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ABSTRACT

Nikolaev N. R. Analysis of the method of utilization of associated petroleum gas on offshore platforms by means of water-gas ejection, 2023 - 130 pages, 49 figures, 11 tables.

Keywords: offshore field development, associated petroleum gas, water-gas ejection, Prirazlomnaya platform, flaring, pump ejector system, utilization.

Scope of work:

This master's thesis is devoted to the analysis of the efficiency of utilization of associated petroleum gas by means of water-gas ejection. Associated petroleum gas is a significant source of greenhouse gas emissions into the atmosphere and a potential source of profit for oil producing companies. However, the use of traditional gas utilization methods, such as flaring or venting, leads to significant environmental problems.

This paper analyzes existing technologies for utilization of associated petroleum gas and identifies the advantages of using water-gas ejection. The technological features of the process, as well as economic and environmental advantages and disadvantages are considered.

Thus, this master's thesis is an important contribution to the field of associated petroleum gas utilization, especially taking into account the fact that this method of utilization is not yet widely used in the oil production industry. The results of the study can be used to develop new technologies and optimize existing methods of utilization of associated petroleum gas.

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List of acronyms

APG	associated petroleum gas
GPP	gas processing plant
DSG	dry stripped gas
MPB	mixture of propane and butanes
WFLH	wide fraction of light hydrocarbons
OIRSP	offshore ice
SG	stable gasoline
WGE	water-gas ejection
LLC	limited liability company
OJSC	open joint-stock company
RPM	reservoir pressure maintenance
CPS	compressor pump station
BPS	block pumping station
HPF	high pressure flare
LPF	low pressure flare
SAO	sharing agreement operator
NPP	nuclear power plant
GPP	gas processing plant
HAZID	hazard identification

Introduction

Over the last decades, oil production has become one of the most important and profitable sectors of the global economy. However, at the same time, the problem of utilization of associated petroleum gas appeared. Previously, associated gas was simply flared, for which large fines were paid. But today, considering the growing environmental requirements, new methods of utilizing associated gas are needed.

Currently, the problem of utilization of sought-after natural resources remains one of the key challenges on the world stage, including Russia. Under increased pressure from environmental organizations and the public, it is necessary to actively engage in the utilization of oil and gas raw materials and associated gas, which are generated in the process of oil production.

Despite the existing technologies and methods of utilization, a considerable amount of associated gas is annually discharged in Russia, which leads to negative ecological consequences and economic losses. In this regard, the topic of research to determine the optimal methods and technologies of utilization of associated gas at Russian oil fields is relevant.

Associated petroleum gas is an important resource for industrial petrochemistry, but its beneficial use is also an environmental problem associated with the negative impact of oil and gas complex on the environment. The oil and gas sector of the economy is responsible for up to 30% of all pollutant emissions, including soot, carbon monoxide, sulfur dioxide, nitrogen oxides, etc.

Data show that about 23 billion m^3 of APG is flared in Russia, accounting for more than 18% of production. This makes Russia one of the countries with the most inefficient use of APG. Flaring of associated petroleum gas leads to direct losses of valuable hydrocarbon raw materials, lost profits of the state associated with the lack of gas chemical products, as well as to deterioration of the environmental situation in the areas of oil production and living conditions in them.

Since transportation of APG to processing plants may be virtually impossible for remote fields and regions with harsh climates, most APG is flared on site. Most gas processing plants in Russia that process APG are part of SIBUR Holding PJSC. They can process no more than 45% of the produced gas even at full capacity.

In order to solve the problem of APG utilization, it is necessary to look for new ways to use it and cooperate with industry to develop new technologies. This will not only reduce the impact of the oil and gas complex on the environment, but also increase the economic and industrial potential of the country. One way of industrial infrastructure, providing for the creation of new fields, including remote and small-sized, and the expansion of transport infrastructure to transport APG to processing plants. However, the implementation of this scheme will require significant investment and time.

Another solution to the problem of APG utilization is to use it as fuel for power generation and heat production. This can be particularly effective in remote areas where no alternative energy sources are available. However, this requires the creation of appropriate infrastructure and equipment, which will also require investment.

There is also the possibility of using APG as a raw material for the production of petrochemical products. However, this requires a developed gas-chemical industry, which Russia, unfortunately, lacks. The development of this industry could become an additional source of income for the state and reduce the volume of APG flaring.

Thus, the problem of APG utilization in Russia requires a comprehensive solution, which includes the creation of infrastructure for APG transportation and processing, its use as fuel for power generation and heat generation, as well as the development of the oil and gas chemical industry. All these measures will help reduce APG flaring and reduce the negative environmental impact of the oil and gas complex, as well as make the use of this valuable resource more efficient.

This master's thesis deals with the utilization of associated petroleum gas on offshore platforms by means of water-gas ejection. Associated petroleum gas, which is emitted in the process of oil production, is one of the main sources of greenhouse gas emissions, which negatively affects the environmental situation in the world.

One of the effective methods of associated petroleum gas utilization in the fields is water-gas ejection. However, for this method to be effective, it is necessary to take into account many factors, such as hydraulic resistance, fluid properties, well geometry and many others.

This method is especially relevant especially for offshore platforms, where due to the lack of possibilities to transport the associated gas to the shore, it is simply flared. Water-gas ejection avoids negative environmental impact and saves resources. In addition, this method is economically advantageous, as it saves companies paying fines for flaring APG.

Thus, the use of water-gas ejection is not only environmentally sound, but also economically profitable way of utilizing associated gas, especially on offshore platforms, where this problem is most acute.

There are many different technologies for utilizing associated petroleum gas, such as compression, power generation, methane production, etc. However, most of these methods have their disadvantages, such as high equipment costs, complexity of implementation or low efficiency.

The method of water-gas ejection is considered the most promising way of utilization of associated petroleum gas. Compared to other methods, it has a number of advantages, such as high efficiency, resource saving and the possibility of reducing greenhouse gas emissions.

The relevance of research in the field of gas utilization is increasing. This paper considers various methods of gas utilization at oil fields, as well as the possibilities and reserves of using the existing infrastructure of oil producing companies.

The purpose of the master's thesis is to study and analyze water-gas ejection as one of the effective methods of utilization of associated petroleum gas on offshore platforms.

In order to achieve this goal, the following tasks must be performed:

- Analyze the current state of the problem of utilization of associated petroleum gas on offshore platforms and evaluate the effectiveness of various existing methods of utilization.
- To study technical aspects of water-gas ejection on offshore platforms.

- Analyze the application of water-gas ejection in real fields and evaluate its effectiveness.
- Develop a technological scheme for the utilization of APG on a specific offshore platform.
- Formulate recommendations on optimization of the water-gas ejection process for utilization of associated petroleum gas on offshore platforms.

Each of these tasks will be solved by analyzing the existing literature, performing calculations and collecting data. The results of the study will identify the advantages and disadvantages of water-gas ejection as a method of utilizing associated petroleum gas on offshore platforms, as well as offer recommendations for its optimization and improvement.

Novelty of the research

This paper is a review of promising methods for utilization of associated petroleum gas in the fields, including research conducted recently. One of the most interesting and new technologies existing today is the method of liquefaction and transportation of associated petroleum gas using special vessels. This method can become an effective solution for gas utilization on offshore platforms, where traditional methods are inefficient or impractical.

Particular attention will be paid to the method of water-gas ejection, which is investigated in the framework of the master's thesis. However, there is not much literature devoted to this method in the open access, which indicates that this technology is not yet widespread and requires additional research. Thus, the research conducted as part of my master's thesis is of great novelty and relevance, as it is aimed at developing and improving the efficiency of this method of utilization of associated petroleum gas on offshore platforms.

Research methods

Research methods may include such steps as a literature review of existing associated gas utilization technologies, analysis of existing global practices, study of various utilization technologies as well as necessary equipment, analysis of the market and potential gas consumers, and numerical simulation of the gas utilization process using water-gas ejection. It is important to take into account the specifics of work on offshore platforms in the Arctic zone and possible limitations on the use of certain technologies in conditions of low temperatures and limited availability of resources.

To achieve the goal of the study, the current situation on the Prirazlomnaya offshore platform with respect to associated petroleum gas utilization will be analyzed. This analysis will examine the volumes of associated petroleum gas produced on the platform, and determine how much of this gas is flared and how much is used for internal platform operations. Possible problems and constraints that affect the effective utilization of associated petroleum gas on offshore platforms will be considered.

To solve the problem of associated petroleum gas utilization on offshore platforms the option of using a pump-ejector will be proposed. Data obtained from the Prirazlomnaya offshore platform will be used to select optimal parameters of the ejector pump. The calculation of the pump-ejector will be carried out taking into account the features of Prirazlomnaya and its operating conditions to ensure effective utilization of associated petroleum gas on the offshore platform.

CHAPTER 1: The water-gas ejection method

1.1 Global practices for APG utilization

Associated petroleum gas (APG) is a valuable natural resource that occurs during oil production, but its utilization remains one of the major challenges for the oil industry. Different countries around the world have different methods of utilizing APG, which depend on many factors, such as technological level, legislation, economic conditions, etc.

In general, global practices for utilization of associated petroleum gas vary depending on the geographic area, volume of oil and gas production, and available technologies and infrastructure (Table 1.1). Some of the most effective and popular methods of utilizing associated gas include gas liquefaction, power generation, use of gas as vehicle fuel, injection into the reservoir, etc. One of the most effective ways to utilize APG is to use it as a raw material for power generation. This allows to reduce greenhouse gas emissions and environmental risks, as well as to obtain an additional source of income [1].

Technology	Company	Result
Parallel injection of water and gas	Statoil	Complex and expensive equipment is used, which requires large capital investments, quality maintenance and competent operation. Attempts to apply it in the conditions of Novogodneye and Samatlorsky fields were unsuccessful.
WGE technology with an ejection-cavitation	OOO "INKO"	In terms of fuel equivalent, the amount of additional oil produced was significantly less than the amount of oil pumped into the reservoir (used at the Samatlorskoe field).

hydrodynamic device		
Pump-and-booster technology	Bashneft PJSC	Complicated set of equipment. Frequent equipment breakdowns.
Pump-and-booster gas flooding technology	PJSC «RITEK»	Extremely sophisticated equipment with gas treatment, two-stage booster piston compressor, two booster units and injection in just one well
Pump-ejector technology for co-injection of water and gas	ПАО «RITEK», АО «PARMGINS»	The system requires high-pressure gas to operate. Withdrawn due to pressure drop in the gas tank [2].

Table 1.1. – Examples of Global APG Utilization Practices

However, modern technologies make it possible to significantly improve the process of APG utilization and reduce the negative impact on the environment. For example, carbon dioxide (CO2) capture and storage technologies can be used to reduce greenhouse gas emissions by capturing and further storing them in underground tanks. There are also technologies for using APG as fuel for trucks and ships, which can reduce emissions of harmful substances into the atmosphere.

In the U.S., where oil and gas production is most active, associated gas is often burned at the production site, resulting in the release of significant amounts of carbon dioxide into the atmosphere. Recently, however, there has been a growing interest in using associated gas for power generation and transporting it over long distances through pipelines in the United States. In some states of the USA (for example, Texas, Oklahoma, New Mexico) associated gas is also actively used for oil injection into reservoirs (water-gas ejection) [3].

In Russia, utilization of associated gas is usually done by injecting it into the gas pipeline system. Recently, however, processing associated gas into fuel, liquefied gas, or power generation has become an increasingly popular way of utilizing it in Russia. In Russia, utilization of associated gas is not always a priority for oil and gas producers. However, in recent years, the Russian government has been actively imposing restrictions on greenhouse gas emissions, which increases the importance of utilizing associated gas. Many utilization projects have been developed as part of the state program "Gasification of Russia".

Kazakhstan is one of the leaders in the world practice of associated gas utilization. The water-gas ejection technology has been successfully implemented in this country.

In America, for example, most oil and gas producers try to utilize associated gas as much as possible, as it reduces their ecological footprint and increases the economic efficiency of projects. Some of them, such as ConocoPhillips and ExxonMobil, achieve almost complete utilization of associated gas. For example, ConocoPhillips utilizes about 97% of associated gas at its Bakken facilities, using it for power generation and on-site liquefaction, while ExxonMobil uses associated gas in its projects in Canada and Guyana for power generation and on-site liquefaction.

The U.S. is one of the largest oil and gas producers in the world and has a high share of associated gas. In 2019, the U.S. produced 32.9 billion cubic meters of associated gas, which is about 12% of total oil production. There is also a strong political will in the U.S. to utilize associated gas, and the U.S. federal government has issued several laws and regulations governing associated gas utilization [39].

Canada also has an obligation to utilize associated gas - oil and gas producers are obliged to utilize 95% of associated gas at their facilities. As part of this obligation, Canadian Natural Resources Limited (CNRL) has introduced an innovative technology - Associated Gas Recovery (AGR), which allows utilization of associated gas and generates additional income from its sale.

Canada is one of the largest oil producers in the world and has a high share of associated gas. In 2019, Canada produced 4.9 billion cubic meters of associated gas, which is about 14% of total oil production.

The most common method of utilizing associated gas in Canada is in-situ combustion, but other methods are also available, such as water-gas ejection and transportation of associated gas to gas processing plants [1].

One of the most innovative and promising ways to utilize associated gas in Canada is to use it as fuel for road transport. In particular, this method is used at oil fields in the province of Alberta, where associated gas is compressed and transported to the nearest gas stations, where it is used as fuel for trucks and cars.

The first country to utilize associated petroleum gas is Norway. This happened back in the 1970s, when they introduced the technology of liquefying natural gas for transportation and use as fuel. Today, Norway continues to lead the way in APG utilization, and according to the International Energy Agency, utilization accounts for about 98% of total oil production.

Norwegian companies have also developed and implemented innovative technologies, such as the GTL (Gas to Liquids) process to convert APG into liquid fuel and secondary combustion technology to combat greenhouse gas emissions. In 2019, Norog and Gassco merged to create a new company called Gassnova, which will develop new methods and technologies for APG utilization [2].

In Norway, the most common method of utilizing associated gas is combustion at heavy-duty gas turbine units (GTU). This method of gas utilization makes it possible to obtain electric power and heat, which are used for production purposes and in residential areas. Also, some companies, such as Statoil, use associated gas to produce liquid hydrocarbons on site. In this country, associated gas produced from oil and gas production on the North Sea shelf is burned and used to generate electricity. In addition, Norway is actively promoting technologies to use associated gas as fuel for vehicles [4].

Thus, we can conclude that Norway is one of the best countries in the world for the utilization of associated petroleum gas, thanks to its innovative technology and strict environmental norms and standards.

China and other Asian countries also face the problem of associated gas utilization. In China, for example, associated gas is usually flared or vented into the atmosphere, which leads to air pollution and environmental degradation.

In recent years, however, China has begun to actively introduce new technologies for utilizing associated gas. One example is associated gas liquefaction technology, which makes it possible to transport it over long distances and use it as fuel for cars and industrial processes.

In addition, China is actively promoting technologies to produce methanol from associated gas. Methanol can be used as fuel for cars and vehicles, as well as in the production of chemicals and materials.

