the long distances can be as follows [33]:

- high-voltage 3-phase alternating current (HVAC);
- low-frequency, high-voltage 3-phase alternating current (LFAC);
- high-voltage direct current (HVDC).

If an alternating current is used at large distances from any power supply, the power loss in the cable will increase. To reduce the loss of electric power transmission the high-voltage direct current (HVDC), 3-phase low-frequency alternating current (LFAC) or 3-phase alternating current with a volt-ampere reactive (VAR) compensation can be used (see Figure 7.7).

LFAC is an inefficient solution because it allows for only a partial reduction of transmission losses in alternating current. Moreover, it would require the development of frequency converters, the technical complexity and the cost of which is comparable to the HVDC converter system (rectifier/ inverters). The LFAC power transmission with VAR system solves the problem of reducing losses in the cable line [55].

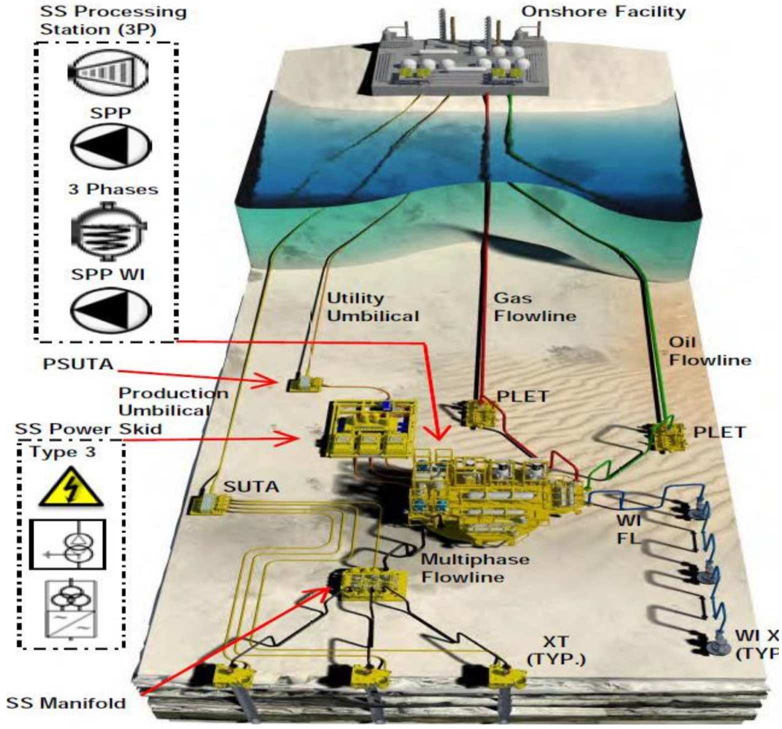

Figure 7.7. Subsea AC power distribution [41]

HVDC system is a progressive transmission system in the hundreds of megawatts at a distance of hundreds of kilometers. The main components of power systems with direct current are rectifiers and inverters. The rectifier must be connected to a source of energy. An inverter power conversion should provide a 3-phase alternating current [55].

Capital expenditures for the electricity supply systems are proportional to the distance between SPS and the shore due to the high cost of both the high-voltage subsea cable and its installation. Power systems with high-voltage direct current and low-frequency AC require high power static converters, designed for underwater use. To this day, there are no converters of such type.

ABB and Statoil have entered an agreement to develop solutions for subsea electrical power transmission, distribution and power conversion systems for over long distances (around 600 km). It is a five-year, 100 million US dollars joint industry project to develop transmission, distribution and power conversion systems designed to provide up to 100 MW of power [56].

The second approach is a local power generation concept. The possible local energy sources are electrochemical generators, nuclear energy or production fluid. Electrochemical generators are based on fuel cells. They have high efficiency in connection with a direct conversion of chemical energy into electrical energy, and they are characterized, in particular, by an absence of rotating parts. The battery cells are unlikely to be used because of high power demand of SPS because the achievable power of the fuel cell battery is around 1 MW. Thus, there is a need of creating the cells with significantly more power.

Nuclear power is not safe and not environmentally friendly. Moreover, it is extremely expensive. According to rough estimates, the cost of a subsea nuclear power plant may be from 1.5 to 5 billion US [55].

The paper concept of subsea local electricity generation with production fluid as a source for a generator is proposed in the thesis. The schematic depiction of the underwater arrangement is shown in Appendix B. It is suggested to use subsea gas and condensate turbines to generate the power. The proposed concept involves the development and creation of subsea gas turbines operating on condensate and gas. From wellheads, the production fluid goes to the 3-phase separator where it is separated into water, gas and gas condensate. When water is mixed with the exhaust gases from the modular power station, it is pumped into the waste injection well. The gas goes to the compressor station, where the pressure is increased that is sufficient for gas transfer to the gas processing facility located on the Yamal Peninsula. After the subsea compressor, hydrate and corrosion inhibitors are injected into the gas flow. After subsea separator, condensate and part of the gas go to the power plant that consumes condensate and gas. The water isobutane vapor is converted into steam and then into electricity. In a closed-loop, the thermal energy from the operation of the plant is used to heat the gas. The required amount of oxygen must be injected from a shore base (block-compressor station) through umbilical from shore.

There are advantages of this concept:

- local electricity generation;
- solving issues related to the transmission of electricity over long distances;
- flow assurance is maintained because of decreasing the content of condensate.

There are disadvantages of this concept:

- low technical reliability;
- regular maintenance works are necessary;
- oxygen is required;
- increasing a temperature of surrounded environment;
- melting of seabed soil is possible (because of permafrost).

The main challenge is to manufacture the subsea modular power block. A possible scheme of the circuit of a block power station using gas and condensate fuel is shown in Figure 7.8 [23].

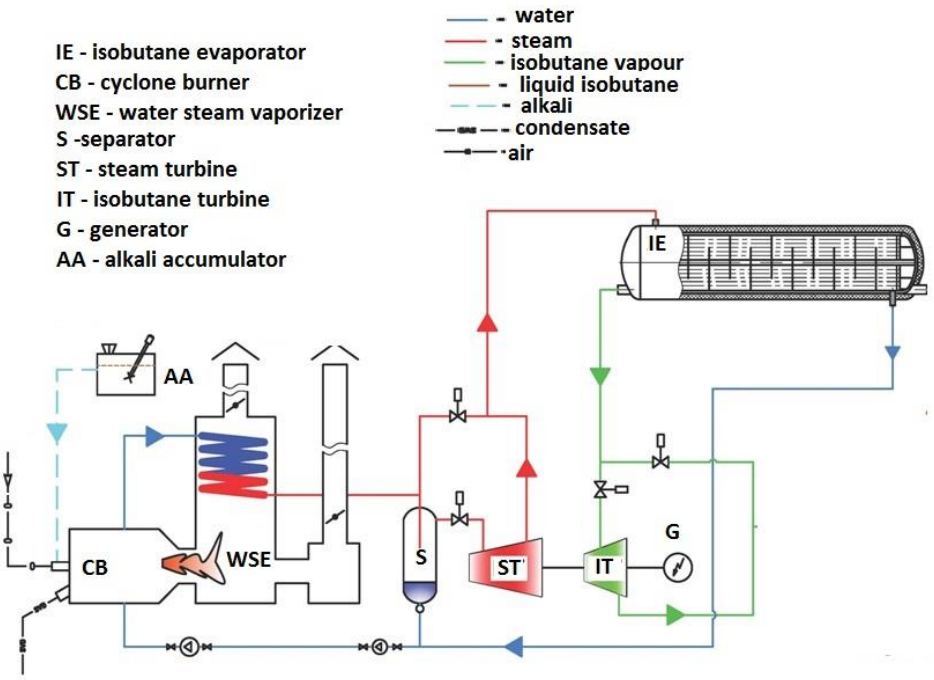

Figure 7.8. A possible concept for subsea modular power station block [23]

The plant comprises three main units: cyclone burner; water steam vaporizer and steam-turbine generator. In a closed cycle, the energy of hydrocarbons is sequentially and continuously converted into water and isobutane vapor. Furthermore, it is converted into electricity with an efficiency of more than 25%. The grid analysis of various technical solutions for power concept is shown in Table 7.3.

Table 7.3. The grid analysis of power concept

Selection criteria (scale 0-5)	Local power generation	Long power distribution	Weight factor (scale 0-5)
Power reliability	4	2	5
Technical feasibility	3	4	3
Maintenance works	2	3	4
Technology readiness level	1	4	4
Total score	0,410	0,500	Max score: 1

According to multi-criteria decision making, the power distribution on the long distance is the better option. It is dictated that the technology readiness level of local electricity generation is TRL 0. The concept of local power generation is suggested in this thesis, meanwhile, no any similar concepts have been found in scientific literature. Therefore, the further study of local power generation is recommended. It will give the advantage to develop remote gas and condensate fields.

7.2.5. The protection of subsea equipment

There is a risk that ice formations can damage subsea equipment in the waters of the Arctic in the location of subsea production systems. The wellhead designs and locations are driven by the well design as well as expectations to the iceberg management effectiveness. In average, the height of the subsea equipment is 10 m above a seabed. In some locations of Leningradskoe field, there is a small probability that icebergs can damage or even destroy the underwater infrastructure.

The need and the way to organize the protection of subsea production system depend on the depth of the sea as well as existing statistical characteristics of ice formations, identified in the area. For example, it is believed that the need for the organization to protect SPS from the effects of ice has disappeared, giving the sea depth of 60 m (on average, in the absence of large icebergs in the waters). In this case, only the organization of equipment from falling objects is required [28].

According to water depths and ice features, the protective structures may be different. The possible protective structures are shown in Figure 7.9. It can be noticed that in water depths of 60 to 100 m it is necessary to bury subsea equipment partially because of probable damage by icebergs.

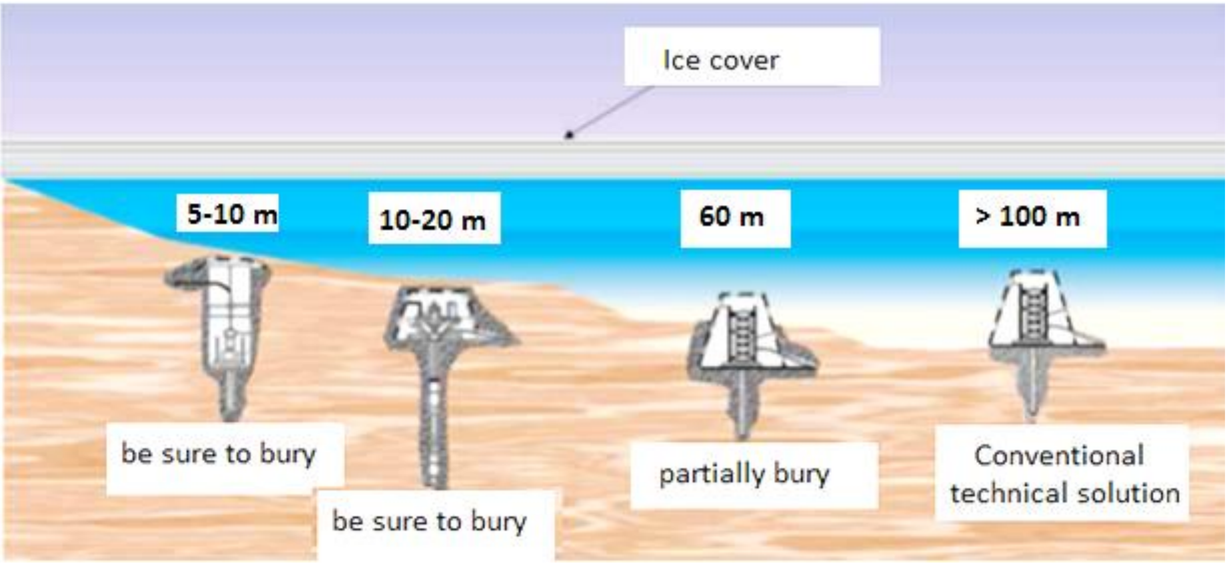

Figure 7.9. The concepts of subsea protection from ice loads [28]

There are different concepts of protection of subsea equipment from the icebergs. In the thesis, most appropriate protective measures that can be applied to Leningradskoe field are discussed.

First, the method of excavation and deepening of manifolds and wellhead equipment in the trenched holes (glory holes) can be put in practice (see Figure 7.10). Glory holes are large depressions excavated into the seabed to house subsea production infrastructure to provide a reduced probability of iceberg keel impact. The encounter rate of an iceberg keel interacting with a glory hole is based on the dimension of the glory hole at the mud line. The trenched holes limit the footprint of the subsea equipment at the bottom of the glory hole. The penetration of the iceberg keel into the glory hole may be estimated as the maximum variation in water depth along the length of a scour [29]. This approach produces results that are conservative compared to a simulation of iceberg dynamics that would lead to the event of an iceberg scouring into a glory hole but are useful for a first-order estimate.

