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Author: Andrey Varentsov	(author signature)
Tutor: Ove T. Gudmestad; Vladimir Sulemanov.	
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Abstract

This master thesis provides an insight into Yuzhno-Kirinskoye field development concept and includes the feasibility study for several different options.

First chapter of this work includes the description of climatic conditions in the region of the Yuzhno-Kirinskoye field displacement and provides the results of geological study of this field.

The second chapter describes perspective schemes of the Yuzhno-Kiriskoye field development.

The third chapter of this paper provides an insight into subsea production systems and the experience of subsea compressor stations implementation.

The fourth chapter provides an insight into the chosen methods for comparison.

The fifth chapter gives an information about the possible risks while the Yuzhno-Kirinksoye gas field development and exploration.

Six chapter shortly describes the principal, which were used in order to make the design of the field.

The seventh part provides the economic calculations for the chosen options.

The eight chapter gives an insight into the chosen alternative solutions for Yuzhno-Kirinskoye field development.

And the last two parts of the thesis gives a conclusion and reccomendations for the further work.

Acknowledgements

Two years of my study have been an unforgettable adventure, which still was anything but easy. It consisted of quite controversial emotions, including the grief because of the alluring yet missed opportunity to visit Norway and to obtain wonderful experience of getting up-to-date knowledge or to learn the latest news of cutting edge technologies. Moreover, the Master program was a second to none chance to improve my English skills.

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Abbreviations

AACE - Association for Advancement of Cost Engineering

CAPEX – Capital Expenditure

CPF – Central Production Facility

DRILLEX – Drilling Expenditure

DPI - Discounted Profitability Index

EPS – Electric Submersible Pump

FEL – Front End Loading

FEED - Front-End Engineering and Design

FID – Final Investment Decision

GBS – Gravity Based Structure

MEG – Monoethilen Glycol

MET – Mineral Extraction Tax

IRP – Ice Resistant Platform

IRR – Internal Rate of Return

OPEX – Operating Expenditure

PLET – PipeLine End Termination

ROV – Remotely Operated Vehicle

SCS – Subsea Compression Station

SPS – Subsea Production System

SCU – Subsea Compression Unit

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Introduction

The gradual depletion of hydrocarbon reserves on the continents inevitably leads to increasing prospects for the development of offshore fields.

A significant part of Russia's offshore fields are located in the Arctic seas or in freezing water areas. As well as deepwater fields that are remote from the coastal infrastructure are being discovered. Development and exploitation of such fields should be carried out with the fullest consideration of all the restrictions imposed by the conditions of the areas where these fields are located. It means that it is necessary to be able to select the optimal solution for the field development, which will meet all the conditions, both natural-climatic and geographical, and the possibility of development of such system in deep water areas.

The Yuzhno-Kirinskoye field is part of the Sakhalin-3 project and is one of the most important facilities for Gazprom's development of the Sakhalin shelf. It will become one of the sources of gas supplies to consumers in Russia's Far East regions and may also be used for supplying the Power of Siberia pipeline in future.

The principal aim of this work is to select and justify the most appropriate type of field facilities for the Yuzhno-Kirinskoye gas condensate field, taking into account all operating conditions and the available general data about the field. The goal is going to be achieved by performing a number of the following tasks:

1. Analysing the principles of the offshore fields development on the example of Kirinskoye gas condensate field;
2. Fulfilment of necessary technical and economical researches for determining the most optimal solution of the field development;
3. Make a proposals on possible alternative arrangement options.
4. Evaluation of the possibility of implementing chosen alternative methods for the field.

Chapter 1 Yuzhono-Kirinskoye field description

1.1. General information about the Yuzhno-Kirinskoye gas condensate field

The Yuzhno-Kirinskoye field is one of the largest fields on the Sakhalin shelfs C1+C2 reserves amount to 711.2 billion cubic meters of gas, 111.5 million tons of gas condensate (recoverable), and 4.1 million tons of oil (recoverable). The planned design capacity is 21 billion cubic meters. meters of gas per year. [1].

The Yuzhno-Kirinskoye gas condensate field is located on the northeastern shelf of the island. Sakhalin and is located within the Kirinsky block of the Sakhalin-3 project. The block is adjacent to the central part of Sakhalin Island, in the area of Lunsky Bay. (Figure 1.1). The field takes place 35 km from the coast. The sea depth within the water area of the field ranges from 110 to 320 m.

In 2010–2011 Gazflot company drilled the first two wells (wells 1 and 2) in the Yuzhno-Kirinskaya structure, which revealed a commercial gas condensate reservoir in the rocks of the Daginsky horizon, Miocene. Later in 2013, wells were drilled. 3 and 4, in 2014 - wells. 5 and 6, in 2015 - wells. 7 and 8.

The field is multi-layered. The thickness of the productive layers varies from 14 up to 26 m. The reservoir conditions are characterized by a pressure of 28–29 MP and an abnormally high temperature of 115–124 ° C.

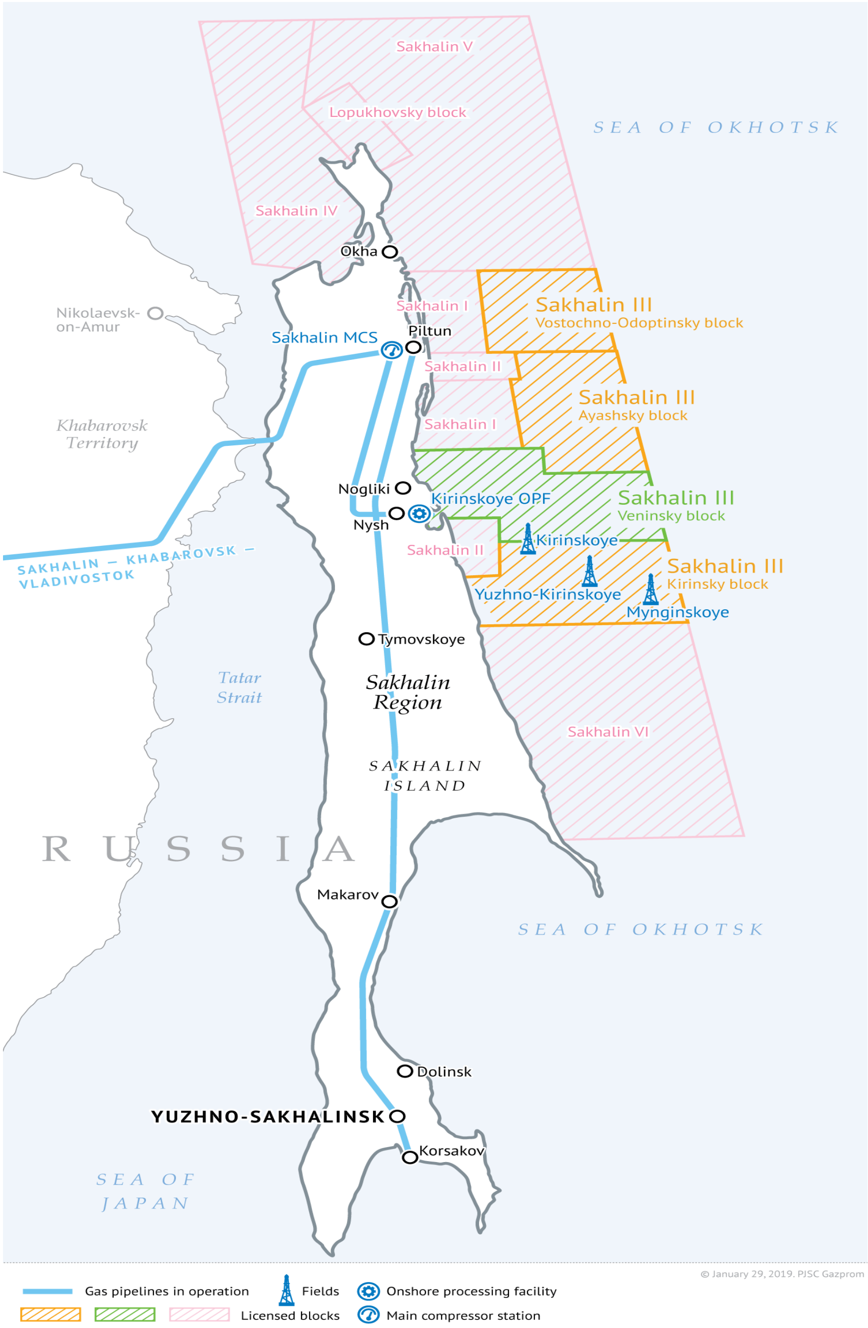

Figure 1-1 The scheme of license areas on the Sakhalin shelf [1].

There are no settlements and seaports in the work area on the coast. The nearest large settlements are the administrative center of the Nogliki district, urban settlement. Nogliki and the administrative center of the Tymovsky district, Tymovskoye settlement. The Yuzhno-Kirinskoye field is located 65 km southeast of the village Nogliki.

From the village of Nogliki to the south of Sakhalin Island there is a railway that passes through the village of Tymovskoye. At the mouth of the Nabilsky Bay, 6 km east of the Katangli village, there is a pier intended for ferry transportation of machinery and equipment through the Aslanbekov Strait, which connects the Nabilsky Bay with the Sea of Okhotsk. From the Sea of Okhotsk to the Nabil pier, ships with a draft of up to 3 m can enter.

It is assumed that gas production at the field will be carried out using wells with subsea wellheads. The production of wells under the influence of reservoir pressure will be supplied through the in-field pipelines to the collection manifold and then through the subsea pipeline to the onshore gas treatment unit. After preparation, the gas will be supplied to the main pipeline.

The gas is intended to be injected into the Sakhalin-Khabarovsk-Vladivostok gas pipeline system. Commercial stable condensate and oil are intended to be pumped into the existing oil pipeline from the Lunskoye field, owned by Sakhalin Energy.

In order to preserve the unique ecosystem of Sakhalin during the creation and operation of hydrocarbon production and transportation facilities, Gazprom strictly follows Russian and international environmental protection standards.

In particular, the modern highly reliable equipment of the subsea production complex has a minimal impact on the environment. On the territory of the onshore technological complex, thermal neutralization of domestic and industrial wastewater is carried out, which makes it possible to exclude pollution of the Sakhalin water area. Industrial environmental control and environmental monitoring are carried out.

In addition, compensation measures for the reproduction of salmon fish species are carried out annually. In 2012-2016, with the support of Gazprom, more than 27 million chum salmon fry were raised and released into the rivers of the Sakhalin Region.

1.2. Characteristics of hydrocarbons gained from the Yuzhno-Kirinskoye gas condensate field.

The gas from the Yuzhno-Kirinskoye gas condensate field is classified as a methane type (83–84% by volume of methane, 4.5–4.8% by volume of ethane, 2.6–3.03% by volume of propane, 1.4–1.8% vol. butanes). It is carbon dioxide (1.68–2.02% by volume of carbon dioxide), low nitrogen (0.19–0.45% by volume of nitrogen), non-helium (0.00% by volume of helium), highly condensate (3.32– 5.64% vol. C5 +).

The condensates gained from different wells of the Yuzhno-Kirinskoye gas condensate field are similar in all physicochemical characteristics to each other, but not identical. This is evidenced by the results of determining their physicochemical properties, as well as fractional, component and group hydrocarbon compositions. The similarity of the condensates lies in the fact that they are all low-paraffinic (the content of solid paraffin is 0.14–0.60 wt %), low in tar (the content of silica gel resins is 0.09–0.22 wt %), low-sulfur (the sulfur content is 0.03–0.04 wt %), boil away in the temperature range of beginning of boiling - 300 ° C with a remainder of 5.5–7.1wt %. Differences are observed in the density values and in the group HC composition. Condensates from wells 1–3, 7 (density 743.0–748.8 kg / m3) are of the light type, and from well 4 (density 765.5 kg / m3) and from wells 5, 6, 8 (density 750, 1–758.5 kg / m3) - to the medium type.

Oils were explored from the rims (wells 3–6). Since condensate inflow was assumed in oil from well 6, a comparative characteristic is given for oils from wells 3–6. Thus, the studied oils differ somewhat in their physical and chemical characteristics. Oil from well 3 (density 851.6 kg / m3) is of the medium type, and oil from wells 4 and 5 (density 834.2 and 832.7 kg / m3, respectively) is of the light type. They are paraffinic (3.4–3.9% by weight), quite rich in tar (silica gel resins – 5.4–8.5% by weight, asphalt – 0.3–0.9% by weight). The indisputable advantage of oils is a low sulfur content – 0.26–0.38% by weight, pour point lies in the range from minus 20 up to minus 15 ° C. The output of the gasoline fraction while boiling at the temperature of 200 ° C is 24.6–30.7% of the mass.

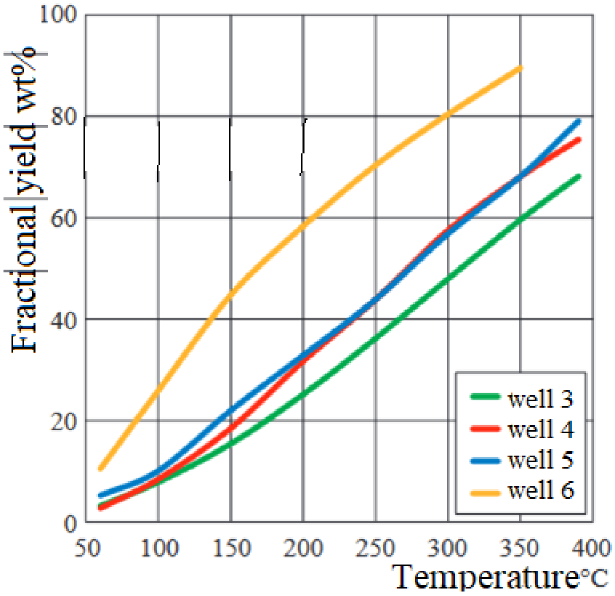

Figure 1-2 Fractional yield of oils [2].

Studies of the gas composition showed that the content of condensate, ethane, propane, butanes significantly exceeds their conventionally applied minimum industrial concentrations. According to the methodological guide, a 3% concentration of ethane in gas is considered to be the minimum profitable at the modern technological level of ethane extraction from gas. Ethane is a valuable chemical raw material for the production of polyethylene. [**Error! Reference source not found.**].

The propane-butane fraction, which is liquefied hydrocarbon gases, is used in the household sector, in industry and as an automobile fuel.

Petroleum oils, kerosene and diesel distillates of oils are characterized by high yields, favorable chemical composition and high level of basic performance characteristics, which will allow using these fractions as a basis for obtaining corresponding fuels according to the fact that it do not require desulfurization.

1.3.Natural and climatic conditions for development of the Yuzhno-Kirinskoye gas condensate field

The Sakhalin region is located in the zone of the monsoon of temperate latitudes. This area is characterized by the highest air temperature variability within the island. The average annual temperature is -2.3 ° C, from -19.2 ° C in January to +13.1 ° C in August. The absolute minimum reaches -40 ° C, the maximum is +30 ° C.

From May to September, weak winds (2-5 m / s) of the southern direction prevail over the sea area. Cases of a short-term sharp increase in wind (up to 20 m / s and more) are associated with the emergence of individual cyclones and typhoons into the sea with a maximum frequency in August-September. Usually there are 1-2, rarely 3-4 cases of typhoon release per year. In the cold season, strong winds of the northern quarter dominate over the sea with the most probable speed values of 5-10 m / s (in some months 10-15 m / s). The recurrence rate of storm winds with a speed of more than 15 m / s on average per year is about 10%.

The salinity of the Sea of Okhotsk near Sakhalin Island reaches 30-32 ppm, in summer it drops to 28-30, and by winter it rises again to 31-33.5 ppm.

In the Sea of Okhotsk, periodic tidal currents are well expressed, which are rotational in open areas, and reversible in coastal ones. Far from the coast, the velocities of these currents are low - 5-10 cm / s, and near the coast, underwater shoals, in bays and straits, they reach extremely high values: in the bays of the eastern coast of about. Sakhalin - 260 cm / s. The main circulation system of water mass in the Okhotsk sea consists of the northward West Kamchatka Current carrying warm Pacific waters and the East Sakhalin Current carrying cold dense shelf waters southward. However, there are plenty of surface currents in the Okhotsk sea, the figure bellow shows that.

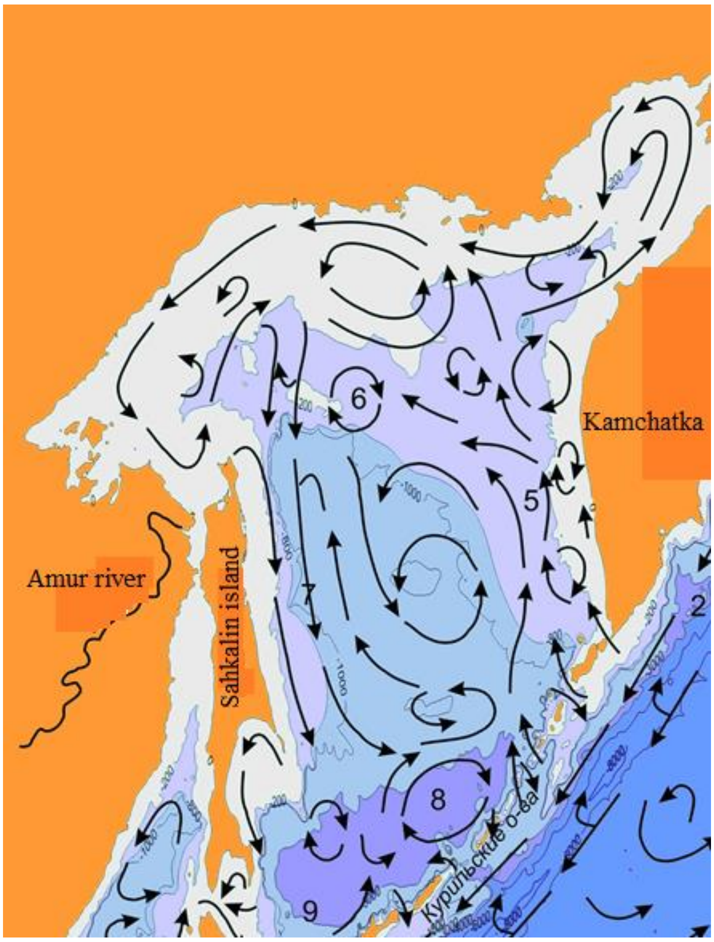

Figure 1-3 The map of currents in the Okhotsk sea [4].

Waves in the summer period reach about 2-2,5 m in most cases, the maximum wave height reaches about 5 m in winter and make up no more than 6-7% of the total number of waves. But, once in five years there is a possibility of accumulation wave with height about 8 m near the costal area. [**Error! Reference source not found.**].

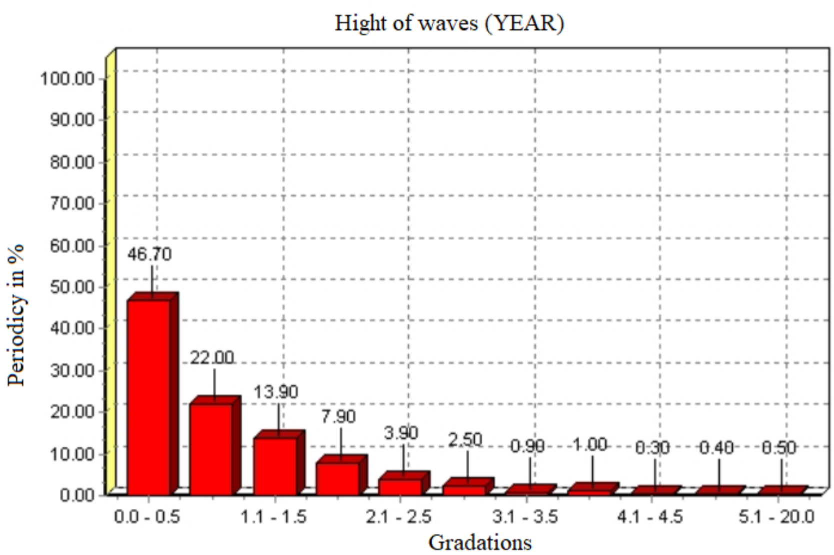

Figure 1-4 The periodicity of wave height in the Okhotsk sea during the year [5].

The relief of the bottom of the Sakhalin shelf in the northeast is rather flat without bright rises and depressions.

Icing of vessels in the northeast of the Sakhalin shelf is possible from October to December. The maximum frequency is observed in November – December. Ice formation on the shelf part of the sea occurs in November, its destruction begins in mid-May of the next year (early ice formation - in November, later - in early December; early ice melting - in June, later - in early July). Thus, the ice-free period is about 5-6 moths each year, that is crucial for the terms of drilling and equipment installation.

On the northeastern shelf of about. Sakhalin annually forms a thick ice cover. Ice formation usually begins in late November - early December. The thickness of the ice cover on average reaches 0.8–1.1 m. The greatest development of the ice cover reaches in March and April. The average duration of the ice period is 175-198 days. [4].

The possible emergence of ridged ice, as well as seismic activity, estimated with 9 points, complicates the production of hydrocarbons in this region.