Other Asian countries are also working on the utilization of associated gas. For example, India uses technology to return associated gas to the fields for use as an energy source for oil and gas production. In South Korea, associated gas is used to generate electricity and heat.

In general, China and other Asian countries are actively working on utilizing associated gas and introducing new technologies to not only reduce the negative impact on the environment, but also to obtain additional sources of energy.

Japan is a large consumer of oil and gas, but it has no natural resources of its own. Therefore, Japan depends on gas and oil imports, including associated petroleum gas. In 2019, Japan imported about 112 billion m^3 of natural gas, with more than 80% of the gas imported as LNG (liquefied natural gas) from Australia, Qatar, Malaysia, Indonesia, and Russia.

Japan uses various technologies to utilize associated petroleum gas. For example, Japan Petroleum Exploration Co. (JAPEX) uses GTL (Gas to Liquid) technology to turn associated gas into synthetic oils and lubricants. The company also uses GTW (Gas to Wire) technology, which turns gas into electricity.

In addition, Japan is actively exploring the possibility of using associated petroleum gas as a source of hydrogen for fuel cells. In 2020, Japan's Kawasaki Heavy Industries launched the world's first hydrogen-fueled ship using associated petroleum gas as a hydrogen source.

Thus, Japan is using various technologies to utilize associated petroleum gas, including the application of GTL and GTW technologies, and is also exploring the possibility of using the gas as a source of hydrogen for fuel cells.

Saudi Arabia is the largest oil producer in the world, and, accordingly, the utilization of associated gas is one of the important tasks for the country. However, for many years, Saudi Arabia has neglected APG utilization and has been flaring it at its fields.

But recently the situation has begun to change. As part of the Vision 2030 strategy, Saudi Arabia has pledged to significantly reduce greenhouse gas emissions and increase the utilization of associated petroleum gas. To this end, the country is actively investing in the construction of gas processing plants that use GTL (Gas-to-Liquids) and FSRU (Floating Storage Regasification Unit) technologies, as well as in the construction of gas pipelines and gasification systems.

One example of successful APG utilization in Saudi Arabia is the Saudi Aramco company, which has built a gas processing plant capable of processing up to 70 million cubic meters of gas per day. This plant uses GTL technology, which makes it possible to produce different types of fuel, such as diesel fuel, fuel oil and motor oil [5].

Thus, Saudi Arabia is starting to actively develop the utilization of associated petroleum gas, and this process is becoming one of the priority tasks for the country.

A comparative analysis has shown that the U.S. is the best at utilizing associated petroleum gas. In 2020, they will utilize 79% of all the APG they release, which is about 110 billion cubic meters of gas. This is achieved through the use of various technologies, including compression, separation, flaring and water-gas ejection.

It is also worth noting that the U.S. has legislation requiring oil companies to dispose of APG, which encourages the use of efficient methods [2].

In general, the U.S. is a striking example of successful APG utilization, which allows to reduce pollution and increase the efficiency of oil production.

1.2 Description of water-gas ejection as a method of APG utilization

The utilization of associated petroleum gas back into the reservoir is one of the methods of solving the problem of its release into the atmosphere. The main principle of such utilization is to return the gas to the reservoir from which it was extracted. Water-gas ejection technology is used for this purpose.

The technology of water-gas ejection means that associated petroleum gas is injected into a well with the help of pump-ejector system, where it mixes with water and forms gas-liquid emulsion. The emulsion then flows back into the reservoir through another well next to the first well. The gas is released from the emulsion and rises to the upper horizons of the reservoir, while the water, enriched with petroleum products, remains in the lower horizons. In this way, the associated petroleum gas returns to the reservoir, where it can be recovered in the future.

This technology has a number of advantages over other methods of associated gas utilization. Firstly, it makes it possible to store gas in the reservoir and use it for future oil production. Secondly, it reduces greenhouse gas emissions into the atmosphere, which in turn contributes to environmental safety. Thirdly, it increases the economic efficiency of oil production by reducing gas losses.

Despite a number of advantages, water-gas ejection technology also has some limitations and disadvantages. One of them is the high cost of the units and high expenses for their operation. In addition, this technology may not be suitable for all types of oil fields, depending on their geological and technical characteristics.

In addition, this technology can significantly reduce greenhouse gas emissions, since associated petroleum gas contains a large amount of methane, which is one of the main substances causing the greenhouse effect. Return of gas into the reservoir can reduce methane emissions into the atmosphere and contribute to a more efficient use of this valuable natural resource [6].

However, it should be taken into account that the use of water-gas ejection technology has some limitations. This technology requires availability of appropriate geological conditions for gas return to formation. In addition, it is necessary to take into account technical aspects and economic factors when implementing this technology.

In general, water-gas ejection technology is an effective method of utilization of associated petroleum gas, which can bring significant environmental and economic benefits. However, it is necessary to conduct additional research and assess the economic feasibility of this technology for each specific field and region.

Water-gas stimulation is an effective method of utilizing associated petroleum gas and also makes it possible to increase oil production from the reservoir. The essence of this method is that when oil and gas are extracted from the reservoir, part of the gas cannot be collected for subsequent processing and is used as fuel at the production site. This not only wastes valuable resources, but also has a negative impact on the environment due to the release of gas emissions into the atmosphere. The water-gas impact on the reservoir consists of pumping the gas that was previously used as fuel back into the reservoir. At the same time a certain amount of water is also injected into the reservoir, which allows to increase the pressure in the reservoir and thereby increase oil production. To use this method effectively, it is necessary to monitor the reservoir condition on a regular basis and optimize the parameters of water-gas impact depending on its changes.

The gas is not recovered and enters the wellbore zone. When the associated gas is not utilized and enters the bottomhole zone, it can cause a decrease in reservoir pressure and oil flow rate.

This method is used to increase reservoir pressure and increase oil flow rate. As a result of water-gas impact on the reservoir, there is an increase in well productivity. However, it should be taken into account that this method has some limitations and is not suitable for all types of fields. In particular, water-gas stimulation may be ineffective in cases when the formation has low permeability or when large amounts of gas are supplied to the well, which may lead to increased pressure losses in the system. In order to effectively use water-gas stimulation, well parameters such as fluid and gas pressure and flow rates must be properly selected. To do this, studies involving hydrodynamic modeling and simulator experiments are conducted to determine the optimal parameters for each specific well.

The proposed method for utilization of associated petroleum gas (APG) on offshore platforms is based on mixing APG separated at the first and second stages of separation and formation water in an ejector chamber and subsequent injection of the resulting gas-liquid mixture back into the formation to maintain reservoir pressure. This method, known as water-gas impact (WGI), is an effective way to increase oil recovery, allowing to utilize APG with a positive economic effect [15].

There are two main methods of WGI: alternate injection and co-injection. At present, joint injection is less frequently used, but has some advantages confirmed by experience. In this paper we consider the joint injection of water and gas using pump-ejector technology, which is the most efficient, reliable and easy to use for preparation and injection of water-gas mixture into injection wells [44].

The use of pump-ejector systems allows surface preparation and water-gas mixture injection with equipment that can be successfully used in the field conditions in the Russian fields. It is noted that all equipment for pump-ejector systems can be manufactured at domestic machine-building plants.

Figure 1.1 shows one of the possible principle process diagrams of pump-ejector systems.

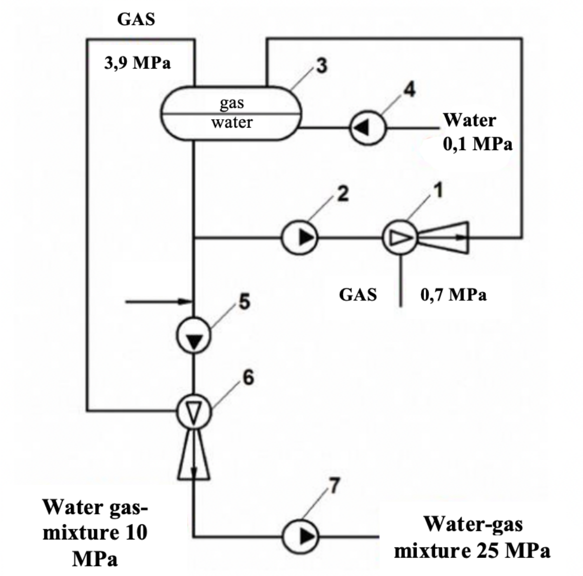

Figure 1.1 – Scheme of pump-ejector system for water-gas mixture injection at the field.

1 - ejector of the first gas compression stage, 2, 4, 5, 7 - multistage vane pumps, 3 - separator, 6 - ejector of the second gas compression stage.

This system is a pump-ejector scheme, in which the pump 2 supplies water to the operating nozzle of the ejector 1 of the first compression stage, which pumps low-pressure gas and pumps the water-gas mixture into the separator 3 under some increased pressure. Separation of gas and water takes place in separator 3. The liquid flows further to the suction of pumps 2 and 5, and the gas to the suction of the ejector 6 of the second compression stage. Circulation water is significantly heated due to transferring energy losses in pump 2 and ejector 1 into heat, but its cooling and correspondingly heating of water supplied by pump 4 for pumping into the injection well is performed due to heat exchange at mixing of two water streams in separator 3. After passing through the ejector 6, the fine-dispersed water-gas mixture is directed to the pump 7, which pumps the mixture to the required injection pressure without affecting the free gas. The results of bench tests confirm the effectiveness and prospects of this pump-ejector scheme of water-gas impact.

Figure 1.2 shows dependences $P_c = f(R)$ of the mixture discharge pressure at the jet outlet P_c on the gas-water factor R, reduced to standard conditions, obtained in experiments for one-stage and two-stage pump-ejector compression [6].

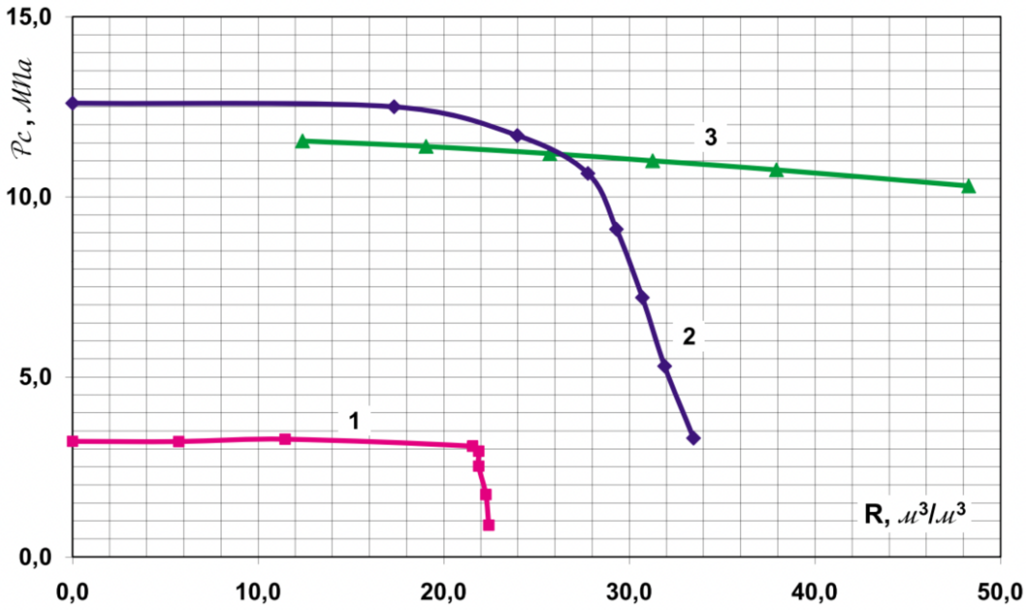

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Figure 1.2 – Dependence of mixture discharge pressure on gas-water ratio Pc=f(R) at one-stage (1) and two-stage pump-ejector compression (2 - with low-performance, 3 - with high-performance ejector)

The gas-water factor is determined by formula (1.1):

$$R = Qg.st/Qw, \tag{1.1}$$

where $Q_{g.\,st}$ – gas flow rate reduced to standard conditions, m^3/s;

Q_w – flow rate of the working fluid through the first ejector (for single-stage compression) or through the second ejector (for two-stage compression),m^3/s.

The results of bench experiments show that the two-stage pump-ejector compression can achieve significantly higher parameters of the gas-water factor and water-gas mixture injection pressure compared to single-stage compression [5].

The results of the experiments carried out in this study indicate the possibility of achieving values of efficiency of the second-stage high pressure jet apparatus exceeding 40%, which corresponds to the maximum efficiency of the low pressure high-efficiency ejector of the first compression stage. The maximum efficiency of the ejector in the experiments was 45.9%. Such results indicate the possibility of effective formation and injection of water-gas mixture into injection wells using high-efficiency ejectors. Optimization of jet apparatus and ejector parameters can lead to significant increase of efficiency of these devices and reduction of costs for formation and injection of water-gas mixture. With proper use of this technology, improved well performance and reduced environmental impact can be achieved [4].

1.3 Classification of known water-gas technologies

Application of water-gas stimulation technologies is currently an actively developing trend in the oil and gas industry. As a result of application of various WGE technologies at more than 100 fields all over the world, a significant increase in the oil recovery factor has been achieved.

Methods of APG utilization at offshore fields:

1. Export by pipeline;
2. Gas re-injection;
3. Production of liquefied natural gas;
4. Compression of APG;
5. Methanol production;
6. Processing of APG into liquid fuel;
7. Flaring.

For a more accurate understanding of this method, it is necessary to clearly define its concept. Water-gas stimulation is the process of injecting water and gas into a reservoir to increase the current and ultimate oil recovery factor. It increases the coverage of the reservoir both in area and thickness, which in turn leads to an increase in the oil displacement rate compared to conventional waterflooding.

To date, there is no unified classification of water-gas stimulation technologies, although several gradations have been proposed, but they cause many controversial opinions and contradictions. At the same time, use of various variants of water-gas treatment allows to manage process parameters and achieve increase of oil recovery, increase of oil flow rate and decrease of water encroachment [7].

Studies have shown that application of VGS technologies can increase the oil recovery factor by 10-30%, and sometimes even by 50%. Moreover, application of this method makes it possible to reduce oil production costs by increasing the efficiency of reservoir utilization.

Various water and gas pumping (WGP) technologies can be classified according to various criteria, including the method of water and gas injection, the ratio between the displacing agents, the type and composition of the gas, the gas source, the location of the water and gas mixture, the displacement mode, the choice of process equipment and the selected object to be affected. One of the main classification criteria is the method of water and gas injection. It may be either alternate water and gas injection or their combined injection in the form of water-gas mixture. Other methods of combined water and gas injection are also known, including "sequential" water and gas injection, which are two separate, alternating processes.

The ratio between the displacing agents is also an important criterion. Usually the recommended water-gas ratio is 1:1, with alternating water and gas injection. However, in conditions of high water cut and reservoir heterogeneity, it is recommended to increase the volume of injected gas, for example, by 4-6 times more than the volume of injected water.

The place of water-gas mixture formation and displacement mode can also vary depending on the conditions in the field. An important factor is the choice of appropriate process equipment to implement the technology, as well as the selected object to be affected.

Thus, WGP can be implemented in different ways, and the choice of the optimal technology should be based on the characteristics of a particular field and its geological conditions.