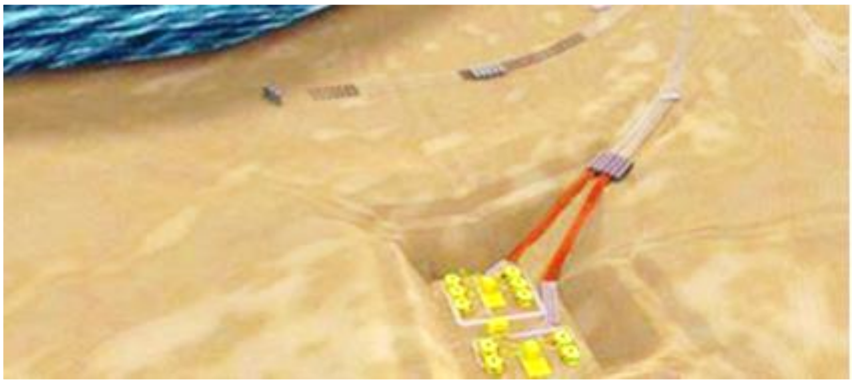

Figure 7.10. Protection of subsea facilities in trenched holes [29]

Trenched holes can minimize the costs of installations as well as give better access to maintenance works. Technology for protecting wells and Xmas tree by locating them in trenched holes does exist, but may not be viable economic soundness for the Leningradskoe region. The excavation operations are large with long time duration and produce excavated material. Therefore, it is probable that particles and silt from these operations pose a threat to the sensitive environment of the Kara Sea. Moreover, the time needed for excavation can be too long**.** The slopes of trenched holes can be strengthened to prevent the erosion of the slopes. This method has been applied, in particular, on the fields such as White Rose and Terra Nova, located near the Grand Banks off the east coast of Canada.

The concept of composite caisson with sacrificial part has been proposed in the Canadian Beaufort Sea area at depths of about 30 meters [30]. The structural protection consists of two caissons. The first is a low section that protected by a removable cover, which houses subsea equipment. The second is a top section that can potentially be cut by the keel of an iceberg. Therefore, the lower caisson, as well as subsea equipment, are safe (see Figure 7.11).

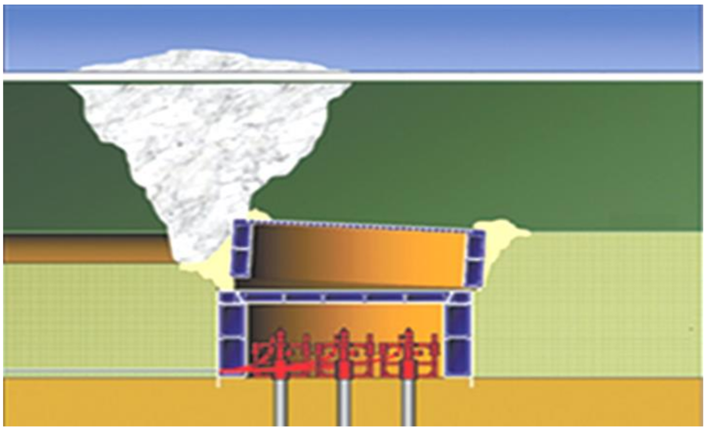

Figure 7.11. Caisson interaction with the underwater part of an iceberg [30]

It is achieved by introducing a weak link - section with low shear resistance at the interface level of two caissons. When plowing the seabed by iceberg keel, the upper caisson is cut by weak cross section. The design is damaged, but generally, the construction remains maintainable, and most importantly - there is no risk of subsea equipment damage and hydrocarbon emissions. However, the technology is costly. Moreover, it limits the access to subsea equipment when maintenance works are required. Thus, it is not recommended to apply this concept in Leningradskoe field.

Thus, it is supposed to choose the deep-water area in order to install subsea equipment. Meanwhile, better mapping of the water depths of the field is required.

7.3. Risk assessment

FMECA (failure modes, effects, and criticality analysis) is a structured approach to examine potential failure modes and to determine the impact of failures on product operation during field use or to identify and correct process problems before first execution [47].

Thus, FMECA is methodology to analyze:

- all potential failure modes of the various parts of a system;
- the effects these failure modes may have on the system;
- measures to avoid these failures and mitigate the effect they have on the system.

First, the subsea production system breakdown and the functional block diagram of the subsea production system are required for carrying out the FMECA [48]. The subsea production system breakdown is shown in Diagram 7.3.

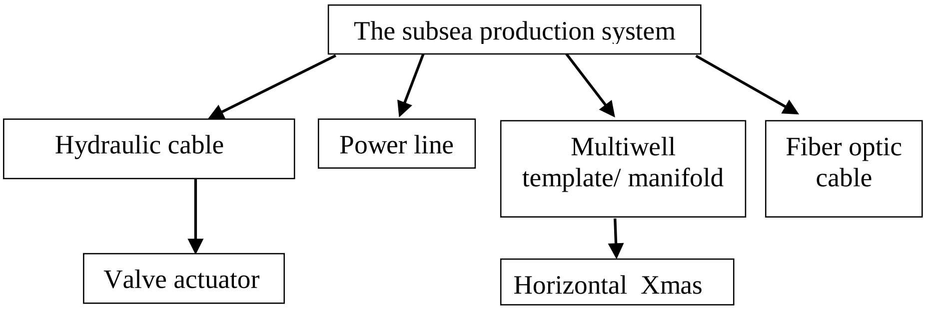

Diagram 7.3. The subsea production system breakdown

The functional block diagram of SPS is illustrated in Diagram 7.4.

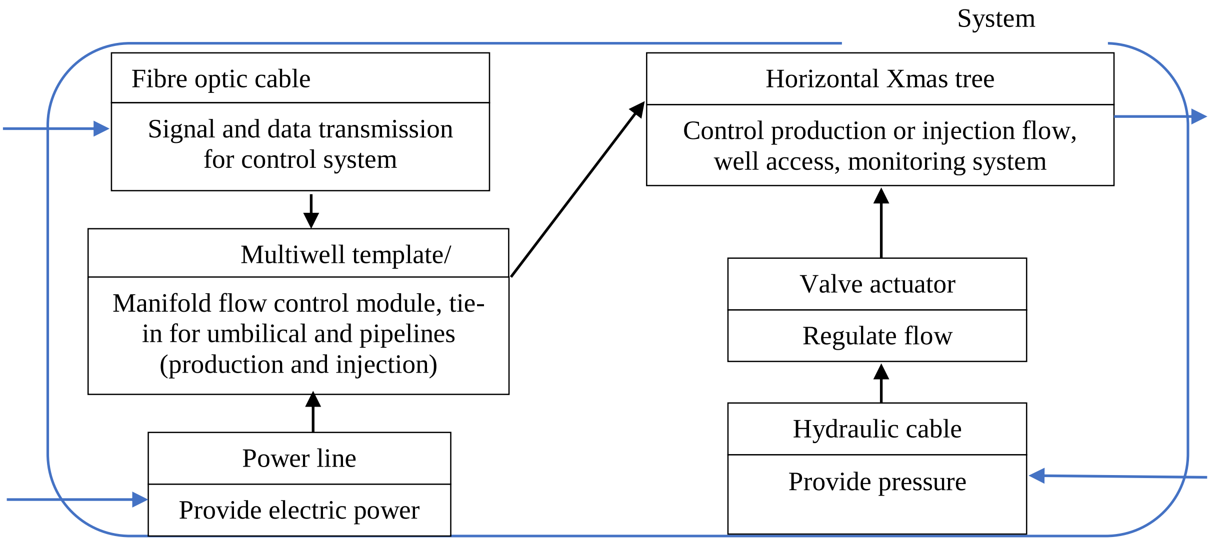

Diagram 7.4. The functional block diagram of SPS

Top-down Failure, mode, effects, and criticality analysis (FMECA) of the subsea production system (SPS) is shown in Appendix F. The top-down approach focuses on top-level system functions rather than all system components. It is often used in early design stages. The objective of FMECA is to support design decision-making process. FMECA can be used both during design to choose among design alternatives and remove potential failures from the design. FMECA is a valuable, time and cost saver and risk assessment tool.

The underwater operations in the Arctic will be accompanied new types of problems. The most important of which are subsea power transmission over long distances, distribution and power conversion, subsea compression of high-pressure gas injection, remote monitoring, diagnostics and inspection, autonomous systems well intervention and subsea separation/ drying/ processing, allowing the transportation of gas. The possibility of iceberg and ice ridge destruction of the subsea pipeline and template installations must be evaluated. Moreover, the ice thickness is up to 2 m in the winter time. In these conditions, it is hard for remotely operated vehicles (ROVs) and autonomous underwater vehicles (AUVs) to get access to underwater units.

Seabed soil conditions are very different from place to place due to the possible presence of frozen ground (permafrost) and gas hydrates. Soil conditions are impossible to be identified only as a "hard" or as "soft" as they will change throughout field life cycle. It is a consequence of climate change, but also the fact that the subsea production system will provide a local effect on the environment. The result of thawing of the seabed soil may be a reduction, but, perhaps, a complete loss of the ability to carry the load [55]. In areas where icebergs or ice ridges gouge a seabed, subsea constructions will be in need of protection or should be safely designed. Therefore, the barriers must be set to provide an efficient isolation of manifold and another subsea equipment. Thus, there are two primary risks to be assessed in the thesis. They are:

- Damage to the subsea equipment due to subsidence of the seabed;
- Damage to the subsea equipment due to possible icebergs – subsea equipment interaction.

The Bow-Tie diagrams are shown in Appendix H.

7.4. Technology readiness and future recommendations

Based on the analysis of the production technical block, the technology readiness levels of the key elements can be evaluated according to API RP 17N [36]. Therefore, the estimated technology readiness levels of the elements of the production technical block are shown below [36]:

- Subsea equipment: TRL = 6;
- The foundation for subsea equipment (permafrost conditions): TRL = 4;
- Subsea control system (over 170 km): TRL = 5;
- Subsea processing system: TRL = 6;
- Power distribution (over 170 km): TRL = 5;
- Subsea protection (glory holes): TRL = 6;
- Support and IMR strategy (Kara Sea conditions): TRL = 3.

Subsea production system is ready to be used if the key challenges are solved: support and IMR, the foundation of subsea equipment. There is a need for innovation and technology development:

- Power system;
- Control system;

- Local power generation concept;
- Subsea protection;
- Design of subsea equipment reducing weight;
- New and innovative wellhead foundation solutions;
- Subsea processing.

The calculation results of prioritization of research issues and technologies for the production technical block is shown in Appendix G.

CHAPTER 8. TECHNICAL BLOCK OF LOGISTICS

8.1. The Screening of technical block of logistics

Arctic region is characterized by its various physical and operational challenges, remote settings and lack of established infrastructure. That includes vessels, the systems necessary to gather and supply of accurate and timely information for safe operations, the resources needed to respond to a variety of potential emergencies, and the onshore and offshore facilities needed to provide supplies and logistics. The transportation of personnel is an important issue. The screening of the technical block of logistics is shown in Diagram 8.1.

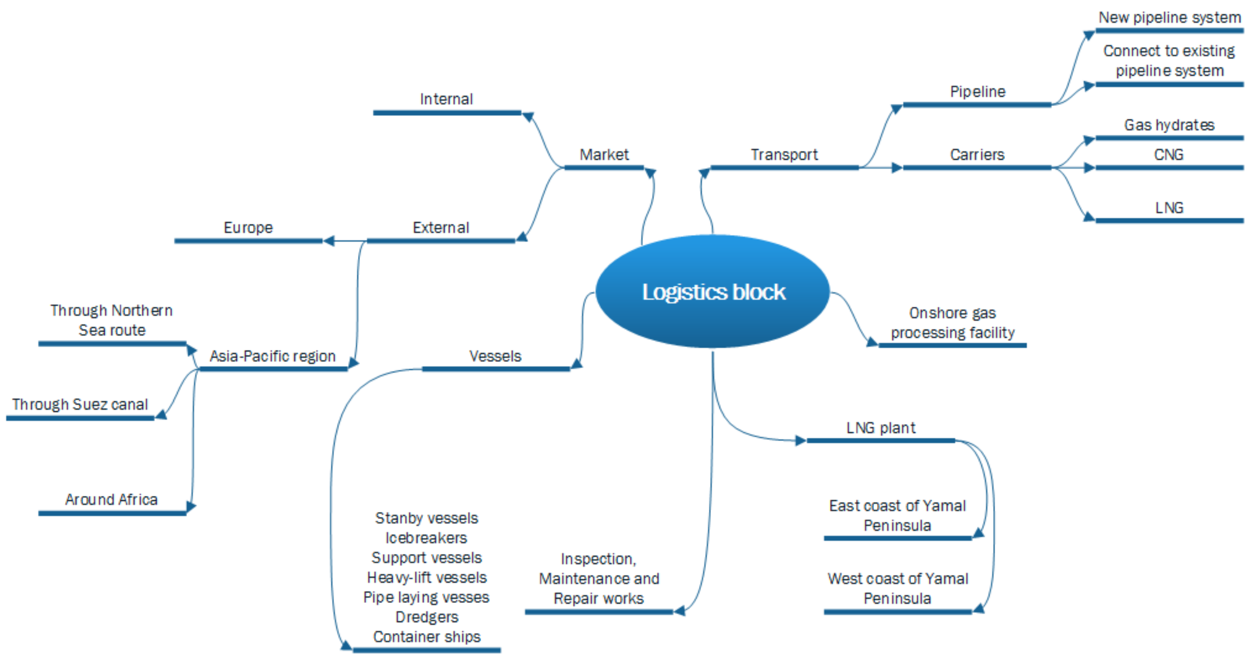

Diagram 8.1. The screening of the technical block of logistics

Increased gas activity will generate a certain need for more transport and land-based infrastructure. Today, the existing port infrastructure of Harasavey is not adapted to the specific needs and requirements of the gas industry.

Maritime traffic today is very limited in the wintertime (mainly vessels to and from Dudinka) and somewhat higher during summer. The traffic is mainly linked to the ongoing activities at Yamal Peninsula («Bovanenkovo», «Sabetta», and «Tambey») [44]. Transport between ports in the Atlantic and the Pacific oceans, using the Northeast Passage has been tested few times over the last couple of years and represents an interesting industrial opportunity regarding future transport.

8.2. The Scoping of technical block of logistics

8.2.1. Logistics and transport in and out of Leningradskoe field

Logistics is dependent on well-developed infrastructure. Leningradskoe field is characterized by physical and operational challenges, remote location and lack of established infrastructure. Logistics and transport challenges in and out of Leningradskoe field are shown in Table 8.1 [44].

