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Abstract

In the modern world, liquefied natural gas plays an increasing role; its consumption grows from year to year.

Liquefied natural gas is relevant since liquid form gas occupies 600 times less volume, is environmentally friendly, and is also easy to transport. There are 6 most commonly natural gas liquefaction technologies: PHILLIPS, PRICO, APCI SMR, APCI C3MR, LINDE MFC, Shell DMR. All of these technologies differ depending on the number of liquefaction cycles and the composition of the refrigerant. The selection of the most suitable technology for the specific conditions in which the plant is located is key to the successful liquefaction of gas.

The Shtokman gas condensate field contains huge reserves of natural gas that can be used for liquefaction and supply to consumers. It is necessary to select the liquefaction technology most suitable for the Arctic conditions, satisfying the requirements.

The Master Thesis overviews the technologies used to liquefy natural gas to select the most suitable one for the Shtokman field. The rationale for the choice of this technology is presented. The analysis of the available information on the deposit is presented. The calculation of the main structure of an underwater LNG storage tank has been performed.

An economic analysis of the efficiency of investments in developing the Shtokman gas condensate field has been carried out.

Acronyms and Abbreviations

API	American Petroleum Institute
CDU	Central Dispatch Office
CGTU	Complex Gas Treatment Unit
DEA	Diethanolamine
DHA	Diglycolamine
DMR	Double Mixed Refrigerant
FPSO	Floating Production Storage and Offloading
FPU	Floating Production Unit
IEA	International Energy Agency
LNG	Liquefied Natural Gas
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MFC	Mixed Fluid Cascade
PLEM	Pipeline-End Manifold
PRICO	Poly Refrigerant Integrated Cycle Operations
SMR	Single Mixed Refrigerant
SPC	Subsea Production Complex
SPS	Subsea Production System

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Chapter 1

1 Introduction

The Arctic zone of the Russian Federation is a significant territory in which only 2% of the Russian population lives. However, it also contains about 22% of undiscovered hydrocarbon reserves: 90 billion barrels of oil (13% of the world's unexplored reserves), 48 trillion m^3 of natural gas (30% of the world's undiscovered reserves), 45 billion barrels of gas condensate (20% of the world's undiscovered reserves) [21].

Thus, the Arctic zone has great potential for development. However, the harsh climatic conditions, the large remoteness of deposits away from settlements and a small population create several problems that hinder development. You should also take into account the lack of Russian modern means and equipment for prospecting, exploration and development of offshore fields, underdevelopment and deterioration of infrastructure, dependence on foreign investments, as well as insufficiently developed navigation and hydrographic support of navigation. So, the development of the Arctic is, if not overwhelming, then a very laborious task [15].

Particular attention is focused on the Shtokman gas condensate field due to its huge reserves and the global trend for the production of liquefied natural gas. Shtokman is located 550 km offshore in the Barents Sea, in an iceberg-hazardous zone. Its reserves amount to 3.9 trillion m^3 of natural gas, making it an extremely promising field for the production of LNG and the struggle for the world market. The project operator was to be Shtokman Development AG, in which 51% belonged to Gazprom, 25% to the French Total and another 24% to the Norwegian company Statoil Hydro [24]. At present, the development is set on hold due to challenges met for the execution of the project. These challenges relate to the physical conditions and the costs for the project.

According to the International Energy Agency (IEA), natural gas consumption will grow by 45% by 2040. According to the Central Dispatch Office (CDU) of the Fuel and Energy Complex, LNG exports from Russia to the Asia-Pacific region from January to August 2018 increased by 48.2%, to 15 billion cubic meters. At the same time, in August 2018, LNG exports decreased by 22% compared to last year's August to 0.9 billion cubic meters [12].

According to the Minister of Energy of the Russian Federation, A. Novak, Russia can increase the share of LNG from today's 4% to 15-20% of the world market in the period up to 2035. According to the ministry's estimates, from 2024 to 2035, a vacant niche will form in the world market by about 200 million tons of LNG per year. Thanks to the presence of competitive projects, Russia can occupy up to half of this space [22].

Therefore, the development of the Shtokman field, including selecting a gas liquefaction technology that will be optimal for the Arctic conditions, is an important task to increase the supply of LNG to the world market.

1.1 Liquefied natural gas - the future of the global energy

Due to global uncertainty at the beginning of the XXI century regarding energy resources, natural gas plays an increasing role in the global energy balance. This contributes to the diversification of energy supply and increases the energy independence of individual regions. Moreover, replacing other fossil fuels with natural gas will lower greenhouse gas emissions and an overall healthier planet.

According to the International Energy Agency (IEA), humanity annually consumes more than 3 trillion m^3 of gas, and the demand for it may grow to 4.5 trillion m^3 by 2035. At the same time, world natural gas production will increase to 5.1 trillion m^3 by 2035 [2].

However, the localization of gas fields often does not coincide with the leading markets for its consumption. Therefore, countries with more gas reserves and low domestic demand are looking to monetize their gas resources. In cases where the construction of a pipeline from supplier to consumer is economically unprofitable, natural gas liquefaction becomes one way to achieve this goal.

The global liquefied natural gas industry is based on a value chain; each of the scheme's elements has its own set of technological tasks. Still, they are all combined into a single whole: no element of the chain can fall out of it without disrupting the viability of other elements.

The production of liquefied natural gas plays an important role in the LNG value chain. Currently, 30 large-scale LNG plants have been built globally, producing 304.5 million tons of product per year and exporting to gas-consuming regions.

The capacity of regasification terminals in 2010 reached 830 billion m^3 of gas (or about 600 million tons), which is twice the world production capacity [7]. On the one hand, the LNG importing countries have deliberately created excess regasification capacity for supply reliability or balancing seasonal gas consumption loads. On the other hand, it was found that gas supplies from the regasification terminal are carried out faster than gas imports through the pipeline. Therefore, many regions of the world continue to build up regasification capacities in anticipation of LNG supplies.

For almost half a century of industrial production of liquefied natural gas in the world, a certain experience has been accumulated in the design, construction, and operation of technological equipment in the production, transport, storage, and storage regasification of liquefied natural gas.

LNG is an extremely promising energy carrier in the modern world due to its physical and chemical properties and environmental friendliness. In addition to its regular use as natural gas after regasification, natural gas in liquid form is used in various applications. Natural gas in gaseous form is used to heat houses as fuel for cars, boilers and thermal power plants in energy generation.

Gas is an environmentally friendly type of fuel because during its use 35-40% of carbon dioxide is emitted into the atmosphere compared to other types of fuel. At the same time, the energy intensity of natural gas is as high as that of other fossil fuel sources. Due to its composition, the discharged gas does not contain sulfur compounds and is also burned more easily than oil and coal [1].

LNG can be stored for a long time, taking up much less volume than traditional natural gas in a gaseous state. In addition, LNG is non-toxic and easy to transport. However, the cost of building an LNG receiving terminal is higher than that of the main pipeline. The main costs are for loading and unloading operations and regasification. Nevertheless, transporting LNG over a distance of over 2000 km, transporting natural gas in LNG is more profitable than transporting it through the main pipeline.

1.1.1 LNG in the world

Over the past 50 years, LNG consumption in the world has grown more than 100 times. At the same time, 70% of LNG consumption in the world falls on Asian countries. Over the past 10 years, LNG consumption in the world has doubled, making it the fastest-growing industry in the energy sector.

At the moment, Qatar is the main exporter of LNG to the market in the world. In second place are Malaysia and Australia. Australia has been able to achieve this capacity thanks to the large number of LNG plants recently built.

In terms of LNG imports, Japan, China, and South Korea have the highest demand for liquefied gas. On the other hand, imports to Europe are gradually decreasing due to alternative energy sources in European countries.

The forecast for supply and demand for liquefied natural gas is presented in
Figure *1*.1.

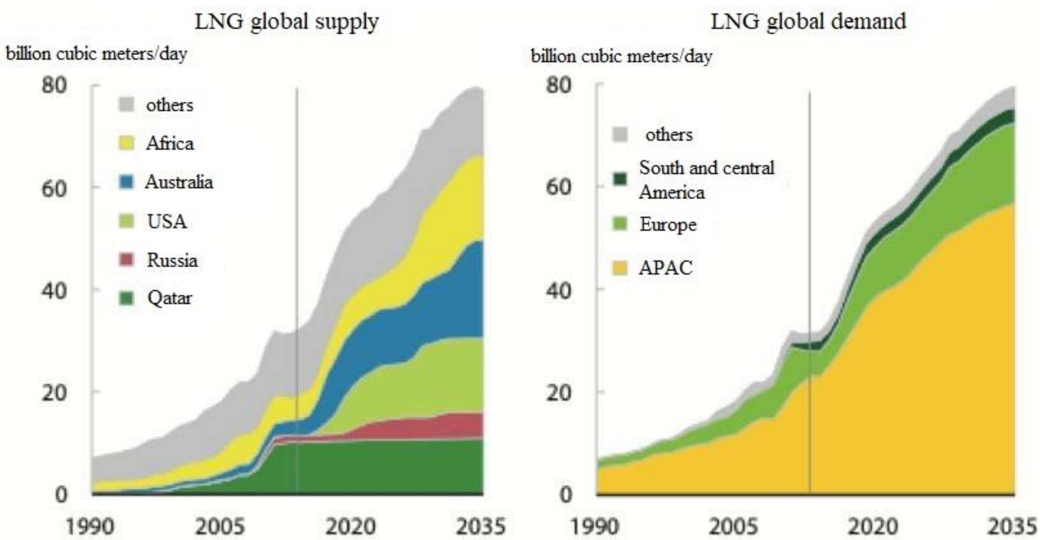

Figure 1.1 Global development forecast [7].

Chapter 2

2. Analysis of existing gas liquefaction technologies

2.1. Physical and chemical properties of LNG

Liquefied natural gas is a cryogenic liquid multi-component mixture of light hydrocarbons based on methane.

LNG is mainly methane with a small content of impurities of other gases: 3.5-4.5% ethane, 1.5-3% propane, up to 2% butanes and up to 1.4% nitrogen. Ethane, propane, butane, heavy hydrocarbons are successively removed to obtain LNG from natural gas. Various impurities such as carbon dioxide and hydrogen sulfide are also removed, and then dehydration is carried out to remove moisture. Next, the gas is cooled to a temperature of -162 °C at a pressure slightly above atmospheric, after which the gas turns into a liquid [17].

Liquefied natural gas is a colorless, odorless, non-toxic liquid, the density of which is half that of water. The occupied volume is 600 times less than the volume of natural gas in a gaseous state makes the liquid very transportable. In addition, the liquid is non-explosive and, at high concentration, without a source of an open fire, it is easily dispersed in the air. Therefore, the LNG spill does not pose an environmental threat [17].

When LNG spills, its vapors condense moisture from the air and become visible, forming white clouds. As the vapors heat up, these clouds dissolve and are no longer visible again. At a relative humidity above 55%, flammable vapors are completely included in the visible cloud. Below 55% RH, the hot cloud is usually partially or completely out of sight.

LNG vapors during a spill accumulate at the earth's surface or water since they have a relative density of 1.7. However, with rapid heating, their density will begin to decrease rapidly, due to which the vapors begin to rise rapidly upward. Therefore, LNG vapors at low temperatures can pose a breathing hazard if they are near the earth's surface because while maintaining negative buoyancy in the air, LNG vapors displace oxygen.

The autoignition temperature of LNG depends on its composition and ranges from 550 to 600 °C. The flame temperature of LNG is 1330 °C, which is higher than the average values for other fuels. During combustion, LNG produces 50 MJ/kg of heat. LNG's combination produces mainly carbon dioxide and water vapor, making LNG one of the most environmentally friendly fuels. Also of great importance is the calorific value, which depends on the composition of the LNG. The presence of nitrogen lowers this value, while ethane and heavier hydrocarbons increase the calorific value [17].

2.2. LNG production

Liquefied natural gas is produced in capacity factories. Depending on it, three types of plants are distinguished:

• Large-scale factories
• Production facilities to cover peak gas consumption loads
• Small-scale factories

The bulk of LNG is produced at large-scale plants with an average production capacity of over 3 million tonnes of LNG per year. Such factories are building small deposits in areas with a high level of gas consumption. Plants are usually built on the coast for loading/unloading LNG into sea tankers.

The second type of plants is smaller plants; natural gas is supplied from the main gas pipelines. Their main function is to store LNG until the peak season. Then, during the warm season, these storage plants actively fill with LNG to regasify reserves, if necessary, and re-supply gas to the main pipeline. Thanks to such plants, it is possible to reduce the price of LNG and equalize supply and demand curves during the period of minimum demand. In addition, storing gas as LNG during periods of low consumption and low prices increases the efficiency of utility companies. The factories have a capacity of up to 100 thousand tons per year and storage tanks and regasification capacities of up to 6,000 tons per day.

The third type is low-tonnage plants with a production capacity of up to 500 thousand tons per year. The purpose of plants of this type is to cover the local demand for natural gas. The factories operate continuously, and the LNG produced is delivered to consumers by small ships or tank trucks.

2.2.1. Gas preparation for liquefaction

Raw natural gas contains components that lead to operational problems during the natural gas liquefaction process. The presence of water, carbon dioxide and other impurities. Therefore, before the liquefaction process, natural gas must be cleaned of impurities.

The produced natural gas is supplied to the mechanical impurities' removal unit. After that, the natural gas passes droplet separators, which pass through an acidic purification plant, such as hydrogen sulfide, to avoid equipment corrosion. In an LNG plant, the most common units are the sour amine components purification unit. Various amines are used in this process: monoethanolamine (MEA), diethanolamine (DEA), diglycolamine (DHA), methyldiethanolamine (MDEA).
Figure 2.1 shows a schematic diagram of an amine treatment plant [11].

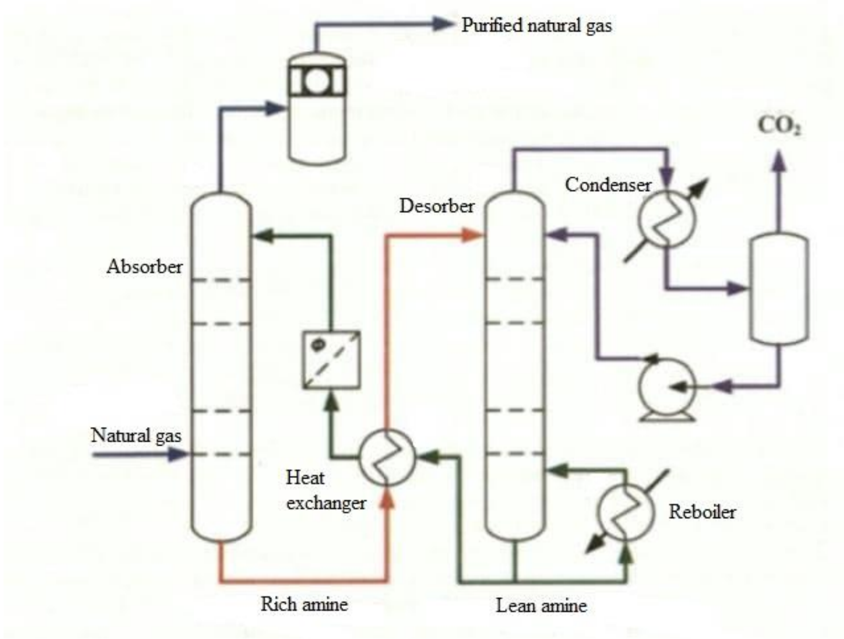

Figure 2.1 Schematic diagram of the amine treatment process [17].

The natural gas passes through an absorber where it contacts the amine on trays or packings. As a result of the ongoing chemical reaction, the amine captures acidic components from the gas and is removed from the bottom of the absorber. After that, the amine is fed to the regeneration column, resulting from which it is purified from acid gases. Finally, the separated acid gases are flared or fed to a sulfur recovery unit.

As a result of the interaction of acid gases with amines, water is formed, which can be removed in an adsorption drying unit, which uses molecular sieves - zeolites. The schematic diagram of the adsorption drying unit is shown in Figure 2.2.

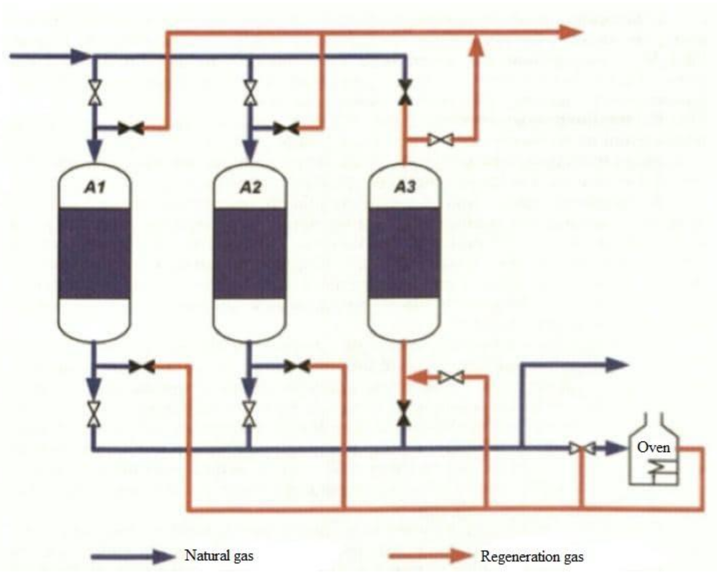

Figure 2.2 Schematic diagram of natural gas adsorption dehydration:
A1, A2, A3 – adsorbers [17].

Natural gas enters two adsorbers while the third of the adsorbers is being regenerated. After passing through the layer of zeolites, natural gas is dried and fed to further purification from mercury or to a gas liquefaction line.

The regeneration of adsorbents occurs by desorption of the absorbed liquid. For this, a stream of hot gas is passed through the stripper. Thus, dehydration with zeolites at low acid content can replace amine refining.

After natural gas has been purified from acidic components, water and mercury, it is fed to a gas liquefaction unit.

2.2.2. LNG industrial production technology

In LNG production, the choice of natural gas liquefaction technology is of key importance.
In the production of LNG, undesirable components are removed from a high-pressure natural gas stream. The gas is cooled to a low temperature and then throttled to atmospheric pressure, as a result of which the gas acquires a predetermined temperature of -160 °C, condenses and turns into LNG.

Depending on the gas refrigeration process used, the refrigeration and condensation methods can vary dramatically. Figure 2.3 Cooling cycles: a - single-stage cycle, b - multi-stage cycle; shows the schematic diagrams of simple single-stage (a) and multi-stage (b) cooling cycles.

