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Abstract

The Master Thesis briefly presents the natural and climatic conditions of the Pechora Sea. The technologies of subsea production, the justified conditions of their use and their layout options are considered. The readiness of the domestic industry to produce components of subsea production systems is analyzed, existing equipment and prospects for its use are presented. Finally, a concept for developing a cluster of promising structures with the help of subsea production complexes is proposed.

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Abbreviations

XT – X-mas Tree

PLET – PipeLine End Termination

SURF – Subsea Umbilicals, Risers and Flowlines

TSR – Total Recoverable Resources

HC – Hydrocarbons

SPS – Subsea Production System

SPC – Subsea Production Complex

ARPD – Asphaltene-Resin-Paraffin Deposits

ITS – Integrated Template Structure

ROV – Remotely Operated Vehicle

TH – Tubing Hanger

CH – Casing Head

AZRF – Arctic Zone of the Russian Federation

GRP – Gross Regional Product

CDP – Common-Depth-Point

ORF – Oil Recovery Factor

DOOU – Direct Oil Offloading Units

NPV – Net Present Value

IRR – Internal Rate of Return

DPI – Discounted Profitability Index

Introduction

The development of the oil and gas sector in the Russian Federation is inextricably linked to the development of fields on the Arctic shelf. However, most of the explored and proven fields are located in very harsh climatic conditions, which imposes several technical problems, examples of which do not exist in world practice.

In addition to the direct impact of natural factors on the technological development process, some more subtle ones are associated with the huge capital costs of industrial realization.

For this reason, the oil and gas industry has set out to develop a technology that is suitable for the development of Arctic resources and that can demonstrate excellent technical and economic performance at the same time. Over time, subsea production systems have become such a technology.

Subsea production systems typically consist of:

- Wellhead equipment, including X-mas tree (XT), tubing hanger and subsea casing head system, etc.;
- Subsea pipeline and structure systems, including manifold, template structure, pipeline end termination (PLET) and protective structures;
- Production monitoring and control systems;
- Subsea umbilicals, risers and flowlines (SURF), including hydraulic, electrical and chemical lines;
- Subsea processing and transfer facilities, including subsea separators, pumps and compressors;
- Subsea storage systems.

The equipment of subsea production systems depends directly on the option and arrangement of the individual field.

1. Characteristics of the Arctic seas

When considering subsoil resources of the Arctic seas continental shelf located on the territory of the Russian Federation, one can confidently state that they are of special industrial interest.

The structure of initial total recoverable resources (TSR) of hydrocarbons of the Arctic shelf of the Russian Federation is presented in Table 1–1.

Table 1–1 Structure of the TSR of the Arctic shelf of the Russian Federation [1]

Oil, mln t	Dissolved gas, bln m^3	Non-associated gas, bln m^3	Gas condensate, mln t	Total HC, mln t fuel equivalent
13016,8	1262,7	95118,5	4504,2	113902,2

A general map of the Arctic seas with characteristic oil and gas structures is presented in Figure 1–1.

Figure 1–1 Arctic sea areas with characteristics of hydrocarbon deposits [2]

One of the main and fundamental characteristics for the analysis of water areas is resource availability in terms of natural, climatic, geographical and environmental conditions. This is a multi-layered parameter consisting of the following criteria [3].

Hydrometeorological conditions

This criterion is needed to assess the level of complexity of hydrometeorological conditions in the region, including the complexity of conditions for personnel work. It considers the impact of natural conditions on offshore oil and gas facilities and many marine operations.

Ice conditions

This parameter is one of the main criteria influencing field development concept, investment costs and operational costs. It includes characteristics such as ice type, average ice thickness and other variables. Moreover, this parameter influences the choice of technology for field development and protection methods for offshore structures.

Icebergs and the probability of their occurrence in the region

Icebergs are the most dangerous ice structure. They pose a particular threat and significantly increase the risks associated with the safe operation of production processes. Icebergs pose a problem not only for navigation but also for the operability of offshore oil and gas facilities.

Gas hydrates deposits

Gas hydrates pose additional problems for hydrocarbon production. The danger of such deposits prompted by thermal decomposition of 1 m^3 of such area; over 160 m^3 of gas is released [4]. These processes often occur during drilling and cementing of the well, as too hot drilling mud and cement significantly increase the temperature in the area of construction works, which changes the pressure-temperature conditions and inevitably leads to the degradation of hydrates.

Duration of the ice-free period

Since exploratory and production drilling generally takes place during ice-free periods, this criterion has a very strong influence on the conduct of these operations. In areas with a short navigation period, prospecting and exploratory drilling cost are significantly higher than in areas with the opposite conditions.

Depth of the sea

This criterion significantly influences the choice of the type of offshore structures. The problems associated with increasing sea depths should increase exponentially. However, shallow depths also present their problems, such as the ploughing of the seabed by stamukhas, which presents problems for subsea equipment and pipelines, and the high ecological sensitivity of coastal zones and coastal erosion [5].

Distance from shore

This criterion affects how hydrocarbons are transported. It is directly related to issues related to health and safety, namely the search and rescue of personnel in case of an emergency. It is these points that bring the importance of this criterion to a high level. This parameter is evaluated as the shortest distance from the water area to the shoreline.

Remoteness from supply bases

In the Arctic, logistics comes to the forefront, and it involves quite complex tasks. It is driven by the need for timely deliveries of equipment, materials, and products, as the process of uninterrupted and efficient production of hydrocarbon resources and the lives of the personnel involved in the process depend directly on this. This parameter affects the provision of the necessary equipment, transport and workforce for industrial plants.

Fauna and flora of the water area

This parameter is determined by the need to preserve the ecological balance in the region, as it is in direct dependence on the number and diversity of species of flora and fauna of the Arctic seas.

Potential environmental threats in case of emergency spills

This parameter reflects the potential damage that may be caused to the ecological balance in the event of an oil spill. It also reflects the potential for the balance to be restored to normal. Consideration of environmental factors is key to a conscientious and responsible approach to developing the Arctic seas.

1.1 Characteristics of the Pechora Sea

The object of the research in this Master's Thesis is the Pechora Sea. Therefore, the analysis of all the above factors will be carried out based on the characteristics of this water area.

Figure 1–2 shows detailed results of each criterion using the fuzzy clustering method [6].

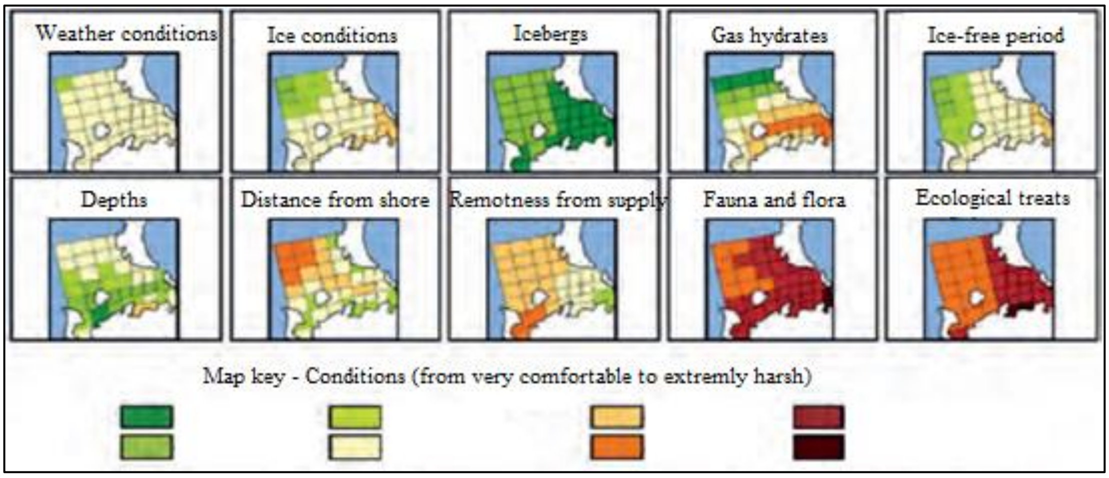

Figure 1–2 Characteristics of the Pechora Sea [6]

In addition to the criteria described above, it is very important to analyze the characteristics of the technological accessibility for offshore operations in the selected water area. The results of this analysis are shown in Figure 1–3.

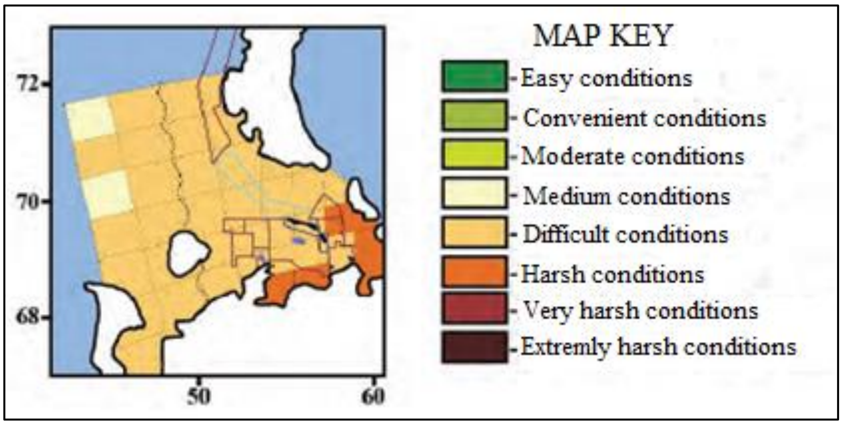

Figure 1–3 Map of technological accessibility of water areas [7]

A detailed study of the Pechora Sea and assessing the data obtained indicate that the region holds great potential for utilizing subsea production systems in its territory.

2. Establishing subsea production

2.1 History of subsea production technology

The use of production equipment from conventional fields was the original way of developing offshore fields.

In 1943, a subsea X-mas tree was commissioned in Lake Erie in the US at a depth of 10 metres without the construction of any specialized hydraulic engineering installations. The positive experience has made it possible to consider this installation promising, due to which the decision has been taken to develop scientific research and create the special equipment capable of operating in contact with water and performing the functions of the X-mas tree [8].

The technology of subsea production of hydrocarbons has its origin in the discovery by Shell Oil in 1961 in the Gulf of Mexico (West Cameron field) [9] at a depth of about 17 m of the X-mas tree, consisting of four valves with joints on bolts. The next stage of industrial development that made it possible to start developing offshore fields was in 1967 when Shell created the first subsea production system (SPS) using unmanned technology.

The installation of a subsea well production system in the Gulf of Mexico that included three sets of X-mas trees with a subsea tie-in device was another landmark event in the mid-1970s.

Between 1960 and 1974, about 106 wells with subsea completions were installed in various fields worldwide. The most famous is the Ekofisk field in the North Sea in 1971.

The global need for this type of technology indicates that 140 wells with subsea completion were in operation by 1978, and already in 1997, 200 wells were constructed.

In the early 1990s, engineers began looking for cost-effective ways to upgrade existing subsea production systems so that in the future, they could be integrated into existing offshore field structures in the most technologically advanced manner. Several fields in the North Sea offshore Norway, Sleipner and Heidrun, have realized these goals.

By the end of the 1990s, Statoil started to consider extending the technologies specific to the Norwegian continental shelf development, which was seen as a leader in subsea technology, to prepare for the commercial development of hydrocarbon fields on the shelves of other countries. These developments have led to the application of subsea technology in West Africa. Many major international companies have shown a particular interest in these solutions, which has provided an impetus for further subsea technology development.

The period 2005 to 2007 has seen many breakthroughs and ideas previously considered impossible, such as multiphase subsea pumps and separators. Scientists and specialists have developed reliable technologies that have made it possible to extract gas from fields as far away as the shore as Snohvit, 143 km offshore, using subsea technology. This prompted subsea production systems with gas piped directly to shore rather than to a platform.

The development of subsea production complex (SPC) technology has also made it possible to develop particularly deep fields. In 2010, the Perdido field in the Gulf of Mexico reached a record depth of 2.934 metres at the subsea installation site.

Of particular note is the Drake Point field, located in Canada in the Beaufort Sea. The first well was drilled there in 1978 in arctic conditions. The distance from the shore was 1.2 km, and the wellhead was at a depth of 55 meters [10]. The drilling was carried out from an ice platform specially adapted for Arctic conditions [11, 12]. A schematic representation is shown in Figure 2–1.

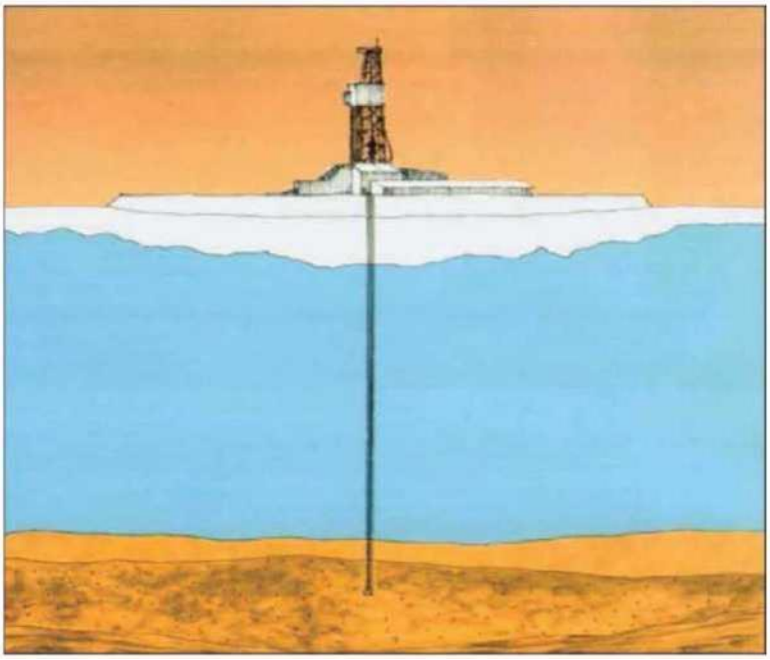

Figure 2–1 A general view of the first drilling rig and the first subsea well in the Arctic [12]

The project demonstrated methods applicable to the development of gas reserves in the Arctic and also proved the feasibility of subsea wells in these conditions. Drake Point also demonstrated that using ice as the basis for a working platform is a feasible concept.

Drake project also proved that gas could be produced from the Arctic shelf using remotely operated subsea wells, despite the presence of sea ice and difficult climatic conditions.

Industry experience shows that subsea production complexes are a very promising way to develop Arctic offshore fields.

2.2 Experience in utilizing subsea production systems

2.2.1 International experience

The problem of hydrocarbon development has recently been one of the most discussed topics among petroleum companies and scientists alike. The debate that has been going on about continental shelf hydrocarbon development regimes in the last ten years has become particularly acute. There is a need to analyze approaches in hydrocarbon development by the world states to find acceptable and effective approaches to hydrocarbon development.