Water-gas ejection (WGE) technology is used worldwide to utilize associated petroleum gas (APG) to reduce greenhouse gas emissions and increase oil production efficiency. However, the use of this technology is associated with high capital costs and environmental risks, such as groundwater contamination and increased seismic activity.

WGE uses various gas agents, such as carbon dioxide, hydrocarbon gas, nitrogen, combustion products of hydrocarbon gas and flue gases (Figure 1.3). The hydrocarbon gas can be both natural gas extracted from gas reservoirs and APG emitted together with oil from oil reservoirs. In addition, the efficiency of oil production is directly related to the content of fatty components in the used gas, as it increases the oil recovery factor [7].

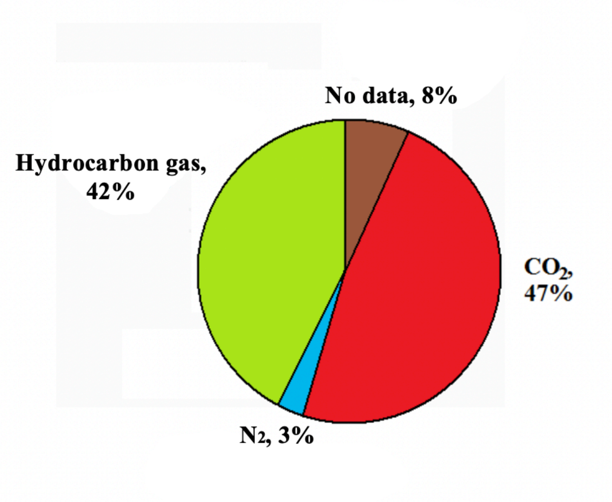

Figure 1.3 – Type of gas injected during water-gas exposure

In the context of using water-gas ejection (WGE) technologies to improve oil production efficiency and reduce greenhouse gas emissions, various gas sources are possible. This can be a gas reservoir that provides the necessary gas for the WGE process. Also, oil treatment and processing facilities, such as separator units or flare lines, can be used as a source of gas. Finally, specialty facilities, including plants that extract nitrogen from the air or that produce APG combustion products, can also serve as sources of gas for WGE. It is important to note that the choice of a particular gas source depends on many factors, such as environmental conditions and technical capabilities, and should be based on careful analysis [8].

Some researchers propose to classify water-gas stimulation (WGS) technologies depending on the place where the water-gas mixture is created: at the surface, in the wellbore and in the formation by injecting water containing heat-resistant agents. This choice is determined by physical and chemical properties of oil and gas, reservoir properties, field infrastructure, availability of technological solutions and economic efficiency of the project. However, high cost of equipment, especially high-pressure compressors, is the main problem in realization of WGE technologies. Therefore, there is great interest in alternative technologies such as boosting plunger compressor pumps, jet pumps and pump-ejector technology. This paper describes the main advantages and disadvantages of the equipment used in the implementation of known WGE technologies [43]. This agrees with previously published studies, which also confirm the importance of choosing the optimal equipment for the implementation of WGE technologies, taking into account the characteristics of a particular field and the economic feasibility of the project.

1.4 Equipment used in various water-gas technologies

Application of alternate water and gas injection technology by water-gas method can be carried out with the help of compressor or non-compressor technology. When using the compressor technology (Fig. 1.4), gas under high pressure is injected into the well for 2-3 months, and then water is injected for a certain period. However, this technology has significant disadvantages, first, it is associated with significant costs of the project, as it is required to use a compressor station with 2-3 to 10 high-pressure compressors.

It should be noted that the use of compressor technology for water-gas impact on a well with associated petroleum gas has certain limitations. The compressor station, as a complex technical system, needs frequent repairs, which can lead to disruption of the gas injection cycle. In addition, conventional high-pressure compressors have limitations on the composition of the injected gas, they can only inject dry gas with liquid fractions of no more than 5%. This limitation significantly reduces the potential increase in oil recovery from the gas and oil booster. In addition, the price of compressors that allow fatty associated gas to be injected is about 1.5 times higher.

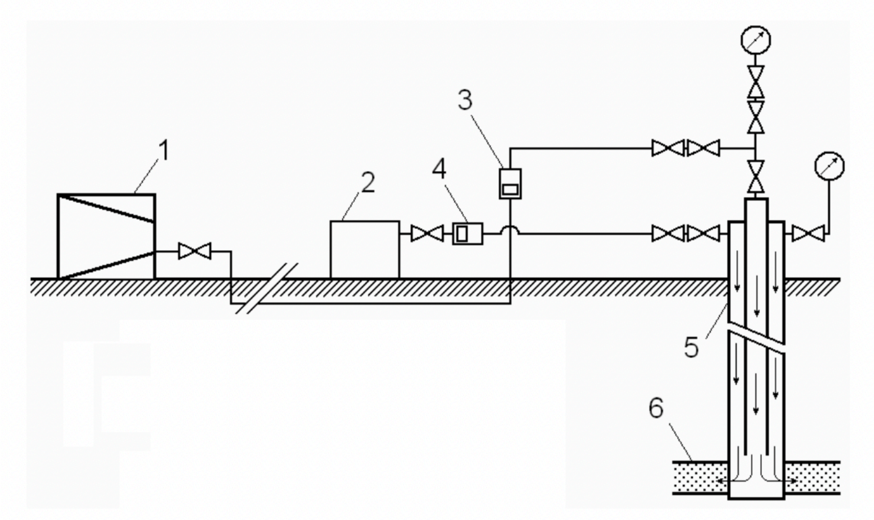

Figure 1.4 – Scheme of gas utilization implementation by compressor method

1 - compressor station, 2 - pumping station, 3 - gas flow regulator. 4 - water flow regulator. 5 - well, 6 – reservoir

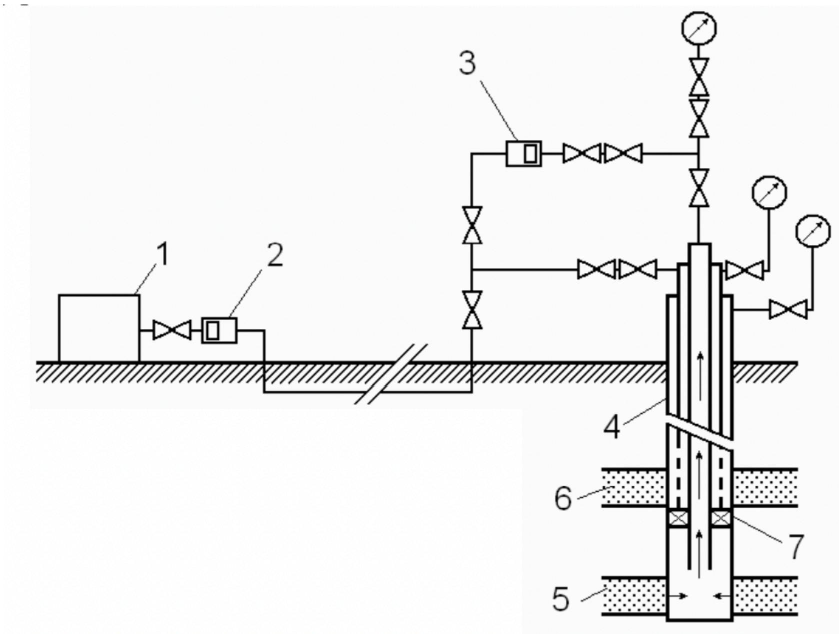

Figure 1.5 – Scheme of realization of WGE without compressor

1 - pumping station. 2 - water flow regulator. 3 - gas flow regulator, 4 - well, 5 - gas reservoir, 6 - oil reservoir, 7 - packer.

One method of injecting associated gas into oil reservoirs is to use gas from gas fields or gas caps of oil and gas fields without prior compression. For this purpose, gas is pumped from these sources alternately with water from the pumping station into the reservoir. However, there are limitations of this method (Fig. 1.5). Firstly, few fields accompany high-pressure gas reservoirs. Secondly, the pressure at the gas wellhead is often insufficient to inject gas into the injection wells, so gas has to be "squeezed" using additional technological devices.

Another method is combined water and gas injection, which is a combination of a gas and water injection line connected by a tee connection. For example, in the Siri field (Figure 1.6) in the North Sea, produced gas and injected water are mixed directly at the wellhead, which prevents the water-gas mixture from separating in the system at the surface. However, this requires installing a system of check valves on the water and gas injection lines to prevent agents from flowing into "alien" lines.

There are various ejector technologies that are used to inject gas and water together. One such method is the use of jetting devices, which can be located at the surface (Fig. 1.6) or at the bottom of the well (Fig. 1.7). Ejector devices are notable for their simple design and low production cost. However, due to the fact that these technologies are not always able to provide a sufficiently homogeneous water-gas mixture, their use is limited. For example, when the jet device is at the surface, the pressure of the water-gas mixture it creates is not high enough to inject this mixture into the borehole [13].

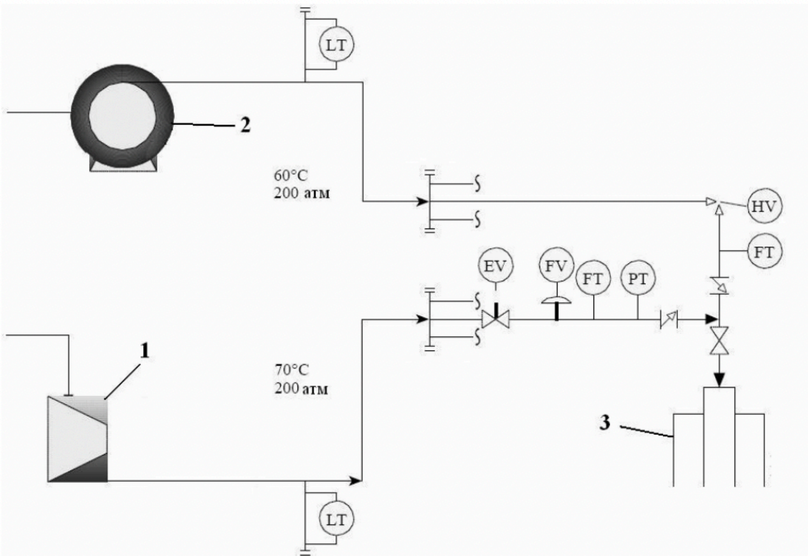

Figure 1.6 – Scheme of equipment for water-gas mixture injection at Siri field
1 - compressor station, 2 - pumping station, 3 - injection well

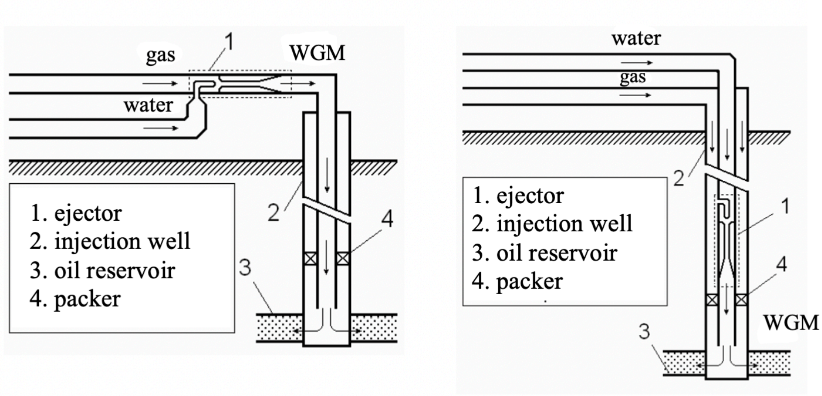

Figure 1.7 – Variants of realization of WGE ejector technologies: 7a - variant with surface location of jet apparatus, 7b - variant with location of ejector in the wellbore.

Researchers A.N. Drozdov and A.A. Fatkullin have developed pump-ejector technology of water-gas impact, which offers solution of many problems arising when using jet devices and centrifugal pumps separately. The basic scheme of this technology is shown in Fig. 1.8. One of the advantages of the pump-ejector technology is the absence of moving parts in the jet apparatus device, which increases the reliability of the system as a whole. Besides, many fields in Russia use centrifugal pumps, their overhaul interval is high, and the operating personnel have sufficient experience in working with them. Pump-ejector technology can be used on individual wells, clusters of wells and entire fields.

It should be noted that the advantage of this technology is that there are no restrictions on the composition of the injected gas. This means that it is possible to inject different types of gases, such as carbon dioxide, dry gas, enriched gases and others, without any restrictions. This significantly expands the field of application of the technology and makes it more versatile in comparison with other methods of water-gas impact [12].

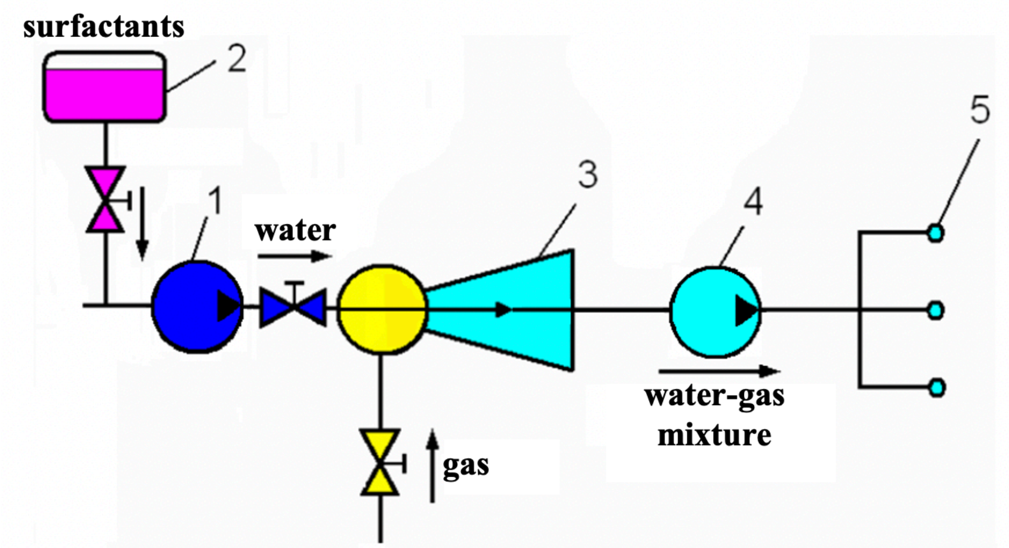

Figure 1.8 – Schematic diagram of the implementation of pump-ejector technology WGE

1 and 4 - electric centrifugal pumps, 2 - tank with surfactant, 3 - ejector, 5 - delivery pumps

1.5 Experience of using the pumping-ejector system for the gas injection and utilization of APG at the Samodurovskoye field

This technology of pump-ejector system was applied at Samodurovskoe field in 2017 and has already shown positive results [21]. The scheme of the pump-ejector system of water-gas impact on the productive formation of the field for the purpose of utilization of associated petroleum gas is shown in Figure 1.9