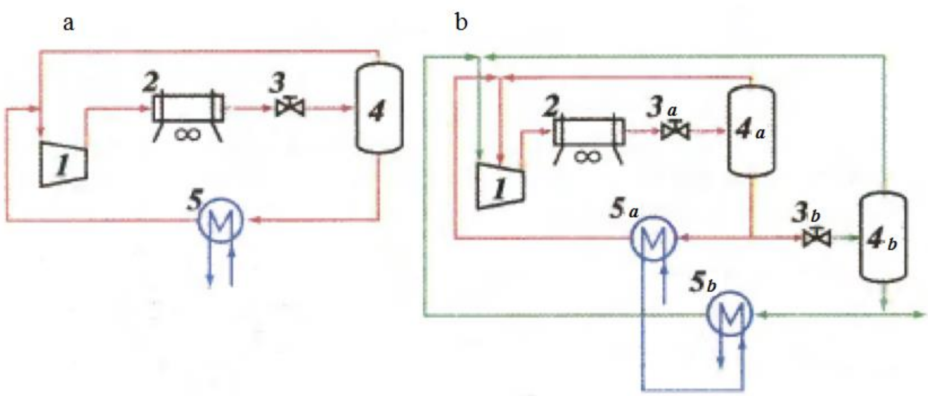

Figure 2.3 Cooling cycles: a - single-stage cycle, b - multi-stage cycle;
1 - compressor; 2 - refrigerator - condenser with external cooling; 3 - throttle; 4 - separator;
5 - refrigerator - evaporator for cooling natural gas [17].

Error! Reference source not found.(a) shows a simple refrigeration cycle using propane as the refrigerant at -30 °C. In the compressor, propane is compressed from a pressure of about 0.18 MPa to 1.7 MPa. The gas heated by compression is cooled in a refrigerator with an external refrigerant to 50 °C and condensed. Then, when passing through the throttle 3, the pressure drops to 0.16 MPa, while the propane is cooled to -30 °C. In separator 4, propane is separated into liquid and vapor phases, after which the vapor phase is directed to the compressor, and the liquid phase is sent to evaporator 5, where propane is evaporated due to the heat of vaporization taken

from the gas stream, while the natural gas is cooled. The vaporized propane is returned to compressor 1 [17].
A distinctive feature of Figures a) and b) is a flow divider, and there is a throttle 3 on the separated flow. Due to the separated flow, it becomes possible to introduce a second cooling stage with a lower temperature and lower pressure.

The more stages of cooling, the more efficient the process will be. If necessary, you can add the third, fourth, fifth and so on stages of cooling. Capital costs are the main limiting factor. Also, the increase in the number of cooling stages greatly complicates the implementation of the technological scheme. To date, the maximum number of refrigeration stages for a single component refrigerant is five.

2.2.3. Schematic diagram of a large-scale LNG plant

The LNG plant is the most important part of the value chain. LNG transport is tanker ships, so LNG plants are most often built on the coast or at river estuaries. Most often, a liquefaction plant is built near large seaports.

LNG plants have the following installations:

- Comprehensive gas treatment
- Gas cooling
- Gas liquefaction
- Fractionating
- LNG storage
- Unloading/loading unit
- Life-supporting system

The composition of the natural gas and the requirements for the final product have the greatest influence on the design of the plant. Based on the presence or absence of various impurities in the gas, capital costs for construction and operating costs proportionally increase or decrease.

The size of the main cryogenic heat exchanger during construction depends on the gas composition, namely the percentage of methane and nitrogen - the higher the concentration of substances, the larger the heat exchanger should be. Ethane and propane also affect the calorific value of LNG - the higher the content, the greater the calorific value. The presence of propane, butane and pentane depends on the layout of the fractionation unit. Another important condition is the presence of a sufficient propane content in the gas - propane is a refrigerant; therefore, if there is a lack of it, there may be a need for additional gas supplies, increasing operating costs.
Gas refrigeration using mixed refrigerants is more advantageous since, in the event of a change in the composition of natural gas, the flow diagram is more flexible, which allows it to adapt to new conditions.

Figure 2.4 shows a schematic diagram of a natural gas liquefaction plant.

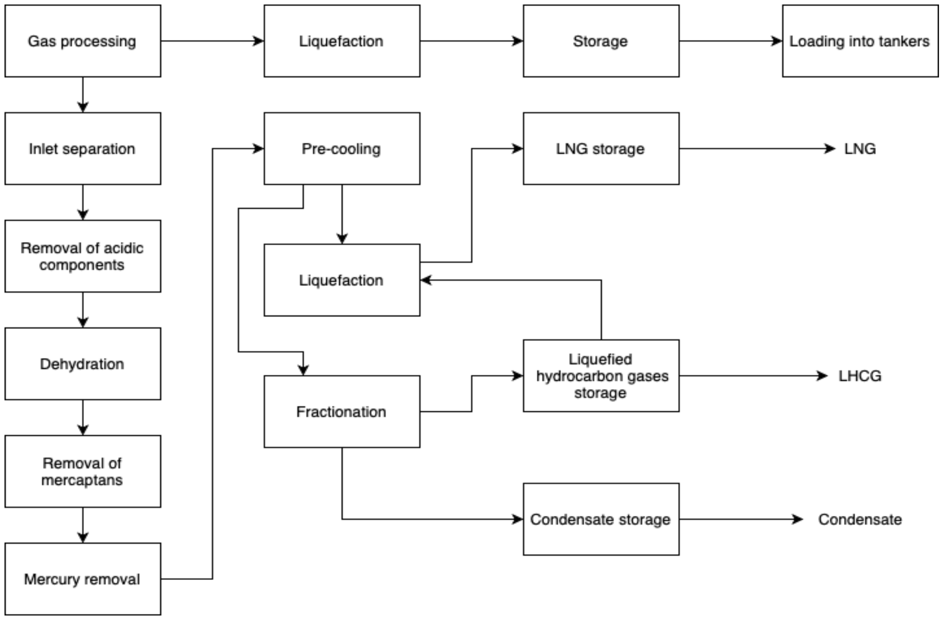

Figure 2.4 Schematic diagram of a natural gas liquefaction plant [17].

A set of units to remove acid components, drying, removal of mercaptans and mercury, pre-cooling, fractionation, and liquefaction form a processing line. To ensure the continuous operation of the plant, two or three parallel processing lines are used.

2.2.4. Large-scale technological processes

In the modern world, many technological processes have been developed for the liquefaction of natural gas. Among the developers of large-scale technologies are Air Products and Chemicals Inc. (APCI), ConocoPhillips, Shell, Statoil, LindeAG, Axens.
The developed technological processes differ in the following parameters:

- Working pressure fluctuates between 3.5-7 MPa
- Presence or absence of a cascade
- Type of cryogenic heat exchanger
- Type of external cooling
- Presence or absence of a turboexpander and its type
- Compressor drives

2.2.4.1. Upgraded PHILLIPS cascade process

The process uses three refrigeration cycles - propane, ethylene and methane. The propane and ethylene cycles are closed, but the methane ones are not. Part of the methane enters the refrigeration cycle after the LNG cryogenic heat exchanger, and part is the methane evaporated during storage. Methane is also supplied from the unloading/loading line of methane tankers, which increases LNG's amount. Gas turbines are used as compressor drives. The annual productivity of the process is from 3 to 5 million tons of liquefied natural gas [17].

The process flow diagram is shown in Figure 2.5.

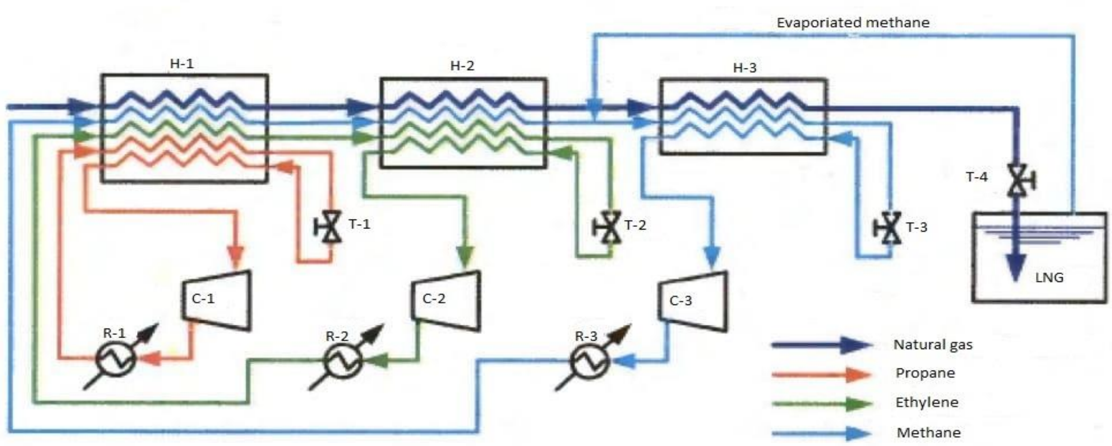

Figure 2.5 Schematic diagram of the modernized Phillips cascade process [17].

In this process, the technological line is not fully duplicated. Less reliable equipment such as compressors and gas turbines are being replicated. However, more expensive and more reliable equipment such as air coolers and heat exchangers are not duplicated. The process uses finned plate heat exchangers. Refrigeration cycles consist of two or three stages. To reduce the risk of two-phase flow, the heat exchanger uses clean refrigerants.

Distinctive special process:

- The process can operate smoothly even if one of the technological lines is disconnected. Productivity drops to 60%
- Possibility to change the composition of the feed gas: when the composition of natural gas changes, the points of LNG and a wide fraction of light hydrocarbons change, and the multistage process allows to reduce the cost of NGLs
- Reduced methane consumption due to the return from the system of methane vapors evaporated during storage
- Wide range of performance. Due to the possibility of switching the compressors to recirculating mode, the possibility of starting and stopping the technological line is facilitated, and it is also possible not to stop the process when the volume of the feed gas supply is reduced by 90%
- Ability to carry out maintenance during periods of reduced productivity
- Compactness, which is achieved through the use of plate heat exchangers
- Standardization of the project

2.2.4.2. PRICO technological process

The PRICO (Poly Refrigerant Integrated Cycle Operations) process uses a single-flow refrigeration cycle. The process flow chart is shown in Figure 2.6.

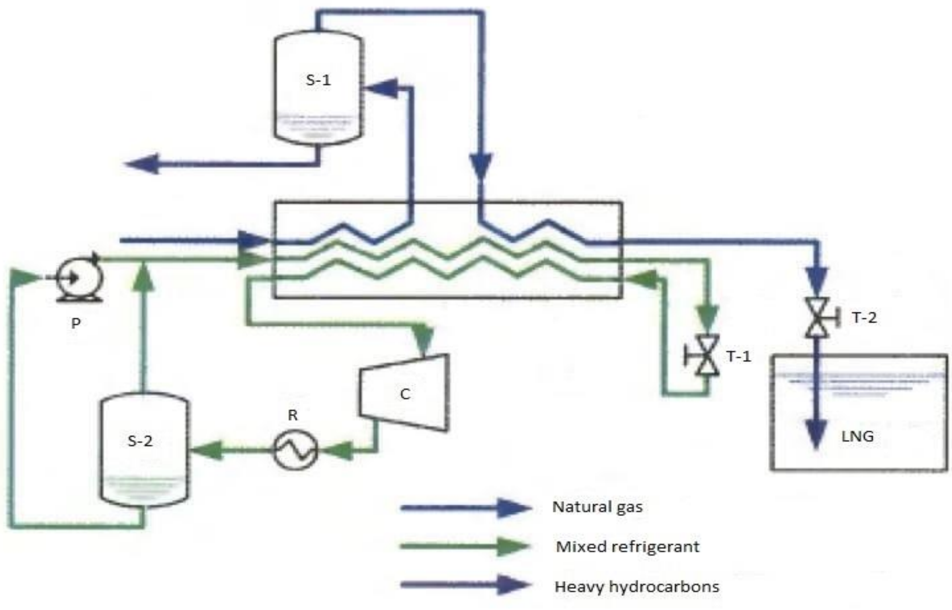

Figure 2.6 PRICO process [17].

The process uses a mixture of methane, ethane, propane, isopentane and nitrogen as a refrigerant. [17].

The gas flow under a pressure of 6 MPa and a temperature of 12 °C, passing through a part of the heat exchanger, is directed to the separator S-1, where heavy components are separated from the gas. After separation, the gas is again sent to the heat exchanger, where the liquefaction process occurs. After the heat exchanger, the gas is fed for throttling to the throttle T2, after which the pressure becomes slightly higher than atmospheric, and the flow temperature drops to -163 °C [17].

A distinctive feature of the process is mixing the liquid and vapor portions of the refrigerant in the main heat exchanger.

After that, some of the heavy components are condensed from the refrigerant at a pressure of 3 MPa, the flow is directed to the separator. The liquid phase is separated and re-mixed with the steam inside the heat exchanger. On its way back through the heat exchanger, the refrigerant heats up after the expansion valve has been depressurized. Finally, it evaporates, cooling the natural gas and the high-pressure refrigerant stream. At the compressor inlet, the refrigerant temperature should be around (+5) - (+10) °C.

A very large amount of refrigerant is required to cool natural gas to the required temperature, which requires significant energy costs. To achieve this, the plant uses plate heat exchangers, which are efficient in heat exchange between the refrigerant and the feed stream. Thanks to heat exchangers, it is possible to cool natural gas down to -156 °C. This temperature is achieved due to the turbulent flow regime.
A significant disadvantage of the process is its low productivity, but the process is simple enough, which reduces the capital cost of equipment and facilitates management and control.

However, due to the need for a large amount of energy to compress the refrigerant, the operating costs are quite high, which increases the final cost of LNG [17].

A streamlined process has been developed to reduce operating costs, as shown in Figure 2.7

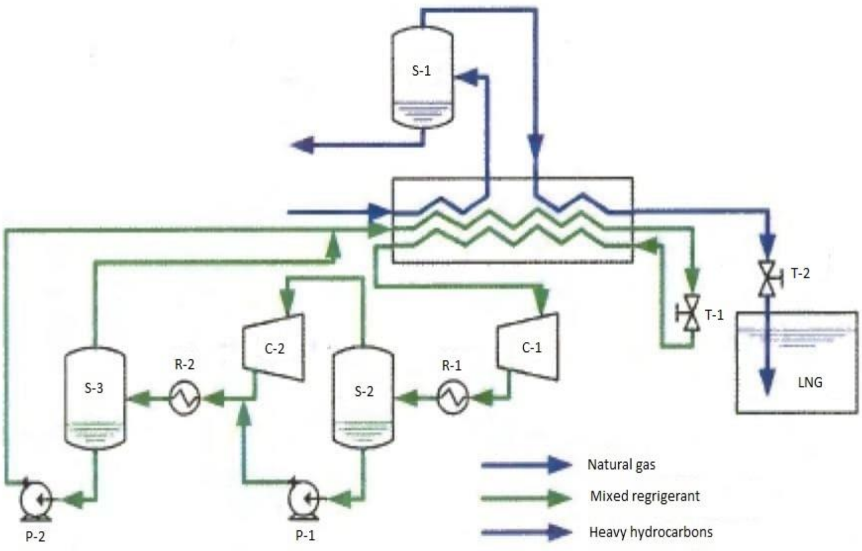

Figure 2.7 Modified PRICO process [17].

The main difference between the modernized process and the standard one is the presence of an intermediate stage at the stage of refrigerant compression. This technological solution reduces the compressor load by 30%, which makes the process more energy-efficient. After compression in compressor C1 and cooling in refrigerator R1, the refrigerant enters the separator S2, in which the vapor and liquid phases are separated. Then, the liquid phase is lifted by the P1 pump and the gas phase by the C2 compressor.

The process productivity is relatively low - up to 1 million tons of LNG per year. However, this process is effective for covering peak loads. Currently, 30% of factories around the world use this process as the main one.

Benefits of the modernized process:

- Economical process - the technology requires the lowest capital costs among all existing schemes for obtaining liquefied natural gas
- Simplicity - simple process flow diagram
- Flexibility - the ability to adapt to changes in the composition of the feed gas flow
- Ease of Management
- Reliability

2.2.4.3. APCI SMR technological process

The SMR (Single Mixed Refrigerant) process was developed by APCI (Air Products and Chemicals Inc.). The efficiency of the process is low; a mixture of nitrogen, methane, ethane and n-butane is used as a refrigerant.

The process flow diagram is shown in
Figure 2.*8*

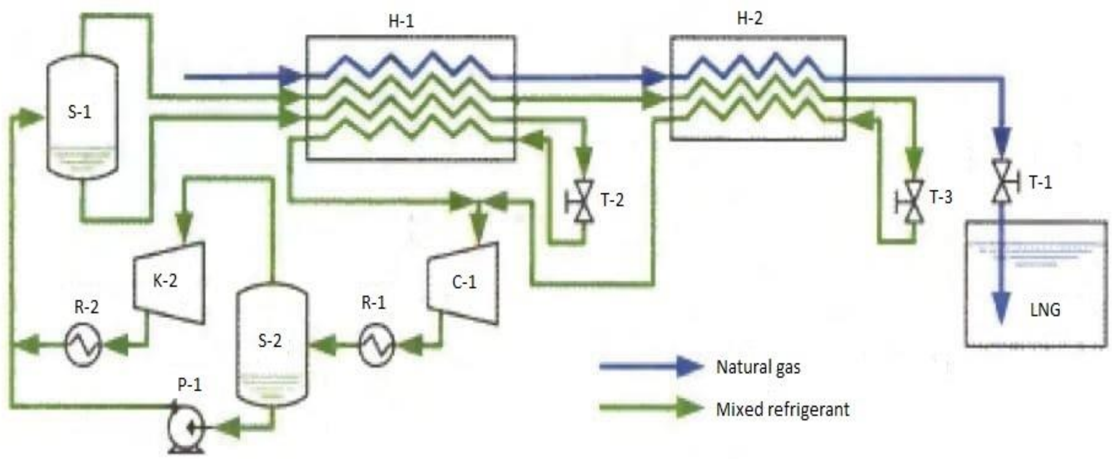

Figure 2.8 APCI SMR process [17].

The refrigerant is compressed in the compressor C1, C2 and cooled in the refrigerators R1, R2. The compressed and cooled stream enters the separator S2 and is separated into liquid and vapor phases and is fed in different streams to the heat exchanger, in which the liquid phase is cooled to a temperature of -100 °C and withdrawn from the side, after which it is throttled again and returned by the reverse flow to the shell side of the heat exchanger for cooling the feed stream and the gas and liquid phases of the refrigerant. Next, the gas phase of the refrigerant passes through the heat exchanger H2, after which it is throttled and returns to the shell side of the heat exchanger.

The main heat exchanger in this process consists of two or three parts. First, the gas phase of the refrigerant after partial condensation in the warm part of the heat exchanger H1 is separated in the separator and returned to the heat exchanger in two streams for further cooling. Then, after the middle part of the heat exchanger, the condensate of the gas phase is removed and throttled, and at the cold end of the heat exchanger, the remaining gas phase.