Activity prospects	Challenges
multipurpose vessels	supply, standby rescue vessels, Ice Management
vessel design for ice covered waters	an issue
communication challenges – real time	above 75 latitude north, reliability and bandwidth questionable / not stable
maritime transport of personnel	possibly an issue

8.2.2. Infield logistics

There are different activities in the various stages/phases for Leningradskoe field development. Some of them, for instance, include seismic operations, exploration drilling, offshore development/ construction and workover & maintenance operations. Thus, Table 8.2 below illustrates major technology or operational issues in the infield logistics of Leningradskoe field [44].

Table 8.2. The challenges in the infield logistics

Activity	Challenges
seismic survey	speed variations due to ice conditions;
site surveys	multi-year Ice, ridges, icebergs; GPS positioning accuracy
exploration drilling	ice interfering with riser/wires; low temperature, icing
seabed Preparation and Subsea Installations	ice interfering with wires, station/course keeping
heavy lift operations	ice interfering with wires, station/course keeping; Low temperature, icing
communication challenges – real time	the reliability and bandwidth are limited and not stable

The biggest challenges of infield logistics are associated with tasks that require marine operations such as the installation of subsea equipment, intervention, inspection, maintenance, and repair. The challenges of marine operations are concentrated on the development of ice resistant ships, human safety (HSE), ROV and AUV operations and methodology of the planning of marine operations in Arctic conditions. The development of structures of ships primarily depends on finding economic solutions for insulation and strengthening of hulls. Moreover, ships must withstand low temperatures and sea ice loads. One of the major problems in the planning methodology is uncertainty associated with the duration of the operational «windows», and the unreliability of weather forecasts. On the issue of human safety, it should be noted that maritime operations require the availability of staff with the necessary knowledge and experience in harsh environments. Furthermore, it is necessary to provide special rules for more frequent shifts of personnel who do operations in remote areas. To improve the safety of marine operations, innovations should include new solutions for search and rescue operations, personnel training, as well as ships that protect the crew from exposure to outside environmental actions during operation.

The choice of ships is a key technology block of the field development because the progress of works depends on it. The construction of specialized vessels conducting complex operations in the maritime waters covered by ice is expensive and often not cost-effective when operating in areas not covered by ice because of limiting operational time. The recommended solution is to have an ice-strengthened vessel capable of carrying out light intervention (Category A), maintenance and capable of launching AUV's. Table 8.3 represents the main challenges of IMR operations in Leningradskoe field [44].

Table 8.3. The challenges of IMR operations

Activity	Challenges
diving and ROV inspection	ice and icing problems in the moon pool
the need of real-time communication	station keeping for Arctic DP
transport of personnel and equipment in the winter season.	customised helicopters and vessels for Arctic winter operation.

Ice management (IM) is necessary to perform during all marine operations. An icebreaker is a vessel where icebreaking is the primary function. IM is implemented by Ice class supply vessels, multifunctional and nuclear-powered icebreakers. It is necessary to highlight that the severity of the ice conditions regulates IM strategy. Nowadays, the Russian Federation lacks the capacity of icebreakers to support gas production activity in the Kara Sea. Submarine intervention and IMR concepts can also be technically feasible, but do not offer an economic attractiveness soon.

8.2.3. Market

It is suggested to supply gas produced from the field to the international market in the form of LNG (liquefied natural gas). Liquid gas has 600 times less volume than natural gas that makes this type of transportation very viable. LNG transport vessels are usually designed for specialized trade, i.e. for round trips between two permanent harbors. Ice class Arc 7 LNG carriers may be chosen to carry liquefied natural gas to the Asian market. However, ice class Arc 6 LNG carriers are supposed to operate on the European market. However, the liquefaction process is quite costly since it requires specialized vessels and terminals on each end of the transport line

Therefore, the plant for liquefied natural gas ought to be built. The construction of the plant for the production of liquefied natural gas (LNG) is costly on the western part of Yamal Peninsula. That is because of shallow water depths, the absence of the necessary infrastructure and the complexity associated with providing logistics. In addition to LNG project, there is a need to build icebreakers and supply vessels with the possibility of placing two ROV to monitor SPS.

Accordingly, it is proposed to construct an LNG plant in the north-east of Yamal Peninsula in Tambey port (see Figure 8.1). There is an experience in the construction of an LNG plant in this region. For example, «Yamal» LNG plant is being built in the port of «Sabetta». «Yamal» LNG plant is the second Russian LNG plant for the production of liquefied natural gas. The designed capacity is 16.5 million tons per year. At the same time, the resource base allows increasing the capacity to 70 million tons per year. LNG port is planned to be equipped with ice class tanker fleet. The Yamal project involves the creation of transport infrastructure, including a seaport and airport in the area of «Sabetta» village. Europe (Belgium) is supposed to be used as a storage base to deliver LNG to the Asia-Pacific region during the periods of difficult navigation along the Northern Sea Route. For the transportation of LNG, sixteen Arc 7 ice-class tankers will be used [50].

For Leningradskoe project, the pipeline laying is required from «Harasavay» port to «Tambey» port along Yamal peninsula. The pipeline route with the lowest crossing parts of water parts with two compressor stations is shown in Figure 8.1.

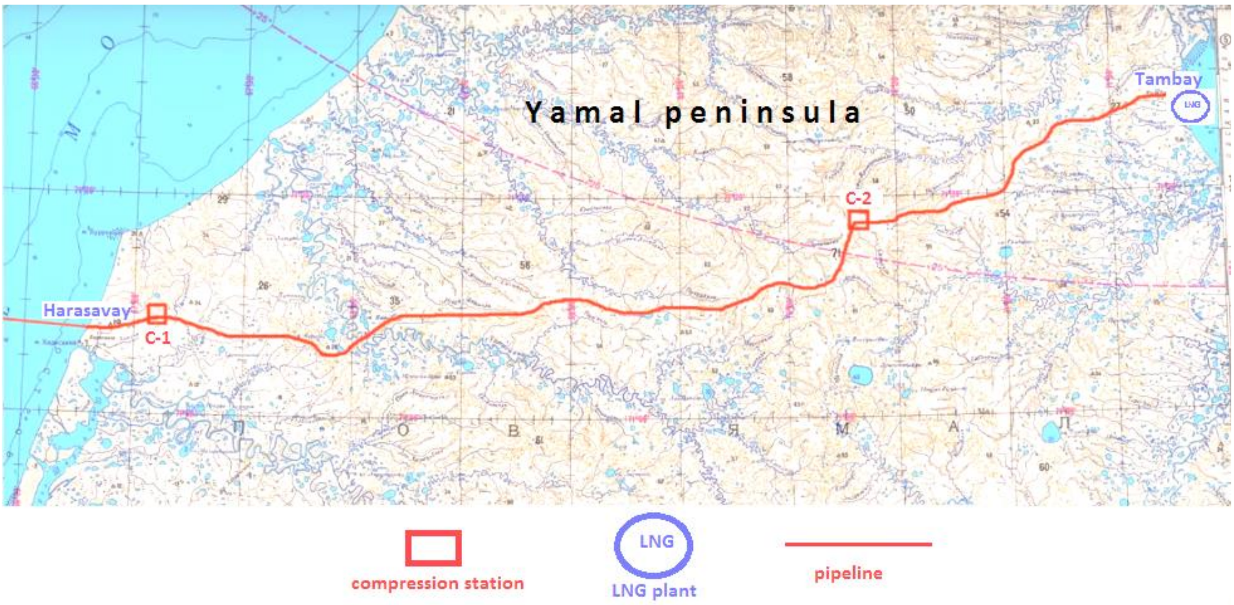

Figure 8.1. The gas pipeline route along the Yamal Peninsula

The construction of LNG carriers must be taken into account during the design stage. South Korean shipyards can be considered for the construction of LNG carriers. At the same time in the Far East of Russia, the shipyard is prepared based on «Zvezda» ship-building center for oil and gas industry. Therefore, LNG tankers can also be constructed there. It is planned that the shipyard «Zvezda» will be launched in 2018 [51].

8.3. Risk assessment of infield logistics

In the section, two major challenges are considered to be in the infield logistics of Leningradskoe field: Inspection Maintenance and Repair (IMR), and heavy lifting operations. The availability of the subsea production system is under question for all-year access because of ice cover. Therefore, IMR is highly dependent on Ice Management philosophy. Moreover, there is no experience with installing and operating equipment for sea areas being ice-covered most of the year, particularly with modules potentially being large and heavy. Furthermore, the number of heavy lift vessels capable of operating in the Kara Sea is limited concerning availability. When lifting a subsea module, there is a probability of uncontrolled movements because of unpredictable weather conditions [78]. Thus, this risk must also be assessed. The Bowtie analyses of the defined risks are shown in Appendix H.

8.4. Technology readiness and future recommendations

Based on the analysis of the technical block of Logistics, the technology readiness levels of the key elements can be evaluated according to API RP 17N [36]. Therefore, the estimated technology readiness levels of the elements of the technical block for logistics are shown below [36]:

- Icebreakers (2 m ice thickness): TRL =7;
- Arctic type AUV/ROV: TRL = 4;
- Heavy lift vessels: TRL = 7;
- Standby vessels (Kara Sea conditions): TRL = 5;
- LNG carriers: TRL = 7;
- LNG plant: TRL = 7;
- Pipe laying vessels: TRL = 6;
- Ice management: TRL = 3;
- Inspection, maintenance, and repair: TRL =2.

There are some key challenges in marine operations: inspection, maintenance, and repair; AUV/ROV deployment; safety; Ice Management. There is a need for innovation and technology development:

- «operational window»;
- Ice Management;
- Inspection, maintenance, and repair (IMR);
- AUV/ROV operations in Arctic;
- Offshore safety, evacuation, and rescue in the Kara Sea;

The calculation results of prioritization of research issues and technologies for the technical block of Logistics are shown in Appendix G.

CHAPTER 9. ECONOMIC DISCUSSION OF THE PROJECT

To this day, the methods of economic evaluation of gas field development on the Arctic shelf are not well tested. There is no unambiguous methods and approaches to the integrated assessment of economic efficiency and optimization of such projects. The novelty and uniqueness of such projects cause significant investments, which depend on the total effect of climatic, geological and technological conditions. However, the discovery of unique reserves, even taking into account the high cost of development, significantly reduces the risks. It justifies all costs, although the payback period of investments, in general, is rather long. It is evident that the calculation of all possible deviations from the plan seems almost an impossible task because of the enormous complexity of the project. Therefore, during the design stage, the pre-estimation of the overall project economics is possible.

Operating costs (OPEX) of the subsea production system are usually lower than traditional solutions that require a production platform. Moreover, because of the extreme weather conditions, subsea production system (SPS) can also be the only viable option. However, weather conditions, remoteness and lack of adequate infrastructure lead to special requirements. Repair vessels will result in the fact that operating costs will be higher than in other areas.

In the process of realization of the project, a company has to pay taxes: severance tax, value added tax, income tax, property tax. It is beneficial for federal and regional budgets of Russian Federation. It was estimated that payments amount to about 35% of the total income during the Leningradskoe project. Undoubtedly, it will have a positive impact on the development of the Arctic region.

The appropriate calculations of the main macroeconomic indicators are carried out for the Rusanovskoe field [37]. It was found that the project can be considered effective when considering the potential of creating new technology for development as well as an increase in gas prices and profits from LNG implementation. All these lead to greatest possible income from the sale in case of orderly and efficient management.

It should be emphasized the prospects of a profitability of Leningradskoe field development as part of a large cluster with Rusanovskoe and Leningradskoe gas and condensate fields (see Figure 9.1).

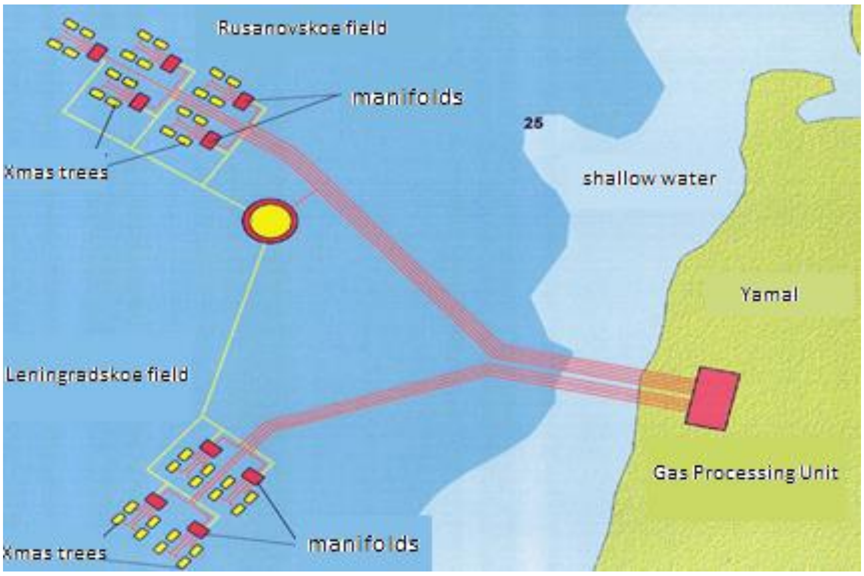

Figure 9.1. Cluster development of Leningradskoe and Rusanovskoe gas and condensate fields [39]

The implementation of technological solutions proposed by the author can be a pulse of the growing of Russian economy. In fact, the direction of the Arctic oil and gas industry is intended to be not only one of the major donors of the economy, but also the engine of development of high technologies in the industry.

However, environmental requirements and safety regulations have to go in close cooperation with the development and integration of the Arctic zone to preserve the unique nature. Further development of the cluster initiates a severe economic synergistic effect on the Russian economy.