The main prerequisites for the application of subsea technologies in the development of the continental shelf fields are:

- Reduction of the weight of the topsides of platforms and the possibility of developing a fully autonomous field;
- Increase of commercial attractiveness of the fields, especially those being developed at the profitability limit;
- Reduction of losses and energy costs associated with the need to lift products onto platforms;
- Improved environmental friendliness of the project.

Current world experience in offshore oil and gas field development demonstrates active development of subsea production technology. Foreign companies have a wide sector of competency in developing and implementing innovative technologies and, in particular, subsea production systems and control and data acquisition systems. This experience has been gained through participation in major offshore development projects using subsea completion equipment.

The main production regions where subsea production systems are used are:

- Gulf of Mexico (up to 3000 m depth);
- Brazilian shelf (up to 3000 m depth);
- Australian shelf (up to 2000 m depth);
- West African shelf (up to 2000 m depth);
- North Sea (up to 700 m depth);
- Seas of South-East Asia (up to 2000 m depth).

The above offshore oil and gas production areas are characterized by the use of a combined field design and the ability to operate in deep water, and the absence of severe climatic constraints on the use of floating production platforms.

The use of subsea equipment in offshore oil and gas fields has a wide range of development, which is why the demand for it is actively growing, resulting in increased production and a search for new ways to upgrade the equipment. Overseas companies have developed a co-investment process to create capital-intensive technologies, while major operators co-fund new advanced solutions.

The global subsea production equipment market is measured by the quantity and quality of wellhead equipment, umbilicals and manifolds manufactured and delivered. Although contract terms are not universally disclosed, leading equipment manufacturers are publishing more and more information about their achievements in subsea production systems, which indicates the competition among its major players. The main companies with extensive experience in subsea equipment are TechnipFMC, Subsea 7, General Electric Company, Aker Solutions, Dril-Quip and OneSubsea [13].

The increase in demand for specific subsea equipment in the oil and gas market varies according to the demand for specific components. Figure 2–2 shows a graph of the growth in spending by major operating companies on this equipment by market segment in the following categories: subsea services, subsea equipment, and SURF.

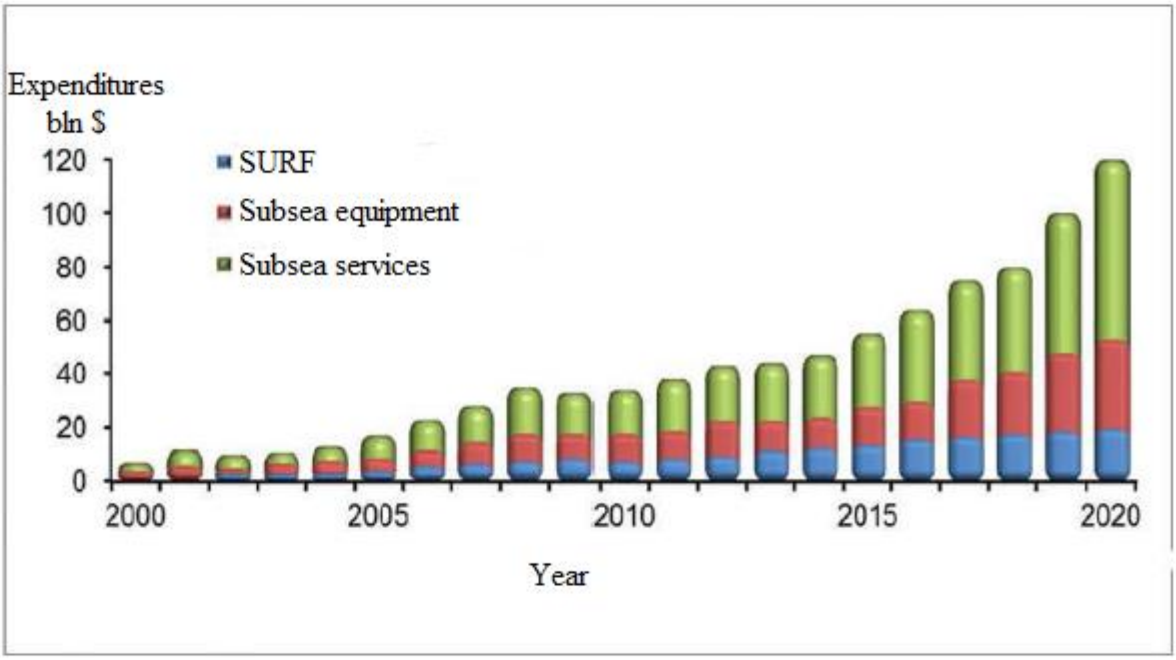

Figure 2–2 Expenditures by operating companies on subsea equipment [14]

Currently, the leading countries in the production and application of subsea production systems are the Norway, USA and the UK.

Most of the Norwegian oil and gas fields on the continental shelf commissioned before 2022 are projected to be equipped with subsea production systems. It is expected that by 2030, more than half of all oil and gas production will be produced with these SPSs.

2.2.2 Russian experience

Today, subsea hydrocarbon production equipment is produced by no more than 10 companies worldwide. As a result, Russia needs significant capital investment to create competitive import-substituting equipment. The situation is aggravated by FMC Technologies, Aker Solutions, Subsea 7, GE and other major equipment manufacturers who are not selling licenses but prefer to organize local production of the equipment under their strict technical control.

Russia's interaction with foreign specialized companies has led to a situation where the Russian industry has found itself in a technically difficult position amid complicated geopolitical processes. Therefore, mastering the production of innovative equipment by domestic enterprises will allow Russia to make a breakthrough and claim its niche in this global market segment.

Russian specialists gained their first experience in developing SPS design solutions during design work in the Shtokman field. Between 2007 and 2012, engineering surveys were carried out, and a full package of design documentation for all SPC equipment of the Shtokman project was generated.

Russia applied subsea production technologies for the first time relatively recently - during the development of the Kirinskoye gas condensate field located on the Sakhalin shelf.

The Kirinskoye gas condensate field subsea production system consists of seven subsea wellheads, a gathering manifold, a system of pipelines and umbilicals, an ethylene glycol supply line and an onshore control platform. All subsea equipment is controlled from the shore employing umbilicals.

The design solution was developed and implemented by FMC Technologies, Inc. Several Russian companies, such as Gazprom Dobycha Shelf, Gazflot and Mezhregiontruboprovodstroy, were involved in the field development, also gained unique experience.

As a starting point in the history of applying subsea production systems on the Russian shelf, commercial gas production at the Kirinskoye gas condensate field started in 2014.

2.3 Offshore fields arrangement

To reveal the most rational development scheme, it is necessary to consider all possible ways for field arrangement [15]. This type of analysis enables selecting the most effective field options or combinations of options, depending on the field area's geological and technical and climatic conditions. When considering the Arctic shelf, the most effective are subsea and sea surface development methods and their combinations.

When arranging the sea surface development method, the whole range of technological operations is performed at sea surface sites. The most common facilities for surface production are fixed and floating platforms of various types. They house both production wellheads and drilling and processing equipment and energy facilities, living quarters, and much more.

If we consider the subsea method, all pre-drilling operations are performed using semi-submersible or jack-up drilling rigs with subsea wellheads, and all processing facilities required for gathering, processing, storage and transportation of oil and gas are located directly on the sea bottom. This method of arrangement uses remote control of subsea complexes and wells. Although subsea production is currently one of the promising areas for deepwater field development, it is relatively new to Russian offshore field development practice. Figure 2–3 shows a schematic diagram of subsea field development.

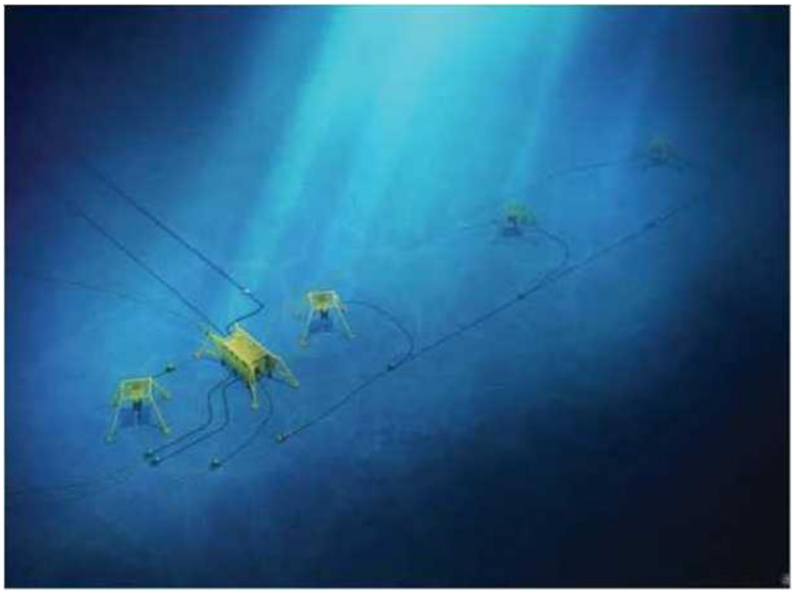

Figure 2–3 The scheme of subsea field development [16]

The distinctive feature of this type of field development is the use of a subsea completion system based on the placement of the wellheads on the sea bottom. Subsea telecommunications and control systems, oil and gas production gathering, processing and transportation system equipment are placed in the same way. Onshore structures and fixed or floating platforms can serve as the control and power supply centre for subsea production.

The inherent advantages of this method of arrangement are:

- Relatively high rates of commissioning the field to its technological capacities;
- Intensive development of the field through flexible installation and replacement of equipment;
- All-season and uninterrupted production due to the absence of direct ice impact;
- Greater adaptability to the development of fields with different geological configurations and reserves.

In terms of disadvantages, they are:

- Limited depth of use;
- Restrictions on the distance to the main sources of energy supply;
- High cost of well construction for arctic conditions;
- Complications caused by transportation of fluids without prior preparation.

But despite the factors mentioned above, it is important to note that implementing SPS often makes it possible to avoid the construction of capital-intensive platforms, which can comprise more than 50% of the total field development cost [15].

However, an important technological aspect in selecting a subsea production system is that it is more susceptible to the formation of gas hydrates and the deposition of asphaltene-resin-paraffin (ARPD). This problem is exacerbated by the low temperatures of the Arctic seas and the remoteness from the main supply hubs.

It should be noted that offshore development with SPCs is highly promising for deepwater areas, both ice-free and ice-covered seas, for most of the year. The favourable factors for this technology will be described in more detail in the next subchapter.

2.4 Favourable factors in the use of SPSs

When developing offshore fields with subsea production complexes, various natural and climatic factors must be taken into account to justify the feasibility of the technology.

The remoteness of the field from the shore is one of the significant factors when choosing a developing scheme. The purpose of extracting hydrocarbons from the deposit is to deliver them to the consumer. We should not forget that an important factor in pipeline transportation is pressure losses, mainly dependent on the length of a pipeline. Booster units are installed in the pipeline section to compensate for this, which inevitably incurs additional costs. Therefore, if the distance between the field and the main consumers is too great, subsea production is inferior to a combined production [17].

The option of using subsea production is worth considering in the case of not very long distances to shore or supply structures, where the pressure losses do not exceed the allowable standard values.

Sea depth is also a significant factor when considering the concept of development with subsea production systems. The depths of Russia's Arctic seas vary considerably. At depths less than 30 m, there is a risk of ice impacts, which is a huge problem for the entire production process. But already at depths of more than 50 m, SPC installation is an economically and technically justified solution.

The duration of the ice-free period affects well construction, which imposes time costs on putting the field into commercial production. Moreover, with a short ice-free period, access to subsea equipment and wells is virtually impossible. The ice period also imposes restrictions on planned and unplanned workovers.

Drifting hummocks and stamukhas is another problem in the Arctic seas. The high threat of mechanical damage to SPSs forces additional protective measures to be taken. For example, dredging at the installation sites or protecting the system with a caisson with a cover. However, the best solution is not to install subsea production systems in ice-affected areas.

Favourable environmental factors will include:

- A short distance from the shore or supply bases;
- Sufficient water depth (≥50 m);
- The long duration of the ice-free period;
- No ice impact on the SPS.

Thus, when approving a development program for the Arctic seas shelf, analyzing the natural and climatic conditions should be carried out. Subsequently, both favourable and unfavourable conditions for the implementation of the subsea production concept should be identified.

2.5 Layout options for subsea production systems

To date, there are more than 130 offshore fields in the world that use subsea production technology. At the same time, these technologies are used in combination with platforms or floating production systems and independently in fully autonomous subsea production. SPS has become widespread worldwide thanks to improvements in operational parameters and reliability of both the subsea equipment and the technological systems that support and ensure its operation.

The following are examples of subsea production system layouts that are used worldwide:

- Systems with individual wells;
- Systems formed by a manifold and a cluster of individual wells;
- Systems installed on an integrated template structure (ITS).

Figures from 2–4 to 2–6 show the SPS layout options.

Figure 2–4 General view of a system consisting of individual wells [18]

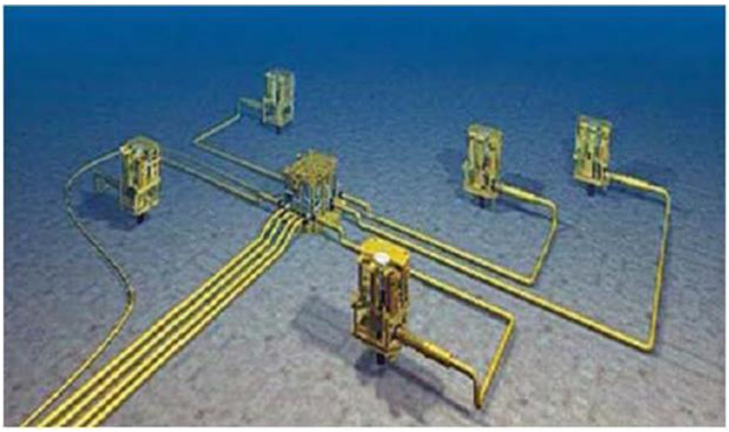

Figure 2–5 General view of a system consisting of a manifold and a cluster of wells [19]

Figure 2–6 Integrated template structure with eight well slots [20]

The type of SPS arrangement choice depends on various factors, such as the size and geological features of the field, the water depth at the installation site, and the distance from the shore or platform.

International practice shows that the most promising layout method, especially for arctic conditions, is field systems [8], installed on an ITS, on which a cluster of wells, manifold and control systems are located.