1.4. Geological and geophysical study of the field

The foundation of the Kirin block is composed of silicified argillites and siltstones, pyroxenites and peridotites, tremolite-serpentine and talc-chlorite-serpentine schists. These rocks come to the surface in the East Sakhalin Mountains, Taulan-Armudan Ridge, etc. The sedimentary cover (5-6 km thick and more) is composed mainly of terrigenous Paleogene and Neogene rocks. The Paleogene complex within the region under consideration is distinguished in a reduced volume and is represented by the Oligocene, which, according to the regional stratigraphic scheme is divided into the Machigarian and Daekhurian horizons. The first is composed of irregular interbedding of gravelites, sandstones, and mudstones, which were formed under shallow water conditions. The second is represented by clay-siliceous rocks of the outer shelf environment. The total thickness of the Paleogene does not exceed 800 m here.

According to the scheme of the Cenozoic stratigraphy of the North Sakhalin oil and gas bearing region, the Neogene consists of (from bottom to top) the Uyninsky, Daginsky, Okobikay, Nutovsky, and Pomyrsky horizons. Rocks of the upper and middle parts of the Daginsky horizon are uncovered at the base of sections of six wells of the Kirinsk block.

Maximum thickness of the horizon according to seismic data is noted in the northern part of Myngin area, where it is 1800-1900 m. The formation of the Daginan deposits was determined by the activity of a powerful delta system of large rivers: Paleotumnin, Paleoamur, and Paleoamgun, which flowed from the uplands of the Asian continent. Three subhorizons are distinguished in the Daginsky horizon. The Lower and Middle Daginian subhorizons are represented by interbedding of fine-grained sandstones, siltstones, and mudstones. The content of sandy strata in the strata increases upward in the section. The thicknesses of individual sand layers in the near-vein part of the Lower-Middle-Dagi sequence vary from 35 to 67 m. The Upper Dagi subhorizon is composed of interbedded sand, silty-sand, and mudstone strata. Thicknesses of individual sand layers vary from 28 to 58 m.

The Yuzhno-Kirinskoye field is located in the southern lowered part of the Sakhalin Island shelf. The map (figure 1-5) shows a structural basement map at the Kirinskiy block of the Sakhalin-3 project.

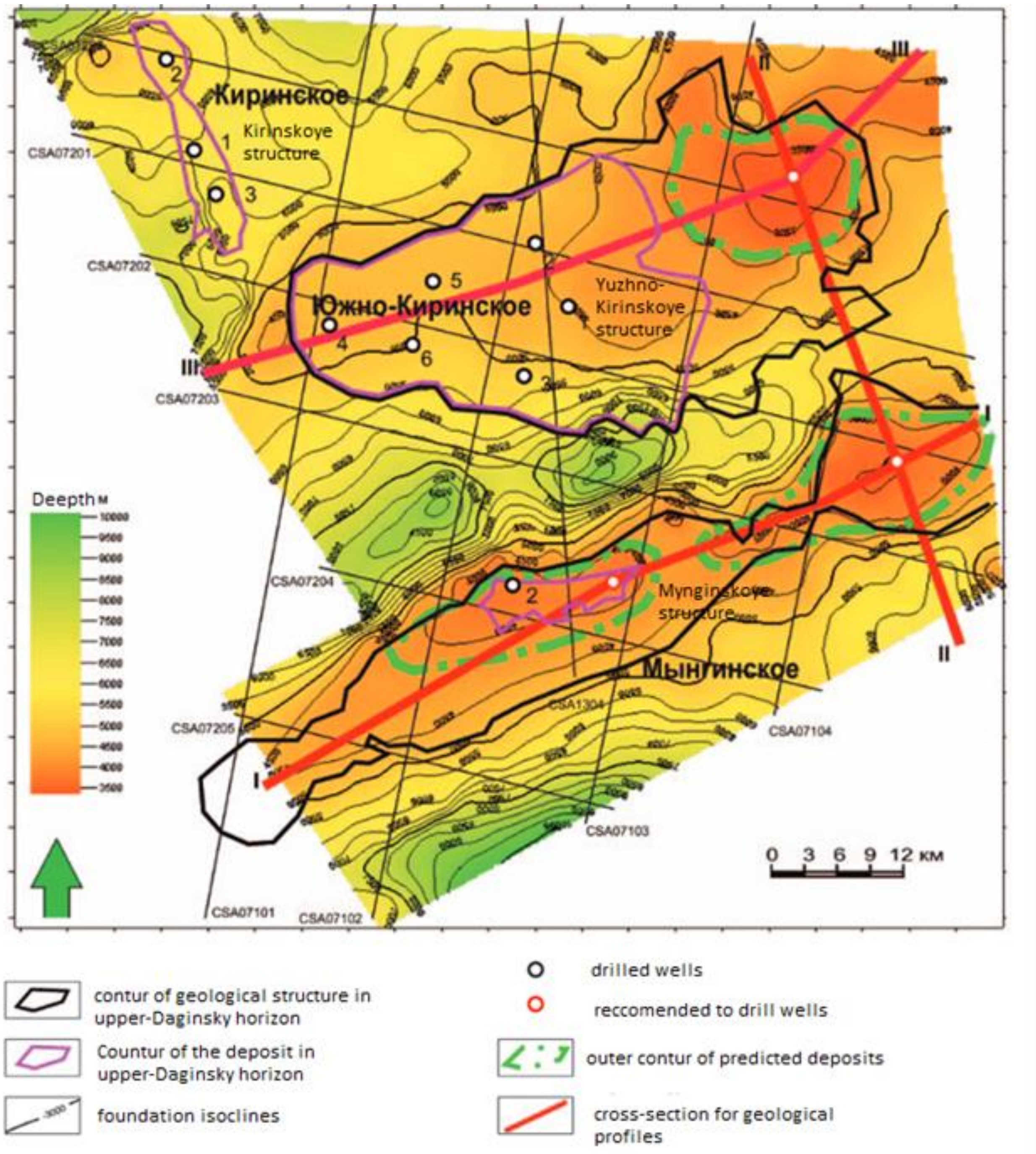

Figure 1-5 Structural map of the acoustic foundation basing [**Error! Reference source not found.**].

Two thick strata of the Daginsky horizon of the Miocene were found to be condensate and gas bearing at the Yuzhno-Kirinskoye field; the reservoir is terrigenous and represented by sandstones containing clays. The figure below shows the lithologic and stratigraphic section of well 2 of the Yuzhno-Kirinsky gas condensate field. The perforation interval of the well is at 2655-2848 m.

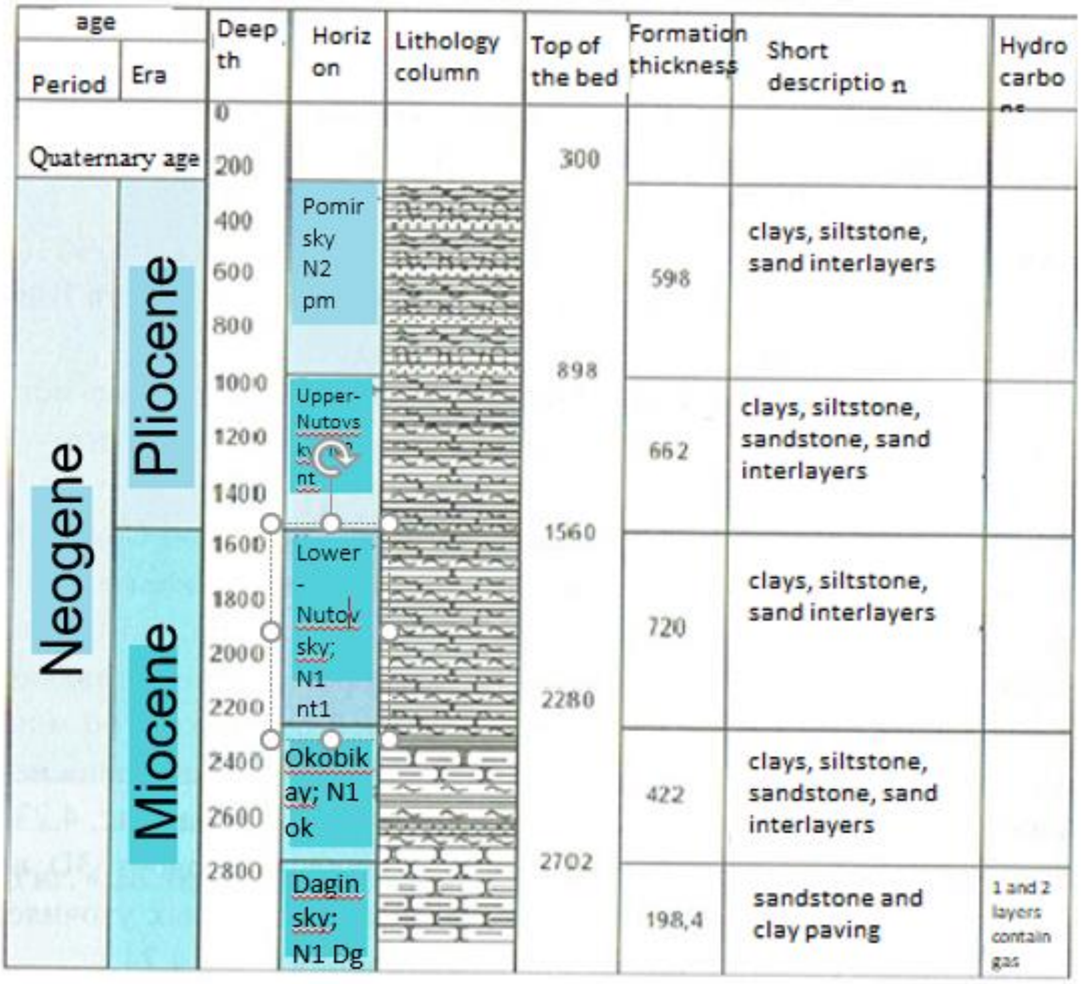

Figure 1-6 Lithological-stratigraphic section of borehole no. 2 Yuzhno-Kirinskoye field [6].

According to the results of the reservoir study, the heterogeneity of filtration-capacitative properties of the Daginsky deposits of different blocks of the Yuzhno-Kirinskoye field depending on the mineral composition, the amount of clay material was revealed. Distribution diagrams of total porosity coefficient in fractions of units and permeability coefficient in 10^{-3} μm^2 are presented below. Numbers show the locations of the drilled wells.

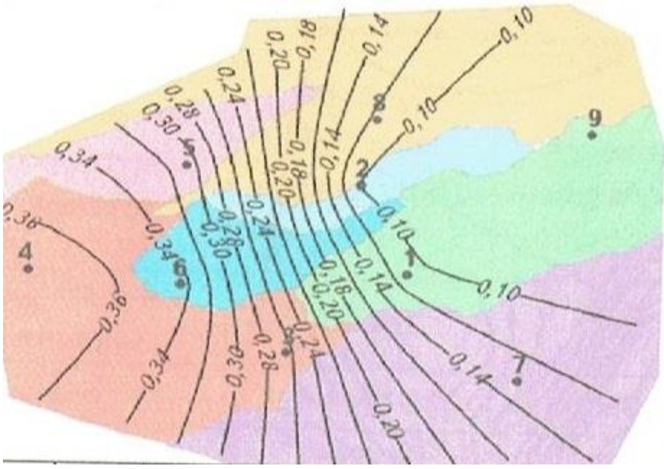

Figure 1-7 Distribution of the volume clay coefficient for the Daginskoye horizon of the Yuzhno-Kirinskoye field. [6].

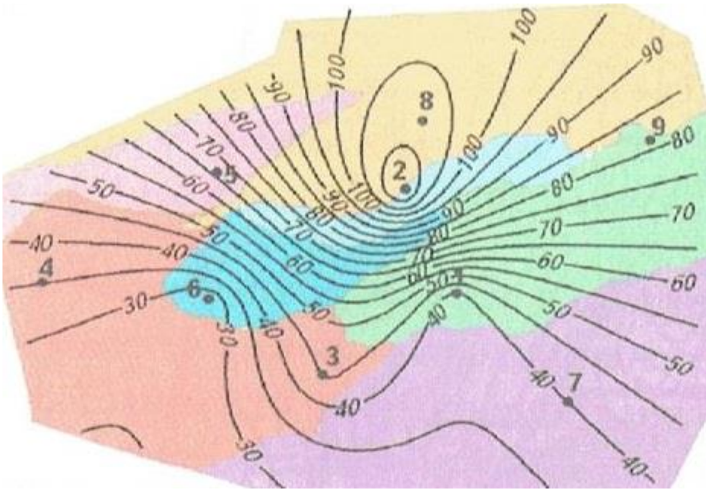

Figure 1-8 Distribution of the total porosity coefficient for the Daginskoye horizon of the Yuzhno-Kirinskoye field [6].

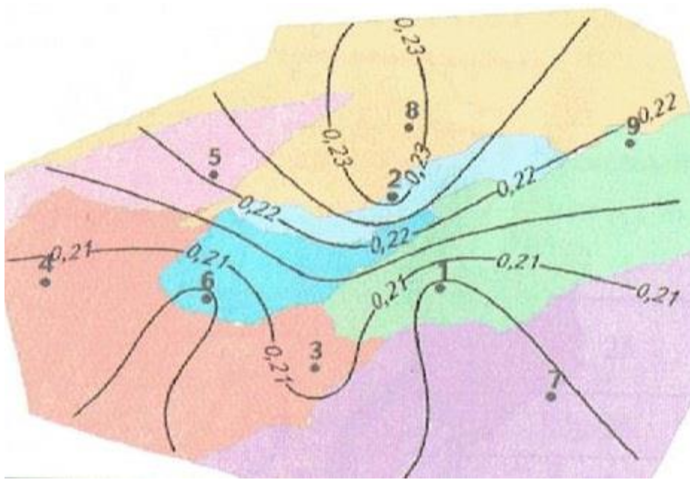

Figure 1-9 Distribution of permeability coefficient in 10^{-3} μm2 of Daginskoye horizon of Yuzhno-Kirinskoye field [6].

Conclusions: It can be seen that shale content decreases significantly in the northeastern direction. The models show that the highest values of porosity and permeability are observed on the north wing, with a slight change in porosity, there is a noticeable change in permeability.

Chapter 2 Possible schemes of the Yuzhno-Kirinskoye gas condensate field development

2.1.Feasibility study of a prospective field development system

The world prospects for the development of the hydrocarbon resource base are associated with the continental shelf of the Barents, Kara and Sea of Okhotsk, where the harsh climate conditions, the presence of ice and rigged ice in the greater part of the year does not allow the traditional methods of hydrocarbon production and transport from wells on the shelf. Therefore, the development of hydrocarbon deposits on the Russian shelf requires special and even exclusive innovative and technological approaches. For the Yuzhno-Kirinskoye gas condensate field, all the equipment, which and communications connecting wells with the onshore control complex are located on the seabed and are reliably protected. There is nothing above sea level. Therefore, everything that happens on the surface - low temperatures, ice movement, storms, ship passage, and so on; has no significant impact on the production process. A similar system is envisioned at the Yuzhno-Kirinsky gas condensate field.

Design solutions for field development and development of the Kirinskiy block of the Sakhalin-3 license area are conditioned by three main factors: seasonal ice conditions, water depth and distance to onshore infrastructure facilities.

Given the relatively small number of wells and the proximity of onshore facilities, the development and construction of the Yuzhno-Kirinsky gas condensate field is planned to use subsea production technologies, which reduces the field start-up time and ensures the transportation of hydrocarbons to onshore facilities in a multiphase condition.

For example, consider the Kirinskoye field which is shown in figure 2-1, where the field is developed with a help of subsea production units that are connected by production pipelines to a gathering manifold, from where a gathering subsea pipeline delivers well production to the onshore CPF

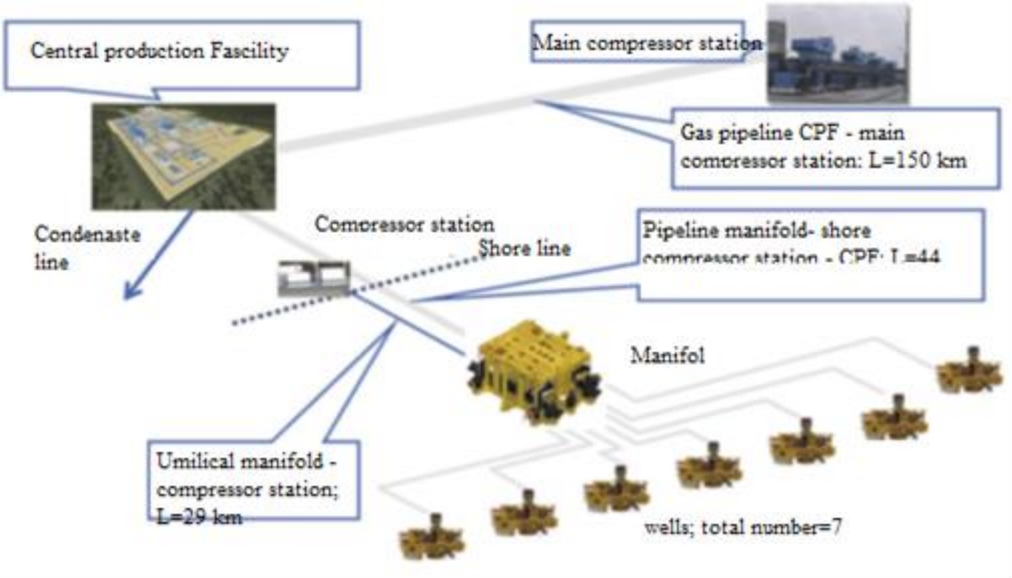

Figure 2-1 Kirinskoye gas condensate field development scheme [7].

The subsea production system design must meet the following conditions:

1) long-term operation with minimal maintenance;
2) constant state monitoring and control from the coastal control room;
3) automatic performance of emergency shutdown operations by signals from the self-test system;
4) availability of possibility of early diagnostics of the events leading to the necessity of maintenance;
5) modular replacement possibility of units and assemblies by means of remotely operated submersibles in ice period;
6) availability of possibility of launching and receiving of diagnostic devices in the pipeline in the area of its landfall;
7) availability of possibility to perform well interventions from floating devices with access to the wellhead via the block of Christmas tree without its disassembly during the ice-free period;
8) possibility to integrate new equipment into the production complex at the subsequent stages of operation and to connect it to the control system;
9) availability of possibility to connect a second redundant control unit with further transfer of dispatching functions to it;
10) availability to increase the productivity through connection of additional wells or connection with neighboring fields.

To meet these requirement of subsea production system equipment of Kirinskoye field includes:

1) gathering manifold;
2) subsea wellhead equipment of seven wells;
3) export gas pipeline;
4) central production facility;
5) system of in-field pipelines and umbilical;
6) subsea launching/receiving chambers for pigging;
7) hydrate inhibitor suppling pipelines with MEG;
8) connecting elements of pipelines (PLETs,);
9) block box of acid corrosion inhibitor;
10) onshore equipment to control the subsea production complex.

As the several fields contained in Kirinkskiy block two possible schemes of complex development of the Kirinskiy block are proposed at this moment:

The first option is supposed to contain subsea complexes and use reservoir energy to deliver multiphase fluid flow to a stationary ice-resistant gravity based offshore platform located in water with depth of the sea about 100-120 meters. This scheme is shown in the Figure 2-2.

Figure 2-2 Development scheme of the Kirinskiy block including an ice resistant platform [7].

The second option involves using subsea complexes for each field and use reservoir energy to deliver multiphase fluid flow to onshore facilities, that is shown in the Figure 2-3. In this method there is an assumption that all the fields are developed separately and the first commissioned field is Yuzhno-Kirinskoye.

Figure 2-3 Development scheme of the Kirinskiy block including only subsea production units [7].

Conclusion: coming from the climate data and the experience of Kirinskoye field, in this thesis the option including subsea production systems is chosen as more preferable. However, due to the inability to use compression of the fluid on the platform in the next chapters the idea of implementing subsea compression units is observed in order to elongate the production plateau and improve the economic indicators.

Chapter 3 Overview of existing subsea hydrocarbon transportation systems.

3.1Subsea production and transport systems description

One of the existing method to increase the coefficient of gas extraction is to elongate the plateau duration via implementing the subsea compression station.

There are several varieties of subsea compressor stations, which differ in the equipment used, which depends on the phase composition of the formation fluid and the number of reservoirs. As it is may be seen on the Figure 3.1 in most cases, such station includes:

1) separator;
2) compressor to transport the gaseous phase of the reservoir fluid;
3) pump for pumping the liquid phase of the reservoir fluid;
4) reservoir header;
5) pump and compressor drives;
6) gate valves;
7) umbilicals and cables;
8) measuring units;
9) the anti-surge system.