CHAPTER 10. CONCLUSIONS AND RECOMMENDED STRATEGY

Therefore, the main conclusions can be highlighted.

1. The calculation of the expected gas production rate of one horizontal well was performed based on the data of two exploration wells. The estimated production rate is around 3.22 million m^3 of gas per day (see Appendix C). It is rather a large production rate; therefore, the field is very productive. Then, two scenarios of the field development were considered. The first option is to drill 40 wells. The second variant is to drill 16 wells. The development schedule depends on the choice of the company.

2. The probability of icebergs' occurrence of at Leningradskoe area was analyzed. Thus, it was defined that the maximum possible depth of icebergs' keels is roughly 80 m. If considering that the average height of the subsea equipment is 10 m, it is recommended to install a subsea production system on those parts of the field where the depth exceeds 90 m. Otherwise, it is necessary to protect the subsea equipment from mechanical damage as a result of a collision with an iceberg. The best solution for protection is a laying of subsea equipment in the trenched holes.

3. The state of readiness of equipment for the development of Leningradskoe field was determined based on the analysis of existing technologies, scientific papers, and risk assessment. It can be concluded that the development of Leningradskoe field is impossible at an acceptable level of risk with existing technologies. The following information comprises the main details for each technical block (see Figure 10.1).

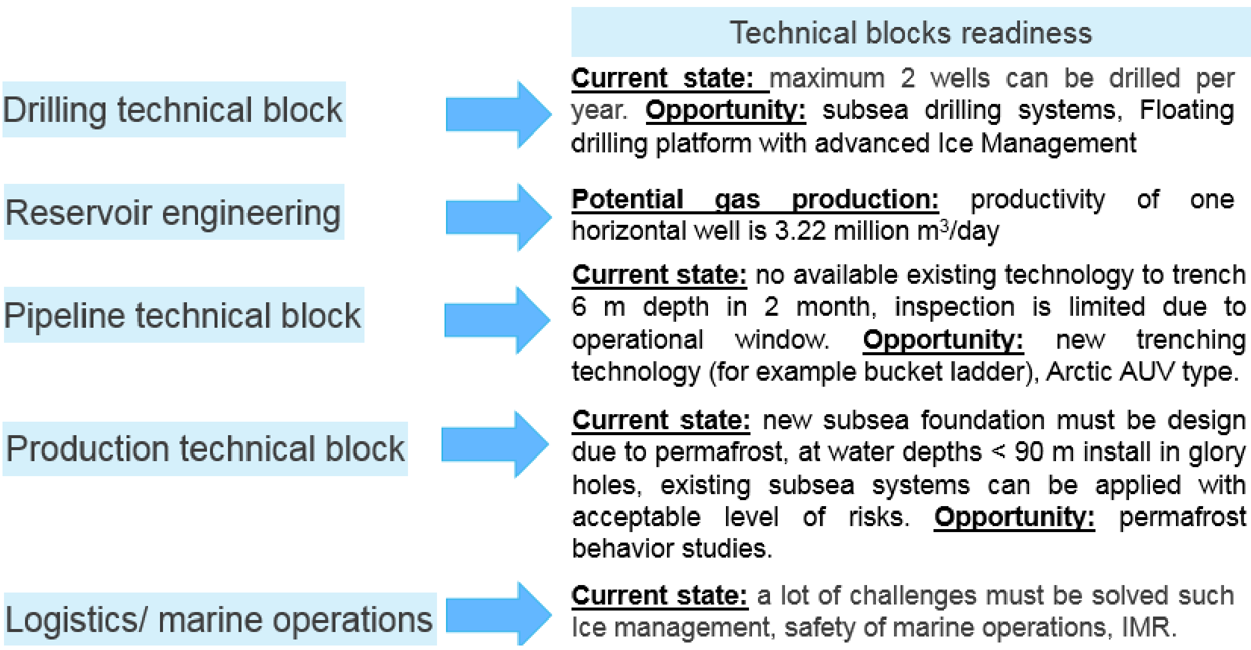

Figure 10.1. The readiness of technical blocks

3.1. Drilling technical block. Nowadays, the maximum number of drilled wells per year is two in the positive evaluation. That is due to severe ice conditions, where the ice thickness is up to 2 m in the winter period, the depth of ridges' keels is up to 25 m, and the probable depth of icebergs' keels is 80 m. In the thesis, the two primary options were compared: subsea drilling system and ice-resistant floating drilling platform/ship with an appropriate ice management. None of these scenarios has shown the potential for the commercial drilling and acceptable level of risk at the current state of the technology. Subsea drilling system is promising to be the most profitable option with larger risks. Therefore, the risks of both concepts were analyzed (see Appendix G). The risk assessment was carried out by the Bowtie technique, where the barriers were proposed to address threats and consequences of the failures. Further, a priority in the development of scientific research for the drilling technical block was identified (see Appendix H). The defined areas of research would significantly contribute to the development of Leningradskoe field. Thus, the medium priority: combined slim hole drilling and large bore completion. High priority: the adaptation of the drilling vessel to the harsh climatic conditions (vessel winterization), riserless drilling. Very high priority: Ice Management, a safe concept of the subsea drilling system, station keeping (dynamic positioning or mooring) of the drilling vessel in the heavy ice conditions.

3.2. Subsea pipeline transport. In the analysis of existing technologies and identifying the key parameters for designing of a pipeline to lay in the direction of the Yamal Peninsula («Harasavey» port), it was determined that there be a possibility of mechanical damage to the pipeline in the shallow water area near the Yamal Peninsula. The main concern is ice ridge gouging. Thus, the bathymetric maps were analyzed, where the shallow water area with water depths of less than 25 m was detected. The estimated length of the pipeline in the shallow area is around 31 km. Then, the maximum depth of a gouge was calculated (see Appendix D). Further, the trunk pipeline diameter was calculated assuming some initial conditions and simplifications. The diameter of the trunk pipeline is 1.28 m (see Appendix E). The required depth of the pipeline burial is 6 m. Therefore, there is a need for trenching to a depth of 6 m in one «operational window». The existing technology does not allow doing it. Therefore, this problem is limiting factor in the development of Leningradskoe field. However, there are prototypes of technologies that could afford to dig a trench to a depth of 6 m during a short period in scientific literature. Then, the areas that have significant risks were identified, for instance, a regular inspection, maintenance and repair (IMR) of the pipeline (see Appendix H). The operations are difficult to carry out year-round because of the presence of ice. Therefore, it is necessary to create the autonomous underwater robotics that could swim under the ice cover for an extended period. Thus, the R&D prioritization was identified that could improve the design and operation of the subsea pipeline at Leningradskoe field (see Appendix G). Hence, the medium priority: the protection of the pipeline from the erosion of a coastal zone of Yamal Peninsula. High priority: the possibility for regular inspection, maintenance, and repair of the pipeline. Very high priority: the technology for digging trenches that are deeper than 6 m in a short period.

3.3. Production system. The various alternatives for the production system were discussed. The best solution is to install a subsea production facility. The following systems were analyzed for the readiness of using in Leningradskoe fields: subsea production system, control system, power system and subsea processing. The various concepts of control system were considered: hydraulic, hydraulic-electric, multiplexed hydraulic-electrical and all-electrical system. The best option at a current state of technologies is a multiplexed hydraulic-electrical system. The power transmission system was reviewed by various concepts: the transfer of electricity over long distances (alternating current or high voltage direct current) and as well as options for local power generation. In the thesis, the following concepts were discussed: the local generation of electricity from nuclear energy, the energy of accumulators or produced fluid (see Appendix B). The subsea equipment was studied: the comparison of different options for Xmas tree (XT), the location of the subsea equipment, the umbilical. It was defined that the best solution for Xmas tree is enhanced horizontal XT, which is capable of drilling through. Then, flow assurance problems associated with providing a continuous stream of fluid were discussed. The basic thermal and hydraulic calculations of temperature and pressure distributions along the trunk pipeline were conducted (see Appendix E). It was defined that some measures to prevent the gas hydrate precipitation are necessary. Further, the major risks regarding subsea production system were analyzed. Risk analysis of the subsea production system was carried out using the method FMECA (failure modes, effects, and criticality analysis (see Appendix C)). The most significant risks, which limit the arrangement of the subsea production facility were studied. Hence, the greatest danger of subsea layout is the unstable soil properties: permafrost, and the presence of gas hydrates. Therefore, a new foundation for subsea equipment is needed to be developed. The foundation should take into account all risks associated with a potential subsidence of the seabed. In the thesis, the risks were analyzed by a Bowtie technique (see Appendix H). In the end, the directions of research works for the subsea production system of Leningradskoe field were detected. Hence. The medium priority: compact design of the subsea equipment. High priority: subsea processing (compression), reliable control and power systems on the distance of 170 km, a safe foundation for subsea equipment.

3.4. Marine operations/logistics. The main challenges associated with marine operations were analyzed. The operations were divided into two major groups: Marine operations in and out of Leningradskoe field and infield logistics. Thus, the key challenges include Ice Management; heavy lifting; lifting of subsea equipment through the splash zone; inspection, maintenance, and repair of equipment. Risks were assessed by the qualitative risk analysis (see Appendix H).

Moreover, the technology readiness for conducting maritime operations was estimated. In general, the technical block of logistics at the current level of technology is not ready for the development of Leningradskoe field. Thus, the following key research directions are needed for logistics. Medium priority: the study of ice mechanics and ice loads. High priority: regular inspection, maintenance, and repair of equipment, Ice Management. Very high priority: Safety of works, the system of evacuation.

4. It can be concluded that the cost-effective and safe development of Leningradskoe field is impossible with existing technologies. The gap between requirements and technologies in the technical blocks can be distributed as follows: logistics, drilling subsea production system and pipeline transport. Before the development of the Leningradskoe field, it is necessary to carry out research works in the following areas (very high priority).

Therefore, at the current state of technology level, the development of Leningradskoe field is not possible due to the intolerable level of risks of six issues: **drilling, dredging/trenching, wellhead foundation, Inspection Maintenance and Repair, Ice Management (IM), Safety of marine operations.**

5. Thus, it can be noted that for the development of Leningradskoe field, it is necessary to use the most advanced production technologies as well as the use of international experience in the development of offshore fields. To this day, some technologies are sufficiently proven to have a high reliability and are ready for use in the freezing waters. At the same time, there some technical problems associated with the adaptation of these technologies to the harsh conditions of the Arctic waters as well as the remoteness of the field. The evaluation of the main challenges is presented in Appendix H in the form of Bowtie risk analysis.

The results of the literature review, analysis of existing technology and research paper concepts were synthesized by organizing the roadmap of R&D (see Appendix G). Thus, the priority ranking of the major research areas is determined by the thematic R&D categories:

- Red – very high priority R&D area: priority ranking factor $P > 12$. It corresponds to technologies to be developed before the start of an intensive exploration and production of hydrocarbons in Leningradskoe field;

- Orange – high priority R&D area: priority ranking factor $8 < P \leq 12$. It corresponds to technologies to be developed to solve issues that significantly hinder the exploration and production of hydrocarbons in Leningradskoe field.

- Yellow – medium priority R&D area: priority ranking factor $6 \leq P \leq 8$. It corresponds to technologies to be developed that substantially affect the development of prospecting and production of hydrocarbons in Leningradskoe field.

Thus, the prioritization of the main research issues and technologies for Leningradskoe field development is illustrated in Figure 10.2.

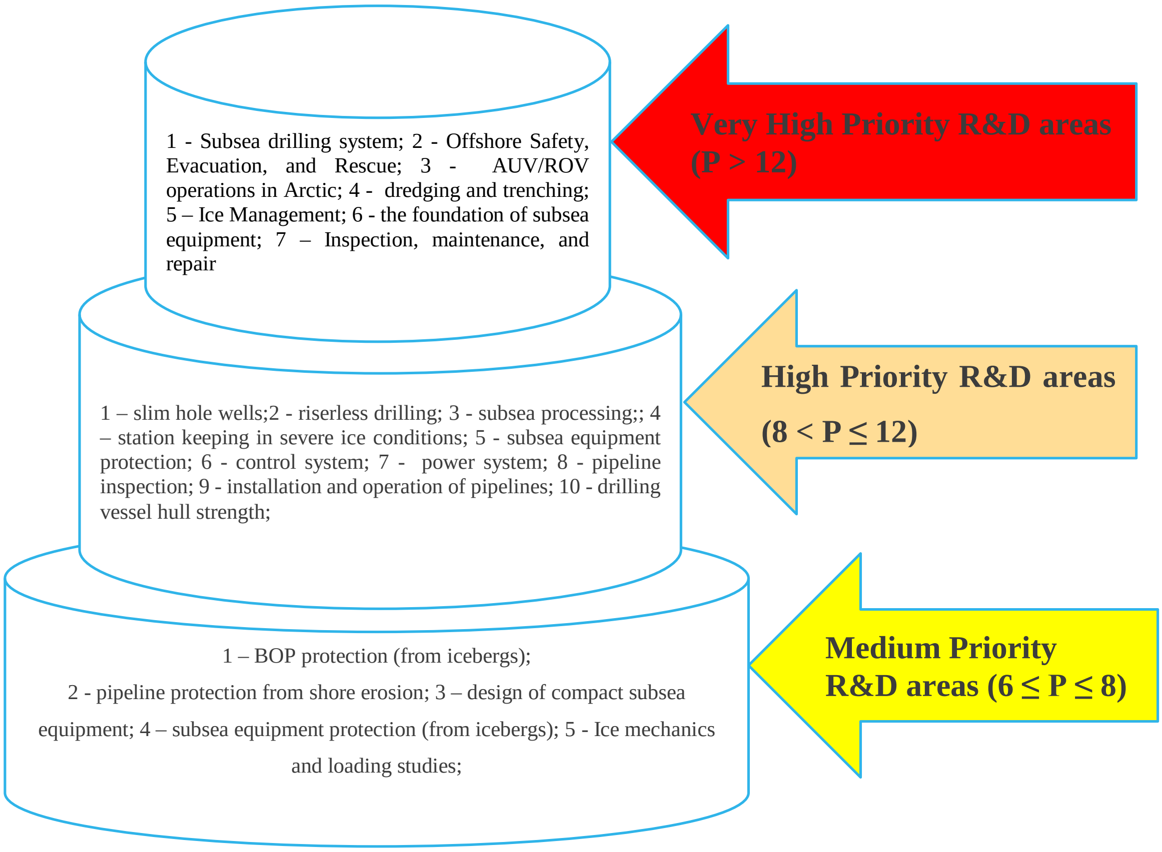

Figure 10.2. R&D roadmap for the development of Leningradskoe field

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APPENDIX A. RISK MATRIX

Risk category = Probability x Consequence

		Risk category				
Probability	E	E1	E2	E3	E4	E5
	D	D1	D2	D3	D4	D5
	C	C1	C2	C3	C4	C5
	B	B1	B2	B3	B4	B5
	A	A1	A2	A3	A4	A5
Consequence		1	2	3	4	5

Risk category: green color – tolerable risk level; yellow color – ALARP (as low as reasonably practicable) region; red color – intolerable (unacceptable) risk.