All wellheads and manifold pipelines and chemical control and metering units are integrated into a monolithic structure in a production complex. One should be kept in mind that the dimensions of the complex are limited by the transport capabilities of delivery and installation. There are advantages and disadvantages inherent in each SPS arrangement, which will determine the effectiveness of the individual complex.

Summing up the analysis of the design and layout of subsea production systems in relatively shallow and frozen waters, it can be concluded that using these systems significantly reduces capital investment in oil and gas field development and expands the drainage area, thereby increasing hydrocarbon production. This leads to a significant increase in the recovery rate and consequently to improved field development efficiency. This is why at present, SPSs are becoming more and more common in offshore developments.

3. Designing domestic technology for subsea production

In June 2017, at the St. Petersburg International Economic Forum, Gazprom PJSC and the Ministry of Industry and Trade of the Russian Federation signed an agreement “On cooperation in creating domestic SPCs”. This cooperation resulted in the organization by the Ministry of Industry and Trade of Russia in 2017 of a series of research and development activities (R&D) within the framework of the RF State Programme [21], aimed at creating ten key types of SPS equipment. Among them: wellhead equipment, control system, manifold, tubing hanger, umbilical, PLET, pig launcher and intelligent devices, equipment connection system, well access system. Gazprom 335 LLC acted as an integrator to ensure the compatibility of the equipment designed in various R&D activities. Each enterprise faced common challenges determined by a significant gap of the domestic industry in designing and manufacturing equipment for offshore fields: lack of experience, some key technologies and materials, domestic normative and technical documentation, calculation methods, testing facilities; shortage of experienced personnel; unavailability of some foreign components due to sanctions and many others.

3.1 Gathering system equipment

The gathering system equipment is an integral part of the subsea production systems that ensure continuous fluid gathering from the wells and transportation to the shore via subsea pipelines. The gathering system comprises manifolds, ITS, PLET, inline tees and subsea booster stations.

3.1.1 Manifold

A manifold is a system of inlet and distribution headers and branch lines. Its main functions are a collection of formation fluid from wells and distribution of chemical agents to wells. The manifold foundation ensures that all kinds of stresses can be absorbed and transferred to the ground during operation without performance loss. It ensures that the manifold is set to the required position. Figure 3–1 shows a prototype of a manifold that domestic manufacturers designed.

Figure 3–1 Manifold prototype [22]

SPMBM Malakhit JSC is the main contractor for the R&D “Manifold”. Izhorskiye Zavody PJSC became a production site for manufacturing, assembling and testing a prototype manifold and a manifold foundation. MosTsKBA OJSC and Kurganspetsarmatura CJSC manufactured the nipples for the manifold and the dump valve for the levelling system. PTPA JSC delivered subsea stabbing valves and slide valves. TD Galion JSC was engaged as a manufacturer of pipeline parts using the hot isostatic pressing method. Large machine-building and metallurgical enterprises such as ChTPZ JSC, Ruspolimet JSC, Petrozavodskmash JSC, Severstal PJSC became the suppliers of materials and some finished equipment.

While carrying out the R&D “Manifold”, specialists of SPMBM Malakhit JSC and Gazprom 335 LLC developed original technical solutions, the novelty of which was confirmed by a patent for invention [23].

The manufactured manifold consists of the following main systems and elements: frame structures, pipeline system, operating and control system elements for remotely operated vehicles (ROVs), cathodic protection wear sleeves, plug kits, and connectivity systems. Manifold configuration depends on field architecture, so there are no universal solutions. Manifold foundation includes frame structures, piling, levelling system, removable ROV panel. Key elements of the manifold piping system are nipples, shut-off valves and fittings. The main material used in constructing these elements is two-phase austenitic-ferritic super duplex stainless steel with a mass content of chromium 25 % (Super Duplex 25Cr).

Izhorskiye Zavody PJSC manufactured the crucial components of the manifold, assembled and tested its systems. Izhorskiye Zavody PJSC specialists organized worksites to assemble steel structures, pipe junction, final assembly of manifold components and systems, certification of stainless steel and nickel alloy welding procedures, painting and storage of purchased parts.

3.1.2 PLET and inline tee modules

A pipeline end termination is a piping system with shut-off valves incorporated into the linear pipe to allow conjunction to the main SPS equipment through pipe inserts. The inline tee is usually welded into the main pipeline and provides one additional connection to the main pipeline later.

The general contractor for the R&D “Termination Devices” is Salavatneftemash JSC. Gazprom 335 LLC acted as an associate contractor in designing individual critical systems and elements and provided technical support for the entire project. Kurganspetsarmatura CJSC was hired as the manufacturer of the connection sleeve DN200 for the prototype inline tee, and Moltek LLC manufactured the connection sleeve DN800 for the PLET prototype. The project’s design involved relevant organizations: Vedeneev VNIIG JSC carried out modelling of SPS interactions with the soil, calculations of operational and installation loads were carried out by MRTS JSC, which has gain experience developing the Kirinskoye gas condensate field.

Compared to the manifold, the PLET and inline tee designs are simpler, primarily due to the absence of control system elements and small-bore piping. The ROV controls the shut-off valves of the PLET and inline tee.

The designed prototype consists of the termination unit with integrated frame structures, levelling frame and foundation. All three elements are installed individually on the seabed using a guiding system developed by Gazprom 335 LLC. Figure 3–2 shows a three-dimensional dismantled model of the PLET.

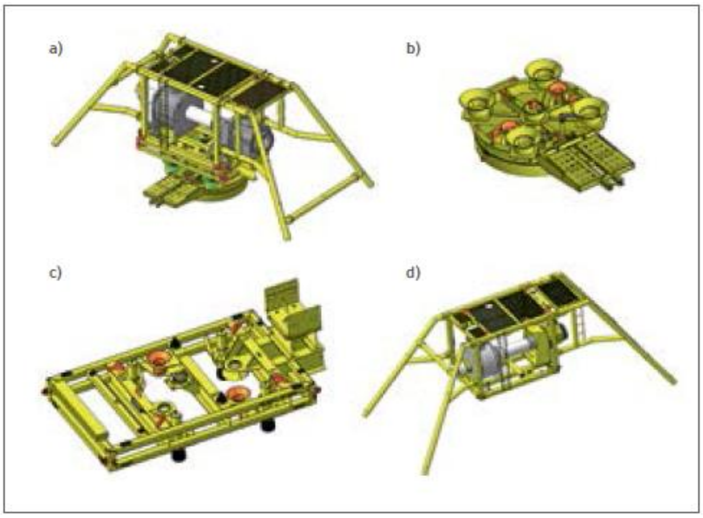

Figure 3–2 Three-dimensional model of the PLET prototype: (a) assembled DN800 PLET; (b) foundation (c) levelling frame; (d) termination unit with integrated frame structures [22]

The main functions of the foundation are to transfer loads to the ground and maintain the specified position of the equipment. The levelling frame is installed on the foundation. The four base jacks on the frame can be used to compensate for any deviation of the termination unit from the horizon, if necessary. The piping with the connection sleeve and the stabbing valve is integrated into the frame structure. The protective screen of the frame structure is made from glass-reinforced plastic with high strength properties and low specific weight. The PLET includes a soft touch-down system for up to 50 t of weight. The main actuator of the system is a soft touch-down cylinder. Four cylinders are located on the supporting frame, reducing dynamic loads during equipment installation [24].

The inline tee, consisting of a connection piping and a protective-support frame, is installed in one marine operation together with the pipeline. The protective frame design includes a hinged cover to access the interconnection system equipment for future connection. The piping with shut-off valves and DN200 connection sleeve is built into the protective-support frame. Figure 3–3 shows a three-dimensional model of an inline tee.

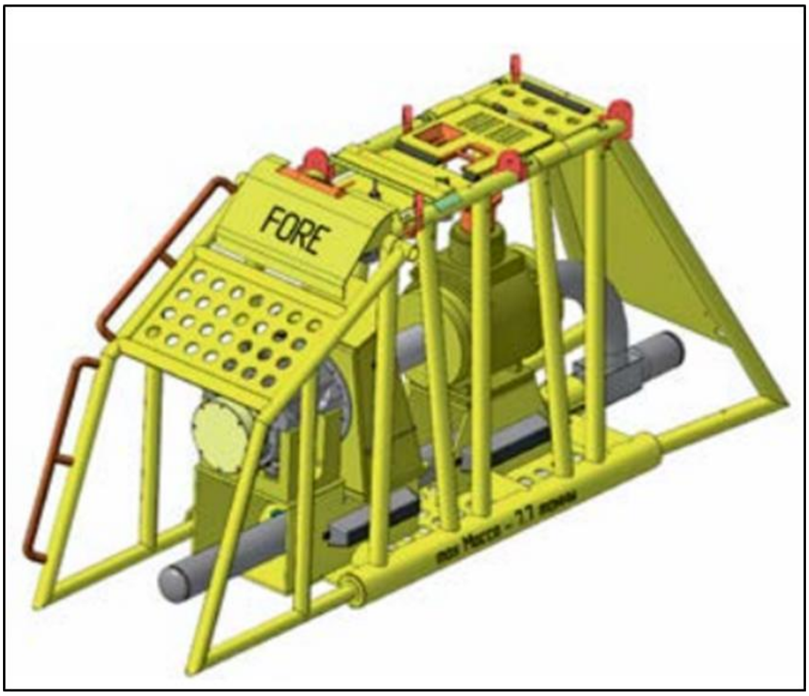

Figure 3–3 Three-dimensional model of a DN200 inline tee [22]

3.2 Wellhead equipment

Wellhead equipment is used for wellhead and casing hanger sealing. It comprises a subsea X-mas tree, tubing hanger (TH) and a subsea casing head (CH) system.

3.2.1 Subsea X-mas tree

Scientific Research Institute of Rubber Coatings and Products JSC was selected as the main contractor of the X-mas tree due to tendering procedures. It was in charge of the entire design, calculations and project documentation development. One of the associate contractors was Gazprom 335 LLC, whose area of direct responsibility was the conceptual design of the assembled X-mas tree, the subsequent control of works performed both by the main contractor of the R&D and the manufacturer.

The X-mas tree consists of a frame, an ROV panel; a valve bank; a wellhead connector; a production flowline; and a choke module.

The key technologies required for X-mas manufacture have been successfully developed and mastered through the joint venture of the manufacturer and Gazprom 335 LLC. For this purpose, Gazprom 335 LLC created technology requirements based on international standards and considered the experience of advanced foreign companies that manufacture equipment for subsea production systems and then adjusted them together with the manufacturing plant. Figure 3–4 shows the three-dimensional prototype model of the X-mas tree.

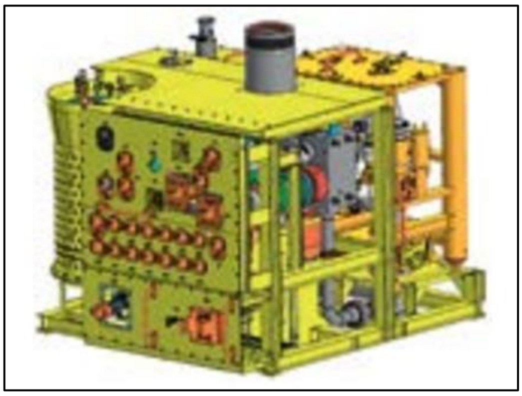

Figure 3–4 Three-dimensional model of the X-mas tree [25]

By the end of 2019, R&D had resulted in working design documentation and prototype testing using the methodology developed by the X-mas tree designer, making serial production possible.

3.2.2 Tubing hanger

Titan-Barrickady FNPC JSC acted as the main contractor of the project. During the R&D, the design documentation was developed, a prototype of the tubing hanger was manufactured and tested.

The tubing hanger consists of wireline chokes installed in the main channel of the tubing hanger, protection inserts for the main channel, various auxiliary tools and gobbing equipment. The prototype is shown in Figure 3–5.

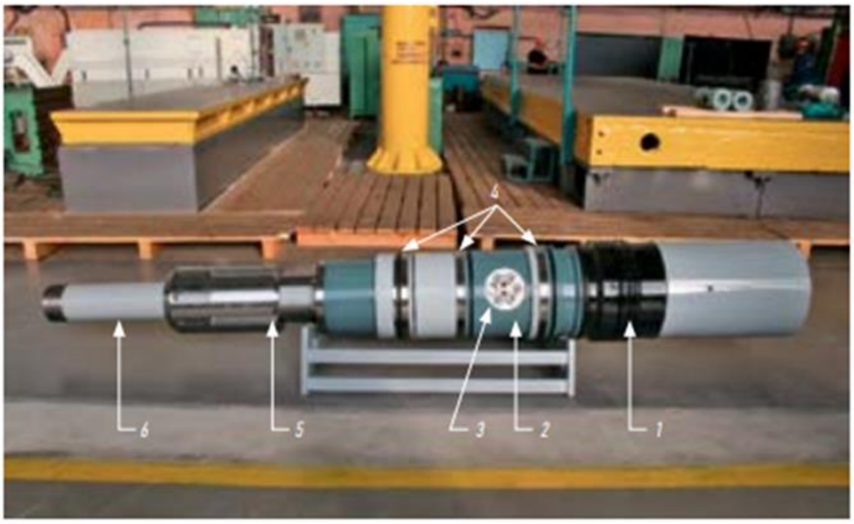

Figure 3–5 Prototype of tubing hanger, where: 1 – locking mechanism in valve bank body of X-mas tree; 2 – TH main body; 3 – penetrator unit; 4 – metal-to-metal seals; 5 – position unit; 6 – adapter [25]

Gazprom 335 LLC was one of the associate contractors whose area of direct responsibility was the conceptual design of the tubing hanger system and the subsequent control of the work carried out by the main contractor. In addition, Gazprom 335 LLC fully designed the tubing hanger lowering tool. It is used to run, install and test the tubing hanger in the wellhead equipment and retrieve it.

After passing the required certification procedures, the TH can be installed at a domestic field together with a production model of the XT and subsequently at fields in foreign projects.

3.2.3 Subsea casing head system

Scientific and Production Association on a Research and Design of a Utilities Equipment of I.I. Polzunov JSC acted as the main contractor for the R&D "Wellhead Equipment". The prototype was manufactured in 2019 at the same production site as the XT.

Gazprom 335 LLC was directly responsible for the conceptual design of the CH system and tool kit with subsequent control of the development schedule of R&D by contractor and manufacturing company of both individual components and assembly units, including approval of the scope of testing.

CH system consists of a casing hanger system with annular seals, creating secure access to the wellbore [26]. At the same time, the CH serves as a safety barrier and the main jointing unit for seafloor drilling and completion systems. Figure 3–6 shows prototypes of the CH system.