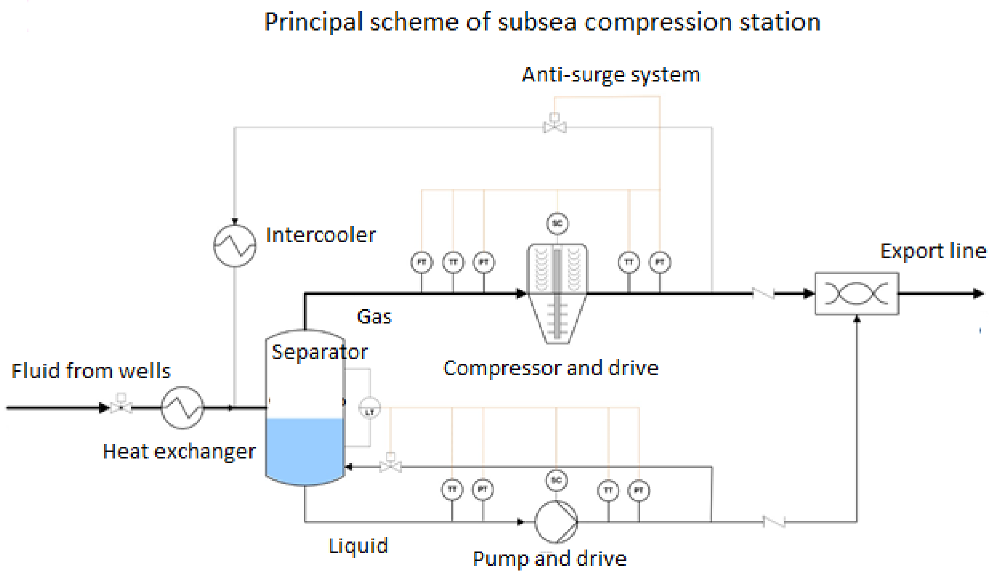

Figure 3-1 Principal scheme of the compression station [8].

There are subsea compressor stations able to transport well fulid to the shore. This makes it possible to avoid considerable capital investments for building an offshore platform. An example of such a field is Ormen Lange in the Norwegian North Sea.

Another option for an offshore compressor station is to combine an offshore compressor station with an offshore platform, which frees up valuable platform space for other operations. An example of this type of field arrangement is the Norwegian Asgrad field.

3.2Experience in the application of subsea transportation systems.

In foreign practice, the launch of subsea compressor stations was initiated by Norwegian specialists with subsea tests of a pilot station in Nyham in a 14 m deep pool in 2011. The installation in the Ormen Lange field was planned, which would have had a capacity of 12.5 MW with a capacity of 15 million m3/day. Emphasis was placed on power supply systems, variable speed drives and electrical connectors, and the system was equipped with acoustic leak detection, in figure 3.2 it is represented.

Figure 3-2 Compressor unit from the Ormen Lange field in the Nyhama basin on the commissioning phase [9].

Only a few fields are currently operated with a subsea compression system, such as Statoil's Norwegian fields Gullfaks and Asgard in the North Sea.

In 2015, a unique subsea compression system was installed in the Gullfaks field, which increased production by 22 million barrels of oil equivalent, raising the gas recovery rate from 63% to 73%. The Gullfax field is scheduled to be developed through 2030. The subsea production compressor station will increase the flexibility of the development system, where three additional flowlines will allow satellite wells to be tied into a system that will be compressed in the future, making room on the platform for other processing units. In this field, the volumetric gas content is about 98%, the compressor system has dimensions of 43 x 18 x 12 m, its total weight reaches 1070 tons, designed for 32 atm compression, the maximum percentage of liquid phase by volume is about 0.25-1.9%, the unit consists of two compressors with liquid piston, each with capacity of 5 MW. [10].

According to the information provided, during commissioning work, one of the compressors was operated for 563 hours in the Gullfax field with no identified problems, the second compressor operated 4 hours and was stopped due to problems in the electrical drive. Further work will be done to identify and prevent leaks. Statoil predicts that the subsea compressor systems will be able to develop large capacities and start "dead wells". [10].

Asgard was supposed to recover 306 million barrels of oil equivalent. The reason is that in order to maintain a stable production rate and to prevent the accumulation of mono-ethylene glycol (MEG) in the flowline, gas pressure from the Mikkel and Midgard satellite fields had to increase the Asgard B platform. The lack of space on top of the platform meant that the alternative to subsea compression was a new compression platform. Subsea compression was chosen as the development concept in 2010.

The Åsgard field, which has been in operation since 1999, lies 200 meters beneath the water surface and is 200 km off the Norwegian shore. It is being developed via the Åsgard B semi-submersible floating platform and Åsgard A FPSO, Åsgard C being the storage vessel for the gas condensate that is later shipped to the Åsgard B platform. Installation of the subsea compressor station at this field will help recover additional 306 million barrels of oil equivalent hydrocarbons. The installation consists of 2 multiphase compressors, each with a capacity of 11.5 MW. The maximum liquid phase content in the compressor can reach 3% by volume and the pressure drop is 50 bar. The total mass of this unit reaches 4,800 tons. The first station was launched on October 16, 2015, and the second began operation on January 28, 2016. [11].

As it was mentioned above subsea compression increases recovery, accelerate production, reduces carbon footprint, mange the flow-assurance of the project in quite a cost-effective manner. Figure 3-3 presents us the scheme of Asgard field, and the Figure 3-4 shows the Gullfaks field layout.

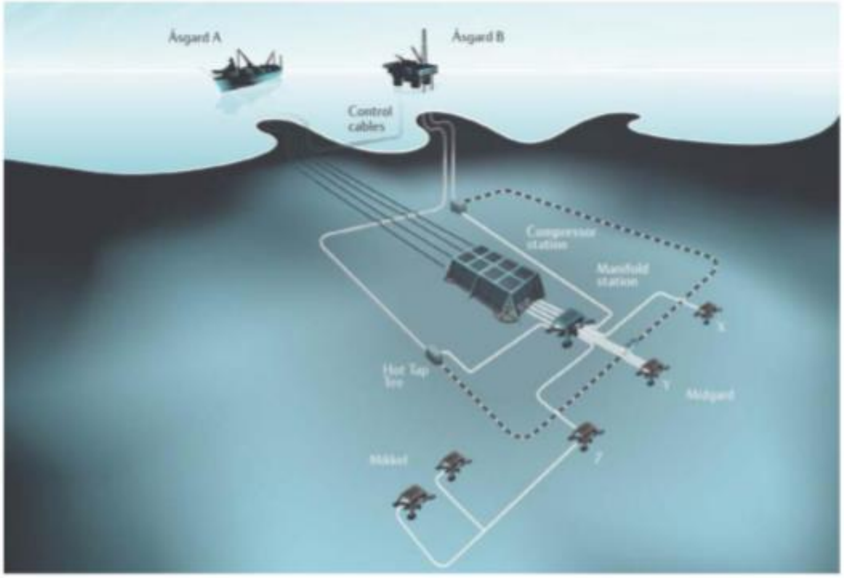

Figure 3-3 Asgard field layout [10].

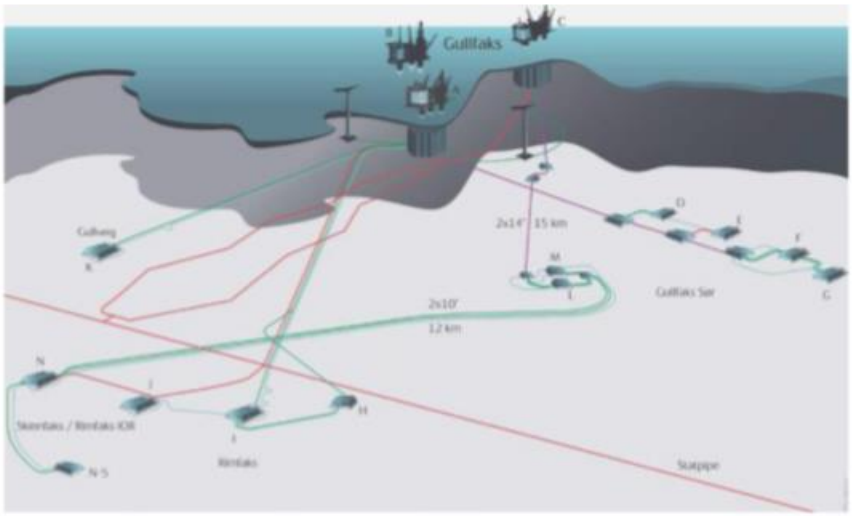

Figure 3-4 Gullfaks field layout [10].

The Table 3.2 shows the main characteristics of subsea production stations offshore Norway, namely the Gullfaks and Åsgard fields. You can also see the difference in equipment and capacity between the two SPSs.

Table 3.1

Comparison of subsea compression stations installed on the Asgard and Gullfaks fields

Field	Gullfaks	Åsgard
Start-up	Q4 2015 (planned)	16 September 2015
Design lifetime	20 years	30 years
Water depth	135 m	250-325 m
Gas Volume Fraction	98-99.75 vol %	97 vol %
Compression system structure size	43 x 18 x 12 m	75 x 45 x 20 m (L x W x H)
Compression system weight	1070 tonnes	4800 tonnes
Design gas flow rate	10 MSm^3/d	21 MSm^3/d
dP (pressure boost)	32 bar	50 bar
Design pressure	390 bar	210 bar
Liquids (max) into station	0.25-1.92 vol %	3 vol %
Max liquids into compressor	0.25-1.92 vol %	0.46 vol %
Step out	15 km	40 km
Additional gas recovery	22 million barrels of oil equivalent Recovery increase from 63 to 73%	306 million barrels of oil equivalent Recovery increase from 67 to 87% (Midgard) and 59 to 84% (Mikkel)
Power	2 x 5 MW wet gas compressors (each with 2 x 2.5 MW motors driving contra rotating impellers)	2 x 11.5 MW centrifugal compressors (with upstream gas scrubbing)

The Asgard field commissioning was carried out onshore, which allowed better control of the safety system and automation and allowed all the work to be carried out in less time than underwater commissioning.

Conclusion: as foreign experience shows, subsea compression systems allow to increase gas recovery factor and oil recovery factor significantly. They can operate in water areas with significant depths and have a great potential for further development in the future.

3.3 Benefits and drawbacks of subsea hydrocarbon transportation systems.

The application of subsea compressor stations makes it possible not only to increase the gas recovery factor, but also to develop previously unreachable fields and increase the profitability of field development, as well as provide an uninterrupted supply of well products to the shore. These systems can be operated in seas with severe climatic conditions where other types of field facilities cannot be used or are too costly. They also make it possible to free up space on platforms for other technological tasks, such as drilling new wells. Moreover, subsea production systems with subsea compressor stations are more eco-logical than platform-based field development.

These systems have limitations that prevent their application in the fields located more than 300 km offshore due to high losses in the electric cable. The fact that there are not many specialists who can operate subsea equipment, moreover, such systems are very expensive and have low reliability at the moment, also plays a great role. These systems need to be buried in freezing seas at depths of no more than 10 meters to avoid damage to the equipment by ice hummocks. Possible difficulties in operating these systems include:

loss of oil followability at low temperatures;

the possibility of gas hydrate plugs formation at low temperatures, high pressures and high produced water content;

Russian legislation prohibits dumping produced water into the sea; part of the power is spent on pumping it;

the possibility of paraffin deposits formation in the pipelines;

possible damage of the pipelines or equipment by trawlers;

high cost of the equipment itself and works connected with installation and servicing of this equipment.

In order to prevent the formation of gas hydrates, as in the Norwegian Asgard field, a system that includes a separate pump for gas condensate in addition to the compressor is used. Also for this purpose, piping of discharge lines with hot water can be used, as at the Gullfaks field.

Conclusion: in Russia, these technologies can be used in the fields of the Kirinskiy block of the Sakhalin-3 project, where subsea production systems are planned, as well as in the Leningrad and Rusanovskoye fields in the Kara Sea, where difficult climatic conditions do not allow applying another type of field arrangement.

3.4 Existing equipment for subsea hydrocarbon transportation systems.

As can be seen in the figure 3-5; an subsea gas field development system using an underwater compressor station includes :

1) integrated base plate and manifold complex;
2) subsea heat exchanger;
3) subsea separation unit;
4) control system signal and chemical distribution module;
5) subsea pipeline termination manifold;
6) compression units.

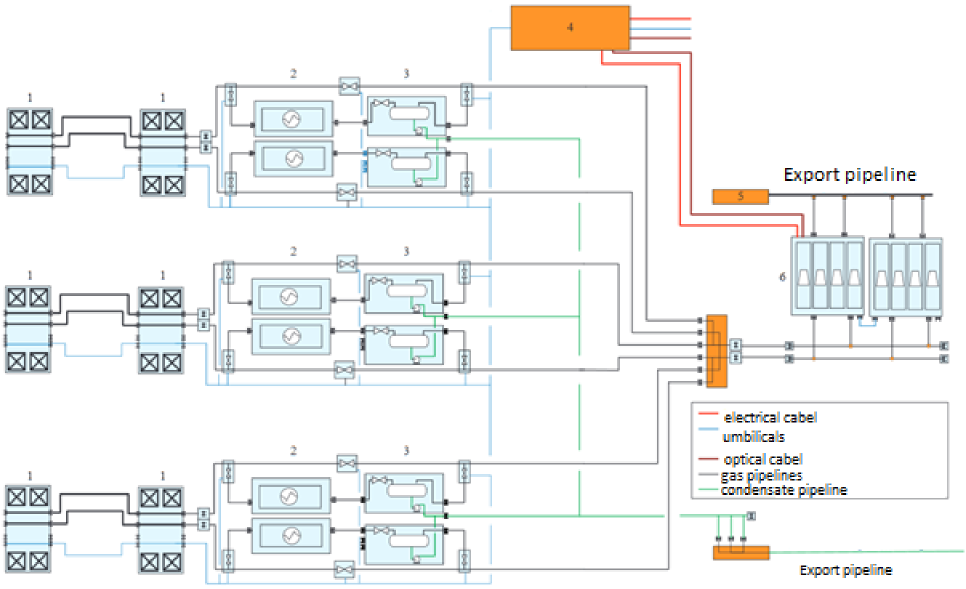

Figure 3-5 Principal scheme for the subsea compressor unit [**Error! Reference source not found.**].

The detailed description of the equipment is to be represented. Separator are used to separate the phase components of a reservoir fluid. At present several technologies of primary underwater separation are applied in the world:

1) two-phase liquid/liquid separation, realized using traditional gravity separators of sufficiently large size or using compact separators, such as caisson separators. The caisson separators are

2) Two-phase liquid/gas separation which is realized similarly to the previous technology;
3) Three-phase separation, when oil, gas and produced water need to be separated from each other. Horizontal separators are often used for three-phase separation, such as the Tordis (Norway) separator, in which the well fluid is first sent to a separation tank equipped with an inlet cyclone separator. In this separator, most of the gas stream is separated from the flow and the remaining water, oil and gas are separated by gravity inside the separator tank, see the figure 3-6.

Figure 3-6 Separator for the Tordis project [12].

Vertical separators are more efficient for gas-liquid separation. Such a separator was, for example, installed at the Pazflor field (Angola). The peculiarity of this separator is the presence of a spiral insert which allows to avoid a free fall of liquid and increases the efficiency of phase separation. The lower part of this separator is conical in shape to avoid sand accumulation. The solution proved to be cost-effective and enabled the operator to successfully develop the field, which is characterized by low reservoir pressure and heavy, high-viscosity oil.

FMC Technologies constructed a caisson-type separation unit for the deepest Perdido project in the Gulf of Mexico . This project utilizes a custom-built cesspool well to perform the skimming process in the borehole space and an ESP to deliver the separated crude oil to the platform for further treatment. In these separators due to the tangential inlet flow inside the caisson a swirling flow is created, providing separation of the droplets to the walls of the separator. [14].

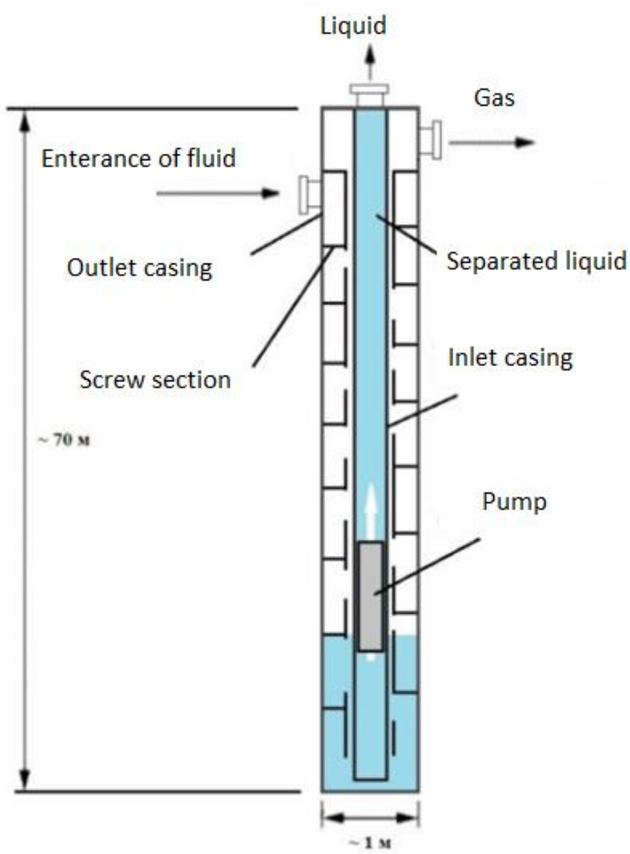

Figure 3-7 Separator for the Tordis project [14].

Recently, a new direction in natural gas separation has been developed - the technology of separation in a supersonic swirling flow called 3S-technology (Super Sonic Separation), the principal scheme of this equipment is shown in figure 3-8. The technology is based on cooling of natural gas in a supersonic swirling gas flow. Separators produced in accordance with this technology not only allow liquid to be separated from the gas, but also select individual target hydrocarbon fractions. In supersonic separation technology the supersonic gas flow is realized by means of a Laval diffusion nozzle. In such a nozzle, gas is accelerated to velocities higher than the speed of sound propagation in gas. At the same time, due to transition of a part of potential energy of the flow into kinetic energy, gas is strongly cooled. Application of a diffuser at the outlet of the working part of the 3S-separator allows by braking to convert part of the kinetic energy of the flow into potential energy.

This provides obtaining (at the outlet of the diffuser) gas pressure greater than static gas pressure in supersonic nozzle, at which condensation of target components occurs. [15].

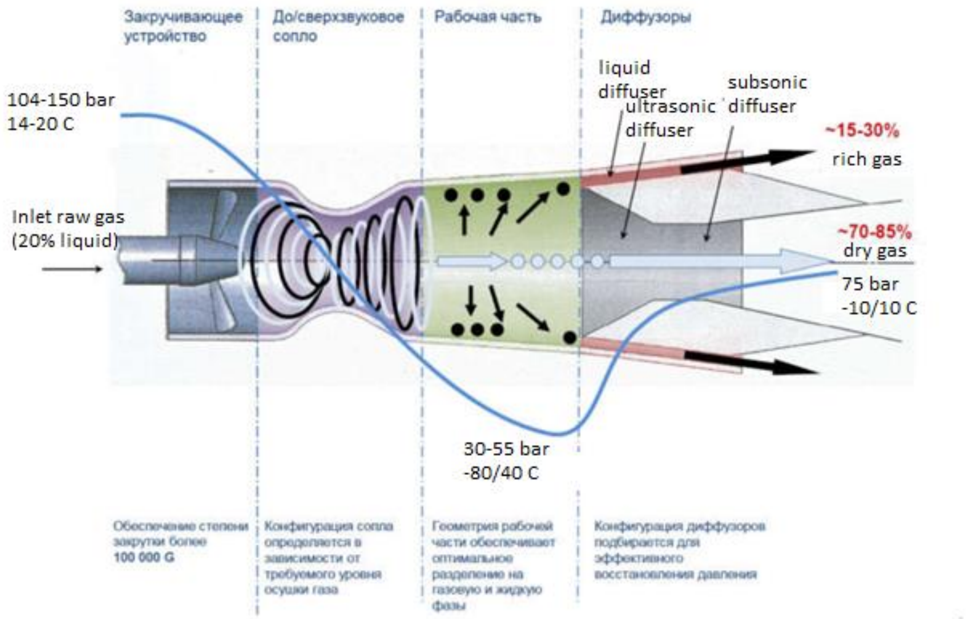

Figure 3-8 Supersonic separator [15].

At the moment the Gasprom company gained experience in testing these separators at the Zapolyarnoye in 2009 , based on the results of these tests 3S - separators were recommended for use at other facilities of Gazprom.

Nowadays there is no experience in implementing subsea separation on the Russian shelf, besides, these systems would require certification in Russia Federation. Due to very strict rules of the Russian Maritime Register of Shipping it could take a long period of time, thus here comes into action the assumption that the subsea processing and separation are not required for the first years of filed life. The idea of subsea separation is going to be under consideration alongside with the concept study phase of subsea compression station. Thus, in this work the multiphase pumping is taken into consideration.

Equipment for multiphase transportation of reservoir fluid is divided into types, depending on the pumped medium and the gas liquid ratio. In the Figure 3-9 the efficient work graph is shown for each type of the multiphase pumps.