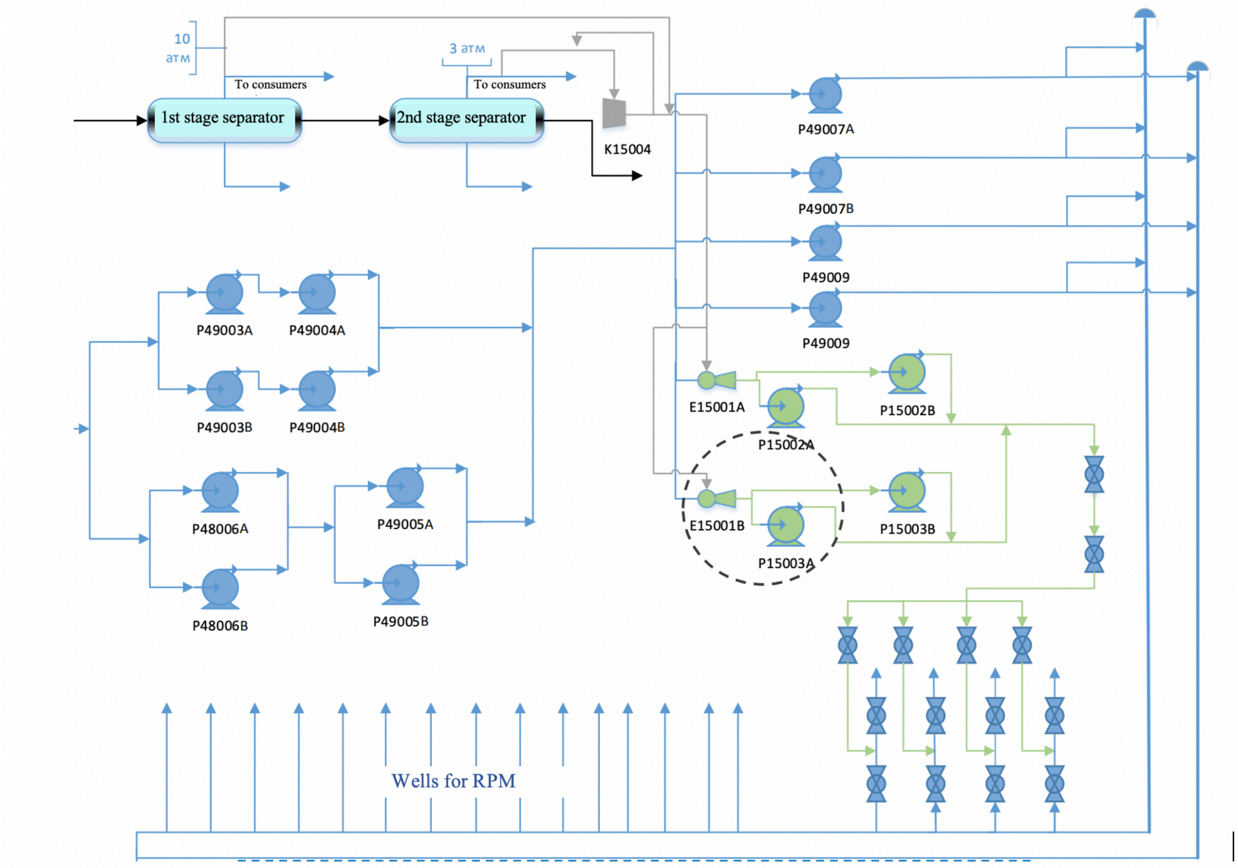

Figure 1.9 – Technological scheme of VGE at Samodurovskoye field

Excess gas from the first separation stage and from the second stage after pressure increase at the compressor enters two chambers of ejectors. Multiphase pumps are installed in parallel with the existing pumps P49009, P49010 with a nominal capacity of 300 m3/h. Liquid after mixing with gas in the ejector chamber enters the reception of multiphase pumps, which, in turn, are the main power elements for water injection in four wells.

Methods of research

At first, laboratory filtration studies were carried out using the technique from [21], which simulates reservoir conditions in the field. It was found experimentally that due to water-gas mixture injection (SWAG) it is possible to increase the oil dispersion coefficient. Further, hydrodynamic calculations of water-gas mixture movement in pipelines and injector wells were performed, and the required pressure for injection was determined in accordance with the methods outlined in [10]. In [33], a methodology for calculating the movement of water-gas mixture in the field conditions was presented. Then, a scheme of the pump-ejector system was developed and equipment parameters were calculated in accordance with the methodology from [21]. Benchmark studies of model ejectors confirmed the results of calculations. Samodurovskoe field, located near the village of Ponomarevka in the Orenburg region (Russia), was chosen for field tests. The benchmark research methodology consisted of comprehensive testing of the block pumping station equipment with a pump-ejector system (PES) for SWAG in several PES operating modes with continuous, uninterrupted operation for at least one hour. In the first phase, the equipment and valves were checked for proper operation. The valves were then opened on the water, gas, and water-gas mixture lines to the booster pump inlet.

After checking that the equipment and the valves on the lines for water, gas and water-gas mixture into the submersible pump are working properly, the submersible pump starts automatically according to the following scheme:

1) the electrically controlled valve on the water supply line opens gradually;

2) When a certain pressure value is reached in the submersible pump intake line (specified during the comprehensive test), the pump motor is started;

3) With the help of a frequency converter the pump starts at a low frequency "until the valve closes". As the pressure in the suction line increases, the frequency increases and when the pump reaches its operating point, the electrically controlled valve on the drain line to the pressure maintenance system opens;

4) By adjusting the electrically controlled valves and the frequency converter, the pump is brought into operation on water;

5) the electric valve on the gas supply line opens and the injector starts mixing the gas in the produced water;

6) the system is brought into operation when running on a water-gas mixture by regulating electrically controlled valves and a frequency converter;

7) after reaching the operating parameters for the water-gas mixture, the mixed flow of water and gas is directed to the watershed point and further to the wells for injection;

8) if necessary, the operating mode of the unit pump station with a submersible pump (SPP) can be adjusted, and if necessary, surfactants can be added to the water and methanol to the gas line. [11]

At the Samodurovskoye field, water and associated gas were injected into the reservoir using a modular pumping station with a pump-ejector system. An electric pump from the pump station supplies water under pressure to the working nozzle of the ejector. When water exits through the nozzle, a vacuum is created in the ejector reception chamber, where the associated gas is sucked in. During the ejector stroke, the water and gas streams mix, as a result of which a water-gas mixture is created. However, at the outlet of the ejector, the mixture pressure is not high enough to inject the water-gas mixture into the wells [1]. Therefore, after the ejector, the water-gas mixture is compressed by a multistage centrifugal pump and injected into the injection wells at the required pressure.

Results and discussion

In this chapter, filtration studies were conducted on models of carbonate-porous reservoirs located in the Samodurovskoye field. These models were used to extract residual oil after a water-molded reservoir experience with a water-gas mixture [8]. This method of research was chosen because the Samodurovskoye field is in the last stages of development with the help of water-and-shoulder bedding. In this study we considered layer T1 of carbonate-porous formations in Samodurovskoe field, which has the following characteristics: reservoir pressure - 16 MPa, reservoir temperature - 30 °C, oil viscosity under reservoir conditions - 7.7 MPa-s, formation water density - 1156 kg/m^3, average permeability - 0.17-10-12 m^2. Associated gas at the Samodurovskoye field contains, in addition to hydrocarbon components, significant amounts of nitrogen (up to 44.7%) and hydrogen sulfide (0.6%). Since no nuclear material was available for the T1 formation at the time of the study, models were created from crushed marble rocks. The permeability of the bulk models for nitrogen ranged from 0.13 to 0.21-10-12 m^2. As the experiments show (Figures 1.10, 1.11), the values of oil displacement coefficient when using SWAG noticeably increased compared to the water-wet deposit, with similarity of the final values of displacement coefficients at inlet gas content of 13 and 25%. The addition of surfactant contributed to a slight increase in the oil displacement factor to 74-78%. [3]

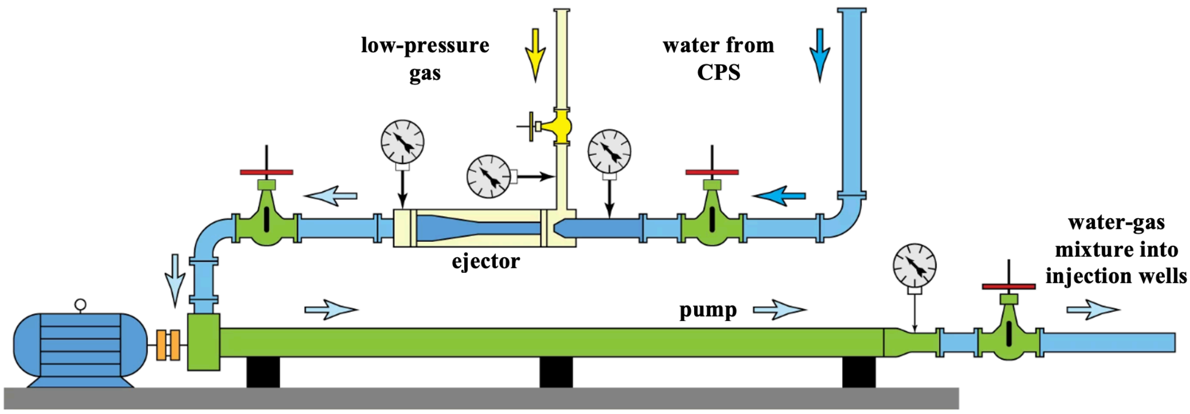

Figure 1.10 – Scheme of the pump-ejector operation at Samodurovskoye field

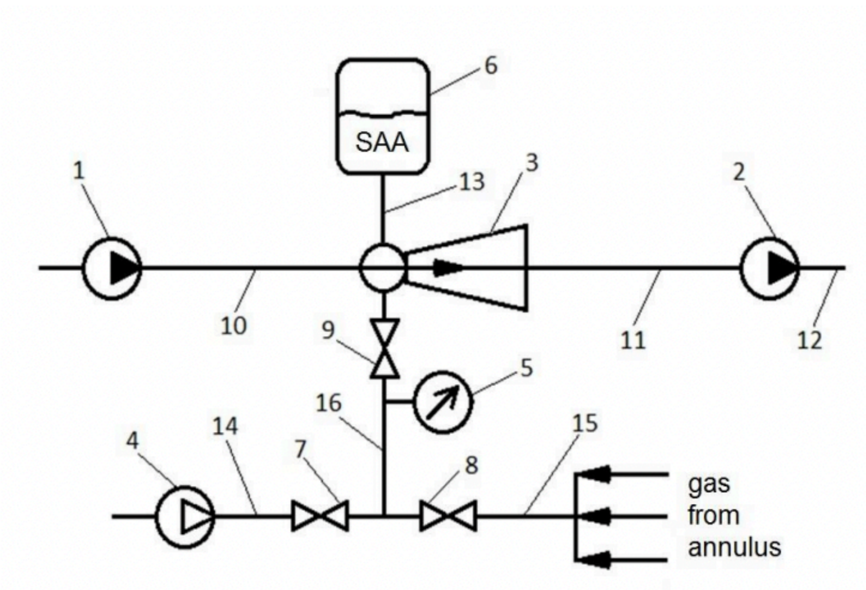

Figure 1. 11 – Scheme of the pump-ejector system

1 - electric pump; 2 - booster pump; 3 - ejector; 4 - nitrogen compressor; 5 - gauge; 6 - surfactant container (SAA); 7-9 - valves; 10 - water injection line; 11 - water-gas mixture supply line to the booster pump 12 - water line to the injection well; 13 - surfactant supply line; 14 - nitrogen injection line; 15 - associated petroleum gas supply line from annular space; 16 - gas mixture supply line.

Associated petroleum gas produced at the Samodurovskoye field contains significant amounts of non-hydrocarbonate components, such as nitrogen and hydrogen sulfide, and does not meet standards for use and transportation. Therefore, its utilization at the field by injecting it together with water into the reservoir is used.

In the work of Nurgaliev A.A. and Khabibullin L.T. [35] gives detailed calculations of initial data for water distribution point (WDP-1) in the reservoir of Samodurovsky field (Table 1.2). Calculations of possibility of delivery of specified volumes of bound oil gas into the specified reservoir by means of non-compressor pump-ejector system were carried out as follows.

First, downhole and uphole pressures were calculated for all injection wells. Then, the water lines from the injection wells to the water distribution station and to the cluster pump station were calculated. The values of the required pressure at the outlet of the pumping and ejector system were determined to be 12 MPa at the current gas flow rate. Calculations at the current gas flow rate showed that it is possible to use only one stage of mixture compression at the ejector, and at the second stage - introduction of water-gas mixture using multistage centrifugal pump.

Calculations of characteristics of jet devices for the pump-ejector system were carried out using a specially developed methodology. To verify the results of calculations, experimental studies of the characteristics of jet devices on a stand under the conditions of the Samodurovskoe field were carried out [33]. [33]. This bench allows to obtain full characteristics of liquid-gas ejectors at different pressures of working fluid (up to 20 MPa) up to the nozzle and pressures at the intake (up to 5 MPa).

Nozzle diameter of the ejector, mm	Water pressure at the inlet to the pumping station unit, MPa	Pressure after the ejector, MPa	Pressure at the outlet of the unit-pump station, MPa	Water consumption for the block pumping station, m3 / day	Gas pressure at the inlet of the unit pump station, MPa	Gas consumption, m3 / day	Test duration, hours
13.7	9.28	1.97	9.49	1140	0.205	10416	2
	11.1	2.19	9.82	1248	0.194	10596	2
	12.47	2.49	9.98	1320	0.205	11424	2
14.2	8.47	1.79	8.78	1176	0.207	5532	2
	10.35	2.24	9.08	1260	0.223	10476	2
	10.74	2.16	9.16	1308	0.215	10812	6

	12.3	2.19	9.47	1404	0.195	10980	2
14.8	9.11	1.55	6.84	1236	0.177	7200	2
	10.96	2.24	6.87	1332	0.215	10128	4
	12	2.6	7.28	1404	0.223	10716	2
	12.51	2.46	7.32	1428	0.213	10896	2
	13.03	2.41	7.24	1464	0.202	11004	2
15.3	9.9	2.45	7.57	1404	0.216	9204	2
	11.16	2.44	7.75	1464	0.199	9228	2
	12.05	2.83	8.13	1524	0.208	10200	2
	12.51	2.71	7.88	1548	0.206	10452	2
15.8	7.19	2.1	9.29	1164	0.25	11880	2
	8.29	1.93	7.26	1248	0.22	9744	2
	10.3	2.38	8.92	1404	0.2	10260	2
	10.9	2.44	9.92	1452	0.217	10884	2
	11.76	2.37	10.05	1500	0.212	11028	2
16.3	8.96	2.13	9.2	1440	0.2	8508	2
	10.01	2.42	9.24	1548	0.226	10968	2
	11.35	2.4	9.84	1632	0.219	11088	6
	12	2.55	9.85	1668	0.223	11244	2
16.8	9.98	2.56	9.33	1644	0.183	8844	2

Table 1.2. – Data from field tests at the Samodurovskoye field, parameters of the pump-ejector system

The test results confirmed the design characteristics of the jet devices. The developed scheme of pump-ejector system for the field "Samodurovskoe" was accepted for realization. The system manufactured by JSC "Novomet-Perm" was launched for implementation in 11 wells of the pilot area of "Samodurovskoe" field. Figure 1.9 shows the scheme of production system. Water is supplied to the ejector nozzle by a pump from the CPS-240-1422 cluster pump station, which also supplies water to the field injection wells that are not part of the SWAG section. The ejector pumps out the gas of the first separation stage and delivers the water-gas mixture to the inlet of the horizontal multistage booster pump ESP8-1600-1450. The system working parameters are as follows: water consumption - 1535 m^3/day, gas consumption - up to 20,000 m^3/day, gas pressure at the inlet - 0.2-0.4 MPa, mixture pressure at the outlet - up to 13 MPa. Water-gas injection unit has been switched to round-the-clock operation to inject the mixture into 11 wells of WDS-2 watershed of Samodurovskoye field. In the process of implementation some design defects of the manufactured equipment were revealed, which were subsequently eliminated.