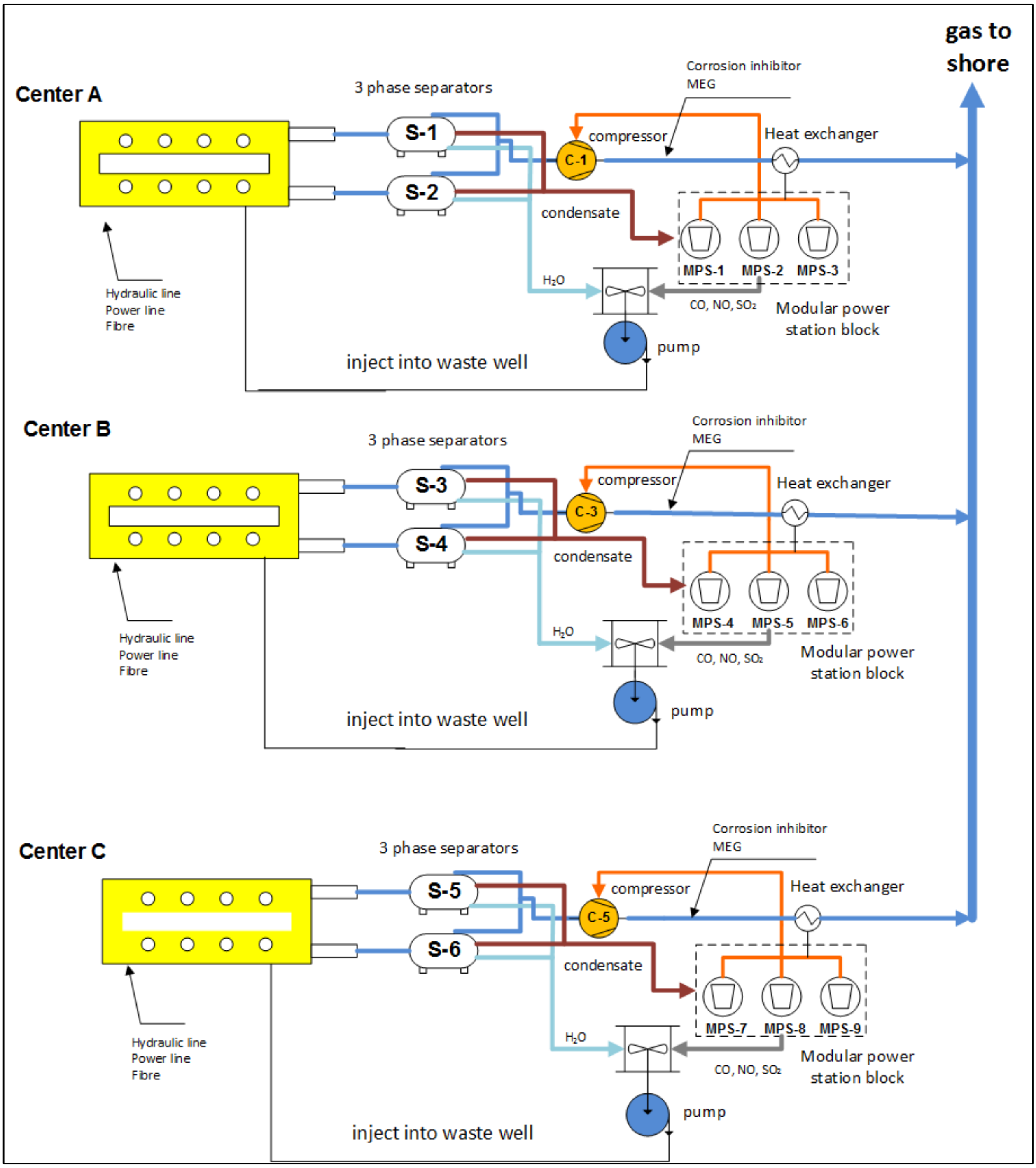
The probability of risk:

- Critical (very likely) – Category E;
- High (probably) - Category D;
- Medium (possible) - Category C;
- Low (Unlikely) - Category B;
- Minor (very unlikely) - Category A.

The consequence of risk:

Consequence	1	2	3	4	5
Assets	Negligible damage	Minor damage	Medium damage	Major damage	Total loss
Personnel	No/ low injury	Minor injury	Serious injury	1-3 fatalities	>3 fatalities
Environment	Negligible impact	Minor impact	Locally limited impact	Major impact	Massive impact
Reputation	Negligible impact	Minor impact	Regional impact	Superregional impact	National impact

APPENDIX B. A POSSIBLE CONCEPT FOR SUBSEA LAYOUT WITH LOCAL POWER GENERATION



APPENDIX C. CALCULATION OF RATE OF A HORIZONTAL WELL

Layers								The sum
№	1	2	3	4	5	6	7	
Parameters	$L/R_{ext} = 2$							
hg, m	8.45	25.35	4.12	4.23	8.55	8.35	8.55	67.6
kg, mD	0.6	1.6	3.3	3.3	3.3	3.3	3.3	
ag*	110.3	13.8	41.1	40.1	19.8	20.3	19.8	
h1, m	4.13	12.58	1.96	2.02	4.18	4.08	4.18	
a*	1863	698	339	339	339	339	339	
Q, million m^3/day	0.104	0.830	0.279	0.288	0.579	0.565	0.579	3.222

Initial data:

T = 323 K;

$p_{reservoir}$ = 17.5 MPa;

p_{well} = 12 MPa;

r_{well} = 0.1 m;

μ = 0.013 mPa·s;

z = 0.78.

APPENDIX D. ICE SCOURING CALCULATIONS

Table 6.1. Initial data. Environmental data in the southwest part of the Kara Sea

Parameter	Unit	Value
Water density	$\rho_w, \frac{kg}{m3}$	1034
Current speed	$u_c, \frac{m}{s}$	2
Current drag coefficient	C_{dw}	0.9
Air density	$\rho_a, \frac{kg}{m3}$	1.3
Wind speed	$u_w, \frac{m}{s}$	8
Wind drag coefficient	C_{dw}	0.9
Wind skin friction coefficient	C_{sw}	0.001

Table 6.2. Initial data. Ice data in the southwest part of the Kara Sea

Parameter	Symbol/ Unit	Value
Level ice thickness	h_i, m	2
Ridge sail height	h_s, m	6,4
Consolidated layer thickness	h, m	3
Keel angle	$a_k{}^o$	30
Sail angle	$a_s{}^o$	20
Keel breadth	B, m	35
Ridge block size	T_b, m	0.45
Ice density	$\rho_i, \frac{kg}{m3}$	916
Ice speed	$u_i, \frac{m}{s}$	1.8
Elasticity modulus	E_i, MPa	8000
Poisson ratio	v_i	0.34
Ice rubble internal friction angle	$\phi_i{}^o$	20
Keel rubble cohesion	c_i, kPa	15
Ridge sail porosity	η_s	0.09

Table 6.3. Initial data. Soil data in the southwest part of the Kara Sea

Parameter	Unit	Value (clay)	Value (sand)
Wall friction angle	${\phi_w}^o$	30	25
Internal friction angle	ϕ^o	23	30
Friction between ice and soil	μ	0.4	0.5
Soil density	$\rho_s, \frac{kg}{m3}$	1760	1905

Table 6.4. Calculation results. Ridge features

Parameter	Unit	Value
Ridge keel macroporosity	η_k	0.25
Average keel density	$\rho_{iw}, \frac{kg}{m^3}$	945.5
Average sail density	$\rho_{ia}, \frac{kg}{m^3}$	833.7
Wind projection area	A_{a1}, m^2	216.0
Wind projection area	A_{a2}, m^2	3459.6
Current projection area	A_w, m^2	822.8
Keel draught	h_k, m	25.28
Keel width at the sea level	w_k, m	98.8
Keel width at the bottom	w_b, m	12.6

Table 6.5. Calculation results. Forces action.

Force component	Unit	Value	
		Sand	Clay
Drag force due to the wind	F_{dw}, MN	0.08375	
Drag force due to current	F_{dc}, MN	1.531	
Ridge weight	W, MN	517.118	
Buoyancy	F_b, MN	527.036	
Force due to drifting ice	F_i, MN	24.623	
Passive earth pressure coefficient	K_p	7.835	4.120
Specific horizontal Coulomb friction	F_{cx}, MN	23.002	21.941
Specific vertical Coulomb friction	F_{cy}, MN	7.794	7.562
Action friction force	F_a, MN	3.845	3.123

Table 6.6. Calculation results. Gouge depth

Force component	Unit	Value	
		Sand	Clay
Gouge width	B, m	35	35
Gouge depth	d, m	2.217	3.5136

The algorithm for calculating ice ridge parameters:

- The density of porous keel part of the ridge:

$$\rho_{iw} = \eta_k \cdot \rho_w + (1 - \eta_k) \cdot \rho_i \tag{6.1}$$

- The density of the upper sail part:

$$\rho_{ia} = \eta_s \cdot \rho_a + (1 - \eta_s) \cdot \rho_i \tag{6.2}$$

- Keel draft:

$$h_k = 3.95 \cdot h_s \tag{6.3}$$

- Keel width at water line:

$$w_k = 3.91 \cdot h_k \tag{6.4}$$

- Keel width at bottom line:

$$w_b = w_k - 2 \cdot h_k \cdot \cot \alpha_k \tag{6.5}$$

- Current projection area:

$$A_w = (h_k - \frac{\rho_i}{\rho_w} \cdot h_i) \cdot B \tag{6.6}$$

The algorithm of calculations of forces on the ice ridge is shown in Appendix D (equations (6.9) - (6.21)):.

Where,

<u>in vertical direction</u> <u>[12]:</u>

- Buoyancy

$$F_b = \rho_w \cdot B \cdot g \cdot [\frac{1}{2} \cdot (w_k + w_b) \cdot \left(h_k - \frac{\rho_i}{\rho_w} \cdot h\right) + \frac{\rho_i}{\rho_w} \cdot h \cdot w_k] \tag{6.9}$$

- Ridge weight

$$W = \rho_{iw} \cdot B \cdot g \cdot [\frac{\rho_{ia}}{\rho_{iw}} \cdot \left(h_s - \frac{\rho_w - \rho_i}{\rho_w} \cdot h_i\right) \cdot cot\, \alpha_s + \frac{\rho_i}{\rho_{iw}} \cdot h \cdot w_k + \frac{1}{2} \cdot (w_k + w_b) \cdot \left(h_k - \frac{\rho_i}{\rho_w} \cdot h\right)] \tag{6.10}$$

- Specific vertical Coulomb friction

Vertical passive friction force

$$F_{cy}(d) = \mu \cdot P_f(d) \cdot \cos \phi_w \cdot \sin \alpha_k \tag{6.11}$$

Front resistance

$$P_f(d) = \frac{1}{2} \cdot K_p \cdot \rho_s \cdot g \cdot (d + 0.635 \cdot d^2) \cdot B \tag{6.12}$$

Passive earth pressure coefficient

$$K_p = \frac{\cos\phi^2}{\cos\phi_w \cdot (1 - \sqrt{\frac{\sin(\phi+\phi_w)\cdot\sin\phi}{\cos\phi_w}})^2} \tag{6.13}$$

- Seabed reaction

$$N(d) = F_{cy}(d) \tag{6.14}$$

<u>in horizontal direction</u> [12]:

- The wind drag force

$$F_{dw} = \frac{1}{2} \cdot \rho_a \cdot C_{da} \cdot A_{a1} \cdot {u_a}^2 + C_{sa} \cdot \rho_a \cdot A_{a2} \cdot {u_a}^2 \tag{6.15}$$

- Current drag force

$$F_{dc} = \frac{1}{2} \cdot \rho_w \cdot C_{dw} \cdot A_w \cdot {u_c}^2 \tag{6.16}$$

- Ice force

$$F_i = 0.43 \cdot 4.059 \cdot B^{0.622} \cdot {h_i}^{0.628} \tag{6.17}$$

- Active friction force

$$F_a(d) = \mu \cdot N(d) \tag{6.18}$$

- Horizontal passive friction force

$$F_{cx}(d) = \mu \cdot P_f(d) \cdot \cos\phi_w \cdot \cos\alpha_k + \mu \cdot P_s(d) \cdot \cos\phi_w \tag{6.19}$$

Side resistance

$$P_s(d) = \frac{1}{6} \cdot K_p \cdot \rho_s \cdot g \cdot d^2 \cdot w_b \cdot (w_b + \frac{d \cdot \mathrm{ctg}\,\alpha_k}{2}) \tag{6.20}$$