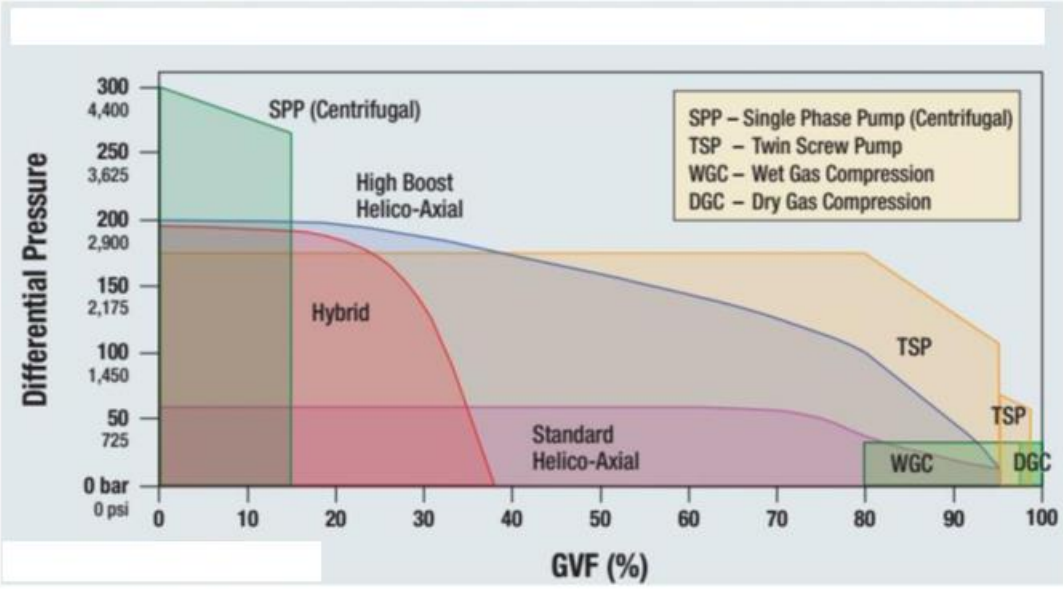

Figure 3-9 The dependence of differential pressure and operating capabilities from the GVF for multiphase pumps and compressors [16].

Currently, there are several possible types of equipment suitable for pumping wet gas:

- Piston pumps.

Piston pumps, are one of the simplest types of multiphase pump. The gas mixture is fed into the cylinder by suction. The volume of the cylinder is then reduced, causing the pressure to increase to the point where the mixture can be discharged into the piping behind the pump. This technology is used in installations with a medium pumping volume - between the smaller screw pump installations and the larger twin screw pump installations. These pumps are small enough to be used on single wells, but powerful enough to pump production from multiple wells. They can be used as grease gas compressors and can withstand considerable periods of time with only the gas phase flowing in the absence of liquid.

The following types of equipment are distinguished for pumping the multiphase product:

- Twin-screw or triple-screw pumps.

For multiphase pumping, twin-screw pumps are the most widely used. In a twin-screw pump, a working volumetric cavity is created by meshing two rotating screws. Unlike a single screw pump, where the steel rotor is in physical contact with the rubber stator, in a twin-screw pump the rotors do not touch - there is a small gap between them and between each shaft and casing. Twin-screw pumps are most commonly used for pumping heavy oil, but are now gaining use in offshore installations and for pumping conventional oil. The high volumetric capacity of these pumps leads to their use in installations serving several wells/well clusters. The main disadvantage is that the higher the gas content, the worse the pump performance, the lower the head and flow rate. Figure 3-10 shows the principal scheme of a twin screw-multiphase pump.

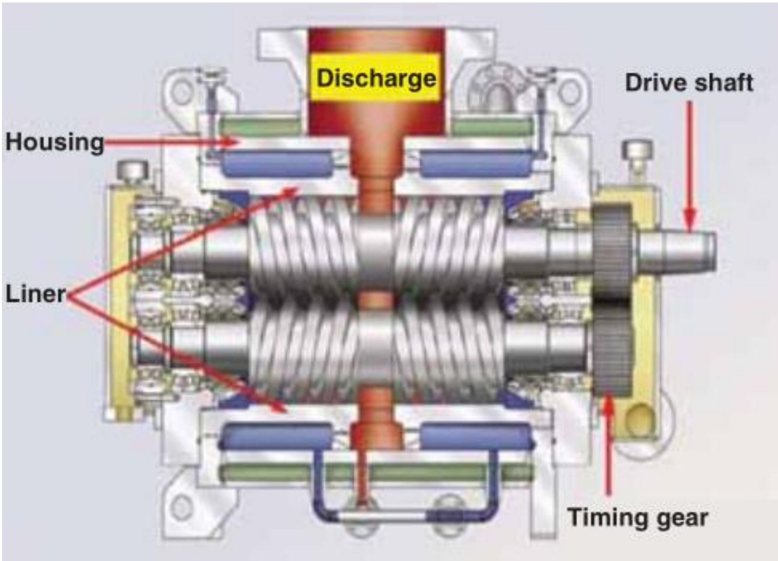

Figure 3-10 Twin-screw pump scheme [1717].

- Helico Axial Pumps

The spiral-axial centrifugal pump was developed and tested in the Poseidon project. This technology uses a spiral-axial fluid pathway to improve performance when pumping a multiphase mixture. This technology was found to have advantages over submersible centrifugal pumps commonly used in oil fields, in which the fluid moves in a radial rather than an axial direction. Spiral-axial pumps are commonly used to pump very large volumes of oil, such as in Yukos' pumping units in Siberia and Total's Dunbar units in the North Sea. There is a tendency to use such units for pumping mixtures with a medium gas volume ratio. An intrinsic disadvantage of centrifugal technology is that gas and liquid streams separate in the pump cavity and the pump loses its ability to raise pressure substantially at some point. It is generally accepted that once the gas volume ratio reaches 80%, other pumping technologies become more efficient. While recirculation systems have been used successfully by manufacturers to increase this upper gas ratio limit, spiral-axial pumping technology has a distinct advantage at medium gas ratios. In the Figure 3-11 the principal scheme of the HAP bundle is represented

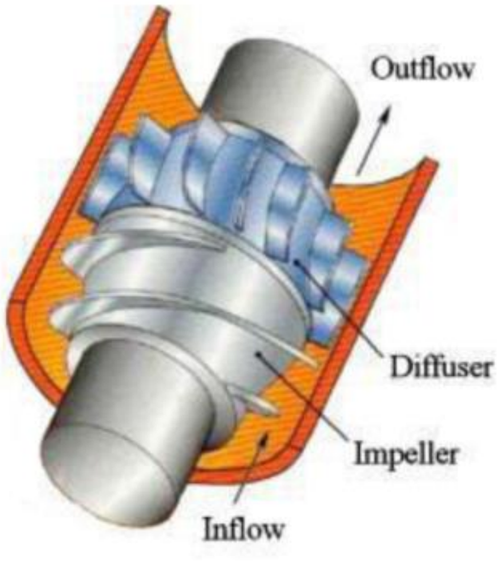

Figure 3-11 HAP bundle [1617].

Conclusion: At this moment the most preferable options for the subsea compression on Yuzhno-Kirinskoye field are HAP and twin-screw pumps due to its high operational and conceptual capabilities. But a more detailed study will be made on further phases of the project development. Moreover, by the time the research started, new kinds of equipment for subsea compression may come to light and should be taken under consideration.

Chapter 4 Schemes selected for the Yuzhno-Kirinskoye gas condensate field development analysis.

4.1Subsea production and transport systems description

Currently, there are several concepts for the subsea development of Yuzhno-Kirinskoye gas condensate field, which include the cluster method and with a help of templates. Both options include a two-line export pipeline which help to threansport well production, where it is compressed at the onshore compression station, after which the field production is delivered to the CPF.

The entire list of equipment for the SPS was presented above. The purpose of this chapter is to describe the key points for selecting the method of developing the Yuzhno-Kirinskoye field and to describe several proposed options.

First of all, it is worth paying attention to the subsea manifold. Manifold system is used in the subsea oil and gas industry to simplify piping, collect fluid form wells, direct fluid, and distribute chemical reagents and hydraulic fluid for control systems. Manifold is a system of pipes, valves and gate valves that work together to optimize and control reservoir production, in the Figure 4.1 the principal scheme of this equipment is represented.

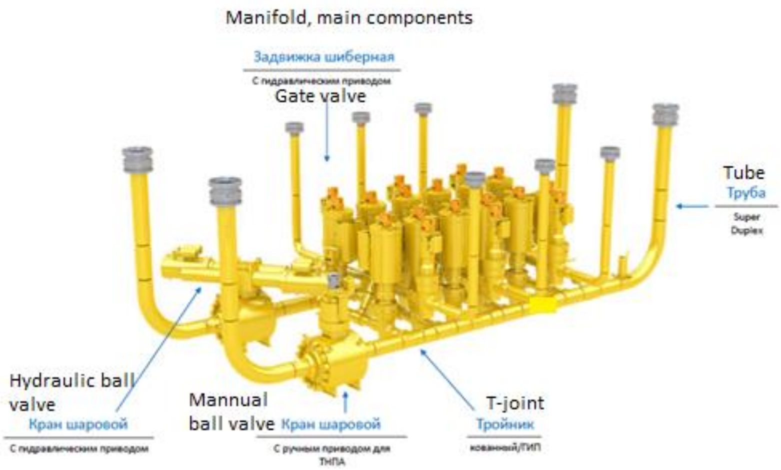

Figure 4-1 Principal scheme of the manifold [1817].

The scheme of the Yuzhno-Kirinskoye field gas-condensate field facilities includes the following two types of manifolds: central gathering manifolds CM1 and CM2, which are connected to the gas gathering manifold, and manifolds for collecting production from production center wells.

The central manifolds must be equipped with a distribution system for MEG, carbon dioxide corrosion inhibitor, methanol, hydraulic and eclectic energy of the subsea equipment control system. If a pressure relief line in the piping is included in the hosepipe, the connection is also made in the manifold distribution system.

The standard weight of a prefabricated manifold varies from 200 to 350 tons, depending on the manifold diameter and the number of pipelines connected to the manifold. The manifold diameters of the CM1 gathering manifold correspond to the diameter of the strings of the connected gas gathering manifold. While smaller manifolds have less weight and are used to collect production directly from wells, after which the reservoir fluid is routed to gathering manifolds and further to the export pipeline.

The first key point for selecting the optimal development method for the Yuzhno-Kirinskoye gas condensate field is to consider two possible schemes for well installation and production gathering manifolds.

The Figure 4-2 illustrates the main options at this time, with prefabricated manifolds. Cluster method of development is going to be described below. While the integrated manifolds (HOST), referred to in this paper as templates, will be described in an alternative arrangement.

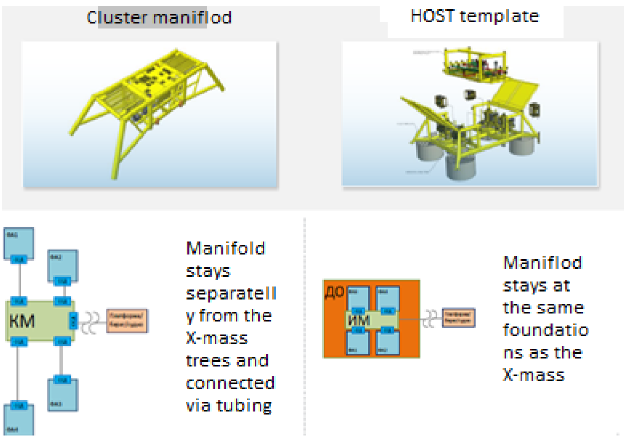

Figure 4-2 Principal scheme of the manifold [1817].

The Table 4.2 shows the main differences between two proposed options of development.

Table 4.2

The differences between cluster method and HOST method of development

Cluster method	**Method implementing HOST templates**
Placement of single wells connected with manifold through tubing	Placement of 2-4 X-mass trees on one basement
Connection of X-mass tree with the manifold:	Joint X-mass trees with the maniflod via flexible or ridged connectior (less than 5 m length)
flexible joint (about 40-50 м)	
tubing insert connetcion	
infield pipeline	
Higher scope of construction and installation work	Less scope of construction and installation work
Manifold can be installed independently from drilling	Requires template installation for drilling
Alongside work of drilling ship and crane vessel possible	Impossibility of alongside work of drilling ship and crane vessel
Each X-mass tree and manifold possess its own protection structure, that requires a crane vessel with smaller capacity	Common protection construction for X-mass trees and manifold, that reqires a crane vessel with higher capacity
In case when the well is lost, new one could be drilled near and that is not crucial for the fluid flow	In case when well slot is lost it is impossible to drill a new well from this position
Long lead item	Long lead item
Certificated in Russia and Kirinskoye field is existing analogue	New technological solution for Russian shelf and not certificate yet, have no analogue in Russia

In addition to the differences shown in the table, as far as the Yuzhno-Kirinskoye field is concerned, the use of templates is limited by the following factors:

1) the presence of significant accumulations of shallow gas in the area of the field significantly increases the risk of an emergency situation during well construction, as a result of which further use of the drilling slot in the temple structure, and in the worst case, the whole temple will be impossible. Given the presence of geological hazards, the construction schedule for all wells in the Yuzhno-Kirinskoye field implies two-stage drilling (first year - up to the roof, second year - completion of the well), which allows correcting wellhead location coordinates in case of gas leakage and reducing overall design risks. In this context, the use of satellite wells is the preferred solution, as it gives additional flexibility to the project;
2) the experience of using templet structures in the North Sea shows that higher economic efficiency of templet application in comparison with a separately located manifold is provided in case of development of the production center for 4 or more wells;
3) The use of temple construction causes the necessity of more complicated and time-consuming operations during maintenance and repair of flowing fittings and manifold at the stage of operation;

Therefore, due to combination of all factors, the choice in this work cluster arrangement is more preferable and chosen as a main option. The Figure 4-3 shows the arrangement scheme, which implies the described method of Yuzhno-Kirinskoye field development in this work. This scheme was implemented in the presented work with minor modifications, which include connecting clusters of 4 wells and 1 manifold for each cluster in order to save money and time for crane operations of manifolds and pipeline termination devices, the Figure 4-4 presents this option.

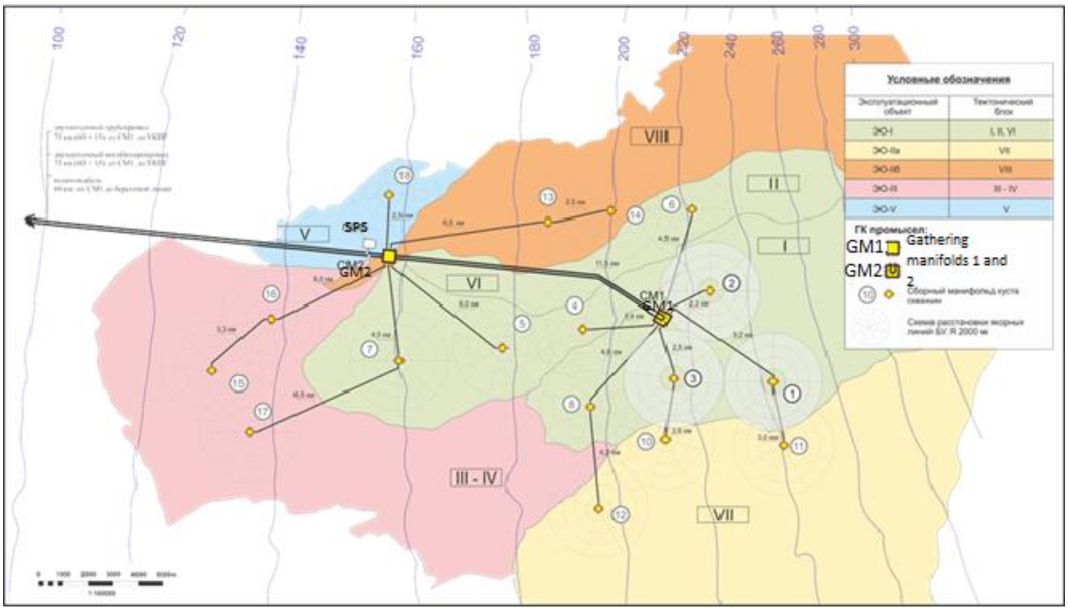

Figure 4-3 The map of field development including blocks of the field[1917].

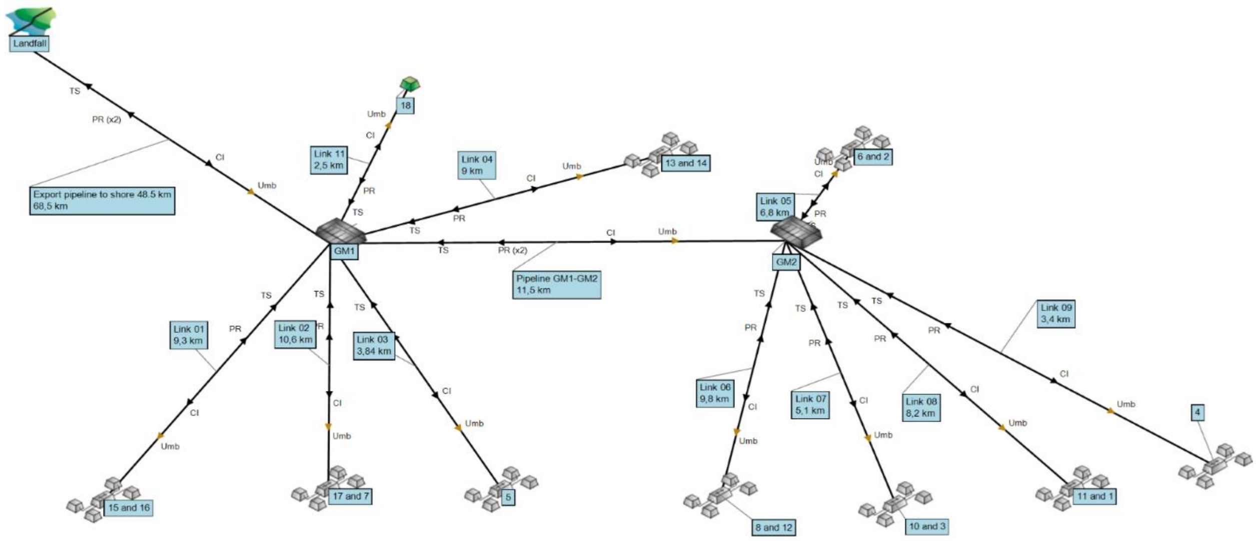

Figure 4-4 Principal scheme of field development gained from Questor17.

In this figure in cluster manifolds are marked with Arabic numerals, while Roman numerals represent different geological formations.

Technological scheme of arrangement with intermediate manifold for field development options considered below provides installation of two main gathering manifolds (GM1 and GM2), which groupe into production centers production of wells, delivered by interfield pipelines. Manifold block is used for mixing of formation products, distribution of inhibitors and chemicals among wells, distribution of hydraulic energy of well control system.

Well products in multiphase condition are supplied from the field to CPF via two-line pipeline connecting both manifolds with total length of 70 km. The GM1 manifold unit, which is the pipeline termination manifold, is equipped with a loop for pigging. Which allows for a circular run of the pipeline cleaning and diagnostics tools when they are launched from onshore facilities.

Pipeline duplication is recommended to ensure reliable and trouble-free operation of Yuzhno-Kirinskoye field facilities and is advisable in difficult natural and climatic conditions of the region, as well as limited accessibility during the ice season.

In order to prevent hydrate formation at wellheads and in the system of infield pipelines MEG is supplied through collecting manifolds, supplied from CPF. The Figure 4-5 shows the CPF process flow diagram for this project.

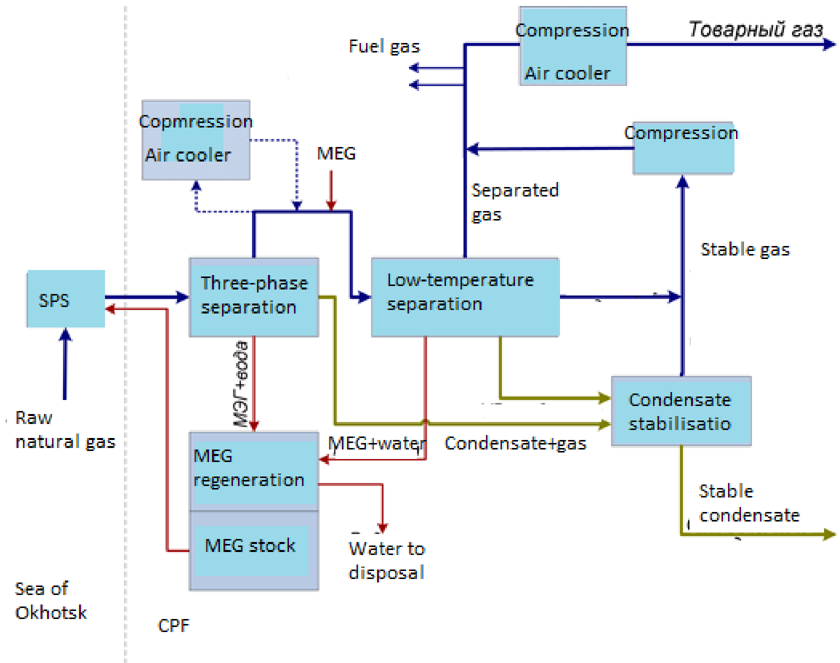

Figure 4-5 Principal scheme of the manifold [1917].