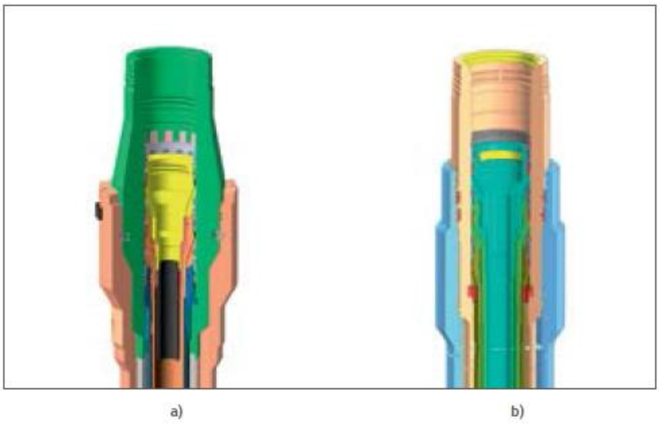

Figure 3–6 Prototypes of the CH system: (a) pilot; (b) pre-production [25]

After several modifications over the pilot prototype, a production prototype was manufactured, which meets the design conditions, performance characteristics and global standards for technical requirements.

3.3 ROV

Since 2015, the imposition of sanctions against Russian offshore oil and gas exploration and production projects has resulted in many foreign ROV manufacturers being uncooperative, including service issues for equipment already used [27].

Even though today, all the necessary technologies cannot be fully implemented in the Russian ROVs, the domestic industry has become less dependent on foreign components such as thrusters, power units, manipulators, sensitive elements over the past few years etc. This has reduced the technological gap, at least in the field of observation and working class ROV.

All Russian companies involved in ROV technology development can be roughly divided into two categories:

- Privately-owned companies: for example, Podvodnaya Robotekhnika LLC, Rovbilder LLC, and Marine Geo Service LLC. The companies are focused on producing serial equipment and components; their products can be freely used in oil and gas projects.
- State-owned military organizations for scientific research and import substitution programmes supported by various ministries and major petroleum companies. Products at these sites are often produced in single units or small batches, and due to various restrictions, cannot be widely used in third-party operations.

Although there has been a qualitative leap in the development of Russian subsea equipment over the last five years, the existing models do not fully meet the market's needs by their technical characteristics. Today 90% of Russian-made serial ROVs belong to the observation or working class, the application of which is limited while performing subsea engineering works. It should be noted that in RF territory, only Marine Geo Service manufactures serial ROVs of the working class. At the same time, no company offers ROVs of the heavy working class, so for the implementation of sophisticated subsea engineering projects in the petroleum industry today, only foreign-made ROVs are used. Figure 3–7 shows the full-scale working ROV class manufactured by Marine Geo Service.

Figure 3–7 Marine Geo Service's serial ROV [28]

The market of domestic serial ROVs started to develop relatively recently due to the peculiarities of technological development of this industry in the Russian Federation. It is mainly represented by small-scaled devices, which cannot be fully used for offshore subsea technical operation. Single proactive companies carry out the development of the working class ROVs; due to the sanction policy of the western countries, the issue of import substitution in the field of development and maintenance of all ROVs classes is acute. For the successful launch of new ROV models, it is necessary to ensure a continuous production and upgrade cycle, as well as to set up mass production of existing models and at the same time to reduce dependence on foreign components.

3.4 Prospects for Russian technology

The history of Russian SPS equipment is relatively young - only three years. During this time, Russian companies have demonstrated their capabilities in developing technology and equipment for offshore fields. At the moment, we are getting familiar with the serial production of some key pieces of equipment needed soon. Gazprom’s immediate plans also include the development of the Yuzhno-Kirinskoye gas condensate field using subsea production equipment.

Gazprom is considering using Almaz-Antey JSC equipment at the Yuzhno-Kirinskoye field, making it the first offshore field to use domestic subsea production systems. Successful testing of the domestic equipment will make it possible to develop the Yuzhno-Kirinskoye gas condensate field and later on in the Shtokman field and other fields that are planned to be developed using subsea facilities. In the near term, it will be possible to create a new industry in Russia that will produce and maintain SPS equipment, where international cooperation will be minimal to avoid already known and potential sanctions risks. It is necessary to build a chain of domestic suppliers as soon as possible and establish design and mass production in Russia of the entire range of SPS equipment. New drilling platforms, pipe-laying vessels, specialized support vessels and ROVs of various classes will be required to fulfil all the stated plans for subsea field development.

The development of the offshore fields where SPS equipment is used will require companies capable of performing service and maintenance, and these companies will require specialized equipment and service bases close to the fields.

Although Russian companies have been making strides in manufacturing domestic equipment for subsea production systems that perform and, in some respects, better than foreign competitors, there is still a long way to go in terms of research and development. The main motivation for Russian companies producing equipment should be to provide domestic offshore projects with the necessary equipment to create a new industry that will be completely independent of foreign technology in the future. All the prerequisites for this are already in place.

At this stage, the most evident and feasible is expanding the domestic competence to manufacture subsea processing and transfer equipment, such as subsea separation units, booster compressor and pump units, and subsea storage units.

It is worth mentioning that the vector of the orientation of the domestic industry towards the development of new industrial capacities in the Northern regions of the country. Creating the urgent infrastructure to reduce the costs of transporting manufactured equipment to production sites and increasing the socioeconomic impact of deploying new production facilities in the regions of Russia’s Arctic zone will have only a positive effect on the development of industry throughout the country.

These issues will be discussed in more detail in the next chapter of this paper.

4. Industrial development of the Arctic zone regions

According to [29], [30], [31], the vector of the country's industrial development for decades to come is predetermined. It consists of the development of industry and infrastructure on the territory of the regions of the Arctic Zone of the Russian Federation (AZRF).

The development of the Northern regions, where oil and gas fields are located, may consist of expanding the existing production capacities and creating a new centre of industry in the Russian industry relying on creating new technologies in areas with difficult climatic conditions.

The development of Russia's Arctic territories should be seen as a long-term, gradual process for the country to enter new development cycles. The development of the Northern regions is inextricably linked to sociodemographic and environmental problems [32].

The driver for Arctic zone development is the oil and gas industry. However, it is important to understand and take into account the integrated industrial development, to this end, to create diversifying industries because the Arctic is still in many ways a pioneering region in the development of potential resource and water areas.

Locating production forces in the new territories is conditioned by the appearance of specific economic opportunities, such as tax benefits and economic indulgences. On the other hand, attention to such areas is related to new geopolitical realities, disputes over the unevenness of global dispersion and distribution of natural resources, and increased pressure on countries with the largest natural resources [33].

The desire to make long-term, large-scale investments and thus ensure greater sustainability and economic growth leads to the initiation of ambitious projects to create new natural resources and create the infrastructure to develop them.

Large northern projects in the energy sector, including many diversifying industries, can work perfectly to benefit the whole country or individual region.

The factor of innovation-driven development of oil and gas projects should be considered because this will make it possible to most effectively address the issues of establishing new industrial facilities in the difficult conditions of the country's Northern regions.

4.1 Macroeconomic performance

Sustainable development of the Northern producing regions presupposes sustainable economic development.

When developing oil and gas fields, the following macroeconomic effects usually stand out:

- The attraction of a vast amount of investments;
- Propagation of modern technologies;
- Increase in budget receipts;
- Boosting local employment in the regions.

The above factors are components of the economic multiplier, reflecting the economic dependence between industries. A characteristic feature of the Northern regions is emphasizing the oil and gas industry as the generator of the investment wave, the vibrations from which are transmitted to related industries.

The multiplier principle is based on the linkage of different industries in the economy. If we try to convey its essence, it will be described as follows. For example, demand for subsea equipment triggers demands for metal, utilities and electricity. Then down the chain, the metallurgic plant increases the demand for ore and the power plants for gas. In this way, a whole series of investment waves are generated, which benefits the economy of the producing region and neighbouring areas.

The oil and gas industry causes high demand for the goods and services of related industries, which is expressed in the multiplication factor. For oil-producing countries, such as Norway, the USA and Russia, this indicator is 1.9, 2.0 and 1.8, respectively [34]. This fact once again indicates the prospects of oil and gas industry development in the Arctic regions of the country.

Thus, the oil and gas industry development in the Nenets Autonomous District will be felt by the economies of adjacent regions, namely, the Murmansk and Arkhangelsk Regions, the Republics of Komi and Karelia. According to the literature sources, each 1 currency unit of additional oil and gas complex production increases gross regional product (GRP) by 1.5-1.6 currency unit [35]. And this will subsequently lead to the growth of the tax basis, create jobs, and, consequently, increase consumer purchasing power. Figure 4–1 shows the spillover effects of offshore field development.

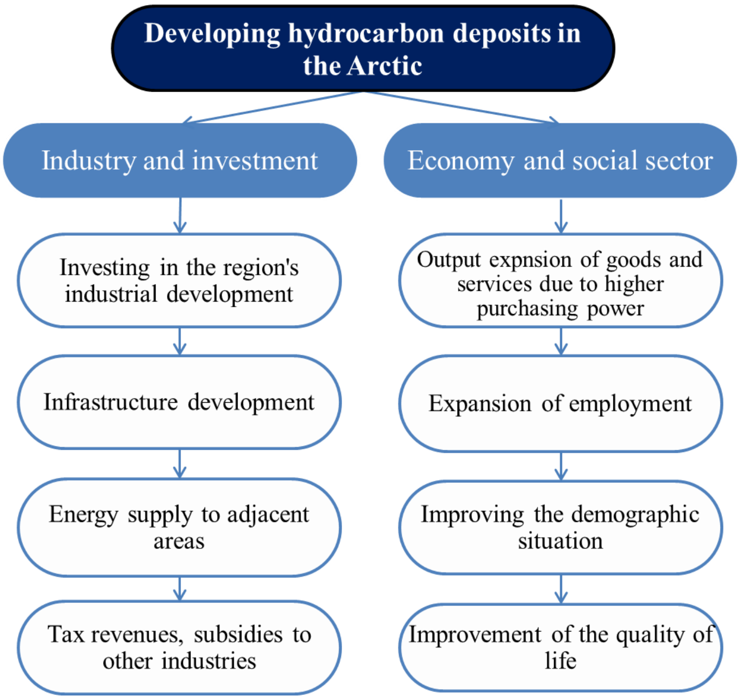

Figure 4–1 Indirect effect in the development of the Arctic offshore fields [35]

The factors and conditions created in the oil and gas industry development process can form a new economic structure of the Northern regions.

4.2 Import substitution policy

The oil and gas industry of Russia strongly depends on supplies of imported equipment and technologies. It is necessary to reduce the presence of foreign companies through a targeted import substitution strategy.

This strategy should be facilitated by local innovation design centres of manufacturing equipment for offshore and subsea production.

A notable example of implementing the import substitution strategy is the Association of Oil and Gas Industry Suppliers Sozvezdye based in Arkhangelsk and the Association of Arctic Project Contractors Murmanshelf based in Murmansk. The activities of these associations are the mainstay of a full-scale import substitution programme for offshore oil and gas production equipment.

It can be assumed that the Arkhangelsk and Murmansk Regions territories have good prerequisites for creating a supporting onshore complex to ensure the creation and operation of offshore systems in the Western Arctic. Moreover, due to high transport risks and significant cargo delivery costs carried out in the Arctic conditions, the most rational is to localize technological facilities at the shortest possible distance from transport communications.

At the moment, the RF authorities have a wide range of tools to implement the import substitution policy. And instead of the previously used forces of coercion, they apply a market-based approach [36] to increase the competitiveness of domestic technologies in the global market and create a favourable climate for business by introducing special trade benefits and production grants [37].

Noteworthy is the experience of Norway in offshore development, which has accumulated a powerful production basis and can meet its own needs in innovative technologies.

The strategy of the Norwegian government was to cooperate with foreign companies, followed by the training of their personnel and the localization of production capacities on their territory.

As a result, Norwegian companies have a significant share of the international market for subsea production systems.

A comprehensive solution to the complex problem of import substitution in the development of offshore fields is impossible without reorganizing the entire industry science, creating new and reorganizing old design-and-engineering institutes, and improving the system for the training of specialists.

4.3 Implementation of industrial clusters

The presence of isolated and closely located oil and gas fields connected by a single transport and service infrastructure system is an excellent condition for forming an industrial cluster.

A cluster comprises independent production or service enterprises, creators of innovative technologies, market institutions, and consumers, closely interacting with each other within a single value chain [35].

This concept becomes particularly relevant when addressing the strategic challenges associated with developing the Arctic regions, which have large reserves of hydrocarbons.

There are enough reasons to suggest that the technologically sophisticated development of offshore reserves can be carried out based on creating a cluster development model.

Clusters are mechanisms for increasing regional competitiveness, shifting to higher value-added production processes, and facilitating new linkages between enterprises.

The cluster approach is advantageous because it emphasizes the microeconomic component, the territorial and social aspects of economic development of the Northern regions. This concept offers an effective setup for the development of industrial regions, which will lead to increased competition of production systems and higher treasury income.

During the development of offshore fields, participants complementarity of the same cluster is easier to achieve when the companies are located close to each other. It is also obvious that integral parts of the cluster are research institutes that create innovative technologies in the specific field of the cluster.

Again, the experience of Norway, whose specific field was offshore development, is noteworthy.

Some oil and gas cluster formations were created on the country's territory [38], concentrated in certain regions. For example, Stavanger became the centre of well technologies; Bergen became the cluster for subsea equipment; Kristiansand became the cluster for drilling equipment.

When applying this approach to the territory of Russia, the location of industrial clusters in the Northwest Federal District seems promising. The region accounts for 10% of the territory and volume of industrial production. Most of the trade with Europe goes through the territory of the District.

While transferring the Norwegian experience, it is obvious that there are enough prerequisites for creating a ship construction cluster in the Murmansk or Arkhangelsk Regions due to existing production sites.

Today, the conditions for creating a cluster for offshore development and particularly for SPS are emerging in the Nenets Autonomous District [39].

Thus, the benefits from the creating of an industrial cluster in the territory of the Northern regions are:

- Increased investment attractiveness of the region due to the development of production infrastructure;
- Stimulation of economic development of the region;
- Increased competencies of the enterprises participating in the cluster;
- Reducing costs due to the cluster participants' proximity to each other;
- Simplification of the technology exchange system;
- Sustainable growth in income and employment.

4.3.1 Region selecting for implementing the industrial cluster

The Russian authorities have identified 8 support zones in 8 regions of the AZRF [40]. These include:

- Kola support zone (Murmansk Region);
- Arkhangelsk support zone (Arkhangelsk Region);
- Nenets support zone (Nenets Autonomous District);
- Vorkuta support zone (Komi Republic);
- The Yamal-Nenets support zone (Yamal-Nenets Autonomous District);
- Taimyr-Turukhan support zone (Krasnoyarsk Region);
- Northern Yakutia support zone (Sakha Republic);
- Chukotka support zone (Chukotka Autonomous District).