Subsequently, the depth of the ice gouge can be calculated according to the equation:

$$F_{dw} + F_{dc} + F_i - F_a(d) - F_{cx}(d) = 0 \tag{6.21}$$

Table 6.7. The calculation results of diameter selection

Data			
Flow rate	q	120	MMsm3/day
Hydraulic friction coefficient	λ	0.0093	-
Pipeline length	l	170	km
Inlet pressure	p_1	14	MPa
Outlet pressure	p_2	3	MPa
Specific gravity	γ_a	0.66	-
Compressibility fact	z_a	0.84	
Average temperature	T_a	333	K
Distance	l	170	km
Dynamic viscosity		0.0000016	Pa·s
Roughness	k	0,03	mm
Iteration process			
Hydraulic friction coefficient iteration	λ_i	0.0093	-
Reynolds number	Re	765570624	
Results			
Internal diameter	d	1154	mm

Table 6.8. The estimation of parameters for temperature distribution along the trunk pipeline

Estimation parametres			
Initial temperature	T_1	323	K
Environmental temperature	T_e	271	K
Exponential parameter for water	a_w	3.4e-05	-
Exponential parameter for soil	a_s	3.2e-05	-
Heat transfer coefficient for water	k_{wa}	0.026	W/m^2K
Heat transfer coefficient for soil	k_{sa}	0.022	W/m^2K
Thermoconductivity for steel	λ_t	47	W/m·K
Thermoconductivity for coating	λ_c	0.16	W/m·K
Pipeline wall thickness	t	32	mm
Corrosion coating thickness	t_c	6	mm
Heat transfer to water	α_w	674.1	$W/m^2 \cdot K$
Heat transfer to soil	α_s	199	W/m2.K
Prandtl number for water	Pr	12.21	-
Water kinematic viscosity	ν_w	1.8e-06	m/s^2
Water heat capacity	C_{pw}	3900	J/K
Water density	ρ_w	1034	kg/m^3
Current speed at seabed	u_r	0.5	m/s
Water thermoconductivity	λ_w	0.6	W/m·K
Gas heat capacity	c_p	2.637	J/K
Joule-Thompson coefficient	D_i	2.6	K/MPa
Average pressure	P_a	9.68	MPa

APPENDIX F. FMECA WORKSHEET OF SUBSEA PRODUCTION SYSTEM

Description of unit			Description of failure			Effect of failure		Likelihood	Severity ranking	Risk-reducing measures
Ref no.	Component / Function	Operational mode	Failure mode	Failure cause or mechanism	Detection of failure	Local effects	Global effects			
1	Fibre cable/ signal transmission	Single/ multi	Fracture	Stress corrosion or fatigue due to microcracks	Loss of signal	No signal	Monitoring system fails	E	3	Threshold tension less than 0,33% tested tensile strength
2	Manifold/ control module, tie-in	operated/ non-operated	Leakage in tie-in points	Integrity of seal not provided	Visual	Hydrocarbon leakage, loss of flow	Environment pollution	B	4	Good design for seal assembly
			Loss of function	Control system does not work properly	Monitoring of production	Stop of production	Loss of production	B	4	Proper design
3	Power line/ provide electrical power	High voltage	Broken line	Stress or fatigue	Voltage drop	No power	Stop production	B	3	Reduce tension, proper design
			Loss of function	Low insulation resistance, cooling system failure	Loss of power	No power	Stop production	C	3	Check for insulation and system cooling
4	Xmas tree/ control flow, monitoring, well access	Producing / standby/ test works	Leak out	Implosion of gas bubbles, loss of sealing	Visual	Small spill	Stop production from the well	C	4	Control for lubrication, relief pressure
			Loss of function	Erosion due to sand, internal corrosion	Monitoring system	Xmas tree damage	Stop production from the well	C	4	Sand control, injection of inhibitors
			Clogging	Gas hydrate formation due to incorrect operation	Increasing pressure stopped flow	Pressure increase	Stopped production from the well	C	4	Follow flow assurance strategy
			Burst	Failure during pressure testing walls thining	Visual, pressure gauge	Xmas tree damage	Hydrocarbon leakage	A	4	Proper material, follow instructions during pressure test
5	Valve actuator/ regulate flow	Open/ close	Failure to close while shut-in	Loss of spring capacity	Pressure gauge, flowmeter	Valve cannot be closed	Other barriers will be trigged	B	3	Design spring for lifetime, reduces pressure in HPU
			Leak in	Loss of insulation	Pressure gauge, flowmeter	Density of control fluid is changed	Pressure change in HPU	B	2	Adjust pressure in HPU
6	Hydraulic cable/ provide pressure	High / low pressure	Broken cable	Stress or fatigue	Pressure drop	Control system fails	Stopped production	B	4	Reduce tension, proper design

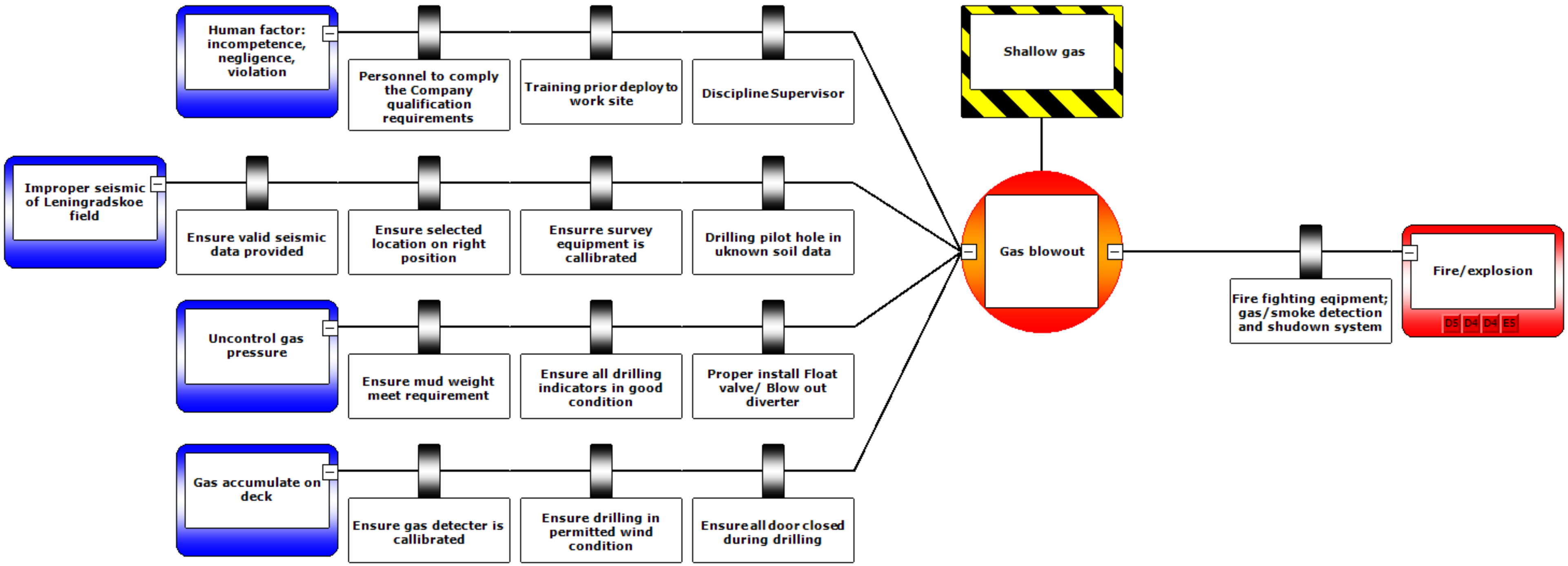
APPENDIX G. THE PRIORITIZATION OF R&D FOR LENINGRADSKOE FIELD

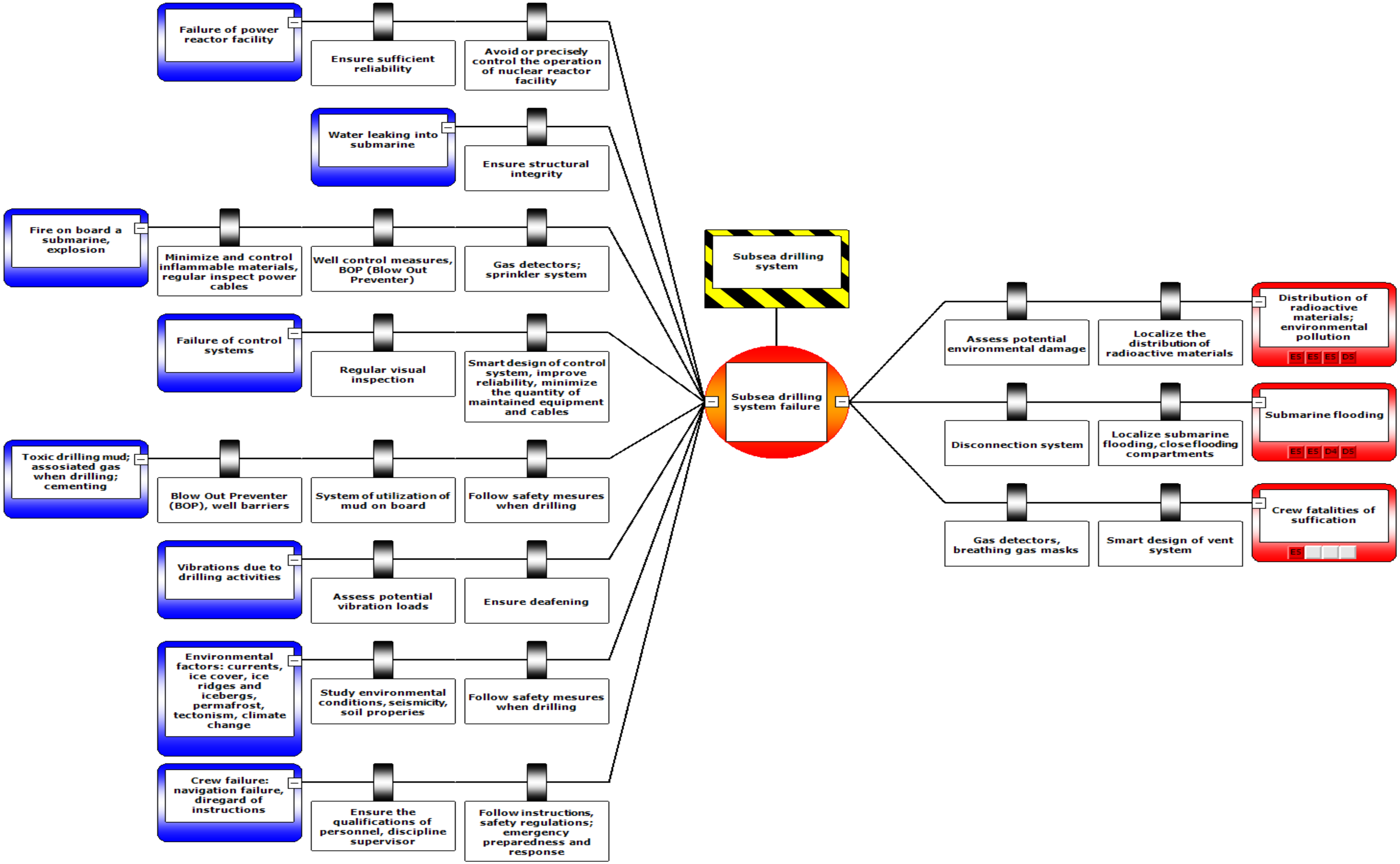
№	R&D opportunities	The prioritization of research issues and technologies					
		factor C (Relevance factor)	factor R1 (expected impact)	factor R2 (time to implementation)	factor R3 (state of knowledge)	Priority ranking factor	Priority ranking area
Drilling technical block							
1	Ice mechanics and loading studies	2	1	1	2	8	Medium Priority
2	Slim hole wells	2	1	2	2	10	High Priority
3	Riserless drilling	2	1	2	2	10	High Priority
5	Subsea drilling system	2	3	3	2	16	Very High Priority
6	BOP protection (from icebergs)	1	2	2	2	6	Medium Priority
7	Stationing-keeping in severe ice conditions	2	2	3	2	12	High Priority
8	Upgrade of drilling vessel hull strength	2	2	2	2	12	High Priority
Pipeline technical block							
10	Installation and operation of pipelines	2	2	1	2	10	High Priority
11	Enhancement of dredging and trenching technique	2	3	2	2	14	Very High Priority
12	Pipeline protection from shore erosion	2	2	1	1	8	Medium Priority