To compare the technical feasibility of various options for developing the Yuzhno-Kirinskoye field and greater project flexibility, two export pipeline options with diameters of 32" and 36" were selected on the basis of Gazprom VNIIGAZ data. Each has its own advantages and disadvantages, which are described below.

The advantage of the double-stranded 36 diameter manifold compared to the 32 diameter manifold is the later introduction of the second line and will reduce pressure losses. Because of which the inlet of the onshore compression station and subsea compression station can be moved further in time, as well as lower costs for this equipment because of lower energy consumption, since less differential pressure will be needed.

The disadvantage of using a 36" diameter pipe is its operation in the area of fluid accumulation regime for a longer time interval. It is necessary to note, that at the beginning of the field with 8 wells (instead of 6 wells at 32") the gas flow rate in the 36" diameter collector pipe will reach 84% of the minimum allowable productivity, which is comparable with the load of the 32" diameter collector in the first year of operation. The table below (Table 4.3) shows Gazprom VNIIGAZ's calculation of pressure drops for two options for the export pipeline with applying both onshore and offshore compression stations. This calculation will help determine the flow regimes, identify the risks of fluid accumulation in the export manifolds and select the best one from a technical aspect.

Table 4.3 [19]

The calculations for pressure drop in export line for different export line diameters

Year of development	Daily flow rate; mln m3	Pressure drop from gathering manifold 2 to the CPF cia the 32” export line; MPa	Pressure drop from gathering manifold 2 to the CPF cia the 36” export line; MPa
1	13,842	1,40	1,64
2	18,456	1,37	1,39
3	23,070	1,64	1,30
4	32,298	1,32	1,62
5	39,219	1,40	2,07
6	46,140	1,62	1,29
7	49,918	1,77	1,31
8	54,132	1,96	1,38
9	56,532	2,07	1,42
10	63,840	2,46	1,60
11	63,682	2,44	1,60
12	63,504	2,43	1,59
13	60,552	2,27	1,52
14	60,552	2,27	1,52
15	60,552	2,36	1,52

Year of development	Daily flow rate; mln m3	Pressure drop from gathering manifold 2 to the CPF cia the 32” export line; MPa	Pressure drop from gathering manifold 2 to the CPF cia the 36” export line; MPa
16	60,552	2,47	1,57
17	60,552	2,70	1,61
18	60,550	2,84	1,66
19	60,550	3,18	1,72
20	60,550	3,59	1,88
21	60,550	4,17	2,02
22	60,550	4,17	2,28
23	60,550	4,17	2,45
24	60,550	4,17	2,88
25	60,550	4,17	2,88
26	59,598	4,13	2,91
27	54,879	3,69	2,72
28	50,325	3,54	2,23
29	46,332	3,16	1,87
30	42,867	2,84	1,60
31	33,291	2,02	1,19
32	28,776	1,68	1,12
33	20,286	1,16	2,01
34	14,672	1,72	1,35
35	13,377	1,54	1,03
36	8,890	1,07	1,24
37	5,436	1,49	1,71
38	2,540	2,03	2,24
39	1,674	2,32	2,56
40	1,104	2,65	2,88

The Figure 4-6 shows the pressure drop as a function of years after first gas production for the two export pipeline options was constructed from the data provided above.

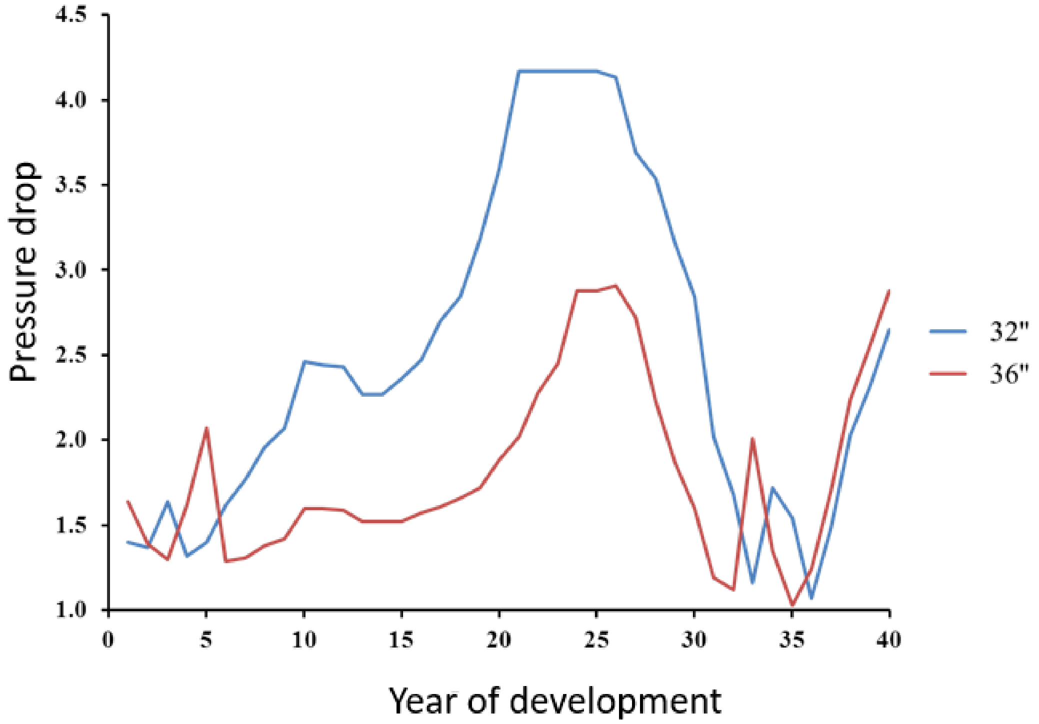

Figure 4-6 Dependence of pressure drop in export pipelines from the year of field development[1917].

Three options of development were selected for further calculation of economic efficiency:

1. Option with installation of onshore compressor station, but without installation of SCS with double-stranded 32" export pipeline. This option is the baseline for comparing the feasibility of installing the SCS.

2. Option with installation of onshore copression station and SCS with double-strand 32" export pipeline.

3. Option with installation of onshore compression station and SCS by double-strand 36" export pipeline. This option is the baseline for assessing the feasibility of installing a larger diameter export pipeline.

Production exports at this stage of project development are assumed to be as follows. For gas, the main options for sales are: transportation via the Sakhalin - Khabarovsk - Vladivostok pipeline, construction of an LNG plant in Vladivostok, conversion of gas to LNG and further sales in APR countries.

Condensate can be transported via a tie-in to an existing oil pipeline that goes on to an oil loading terminal in the south of Sakhalin Island in the village of Prigorodnoye (condensate is not considered in economic efficiency calculations). The Figure 4-7 provides an insight into the scheme of hydrocarbon transport in the Far East region of Russia.

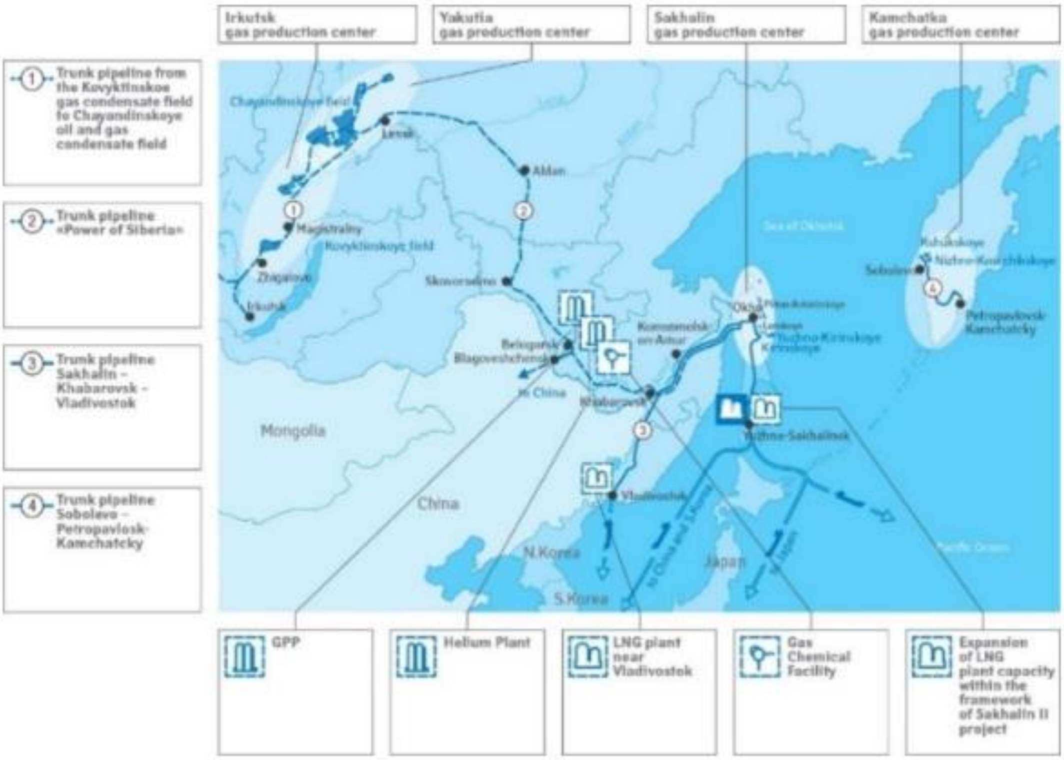

Figure 4-7 Hydrocarbon transport facilities in the Far East region of Russia [**Error! Reference source not found.**17].

The following assumptions were made for all development options of the Yuzhno-Kirinskoye field:

1) At the moment the project is at the stage of definition concept study after conducting geological exploration.
2) Specification of diameters of export pipelines is made at the next phases of design.
3) The scheme of the CPF equipment and onshore booster compressor station capacity will be specified at the next design phases.
4) At the moment the design scope is limited to the development of offshore facilities and onshore booster compressor stations, so the product marketing routes will be clarified during the next design phases.

Chapter 5 Possible risks during Yuzhno-Kirinskoye field development.

5.1 Risk of gas hydrate formation

First of all, it is crucial to highlight the possibility of formation of gas hydrates. Gas hydrates are solid crystalline compounds of natural gas components (from C4+) and formation water, which are formed under certain thermobaric conditions. At low temperatures and high pressures, the moisture contained in the gas can be converted from a gaseous state to a hydrate, bypassing the condensation phase to a liquid. In case of multiphase flow or insufficient dehydration of well production along the flow, the formation water droplet-liquid phase is released and further dispersed with the flow. After that, when the temperature further decreases in the system, the water droplets become hydrate film and become hydrate particles. These wet hydrate particles combine with each other, accumulating, especially in the lowering of the pipeline, which leads to the formation of hydrate plug, which overlaps the inner cross-section of the pipeline. The Figure 5-1 illustrates hydrate plug formation in a multiphase pipeline.

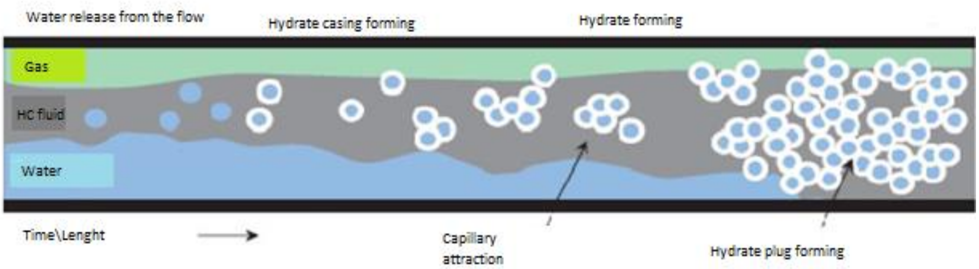

Figure 5-1 Gas hydrate plug formation in pipeline [18**Error! Reference source not found.**17].

As the Kirinskoye field development experience has shown, there is a probability of hydrate plugs in the considered area of the Sea of Okhotsk.

At the Kirinskoye field, reservoir gas from wells of subsea production systems is delivered for subsequent treatment to an onshore processing terminal. After treatment, gas is fed into the trunk pipeline. At the complex gas treatment unit gas is dehydrated, purified from heavy hydrocarbons, mechanical impurities, and natural gas and stable gas condensate are prepared for transportation in accordance with the requirements of STO Gazprom 089-2010, in which the requirements for the dew point of dehydrated gas by moisture and hydrocarbons are specified, depending on the macroclimatic region. [17]. This circumstance may require additional injection of a hydrate formation inhibitor both at GTP before the low-temperature separation unit, and in the gas gathering system of the field.

Factors contributing to hydrate formation and precipitation in the pipelines include:

1) insufficient drying of gas from water vapor;
2) the great length and depth of the gas pipeline;
3) difficult relief of the underwater part of the pipeline;
4) presence of bottom currents;
5) high cooling rates;

When the pipeline is long, it is difficult to control thermal and pressure conditions of the pumped medium because of a large number of factors which affect these conditions.

The hilly relief of the underwater part of the pipeline contributes to the formation of gas hydrates, as the liquid phase falls out and accumulates, mainly, in the lower sections of the pipeline.

In the pipeline, the pipeline products heat exchange with the seafloor and water masses carried by bottom currents, if any, has an effect on lowering the fluid temperature in the pipeline along its route.

It can be concluded that the main factors influencing the change of temperature and pressure of gas in the pipeline along its way are: the work of gravity and heat exchange of gas with different layers of water during immersion and landfall of the pipeline.

In pipelines of small diameter, the live cross-section is more easily blocked by hydrate plugs, as it requires a smaller size of hydrate plug.

Various methods are used to combat the formation of gas hydrates, which include:

1) Heating a portion of the pipeline with heating cables;
2) Using inhibitors of gas hydrate formation
3) Changing the diameters of the chokes to change the pressure in the gas export system.

The Figure 5-2 shows a diagram with different methods of gas gathering networks protection against hydrate formation.

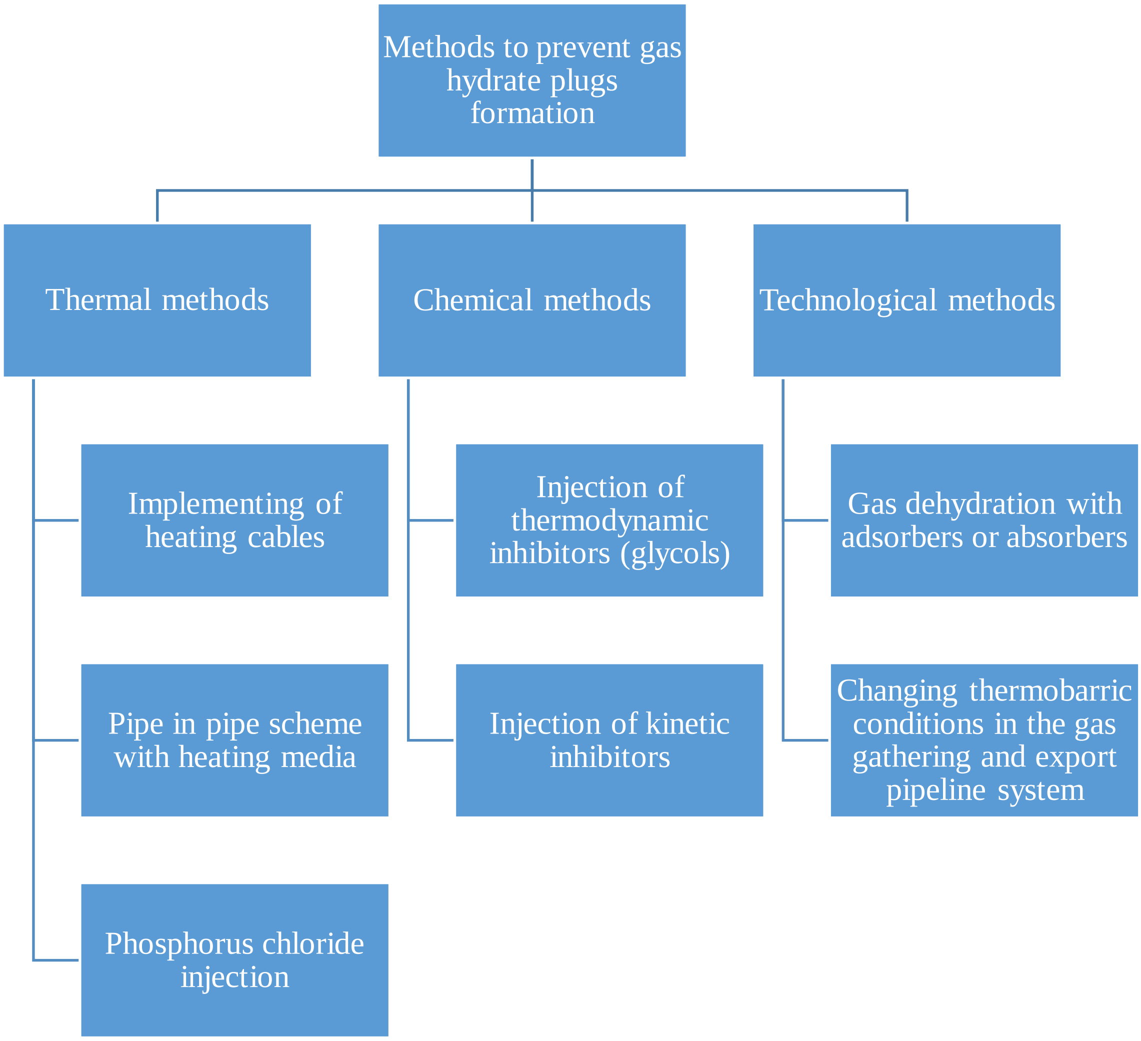

Figure 5-2 Methods of preventing gas hydrate formation

Let's consider each of these methods separately. Thermal methods are based on the principle of increasing the temperature of the flow by different heat carriers: water, steam, heating cable. Equipment standing on the shore or on the platform is used as a heat generator. An example of the heating cable application is the "Turkish Stream", where a part of the heating cable is laid on the pipeline section that goes up to the shore. It is also possible to feed the heating agent with a special bundling line at the outfall lines, as was done in the Gullfax field. It is possible to raise the temperature by an exothermic reaction by mixing $PCl5$ phosphorus pentachloride with water:

$$2PCl_5 + 8H_2O \rightarrow 2H_3PO_4 + 10NCl + 514\ J.$$

But since phosphorus pentachloride is extremely poisonous and very corrosive element, this technology has not been widely used.

Hydrate inhibitors are reagents that can affect the rate of hydrate formation (kinetic) or changing the thermobaric conditions of hydrate formation (thermodynamic).

Thermodynamic inhibitors are soluble in water, which change the interaction energy between the molecules of water, reducing the water vapor pressure above it, thus there is a decrease in the equilibrium temperature of hydrate formation (as is clear from the Mendelev-Clyperon equation, with decreasing pressure in a limited volume comes a decrease in system temperature). By acting directly on the hydrate plugs, the inhibitors also reduce the water vapor pressure above them and cause a gradual decomposition of the hydrate plugs.

Thermodynamic inhibitors of hydrate formation are alcohols, among which methanol, which is often used in the fields of Western Siberia, stands out. But it is worth bearing in mind that high toxicity of methanol and its fire hazard require strict compliance with safety regulations, which virtually minimizes the possibility of methanol poisoning of trained technical personnel. Nevertheless, there is always the possibility of an accident at any stage of the use of methanol as an inhibitor of hydrate formation at a particular site of the gas industry, and, as a result, methanol spills, environmental pollution and poisoning of personnel. Based on the shortcomings associated with toxicity, fire hazards, and insufficiently developed technologies for disposal of low concentration spent solutions, requirements were formulated for new inhibitors that could compete with methanol. These requirements include:

1) High reliability of the hydrate prevention process under field conditions and the ability to automate it.
2) Low toxicity of reagents;
3) Compatibility with conventional thermodynamic inhibitors;
4) Lower specific consumption of inhibitor and lower operational costs;
5) No need to regenerate the used inhibitor;
6) The possibility of injection of the used solutions of low concentrations into the formations. [21]

Another type of thermodynamic inhibitors of hydrate formation can be glycols, among which are monoethylene glycol (MEG), as well as aqueous solutions of calcium chloride salts or nitrate salts. But from an economic point of view, calcium chloride is the most advantageous option of the other salts. The advantages of this inhibitor are high melting hydrate activity, cheapness, easy preparation of solution and non-toxicity. The disadvantages are very high corrosive activity, the possibility of inorganic precipitation when mixed with saline formation water, the need for a special unit for the preparation of the working solution.

When comparing the thermodynamic inhibitors of MEG and methanol, it should be noted that due to differences in density (MEG is heavier) methanol will be present higher along the cross section in the pipe than condensate, while MEG will separate these flows, reducing the miscibility of these agents, thus reducing the probability of precipitation of gas hydrates. In the Figure 5-3 and Figure 5-4, the flow in gas flow with a high amount of hydrocarbon liquid.

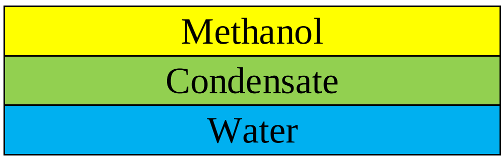

Figure 5-3 Flow in gas pipe with high amount of condensate and methanol as an inhibitor of gas hydrates.