The feed gas enters at a pressure of 5-6 MPa, passes through a heat exchanger, after which it expands in throttle or an expander to a pressure acceptable for LNG storage [17].

Technology advantages:

• Simplicity
• Low capital costs for the construction of the unit
• Economical - the unit does not require a large amount of refrigerant to operate

The use of a single-flow refrigeration cycle in this process reduces the amount of equipment, but its energy efficiency is significantly lower than that of a cascade process. The decrease in energy efficiency is associated with the condensation of substances with different boiling points. Therefore, it was proposed to use a mixed refrigerant and to introduce a pre-cooling unit to solve this problem.

2.2.4.3. APCI SMR technological process

The C3MR process is the most common. The process capacity varies from 1.5 to 4.5 million tons of LNG per year. The process is shown in

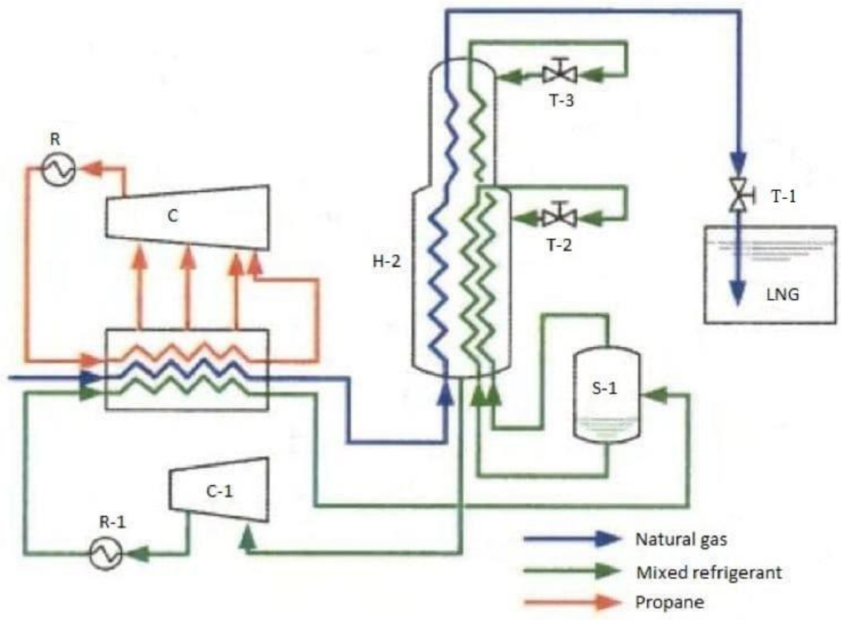

Figure 2.*9*

Figure 2.9 APCI C3MR Process [17].

The process uses two cooling cycles - preliminary and main. The pre-cooling cycle uses propane as the refrigerant, while the main cycle uses a mixed refrigerant consisting of nitrogen, methane, ethane, propane. For the pre-cooling of the gas to occur gradually, the cycle uses a three- or four-stage refrigeration system at different pressures.

The mixed refrigerant is cooled to a temperature of (-30) - (-40) °C after being compressed in the C1 compressor and then sent to a separator for separation into liquid and gas phases.

The raw gas flow under a pressure of 7 MPa is cooled in the pre-cooling cycle to (-30) - (-40) °C, after which it is sent to the heat exchanger, where the main cooling cycle takes place to a temperature of (-155) - (-163) °C. After cooling, the liquefied gas enters the throttle or expander, where it is cooled to the required temperature by lowering the pressure. After that, the final product enters a separator for separation into liquid and vapor phases [17].

A distinctive feature of the process is low metal consumption, the ability to use feed gas with different composition, and high efficiency.

2.2.4.5. Statoil LINDE MFC technological process

The MFC (Mixed Fluid Cascade) process is used in harsh environmental conditions at the Snohvit plant in Norway. A distinctive feature of the LNG plant's conditions is the large temperature difference between winter and summer seasons, which makes the propane refrigeration cycle ineffective. Therefore, three cooling cycles are used in the process: preliminary, liquefaction and supercooling. All cycles use a mixed refrigerant consisting of methane, ethane, propane and nitrogen, but the composition of the refrigerant is different for each cycle.

A schematic diagram of the process is shown in Figure 2.10

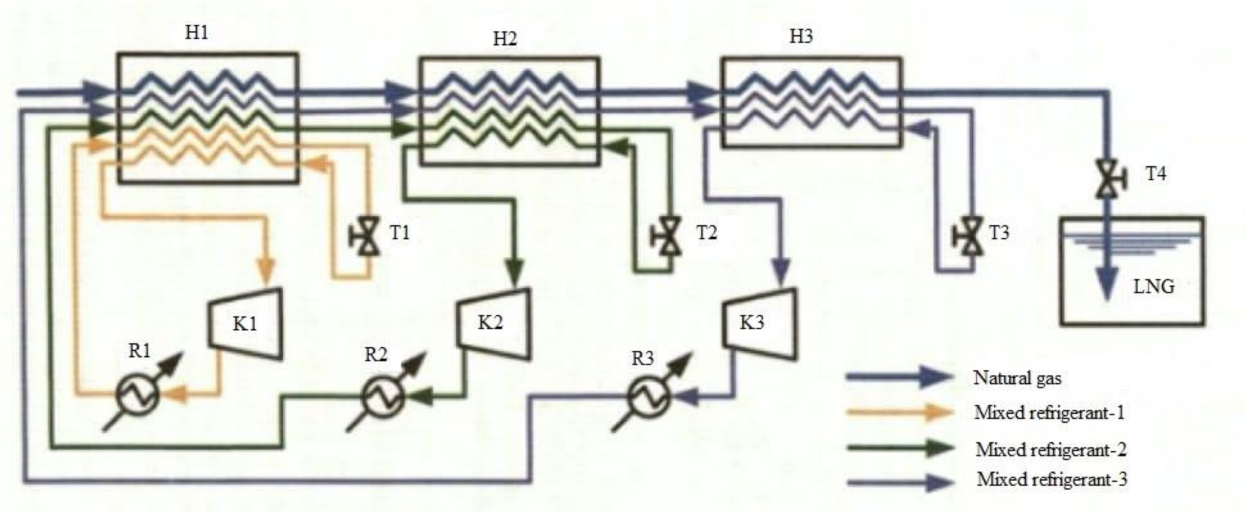

Figure 2.10 Statoil-LINDE MFC process [17].

Natural gas under a pressure of 50-60 MPa is cooled in a pre-cooling cycle in a heat exchanger T1 to a temperature of (-50) - (-60) °C. After that, the flow enters the second stage of cooling into the heat exchanger T2, where it is cooled to a temperature of (-70) - (-80) °C, and then to the third stage of cooling, into the heat exchanger T3, where it is cooled to a temperature of (-140) - (- 150) °C. This is followed by final cooling to a temperature of -160 °C due to expansion in throttle T4 to a pressure of 0.11 MPa [17].

2.2.4.6 Shell DMR process

The DMR (Double Mixed Refrigerant) technological process is used for medium and large-scale production. This technology is used at the LNG plant in Sakhalin and in the world's largest floating plant Prelude. A distinctive feature of the process is changing the pre-cooling cycle depending on the ambient temperature.

The refrigerant in the pre-cooling cycle is a mixture of ethane and propane. The process is flexible due to the possibility of changing their ratio in the cooling cycle, which allows unloading the cryogenic heat exchanger. Figure 2.11 is a schematic diagram of the Shell DMR process.

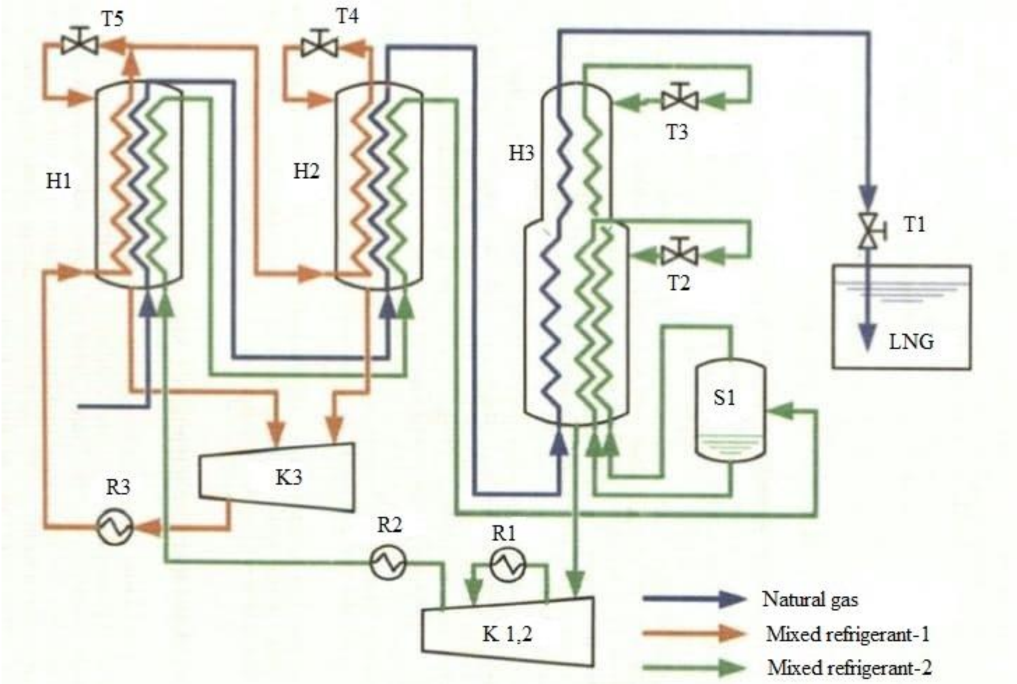

Figure 2.11 Shell DMR process [17].

The refrigerant from the pre-cooling cycle enters the C3 two-stage compressor, where the compression process takes place. After that, the compressed refrigerant is sent to the heat exchanger H1, where it is divided into two streams: the first stream, passing through the throttle, is again sent to the heat exchanger H1 for cooling, and the second stream is directed to the next heat exchanger for further cooling and throttling. Finally, gas streams leaving the bottom of the heat exchangers are directed to compressor 3.

Natural gas and refrigerant in the liquefaction cycle are cooled in the pre-cooling cycle to (-55) - (-85) °C. After that, the refrigerant, consisting of methane, ethane, propane and nitrogen, passes through separator 1, separated into liquid and vapor phases, and enters the heat exchanger 3, where the main natural gas cooling cycle takes place [18]. In heat exchanger 3, pre-purified and cooled natural gas is subcooled to -155 °C, leaving the heat exchanger. It expands in T1 to 0.11 MPa, as a result of which it reaches a temperature of -160 °C and is sent to a storage tank [18].

2.3. Technological subsystem of liquefaction, storage and transportation of gas on the shelf

Ch.S. Huseynov has developed a new technological solution, which consists of the liquefaction of natural gas underwater [4].

It is planned to carry out the gas liquefaction process in the subsea LNG plant using a heat exchanger with counterflow interstage separation. However, the creation of an underwater complex of the same size as a surface plant is unacceptable for many reasons: high metal consumption, a large amount of technical equipment, and the electricity required for operation. Therefore, Ch.S. Huseynov proposed new technology for gas liquefaction.

This technology uses liquid air as a refrigerant. Due to its liquefaction temperature (-195 °C), air completely cools natural gas to the required temperature (-163 °C). Cooling is provided by the counterflow of natural gas and liquid air, in which natural gas moves due to reservoir pressure, and a cryogenic pump pumps liquid air. The process reliability is also ensured by cold arctic water [4].

For security reasons, it is proposed to carry out the necessary operations separately. The layout of all underwater objects is shown in Figure 2.12

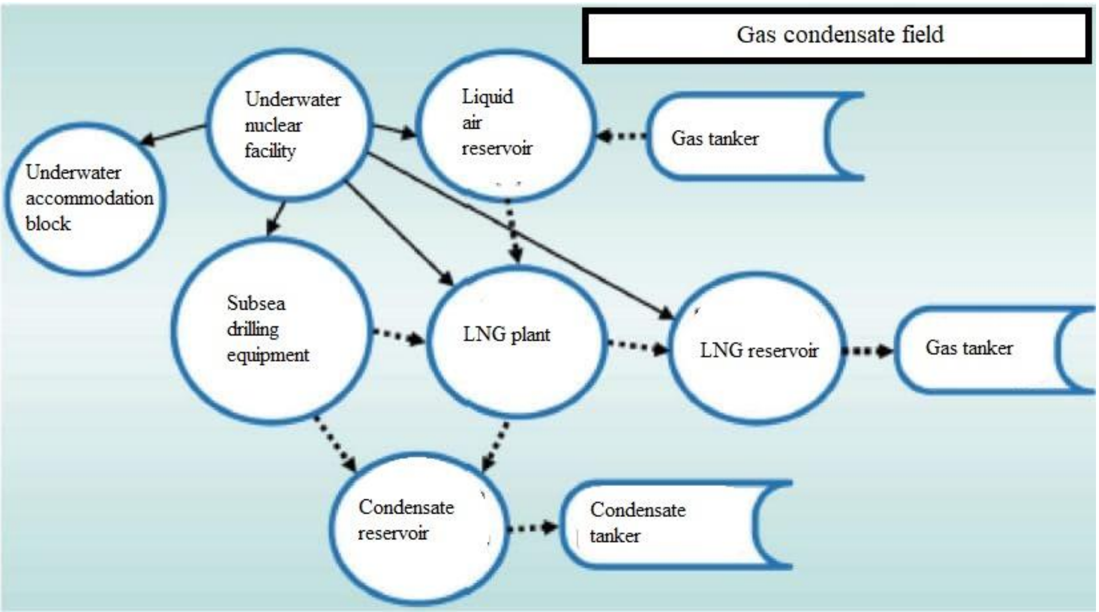

Figure 2.12 Scheme of a complex of subsea facilities for the subsea development of a gas condensate field [4].

The design should consider the constant loads that will be on the subsea plant at a depth of about 115 m and the hydrostatic pressure of 1-1.1 MPa, as well as underwater currents. It is impractical to locate the plant at a shallower depth due to the risks associated with icebergs and ice formation.

The first natural gas cooling cycle is carried out in a flexible non-insulated pipe connecting the SPS and the underwater gas liquefaction plant itself. The cycle diagram is shown in Figure 2.13.

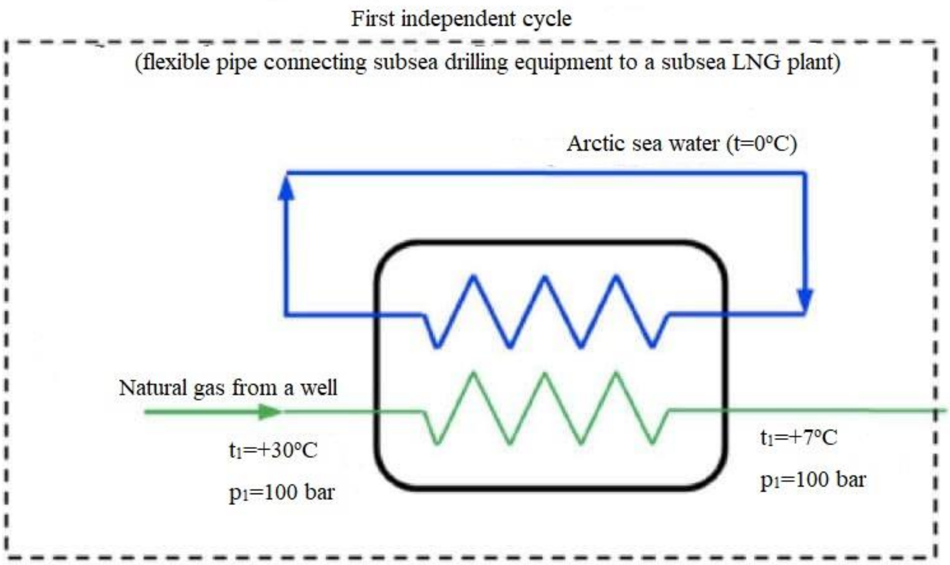

Figure 2.13 The first independent cycle [4].

In this cycle, natural gas is cooled in a heat exchanger with arctic seawater.
After separation, the gas enters the second independent cooling cycle, where liquid air is already used as a refrigerant. Thus, the gas is cooled in a cascade of four stages after each separation of the gas and liquid phases.

The air, which has turned into a gaseous state due to the cycle of work, is sent to the life support system of the plant for the breathing of personnel. Then it is thrown into the water, which has a beneficial effect on the arctic sea waters, which is not rich in oxygen.
The scheme of the second independent liquefaction cycle is shown in Figure 2.14.

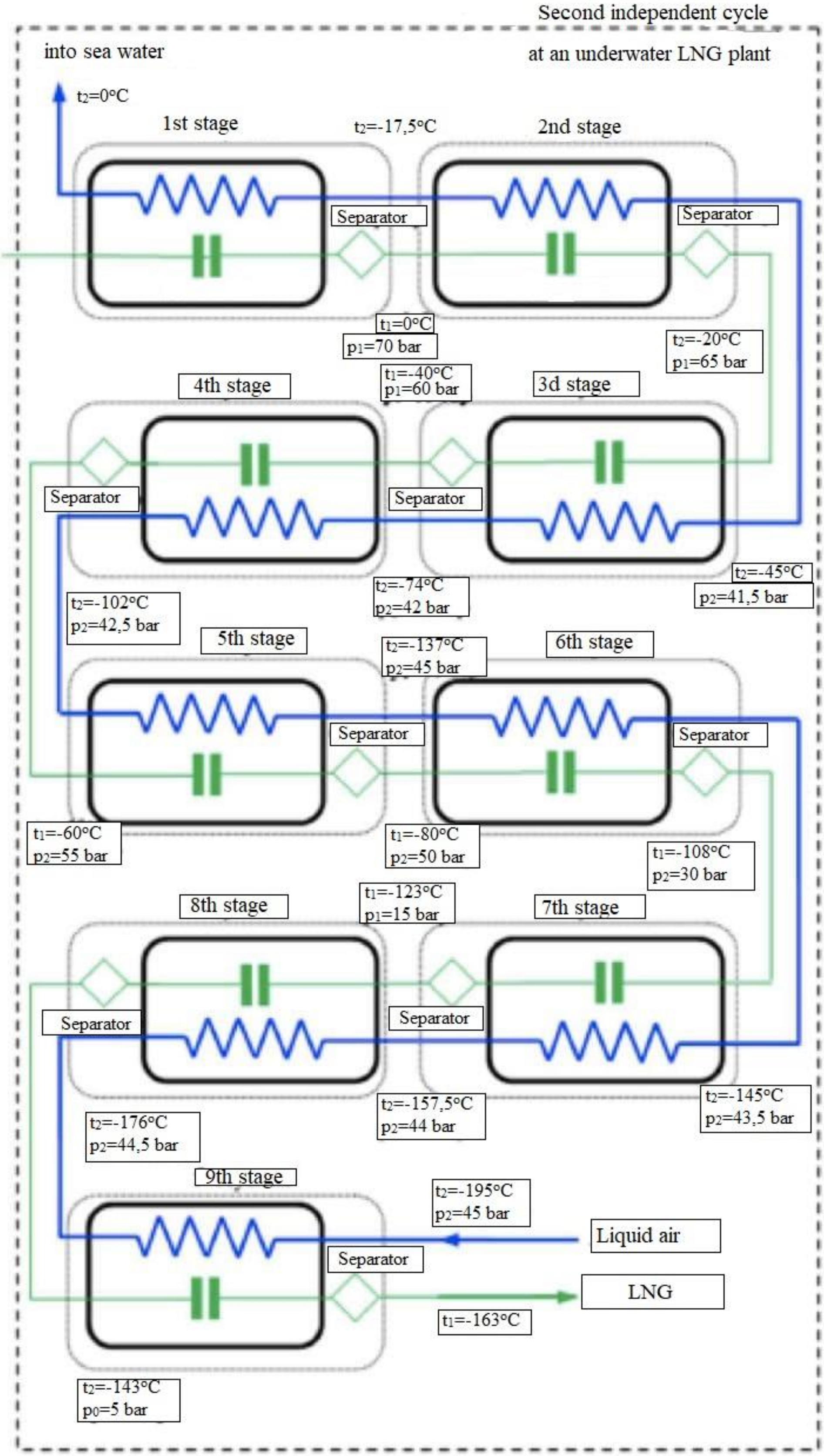

Figure 2.14 The second independent cycle [4].