Field tests of the pump-ejector unit at different values of the ejector nozzle diameter were performed. The motor current frequency was 50 Hz, and the current values varied in the range of 42.4-57.6 A. The results showed that the pump-ejector system adapts to changing operating conditions and fully pumps the associated gas of the first stage of separation from the fields Samodurovskoye, Efremov-Zykovskoye and Spasskoye. In addition, it allows the use of APG from the neighboring Ponomarevskoye field, which is also fed through the pipeline to the inlet of the pump-ejector system using a low-pressure compressor. The pump-ejector system worked stably at Samodurovskoye field in various modes; there were no violations of the ejectors and pumps. Thus, the results of previously conducted theoretical and experimental studies, on the basis of which the SWAG technology was developed using the pump-ejector system, were confirmed during implementation in the field. The experience of system operation at Samodurovskoye field also allowed identifying measures to improve the technology of implementing water-alternating-gas injection using pump-ejector system at other fields in the Ural-Volgodonsk region, taking into account the results of previously published works.

In the work of Nurgaliyev A.A. and Khabibullin L.T. it is proposed to implement water-gas injection cycle using associated petroleum gas (APG) pumped from the annulus spaces of producing wells. It is known that in mechanized pumping wells the pressure in the annulus may reach critically high values due to the high linear pressure during oil gathering. In this case, the level of dynamic pump load decreases so much that the flow rate is disturbed, and pump failure occurs at the bottom of the well. In order to eliminate these undesirable factors, it is suggested to use APG from annular spaces of producing wells by pumping it out with ejector and directing it together with water as a mixture to the injecting well in order to create water-gas impact. It should be noted that in many fields of the Ural-Volgograd region gas factors of oil have low values, usually not exceeding 60 m3/t (for deposits of middle and lower Carboniferous). At the same time APG consumption from annular spaces of producing wells is insufficient to create a water-gas mixture with the required values of gas content, which can significantly increase oil recovery.

In various research literature, it is noted that in order to significantly increase the oil dispersion factor, it is advisable to ensure that the gas content of the water-gas mixture in the reservoir conditions is not less than 13-20%. One of the options for solving this problem is the introduction of nitrogen together with APG using a pump-and-displacement system. It should be noted that water-gas replacement with nitrogen, as shown in the work of the authors from the Institute "TatNIPINeft" [33], increases oil recovery for the conditions of Tatarstan fields.

In this paper, in order to improve the technology, calculations of water and gas exposure process and calculation of pumping and displacement unit using nitrogen and APG for conditions of one of the license areas of N field in Ural-Volga region of PJSC Tatneft were carried out. Nitrogen has a low corrosiveness, has no adverse effect on equipment and is not flammable. Nitrogen can be obtained from the air almost anywhere, which makes it possible to produce it using nitrogen recovery units (membrane, adsorption, etc.) on-site near wells for injection [15].

There is an injection well A in one section of the N field and three production wells, B, C and D, in close proximity to it, which are operated by sucker-rod pumps. Well D operates two formations at the same time. To avoid disruption of the pumps due to increase of pressure in the annulus to the buffer value (from 1.3 to 1.7 MPa, depending on the ambient temperature), the wells are periodically stopped to accumulate.

In order to solve the problem of possible well pump malfunctions associated with increased annular pressure, it is proposed to use a pump-ejector system, which provides gas extraction from wells and mixing it with water and nitrogen. Data on production wells are presented in table 1.3.

Parameter name	Values by well number.			
	B		C	D
Collector type	Terrigenous	Terrigenous	Carbonate	Terrigenous
Reservoir pressure, MPa	16.4	15.3	7.84	11.83
Gas density st.cond., kg / m^3	1.079	1.079	1.24	1.274
Current gas consumption from	53.27	89.86	9.69	2.98

circular space st.cond.,m^3 / day				
The gas factor of oil, m^3 / t	38.6	38.6	2.6	11.78
Formation temperature, ° C	37.4	35.9	23	25

Table 1.3 – Data on production wells

Table 1.3. shows that the gas ratio is low and the associated gas alone is not sufficient to create the required gas content in the water-gas mixture under tank conditions. This problem can be solved by adding nitrogen from the nitrogen compressor to the associated gas. Schematic diagram of the pump-ejector system for Tatneft field conditions is shown in Fig. 1.11. In accordance with the recommendations [28], in this case one stage of ejector compression is provided. At the second stage the water-gas mixture is supplied by high-pressure pump. A multistage vane pump can be used as such a pump. The system located near the injection well works as follows. The power pump (1) pumps water into the reservoir pressure maintenance system, from where it enters the ejector nozzle (3) through the water line. Gas from the space between the production well casing through line (15) mixes with nitrogen injected by the compressor (4) through line (14), forming a gas mixture. This water-gas mixture is prepared with a foaming surfactant coming from a container (6) through line (13) and is drawn by an ejector (3) through line (16). The ejector (3) facilitates the formation of a finely atomized water-gas mixture, which has a certain increased pressure at the outlet. Through line (11), it enters the intake unit of the high-pressure pump (2), which pumps the water-gas mixture under the required pressure into the water line (12). The mixture then enters the well for injection. This system includes valves (7), (8) and (9) to control the gas flow rate, if necessary, and a pressure sensor (5) to monitor the pressure at the inlet to the ejector (3). The valves are used to control the gas rate depending on operating conditions and well capacity. The pressure sensor is necessary to control the pressure at the ejector inlet (3), because the optimal pressure allows to achieve the maximum efficiency of the system.

The pressure at the wellhead of injection well A was calculated using the following input data:

1. injection well flow rate $Q_{well\ w} = 70\ m^3/day$;

2. pumped water density $\rho_w = 1122$ kg/m^3;
3. vertical depth of the borehole to the top of the formation $H_{well} = 1745{,}96$ m;
4. nominal tubing diameter d = 60 mm;
5. inner tubing diameter $d_{in} = 50{,}3$ mm;
6. wellhead pressure during water injection $P_{m.w.} = 14{,}6$ MPa;
7. formation pressure $P_r = 17$ MPa;
8. gas mixture flow rate at standard conditions $Q_{g.\ st} = 3761{,}8$ m^3/day;
9. density of the gas mixture at standard conditions $\rho_{mix.\ st} = 1{,}1621$ kg/m^3;
10. value of the gas-water factor under standard conditions R = 53,74 m^3/m^3.

To ensure the gas content in the mixture under tank conditions equal to 24%, it is necessary to use a unit that generates 140 normal m³/h of nitrogen with 95% purity and 1 MPa discharge pressure (for example, a nitrogen adsorption unit of the "PROVITA-N" type). Calculations of necessary pressures and parameters of the pump-ejector system were performed according to the method described in [10], and calculations of the ejector according to the method [28]. The design pressure at the wellhead during water-gas mixture injection was 20 MPa, and at the outlet of the ejector pump system - 20.1 MPa. At gas pressure at the ejector inlet 1 MPa and working water pressure before the nozzle 15.6 MPa, provided by the pump of the pressure maintenance system, the pressure and energy characteristics of the ejector, shown in Fig. 1.12, are obtained.

A multistage centrifugal vortex pump VNN5A-124-3000 selected according to [10] was used to increase pressure in the system. At an average integral flow rate of 115 m^3/day, the pump develops a head of about 2500 m, a pressure of 17.7 MPa at an efficiency of 59% and power consumption for water-gas mixture of 58.69 kW.

It is important to carry out special studies aimed at suppressing gas bubble fusion in water to determine the need for surfactant supply in the future [10]. Since the injected water in the considered field is highly mineralized, its composition, as shown in [10, 19], can prevent the merging of negatively charged gas bubbles due to their repulsion in the electrolyte salt solution.

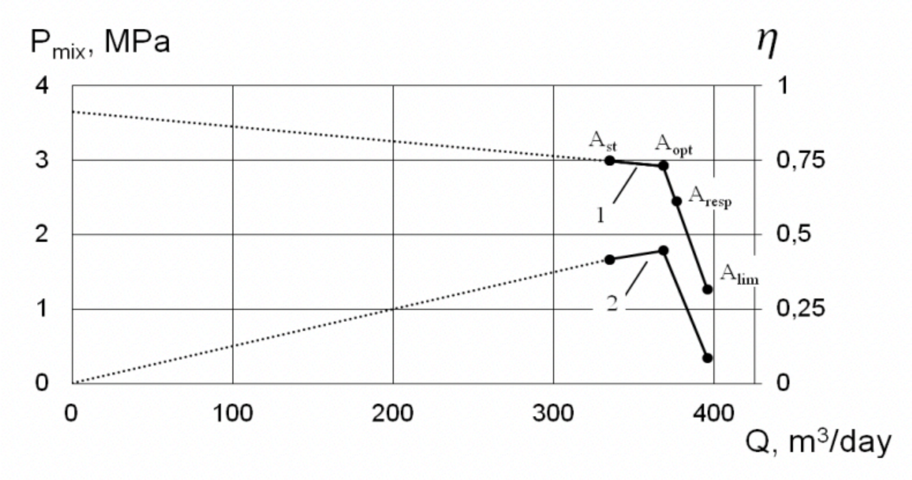

Figure 1.12 – Pressure characteristic of the ejector

(1) - dependence of mixture discharge pressure on gas supply Q at the inlet Pmix = f (Q) and energy characteristic of the ejector (2) - dependence of efficiency η on gas supply Q at the inlet η = f (Q): Ast. Aopt. Alim - respectively. points of stall. optimal and limiting modes; Aresp - point of resumption of gas pumping.

For a pilot zone of field N, including 7 production wells, including B, C and D, responding to injection well A, the expected additional production was estimated based on geological information. According to filtration studies for similar fields, the increase in the oil displacement rate due to water-gas mixture (WGE) injection is up to 15%. Taking this into account, the expected additional production can be expected to be up to 1,500 tons of oil per year.

Expanding the application of VGE technology in the fields of Tatarstan is also possible due to the use of high-pressure nitrogen reserves, which were discovered during gas production during well drilling. Gas-bearing strata were found in the areas of the Biklyanskoye, Afanasovskoye, Novo-Suksinskoye, Azevo-Salauskoye and Novo-Yelkhovskoye fields. According to geophysical survey data penetrating into the sediments, the Vereya horizon, the depth of nitrogen layers location was determined - 731.2-743.8 m. In addition, gas-bearing strata were found in other horizons at depths of 642.0-652.5 m, 670.5-673.0 m, 878-892 m, and 928.6-948.4 m. At a depth of 863-866 m, a nitrogen gas inflow was obtained by testing.

To assess the possibility of using nitrogen from such reservoirs in the future, it is necessary to estimate the reserves of test wells penetrating these formations. This means that studies of gas reserves in non-subsea wells that penetrate these reservoirs must be conducted, and the structure of geological formations and reservoirs must be studied. These data can be used to identify prospective fields and prepare plans for gas production and its use as a substitute for oil production by water-gas ejection (WAG).

Conclusions

This experience examines the technology for increasing oil production and utilization of associated petroleum gas by water-gas injection (SWAG) using pump-injection systems. This technology allows the use of existing field infrastructure without the need to build additional high-pressure gas pipelines and complex gas wells. The technology requires significantly lower discharge pressure than using a compressor and achieves somewhat higher water-gas mixture pressure than known ejector technologies.

Measures have also been developed to further increase the efficiency of the VGE method, including the use of nitrogen as a water-gas replacement gas and the need for salinity studies to improve the efficiency of the pump-and-push system. The concentration of salts in the water must be in the optimal range to improve the stability of the fine water-gas mixture.

Shallow formations containing high-pressure nitrogen reserves (6.5 MPa at 850 m depth) may become an additional source of nitrogen in the Republic of Tatarstan (Russia).

Thus, on the basis of this article, we can conclude that the use of pump-and-pump systems when applying the WGE method is an effective, reliable and easily accessible way to increase oil production and utilization of APG. At the same time, the use of nitrogen as a gas for water-gas replacement can increase the efficiency of the technology, and studies on mineralization will help to further optimize the pumping-pumping system.

1.6 Overview of the application of water-gas impact technology in foreign fields

Water-gas stimulation (WGS) methods are an effective way to increase oil and gas production in the fields. Most foreign fields where this technology has been applied are in Canada and the USA [6]. The project at the North Pembina field in Alberta, began in 1957 and was carried out by Mobil. In the WGS process, gas and water are injected into the same well by alternating water and gas injection, as well as co-injection of a water-gas mixture.

At present, WGS technology is being used in several fields in the North Sea. Out of more than 60 field applications, only a few have been unsuccessful, indicating that the technology is highly effective. Generally, WGS is used as a tertiary recovery method to obtain additional production over other possible recovery methods, especially over waterflooding. The majority of WGS applications have shown a 5% increase in oil recovery, but some fields, such as Dollarhide, Rangely-Weber and Slaughter Estate, have seen up to a 20% increase in oil recovery.

In some fields, such as University Block 9, Lost Soldier, Rock Creek and Garber, reservoir pressure was maintained to achieve fluid miscibility before water-gas stimulation. Successful experience of water-gas stimulation was carried out in the University Block field [19]. In this field the productive formation lies at a depth of 2562+2592.5 m in limestone sediments. Three productive intervals with intercrystalline cavernous porosity are distinguished in the deposit. Reservoir permeability (by core) is 0.014 μm^2, porosity is 10.2%, and average effective thickness is 9.1 m. The initial reservoir pressure at the time of the WGS was 24.5 MPa, but decreased to 9.97 MPa, 2.46 MPa below the oil gas saturation pressure.

Oil viscosity in formation conditions at a temperature of 60°C was 0.25 MPa. The results of experimental studies have shown that the application of water-gas stimulation (WGS) technology at oil fields can significantly increase the efficiency of oil production.

These results indicate that water-gas stimulation is an effective method for increasing oil production from reservoirs with low reservoir pressure. In this case, it was possible to increase pressure in the field by 14.53 MPa, which contributed to an increase in oil flow rate to 75 tons per day. At the same time a small amount of gas was required for the intensification, which allows to reduce the cost of purchasing gas for well injection [16].

It is also worth noting that the data obtained on permeability and porosity of the reservoir can be used to plan future operations in the field and optimize oil production processes.

Experience with this technology in the North Sea, particularly in the Gullfaks and Statfjord fields, confirms its high efficiency.

The Gullfaks field, located offshore the North Sea, was discovered in 1973. In 1984, an APG water-gas ejection system was installed on the field, which resulted in a significant increase in gas production. Currently, the Gullfax field's APG water-gas ejection system consists of 18 wells, which together produce about 10 billion cubic meters of gas per year (Figure 1.13).