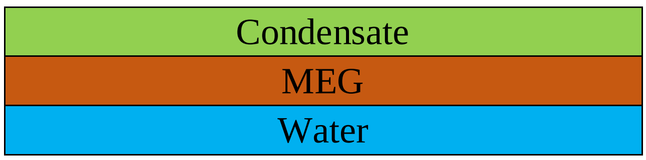

Figure 5-4 Flow in gas pipe with high amount of condensate and MEG as an inhibitor of gas hydrates.

Kinetic inhibitors are water-soluble polymer compositions in sufficiently low concentrations (0.5 - 1.0 wt.%) prevent for some time the hydrate formation process and dramatically slow down the growth of crystallization centers. These inhibitors change the consistency of the hydrate mass, making it fluid, for example, by dispersing gas hydrates in the gas-liquid flow or changing the conditions of adhesion (sticking) of hydrates to the internal surfaces of field communications.

Inhibitors are introduced into the gas stream before sections where hydrate formation is possible, for example, before low-temperature separation units or in a collecting manifold before products are transported to the shore in case of subsea development of the field. Injection is carried out centrally - from one unit at a gathering station into a group of wells, field communications and technological devices (by a dosing pump) or individually - into each object (by pump or by gravity flow). The maximal effect is reached at continuous supply of inhibitors (regardless of the input scheme) by means of nozzles (in sprayed state). Regeneration of spent hydrate inhibitors is carried out by rectification (for methanol and glycols) or evaporation (for calcium chloride solutions).

Figure 5-5 gives an insight into the component composition of the reservoir gas.

Block	Layer	Compound (mol) %									C5+ compound in gas (g/m3)	Molar fraction of dry gas
		CH_4	C_2H_6	C_3H_8	iC_4H_{10}	nC_4H_{10}	C_5H_{12+}	H_2	N_2	CO_2		
block I	DGII	82,04	4,84	2,84	0,66	0,93	5,15	0	0,40	3,14	230	0,9485
	DGI	84,12	4,92	2,83	0,64	0,94	4,54	0	0,35	1,66	205	0,9546
block III	DGII	79,38	4,72	3,05	0,78	1,10	7,62	0	0,49	2,86	356,6	0,9238
	DGI	81,29	4,61	2,88	0,75	1,07	7,46	0	0,28	1,66	349	0,9254
block IV	DGI	84,25	4,52	2,72	0,68	1,03	4,69	0,03	0,24	1,84	219	0,9531
block V	DGI	83,73	4,80	2,77	0,69	1,10	4,75	0,02	0,38	1,76	225,5	0,9525
block VI	DGII	82,97	4,74	2,60	0,70	1,11	5,38	0	0,33	2,17	254,2	0,9462
	DGI	85,09	4,48	2,25	0,58	0,89	4,72	0	0,25	1,74	224,2	0,9528

Figure 5-5 Flow in gas pipe with high amount of condensate and MEG as an inhibitor of gas hydrates [19].

Based on the data obtained, a representative plot was made for the phase diagram of the well production and the hydrate formation curve for the 32” export line, see Figure 5-6. For which was the volume of hydrate formation inhibitor injection, in this case MEG in the export pipeline. The total output MEG fraction is 0.058 % mol.

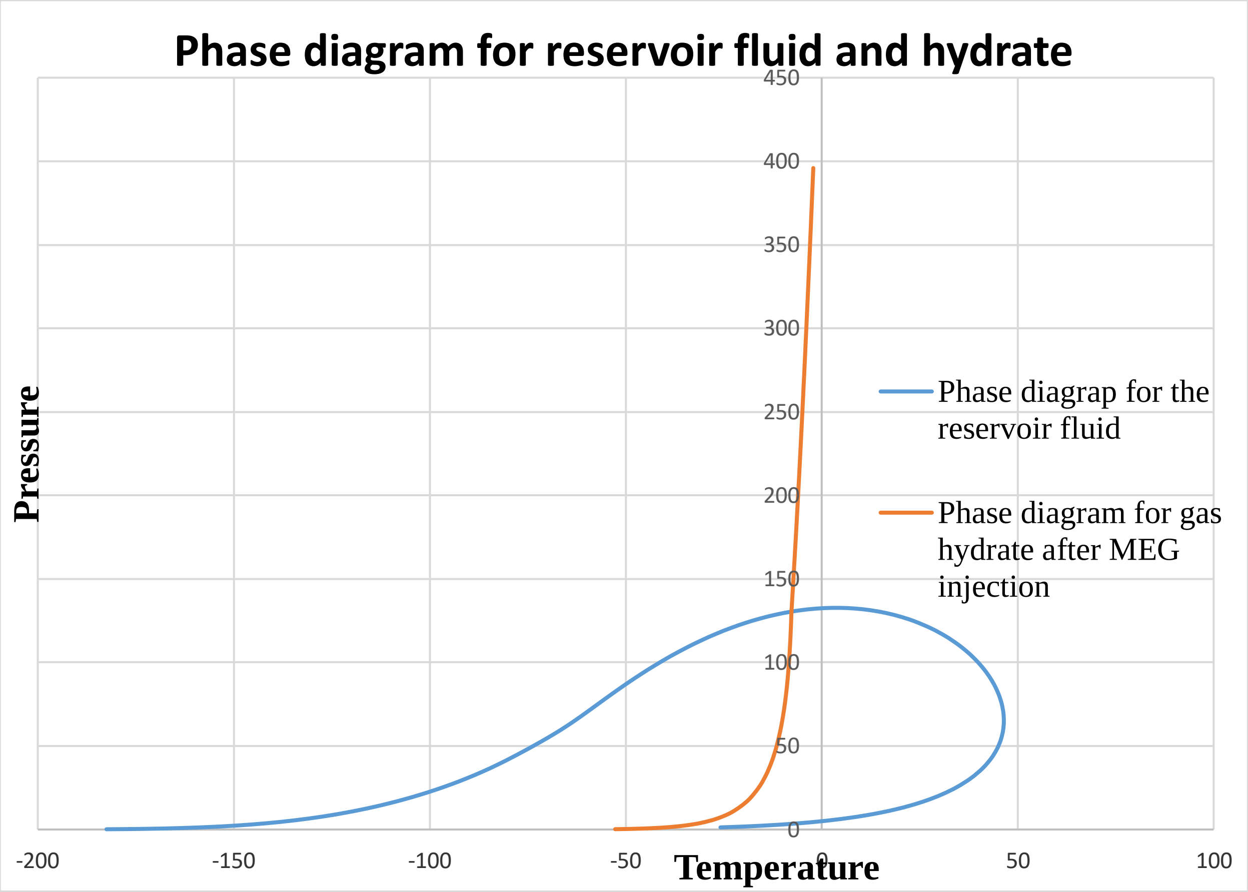

Figure 5-6 Phase diagram for the reservoir fluid and gas hydrate after MEG injection.

As can be seen from the graph, the necessary condition for the occurrence of hydrates in the export pipeline 32" is temperatures below 0 °C and pressure over 125 bar.

Conclusion: in this work, monoethylene glycol was chosen as an inhibitor of hydrate formation. It is also worth considering that the MEG supply system should prevent the possibility of hydrate formation, both in normal operation mode and in start-up and shutdown modes of the offshore production complex. Technical solutions with regard to the design of the main and in-field hoses should provide for the possibility of methanol supply to the wellheads and collecting manifolds.

5.2 Risks of abrasion equipment wear and water flooding of the productive formation.

When a reservoir is in operation for a long time, there is always the potential for sand or fine particles to be carried out of the reservoir. These particles can lead to abrasive wear of equipment, such as wellheads or inside field pipelines. This process can also be impaired if the liquid phase content in the perforated area of the payzone is high.

In order to prevent erosion of downhole equipment, the flow velocity at the wellhead is limited to 20 m/s. Nevertheless, at different stages of development of Yuzhno-Kirinskoye field fluid may complicate operation of wells, gas gathering system and gas treatment processes. Gas extraction can be maintained at the planned level by using a regulated choke. However, due to the lack of conditions for self-cleaning of the perforation interval and the bottomhole from liquid and mechanical impurities, there is a high probability that the liquid will start to limit the operating rate of the well.

Operating wells with a fluid phase that overlaps the perforation interval is a serious problem that affects the well's production capability. It is not possible to ensure conditions for carrying fluid with mechanical suspended matter out of the entire perforated interval of the wellbore. In the remote section of the wellbore from the end of the elevator string the gas flow rate will be insufficient to carry out the liquid. Deposition of liquid phase in the interval of productive formation perforation can lead to additional losses in pressure during gas phase movement, as well as to wetting and destruction of rock - reservoir, which can lead to deterioration of collision properties around the well and removal of small particles of solid fraction.

Water accumulation will lead to increased filtration resistances, further decrease in flow rate and eventually, quite likely to stop the wells. Sand accumulating in the perforation interval will provide additional resistance to gas inflow from the productive formation. The sand out of the well together with the gas will lead to abrasive wear of downhole and wellhead equipment.

To minimize the influence of periodic accumulation of liquid phase in the perforated zone of productive horizon on well operation it is recommended to use control and management systems, which will transmit real-time data on flow rate, pressure, temperature to the shore for further regulation of well operation parameters.

Equipment and technologies used in the development of the Yuzhno-Kirinskoye field must meet a number of requirements, which must be taken into account in the working designs of field development to ensure reliable operation of wells, namely:

equipment resistance to the impact of formation water with high salinity;

equipment resistance to high pressures and abnormal situations

adaptability to use of technological processes, which provide stable operation mode of wells with specified production volumes, including the presence of fluid and mechanical cuttings (sand, rock pieces, etc.);

Therefore, in order to prevent abrasive particles from being carried out of the formation, a gravel filter is made in the perforation zone. The Figure 5-7 provides the layout of downhole equipment for development of Yuzhno-Kirinskoye field.

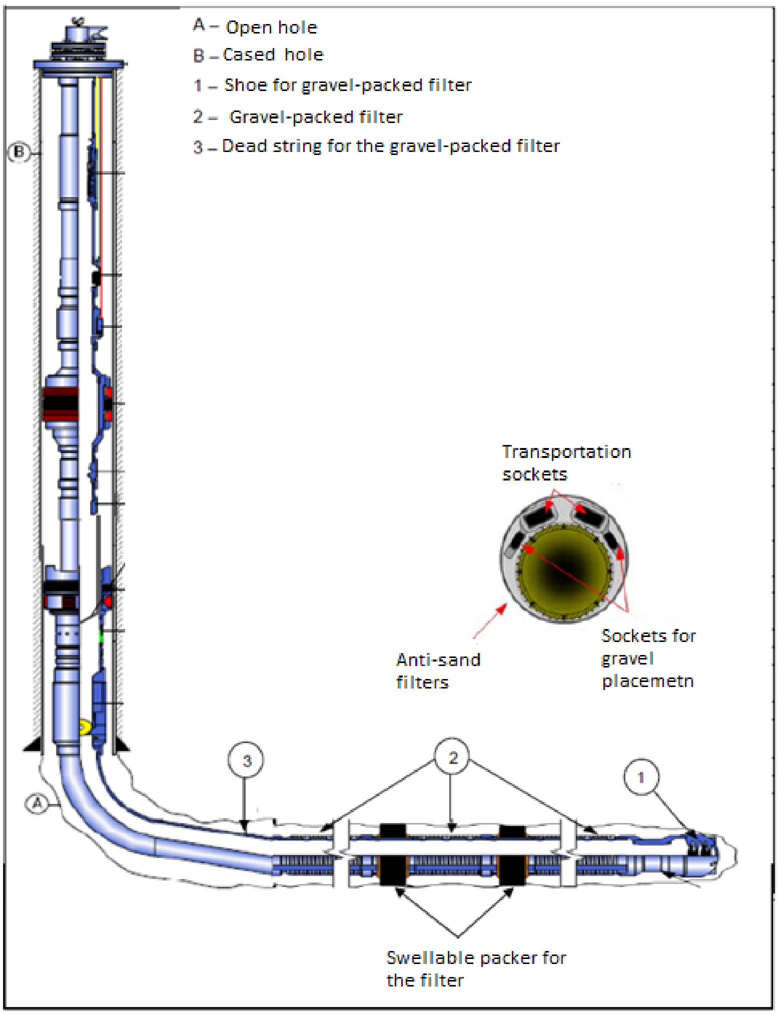

Figure 5-7 Layout of the gravel filter in the well [19].

Well operations will inevitably require operations that affect downhole equipment, the well itself, or adjacent reservoir areas. Well workovers will require the use of a jack-up vessel equipped with a reduced diameter blowout preventer to perform tripping operations.

The following subsea production systems may need to be worked on, which would require outside intervention:

1) failure of tubing;
2) failure of downhole filter;
3) removal of fluid liquid accumulations, which are limiting productivity of the well;
4) flushing sand plugs;
5) remedial cementing;
6) killing and abandonment of the well.

Each situation can be solved using a special support vessel or drilling platform.

Conclusions: To minimize emergency situations, it is recommended to install pressure and temperature sensors as part of the top-loading assembly to control and optimize processes that occur during gas production. The sensors should be tested under high vibration and thermobaric cycles. Also, the gravel filters must be installed in order to prevent the abrasive wear of the equipment, moreover, this filter should be replaced as the well starts to concentrate the liquid in downhole.

Chapter 6 Field development process description

According to the most effective solutions in the field of oil and gas field design, this process consists of several consequent stages.

It starts with a declaration of intent, which is prepared for a specific license area. Then comes the beginning of research (preliminary study), which tentatively determines whether the license area is of commercial interest or not worthy of attention. Then comes geological study, where 2D and 3D seismic is done, exploration wells are drilled, and reservoir and reservoir fluid data are clarified. This is followed by the concept study phase, which focuses on assessing the feasibility of the project and its alignment with the company's business strategies. This is followed by Pre-FEED phase during which the preferred option of the project is selected. After that the FEED phase takes place, where the final determination of the project scope, cost and schedule is made, as well as the question of funding. Often, at the end of the development stage, the FID (final investment decision) or FID (final investment decision) in English-speaking sources, this decision affects the fate of the project, whether it will be realized or not. Then comes the implementation stage, during which a functioning asset is created in accordance with the planned scope of work, budget and timetable, negotiations with suppliers are held, tenders are held, and contractors are selected. In many cases, companies choose different strategy of contracts with the contractor, they can hire a general contractor, who can monitor the implementation of the entire project, or enter into several EPC (engineering, procurement construction) contracts for the project. At the end comes the period of operation of the created project, where it is possible to refine the project based on new data obtained during the field operation. An important clarification is the fact that after each phase there is a decision point, where it is decided whether to move to the next phase of the project or return to a certain phase of the project for revision, or postpone the next phase until certain conditions, such as rising oil prices for the project to become profitable.

An important point is the assumptions made in this paper. The author considers the project at the stage of definition, because of the high degree of uncertainty of this problem and the little experience of Russian companies in implementing such projects. Also an important assumption is the fact that the design is done without taking into account the introduction of sanctions against Russian companies.

Chapter 7 Economic performance of prospective development schemes for the Yuzhno-Kirnskoe gas condensate field

7.1 Assumptions

This chapter reviews the economic performance of the three options presented, which will help to choose the most profitable and to direct the forces for its further development and implementation.

For this work the calculation of CAPEX and OPEX costs was made in a special software Questor. The data download will be provided for the preferred option in the appendix.

The following assumptions were made for all variants of the Yuzhno-Kirinskoye field development in this paper:

1) The project is currently at the identify stage (concept study);
2) The beginning of the geological research stage is accepted 2021, which is year zero for economic indicators calculation;
3) Condensate and oil are not considered in this model, due to its relatively small amount in reservoir fluid;
4) The exchange rate of the national currency (rub) is calculated as the exchange rate for 2021, taking into account inflation of 2%.
5) The discount factor for all options is 15%, based on the experience of offshore projects.
6) The following reference table for the ruble-dollar ratio and mineral extraction tax rate was used for the calculations. The full version of the table is given in the appendix.

Table 7.4

Table of reference data for calculating economic indicators for this work

Years of development	Rate	0	1	2	3	4	39
Exchange rate of national currency	RUB./$	74	75	77	79	80	87
MET (natural gas)	RUB./1000 m3	690	711	733	754	777	1632

7.2 Option without subsea compression station

This variant is basic for comparison of economic indicators and is considered for comparison with other options. First of all, it should be noted that to build the economic model, a production profile graph was built, based on the Gazprom VNIIGAZ graph, but slightly different from it, due to the introduction of the conversion factor and the production shelf reduced in time due to the absence of SCS The figure 7-1 shows the production profile for this variant.

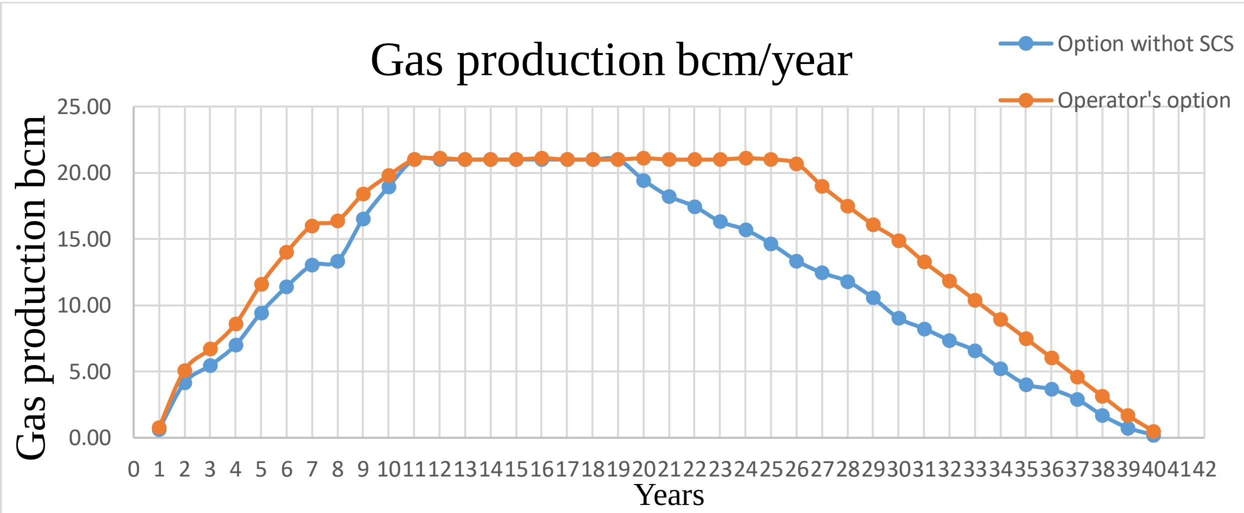

Figure 7-1 Production profiles for basic option and operator’s option .

As can be seen from the graph, the production shelf falls faster and more rapidly than that of the operator, this is due to the introduction of SCS under the option of Gazprom VNIIGAZ in year 22 of field development and the lack of this equipment in the basic option of this work.

The project implementation schedule was also developed for this work. The main theses of this schedule is the need to drill wells for at least two years due to the difficult ice conditions in the region.

The figure 7-2 shows this schedule of field development based on data gained from Questor.

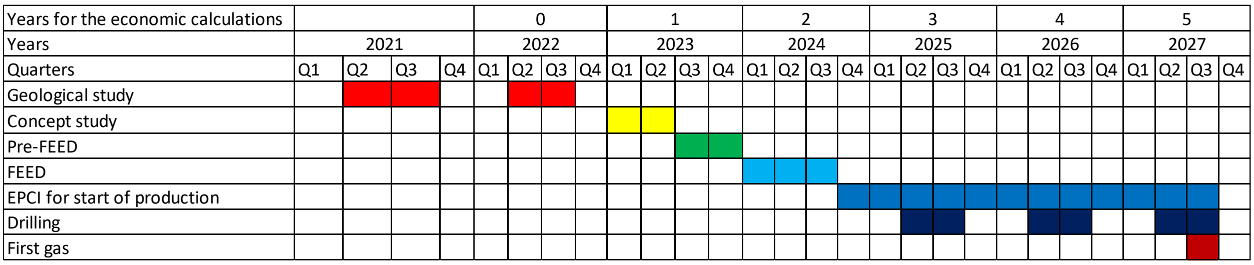

Figure 7-2 Field development schedule

As can be seen from the schedule, the start of natural gas production is scheduled for 2027, after the drilling of the first 6 wells. In this project, the second string of the export pipeline is scheduled to be commissioned in 2029, the 3rd year after the start of commercial gas production. The onshore compression station is scheduled to be commissioned in 2033, the 7th year, after the start of commercial production of the first gas. The presented milestones are clearly seen in the economic model of development under this option. The table below shows the main economic indicators.