The resulting liquefied natural gas is stored in a special tank and removed from the plant by a special tanker.

The same tanker brings liquid hydrogen, simplifying logistics and making it possible to implement a continuous cycle of gas liquefaction and shipments. However, before pumping into the LNG tanker, after there has been liquid air, the tank should be treated with nitrogen to prevent the formation of an explosive mixture.

2.4. Major global LNG projects

2.4.1. Yamal LNG and Arctic LNG-2 in the Arctic

Yamal LNG is a complex project of the Novatek company, which includes natural gas production, liquefaction, and delivery to the end consumer. Yamal LNG is located in Russia on the Yamal Peninsula in the Arctic. The plant consists of three production lines, each with a capacity of 5.5 million tons of LNG per year. The resource base of the project is the Yuzhno-Tambeyskoye field located on the shore of the Ob Bay. Gas reserves are estimated at 1,380 billion m^3. The first production line was launched in 2017 [2].

Arctic LNG-2 is a new project of the Novatek company, the resource base of which is the Utrennee field, located in the Yamal-Nenets Autonomous District at a distance of 70 km from the Yamal LNG plant. The project is at the last stage of construction; it is planned to launch three technological lines with a total capacity of almost 20 million tons of LNG per year. Three processing lines will be located on offshore gravity platforms [22].

Both factories are located in the Arctic Circle in an area where winter temperatures can drop to -52 °C.

Total investments in the Yamal LNG project amounted to about $ 27 billion. Capital expenditures for the construction of Arctic-2 are estimated at $ 21 billion. This cost difference is due to gravity platforms in the Arctic-2 project, which significantly reduces the volume of onshore construction and eliminates the need to build storage tanks. In addition, it was necessary to build a seaport for the transport of LNG from the Yamal plant.

2.4.1.1. Scheme of Yamal LNG and Arctic LNG-2 plants

The Yamal LNG plant consists of the main building, a power plant, engineering facilities, a gas treatment unit, 2 separation units, 3 LNG production lines and 4 LNG storage tanks. The production process is as follows: natural gas is fed to the complex gas treatment unit, after which it is fed to the liquefaction unit. For safety reasons, the control center building is located far from the LNG production lines and tankers.

Unlike the classic onshore Yamal LNG plant, Arctic LNG-2 uses innovative offshore gravity platform technology. An offshore platform of this type is a concrete structure held in place by gravity. The platform is 330 m long, 152 m wide, 30 m high. Most of the processing lines are installed at the top of the platform. The first two platforms contain a storage facility with a capacity of 115 thousand m^3 of LNG and an ethane storage facility with 980 m^3. The third gravity platform contains only LNG storage tanks [22].

The total area of the Yamal LNG plant is 1.9 million m^2, and the area of Arctic LNG-2 is 0.75 million m^2.

2.4.2. Shell Prelude

Prelude FLNG (Floating Liquefied Natural Gas) is a floating liquefied natural gas plant located off the coast of Australia. The plant is owned by Shell and is located more than 200 km offshore. The resource base of the plant is the Prelude field, the reserves of which are estimated at more than 4 trillion m^3. There are 7 production wells under the vessel. The plant's capacity is 5.3 million tons per year: 3.7 million tons of LNG, 1.2 million tons of gas condensate and 0.4 million tons of LPG. The plant is designed for the extraction, treatment, liquefaction, and storage of natural gas and the shipment of LNG to tankers for further deliveries to the consumer [23].

2.4.2.1. LNG production scheme

The Prelude is 488 meters long, 74 meters wide and 195 meters high. The Prelude is the largest ship in the world. Energy is generated onboard by steam turbines.

There are 7 production wells under the vessel, from which the produced fluid flows through offshore risers. Gas treatment and liquefaction plants occupy about of the usual sizes of these plants in the onshore plant [23].

2.5. LNG projects

The choice of natural gas liquefaction technology is an important issue, especially in the Arctic conditions, on the answer to which capital costs, process safety, and the cost of the final product depend.

2.5.1. Yamal LNG

The Yamal LNG plant uses the APCI C3MR process. The process has the following advantages: low metal consumption, high energy efficiency, and reliability. The process uses two refrigeration cycles: a pre-cooling cycle and a gas liquefaction cycle. The pre-refrigeration cycle uses propane as the refrigerant and is primarily nitrogen, methane, ethane and propane.

This process was chosen for both its reliability and political reasons [22].

2.5.2. Arctic LNG-2

Arctic LNG-2 uses the LINDE process developed by Statoil for cold conditions. This process is also used at the Norwegian plant Snohvit, characterized by air temperature differences from +26 °C in summer to -20 °C in winter. The process uses three refrigeration cycles: pre-cooling, liquefaction and subcooling. Mixtures of nitrogen and hydrocarbons are used as refrigerants; the composition of the refrigerant differs in each cycle. The disadvantages of the process include high metal consumption, and the advantages are the flexibility of the process and its adaptability to harsh conditions and a wide range of temperatures [22].

2.5.3 Shell Prelude

The Shell DMR process was chosen to liquefy natural gas on board. The project consists of two cooling cycles: preliminary and natural gas liquefaction cycle. The refrigerant in the pre-cooling cycle is composed of propane and ethane. This refrigerant composition allows you to adjust to the ambient temperature: the more ethane in the refrigerant composition, the colder gas is obtained after the pre-cooling cycle, which allows unloading the main cryogenic heat exchanger and getting more LNG with the same heat exchange surface. This process is reliable and energy-efficient. This technology was also applied in the Sakhalin-2 project [2].

2.6 The principle of the regasification terminal

LNG regasification is carried out after transportation to the destination. The LNG receiving terminal includes an LNG offloading unit, storage tanks, pumps and a regasification unit. The schematic diagram of the receiving terminal is shown in Figure 2.15.

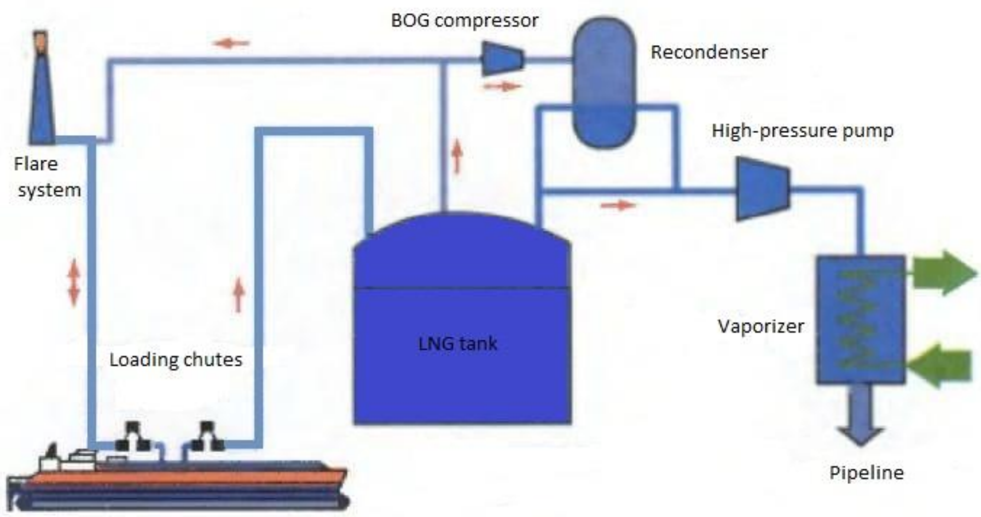

Figure 2.15 Schematic diagram of the receiving terminal [17].

The arms are attached to the vessel to unload an LNG tanker, after which pumps pump the liquefied natural gas into storage tanks. Unloading a tanker takes 10-15 hours on average. The gas that evaporates in the process is compressed to a pressure of 1 MPa, after which it is again liquefied and combined with the LNG stream, which goes for regasification. Regasification is the process of returning LNG to a gaseous state by heating and evaporation at a pressure of 6-10 MPa. LNG is heated by air or seawater to a temperature slightly above zero [17].

Chapter 3

3 Features of the development of the Shtokman gas condensate field

3.1. Shtokman gas condensate field

The Shtokman gas condensate field was discovered in 1981 due to geophysical surveys conducted from the Professor Shtokman vessel. Thanks to the ship, the field got its name. Soon, studies began to identify the structure of the field. Finally, in 1988 the first appraisal well was drilled. As a result of drilling, 2.4 trillion m^3 of gas and gas condensate deposits were confirmed.

The Shtokman field is located on the shelf of the Barents Sea in the central part of the East Barents Sea trough, which stretches in the submeridional direction along the western shores of the Novaya Zemlya islands. The trough has a complex structure due to three deep vugs - the South Barents Sea, North Barents Sea and Nansen, separated by regional uplifts-saddles of the sea 550 km north-east of Murmansk. The average sea depth in this area is 330 m [10].

3.1.1. Climate

Their severity distinguishes the climatic conditions of the region where the deposit is located. The Barents Sea is distinguished by a significant amount of precipitation, high temperatures compared to other Arctic regions, and a relatively mild winter period. As you move north, the climate becomes more severe. The average annual temperature varies within 9 degrees: on Bear Island it is -1.7 °C; on Spitsbergen -5.1 °C; and in Tikhaya Bay the temperature is already -10.6 °C.

Such climatic conditions are because both the warm Norwegian Sea and the cold Arctic basin are located near the Barents Sea. The sea is characterized by cold cyclones, due to which cold arctic winds can penetrate far south. The Barents Sea is one of the most unstable climatic regions [10].

3.1.2. Features of the natural environment

The Shtokman field is unique not only because of the colossal reserves of hydrocarbons but also because of the peculiarities of the natural environment. The deposit was assigned the third category of complexity due to the dissected bottom topography, clayey soils that make up the sea bottom, and multiple dissections of Mesozoic rocks. The bottom water temperature does not rise above 0 °C all year round. In addition, the ground temperature is also negative down to a depth of 15 m. Considering all of the above factors, the construction of underwater structures at the bottom of the Barents Sea requires significant engineering surveys to find suitable sites for constructing the necessary field facilities. The average wind speed in Shtokman gas condensate field is 40 m/s, but it can reach 50 m/s. The maximum wave height is 19 m. The maximum mass of ice that forms during splash icing is 820 kg/m^2. The icing of surface objects occurs from October to May [14].

Ice does not form in the water area of the field; icebergs come here from the colder regions of the Barents Sea. Ice floes can reach a size of up to 13 km with an average ice thickness of 1.5 m and have a maximum speed of 1 m/s. However, the most common ice is up to 1 km in size. Near the Kola Peninsula, ice formations are practically not observed throughout the year. Icebergs pose a serious threat to offshore structures. Therefore, when developing a field, special attention should be paid to studying the characteristics of drifting ice and icebergs in the production area. All of the above environmental factors of the field make the field development project the most difficult task faced by engineers during their work on the Arctic shelf [20].

3.2. Scheme of construction of the Shtokman gas condensate field

Due to the great distance from the coast, great depth and harsh weather conditions, specialists proposed a combined plan for developing the Shtokman field. The development of the field was planned to be carried out in 3 phases. A schematic of the offshore production facility is shown in Figure 3.1.

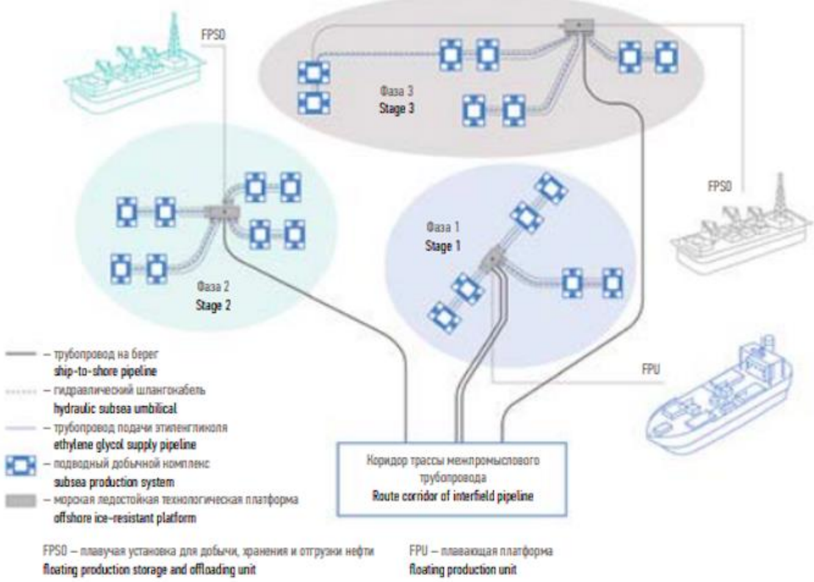

Figure 3.1 Figure 3.1 Scheme of the offshore production complex [16].

The subsea production complex consists of wells, manifolds, and Christmas tree. The SPS is connected to the technological platform using risers. It was planned to transport gas and gas condensate to the shore using an offshore two-line pipeline in a two-phase flow. The two-phase flow was separated onshore: the gas was sent for cleaning, drying, and liquefaction, and the condensate was sent for further processing.

The development of the field is planned for 50 years.

3.2.1. Phase 1

The first phase of the field development includes hydrocarbons production from 16 wells of the J1 and J2 reservoirs in the natural depletion mode. The planned production volume is 24 billion m^3 per year. At the same time, the flow rate of the wells will be 71 million m^3 per day. The total productivity of the SPC per day will be 70 million m^3. The offshore phase of the development project includes the construction of the following facilities [24].

- 16 wells
- Underwater production system
- Technological vessel
- Offshore two-line pipeline

3.2.2. Phase 2 and Phase 3

The second phase of development will begin in the fourth year of field development and the third phase in the eighth year. At the beginning of each phase, a technological platform with a capacity of 24 billion m^3 per year is put into operation. In the second and third phases, only natural gas is supposed to be transported onshore in a single-phase flow, while gas condensate was to be stored on the platform and removed by tankers as it accumulates. In phases 2,3, it is planned to commission another 56 wells and increase the number of SPC to 11. The average annual flow rate of wells will amount to 2.7 million m^3 per day.

The period of stable production is approximately 25 years. It is planned to extract 2,110 billion m^3 of gas with a gas recovery rate of 53.5% and 31,008 thousand tons of gas condensate with a recovery rate of 49%. The overall gas recovery factor will be 80.2%, and the condensate recovery factor will be 68.6% [15].

Gas and gas condensate is planned to be delivered to an ice-resistant technological vessel (FPSO) using a riser system. The FPSO is designed for possible ice loads; however, the vessel may become detached from the anchor system in the event of excessive ice loads. A ship is designed to prepare the produced hydrocarbons for further transportation through the pipeline.

The subsea production system includes drilling centers, which consist of two bottom plates, each of which is connected to four drilling windows. The bottom plates consist of wellhead equipment, Christmas tree, manifolds and a control system. In addition to drilling centers, SPS also includes a system of risers and pipelines.

The produced hydrocarbons are delivered to the process vessel via a riser system. After that, the plant separates them into the water, condensate and natural gas. Then, water is pumped back into the reservoir, natural gas is compressed and sent to the main pipeline, and condensate is stored on a ship and then transported by tankers.

3.2.3. Technological complex

The project considered the possibility of using a low-temperature separation process to separate water and condensate from natural gas. A feature of the low temperature separation process is the ability to operate in a mode of varying pressure at the inlet to the unit, which is especially important at the stages of declining gas production. At the initial stage of production, the pressure is excessive. Due to this, low temperatures are achieved at the installation. The process uses monoethylene glycol to prevent hydrate formation.

A schematic diagram of the low temperature separation process is shown in Figure 3.2.

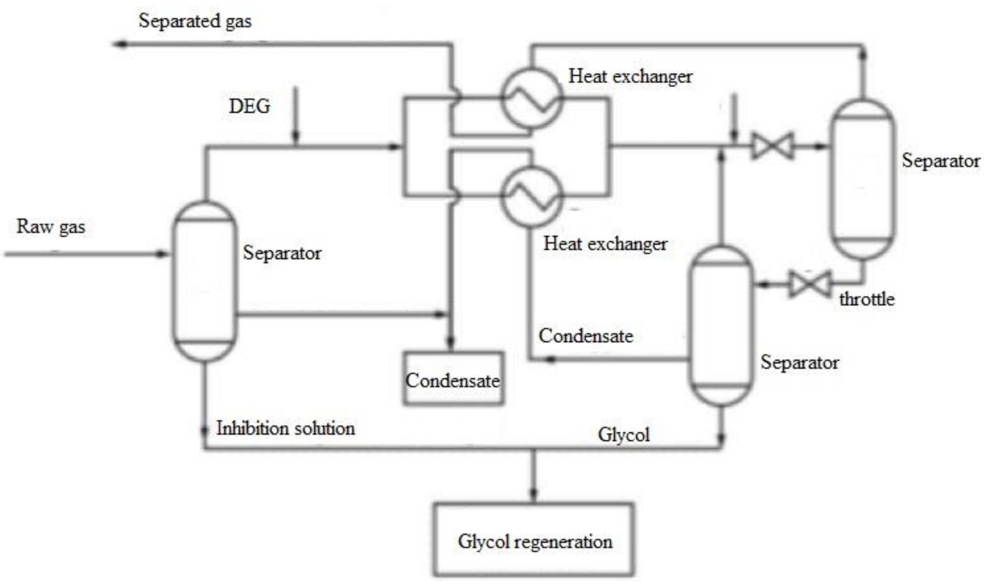

Figure 3.2 Schematic diagram of the low temperature separation process [11].