These zones were formed to create conditions for the industrial development of natural resources, improving transport infrastructure, development of the Northern Sea Route and business. Because of the development of ever new deposits on the continental shelf, these zones will be of long-term critical importance. Ambitious petroleum projects and the infrastructure associated with them are expected to become the growth drivers of the support zones.

The level of economic development of the regions is characterized through the GRP per capita. As shown in Figure 4–2, the highest value of this indicator is in the Nenets and Yamalo-Nenets Autonomous Districts, where the oil and gas industry plays a significant role in the industrial structure.

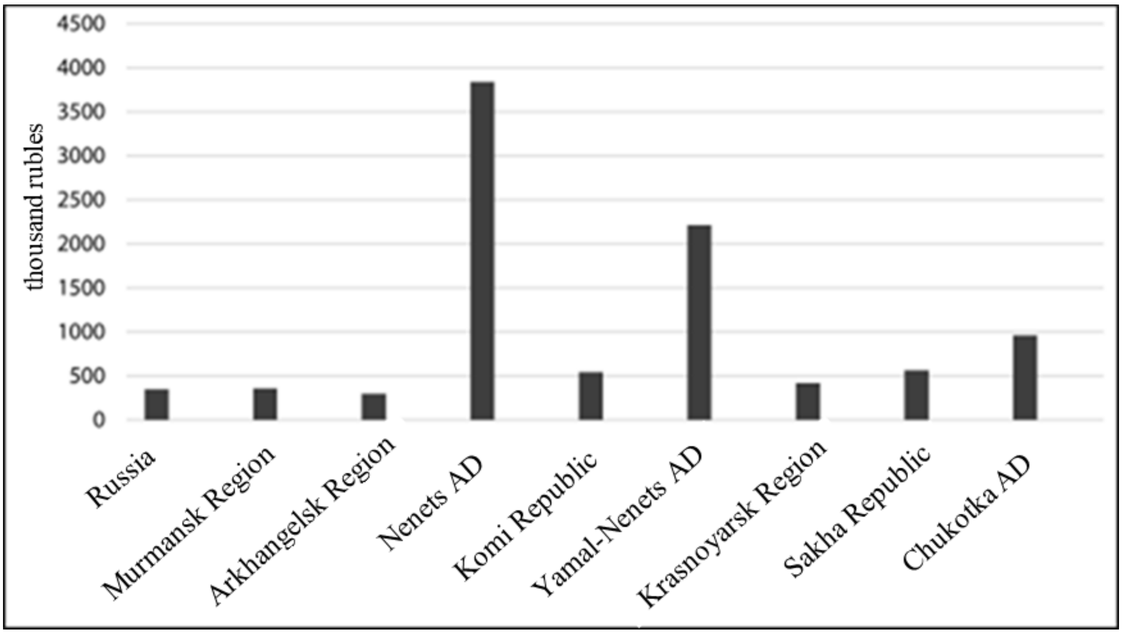

Figure 4–2 GRP per capita in the regions of the AZRF [41]

As noted in the previous subchapter, the Nenets Autonomous District (NAD) territory is a promising site ready for creating an industrial cluster to meet the needs of oil and gas production enterprises, particularly the production of equipment for subsea production systems.

The industrial potential of NAD in terms of implementation of oil and gas projects on the Arctic shelf cannot be overestimated. The peculiarity of this region lies in its geographical proximity to proven hydrocarbon deposits, with major industrial enterprises and scientific-research institutions located here.

All of this is complemented by the obvious competitive advantages of the Varandey transport hub, which make the NAD a promising base for the development of the Arctic shelf and the most important transport hub of the Russian Federation.

Table 4-1 provides a SWOT analysis of the industrial complex, which provides a comprehensive assessment of the conditions for developing the oil and gas industry in the Nenets Autonomous District.

Table 4-1 SWOT analysis of the industrial complex in the Nenets Autonomous District

Strengths: 1.Multifunctionality of the production complex 2.Strong competitive position on domestic and foreign markets for some products 3.Significant export potential 4.Extensive geographical spread of sales markets	**Weaknesses:** 1.Low diversification of industrial production 2.Poor development of high-tech industries 3.Limited capacity for self-financing and lack of investment 4.Insufficient qualification level of personnel
Opportunities: 1.Advantageous transport and geographical location of the region 2.Availability of promising new deposits 3.Participation of the region in various international programmes and projects 4.Special economic zones may appear in the region	**Threats:** 1.Remoteness of the region from the centre of Russia 2.Difficult natural and climatic conditions 3.Progressive out-migration 4.Fluctuations of world prices for oil and gas

Despite the existing weaknesses and threats, in almost all possible options for developing hydrocarbon fields of the Arctic shelf, the NAD will be a base region for hosting logistics bases and performing a wide range of operations, which is well within the economic performance of the region.

The development of Arctic seas deposits creates favourable conditions for creating an oil and gas cluster, especially subsea equipment cluster in the Nenets Autonomous District.

Thus, based on this section, it can be concluded that the sustainable industrial development of the Northern Regions of the Russian Federation will be facilitated by the comprehensive implementation of import substitution measures and the implementation of industrial clusters looking back and taking the best from the Norwegian experience in offshore development.

5. Development Concept

This chapter of the Master's Thesis will focus on a proposal to develop a promising oil cluster structure located on Gazprom Neft's Northwest license block using domestic subsea production systems. This block is located on the shelf of the Pechora Sea. There is every reason to suggest that the development of this license block in the future will be primarily a driver for the development of Russian subsea production technologies, together with the development of Nenets Autonomous District and its adjacent territories and water areas.

5.1 Block description

Gazprom Neft's Northwest license block is located on the shelf of the Pechora Sea. The nearest settlement on the coast is the Varandey village which is 100 km away. The nearest port terminal is located in the Naryan-Mar town, within 200 km away.

The license to develop this block was issued to Gazprom Neft in 2014 and runs until 2044. The target purposes of the granting are geological study, exploration and subsequent production of hydrocarbons.

The seismic survey of the area reaches 12809 linear kilometres of common-depth-point (CDP) method profiles. There are also no wells drilled in the block, and the closest wells are located in the Dolginsky license block. The Dolginskoye oil field is the closest discovered field.

There are no federal or regional special-purpose areas in the Northwest license block.

The terms of the licence agreement stipulate the following scope of geological prospecting and exploration activities in the area:

- To collect and analyze geological and geophysical data on the area within two years;
- To agree and approve, as appropriate, the project plan of prospecting and evaluation works no later than the third year from the commencement of the licence;
- Commence 3D seismic surveying no later than the fourth year from the commencement of the licence and within the next four years to carry out a scope of work equal to at least 1000 km^2;
- Start the construction of an exploration well no later than the eighth year from the commencement of the licence and complete its construction within two years.
- Guarantee the performance of the whole complex of works on exploration and evaluation of hydrocarbon deposits during the geological phase study determined by the ten years from the start of the license, following the prospecting and evaluation

project plan, and the volume of work performed cannot be lower than the indicators established in the agreement;

At this stage of prospecting and exploration in the license block, it is envisaged to carry out 3D surveys with a volume of 1550 km^2 and 2D surveys with 261 linear kilometres.

Once the planned seismic surveys are completed, it will be possible to determine the boundaries of prospective structures and rectify the resource potential of the license block and subsequently prepare structures for exploration drilling and make the prerequisite for future hydrocarbon production.

The following prospective structures have been discovered in the Northwest license block: Mezhdusharskaya, Kostinosharskaya, Papaninskaya, Rakhmanovskaya, Yuzhno-Rakhmanovskaya-1, Yuzhno-Rakhmanovskaya-2. Their geographical location is shown in Figure 5–1.

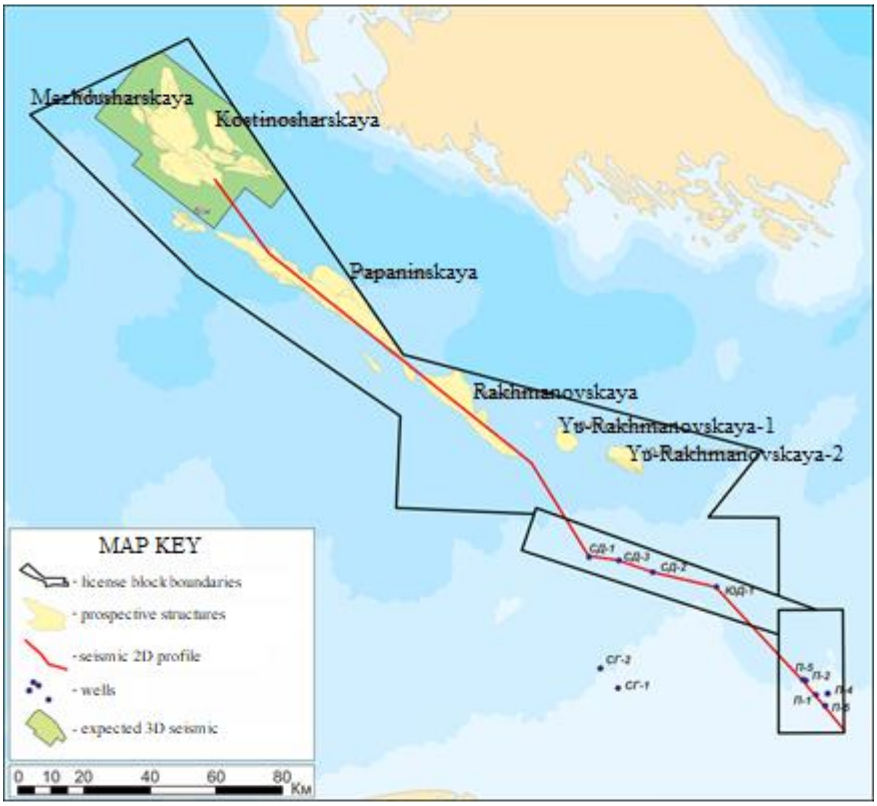

Figure 5–1 Prospective structures of Northwest license block [42]

5.2 Geological properties of prospective structures

Carbonate reservoirs of the Paleozoic age characterize the Pechora Sea. Massive deposits have been discovered in the vicinity of the Sorokin Shaft, namely in Lower Permian and Carboniferous carbonate sediments. The Northwest licence block, Prirazlomnoye and Dolginskoye deposits are classified as Lower Permian biogerms.

Sedimentation in the Lower Permian sediments occurred within the carbonate shelf under normal marine basin conditions, with accumulation conditions varying from nearshore and shallow to very deep. Biogerms were formed in the upland areas of the shallow shelf. Clastic limestones mainly characterize the Lower Permian deposits. Their genesis explains the heterogeneity of pore space of reservoir beds in complicated hydrodynamic conditions.

5.3 Cluster development scenario

Three promising oil structures, namely Rakhmanovskaya, Yuzhno-Rakhmanovskaya-1 and Yuzhno-Rakhmanovskaya-2, were chosen as the object of study in this Master’s Thesis.

The producing depth of formations is 2850-3000 m.

The water depth in the proposed development area is 50-60 m, which allows the use of various types of drilling rigs for well construction, such as semi-submersible and jack-up rigs as well as drillships. Selection of the optimal rig will be made in the following subchapters.

The ice-free period in the selected area is 3-4 months.

Recovery is performed using subsea production complexes installed on an integrated template structure as it is the most applicable layout option for Arctic conditions [44]. The produced fluids from a cluster of prospective structures are proposed to be collected in a single manifold and then transported to the proposed platform for further processing and offloading commercial oil. The water-gas mixture is planned to be returned to the reservoir after separation on the platform to maintain reservoir pressure.

It is important to note that there is no ice load on subsea production systems due to the acceptable water depth. This fact also means that no dredging or installation of special protective structures is necessary.

Figures 5–2-5–3 presents two scenarios for the development of prospective structures.

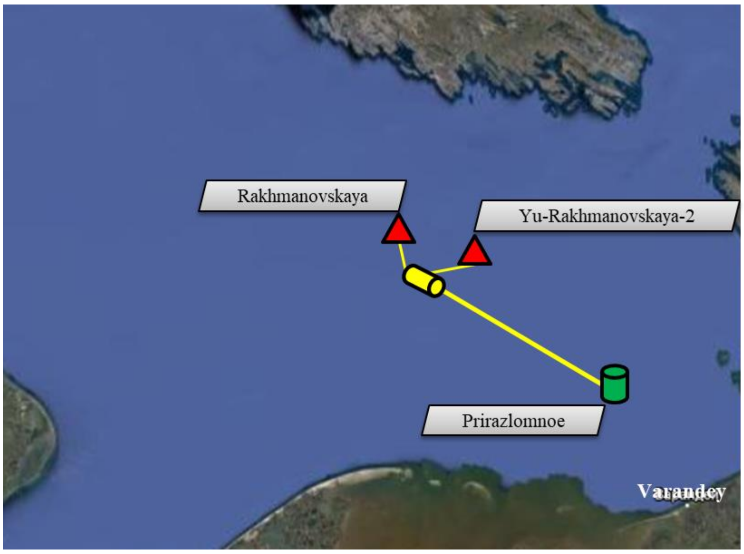

Figure 5–2 First development scenario

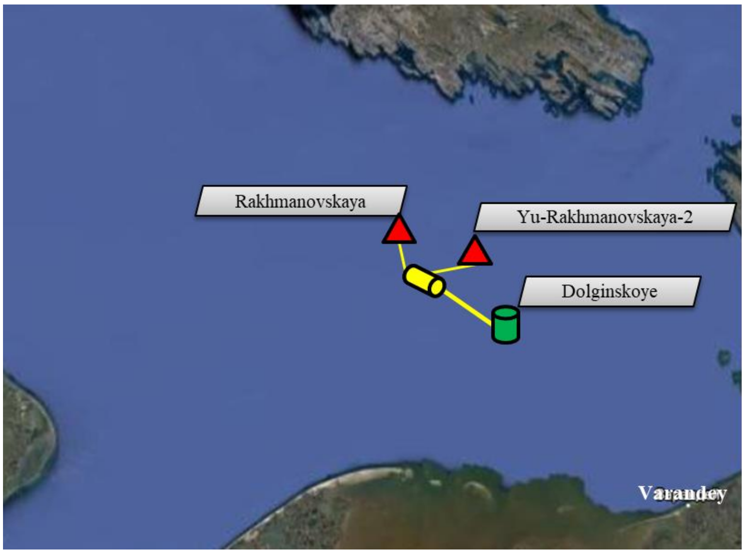

Figure 5–3 Second development scenario

According to the first development scenario, the extracted oil is supposed to be transported via a 75 km pipeline to the existing and operating Prirazlomnaya Platform with the further use of its capacities to process and offload the commercial oil. But implementation of this scenario imposes certain difficulties due to the length of the pipeline. With such a length, several subsea booster stations will inevitably have to be installed, which implies some problems, in particular:

- Significant increase in capital costs;
- The lack of tested domestic subsea booster units.