Table 7.5

The economic calculation for the option without SCS

		Total
Technological data		
Gas production	mln.m3	**479 461,3**
Macroeconomic calculation conditions		
Gas price	$/1000 m3	See the appendix
Revenue		
Revenue from selling gas	mln.rub	3440437,049
Investments (CAPEX)		
Geological study	mln.rub	-
Drillex	mln.rub	**138 992,3**
Development (eqipment+logistics+installation)	mln.rub	**239 778,4**
Subsea compression station	mln.rub	**70 766,1**
Onshore compression station	mln.rub	**18 811,6**
FEL	mln.rub	**468 348,5**
TOTAL	mln.rub	
OPEX		4368,441
OPEX	mln.rub	
Taxes		
Net assets for equipment and wells	mln.rub	**49 449,1**
Property tax (2,2% amortisation period 7 years)	mln.rub	**449,2**
MET (natural gas)	mln.rub	**1 888 241,8**
Assessable profit	mln.rub	**377 648,4**
Income tax	mln.rub	
Cashflow		2414460,949
Operating cashflow	mln.rub	- **468 348,5**
Investment cashflow	mln.rub	**1 946 112,5**
Net cash flow	mln.rub	**22 378,7**
Net cash flow	mln.$	
Cumulative cash flow	mln.$	**0,2**
Discount factor		
Discounted cash flow	mln.$	
Cumulative discounted cash flow	mln.$	
NPV	mln.$	**2 225,2**
IRR	%	**18%**
DPI		**1,2**
Payout time	years	**28,0**

The key indicators are NPV, which equals $2,252.2 million, and IRR, which equals 18%. The Figure 7-3 and Figure 7-4 shows the curves of sensitivity analysis of the project as a function of gas prices and total capital costs.

Figure 7-3 Sensitivity graph for IRR

Figure 7-4 Sensitivity graph for NPV

7.3 Option with subsea compression station and 32” export gas pipeline

This option, when compared with the basic one, can help establish the necessity of installing an MPCS in the Yuzhno-Kirinskoye field, as well as is a baseline for comparing economic indicators with the option with a 36-inch export pipeline.

First of all, it should be noted that in order to build the economic model, a production profile graph was built, based on the Gazprom VNIIGAZ graph, but slightly different from it, due to the introduction of a conversion factor. The Figure 7-5 shows this graph.

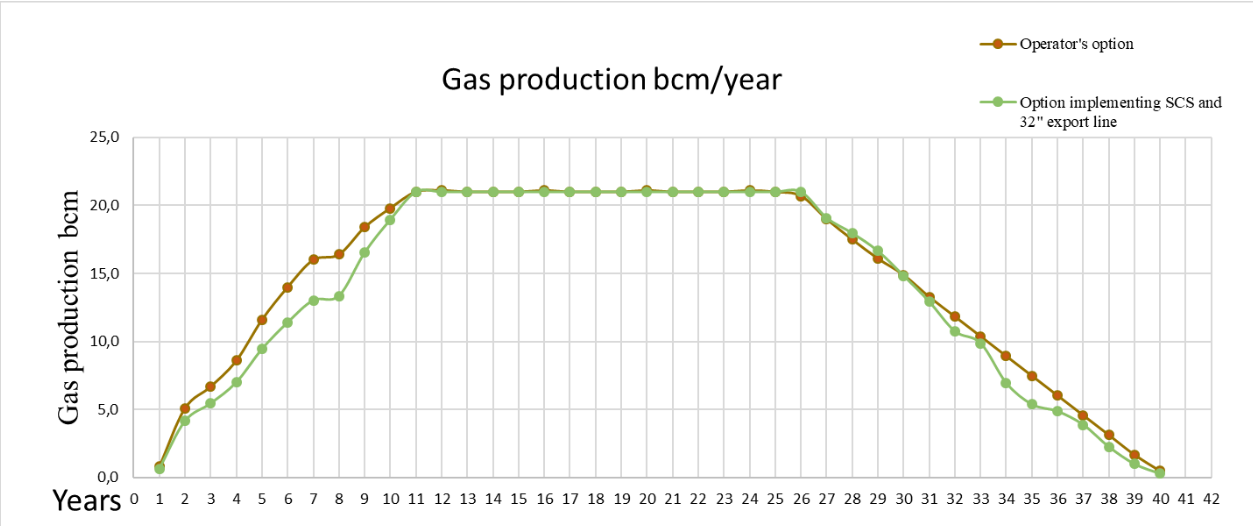

Figure 7-5 Production profiles for option with SCS and 32” export pipeline in comparison with operator’s one.

According to the graph, due to the introduction of the conversion factor at the stages of increasing and decreasing production, the flow rate by years falls faster and more rapidly than that of the operator, otherwise the graph repeats the graph of Gazprom VNIIGAZ due to the introduction of onshore and subsea booster compressor stations.

The project implementation schedule was also developed for this work. The main thesis of this schedule is the necessity to drill wells for at least two years due to the difficult ice conditions of this region.

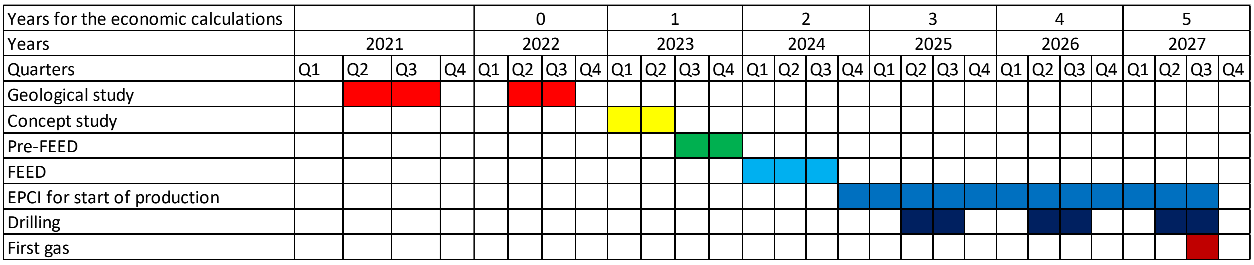

Figure 7-6 Field development schedule

The schedule shows that natural gas production is set to start in 2027, after the first 6 wells are drilled. In this project, the second string of the pipeline is scheduled to be commissioned in 2029, the 3rd year after the start of commercial gas production. The onshore compression station is scheduled to be commissioned in 2033, the 7th year, after the start of commercial production of the first gas. Commissioning of the offshore compressor station is scheduled for 2041, the 15th year after the start of commercial gas production. The presented milestones are clearly seen in the economic model of development under this option. The table 7.7 shows the main economic indicators.

Table 7.6

The economic calculation for the option with SCS and 32” export line

		Total
Technological data		
Gas production	mln.m3	**550 418,9**
Macroeconomic calculation conditions		
Gas price	$/1000 m3	
Revenue		
Revenue from selling gas	mln.rub	**4 050 537,7**
Investments (CAPEX)		
Geological study	mln.rub	**-**
Drillex	mln.rub	**138 992,3**
Development (eqipment+logistics+installation)	mln.rub	**239 778,4**
Subsea compression station	mln.rub	**19 508,1**
Onshore compression station	mln.rub	**70 766,1**
FEL	mln.rub	**18 811,6**
TOTAL	mln.rub	**487 856,6**
OPEX		
OPEX	mln.rub	**577 090,5**
Taxes		
Net assets for equipment and wells	mln.rub	**2 442 765,5**
Property tax (2,2% amortisation period 7 years)	mln.rub	**53 311,7**
MET (natural gas)	mln.rub	**449,2**
Assessable profit	mln.rub	**2 063 661,4**
Income tax	mln.rub	**412 732,3**
Cashflow		
Operating cashflow	mln.rub	**2 827 413,2**
Investment cashflow	mln.rub	**- 487 856,6**
Net cash flow	mln.rub	**2 339 556,6**
Net cash flow	mln.$	**26 916,1**
Cumulative cash flow	mln.$	
Discount factor		**15%**
Discounted cash flow	mln.$	
Cumulative discounted cash flow	mln.$	
NPV	mln.$	**2 408,2**
IRR	%	**18%**
DPI		**1,3**
Payout time	years	**29**

The key parameters are NPV equal to $2408.2 million and IRR equal to18%. The Figure 7-7 and Figure 7-8 below shows the curves of sensitivity analysis of the project as a function of gas prices and total capital costs.

Figure 7-7 Sensitivity graph for IRR

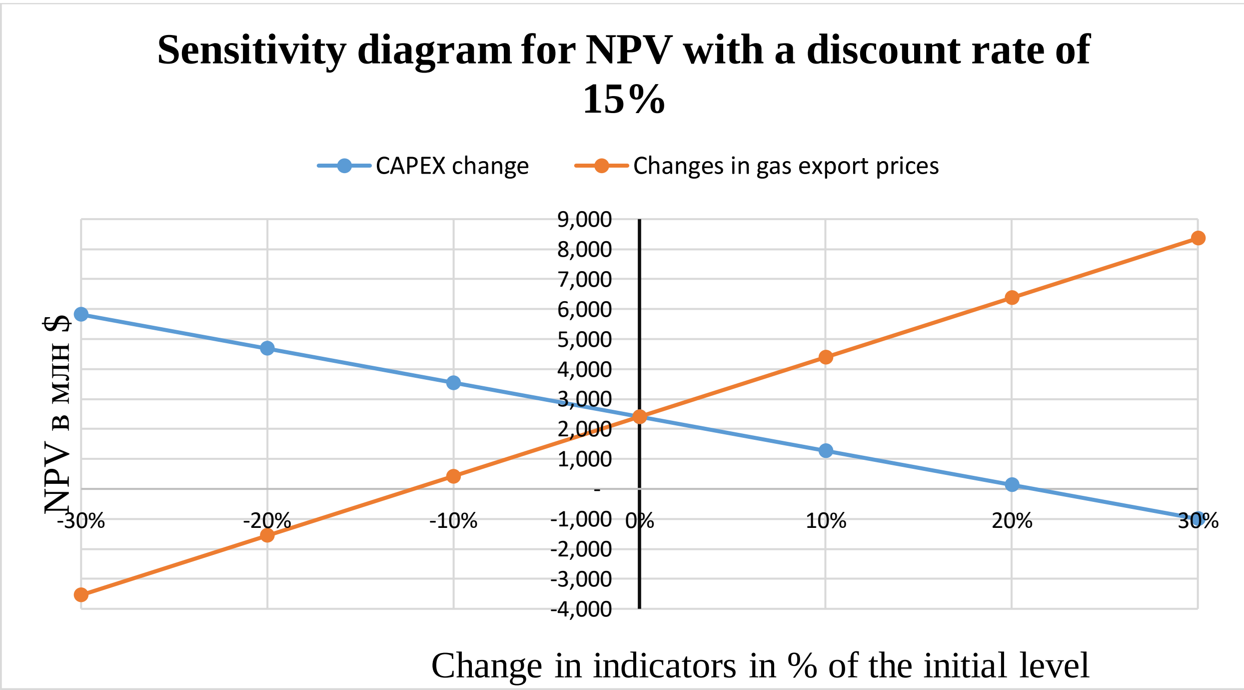

Figure 7-8 Sensitivity graph for NPV

7.4 Option with subsea compression station and 32” export gas pipeline

This option, when compared with the 32-inch pipeline option, will help establish the necessity of laying a 36-inch export pipeline.

First of all, it should be noted that to build the economic model, a production profile graph was plotted based on the Gazprom VNIIGAZ graph, but slightly different due to the introduction of a conversion factor as well as drilling more wells to run the 36-inch pipeline. The Figure 7-9 shows this graph.

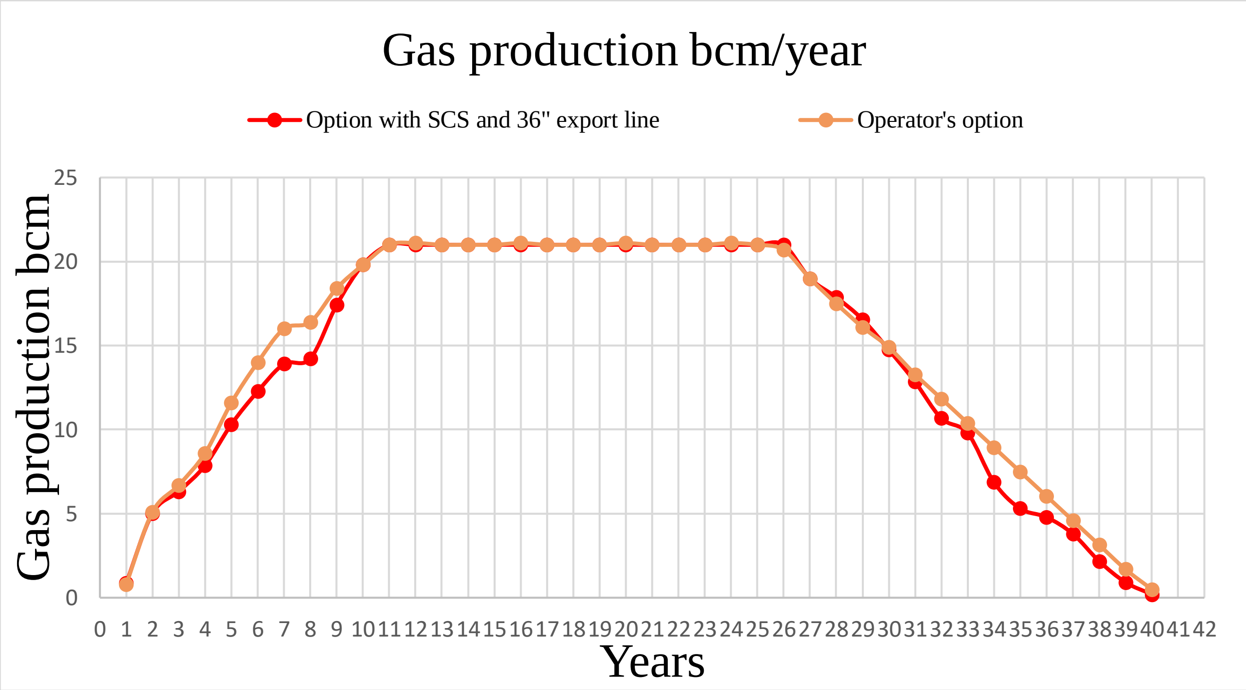

Figure 7-9 Production profiles for option with SCS and 36” export pipeline in comparison with the operator data.

As can be seen from the graph, due to the introduction of the conversion factor at the stages of increasing and decreasing production, the flow rate per year falls faster and more rapidly than that of the operator, otherwise the graph repeats the graph of Gazprom VNIIGAZ due to the introduction of onshore and subsea compressor stations. In the project was also developed a schedule for this work. The main thesis of this schedule is the necessity to drill wells for at least two years due to the difficult ice conditions in the region.

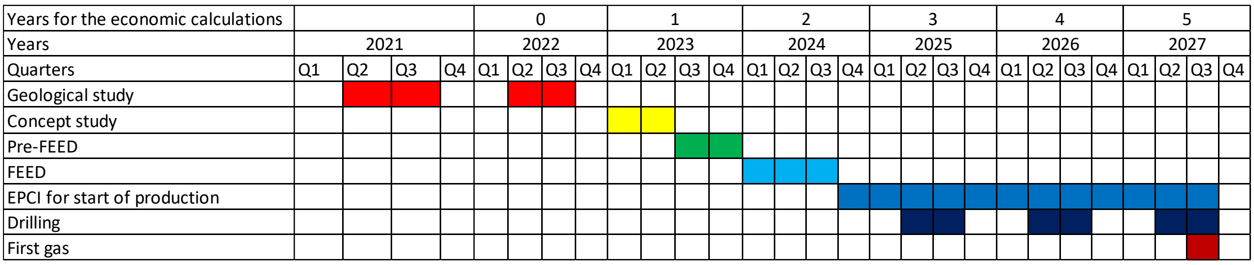

Figure 7-10 Field development schedule

As shown in the schedule, the start of natural gas production is scheduled for 2027, after the drilling of the first 8 wells, which will entail additional costs. In this project, the second string of the pipeline is scheduled for commissioning in 2031, the 5th year after the start of commercial gas production. The onshore compression station is going to be commissioned in 2034, year 8, after the start of commercial production of the first gas. The subsea compression station is scheduled for commissioning in 2040, the 16th year after the start of commercial gas production. The presented milestones are clearly seen in the economic model of development under this option. The table 7.8 gives an insight into the main economic indicators of this option.

Table 7.7

The economic calculation for the option with SCS and 36” export line

		TOTAL
Technological data		
Gas production	mln.m3	**557 673,7**
Macroeconomic calculation conditions		
Gas price	$/1000 m3	
Revenue		
Revenue from selling gas	mln.rub	**4 088 349,8**
Investments (CAPEX)		
Geological study	mln.rub	**-**
Drillex	mln.rub	**138 992,3**
Development (eqipment+logistics+installation)	mln.rub	**239 778,4**
Subsea compression station	mln.rub	**17 340,6**
Onshore compression station	mln.rub	**67 398,3**
FEL	mln.rub	**18 811,6**
TOTAL	mln.rub	**482 321,2**
OPEX		
OPEX	mln.rub	**552 123,7**
Taxes		
Net assets for equipment and wells	mln.rub	
Property tax (2,2% amortisation period 7 years)	mln.rub	**52 512,0**
MET (natural gas)	mln.rub	**449,2**
Assessable profit	mln.rub	**2 134 191,8**
Income tax	mln.rub	**426 838,4**
Cashflow		
Operating cashflow	mln.rub	**2 877 168,9**
Investment cashflow	mln.rub	**- 482 321,2**
Net cash flow	mln.rub	**2 394 847,7**
Net cash flow	mln.$	**27 556,9**
Cumulative cash flow	mln.$	
Discount factor		**15%**
Discounted cash flow	mln.$	
Cumulative discounted cash flow	mln.$	
NPV	mln.$	**3 586,6**
IRR	%	**19%**
DPI		**2,0**
Payout time	years	**25**

The key performance indicators are NPV equal to $ 3 586,6 million and IRR equal to19%. The Figures 7-11 and 7-12 provide the curves of sensitivity analysis of the project as a function of gas prices and total capital costs.

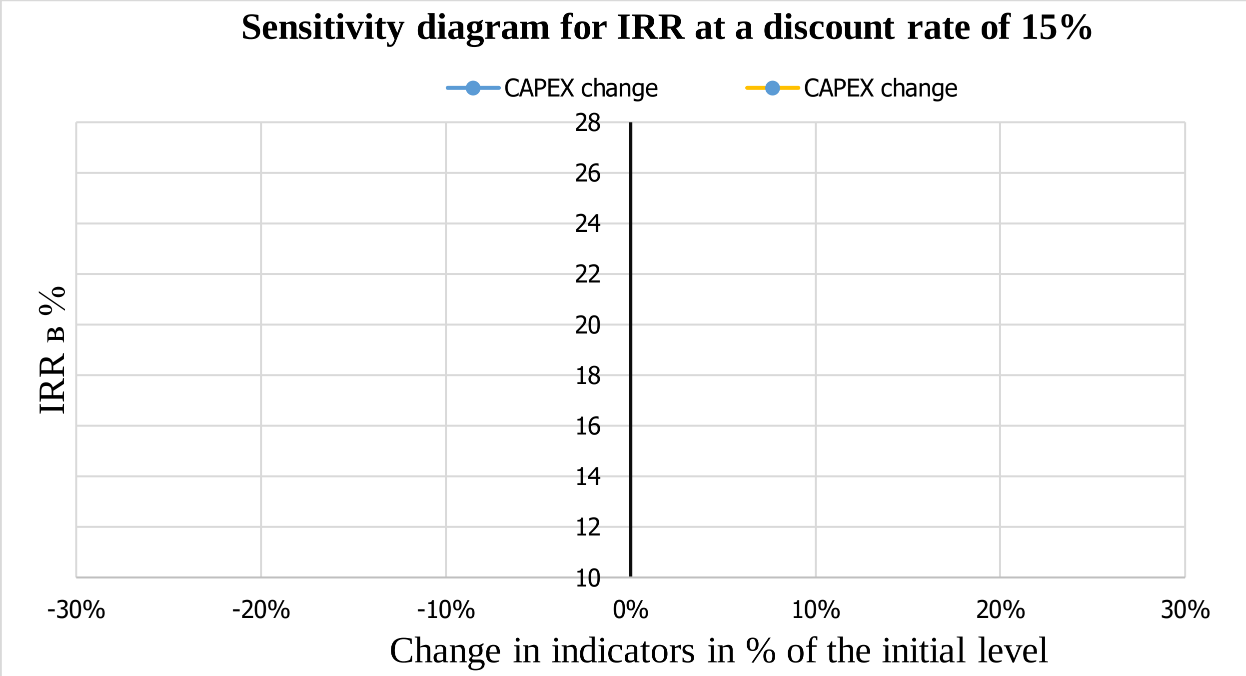

Figure 7-11 Sensitivity graph for IRR

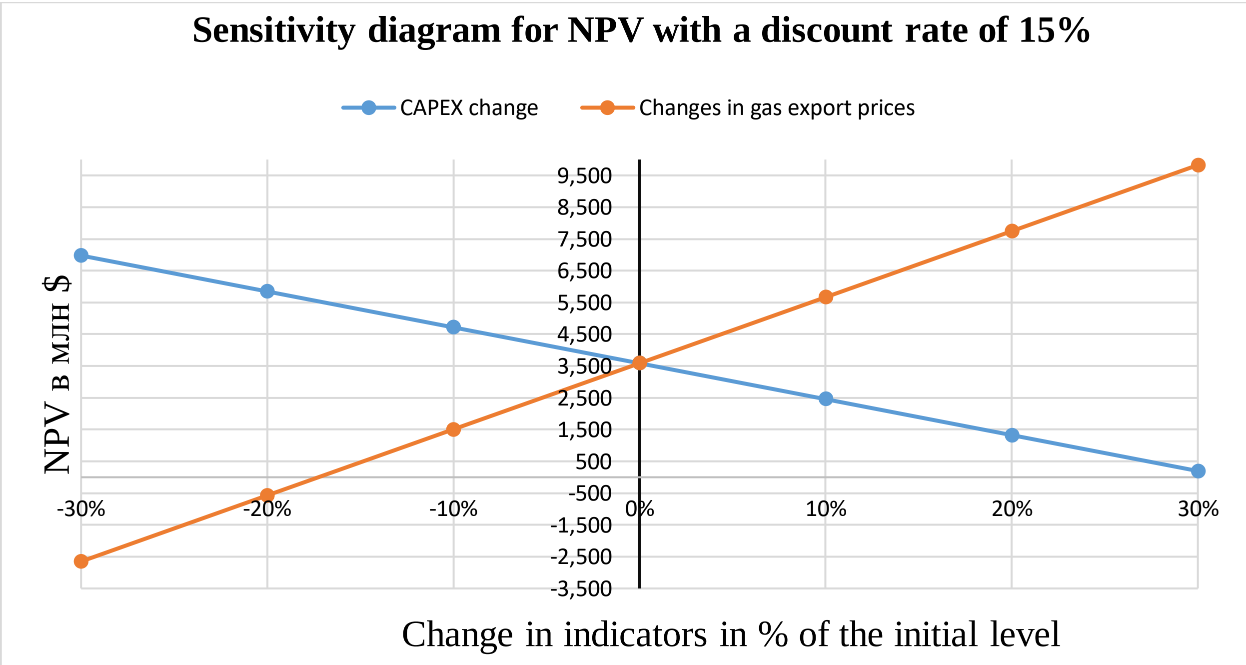

Figure 7-12 Sensitivity graph for NPV

7.5 Option with subsea compression station and 32" export gas pipeline

In this part of the chapter is a comparison of all three options presented above, to select the best option and its further elaboration is necessary to make a comparison of economic indicators.