Raw gas enters separator 1, where formation water and condensed condensate are separated. After that, the liquid phase leaves the bottom of the separator, and the gaseous phase, into which glycol is injected to prevent hydrate formation, is cooled and enters the separator 5. After the separator, the gas is sent through the heat exchanger to the main pipeline, and the liquid enters the three-phase separator 6, from where gas comes out from above weathering. The inhibitor liquid solution is sent for regeneration.

3.3. Subsea production system

The subsea production system injects water into the reservoir, transports the produced products to the process vessel, and transports gas and condensate to the offshore two-line pipeline.
It was planned to locate three independent drilling centers at the field containing two production plates. It is planned to drill 20 wells at the field, 16 of which are operational and 4 are reserve ones. The entire underwater complex includes:

- Six infield pipelines
- Three mining centers

• Three devices for connecting risers to infield pipelines
• Six production risers
• Four export risers
• Three umbilicals to control the production plate and manifolds
• Two manifolds installed at the ends of two pipelines
• Two main pipelines

3.4. Offshore ice-resistant platform (FPU)

The platform is a technological vessel with a developed superstructure, the design of which takes into account ice loads. It includes the following elements:

• Hull and superstructures
• Systems and equipment
• Power plant
• Turret assembly with a rotary system
• Buoy of the riser retention system
• Connection and disconnection systems
• Living accommodations

The production vessel is delivered to the processing vessel through risers. Then there is a separation of gas and liquid at the inlet separators. Next, the gas phase is directed to drying and the liquid phase to the condensate treatment lines. Finally, gas dehydration is carried out to achieve the dew point set points to prevent hydrate formation in the offshore pipeline and prevent corrosion.

Gas is compressed on four compression lines, after which the gas is cooled and mixed with condensate for further transport via an offshore pipeline.

Condensate treatment is also carried out to reduce the water content to 0.01%.

The liquid coming from the inlet separators is heated to 40 °C to destroy the emulsion consisting of water, monoethylene glycol and condensate. Then the condensate is heated to 60 °C and sent to the dehydrator, and then to the stripping column.

The technological vessel must be self-propelled to move to a safe distance in the event of ice threats. In addition, the vessel is ice-resistant and designed to operate in arctic conditions [24].

3.5. Offshore Ice Resistant Technology Platform (FPSO)

The offshore ice-resistant self-propelled platform is designed to receive produced products, prepare gas, condensate for transportation, and store and stabilize condensate. Also, staff live on the platform.
The main elements of FPSO are:

• Hull
• Technological modules of the superstructure
• Residential module
• Helipad
• Turret
• Mooring and riser buoy

Condensate storage tanks are also provided on the platform. When filling the storage facilities, condensate is sent to the tanker for further transport to the destination [24].

Vessel dimensions: length - 320 m, width - 63 m, height - 27 m.
The vessel will have four gas compression lines.

The platform is autonomous for at least 90 days: a sufficient amount of fresh water, food, supplies for personnel and crew on board.

The platform is installed in the field using a turret, which allows you to change the vessel's orientation in space if necessary.

Chapter 4

4 Selection of the optimal liquefaction technology for the Shtokman gas condensate field

It is necessary to carry out a comparative analysis of the three technologies for liquefying the natural gas to select the optimal liquefaction technology for the Shtokman gas condensate field.

The main selection criteria are adaptability to low temperatures, low metal consumption, which determines the capital costs of construction, process flexibility, which means the ability to adapt to changing environmental conditions, and the ability to use the process in arctic conditions. Comparative analysis of technologies is presented in Table 4.1.

Table 4.1 Comparative analysis of natural gas liquefaction technologies

Criteria	C3MR	LINDE MFC	Shell DMR
Metal consumption	high	the highest	low
Energy consumption	low	low	the lowest
Complexity	high	the highest	least of all
Efficiency	high	high	the highest
Adaptability in northern conditions	average	high	high
Flexibility	average	high	the highest
Shifts in productivity	slow	slow	apace

The LINDE technology used at the Norwegian plant Snohvit is suitable for Shtokman. However, this process was brought productivity with a delay of 3 years, which speaks of its technical complexity and high requirements for personnel qualifications.

The DMR process was not chosen as a gas liquefaction technology for the Arctic LNG-2 project, despite its flexibility. In this process, it is easy to increase productivity and, as a result, obtain surplus production that will need to be transported to the consumers in Europe and other places extremely remote from the field.

Based on a comparison of the three liquefaction technologies, it can be concluded that the Shell DMR technology is the most suitable for the Shtokman gas condensate field. The process allows to regulate productivity, adapt to changing environmental conditions, it does not require significant capital expenditures and operating costs, consume a small amount of energy, and does not require a lot of time to reach the set productivity.

4.1. Assessment of the possibility of using a vessel - an analogue of Prelude FLNG at Shtokman gas condensate field

The use of a vessel - an analogue of the Prelude at the Shtokman field - seems promising. Still, after analysis, it can be concluded that the use of this technology is impossible in Arctic conditions:

1. The ice situation in the Barents Sea poses a great danger for a large vessel, namely the possibility of massive icebergs drifting.
2. The external equipment of the vessel, such as metal structures, complex gas treatment units, are not designed for operation at low temperatures.
3. The icing of steel structures adds a significant load to the vessel.
4. The field is located far from the coast, which makes storing large quantities of LNG on a ship in Arctic conditions impractical and complicates the transportation of LNG to the consumer.

Chapter 5

5. Peculiarities of LNG transportation in the conditions of the Shtokman field. Teriberka

5.1. Teriberskaya Bay. Brief description of the area

The Teriberskaya Bay is located on the shores of the Barents Sea 60 km east of the Kola Peninsula between Cape Dolgiy and Teribersky. The bay juts into the land for 9 km, has a maximum depth of 120 m and a width of 5 km. The bay is divided into two parts: outer (northern) and inner (southern). Lodeynaya and Korabelnaya bays are located in their inner part. The eastern half of the outer part of the Teriberskaya Bay is called Orlovka Bay.

The river Teriberka flows into the bay, at the mouth of which is the village of the same name Teriberka. The banks of the bay are high and steep, except a relatively low area located south of the mouth of the Orlovka River.The depth of the sea ranges from 20 to 120 m, the bottom is composed of sand and silt, and the shores are composed of stone rocks. The tidal currents in the Teriberskaya Bay are not too strong: from 20 to 25 cm/s. However, a small swell comes from the sea, and strong wind waves are also observed. The sea depth in Orlovka Bay, located on the eastern coast of Teriberka Bay, is more than 90 m deep, and the shores are high and steep. The Zavalishina Bay flows into the Orlovka Bay in the south. The shores are also high, but the depths are shallow, about 15 m. A strong swell comes to the sea surface in the Zavalishina Bay with a north-westerly wind [10].

The ice situation in the Teriberskaya Bay is generally favorable; in the summer months, the water surface is free of ice. In the winter months, beginning in November, first-year ice enters the mouth. In cold winters, stationary ice forms at the river's mouth, but waves and wind quickly destroy it.

The Teriberskaya Bay and the adjacent territories are favorable for fishing; in the spring-summer period, the river mouth is a place for fish spawning. In this regard, there may be restrictions on the performance of work.

5.2. Logistic solutions for the transport of produced fluid

Based on the results of the studies, it was decided to transport a two-phase flow consisting of gas and condensate from the field to the shore with their further separation on the shore. This decision was made to reduce offshore operations and avoid storage and gas condensate in the harsh Arctic conditions offshore.

Gas produced in the subsea production facility will be fed through a system of welded bottom plates through production risers to a ship-type floating installation (FPSO). Primary separation, separation of water and mechanical impurities will take place on board. After that, the two-phase flow is delivered via an offshore two-line pipeline to onshore facilities in the village of Teriberka [8].

5.2.1. Onshore facilities of Teriberka village

The onshore part of the Shtokman gas condensate field development project consists of:

- Onshore section of the offshore trunk pipeline
- Complex gas treatment units (CGTU)
- Natural gas liquefaction plant
- Infrastructure facilities for the CGTU and the LNG plant
- Seaport in the Teriberskaya Bay

The pipeline, which contains gas and gas condensate, comes ashore on the northern shore of the Kola Peninsula in Opasova Bay. The onshore section of the pipeline will be underground and extend up to 10 km. After the pipeline, gas and condensate enter the slug catcher of the integrated gas treatment unit, after which the stream is divided into two parts: part will go to the LNG plant for liquefaction, and the second will be sent to the CGTU [10]. The main purpose of the complex gas treatment units is to separate gas and gas condensate and prepare the flow for further transportation. After installing the gas treatment plant located at the Zavalishina Bay, gas is sent to the main pipeline Murmansk-Volokhov. The extracted condensate will be sent for stabilization and then sent to the storage facilities of the Korabelnaya Bay.

Also, within phases 2 and 3 of the field development framework, it is planned to build a seaport in the Teriberskaya Bay. Its purpose:

- Provision of loading/unloading of LNG tankers
- Cargo handling of ships
- Control over movement across the border of the Russian Federation

The seaport should be located in the northeastern part of the Teriberskaya Bay.

5.3. Technical solutions for fluid transport from the Shtokman field to onshore facilities in the village Teriberka

5.3.1. Characteristics of the offshore double-strand pipeline

The offshore two-line pipeline is designed to transport a pre-dehydrated two-phase flow, consisting of a mixture of gas and condensate, to onshore facilities in the village of Teriberka. The underwater part of the pipeline is 550 km, and the onshore section is 8 km. The offshore section of the pipeline begins at the PLEM inlet flange at the field and ends with a launching/receiving chamber in the village of Teriberka. The pipeline consists of two parallel lines with an outer diameter of 36 inches. The design life is 50 years.

For the offshore double-strand pipeline, carbon-manganese steel pipes are used. It is covered with three-layer polypropylene or bitumen enamel for corrosion protection; protective electrochemical corrosion protection is also used on the offshore part of the pipeline. For protection and stabilization on the seabed, the pipeline is concreted, and avalanche limiters are installed.

The onshore section of the pipeline is underground at a depth of at least 1 m. For corrosion protection, electrochemical protection is used in conjunction with a triple layer of polyolefin [24].

5.3.1.1. Flow chart and product flows

The floating production unit (FPU) prepares gas and condensate for transport: dehydration and compression. After that, the two-phase flow is directed through the export risers and the PLEM to the pipeline. The temperature of the gas-condensate mixture at the inlet to the pipeline is 60 °C, and the pressure is 153 bar. The mixture enters the inlet flange of the plug catcher at a pressure of 65 bar and then to the onshore complex from the pipeline [24].
Main technical and economic characteristics:

- Planned volume of gas supplied through the pipeline - 23.8 billion cubic meters/year
- Planned volume of condensate - 290 thousand m^3 / year
- Daily productivity of one pipeline string - 35 million m^3 / day

5.3.1.2. Equipment used in the technological process

The infrastructure of the offshore two-line pipeline includes:

- Manifold (PLEM)
- Cameras for launching/receiving cleaning devices
- Pipeline
- Cutoff cranes

5.3.1.3. Subsea pipeline manifold (PLEM)

The manifold is a modular design that is installed at the end of each line of the pipeline. With the help of this design, the gas-condensate mixture is supplied from the risers to the pipeline. Another function of the manifold is in-line pipeline diagnostics and maintenance of pipeline cleaning operations. The manifold does not require additional anti-trap protection, as it is located inside the safety zone.

The PLEM, which is fixed at the bottom with four anchors with the possibility of levelling, consists of a basic structure and modules connected in series, including a levelling frame, a block valve module, and a chamber module for launching/receiving cleaning and diagnostic facilities. A lattice panel is installed on top of each module to protect it from falling objects. The PLEM design provides for the possibility of vertical and horizontal alignment of the end of the laid pipeline in V-shaped support [24].

5.3.1.4. Launch-receiving chamber

The chamber module is not a regular part of the manifold but comes in two variations: a pre-commissioning modification and a pipeline modification. The first modification weighs more than 100 tons due to the size of the pistons used. The second modification is much smaller than the first. A module is a design with an internal manifold, piping and valves.

The onshore chamber for launching and receiving the cleaning and diagnostic facilities is equipped with an additional protective mechanism that prevents depressurization of the pipeline during its operation under pressure. The chamber has an operating pressure of 60 bar and is suitable for use during commissioning [24].

The launch-receiving chamber is a structure that consists of a coupling, small and large cylinders, an end cap, branch pipes, mounting lugs and two saddle supports, which make it possible to move the chamber by 10 cm.

The end cap has the following protective devices:

- Safety valve that informs the operator of the pressure in the chamber
- A locking device that prevents the plug from opening when it is under pressure

5.3.1.5. Shut-off cranes

Shut-off valves are used to isolate a section of the pipeline in a leak or an unforeseen situation. Installed at a distance of 800m from each other. The closing time is 12 seconds, and the opening time is a minute. The valves are closed by a spring and opened by a hydraulic line. The design also provides for the installation of emergency shut-off valves to provide additional safety in emergencies [24].

5.3.1.6. Constructive decisions

The two pipelines are located on average 50 m apart on the seabed. However, at manifolds, this distance increases to 80 m, and in the area of the pipeline landfall, it decreases to 10 m.

The choice of the steel grade is an important task since the steel of a higher grade allows to reduce the pipe thickness. However, it requires a large capital investment and additional concrete coating. During normal operation of the drying system, the two-phase mixture does not contain water; however, to prevent corrosion in the event of malfunctions in the drying system, an allowance of 1.5 mm is provided to consider possible corrosion. The inside of the piping is epoxy coated to reduce resistance to fluid flow. In addition, a polypropylene coating is used as external protection of the pipeline against corrosion.

Rock embankments will be used to reduce vibrations and reduce expansion opportunities on selected peaks. The pipeline is laid according to the terrain; its turns are carried out by bending pipes, cold-bending bends and factory-made bends.

The subsea pipeline end manifold serves to transfer two-phase flow from the riser base plate to the subsea section of the pipeline. PLEM is fixed to the bottom with anchors. The manifold is protected against corrosion by a combination of anti-corrosion coatings and cathodic protection [24].

5.4. The role of subsea reservoirs and tankers in the development of the Shtokman gas condensate field

A floating LNG plant is a vessel that serves as an offshore platform. Onboard the vessel, there are gas treatment, purification and dehydration units, and a liquefaction unit. LNG storage tanks are located in the ship's hull. Also, the ship has a system for unloading liquefied gas to tankers (Figure 5.1).

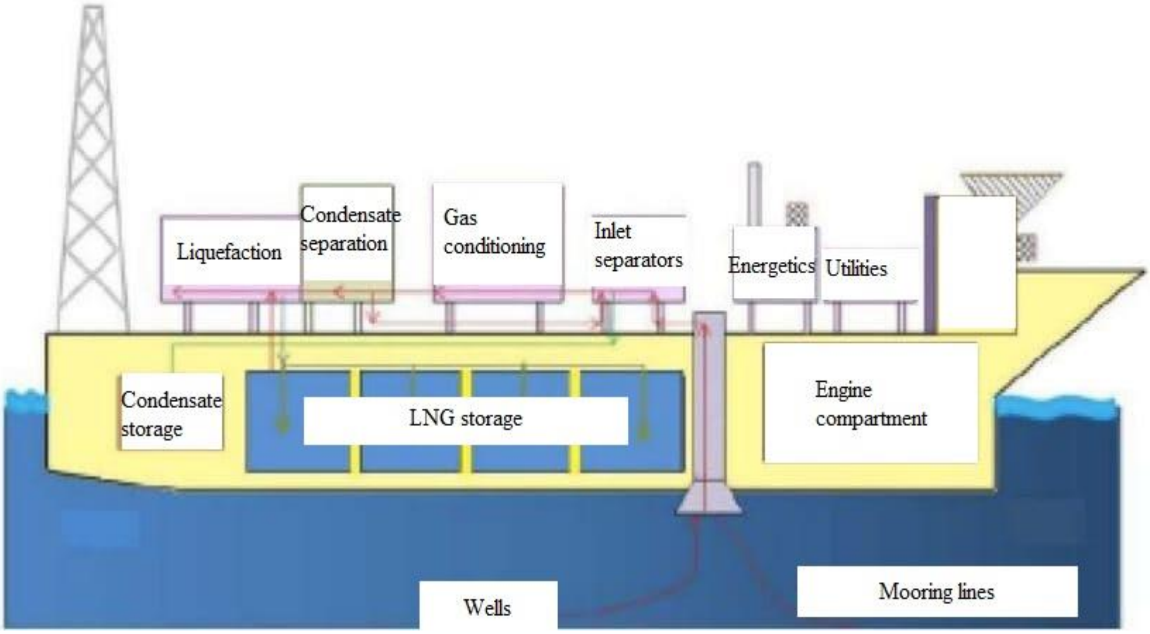

Figure 5.1 FLNG plant [3].

To reduce capital costs, the vessel is positioned directly above the field, avoiding the construction of long offshore pipelines. Since the vessel is in one place for a long time (until the end of the development of the field), it must be sufficiently equipped technically to move to a safe distance in the event of an ice hazard [19].

Advantages of a floating LNG plant:

- Competitive cost of LNG with other advantages
- Reduced likelihood of unforeseen external risks

• The possibility of renting
• Possibility of transportation if necessary

Disadvantages of a floating LNG plant:

• High power consumption
• The need to use aircraft if the vessel is far from the coast

Also, during the operation of the vessel, you will have to face several difficulties:

• Heavy ice conditions
• Harsh climatic conditions
• Storm period of waves up to 6 m
• Frequent and prolonged fogs
• Gusty wind

Loading LNG onto tankers under the external influence of the environment (waves, wind) is also difficult. From an environmental point of view, a floating LNG plant is also inferior to subsea plants, as it produces a significant amount of emissions that pollute the atmosphere. Underwater complexes have 0 release into the environment. The number of personnel required to service the floating plant is 200-300 people, which entails serious operating costs while servicing an underwater reservoir requires only sensors and an automated control system.

The scheme of loading a surface gas carrier from an underwater tank for surface development of the field is shown in Figure 5.1. The scheme of fully underwater (under-ice) field development is shown in Figure 5.2.