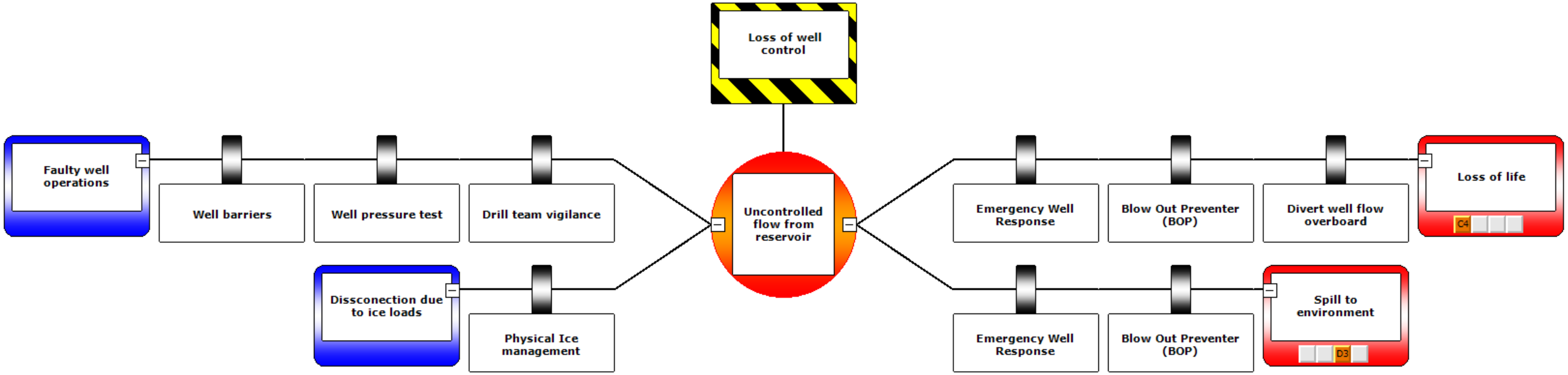
13	Pipeline inspection	2	2	1	2	10	High Priority
Production technical block							
14	Power system improvement	2	2	1	2	10	High Priority
15	Control system improvement	2	2	1	2	10	High Priority
16	Local power generation concept development	0.5	3	3	3	4.5	Low Priority
17	Subsea equipment protection	1	2	2	2	6	Medium Priority
18	Design of subsea equipment reducing weight	2	2	1	1	8	Medium Priority
19	New and innovative wellhead foundation solutions	2	3	2	2	14	Very High Priority
20	Subsea processing	2	2	1	2	10	High Priority
Technical block of logistics							
21	Weather «operational window»	2	2	2	2	12	High Priority
22	Ice Management	2	3	2	2	14	Very High Priority
23	Inspection, maintenance, and repair	2	3	3	3	16	Very High Priority
24	AUV/ROV operations in Arctic	2	3	2	3	16	Very High Priority
25	Offshore Safety, Evacuation, and Rescue in the Kara Sea	2	3	2	3	16	Very High Priority
26	New hydrocarbon export technologies (CNG, hydrates)	1	1	2	2	5	Low Priority

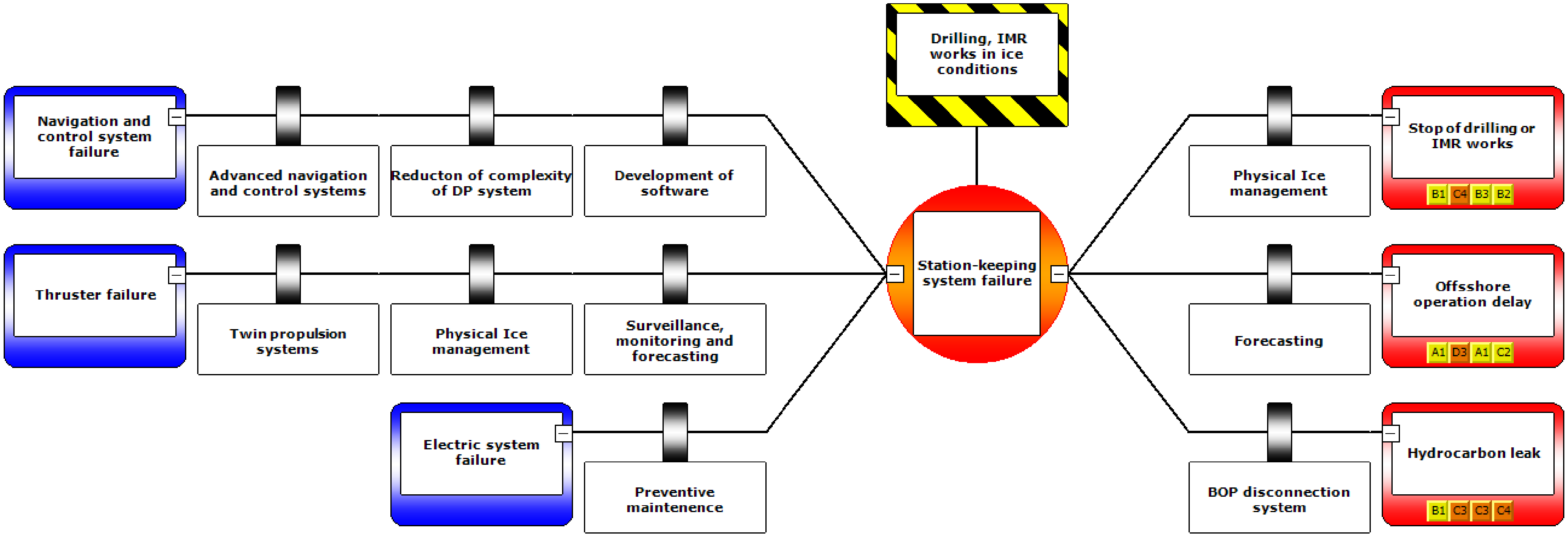
APPENDIX H. BOWTIE RISK ASSESSMENT

Main challenges in the drilling technical block

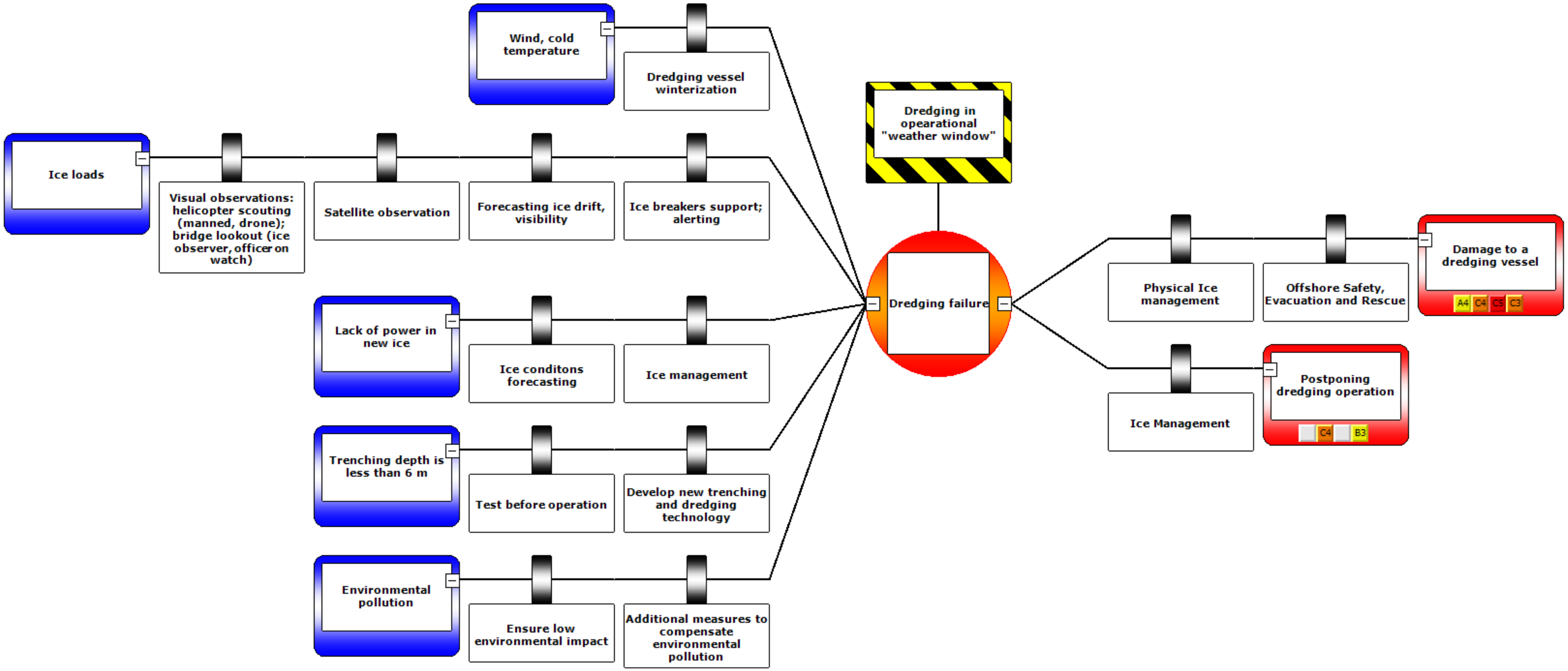


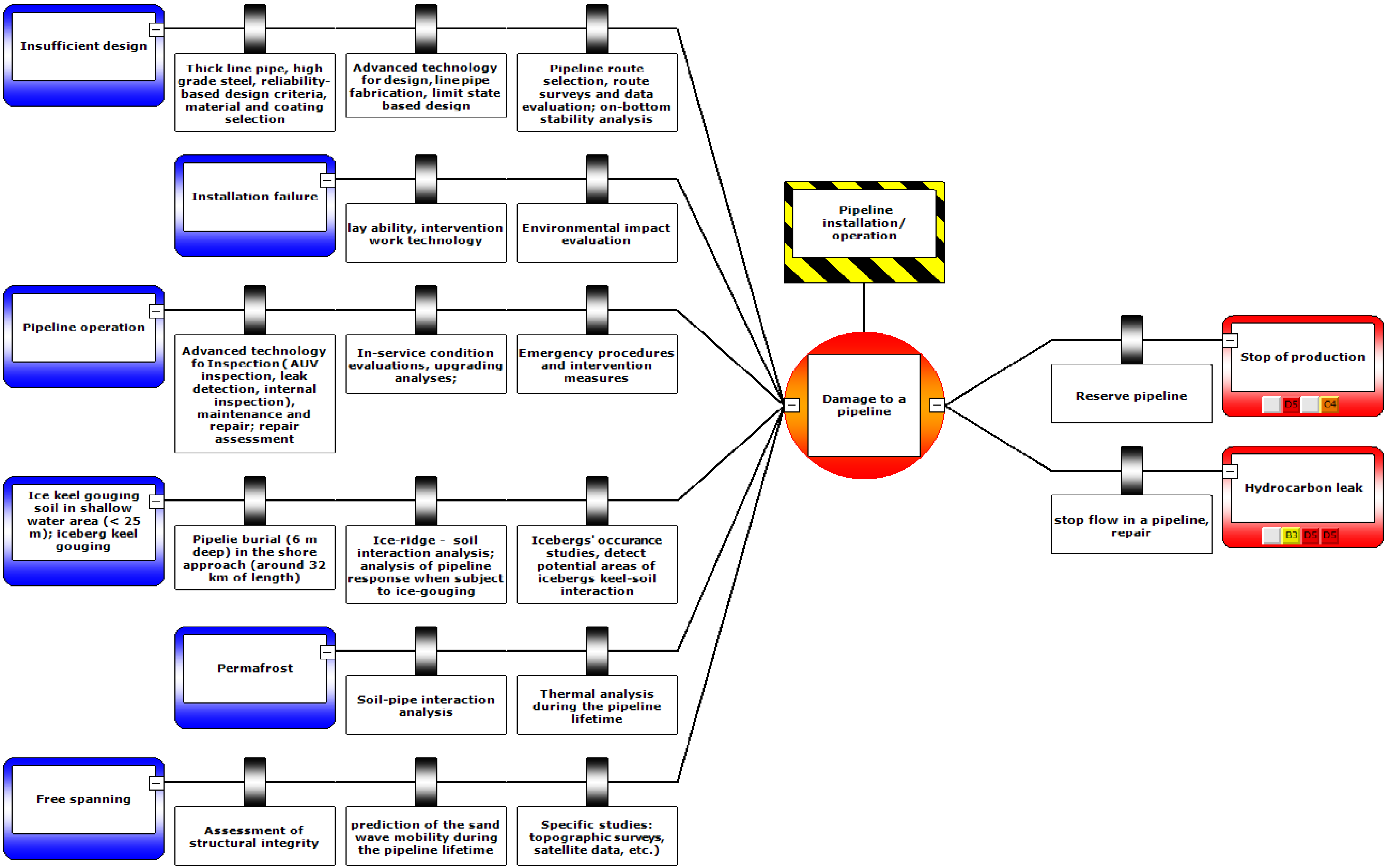

Failure of power reactor facility
Ensure sufficient reliability
Avoid or precisely control the operation of nuclear reactor facility
Water leaking into submarine
Ensure structural integrity
Fire on board a submarine, explosion
Minimize and control inflammable materials, regular inspect power cables
Well control measures, BOP (Blow Out Preventer)
Gas detectors; sprinkler system
Failure of control systems
Regular visual inspection
Smart design of control system, improve reliability, minimize the quantity of maintained equipment and cables
Toxic drilling mud; assosiated gas when drilling; cementing
Blow Out Preventer (BOP), well barriers
System of utilization of mud on board
Follow safety mesures when drilling
Vibrations due to drilling activities
Assess potential vibration loads
Ensure deafening
Environmental factors: currents, ice cover, ice ridges and icebergs, permafrost, tectonism, climate change
Study environmental conditions, seismicity, soil properies
Follow safety mesures when drilling
Crew failure: navigation failure, diregard of instructions
Ensure the qualifications of personnel, discipline supervisor
Follow instructions, safety regulations; emergency preparedness and response
Subsea drilling system
Subsea drilling system failure
Assess potential environmental damage
Localize the distribution of radioactive materials
Distribution of radioactive materials; environmental pollution
Disconnection system
Localize submarine flooding, close flooding compartments
Submarine flooding
Gas detectors, breathing gas masks
Smart design of vent system
Crew fatalities of suffication


Loss of well control
Faulty well operations
Well barriers
Well pressure test
Drill team vigilance
Uncontrolled flow from reservoir
Emergency Well Response
Blow Out Preventer (BOP)
Divert well flow overboard
Loss of life
C4
Dissconection due to ice loads
Physical Ice management
Emergency Well Response
Blow Out Preventer (BOP)
Spill to environment
D3