This concept can be commercially implemented to compensate for the inevitable production decline at the Prirazlomnoye field, but only if the abovementioned factors are resolved.

The second concept is proposed to transport the extracted products to a platform that will be installed at the Dolginskoye field in the future, which seems more promising. However, it should be considered that the start of production on this platform will not begin until 2031 [43], which means that efficient management of the commissioning period for this scenario will be required.

It is important to note that the proposed concept is viewed in isolation from constructing a separate platform but rather as a proposal to maintain production capacity as the Dolginskoe field inevitably depletes and extends the future platform’s service life.

If such a concept is implemented, the length of the pipeline would be significantly less that is 30 km and would not require a large number of booster units. Since this concept will not be realizable in ten years from now, there is every reason to suggest that there will be domestic models of subsea booster units to maintain the specified pressure in the pipe, considering the huge industrial leap that occurred in the last three years in the national industry.

A calculation of the pipeline is provided to confirm this assumption. It should be noted that the calculations use the assumption that the seabed topography in the study area is fairly flat and has no sharp rises or dips and that the depth of the entire pipeline section is approximately the same.

5.4 Pipeline calculation

According to international standards API 5L, we accept the values shown in Table 5–1.

Table 5–1 Pipe properties according to API 5L

Nominal pipe diameter	10”	12”	14”
External diameter	273,1 mm	323,9 mm	355,6 mm
API 5L wall thickness	9,3 mm	9,5 mm	9,5 mm
	–	10,3 mm	10,3 mm
	11,1 mm	11,1 mm	11,1 mm
	12,7 mm	12,7 mm	12,7 mm
	14,3 mm	14,3 mm	14,3 mm
	15,9 mm	15,9 mm	15,9 mm
	18,3 mm	18,3 mm	18,3 mm

The following is the input data required for the subsequent calculation in Table 5–2.

Table 5–2 Input data for the calculation

Parameter	Values	Metric units
Initial external diameter, *D*	273,1	mm
Initial wall thickness, *t*	9,3	mm
Pipeline length, *L*	30000	m
Water depth, *h*	50	m
Inner roughness, *k*	0,05	mm
Inlet pressure, P_1	35	MPa
Arrival pressure, P_2	5	MPa
Fluid velocity, *Q*	29900	m^3/day
Dynamic viscosity, μ	$3,5\cdot10^{-6}$	Pa·s
Density of mixture, ρ	875	kg/m^3
Steel grade	X65	
Minimum yield strengh, *G*	448	MPa

Firstly, it is necessary to assume the nominal diameter of the pipeline and its wall thickness.

So, we take the nominal diameter *D* to be 273 mm and the wall thickness *t* to be 9.3 mm.

Next, calculate the inner diameter of the pipeline using the formula:

$$D_i = D - 2 \cdot t \tag{5.1}$$

$$D_i = 254.5 \text{ mm}$$

Calculate the Reynolds number according to the input data and the formula:

$$\mathrm{Re} = \frac{v \cdot D_i \cdot \rho}{\mu} = \frac{4 \cdot Q \cdot D_i \cdot \rho}{\pi \cdot D_i^2 \cdot \mu} = \frac{4 \cdot N \cdot q_w \cdot \rho}{\pi \cdot D_i \cdot \mu} \tag{5.2}$$

$$\mathrm{Re} = \frac{4 \cdot 26 \cdot 1150 \cdot 875}{\pi \cdot 86400 \cdot 0.2545 \cdot 2.3 \cdot 10^{-6}} = 4.32 \cdot 10^{8}$$

where $Q=N\cdot q_w$, *N* is the number of wells;

q_w is the flow rate of one well, m^3/day

Since Re > 2300, the fluid flow inside the pipeline will be turbulent.

Calculate the relative roughness using the formula:

$$r = \frac{k}{D_i} \tag{5.3}$$

$$r = 0.196 \cdot 10^{-3}$$

Next, using the Moody diagram from Appendix A, find the Darcy-Weisbach friction coefficient *f* equal to 0.0137.

Let's calculate the actual pressure drop, consisting of friction head loss and hydrostatic pressure.

$$\Delta p = \frac{f \cdot \rho \cdot v^2 \cdot L}{2 \cdot D_i} + \rho \cdot g \cdot h \tag{5.4}$$

where ρ is the density of seawater, kg/m^3;

g is the acceleration of gravity, m/s^2.

$$\Delta p = 29.91 \text{ MPa}$$

Check the actual pressure drop to meet the appropriate pressure drop requirements.

$$P_1 - \Delta p > P_2 \tag{5.5}$$

$$35 - 29.91 = 5.09 \text{ MPa} > P_2 = 5 \text{ MPa}$$

Since the actual pressure drop satisfies (5.5), the chosen pipe diameter and wall thickness are suitable.

To confirm the optimum wall thickness, a design factor α equal to 0.72 must be used, and a check must be carried out by calculating the hoop stress. To do so, we will use the following formula:

$$\sigma_H = \frac{P_1 \cdot D_i - p \cdot D}{2 \cdot t} = \frac{P_1 \cdot D_i - \rho \cdot g \cdot h \cdot D}{2 \cdot t} \tag{5.6}$$

$$\sigma_H = \frac{35 \cdot 10^6 \cdot 0.2545 - 1025 \cdot 9.81 \cdot 50 \cdot 0.2731}{2 \cdot 0.0093} = 471.52 \text{ MPa}$$

Based on the API 5L standard for steel grade X65, the minimum yield strength *G* is 448 MPa. The following condition must be fulfilled to confirm the selected optimum wall thickness:

$$G \cdot \alpha > \sigma_H \tag{5.7}$$

$$448 \cdot 0.72 = 322.56 \text{ MPa} < \sigma_H = 471.52 \text{ MPa}$$

Condition (5.7) is not fulfilled for the selected wall thickness, so choose another value of *t* equal to 18.3 mm and recalculate according to (5.6).

The new value of hoop stress:

$$\sigma'_H = \frac{35 \cdot 10^6 \cdot 0.2545 - 1025 \cdot 9.81 \cdot 50 \cdot 0.2731}{2 \cdot 0.0183} = 239.62 \text{ MPa}$$

$$322.56 \text{ MPa} > \sigma'_H = 239.62 \text{ MPa}$$

This equates to condition (5.7), and therefore the new wall thickness is appropriate.

It must also be taken into account that the pipeline is subject to a residual axial stress F_{ax} equal to 0.1 MPa and a bending moment *M* equal to 0.05 MPa. It is, therefore, necessary to calculate the total stress (von Mises yield criterion).

$$\sigma_t = \sqrt{\sigma_H^2 + \sigma_l^2 - \sigma_H \cdot \sigma_l} \tag{5.8}$$

Calculate the moment of inertia *J* using the formula:

$$J = \frac{\pi}{64} \cdot (D^4 - (D - 2 \cdot t)^4) \tag{5.9}$$

$$J = \frac{\pi}{64} \cdot (0.2731^4 - (0.2731 - 2 \cdot 0.0183)^4) = 0.12 \cdot 10^{-3}$$

Next, find the bending stress:

$$\sigma_b = \frac{M}{J} \cdot \frac{D}{2} \tag{5.10}$$

$$\sigma_b = \frac{0.2731}{2} \cdot \frac{50 \cdot 10^3}{0.12 \cdot 10^{-3}} = 56.90 \text{ MPa}$$

Then, find the longitudinal stress using the formula:

$$\sigma_l = \sigma_{ax} + \sigma_b = \frac{4 \cdot F_{ax}}{\pi \cdot D^2} + \sigma_b \tag{5.11}$$

$$\sigma_l = \frac{4 \cdot 100 \cdot 10^3}{\pi \cdot 0.2731^2} + 56.90 \cdot 10^6 = 58.61 \text{ MPa}$$

As a result, we obtain:

$$\sigma_t = \sqrt{(239.64^2 + 58.61^2) - 239.64 \cdot 58.61} = 216.37 \text{ MPa}$$

Check with the following condition, whereby the calculation factor α for the new wall thickness is 0.8.

$$G \cdot \alpha > \sigma_t \tag{5.12}$$

$$448 \cdot 0.8 = 358.4 \text{ MPa} > \sigma_t = 216.37 \text{ MPa}$$

Condition (5.12) is fulfilled.

As shown in the given calculation, the optimal values of pipe diameter and wall thickness are 273.1 mm and 18.3 mm, respectively. These calculated values are appropriate to withstand industrial loads.

It should be noted that the pipeline to be laid on the bottom of the Pechora Sea must be provided with corrosion protection and additional heating for flow assurance of hydrocarbons to the platform.

5.5 Geological Reserves

To justify the selected scenario of development of the prospective cluster, it is crucial to precise the expected geological reserves and recoverable resources, given in Table 5–3.

It should be noted that due to the lack of data on gas condensate content, it is not considered in this project.

Table 5–3 Geological reserves and recoverable resources for prospective structures [42]

Structure	Oil, mln t		ORF	Associated gas, bln/m3	Water depth, m
	Reserves	Recoverable			
Rakhmanovskaya	210,8	63,20	0,3	9	60
Yuzhno-Rakhmanovskaya-1	2,9	0,87	0,3	–	50
Yuzhno-Rakhmanovskaya-2	68,2	19,74	0,3	3	50

As can be seen from the data on recoverable resources, only the Rakhmanovskaya and Yuzhno-Rakhmanovskaya-2 structures have a commercial interest, which means that further clarification of the scenario will focus on these structures.

5.6 Well construction and well stock

Since the investigated area of the Pechora Sea is located at a short distance from well-known geological structures (Prirazlomnoye and Dolginskoye fields), it can be assumed that the reservoir properties will be largely similar. Hence, a similar well placement principle can be used, adjusted for the volume of recoverable reserves.

As stated above, drilling operations can be carried out from different rigs. Still, as the world practice shows, at depths of 50-60 m, the most advantageous option in terms of economic efficiency is a jack-up drilling rig.

It is proposed to use two jack-up rigs at the same time to construct wells on each structure. As the production will be carried out utilizing the SPC, the wells will be suspended until all drilling operations have been completed as the construction progresses.

Table 5–4 shows the number of production and injection wells at each prospective structure. In addition, the number of years required to construct the required stock of wells at each structure using only one drilling rig is shown in the table. Due to the short ice-free period (3-4 months) in the selected water area, well construction capability is significantly reduced, allowing only up to two wells per season using one jack-up rig.

Table 5–4 Number of wells in each structure

Structure	Production wells	Injection wells	Number of years
Rakhmanovskaya	18	10	14
Yuzhno-Rakhmanovskaya-2	8	5	7

Figure 5–5 below shows the schedule for well construction on both structures. Once the drilling operations at the Yuzhno-Rakhmanovskaya-2 structure are completed, one jack-up can move to the Rakhmanovskaya structure, which will reduce the total number of years required to complete all operations.

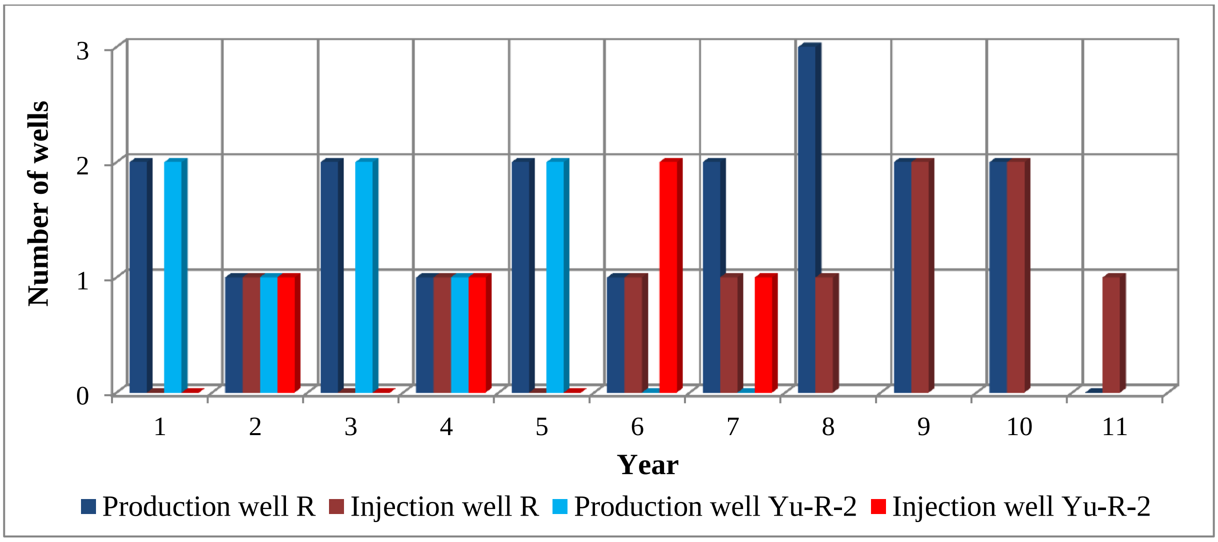

Figure 5–4 Well construction schedule

5.7 Production profile

In order to justify the selected development scenario, production profiles of each of the selected structures need to be established. These are shown in Figures 5–5-5–6.