To begin with, it is required compare the main characteristics for making a decision:

Table 7.8

Table of the main economic indicators of the three proposed options

indicators\option	Without SCS	With SCS and 32-inch pipe	With SCS and 36-inch pipe
NPV (млн $)	2225	2408	3587
IRR %	18	18	19
DPI	1,2	1,3	2,0
Payout time	28	29	25

For the more accurate choice of the field development option the Figure 7-13 shows a graph of the accumulated discounted cash flow depending on the year of field development.

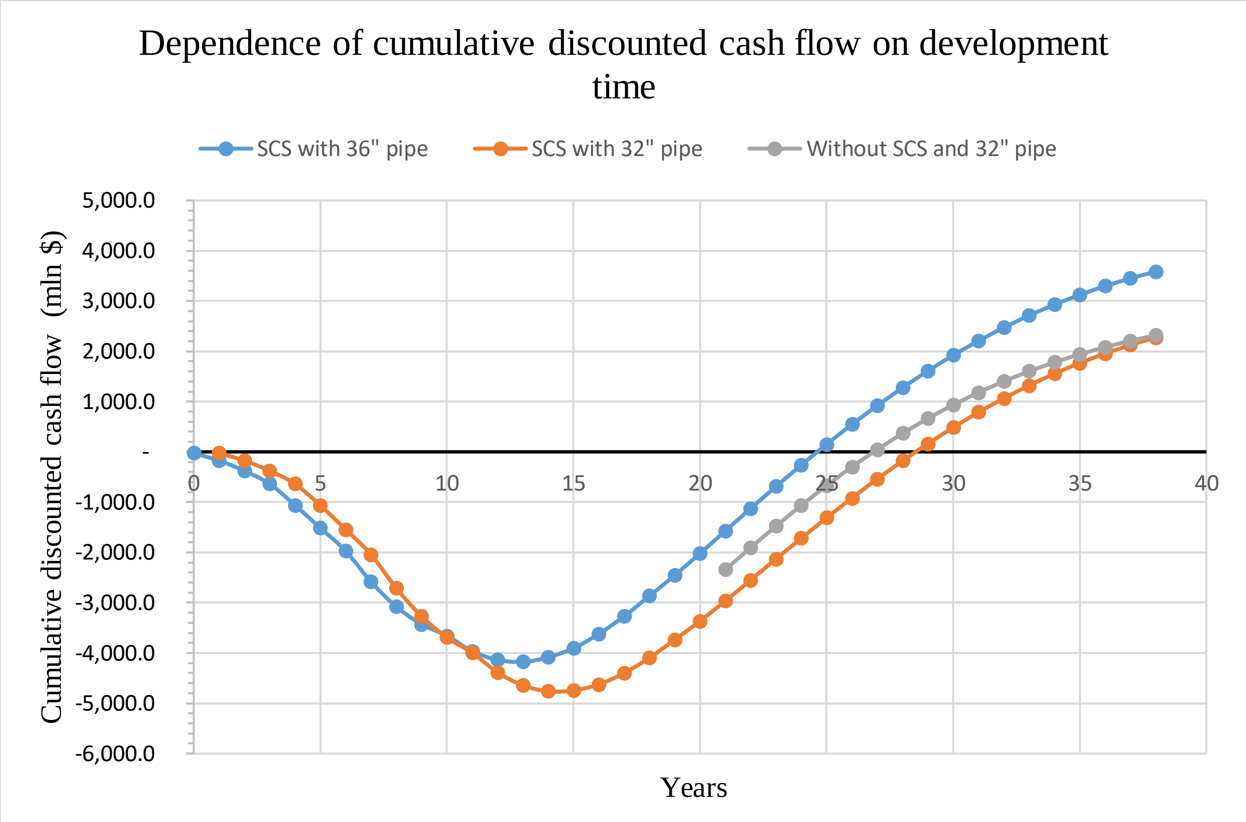

Figure 7-13 Dependence of cumulative discounted cash flow on development time

As can be seen from the data obtained, the most profitable option is the option with a subsea compression station and a 36-inch export pipeline. There are several reasons for reaching this point:

1) Compared to other options, the construction of the SCS and onshore compression station is postponed, which helps reduce CAPEX;
2) The onshore compression station and the SCS should have less capacity, which helps reduce capital costs and also reduces the consumption of fuel gas at the onshore compression station and reduces the electricity consumption of the SCS;
3) At the startup, more wells are required to be drilled and a larger diameter pipe laid to start the pipeline, which increases CAPEX in the first year of drilling the production wells, but pays off because of the higher flow capacity of the pipeline;
4) Due to less pressure difference between CPF and wells, it is possible to deliver assembled manifolds with less weight and, as a consequence, cheaper.

According to the calculated data, the project is profitable. For further elaboration at the next stages of the field development it will be preferable to refine this option, but the work aimed at the development of alternative options is not excluded.

Chapter 8 Alternative solutions for the Yuzhno-Kirinskoye gas condensate field development

8.1 Option implementing HOST templates

As mentioned above, it is theoretically possible to use integrated structures of a 2-4-well base plate (temple) and prefabricated manifold when constructing drilling and production centers in the Yuzhno-Kirinskoye field. This technical solution has both advantages and disadvantages compared to the scheme including satellite wells and an independent prefabricated manifold.

The main positives of using templates are:

1) Reduction of the volume and time of construction and installation works, performed in the field water area;
2) Reduction of the number of tripping operations restricted by weather conditions;
3) Possibility of using flexible inserts to connect wellhead fittings to manifold, which excludes the necessity of measuring immediately after the installation of the wellhead, designing and manufacturing a rigid pipe insert and as a result drastically reduces the time of connecting the well after its development;
4) Decrease of total number and weight of protective structures;
5) Simpler distribution scheme for power and signals of well control system, because both hydraulic and electrical distribution circuits are included in the design of the manifold placed on the template;
6) Elimination of the usage of distribution nodes and hose-cable jumpers;

It is necessary to note, that it is also possible to connect satellite wells to a separately placed manifold by means of flexible inserts, but they are rather expensive due to their considerable length (30-40 meters). At the same time, the use of flexible connections leads to cyclic loads on the connection nodes and, consequently, to the possibility of fatigue failure of the connections.

In addition to the disadvantages of the scheme with the use of templates, mentioned at the beginning of this section, we can note:

1) Integrated structures have a long manufacturing period, this circumstance imposes restrictions on the well drilling schedule, as the beginning of drilling is impossible before the installation of the temple;

2) The weight and dimensions of the protective construction greatly increase, which leads to the necessity of using crane vessels of high lifting capacity and tougher restrictions on the weather window during the installation works;
3) Due to considerable weight the integrated manifold design requires special technical solutions for installation on soils with low bearing capacity;
4) Limited access for remotely operated vehicles;
5) During seismic activity there is an increased risk of mutual displacement of connectors within the manifold structure between manifold and wells;
6) Increased stress on wellheads due to thermal expansion of wells after production starts;
7) Increased risk of accidents when simultaneously drilling a well and producing within the same template, the need to stop production during operations such as running a wellhead or blowout preventer.

The Figure 8-1 shows a scheme of the templating structure, which clearly shows the central manifold and the fountain valves connected to it on the same base.

Figure 8-1 Template scheme [19].

Conclusion: To provide flexibility in the development of the field structure and reduce the risk of "losing" a drill slot in case of an accident while drilling a well, it is necessary to provide reservation of drill slots in the baseplate. Thus, for two- and three-well drilling centers, it is possible to install templates for four slots. However, this approach will lead to an increase in the mass-dimensional characteristics of templates and protective structures, and to an increase in the cost of construction and installation works.

8.2 Assessment of the proposed alternative solution applicability with the application of templates

Template design is quite widespread on the Norwegian shelf, as it has a number of advantages described in the chapter above, but there are no fields on the Russian shelf where this technological solution is applied. Moreover, in order to use this type of equipment on the Russian shelf, it will be necessary to certify it on the territory of the Russian Federation, which may take quite a long period of time, pushing the terms of the project implementation even further.

In the future, if this equipment is certified in the territory of the Russian Federation, the development of the Yuzhno-Kirinskoye field using this arrangement may be considered.

8.3 The concept of arrangement using the SPAR-type platform

The SPAR-type platform consists of a large-diameter spar (cylinder) to which the drill deck is attached. The cylinder has its main weight at the bottom of the spar filled with a material that is denser than water, which lowers the center of gravity of the platform and provides stability. The success of the world's first SPAR platform of the Neptune system marked the beginning of a new era for deepwater oil platforms.

Floating oil platforms with a spar underwater extending up to 200 meters are fixed to the seabed by a special mooring system (anchors) that are cut into the seabed.

Over time, SPAR-type oil platforms have also been upgraded. The first floating oil platform had a one-piece hull, but now the spar is one-piece only up to half of its length. Its lower section is a mesh structure with three horizontal plates, as shown in the figure below. Water is trapped between these plates, creating a liquid cylinder, helping to stabilize the entire structure. This solution allows you to hold more weight using less steel. The Figure 8-2 shows us the scheme of SPAR platform.

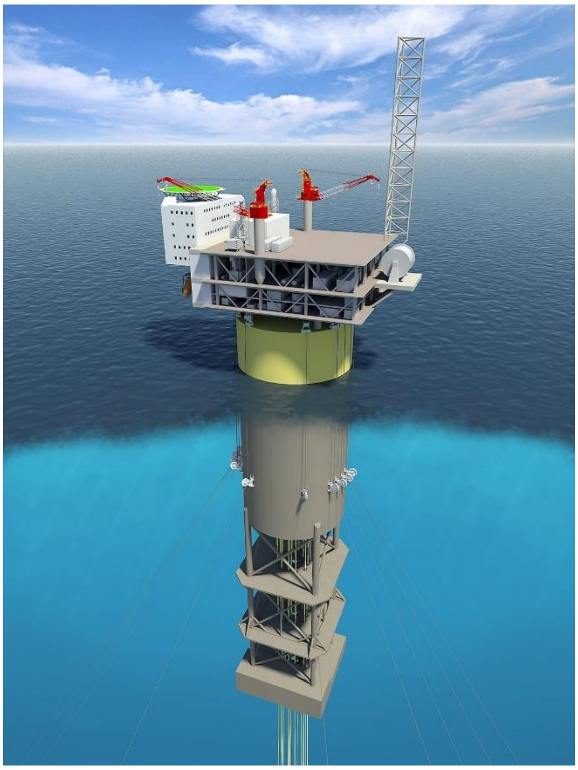

Figure 8-2 Template scheme [19].

Today, oil platforms of SPAR type are the main type of floating oil platforms used for hydrocarbon production in very deep waters and areas where floating ice is possible, because it occupies a smaller water surface area than other structures and thus has a smaller hull area exposed to floating ice flows. The possibility of using this type of platform in deep waters is provided by the most stable platform design and reduced metal consumption, due to the developed cellular design of the lower part of the hull.

8.4 Assessment of the proposed alternative solution applicability with the application of SPAR-platform

Development of the field using a SPAR platform is possible, as the field is located at a depth of 110-320 m, while the SPAR platform allows development of fields at depths close to 1600 m (as an example, Red Hawk, installed in the Gulf of Mexico at a depth of 1600 m). The presence of floating ice, typical of the region, is also a serious threat for platforms of this type.

However, significant seismic activity in the region could lead to the loss of the load carrying capacity of the seabed and become a problem for the platform's anchoring system on the base point.

In addition, the relative proximity of the shore (60 km) in the case of the gas-condensate mixture allows multiphase transport of the produced product without the use of pretreatment on a floating platform. Therefore, application of above-water or complex completion systems is not an optimal type of completion as applied to fields of Kirin block.

The subsea completion system makes it possible to put the field into operation in the shortest possible time, ensures year-round production regardless of the navigation period, and the developed protective construction of the MAC ensures its protection from falling objects, floating ice and is seismically stable.

The only possible use of this platform may be its periodic operation for the preparation of well products and further compression of already dried gas, as well as for the supply of electricity and chemical reagents to subsea production systems. But in this case a lot of money and time will be needed to put this platform into operation after the ice period. Based on everything written above, this option of arrangement is not recommended for further study and improvement.

CONCLUSION

To achieve the objectives of this work, the initial data on the Yuzhno-Kirinsk gas condensate field were considered: the geological structure, natural and climatic conditions of the field location area, as well as the remoteness from the onshore infrastructure.

The decision on the underwater system of the Yuzhno-Kirinsk gas condensate field arrangement was also considered, the system of production realization with the use of the underwater production complex was described and the substantiation that such system of arrangement is optimal for this field and corresponds to all conditions of its location was given. This paper proposes three options for developing the field with subsea production systems.

Necessary assumptions have been made, implementation schedules for each of the projects have been built, and the timeframe for commissioning the necessary infrastructure has been analyzed.

The main economic indicators for three variants of the field development were calculated, the optimal variant was chosen and recommendations were given for further specification of the optimal variant at the next stages of the project development.

The final chapter included an alternative development option for the Yuzhno-Kirinskoye field using sub-sea injection molding and a SPAR platform, describing all the advantages of using a similar sub-sea injection molding system.

When comparing the existing subsea completion system and the SPAR-type platform system, it was concluded that application of the subsea production complex in this field is the most optimal completion system for all conditions of the Sakhalin shelf and peculiarities of the Kirinsk block fields.

RECCOMENDARIONS FOR FURTHER WORK

In order to develop the most optimal method and launch this field it is necessary to do the following at the following stages of project development:

1. Clarify the possibilities of marketing of marketable gas and condensate;
2. 2. If certain conditions are met, we will consider the possibility of developing the field with templates;
3. To make additional calculations for the variant recognized in this article as optimal;
4. To make clarifying calculations of hydraulics at launching onshore and offshore compression stations;
5. To work out a list of the necessary equipment for the CPF.

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APPEDIX

Table 9

Table of reference data for calculating economic indicators in this work

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Nominal exchange rate of national currency	RUB./$	74	75	77	79	80	82	83	85	87	87	87	87	87	87	87	87	87	87	87	87	87	87
MET natural gas	RUB./1000 м3	690	711	733	754	777	800	824	849	875	901	919	937	956	975	995	1015	1035	1056	1077	1098	1120	1143

		2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060
Nominal exchange rate of national currency	RUB./$	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87
MET natural gas	RUB./1000 м3	1166	1189	1213	1237	1262	1287	1313	1339	1366	1393	1421	1449	1478	1508	1538	1569	1600	1632

Table 10

The offshore and onshore cost summary for the option with SCS and 36 inch export pipeline

COMBINED COST SUMMARY

Project	газ кластер С КОМПРЕ ССОРОМ 36 дюйм
Location	Europe
Development type	Gas
Currency	US Dollars
Procurement strategy: Offshore	Norway (North)
Procurement strategy: Onshore	Azerbaijan

Cost centre	Totals	Equipment	Materials	Fabrication	Prefabrication	Installation/ Construction	Hook-up & commissioning	Design	Project management	Insurance & certification	Contingency
Offshore drilling 8	1 605 360 000	28 316 000	78 717 000			979 901 000		2 168 000	2 980 000	54 604 000	458 674 000
Subsea without pump	3 864 421 000	1 224 075 000	997 718 000			338 332 000		44 923 000	23 810 000	131 443 000	1 104 120 000
Production facility 1	777 349 000	253 882 000	59 840 000		41 992 000	119 070 000		48 105 000	26 862 000	5 498 000	222 100 000
CAPEX TOTALS	6 247 130 000	1 506 273 000	1 136 275 000	0	41 992 000	1 437 303 000	0	95 196 000	53 652 000	191 545 000	1 784 894 000

CAPEX sub total	4 462 236 000
CAPEX contingency	1 784 894 000
Project costs	0
GRAND TOTAL	6 247 130 000

Table 11

The offshore and cost summary for the option with SCS and 36-inch export pipeline

Subsea with compressor		Name	Subsea with compressor
TOTAL COST	US Dollars		3 864 421 000

EQUIPMENT			Procured from: N. North Sea (Norway)
	QUANTITY	UNIT RATE	COST
15 и 16			112 305 000
17 и 7			112 305 000
5			112 305 000
13 и 14			91 697 000
6 и 2			112 413 000
8 и 12			112 413 000
10 и 3			112 413 000
11 и 1			112 413 000
4			112 413 000
18			47 301 000
CM1			58 697 000
CM2			60 546 000
Onshore controls - main	1	565 000	565 000
Onshore controls - additional	36	66 200	2 383 000
Topsides equipment			
DEH power control unit	0 te	0	0
EHTF power control unit	0 te	0	0
Multiphase pumping process control module	211 te	133 900	28 253 000
Sub Total			1 188 422 000
Freight	3,00%		35 653 000
Total Equipment		$	**1 224 075 000**

MATERIALS			Procured from: N. North Sea (Norway)
	QUANTITY	UNIT RATE	COST
Link 01			29 413 000
Link 02			37 448 000
Link 03			18 889 000
Link 04			28 799 000
Link 05			26 934 000
Link 06			30 335 000
Link 07			21 309 000
Link 08			32 498 000
Link 09			19 878 000
Экспортный трубопровод до УКПГ			599 125 000
Link 11			9 516 000
Экспортный трубопровод CM1-CM2			124 011 000
Riser systems (arch/buoy)	0	0	0
Sub Total			978 155 000
Freight	2,00%		19 563 000
Total Materials		$	**997 718 000**

INSTALLATION			Location: N. North Sea (Norway)
	QUANTITY	UNIT RATE	COST
Reel-lay	77 day	186 057	14 326 000
S-lay without DP	465 day	251 724	117 052 000
S-lay with DP	0 day	356 627	0
J-lay	0 day	492 503	0
Ultra-deep	0 day	861 333	0
Diving support vessel	520 day	157 601	81 953 000
Semi-submersible crane vessel	0 day	290 030	0
Semi-submersible drilling vessel	0 day	156 069	0
Trench vessel	138 day	114 917	15 859 000
Survey vessel	48 day	62 384	2 994 000
Dredge vessel	0 day	155 412	0
Rock install vessel	0 day	63 478	0
Supply vessel	226 day	27 142	6 134 000
Testing & commissioning equipment	48 day	31 520	1 513 000
Shore approach			98 501 000
Total Installation		$	**338 332 000**

DESIGN & PROJECT MANAGEMENT			N. North Sea (Norway)
	QUANTITY	UNIT RATE	COST
Design	275 600 mhr	163	44 923 000
Project management	79 900 mhr	298	23 810 000
Total Design & Project management		$	**68 733 000**

INSURANCE & CERTIFICATION			N. North Sea (Norway)
	QUANTITY	UNIT RATE	COST
Certification	1,00%		26 289 000
Insurance	4,00%		105 154 000
Total Insurance & Certification		$	**131 443 000**

CONTINGENCY			N. North Sea (Norway)
	QUANTITY	UNIT RATE	COST
Contingency	40,00%		1 104 120 000
Total Contingency		$	**1 104 120 000**