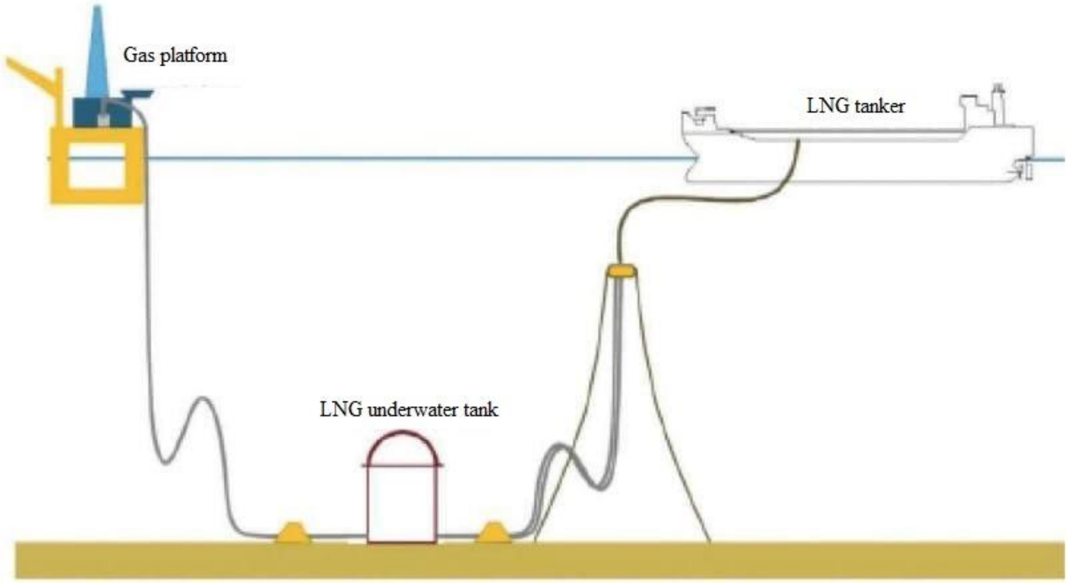

Figure 5.1 Surface field development with an underwater reservoir.

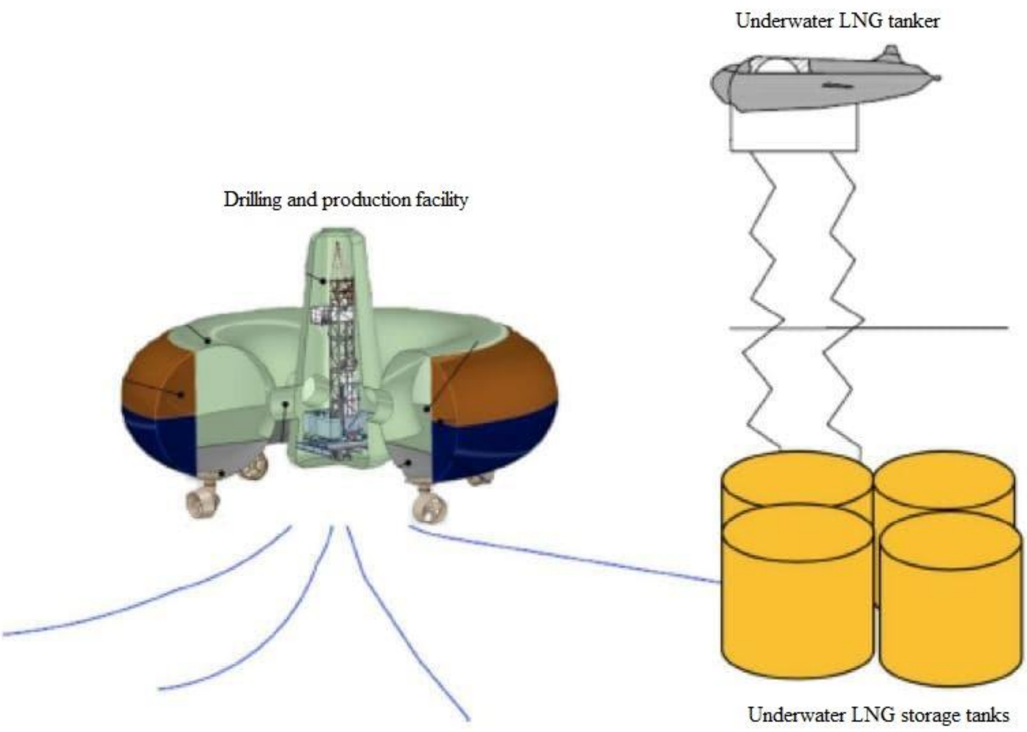

Figure 5.2 Underwater field development with an underwater reservoir.

This development option seems to be very promising for the construction of the Shtokman field. Conceptually, experts imagine development as equipping fields with multi-module unmanned complexes with a full production cycle.

In the harsh Arctic conditions, the traditional gas carrier-icebreaker gas transportation system becomes especially vulnerable. The likelihood of unforeseen emergencies increases, navigation is complicated by ice conditions, and the vessel moves more slowly than usual, which can cause supply problems. In winter, however, LNG transport by this method becomes completely inaccessible due to the too low speed of the gas carrier.

Thus, one of the main advantages of subsea facility construction is a stable year-round LNG delivery. A reliable guarantee of the success of the flight, high and stable speed of movement, the ability to choose the shortest routes will reduce the time spent on a circular flight, increase their frequency, and make traffic stable and regular.
Regular deliveries have another advantage beyond the obvious - the need to build and maintain LNG storage tanks will decrease [4].

Based on all of the above, the use of stationary LNG storage facilities in the offshore subsea transport system allows:

- To supply LNG to the consumer all year round without delays and with minimal risks
- Reduce operating costs by eliminating the need to hire personnel for the plant
- Simplify the process of loading LNG onto tankers by minimizing external influences

• Reduce the cost of building offshore pipelines

5.4.1. Basic requirements for the design of a tank for underwater storage of liquefied natural gas on the Russian sea shelf

Analysis of the structures of various types of tanks made it possible to formulate the basic requirements for designing an underwater storage facility for liquefied natural gas on the continental shelf of Russia.

The design of the tank should exclude contact of the filling product with sea water. Due to this contact, there is a high probability that LNG (temperature = -163 °C) will freeze seawater (temperature = 10-12 °C), turning abundantly into stripping gas, which is very undesirable. Furthermore, ice formed at the LNG-water boundary will reduce the storage capacity and destroy the reservoir itself. Therefore, a pontoon between the two media or a completely sealed tank will eliminate the possible risk of LNG interaction with the marine environment.

The presence of a compressor, which must regulate the pressure inside the tank, keeps it above the water's hydrostatic pressure. Pressure controlled by injection of natural gas or nitrogen under pressure.

Fight against the phenomenon of "rollover". Recommendations for preventing rollover formation: periodic mixing, using a nozzle to create a turbulent flow in the pipeline, pumping LNG from one reservoir to another, cooling the bottom layers [5].

Steel, reinforced concrete or polymers can be used as materials for the storage shell. The use of polymers is based on the fact that these materials have lighter weight and lower thermal conductivity, making it possible to partially or completely abandon expensive thermal insulation. In addition, polymers are resistant to aggressive soil substances and are not subject to electrochemical corrosion. At the moment, there is an intensive development of polymer and composite materials based on them, for example, ultra-high molecular weight polyethylene, which has a high specific strength exceeding carbon aramid fibers.

Reinforced concrete shell provides good insulation and high density required for negative buoyancy. The disadvantage is low fracture toughness.

A steel shell is lighter than reinforced concrete so that the storage will have positive buoyancy. To install the tank to the bottom, anchoring devices, anchors, weights will be required. Such storage needs good corrosion protection and thermal insulation. The polymer shell will be lighter than steel and much less massive relative to reinforced concrete. Thermal insulation properties of polymers are superior to steel but inferior to reinforced concrete. The main advantages are high corrosion resistance and good strength characteristics.

Sea depth for stationary LNG storage. The attention of our state is increasingly turning to the development of hydrocarbon resources of all the long-frozen seas of the Arctic Ocean. But the depths of these seas largely exceed 100 m. According to the Arctic and Antarctic Research Institute information, in the waters of the Arctic Ocean, the depth of immersion of ice formations from the sea surface does not exceed 30-35 m. Therefore, at depths of more than 60-80 m, there is no need to organize structure protection from ice impacts. However, consideration should be given to the potential impact of falling elements on the tank [4].

Heating of the LNG storage tank foundation. Since LNG is stored at -163 °C, the foundation slab must be heated to prevent freezing up of the ground and potential deformation of the foundation due to the formation of ice lenses, leading to the destruction of the tank.

The thickness of the insulation and the composition is selected to reduce the loss of LNG due to evaporation by up to 0.05-0.06% per day of the total volume of the stored liquid, as well as for safe operation of the tank underwater in case of emergency: internal or external tanks, for this purpose, both internal and external tanks are covered with waterproofing. Thermal insulation is most often used: rigid materials, screen, powder, porous [5].

The tank must be cooled before filling with LNG. Since the cooling of the tanks must be symmetrical, it is necessary to provide liquid nitrogen and a uniform injection system over the cross-sectional area of the tank.

The preferred shapes of underwater reservoirs are sphere, hemisphere. It is also hypothesized to use shapes such as a cylinder, drop-shaped storage, a toroid, and a cubic toroid. The tank's shell can be made of almost any geometric shape, but when the pressure of the hydrostatics of seawater is applied to the storage, the spherical shapes are the most durable and stable. The choice is based on the dimensionless coefficient of form resistance, determined experimentally. The teardrop-shaped and spherical shell, in comparison with others, has a low coefficient of drag when flowing with a stream of liquid. The lower the drag coefficient, the lower the total frontal load in areas with significant underwater currents. It should be said that the structural form of a structure and its elements can promote or hinder the development of hazardous, corrosive forms with the smallest specific surface [5].

Optimization of the design. After calculating the storage for the strength and stability of the shell according to the limiting states of the structure, it is necessary to modernize the structure to select the optimal overall dimensions.

The storage facility manufacturing technologies should ensure that the main assembly operations are carried out onshore: sheet welding, filling the thermal insulation layer, checking for leaks, etc. It is necessary to minimize the amount of work on the open sea with difficult ice conditions.
Tank immersion technology. When a tank is submerged, we may encounter such problems as positive buoyancy and high sink rates, at which the storage can crash on the seabed. Therefore, it is necessary to carry out calculations and select the most appropriate negative buoyancy value or apply a means to reduce the sink rate. It is also necessary to pre-prepare the installation area with marine bulldozers.

5.4.2. Loads and impacts on Subsea LNG Storage Facilities

The life cycle of a subsea LNG tank consists of the following stages:

1. Construction on an onshore base and carrying out various tests for the suitability of this structure.
2. Transportation by tugs to the place of installation.
3. Filling the tank with water and smooth immersion underwater.
4. Installation in the design position on a pre-prepared area of the seabed, piping and commissioning.
5. Operation and maintenance after a certain period of time.
6. Decommissioning and dismantling.

At rest, water is very rarely found. Even in closed containers, there is a constant movement of water. The movement of water masses creates a force effect on the reservoir. And the immersion of the storage is accompanied by increasing hydrostatic pressure.
All loads can be divided into external and internal. External include:

- Constant loads: hydrostatic water pressure, tank and ballast weight
- Long-term loads: weight of stationary equipment
- Short-term loads: underwater currents
- Special loads - loads that arise during emergencies: earthquakes, collisions with foreign objects, hydrodynamic effects from tsunamis and loads from explosions.

Internal loads include such long-term loads as the hydrostatic pressure of LNG on the walls and pontoon of the tank, the pressure of the stripping gas above the LNG, the hydrostatic pressure of seawater on the inner walls of the storage, the weight of the loading product, and the weight of water in the tank.

Types of influences experienced by structures: chemical (interaction of sea water with the material of the tank, since water is a saline solution), mechanical (the effect of foreign objects, ice), biological (the effect of marine biota on the durability of the storage facility).

In deep-water zones - zones with a depth exceeding half the value of the wavelength, the seabed does not significantly affect the nature of the wave. Based on this, the particles move uniformly around the circumference with insignificant translational displacement, which can be neglected.

5.4.3. Calculation of the main tank beam

5.4.3.1. Concept № 1

All formulas in this chapter were used from the book [25]. A calculation (done by the author) is presented in this chapter.

The main beams in the design diagram are represented as three-articulated arches (Figure 5.3).

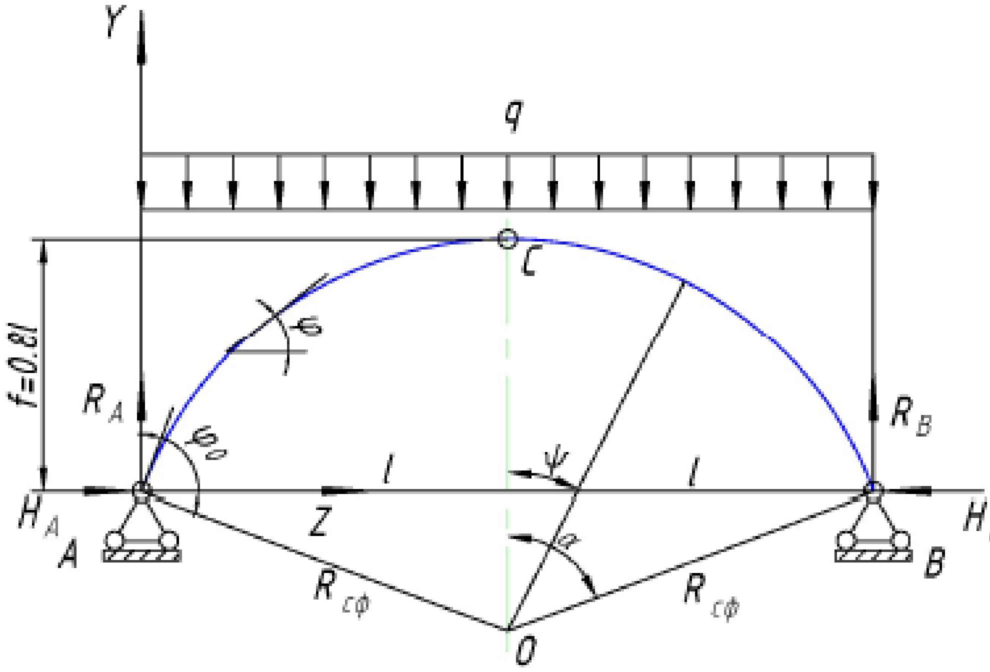

Figure 5.3 Design scheme of the main beams of a spherical tank in the form of a three-articulated arch

Angle α depends on the ratio R_{sph} и l [25]:

$$\sin\alpha = \frac{l}{R_{sph}}, \quad \alpha = \arcsin\frac{l}{R_{sph}} \tag{5.1}$$

$R_{c\phi}$- radius of the spherical shell, m.

The height of the dome f is determined from the geometric ratio [25]:

$$f = R_{sph} - R_{sph} \times \cos\alpha \tag{5.2}$$

f - height of the dome, m.

For the main beam, which is a part of a circle, we write the equation in parametric form as [25]:

$$z = R_{sph} \times (\sin\alpha_1 - \sin\varphi), \; y = R_{sph} \times (\cos\varphi - \cos\varphi_0) \tag{5.3}$$

φ_0 – the angle of inclination of the tangent to the arc of the main beam at the origin.

$$R_{sph}^2 = (\frac{2\times l}{2})^2 + (R_{sph} - f)^2 \tag{5.4}$$

Let's expand the equation and get:

$$R_{sph}^2 = l^2 + R_{c\phi}^2 - 2 \times R_{sph} \times f + f^2$$

$$2 \times R_{sph} \times f = l^2 + f^2$$

$$R_{sph} = \frac{l^2}{2\times f} + \frac{f}{2} \tag{5.5}$$

$$\cos\varphi_0 = \cos(\frac{\pi}{2} - \beta) = \sin\beta = \frac{R_{sph} - f}{R_{sph}} = 1 - \frac{f}{R_{sph}} \quad \textbf{(5.6)}$$

$$\sin\varphi_0 = \sin(\frac{\pi}{2} - \beta) = \cos\beta = \frac{l}{R_{sph}} \quad \textbf{(5.7)}$$

Let us determine the reactions of the supports using the equilibrium equation for this. Let's assign a sign (-) clockwise, and against (+).

$$\sum M_B = -R_A \times 2 \times l + q \times 2 \times l \times l = 0$$

$$R_A = \frac{2ql^2}{2l} = ql$$

$$\sum M_A = R_B \times 2 \times l - q \times 2 \times l \times l = 0$$

$$R_B = \frac{2ql^2}{2l} = ql$$

Verification:

$$\sum Y = 0$$

$$R_A + R_B - 2 \times q \times l \times 2 \times l = 2 \times q \times l - 2 \times q \times l = 0$$

The thrust $H_A = H_B$ is determined from the equation of moments relative to the joint C, drawn up for the left or right halves of the arch.

$$\sum M_C^{left} = 0$$

$$-R_A \times l + H_A \times f + q \times l \times \frac{l}{2} = 0$$

$$H_A = \frac{\left(q \times l^2 - \frac{q \times l^2}{2}\right)}{f}$$

Let's take f = 0.8l, then

$$H_A = 0{,}625ql$$

Under the action of external loads in the sections of a three-hinged beam, the following arises: bending moment Mb, transverse force Q and normal force N, which are determined from the equilibrium equations of the cut-off part of the beam. The forces are projected onto the normal to the section to define N and the perpendicular axis, the normal to the section, to determine Q.

Let us agree that if the normal force causes tension, then it is positive. If it rotates the considered part of the arch around the section clockwise, the transverse force Q is positive. The bending moment is positive if it causes compression of the upper fibers of the arch.

When calculating the arch for the action of a vertical load, we use an equivalent beam (Figure 5.4).