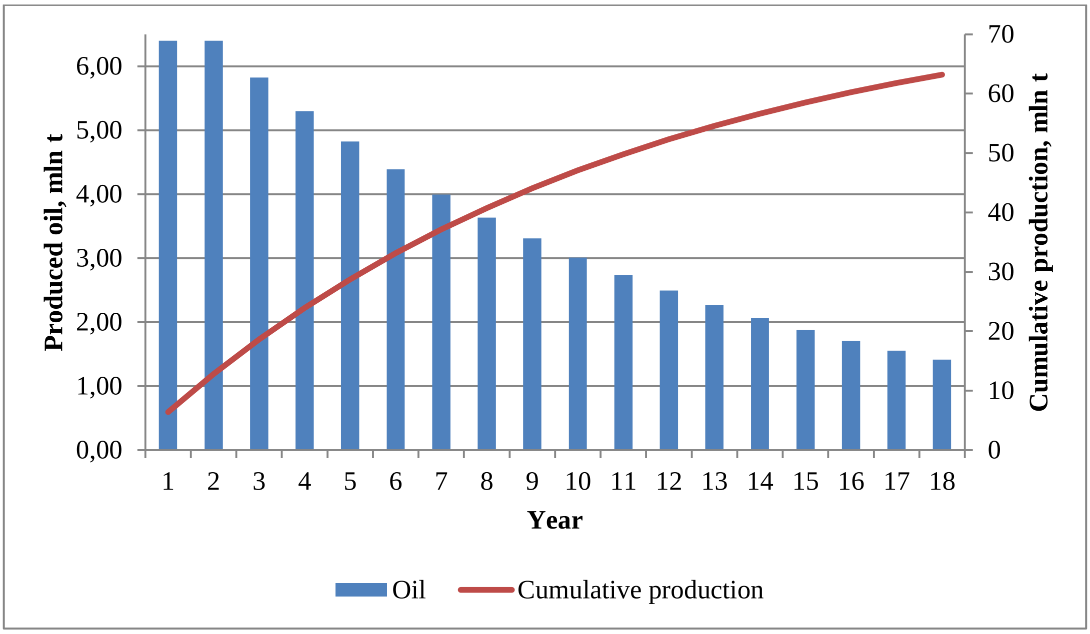

Figure 5–5 Production profile of the Rakhmanovskaya structure

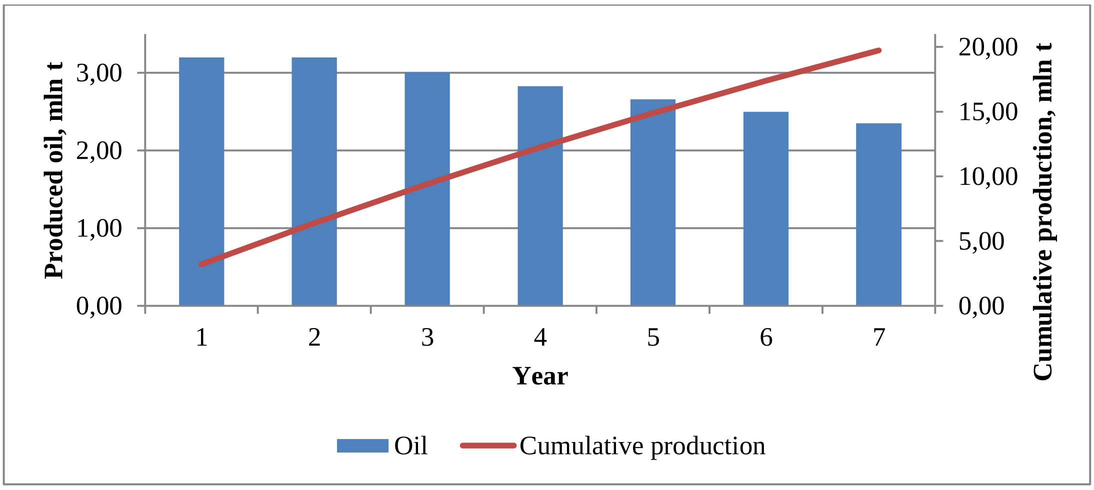

Figure 5–6 Production profile of the Yuzhno-Rakhmanovskaya-2 structure

As can be seen from the presented production profiles, when utilizing SPC, the entire well stock is put into production simultaneously, allowing to reach the production plateau in the first year.

Next, the general production profile for the two structures needs to be established. Results are shown in Figures 5–7-5–8.

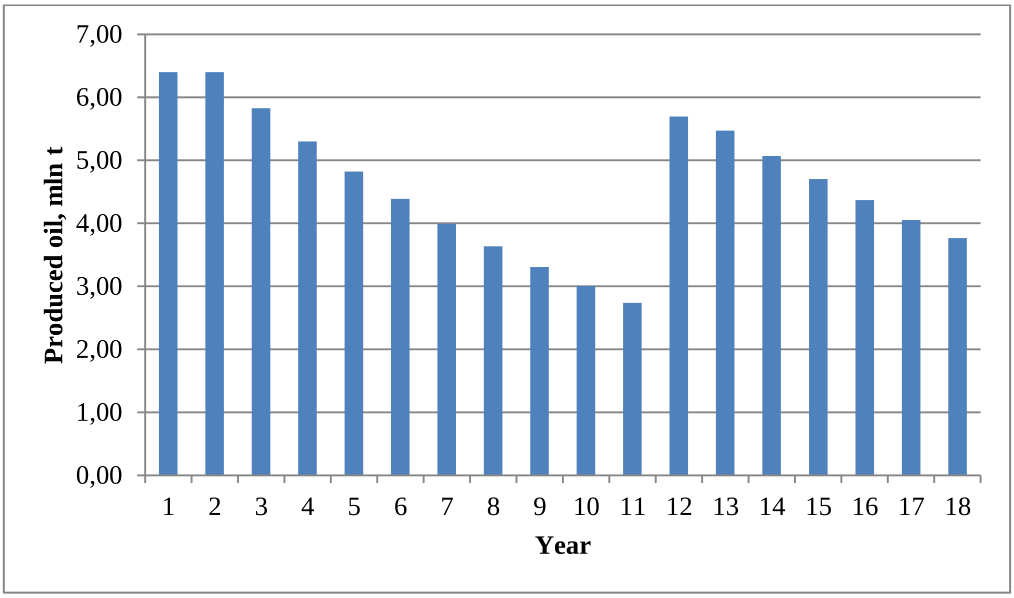

Figure 5–7 First version of the general production profile

In addition to this option, there is another one for the gradual commissioning of the structures.

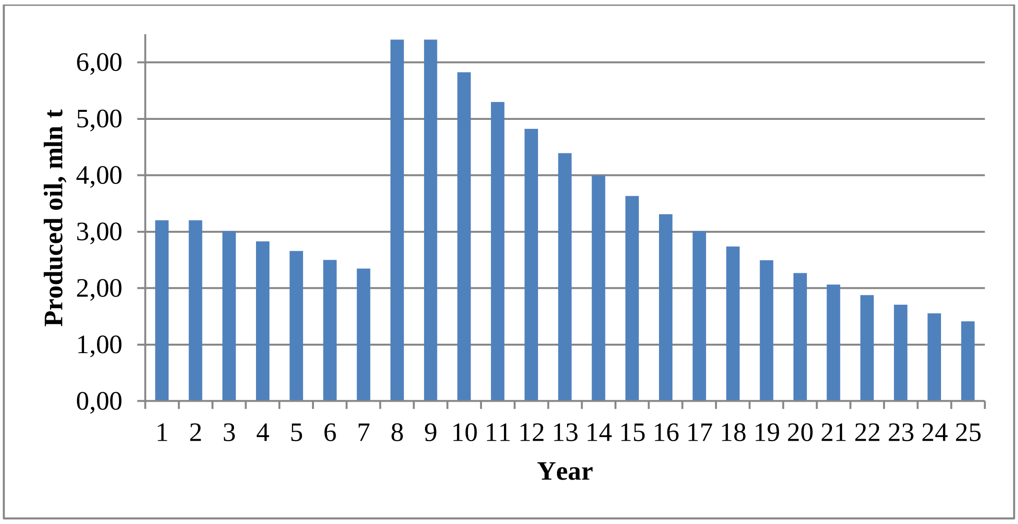

Figure 5–8 Second version of the general production profile

The first version is characterized by a smoother production profile and a shorter depletion period, and a longer downtime period, as wells will be brought on stream after completing drilling operations at the Rakhmanovskaya structure.

The second version has a less smooth production profile and a longer depletion period but a shorter downtime time. This is due to the period of drilling operations at the Yuzhno-Rakhmanovskaya-2 structure, which is half as long as at the Rakhmanovskaya structure, which allows to start production already in seven years after the start of well construction at the Yuzhno-Rakhmanovskaya-2 structure and then another seven years later to bring wells on stream at the Rakhmanovskaya structure.

But if we consider both of these versions in terms of further transportation of reservoir fluids to the offshore platform, where the processing and offloading of commercial products will take place, it is much more technologically efficient to use the following version of the general production profile shown in Figure 5–9

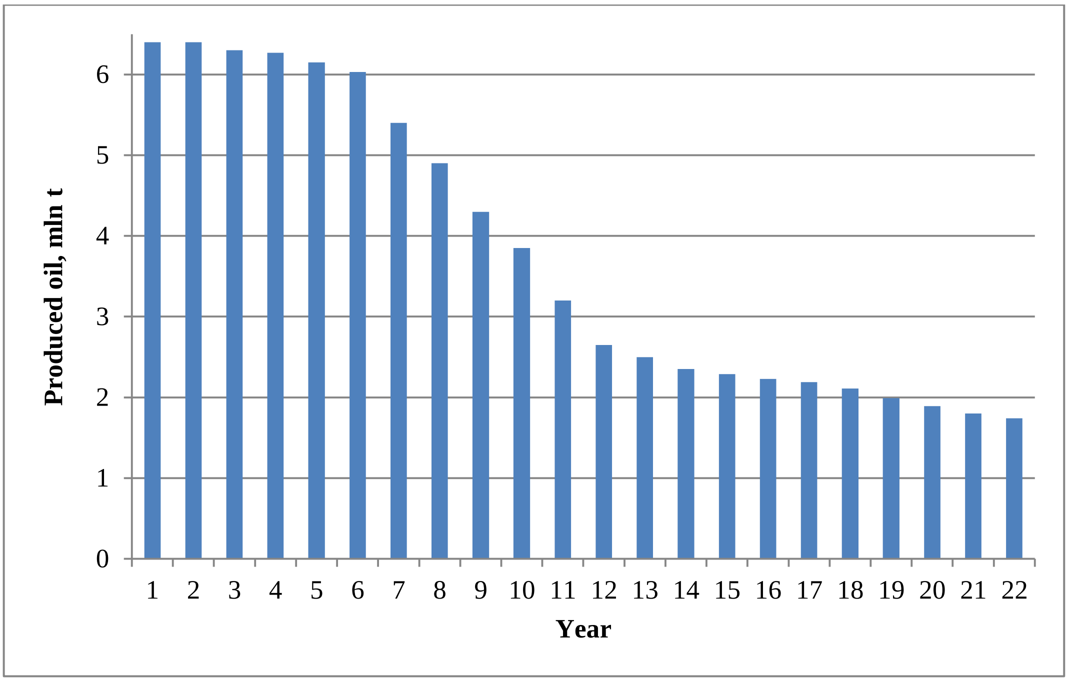

Figure 5–9 Final version of the general production profile

The final version of the overall production profile is designed to extend the maximum operating rate of the future platform. It has the advantage of a gradual commissioning of production capacity and a more smooth production rate. This is done by compensating for the decline in production from one structure by adding capacity from another structure.

It is also important that this particular version shortens the period of drilling operations. After the completion of drilling at the Yuzhno-Rakhmanovskaya-2 structure, the drilling equipment of this section can intensify drilling at the Rakhmanovskaya structure and reduce the number of years required to construct the whole well stock.

The economic calculation of this version will be presented in the following subchapters.

5.8 Gathering system

As previously established, production on the prospective structures will be conducted by SPC installed on integrated template structures. Based on the conclusions drawn in [44], the best option for Arctic conditions is ITSs with four and six well slots.

It is planned to drill 18 production wells and 10 injection wells at the Rakhmanovskaya structure. Five ITSs with six well slots are proposed for this structure.

At the Yuzhno-Rakhmanovskaya-2 structure, 8 production wells and 5 injection wells are planned to be drilled. One ITS with six well slots and two ITSs with four well slots are considered for this option.

The presence of free well slots in the ITS will allow them to be used for additional wells if required.

The produced fluids from each structure are planned to be transported to a general manifold installed at an equal distance from each structure and then transported as unified flow to the platform via a 30 km pipeline. Figure 5–10 shows a schematic representation of this concept.

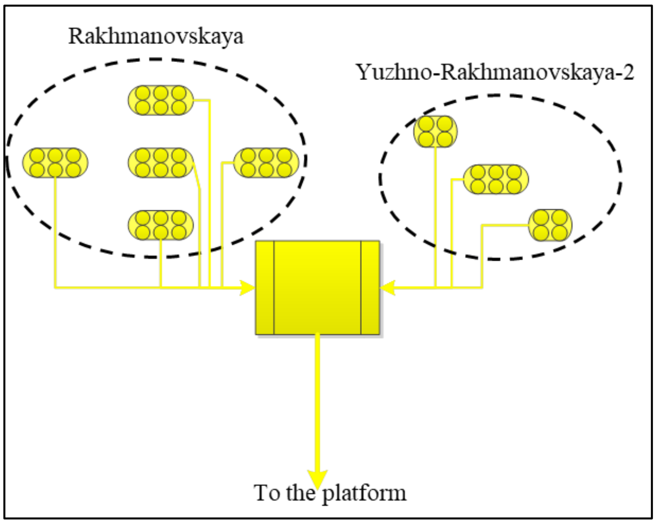

Figure 5–10 Schematic representation of gathering system

5.9 Processing, storage and offloading systems

It was indicated that all reservoir fluids is planned to be transported through a subsea pipeline to a future ice-resistant platform to be installed at the Dolginskoye field. There is every reason to suggest that the technology used in the Dolginskoye field will be similar to that used in the Prirazlomnoye field due to the identical marine and geological conditions and similar development systems. The only adjustment would be the depth of the sea.

However, it should be noted that the Dolginskoye field has larger reserves and hence more capacity for the processing, storage and offloading of commercial products. While the Prirazlomnoye field has recoverable resources of 70 million tons of oil [45], the Dolginskoye field has approximately 220 million tons of recoverable resources. The difference of more than three times suggests that the future platform will have a higher receiving capacity.

This is why transportation of oil from the cluster of structures is a reasonable decision, as it will compensate for the inevitable production decline at the Dolginskoye field and extend the future platform's lifespan.

5.9.1 Processing system

When the formation fluid arrives at the platform, the mixture undergoes a processing stage. After separation at the receiving three-phase separators, oil is sent for storage into special tanks of the platform. The gas-water mixture is sent back to the field to maintain reservoir pressure.

From the literature data [45], the processing units' capacity at Prirazlomnaya Platform is 8.2 mln t/year. As it has already been noted, there is every reason to suggest that the capacity of similar units on the future platform of the Dolginskoye field will be higher, which perfectly agrees with the production profile given in the previous subchapter.

It should be borne in mind that at the initial stage of Dolginskoye field development, there will be much less available capacity for processing of oil delivered from the structures under study. But as the Dolginskoye field depletes, there will be more available capacity due to the increasing water cut of the oil (water will become much easier to separate in the first stage), which means that efficient management of commissioning of the study cluster is needed to evenly load the processing facilities of the future platform.