Figure 1.13 – Gullfax Field

The Statfjord field, located in the North Sea on the Norwegian continental shelf, was discovered in 1974. In 1987 a water-gas ejection system for APG was installed in the field. Currently, the APG water-gas ejection system in the Stafjord field consists of 19 wells, which together produce about 25 billion cubic meters of gas per year (Figure 1.14).

At the Statfjord field, the application of water-gas ejection technology has yielded positive results. In the period from 1995 to 2002 more than 30 operations of APG injection into the reservoir using this technology were carried out. The total volume of gas injected was about 130 million m^3.

One of the key advantages of using water-gas ejection technology in the North Sea fields is the possibility of reducing operating costs and increasing hydrocarbon production. This is achieved through the use of existing centrifugal pumps and pipelines at the wells, as well as the possibility of regulating injection parameters.

In addition, water-gas ejection technology has low environmental risks, since no additional chemicals or equipment are required.

However, it should be taken into account that the use of this technology may be limited by the peculiarities of the geological structure of formations and the presence of sufficient pressure in the reservoir for injection.

The use of water-gas impact technology with simultaneous utilization of APG at foreign fields has great potential to increase oil and gas production, as well as to reduce the harmful environmental impact. However, it is necessary to take into account peculiarities of geological conditions of each field and approach the choice of optimal technology taking into account these conditions. It is also necessary to ensure effective and safe operation of the water-gas intensification system, including control of pressure, temperature and other parameters [17].

Figure 1.14 – Stafjord field

CHAPTER 2: APG combustion

2.1 Analysis of the global situation on APG combustion

The problem of flaring associated petroleum gas (APG) in the Russian oil and gas industry remains a pressing issue. About 94 billion m^3 of APG is produced annually, which is 12.7% of the total volume of gas production in the country. However, about 23 billion m^3 of APG is flared, which exceeds 18% of production. This puts Russia among the leading countries in inefficient use of APG.

The direct consequences of APG combustion are the loss of valuable hydrocarbon raw materials and the lost profits for the state associated with the shortfall of gas-chemical products at gas-processing plants. In addition, the combustion of APG negatively affects the environment and living conditions of people in areas of oil production.

The solution to this problem can be associated with the development of technologies for APG utilization, which can help to reduce its combustion and reduce the negative impact on the environment. One of such methods is the water-gas impact on reservoirs during oil extraction, which allows using APG to increase oil production and at the same time to utilize it [18]. The introduction of such technologies can contribute to a more efficient use of resources and improve the environmental situation in the regions of oil production.

Until the middle of the XX century, associated petroleum gas was not used in oil production, but was either released into the atmosphere or flared, which led to the destruction of valuable hydrocarbon raw materials and a negative impact on the environment and human health. In Russia the first gasoline plant was launched in 1925. In the 1960s, the USSR processed only 10-11% of recoverable associated petroleum gas, while the United States processed 78% and Canada processed almost all of its produced gas [3].

The first serious steps on the use of associated petroleum gas were taken in the USSR in 1986 with the adoption of Minnefteprom Decree No. 41, which set the goal of ensuring the use of petroleum gas resources by at least 97%. However, in the early 1990s, oil production declined, which led to a decrease in the production of associated petroleum gas. In the 2000s a new stage of solving the issue of rational use of associated petroleum gas began. Figures 2.1 and 2.2 show official data on the volumes of recovery, flaring and use of associated petroleum gas in the USSR and Russia from 1980 to 2019 [41].

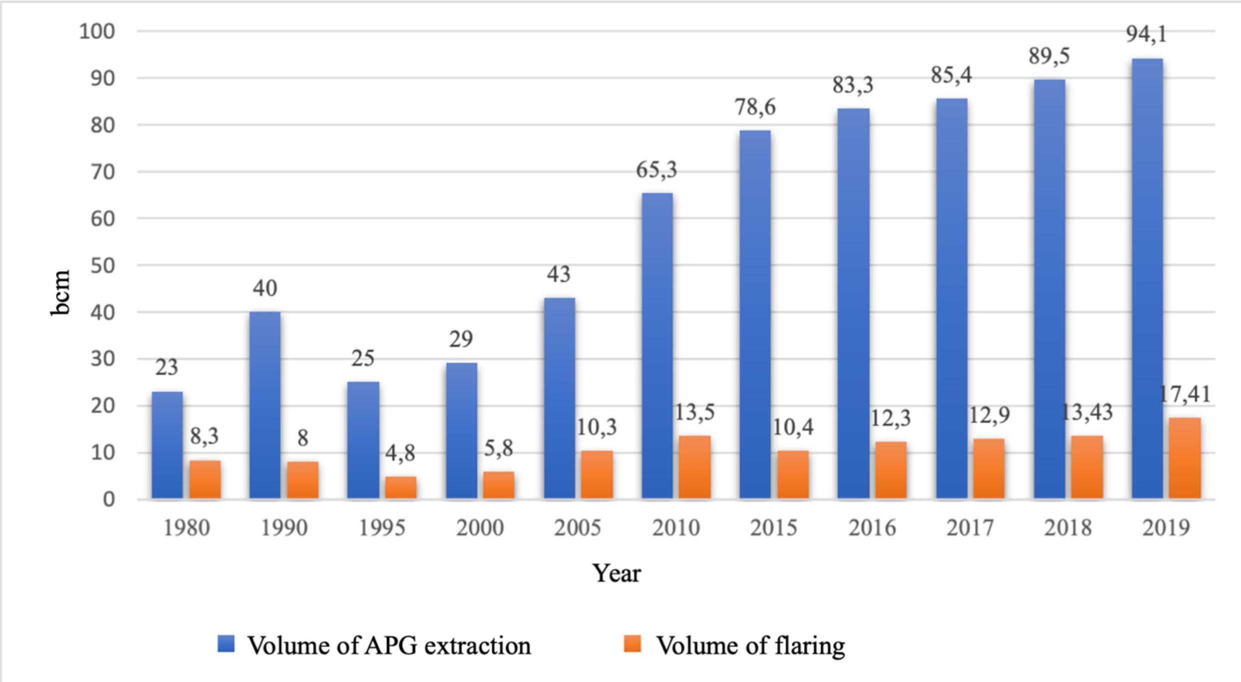

Figure 2.1 – Dynamics of production and flaring of associated petroleum gas in the USSR and the Russian Federation in 1980-2019.

As a result, until 2012, Russia was losing up to 20 billion dollars of additional income annually due to APG combustion, which amounted to a quarter to a third of the global volume [3]. By 2015, however, the government took measures that helped improve the situation.

Economic losses from APG combustion are only one of the problems [41]. Gas combustion in flares produces substances harmful to the climate and human health [41]. According to a Greenpeace study from 2012, almost 100 million tons of CO2 were emitted annually in Russia due to APG combustion [41]. Methane contained in

APG in significant amounts (about 60-80%) also enters the atmosphere, which has a negative impact on the environment [41]. In addition, combustion products contain nitrogen oxides, which are harmful to the health of people living in oil-producing areas.

In Russia, an urgent problem is the inefficient use of associated petroleum gas (APG), which causes its excessive flaring. In 2007, the President of the Russian Federation set a goal of achieving a 95% level of APG utilization by 2012 [3]. However, the economic crisis of 2008 prevented the achievement of this goal. Nevertheless, the volume of flared associated gas continued to increase year by year.

Data from the Russian Ministry of Natural Resources and Environment show that 17.1 billion cubic meters of APG were burned in Russia in 2012, while annual production was 55 billion cubic meters [3]. However, the exact amount of APG flared remains unknown, since there are no accounting systems in more than half of the cases [2]. International Economic Agency (IEA) estimates range from 16 to 20 billion cubic meters for 2010, while satellite monitoring gives a result of 35 billion cubic meters [2].

Only in 2013, the Russian government decided to approve increased penalties for APG flaring, which reduced the volume of flaring to 15.8 billion cubic meters [3]. In 2022, the volume of flared associated gas in Russia dropped to about 14 billion cubic meters [2].

It should be noted that the production of associated petroleum gas in Russia has increased to 70 billion cubic meters by 2012 [2]. This indicates a significant potential for the utilization of associated gas in the country. Therefore, the effective use of APG should be a priority task for Russia's environmental policy.

Despite the decrease in the volume of flared associated gas, the level of its processing in Russia leaves much to be desired. Regional gas and petrochemical clusters can help solve this problem. For example, a unique project is being created in the Khanty-Mansi Autonomous Okrug aimed at utilization of APG and development of advanced processing of raw materials. The government of the Khanty-Mansiysk Autonomous Okrug will offer tax incentives to cluster participants, and the companies are planning to invest 65 billion rubles by 2021 in the construction of facilities for the beneficial utilization of associated petroleum gas..

Creating a gas cluster in Western Siberia is a successful idea that could be extended to other regions, especially Eastern Siberia, where the average natural gas utilization rate is one of the lowest in Russia at only 60-62%. However, state support is needed to create a zone where new gas processing facilities can be built and a favorable investment and taxation climate can be ensured. The implementation of projects for the beneficial use of natural gas requires significant investments in new production facilities, as well as the reconstruction and modernization of existing petrochemical and gas-processing facilities.

In order to stimulate subsoil users, the state should take supportive measures, such as installing tax, customs, tariff and other measures, as well as creating a legislative framework that regulates the beneficial use of natural gas [19]. However, despite the fact that the bill on APG was developed in the 1990s and was repeatedly finalized, it still remains under consideration in the lower house of parliament. The government was only able to pass a resolution to tighten penalties for gas flaring, but measures to stimulate the beneficial use of APG are still uncertain. Perhaps Russia's support of an international initiative will help solve this problem.

On the basis of space imagery data a calculation has been made which shows that gas flaring on the planet has reached a record scale for the last ten years. The volume of flared gas is 150 billion m3, which is equivalent to the annual consumption of natural gas by all sub-Saharan African countries [3]. In 2019, gas flaring increased by 3% compared to 2018, mainly due to increases in the United States (23%), Venezuela (16%), and Russia (9%) [3]. Flaring in unstable or conflict-affected countries such as Syria (by 35%) and Venezuela (by 16%) was also seen increasing, although oil production in Syria was not increasing and Venezuela was down 40%. Based on 2019 data, Figure 2.3 shows the top ten countries in the world in terms of associated petroleum gas flaring. This data shows the need to take measures to address gas flaring in order to minimize its environmental impact and maximize the use of resources.

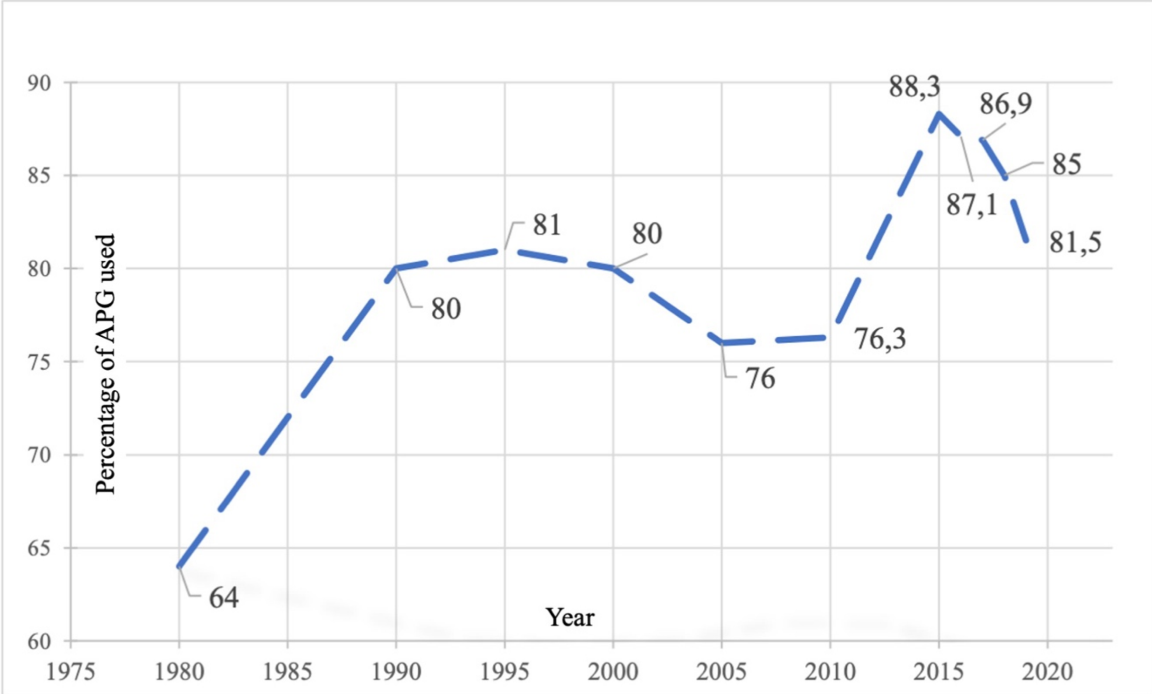

Figure 2.2 – The dynamics of the use of associated petroleum gas in the USSR and Russia in 1980-2019.

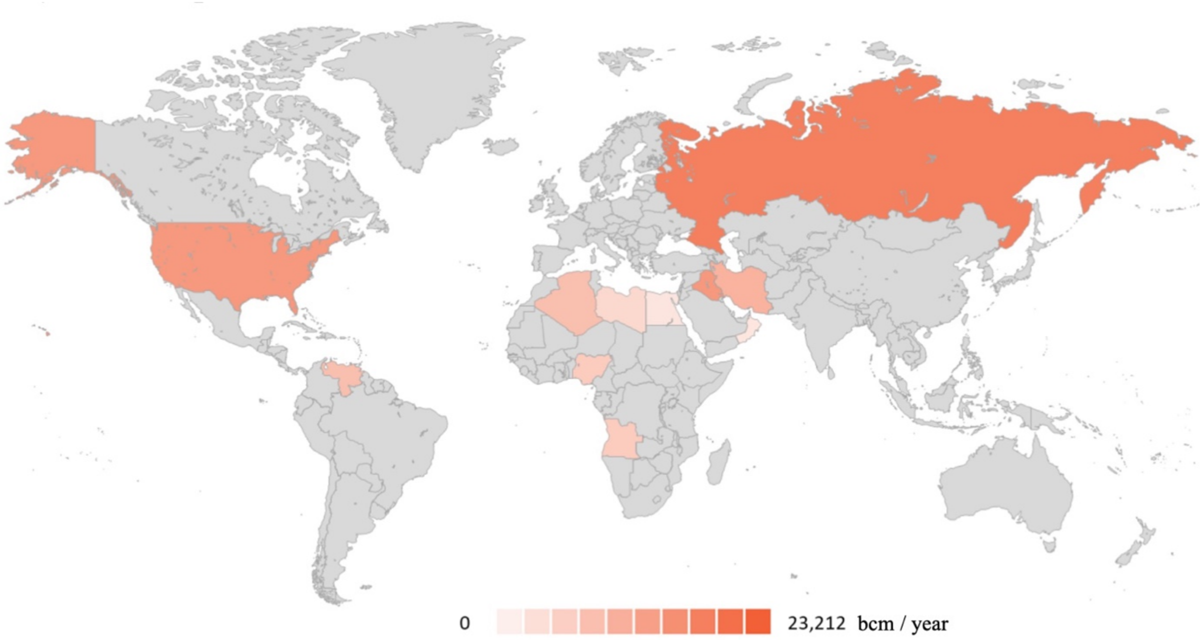

Figure 2.3 – Top 10 countries by APG flaring in 2019.