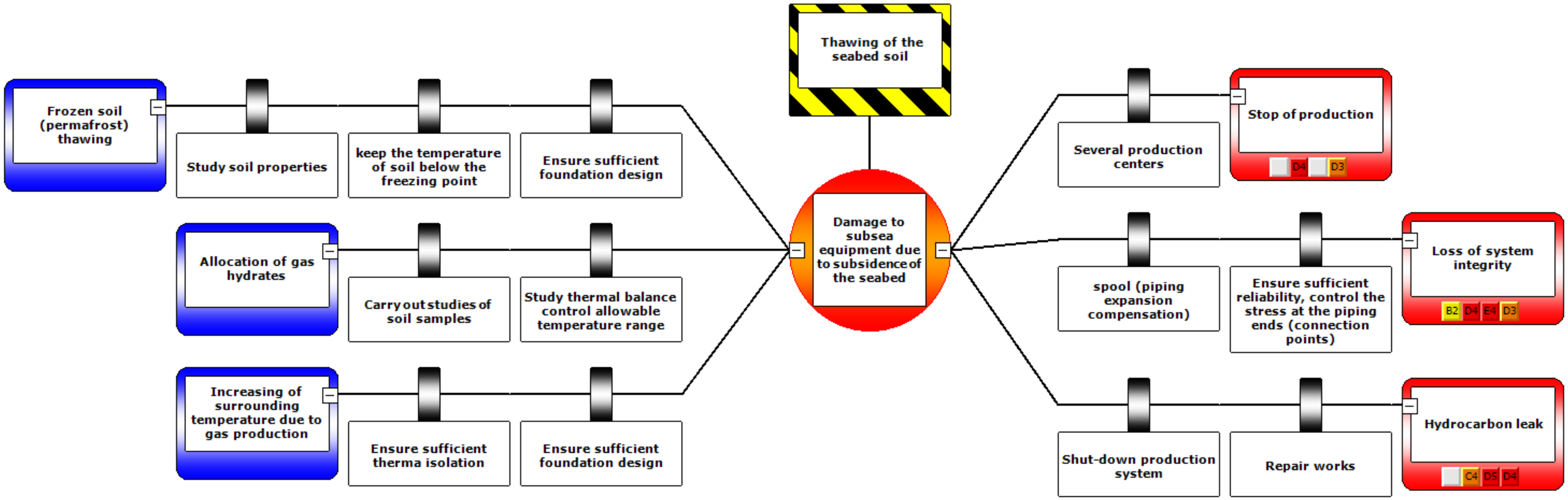

Drilling, IMR works in ice conditions
Navigation and control system failure
Advanced navigation and control systems
Reducton of complexity of DP system
Development of software
Thruster failure
Twin propulsion systems
Physical Ice management
Surveillance, monitoring and forecasting
Electric system failure
Preventive maintenence
Station-keeping system failure
Physical Ice management
Stop of drilling or IMR works
B1 C4 B3 B2
Forecasting
Offsshore operation delay
A1 D3 A1 C2
BOP disconnection system
Hydrocarbon leak
B1 C3 C3 C4

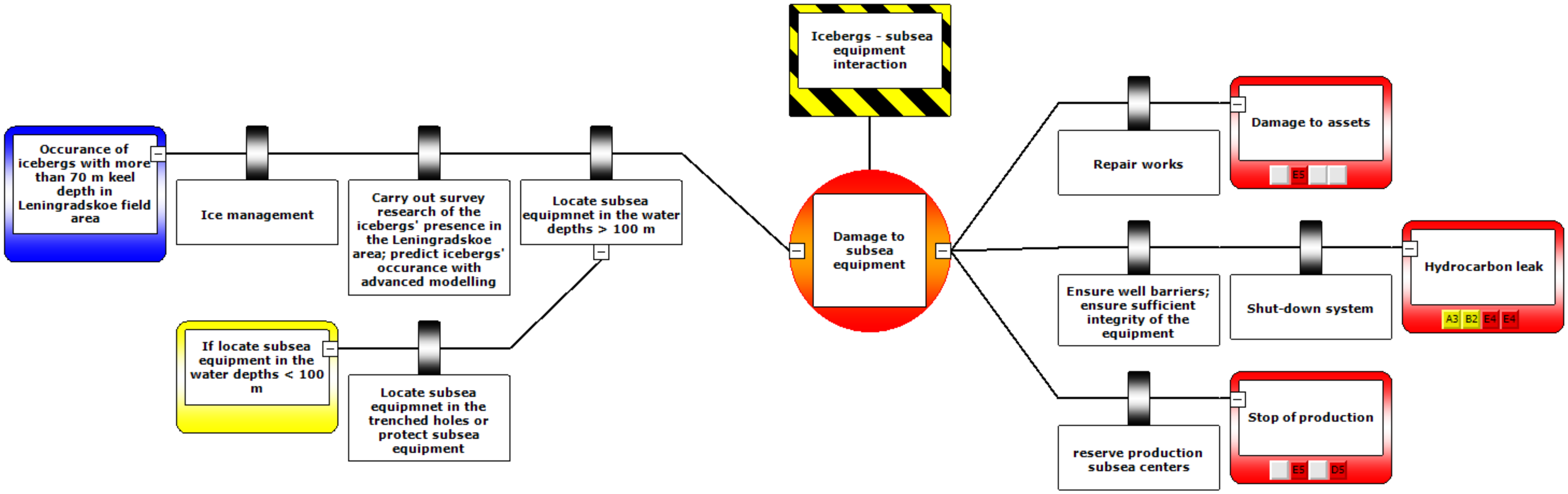
Main challenges in the pipeline technical block



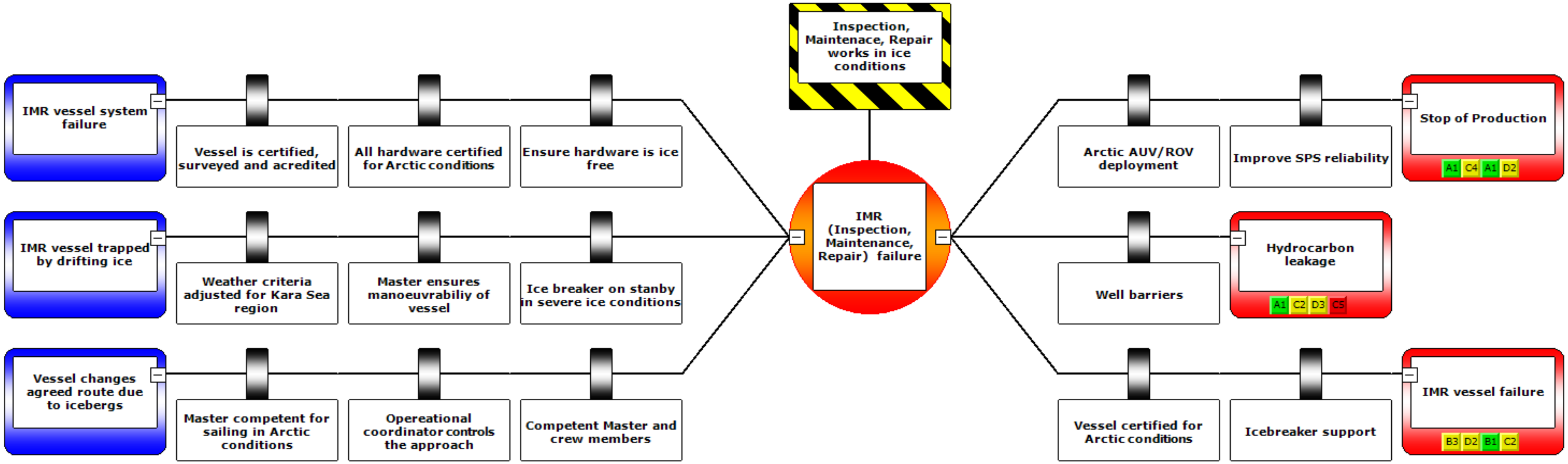

Insufficient design
Thick line pipe, high grade steel, reliability-based design criteria, material and coating selection
Advanced technology for design, line pipe fabrication, limit state based design
Pipeline route selection, route surveys and data evaluation; on-bottom stability analysis
Installation failure
lay ability, intervention work technology
Environmental impact evaluation
Pipeline operation
Advanced technology fo Inspection (AUV inspection, leak detection, internal inspection), maintenance and repair; repair assessment
In-service condition evaluations, upgrading analyses;
Emergency procedures and intervention measures
Ice keel gouging soil in shallow water area (< 25 m); iceberg keel gouging
Pipelie burial (6 m deep) in the shore approach (around 32 km of length)
Ice-ridge - soil interaction analysis; analysis of pipeline response when subject to ice-gouging
Icebergs' occurance studies, detect potential areas of icebergs keel-soil interaction
Permafrost
Soil-pipe interaction analysis
Thermal analysis during the pipeline lifetime
Free spanning
Assessment of structural integrity
prediction of the sand wave mobility during the pipeline lifetime
Specific studies: topographic surveys, satellite data, etc.)
Pipeline installation/ operation
Damage to a pipeline
Reserve pipeline
Stop of production
D5
C4
stop flow in a pipeline, repair
Hydrocarbon leak
B3
D5
D5

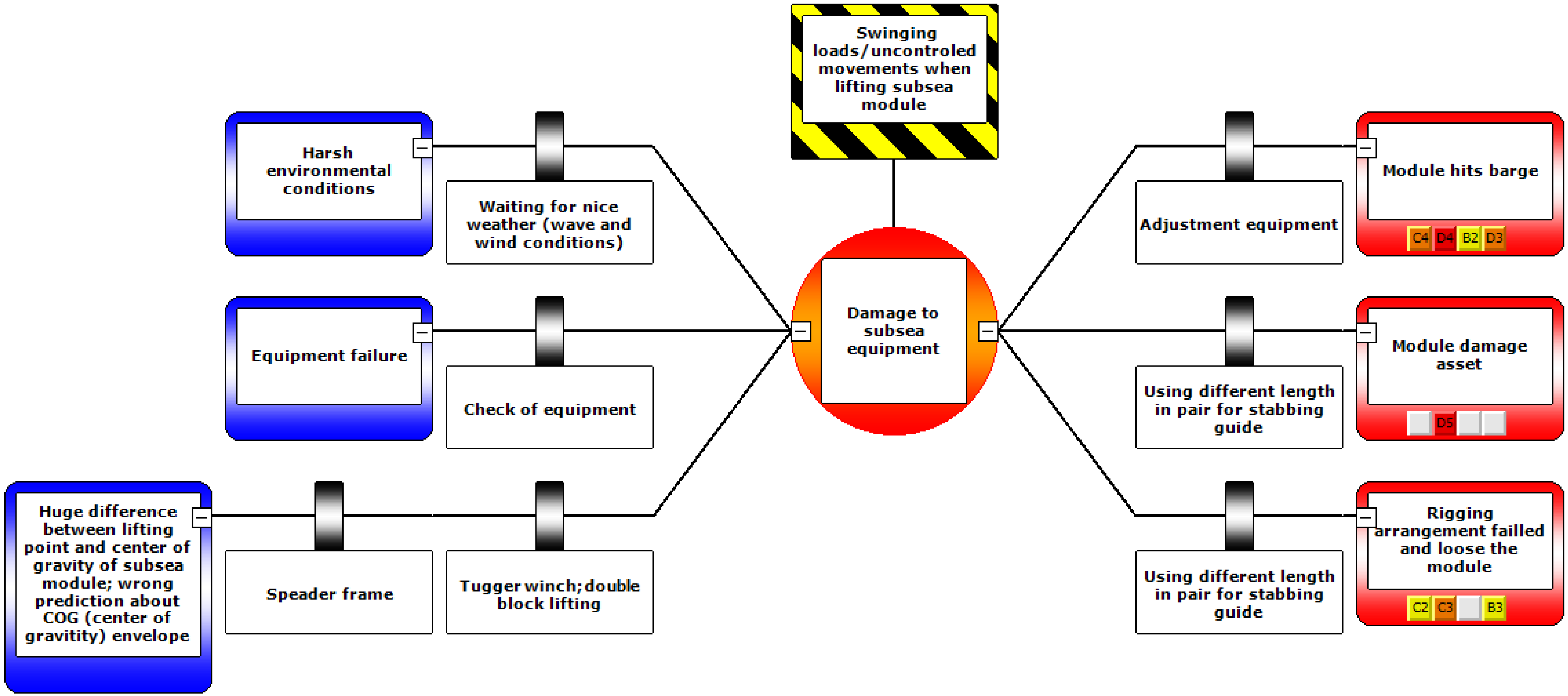
Main challenges in the production technical block




Icebergs - subsea equipment interaction
Occurance of icebergs with more than 70 m keel depth in Leningradskoe field area
Ice management
Carry out survey research of the icebergs' presence in the Leningradskoe area; predict icebergs' occurance with advanced modelling
Locate subsea equipmnet in the water depths > 100 m
If locate subsea equipment in the water depths < 100 m
Locate subsea equipmnet in the trenched holes or protect subsea equipment
Damage to subsea equipment
Repair works
Damage to assets
E5
Ensure well barriers; ensure sufficient integrity of the equipment
Shut-down system
Hydrocarbon leak
A3
B2
E4
E4
reserve production subsea centers
Stop of production
E5
D5

Main challenges in the infield logistics




Swinging loads/uncontroled movements when lifting subsea module
Harsh environmental conditions
Waiting for nice weather (wave and wind conditions)
Equipment failure
Check of equipment
Huge difference between lifting point and center of gravity of subsea module; wrong prediction about COG (center of gravitity) envelope
Speader frame
Tugger winch;double block lifting
Damage to subsea equipment
Adjustment equipment
Module hits barge
C4
D4
B2
D3
Using different length in pair for stabbing guide
Module damage asset
D5
Using different length in pair for stabbing guide
Rigging arrangement failled and loose the module
C2
C3
B3