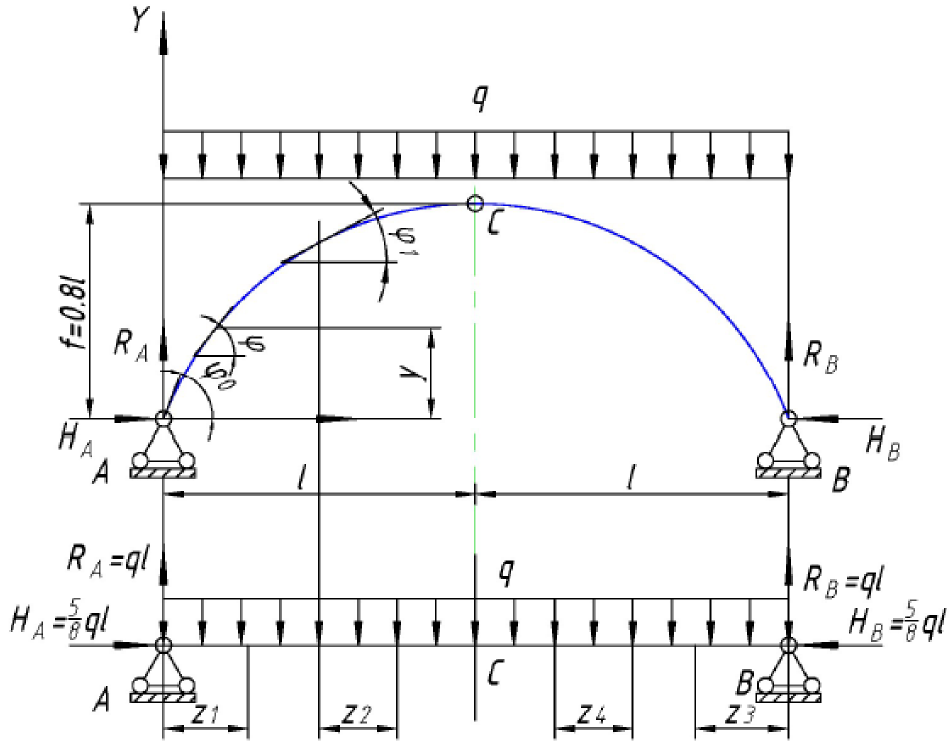

Figure 5.4 Equivalent beam.

Efforts in this case are determined by the formulas:

$$M_b = M_b^b - H_A \times y \tag{5.8}$$

$$Q = Q^b \times \cos\varphi - H_A \times \sin\varphi \tag{5.9}$$

$$N = -(Q^b \times \sin\varphi + H_A \times \cos\varphi) \tag{5.10}$$

φ - the angle between the tangent to the arch axis and the OZ axis, z, y - coordinates of the section of the arch, M_b^b - bending moment in the corresponding section of the equivalent beam, Q^b - shear force in the corresponding section of the equivalent beam.

We select the origin of coordinates in support A.

Let's define the internal force factors on the site:

$$0 \le z_1 \le \frac{l}{2}\ (\varphi_0 \ge \varphi \ge \varphi_1, 0 \le y \le y_1)$$

$$M_b(z_1) = R_A \times z_1 - q \times \frac{z_1^2}{2} - H_A y = ql \times z_1 - q \times \frac{z_1^2}{2} - 0{,}625ql \times y \tag{5.11}$$

$$Q(z_1) = (R_A - qz_1) \times \cos\varphi - H_A \times \sin\varphi \tag{5.12}$$

$$N(z_1) = -[(R_A - qz_1) \times \sin\varphi + H_A \times \cos\varphi] \tag{5.13}$$

To build diagrams, define φ_0 and φ_1 φ_1 - the angle of inclination of the tangent at the plot's boundary).

$$R_{sph} = \frac{l^2}{2 \times f} + \frac{f}{2} = \frac{l^2}{2 \times 0{,}8l} + \frac{0{,}8l}{2} = 1{,}025l$$

$$\sin\varphi_0 = \frac{l}{1{,}025} = 0{,}976;\ \varphi_0 = 77{,}4°$$

$$\frac{l}{2} = 1{,}025 \times (0{,}976 - \sin\varphi_1);\ 0{,}488 = 0{,}976 - \sin\varphi_1;\ \varphi_1 = 0{,}488$$

$$\varphi_1 = 29{,}2°$$

$$y = 1{,}025l \times (\cos 29{,}2° - \cos 77{,}4°) = 0{,}67l$$

$$M_b(z_1 = 0) = ql \times 0 - q \times \frac{0}{2} - 0{,}625ql \times 0 = 0ql^2$$

$$Q(z_1 = 0) = (ql - q \times 0) \times \cos 77{,}4° - 0{,}625ql \times \sin 77{,}4° = -0{,}39ql$$

$$N(z_1 = 0) = -[(ql - q \times 0) \times \sin 77{,}4° + 0{,}625ql \times \cos 77{,}4°] = -1{,}11ql$$

$$M_b(z_1 = 0{,}5l) = ql \times 0{,}5l - q \times \frac{(0{,}5l)^2}{2} - 0{,}625ql \times 0{,}67l = -0{,}0438ql^2$$

$$Q(z_1 = 0{,}5l) = (ql - q \times 0{,}5l) \times \cos 29{,}2° - 0{,}625ql \times \sin 29{,}2° = -0{,}132ql$$

$$N(z_1 = 0{,}5l) = -[(ql - q \times 0{,}5l) \times \sin 29{,}2° + 0{,}625ql \times \cos 29{,}2°] = -0{,}789ql$$

Let's determine the internal power factors on the site:

$$\frac{l}{2} \le z_2 \le l\ (\varphi_1 \ge \varphi \ge \varphi_2, y_1 \le y \le f)$$

$$l = 1{,}025l \times (0{,}976 - \sin\varphi_2); 0{,}976 = 0{,}976 - \sin\varphi_2; \sin\varphi_2 = 0$$

$$\varphi_2 = 0°$$

$$y = 1{,}025l(\cos 0° - \cos 77{,}4°) = 0{,}8l = f$$

$$M_b(z_2 = l) = ql \times l - q \times \frac{l^2}{2} - 0{,}625ql \times 0{,}8l = 0ql^2$$

$$Q(z_2 = l) = (ql - q \times l) \times \cos 0° - 0{,}625ql \times \sin 0° = 0ql$$

$$N(z_2 = l) = -[(ql - q \times l) \times \sin 0° + 0{,}625ql \times \cos 0°] = -0{,}625ql$$

Let's change the direction of the sense of rotation z_3 and start with support B. Determine the internal force factors in the section

$$0 \le z_3 \le \frac{l}{2}\ (\varphi_0 \ge \varphi \ge \varphi_3, 0 \le y \le y_3)$$

$$\sin\varphi_0 = \frac{1}{1{,}025} = 0{,}976;\ \varphi_0 = 77{,}4°$$

$$\frac{l}{2} = 1{,}025 \times (0{,}976 - \sin\varphi_3); 0{,}488 = 0{,}976 - \sin\varphi_3; \sin\varphi_3 = 0{,}488$$

$$\varphi_3 = 29{,}2°$$

$$y = 1{,}025l(\cos29{,}2° - \cos77{,}4°) = 0{,}67l$$

$$M_b(z_3) = -R_B \times z_3 + q \times \frac{z_1^2}{2} + H_B \times y = -ql \times z_3 + q \times \frac{z_3^2}{2} + 0{,}625ql \times y$$

$$Q(z_3) = -[(R_B - qz_3) \times \cos\varphi - H_B \times \sin\varphi]$$

$$N(z_3) = -[(R_B - qz_3) \times \sin\varphi + H_B \times \cos\varphi]$$

$$M_b(z_3 = 0l) = -ql \times 0l + q \times \frac{(0l)^2}{2} + 0{,}625ql \times 0l = 0ql^2$$

$$Q(z_3 = 0l) = -[(ql - 0ql) \times \cos77{,}4° - 0{,}625ql \times \sin77{,}4°] = 0{,}392ql$$

$$N(z_3 = 0l) = -[(ql - 0ql) \times \sin77{,}4° + 0{,}625ql \times \cos77{,}4°] = -1{,}11ql$$

$$M_b(z_3 = 0{,}5l) = -ql \times 0{,}5l + q \times \frac{(0{,}5l)^2}{2} + 0{,}625ql \times 0{,}67l = 0{,}0438ql^2$$

$$Q(z_3 = 0{,}5l) = -[(ql - 0{,}5ql) \times \cos29{,}2° - 0{,}625ql \times \sin29{,}2°] = -0{,}132ql$$

$$N(z_3 = 0{,}5l) = -[(ql - 0{,}5ql) \times \sin29{,}2° + 0{,}625ql \times \cos29{,}2°] = -0{,}789ql$$

Let’s determine the internal power factors on the site

$$\frac{l}{2} \le z_4 \le l \; (\varphi_3 \ge \varphi \ge \varphi_3, y_3 \le y \le f)$$

$$l = 1{,}025l \times (0{,}976 - \sin\varphi_4); 0{,}976 = 0{,}976 - \sin\varphi_4; \sin\varphi_4 = 0$$

$$\varphi_4 = 0°$$

$$y = 1{,}025l(\cos0° - \cos77{,}4°) = 0{,}8l = f$$

$$M_b(z_4 = l) = -ql \times l + q \times \frac{l^2}{2} + 0{,}625ql \times 0{,}8l = 0{,}0438ql^2$$

$$Q(z_4 = l) = -[(ql - ql) \times \cos0° - 0{,}625ql \times \sin0°] = 0ql$$

$$N(z_4 = l) = -[(ql - ql) \times \sin0° + 0{,}625ql \times \cos0°] = -0{,}625ql$$

Epures N, Q, M are shown in Figure 5.*5*.

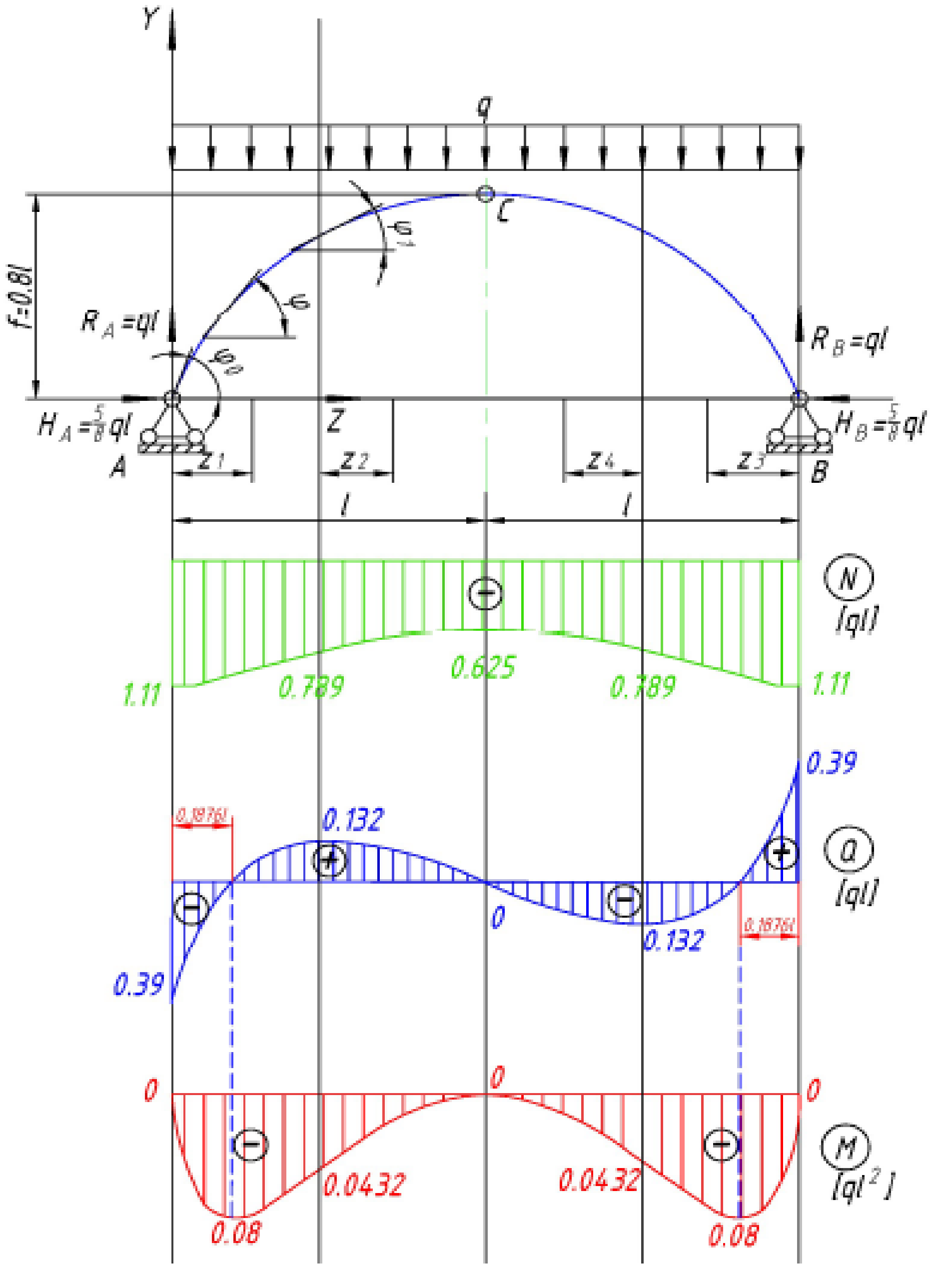

Figure 5.5 Epure calculation of the main beam of a spherical tank at f = 0.8l.

Determination of the maximum deflection moment

To determine M^{max}, equation (5.7) is equated to 0. As a result, we find z*, which determines the position of the section in which the bending moment takes the maximum value. Solving the system of two equations (5.7) and (5.3), we obtain the following result: z* = 0.1876, φ = 52.5°.

$$M_b^{max}(z *= 0{,}1876l) = ql \times 0{,}1876l - q \times \frac{(0{,}1876l)^2}{2} - 0{,}625ql \times 0{,}4l = 0{,}08ql^2$$

It is recommended to use steel of class C345 as per GOST 27772 (O9G2S-12) as the material for the tank frame

For steel S345, the standard design resistance Ry = 345 MPa.

A condition expressing the limit state for the main beam:

$$\sigma_{max} = \frac{M_{max}}{W_x} \leq \gamma_c \times R_y \tag{5.14}$$

γ_c - coefficient of working conditions, W_x - the moment of resistance of a standard rolled I-section.

Design steel resistance

$$R_y = \frac{R_y^{н}}{\gamma_M \times \gamma_н} = \frac{345}{1{,}025 \times 1{,}15} \approx 293 \text{ MPa}$$

γ_M=1,025 - material safety factor, γ_n = 1.15 – safety factor for responsibility.

From equation (5.14), determine the value of the moment of resistance W_x, which satisfies the strength condition:

$$W_x \geq \frac{M_{max}}{\gamma_c \times R_y} = \frac{0{,}08ql^2}{0{,}8 \times 293 \times 10^3}$$

5.4.3.2. Concept №2

Let's carry out the calculation according to the methodology:

$$H_A = \frac{\left(q \times l^2 - \frac{q \times l^2}{2}\right)}{f}, \text{ accept f=l, } H_A\text{=0,5ql}$$

$$z^*\text{=0,134 and y=0,5l}$$

$$M_b^{max}(z* = 0{,}134l) = ql \times 0{,}134l - q \times \frac{(0{,}134l)^2}{2} - 0{,}5ql \times 0{,}5l = -0{,}125ql^2$$

From equation (5.14), we determine the value of the moment of resistance W_x, which satisfies the strength condition:

$$W_x \geq \frac{M_{max}}{\gamma_c \times R_y} = \frac{0{,}125ql^2}{0{,}8 \times 293 \times 10^3}$$

We will choose the number of the I-section in accordance with GOST 26020-83.

The resulting epures N, Q, M are shown in Figure 5.6.

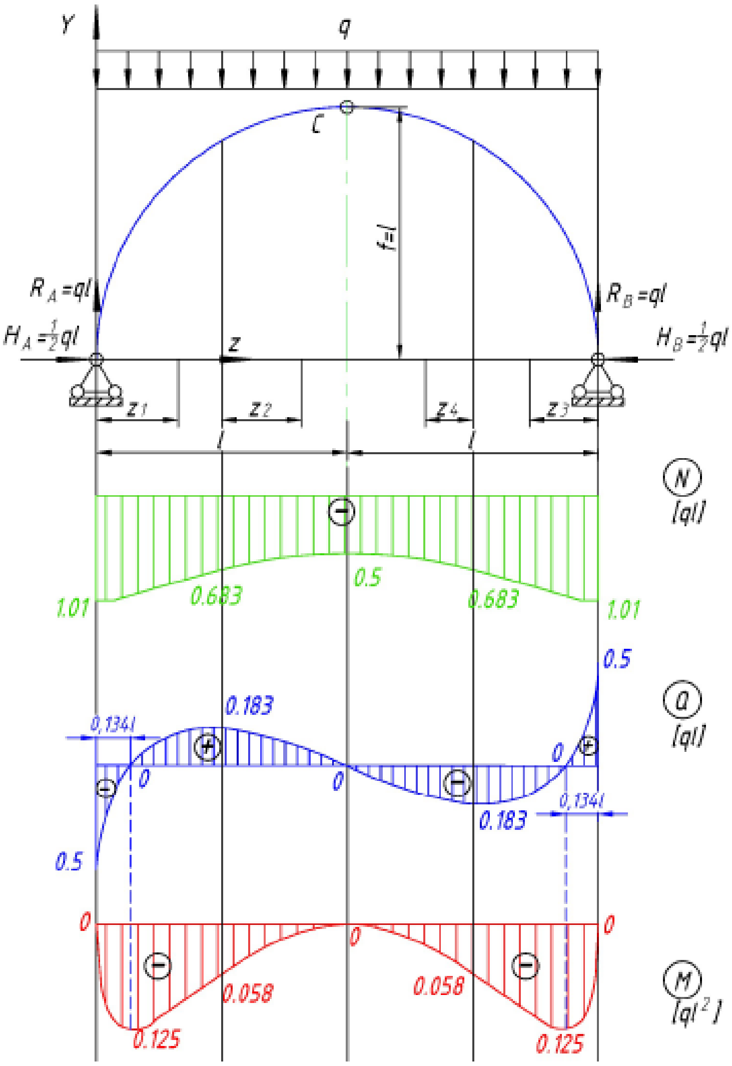

Figure 5.6 Epure calculation of the main beam of a spherical tank at f = 1.

Chapter 6

6. The impact of the production processes and transportation of LNG on the environment

When natural gas is burned, far less harmful substances are emitted into the atmosphere than any other fossil fuel source. However, LNG does harm the environment: from the construction of factories and receiving terminals to transport and regasification. The damage is especially serious in the Arctic because here, due to the harsh conditions, it will take much longer to restore flora, fauna and soil than in warmer latitudes.

LNG, which is composed primarily of methane, is one of the top five sources of methane emissions into the atmosphere, causing global warming and climate change.

6.1 Plants for liquefaction of gas

The greatest harm to the environment is caused during the construction of the LNG plant and all adjacent infrastructure. Gas and condensate deposits are often found in areas rich in diverse flora and fauna. The extraction of gas and condensate and the necessary accompanying development of territories leads to a change in the environment.