According to Figure 2.4, there is an increase in the level of flaring of associated petroleum gas in the countries from 2015 to 2019. This confirms the previously identified trend of increasing APG flaring.

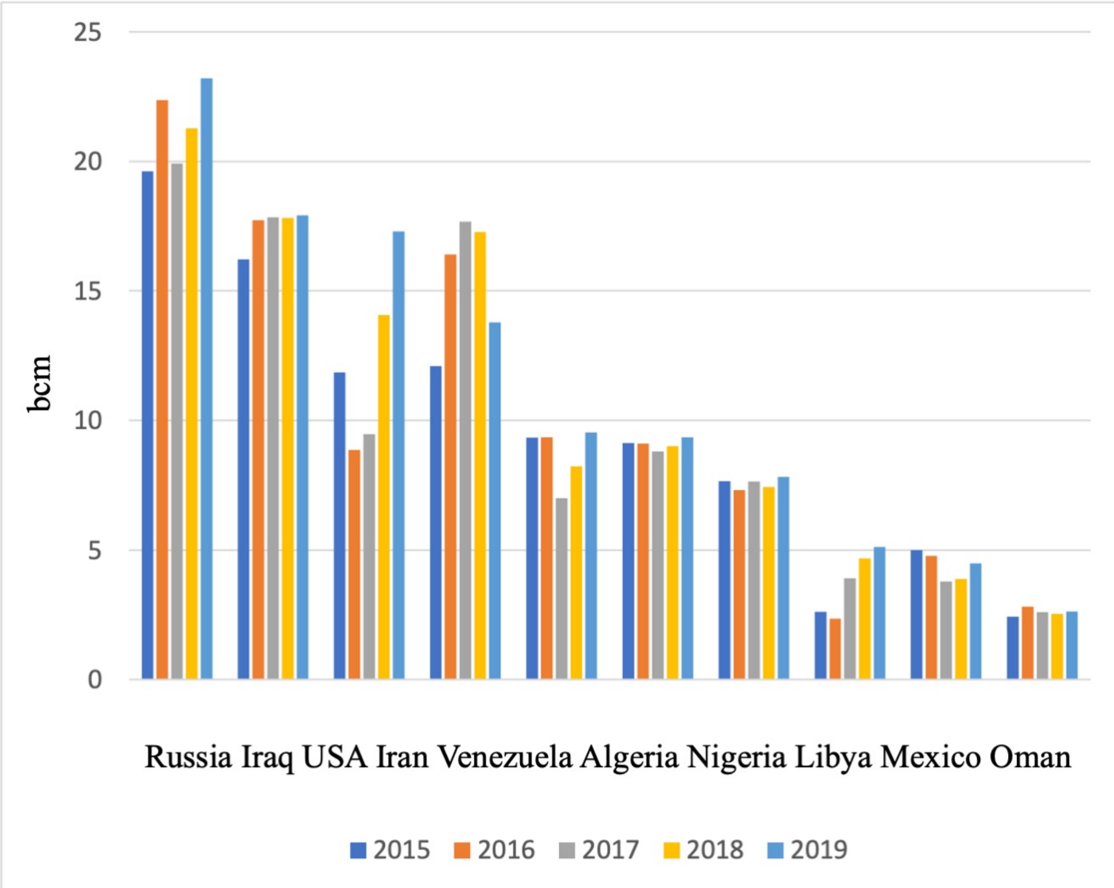

Figure 2.4 – Top 10 countries in terms of APG combustion from 2015 to 2019

2.2 Mathematical model for calculating the projected volume of APG combustion

Considering the growing dangers associated with climate change due to global warming, the 2015 Paris climate summit adopted a recommendation for states to develop measures to mitigate the greenhouse effect in order to prevent an increase in the average annual temperature on Earth by more than 2°C by the middle of this century [3]. One of the factors contributing to the greenhouse effect is the combustion of associated petroleum gas (APG) in oil-producing regions of Russia, which emits significant amounts of environmentally hazardous combustion products such as soot, nitrogen oxides, aromatic hydrocarbons and heavy metals, as well as carbon dioxide.

The reports of the Federal Agency for Subsoil Use and Natural Resources of the Russian Federation [22], published on the official website, were used to obtain information on the actual volumes of APG combustion. These reports contain quarterly statistical information on the total volumes of APG flared throughout the Russian Federation.

From the graph in Figure 2.1, we can conclude that there is a correlation between the volumes of flared gas and oil production in the region, which correlate with each other. To establish the relationship between volumes of flared gas and natural gas production in Russia, a linear regression analysis was conducted. Data on quarterly volumes of flared gas and oil production from the first quarter of 2015 through the fourth quarter of 2019, inclusive, were used as the training sample. This analysis made it possible to assess the strength of the relationship between these indicators and identify possible correlations [26].

In light of the above, the forecasting model can be represented as two components. The first component is an exponential function, which takes into account trends in APG combustion volumes over time. The second component is an average of intra-annual deviations, which reflects seasonal fluctuations in APG combustion volumes. These components together allow us to determine the predicted values of APG combustion volumes for a future period of time. In this regard, the forecast model may have the following form (2.1):

$$V_f = (ae^{bt}) \times (1 + \Delta_q), \tag{2.1}$$

where V_f - forecasted volume of APG burned, mln m^3;

q – sequence number of the quarter (within each year);

Δ_q – a dimensionless value obtained by averaging (over a historical period) the average quarterly values of deviations of the volumes of APG combusted from their annual average values calculated for each year.

ab – dimensionless coefficients.

t — time expressed as a consecutive series of numbers in which the integer part of the number denotes a year, and the fractional part denotes a quarter, namely: 2015.00 - 1st quarter of 2015; 2015.25 - 2nd quarter of 2015; 2015.5 - 3rd quarter of 2015; 2015.75 - 4th quarter of 2015.

The coefficients a and b were determined using the actual volumes of APG burned for the period from the first quarter of 2015 to the fourth quarter of 2019 (hereinafter the historical period). The value of Δq was calculated by formula (2.2).

$$\Delta_q = \frac{1}{N}\sum_{i=2015}^{2019}\sum_{q=1}^{4}\frac{V_{iq} - \bar{V}_{iq}}{\bar{V}_{iq}}, \qquad (2.2)$$

where N – total number of quarters in the historical period;

V_{iq} – actual volume of APG combusted in the q-th quarter of the i-th year, mln m^3;

$\bar{V}_{iq}$ – is the average actual volume of APG burned in the q-th quarter of the i-th year, million m^3, calculated by formula (2.3):

$$\bar{V}_{iq} = \frac{1}{4}\sum_{q=1}^{4} V_{iq}, \qquad (2.3)$$

Checking the adequacy of the model

In order to verify the reliability of the proposed forecast model, it is necessary to assess its accuracy, using the formula that will determine the error of the forecast (2.4).

$$\delta_m = \frac{1}{n}\sum_{q=1}^{4}\left|\frac{V_{fiq} - V_{iq}}{V_{iq}}\right|, \qquad (2.4)$$

where δ_m – average relative forecast error;

V_{fiq} – forecasted volume of APG combusted in the q-th quarter of the i-th year, mln m^3;

n – Number of quarters in the control period.

This mathematical forecasting model allows us to estimate the flaring volumes for the next year with sufficient accuracy. This model can be useful for companies involved in oil and gas production, as well as for organizations involved in environmental monitoring and natural resource management. Forecasting gas flaring volumes can help companies reduce the negative impact on the environment and reduce the costs of oil and gas field operations [25].

Thus, the model for forecasting total flaring volumes in the oil production area is an important tool for risk management and process optimization in the oil and gas industry.

Forecasting natural gas flaring volumes at the Prirazlomnaya Platform is an important task in the context of increasing hydrocarbon production efficiency and reducing the negative environmental impact. To solve this problem, various mathematical models can be used, which take into account various factors affecting APG flaring volumes.

One of such models can be a linear regression model based on the analysis of statistical data for previous periods. Such a model can take into account different factors, such as oil production volume, time factors, peculiarities of technological processes, etc.

An important aspect in predicting APG flaring volumes at Prirazlomnaya OIRSP is also accounting for seasonal factors, since flaring volumes can vary significantly depending on the time of year, climatic conditions, etc.

Thus, forecasting of APG combustion volumes at Prirazlomnaya OIRSP can be done using different mathematical models, which take into account various factors affecting this process, as well as seasonal factors. This can help improve the efficiency of hydrocarbon production and reduce the negative impact on the environment [36].

2.3 Methodology for forecasting the use of associated petroleum gas for own needs of the Prirazlomnaya Platform

A total of 3 gas treatment systems are provided on the platform:

1. Gas compression system

The compression system is designed to receive gas from the 1st and 2nd stage separators, compress it, purify it from sulfur compounds and feed it into the fuel gas system for power turbine generators and fire heaters. Excess gas is burned in high and low pressure flares. Purification of fuel gas from sulfur compounds is carried out in the high-pressure amine contactor with an aqueous solution of diethanolamine (DEA).

Composition of the gas compression system (Figure 2.5):

- associated gas compression unit, coming from the separator of the second stage, with subsequent cooling and separation of the total gas flow of the second and first separation stages before supplying to the high-pressure amine contactor ("low-pressure compression system") [16];
- sour gas purification unit in the high-pressure amine contactor.
- a unit for compression of high-pressure purified amine gas in the contactor for feeding into the fuel system ("high-pressure compression system") having a backup string with a separate compressor ("backup high-pressure gas treatment system").

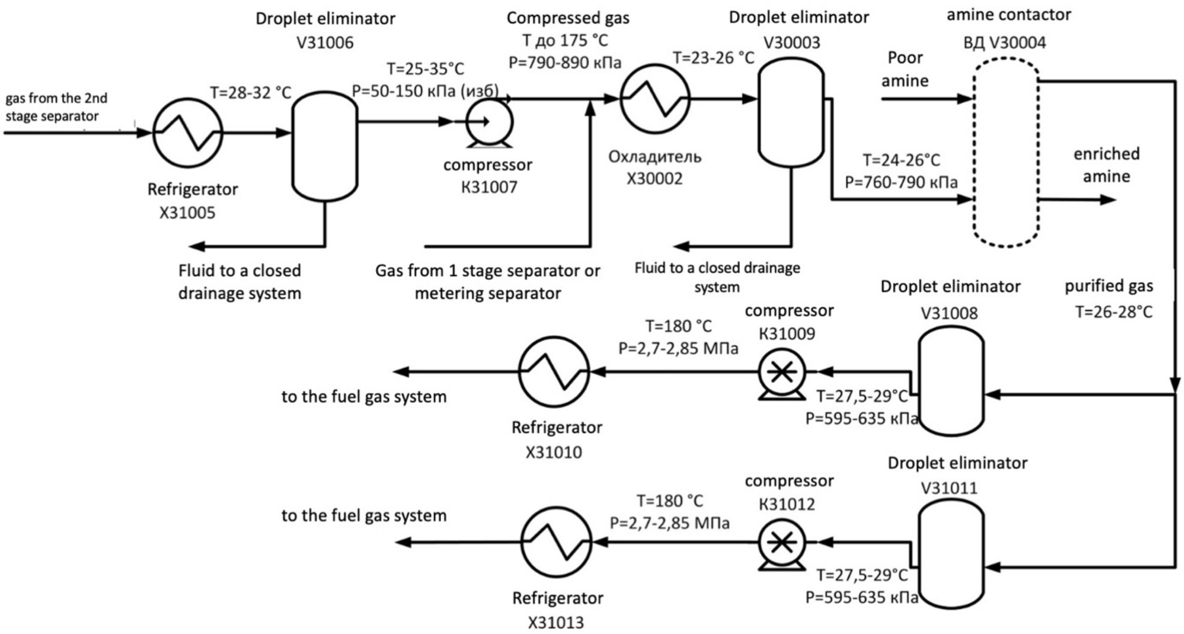

Figure 2.5 – Process diagram of gas compression

2. *Process gas system (Figure 2.6)*

The process (absorption) gas system is designed to receive gas containing sulfur compounds from stripping column and supply it by compressor through low pressure amine contactor back to stripping column to clean oil from hydrogen sulfide. Operational control of technological processes of the system is carried out by operator from CPU.

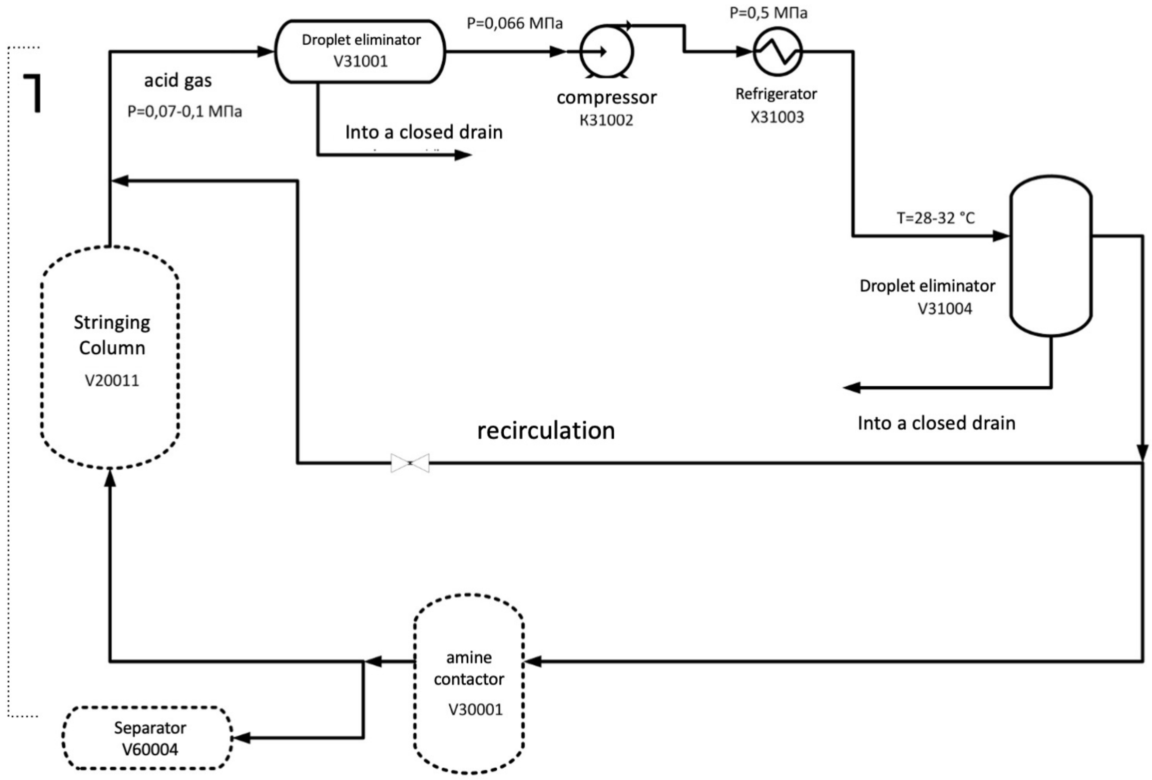

Figure 2.6 – Process diagram of the process gas system

3. Fuel gas system

Fuel gas is a mixture of several different gases (components), which can be mixed together in any quantitative ratios.