5.9.2 Storage system

After the oil is processed, it enters special storage tanks located under the platform’s topside.

To avoid the formation of explosive gas mixtures, the oil in the tanks is stored in combination with a small amount of water, which prevents the free release of oxygen.

5.9.3 Offloading system

Oil offloading from the future platform will be carried out using direct oil offloading units (DOOU). This technology has proven itself at the Prirazlomnaya platform, and there are all the prerequisites for its use on the platform that will be installed at the Dolginskoye field. The DOOU is equipped with an emergency shutdown system to eliminate the risk of oil spills during offloading into tankers. This device is shown in Figure 5–11.

Figure 5–11 Offloading of oil using DOOU [46]

For year-round commercial oil transportation from the field, considering ice conditions in the water area, it is proposed to use several Arc6 oil tankers, capable of navigating independently in one-year Arctic ice up to 1.3 m thick and navigating through a channel made by an icebreaker in ice up to 1.7 m thick.

In addition to shuttle tankers, it is proposed to use Icebreaker7 icebreaking vessels capable of performing icebreaking operations in ice up to 2.5 m thick and continuously navigating in ice up to 1.5 m thick to route through the ice conditions of the Pechora Sea and support uninterrupted oil supplies.

5.10 Economic calculation

In order to validate effectiveness of the chosen development scenario of a promising cluster of structures, it is essential to make an economic calculation.

It should be noted that the further calculation uses approximate values and is rather an estimate and does not take into account all the associated costs of installing a platform at the Dolginskoye field, as this is not part of the proposed development scenario.

To competently calculate the economic model of a project, it is necessary to find the following economic indicators:

- Net present value (NPV);
- Internal rate of return (IRR);
- Discounted profitability index (DPI).

To calculate these indicators, we need to use the following formulas:

$$NPV = \sum_{t=1}^{n} \frac{CF_t}{(1+r)^t} \tag{5.13}$$

where CF_t is cash flow;

r is the discount rate;

t is a term of project realization

If the NPV value ≤ 0, the project does not cover future costs or runs at a loss, but if $NPV > 0$, then the project is attractive for further analysis.

$$DPI = \frac{\sum_{t=1}^{n} \frac{CF_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{IC}{(1+r)^t}} \tag{5.14}$$

where *IC* is the initial capital

If *DPI* values < 1, then the project is unprofitable, if *DPI* = 1, then the project income is equal to its costs, and if *DPI* > 1, then the investment project is promising for further consideration.

Also, justification of the project requires the values of capital and operating costs, depreciation accounting and tax liabilities. For this purpose, let us put all the required values for calculation below in Table 5–5.

Table 5–5 Calculation data

Parameter	Value	Unit
Annual production	6,4	mln t/year
Duration of a project	32	year
Oil price	60	$/barrel
Capital expenditure	1960	mln $
Operational expenditure	90	$/t
Depreciation	20	%
Income tax	25	%
Discount rate	12	%

The capital cost of the project is based on the following values:

- Cost of one template is $120 million;
- Construction of one well is $12 million;
- Laying of 1 km of pipeline in arctic conditions is $2 million.

Data on capital costs are taken from similar offshore projects and presented in Table 5–6.

Table 5–6 Capital expenditure

Parameter	mln $
Subsea production system	1310
Wells construction	540
Pipe laying	80
The conjunction to the platform	30
Total	1960

All calculations were performed in MS Excel. The results of the main economic indicators are shown in Table 5–7.

Table 5–7 Values of economic indicators

NPV, mln $	2725,83
IRR	20,9 %
DPI	2,65

Also in the calculation process was built and presented in Figure 5–12 graph of the cumulative cash flow for the entire period of the project, which only confirms its investment attractiveness.

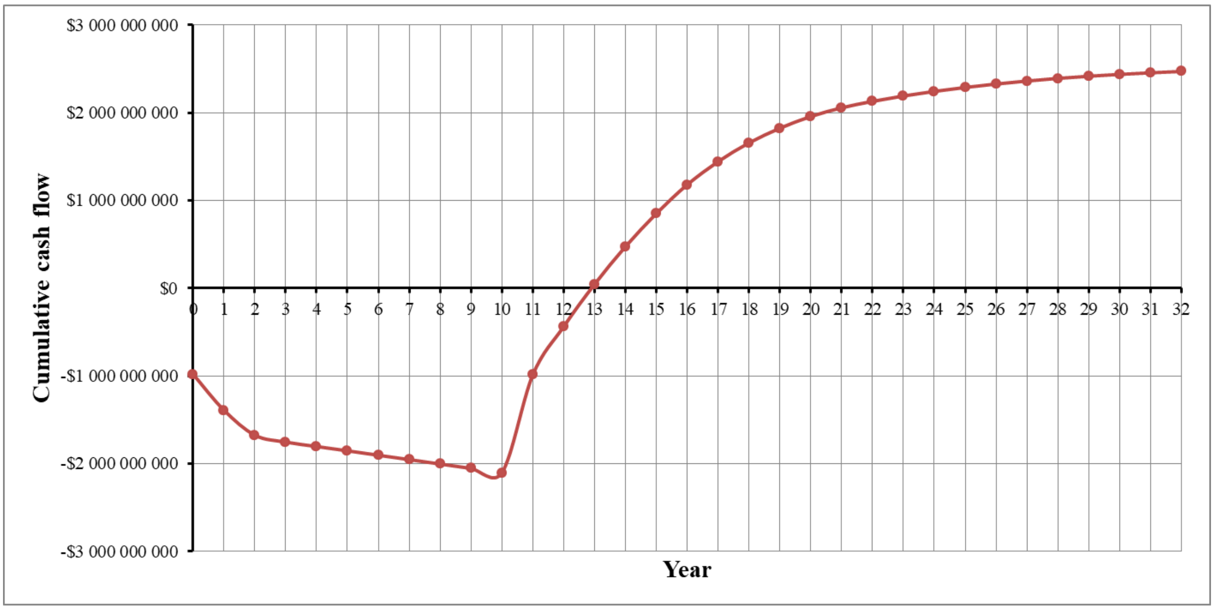

Figure 5–12 Cumulative cash flow of the project

As seen from the graph, the project will begin to bring profit after 12 years due to the long period of well construction, but after the start of production, it pays off quite rapidly.

The development of the Arctic fields is directly dependent on oil prices. For this purpose, another graph was established, which demonstrates the worst and best development scenarios for a considered project in Figure 5–13.

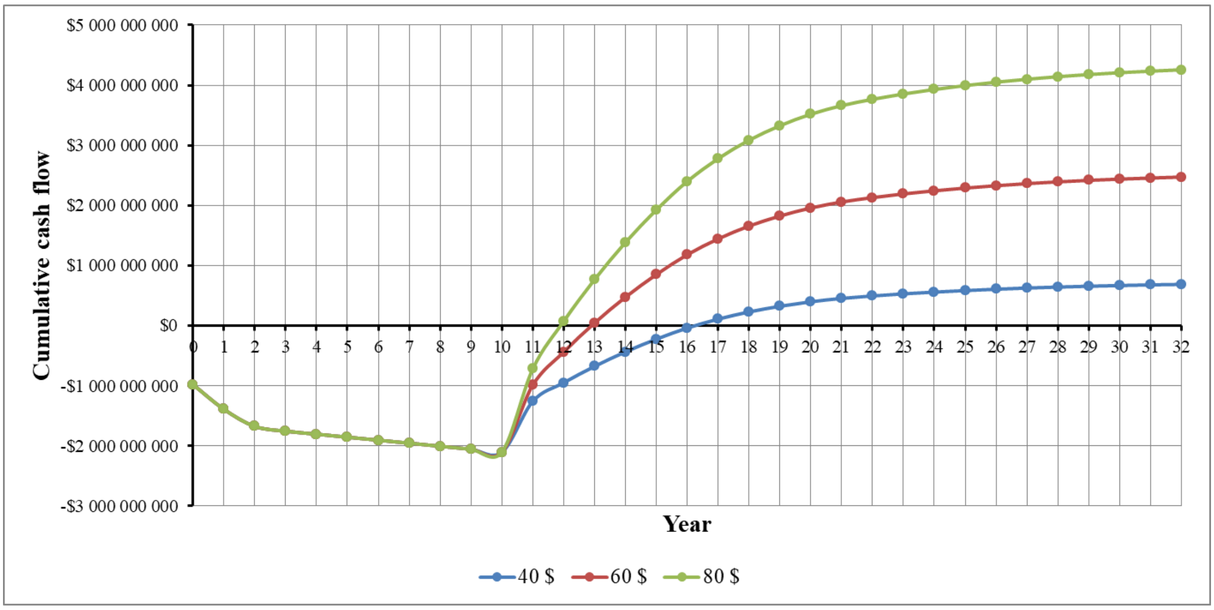

Figure 5–13 Cumulative cash flow at different oil prices

As can be seen from the graph, investment attractiveness will be at oil prices above $ 40 per barrel.

Thus, considering all the economic indicators, one can confidently claim that this project has all chances for industrial implementation.

Conclusion

The subject of research in this Master's Thesis was perspectives of using subsea technologies on the shelf of the Russian Federation, specifically in the Northwest license block of Gazprom Neft. In the course of the work, the natural and climatic conditions of the Pechora Sea water area, in which this block is located, were analyzed. Also, subsea production technologies, how they are organized, and their technical applicability conditions were considered.

The current state of subsea production systems on the territory of the Russian Federation was reviewed. Domestic producers have created a regulatory structure and manufactured the basic elements for conducting subsea production in a very short period. Despite notable progress in the new branch of domestic industry, there is still a lot of work to set up mass production of the existing components and create new equipment.

Based on the existing vector of industry development, the feasibility of localizing production centres based on the Russian Federation's Arctic zone regions was assessed to minimize logistical risks and costs and develop a new industrial cluster of enterprises. The analysis showed that with the competent implementation of the import substitution strategy, creation of own innovative technologies and close cooperation between the state, oil and gas companies and the locals, the industrial associations of the northern regions could become a driver for the development of all industry in the country.

The development concept for the cluster of structures was proposed. It was suggested that instead of installing separate capital-intensive ice-resistant platforms at each prospective structure, it is reasonable and economically feasible to use subsea production complexes, with their subsequent connection to the existing production infrastructure, thereby implementing a certain kind of fan-type way of developing offshore oil and gas fields. This approach can extend the service life and improve the efficiency of existing platforms operating during declining production.

When elaborating the concept, special attention was paid to the possibility of developing promising structures, using equipment, which is mostly made based on Russian enterprises, to show the feasibility of large-scale plans to develop the Arctic by own forces.

It should be noted that the considered concept is rather an estimation of the feasibility on an industrial scale. For a more comprehensive elaboration, it will be essential to specify production data, calculate the route of the pipeline and model the development with the help of special software packages.

Future research may focus on the uninterrupted power supply to subsea production systems and industrial risk management.

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Appendix

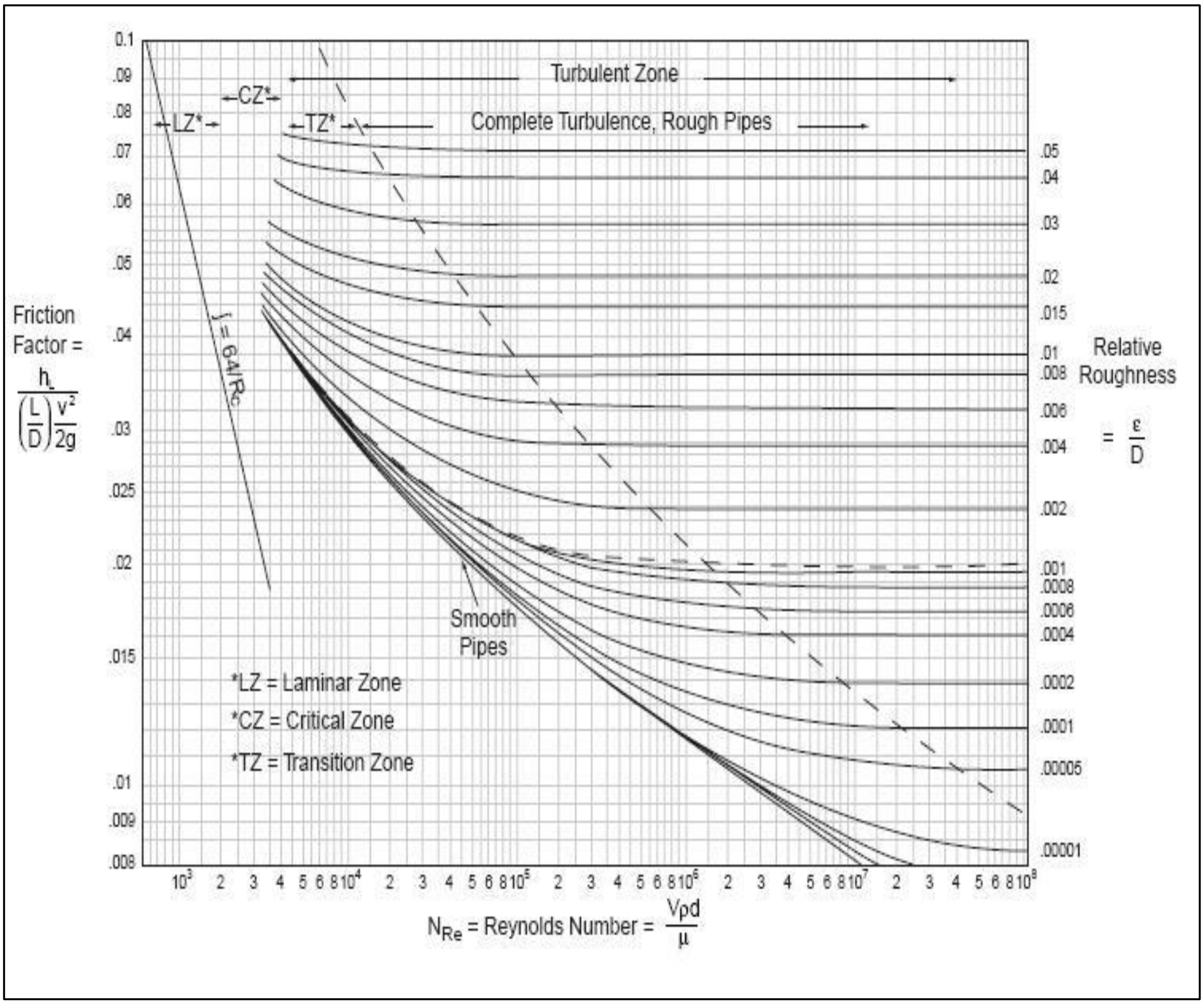

Figure A–1 Moody diagram