During the construction of LNG, deforestation and excavation take place. As a result, it is also possible for mail and water to become contaminated by leaking fuel and chemicals. In addition, air pollution occurs due to exhaust fumes and large amounts of dust during excavation. Environmentalists are also concerned about large light and noise pollution, which harms animals and fish living in the area of the plant's construction. In addition to all of the above, during the plant's construction, a large amount of toxic wastewater is formed, which poison water bodies [1]. During the construction of factories in permafrost conditions, soil warming is possible, which can cause partial melting of ice.

When the plant is put into operation, flare gas is burned for several days - this leads to additional emissions into the atmosphere and air pollution. Birds and insects can also enter the flare smoke.
During the operation of the plant, the harm caused to the environment is reduced. Still, it does not disappear at all: air pollution occurs during the purification and liquefaction of gas. The main sources of pollution are flares, gas turbines, generators and boilers. In addition, compressors, electric motors and turbines create additional noise pollution that affects animals and birds. Also, wastewater generated in large quantities during the operation of the plant has a great impact on the ecosystems of reservoirs.

6.2. LNG loading/unloading terminals

For loading/unloading LNG onto tankers, a seaport and berths are required. During its construction, underwater inhabitants suffer, water and air are polluted, and underwater landscapes are changed. During the construction of the port, the impact on the coastal zone and the underwater landscape is exerted, which leads to the destruction of the habitats of many marine animals and fish and part of the terrestrial fauna. Also, during construction, the water in the coastal zone becomes cloudy, which also negatively affects the underwater inhabitants [13].

Air pollution during the construction of the port is due to the increased amount of emissions from transport and equipment involved in the process [1].

During the operation of the port, noise and light pollution occurs, as well as the discharge of sewage and waste into the water area. In addition, the changed bottom topography negatively affects the number of coastal inhabitants. Air pollution occurs due to leaks in pipe connections, as well as due to the release of methane into the atmosphere. To prevent these problems, ports are equipped with boil-off gas traps. Also, from time to time, the ecological community recommends deepening the coastal zone to prevent the accumulation of silt, which destroys the normal habitat of marine animals and fish [1].

6.3. LNG tankers

LNG tankers are huge ships that, while sailing, cause light and noise pollution that affects marine life. Also, during the tanker's route, ballast water is discharged, containing microorganisms foreign to the area, which can adversely affect the bio balance of the area. To prevent water contamination by microorganisms, tankers are equipped with ballast water disinfection devices.

During the transport of LNG, part of the gas evaporates. The vaporized gas is used as fuel for the tanker, and the excess is either liquefied again or burned at the facility. Since natural gas is an environmentally friendly type of fuel, emissions into the atmosphere from this type of transport are significantly lower than ships using conventional fuel [13].

6.4. Comparative analysis of the environmental impact of the LNG production and transport cycle

During the construction and operation of the LNG regasification terminal, pollution occurs, similar to the construction of a seaport.

Table 6-1 summarizes the environmental impacts of LNG at various stages.

Table 6-1 Environmental impact of LNG [1].

Stages	Biodiversity	Climate	Air	Soil	Water	Flora and fauna	Habitat	Fish	Seabirds	Mammals	Landscape
LNG plant construction	X	X	X	X	X	X	X		X		X
LNG plant operation	X	X	X	X	X	X	X				X
Construction of an LNG loading/unloading terminal	X	X	X		X	X	X	X	X	X	X
LNG terminal operating	X	X	X			X	X			X	X
Dredging	X	X					X	X		X	
LNG transport	X	X	X	X	X		X	X	X	X	X

Chapter 7

7. Evaluation of the economic efficiency of the Shtokman project

A calculation of the economical benefits of the development (done by author) is presented in this chapter.

A competent assessment of an investment project predetermines its success and its further existence in the modern world.

Moreover, the construction of a new facility significantly affects the economy of the region in which the construction is taking place and the country. This is because it predetermines the employment of the population, creates new jobs, and increases the standard of living in the long term.

However, an unsuccessful investment of capital can lead to serious economic problems, project closure and bankruptcy of investors. Therefore, it is extremely important to make a correct assessment of the investment project.

Evaluation of the effectiveness of an investment project takes place in three stages:

1. Assessment of the scale of the project, its economic component and social efficiency for the region of location.
2. Calculation of the most important economic indicators of the project to determine its profitability and payback periods.
3. Assessment of the impact of external negative factors on the project.

The main economic criteria for evaluating the effectiveness of an investment project [9]:

• Net Present Value (NPV)

• Payback period

• Index of profitability

• Internal rate of return.

At any time, a competent assessment of the profitability of a project predetermines its existence and is a guarantor of investments.

7.1. Economic calculation of an investment project for the development of the Shtokman gas condensate field

The development of the Shtokman field bears many difficulties:

• The need for high capital investments in the project

• Difficult natural and climatic conditions that require additional financial costs

• Large icebergs may appear in the area of the deposit

• Great remoteness of the field from the coast

Based on these factors, the main task of the development project is to reduce the capital costs of developing the field without losing reliability and quality. Therefore, based on economic calculations, it was decided to stage-by-stage launch the development project.

Table 7-1 shows the project indicators of the facility.

Table 7-1 Project indicators

Project indicators	Value
Gas recovery factor	86%
Economic life	More then 50 years
Annual gas production, billion m^3	67,5
Annual condensate production, mln tonns	0,5
Period of constant production, years	25

The required capital investments in the project are presented in Table 7-2.

Table 7-2 Capital investments

Capital investments	bln $	bln rubles
1 Offshore operations	10,8	797,8
platforms	8,6	635
drilling	2,2	163
2 Offshore pipeline	3,7	273
3 Sales of products	11,3	836
LNG plant	6,8	503
LNG terminal	0,2	14,8
Teriberka-Volkhov onshore gas pipeline	4,3	318
Total	25,8	1906,8

Thus, the initial capital investment in the project will amount to 1906.8 billion rubles. Operating expenses will vary from year to year depending on contingencies, employee salaries, depreciation, tax deductions, equipment maintenance costs.

Changes in various indicators over the years during constant production are presented in Table A-1 and Table A-2 (Appendix A).

Let's calculate the economic and investment indicators of the project [9].

Proceeds from the sale of commercial products:

$$\mathrm{CO} = \mathrm{P} \times \mathrm{Q}, \tag{7.1}$$

P - price of marketable products, rubles, Q is the volume of goods produced.

Amortization:

$$\mathrm{A} = \frac{\mathrm{KI}}{\mathrm{N}} \tag{7.2}$$

KI – capital investments, million rubles, N – lifetime, years.

Price cost:

$$\mathrm{P} = \mathrm{OP} + \mathrm{A} \tag{7.3}$$

OP - operating costs, million rubles, A - amortization, million rubles.

Annual balance sheet profit:

$$\mathrm{B} = \mathrm{SP} - \mathrm{P} \tag{2.4}$$

SP - proceeds from the sale of commercial products, million rubles, P - price cost, million rubles.

Income tax is 20%, which means that the net profit will be:

$$\Pi = \mathrm{B} - \mathrm{B} \times \mathrm{T} \tag{7.5}$$

B - balance sheet profit, million rubles, T - income tax (20%).

Cash flow:

$$\mathrm{CF} = \mathrm{N} + \mathrm{A} - \mathrm{CI} \tag{7.6}$$

N - net profit, million rubles, A - amortization, million rubles,CI - capital investments, million rubles.

Let's take the inflation rate, according to the normative documents, equal to 8-10% annually. Then the cash flow adjusted for inflation will be:

$$\mathrm{CF_i} = \mathrm{CF} - \mathrm{CF} \times \frac{\mathrm{I}}{100} \tag{7.7}$$

I - inflation rate (8-10%).

Discounting is a method that allows you to determine the final value of a cash flow at a certain point in time (current). For the calculation, it is necessary to use the discount rate, which is assumed to be 10%.

In this case, the discounted cash flow is calculated as follows:

$$\mathrm{DCF} = \frac{\mathrm{CF_i}}{\mathrm{DF}} \tag{7.8}$$

DF - discount factor (10%).

Net present value (NPV) is the summed stream of expected payments, the value of which is given at the moment.

$$\mathrm{NPV} = \mathrm{CF} \times \mathrm{DF} \tag{7.9}$$

The following indicators can assess the effectiveness of an investment project:

• Risk capital - the amount of which investors risk for long-term investments

• Payback period - the period of time during which the project will fully pay off and start making a profit

• Profitability index - the ratio of profit to the cost of capital investments. Characterizes the efficiency of investments

The calculation results of the investment project assessment for the development of the Shtokman gas condensate field are presented in Table A-3 (Appendix A).

The final performance indicators of the investment project are shown in Table 7-3.

Table 7-3 Final performance indicators of the investment project for the development of the Shtokman gas condensate field

Indicators	Value
Cash flow adjusted for inflation, million rubles	76050551,8
Capital investments, million rubles	1906800,0
Payback period, years	12
Profitability index	40

7.2. Conclusions on the project profitability

The profitability of the project is low; the profitability index is 40. Capital expenditures will amount to 1,906,800 million rubles, and the profit will amount to 83,948,560 million rubles. The project will pay off in 12 years and start making a profit from the 13th year. Low-profit margins and a long payback period are associated with large capital investments and operating costs for the development of the field.

Chapter 8
Conclusions

In my master thesis, I made a comparative analysis of six of the world's most commonly natural gas liquefaction technologies was carried out, and one innovative technology of underwater gas liquefaction was highlighted. Of these technologies, the choice was between the three most suitable for arctic conditions: APCI C3MR, Shell DMR, LINDE.

Based on the results of comparative analysis, I found that Shell DMR is the most suitable technology for the Shtokman due to its low capital intensity, the ability to regulate productivity and adapt to the harsh Arctic conditions.

Also, within the working framework, indicators of the economic and investment efficiency of the development of the Shtokman field were calculated. The project will pay off in 12 years and, starting from the 13th year, it will start making a profit. The construction profitability index will be 40.

The development of the Shtokman gas condensate field creates the basis for the industrial development of the hydrocarbon potential of the Arctic shelf. Also, it strengthens Russia's position as a leading player in the European gas market and the global energy market.

In addition, the Shtokman project will create a basis for transferring to Russia modern management technologies, design and production of industrial products for the development of offshore hydrocarbon deposits and, importantly, will ensure the utilization of the production capacities of Russian industrial enterprises in the context of the global economic crisis. The scale and complexity of the work, special climatic conditions in the area of gas production and transportation, the need to use fundamentally new technical and technological solutions in the development process allow us to speak of the uniqueness of the Shtokman project.

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Appendix A

Table A-1 Changes in the economic indicators of the Shtokman field development project

Year	Natural gas produced, m^3/year	Operating cost, rubles/year	Total operating cost, rubles/year	Price cost of 1 m^3 of natural gas, rubles	Price for 1 m^3 of natural gas, rubles
1	67500000000	3375000000000	5281800000000	79,38	25,00
2	67500000000	3375000000000	5281800000000	79,22	25,00
3	67500000000	3375000000000	5281800000000	79,22	26,00
4	67500000000	3375000000000	5281800000000	79,22	26,00
5	67500000000	3375000000000	5281800000000	79,22	27,00
6	67500000000	3375000000000	5281800000000	79,22	27,00
7	67500000000	3375000000000	5281800000000	79,22	28,00
8	67500000000	3375000000000	5281800000000	79,22	28,00
9	67500000000	3375000000000	5281800000000	79,22	29,00
10	67500000000	3375000000000	5281800000000	79,22	29,00
11	67500000000	3375000000000	5281800000000	79,22	30,00
12	67500000000	3375000000000	5281800000000	79,22	30,00
13	67500000000	3375000000000	5281800000000	79,22	31,00
14	67500000000	3375000000000	5281800000000	79,22	31,00
15	67500000000	3375000000000	5281800000000	79,22	32,00

16	67500000000	3375000000000	5281800000000	79,22	32,00
17	67500000000	3375000000000	5281800000000	79,22	33,00
18	67500000000	3375000000000	5281800000000	79,22	33,00
29	67500000000	3375000000000	5281800000000	79,22	34,00
20	67500000000	3375000000000	5281800000000	79,22	34,00
21	67500000000	3375000000000	5281800000000	79,22	35,00
22	67500000000	3375000000000	5281800000000	79,22	35,00
23	67500000000	3375000000000	5281800000000	79,22	36,00
24	67500000000	3375000000000	5281800000000	79,22	36,00
25	67500000000	3375000000000	5281800000000	79,22	37,00

Table A-2 Changes in the economic indicators of the Shtokman field development project

Year	Volume of gas condensate produced, tons/year	Operating cost, rubles/year	Total operating cost, rubles/year	Price cost of 1 m^3 of gas condensate, rubles	Price for 1 m^3 of natural gas, rubles
1	500000000	25000000000	1931800000000	4016,1	28000
2	500000000	25000000000	1931800000000	4016,1	28000
3	500000000	25000000000	1931800000000	4016,1	28000
4	500000000	25000000000	1931800000000	4016,1	28500
5	500000000	25000000000	1931800000000	4016,1	28500
6	500000000	25000000000	1931800000000	4016,1	28500

7	500000000	25000000000	1931800000000	4016,1	29000
8	500000000	25000000000	1931800000000	4016,1	29000
19	500000000	25000000000	1931800000000	4016,1	29000
10	500000000	25000000000	1931800000000	4016,1	29500
11	500000000	25000000000	1931800000000	4016,1	29500
12	500000000	25000000000	1931800000000	4016,1	29500
13	500000000	25000000000	1931800000000	4016,1	30000
14	500000000	25000000000	1931800000000	4016,1	30000
15	500000000	25000000000	1931800000000	4016,1	30000
16	500000000	25000000000	1931800000000	4016,1	30000
17	500000000	25000000000	1931800000000	4016,1	31500
18	500000000	25000000000	1931800000000	4016,1	31500
19	500000000	25000000000	1931800000000	4016,1	31500
20	500000000	25000000000	1931800000000	4016,1	32000
21	500000000	25000000000	1931800000000	4016,1	32000
22	500000000	25000000000	1931800000000	4016,1	32500
23	500000000	25000000000	1931800000000	4016,1	32500
24	500000000	25000000000	1931800000000	4016,1	33000
25	500000000	25000000000	1931800000000	4016,1	33000

Table A-3 Results of the economic calculation of the project for the development of the Shtokman field

Year	CI, trillion rubles	Gas production, billion m^3	Condensate production, billion tons	Sales revenue, trillion rubles	Operating costs, trillion rubles	Amortization, bln rubles	Price cot, mln rubles	Balance sheet profit, trillion rubles	Income tax (20%), bln rubles	Net profit, trillion rubles	Cash flow, bln rubles	Inflation rate,%	CF_i	Accumulated CF	Discount factor (10%)	DCF	NPV
1	1,9										-1,90	8	-1,5	-1,75			
1		67,5	0,5	3,09	7,2	76,3	7,28	-4,2	-840,47	-3,36	-3,35	8	-3,02	-4,77	1,00	-3,02	-3,02
2		67,5	0,5	3,09	7,2	76,3	7,28	-4,05	-840,47	-3,36	-3,28	8	-3,02	-7,79	1,10	-2,74	-5,77
3		67,5	0,5	3,09	7,2	76,3	7,28	-3,85	-826,97	-3,30	-3,25	8	-2,97	-10,77	1,21	-2,45	-8,22
4		67,5	0,5	3,09	7,2	76,3	7,28	-3,72	-821,97	-3,28	-3,21	10	-2,89	-13,66	1,33	-2,17	-10,39
5		67,5	0,5	3,09	7,2	76,3	7,28	-3,38	-808,47	-3,25	-3,15	8	-2,90	-16,5	1,46	-1,98	-12,38
6		67,5	0,5	3,09	7,2	76,3	7,28	-2,98	-808,47	-3,23	-3,11	8	-2,90	-19,47	1,61	-1,80	-14,18
7		67,5	0,5	3,09	7,2	76,3	7,28	-2,34	-789,97	-3,15	-3,08	8	-2,83	-22,31	1,77	-1,60	-15,78
8		67,5	0,5	3,09	7,2	76,3	7,28	-1,82	-789,97	-3,15	-3,08	9	-2,80	-25,11	1,95	-1,43	-17,22
9		67,5	0,5	3,09	7,2	76,3	7,28	-1,05	-776,47	-3,1	-3,02	8	-2,78	-27,90	2,14	-1,30	-18,52
10		67,5	0,5	3,09	7,2	76,3	7,28	-0,30	-771,47	-3,08	-3,00	8	-2,76	-30,67	2,36	-1,17	-19,70

11	67,5	0,5	3,09	7,2	76,3	7,28	1,44	-757,97	-3,03	-2,95	9	-2,68	-33,36	2,59	-1,03	-20,74
12	67,5	0,5	3,09	7,2	76,3	7,28	2,08	1897,0	7,58	7,66	9	6,97	-26,38	2,85	2,44	-18,29
13	67,5	0,5	3,09	7,2	76,3	7,28	2,99	1960,5	7,84	7,91	9	7,20	-19,18	3,14	2,29	-15,99
14	67,5	0,5	3,09	7,2	76,3	7,28	3,84	1960,5	7,84	7,92	9	7,20	-11,97	3,45	2,08	-13,91
15	67,5	0,5	3,09	7,2	76,3	7,28	5,02	1974,02	7,89	7,97	10	7,17	-4,80	3,80	1,88	-12,02
16	67,5	0,5	3,09	7,2	76,3	7,28	7,59	1974,02	7,89	7,97	8	7,33	2,53	4,18	1,75	-10,26
17	67,5	0,5	3,09	7,2	76,3	7,28	8,68	2137,52	8,55	8,62	9	7,85	10,38	4,59	1,70	-8,55
18	67,5	0,5	3,09	7,2	76,3	7,28	9,46	2137,52	8,55	8,62	10	7,76	18,14	5,05	1,53	-7,02
19	67,5	0,5	3,09	7,2	76,3	7,28	10,75	2151,02	8,60	8,68	10	7,81	25,95	5,56	1,40	-5,61
20	67,5	0,5	3,09	7,2	76,3	7,28	11,00	2201,02	8,80	8,88	10	7,99	33,95	6,12	1,30	-4,31
21	67,5	0,5	3,09	7,2	76,3	7,28	11,07	2214,52	8,85	8,93	8	8,21	42,17	6,73	1,22	-3,08
22	67,5	0,5	3,09	7,2	76,3	7,28	11,32	2264,52	9,05	9,13	9	8,31	50,48	7,40	1,12	-1,96
23	67,5	0,5	3,09	7,2	76,3	7,28	11,39	2278,02	9,112	9,18	9	8,36	58,84	8,14	1,02	-9,38
24	67,5	0,5	3,09	7,2	76,3	7,28	11,64	2328,02	9,31	9,38	8	8,63	67,48	8,95	0,96	2,58
25	67,5	0,5	3,09	7,2	76,3	7,28	11,70	2341,52	9,36	9,44	9	8,56	76,05	9,85	0,86	8,69