Fuel gas

The combustible part

- Hydrogen (H_2)
- Methane (CH_4)
- Ethan (C_2H_6)
- Propane (C_3H_8)
- Bhutan (C_4H_{10})
- Carbon monoxide (CO)

Ballast part

- Nitrogen (N_2)
- Carbon dioxide (CO_2)
- Water vapors (H_2O)
- Helium (He)

The fuel gas system is designed to prepare gaseous fuel and provide it to the power and technological systems of the offshore ice-resistant stationary platform (OIRSP).

Fuel gas is an associated petroleum gas purified from hydrogen sulfide and carbon dioxide in an amine contactor (absorber) HP [36].

The fuel gas system consists of (figure 2.7):

- high-pressure (HP) fuel gas systems.
- low pressure (LP) fuel gas systems.

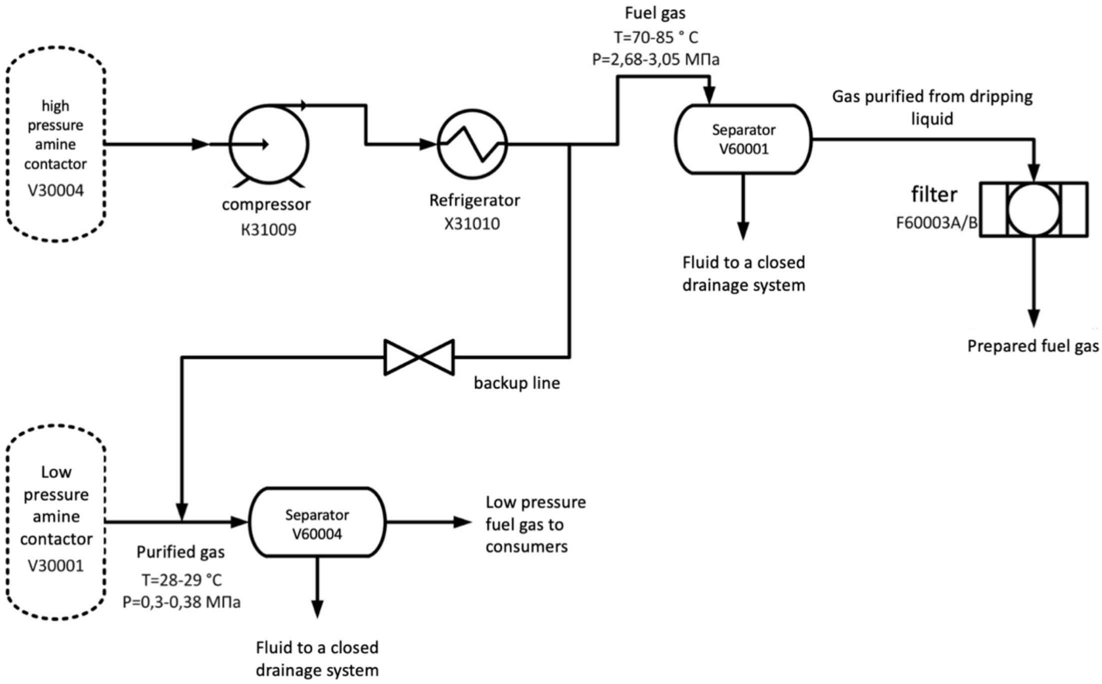

Figure 2.7 – Process diagram of the fuel gas system

In order to effectively apply this methodology, it is recommended to define a list of APG consumers on the Prirazlomnaya offshore ice-resistant stationary platform:

- Three gas turbine units (running on associated petroleum gas or diesel fuel);
- Four fire heaters (run on associated petroleum gas, oil or diesel fuel);
- Flare burners on duty and flare manifold blowdown.

To calculate the annual demand of the OIRSP for associated petroleum gas, it is necessary to obtain the following input data, Table 2.1.

Indicator	Source of information
Construction and workover schedule for wells in the Prirazlomnoye oil field	Technological information
Number of shipments of full shipments of oil in the period, thousand tons	Calculation information
Gas production forecast, (mln. m^3) per year	Technological information
Total oil production forecast, thousand tons	Technological information

Projected volume of water injection for RPM, thousand m^3	Technological information
OP load (taking into account the LSR) for the period [%]	Technological information
The number of working OPs in the period	Technological information

Table 2.1 – Initial data for calculations of the OIRSP annual demand for associated petroleum gas

The calculated values and constants used in forecasting are shown in Table 2.2.

When forming GTM for the next month, actual data for the previous month, planned work on equipment in the billing period, affecting gas consumption are considered [18].

Indicator	Value
Non-fuel needs (gas consumption used to purge collectors and maintain standby combustion), [m^3/day]	2 400
APG technological loss standard for 2022 [%] (requires updating the standard upon approval by the Ministry of Energy)	0,0035
The average permanent safe load on the OP to ensure the production of thermal energy in the required quantities	25 – 30%
Periods of use of two OPs to ensure the necessary heat production (needs to be updated if it is necessary to perform scheduled maintenance work on heaters, coolant system and other process equipment)	January - May October - December
Periods of use of one RP to ensure production of the required heat (needs to be updated if it is necessary to perform scheduled maintenance of heaters, coolant system and other process equipment)	июнь июль
Periods without the use of WU, generation of the required heat energy is carried out by the UUT	August, September

Average actual gas consumption for heat generation during the operation of one unit, taking into account unforeseen gas losses, [m3/day]	21 790
Minimum daily gas consumption per one RP at a load of at least 25%, [m3/day]	19 500
Operating ratio of the OP	0,96
Average actual gas consumption for E/P generation including unforeseen gas losses [m3/day]	164 718
Operating coefficient of CTG	0,99

Table 2.2. – Constants used in the calculation, taken from the actual indicators 2021.

The procedure for calculating the associated petroleum gas demand of the OIRSP is based on the actual data for the past period, the projected hydrocarbon production indicators and the projected calculations for the coming period.

Gas consumption for non-fuel needs (gas consumption used for blowdown of collectors and maintenance of standby combustion) is determined by formula (2.5):

$$q_{\text{fn}} = q_{\text{fn.day}} N \cdot 10^{-6}, \tag{2.5}$$

where q_{fn} – gas consumption for non-fuel purposes during the period, million m^3/period;

$q_{\text{fn.day}}$ – gas consumption for non-fuel needs per day, m^3/day;

N – number of days in the period, days.

Technological gas losses during production, technologically related to the adopted scheme and technology of field development

Technological gas losses are determined by the formula (2.6):

$$q_{\text{tl}} = q_{\text{pr y}} \cdot n_{tl}/100, \tag{2.6}$$

where q_{tl} – process loss consumption for the period, mln m^3/period;

$q_{\text{pr y}}$ – gas production, mln m^3/period;

n_{tl} – norm of technological losses, approved by the Ministry of Energy for the current period, %

Gas consumption for heat generation (fire heaters)

To predict the consumption of gas for heat production, it is necessary to ensure the operation of RP with a constant, maximum allowable safe load on the RP, the necessary afterheating of the coolant is carried out with the use of UHS [36].

Permissible constant load, which provides safe operation of the LPF, is within the range from 25% to 30%. Exceeding the permissible load leads to the risk of burnout, deformation, destruction of the internal equipment of the pilot plant, load reduction below the permissible load leads to reduction of APG utilization and increase in the amount of gas burned in the flare.

The volume of gas required for heat production in the period is determined by the formula (2.7):

$$V_{\text{OPforec}} = q_{OPav.day.} * N * 10^{-6}, \qquad (2.7)$$

where V_{OPforec} – forecast gas consumption for the period, mln m^3/period;

$q_{OPav.day.}$- average daily gas consumption at the RP including unforeseen gas losses associated with the reduction of load on the RP due to production needs, m^3/day [19];

N – number of OPs in operation (units)

The average daily gas consumption for the forecast is determined based on actual data for the past period, taking into account unforeseen gas losses associated with a decrease in load on the OP due to production needs. In this case, equality (2.8) is fulfilled:

$$q_{OPav.day.} = q_{OPav.day.f}, \qquad (2.8)$$

where $q_{OPav.day.f}$ – average daily actual gas consumption at the RP including unforeseen gas losses associated with the reduction of load on the RP due to production needs, [m^3/day]..

The average daily actual gas consumption at the OP, taking into account unforeseen losses, is determined by the formula (2.9):

$$q_{OPav.day.f} = \frac{V_{OP.f}}{N_f}, \tag{2.9}$$

where $V_{ОП.факт}$ - actual volume of gas used for heat generation over the past period, m^3;

N_{fact} – number of days in the period.

According to the results of actual indicators, when operating RPF with a constant load in the adopted range, unforeseen gas losses, consumed by RPF, arise when the daily consumption of gas at the OP below 19 500 m^3 per OP, below 39 000 m^3/day when operating two OPF simultaneously (data taken from the actual gas consumption, when operating RPF with a constant load of 25-30% for the period from March to June 2022 inclusive).

In the absence of unforeseen losses of gas for the past period, the average daily gas consumption is determined by the formula (2.10):

$$q_{OPav.day.} = q_{OPav.day.max} * k_{ex.OP}, \tag{2.10}$$

where $q_{OPav.day.max}$ - average daily maximum gas consumption at the OP for the period, m^3/day

$k_{ex.OP}$ – operating rate of the OP.

The average daily maximum gas flow rate is determined by the formula (2.11):

$$q_{OPav.day.max} = \frac{V_{OP.max}}{N_{max}}, \tag{2.11}$$

where $V_{OP.max}$ – is the maximum volume of gas used for heat production in the past period, m^3;

N_{max} – the number of days in which gas consumption of the OP with the maximum consumption in the past period was provided.

To determine the number of days of operation of the OP without unforeseen losses, the days of operation of the OP with a daily flow rate that meets the requirement:

$q_{day} > 19\,500\ m3/day$ when working with one OP, or

$q_{day} > 39\ 000\ m3/day$ when working with two OPs at the same time.

The operation factor of the OP is determined by the formula (2.12):

$$k_{ex.OP} = \frac{q_{OPav.day.fact}}{q_{OPav.day.max}} \qquad (2.12)$$

According to the results of the actual indicators, at the operation of RP with a constant load in the adopted range, the average actual consumption of gas for heat production, considering unforeseen losses is equal to:

- With the operation of one OP - 21,790 m^3/day;
- When operating two compressor stations simultaneously - 43,580 m^3/day;
- The operating ratio of the OP is 0.96.

Data are based on actual gas consumption figures, with the operation of the OP at a constant load of 25-30% for the period from March to June 2022 inclusive.

Gas consumption at GTG

Calculation of gas at GTG is performed based on actual gas consumption for the past period, taking into account unforeseen gas losses.

At present all consumers of electric power are engaged and the OIRSP is operating at maximum capacity, the increase in gas consumption at GTG occurs only during periods of oil shipment, the reduction of electric power generation should be envisaged after the completion of well construction.

The volume of gas required to generate the necessary electricity in the period is determined by the formula (2.13):

$$V_{GTGforec} = (q_{GTGav.day.} * N + q_{\mathrm{GTGav.day.K}} * N + V_{\mathrm{GTG}s}) * 10^{-6}, \qquad (2.13)$$

where $V_{GTGforec}$ – forecast gas consumption at GTG for the period, mln m^3/period;

$q_{GTGav.day.}$– average daily gas consumption at GTG during drilling, including unforeseen gas losses due to unscheduled GTG shutdowns or GTG switching to diesel fuel, m3/day;

$q_{GTGav.day.K}$ – average daily gas consumption at GTG in the period after completion of well construction, including unforeseen gas losses due to unscheduled GTG shutdowns or GTG transition to diesel fuel, m3/day. The procedure for determining $q_{GTGav.day.K}$ is identical to the algorithm described below for calculating average daily gas consumption during well drilling;

V_{GTGs} – volume of gas consumed by GTG during the period of oil shipment to the tanker, m^3;

N – number of days in the period, it is necessary to count separately the days of work when drilling wells and without drilling (K), days.

The average daily gas consumption for the forecast is determined based on actual data for the past period, taking into account unforeseen gas losses associated with a decrease in gas consumption by GTG. In this case, equality (2.14) is fulfilled:

$$q_{GTGav.day.} = q_{GTGav.day.f} \tag{2.14}$$

where $q_{GTGav.day.f}$ – average daily actual gas consumption at GTG including unforeseen gas losses associated with a decrease in gas consumption by, m^3/day.

Average daily actual gas consumption at GTG including unforeseen losses is determined by the formula (2.15):

$$q_{GTGav.day.f} = \frac{V_{GTG.f}}{N_f}, \tag{2.15}$$

where $V_{GTG.f}$ – actual volume of gas, taking into account unforeseen losses, used to generate electricity over the past period, m^3;

N_{f} – number of days in the period.

According to the results of the actual indicators, unforeseen gas losses occur when one or two GTG are switched to diesel fuel, or full stoppage of generators. Unforeseen gas losses at GTG are determined according to the actual operation of GTG for the past period by summing all gas losses at GTG stops and transitions to diesel fuel (2.16):

$$\boldsymbol{L_{GTG}} = \sum \boldsymbol{L_{day}} \tag{2.16}$$

where L_{GTG} – gas losses over the past period, m3;

$\sum L_{day}$ – total daily gas losses over the past period, m^3.

Daily gas losses are calculated by the formula (2.17):

$$L_{day} = q_{GTGav.day.max} - q_{GTGday.f} \qquad (2.17)$$

where $q_{GTGday.fact}$ – actual daily gas consumption during the period of reduced gas consumption by GTG.

Example:

Over the past month (31 days) the GTG operated without unforeseen stops for 29 days, and the average daily maximum flow rate (including oil shipments) was 166,000 m3 [36].

On the 1st day one GTG was switched to diesel fuel and its actual gas consumption was 40,000 m3;

On the first day there was a full transition of GTG to diesel fuel due to an unscheduled compressor shutdown, both GTGs operated on diesel fuel for a full day.

Thus, the losses for the past month are:

In 1 day 166,000/2 -40,000 = 43,000 m^3;

For 1 day (full GTG-to-DF transition) = 166,000 m^3;

Total losses for the period were 43,000 + 166,000 = 209,000 m^3.

If there are no unforeseen losses of gas for the past period, the average daily forecast gas flow rate is determined by the formula (2.18):

$$q_{GTGav.day.} = q_{GTGav.day.max} * k_{ex.GTG} \qquad (2.18)$$

where $\boldsymbol{q_{GTGav.day.max}}$- average daily maximum actual gas consumption at GTG over the past period, m^3/day;

$\boldsymbol{k_{ex.GTG}}$ – GTG operating rate.

The average daily maximum actual gas consumption for the past period is determined by the formula (2.19):

$$\boldsymbol{q_{GTGav.day.max} = \frac{V_{GTG.max}}{N_{max}}} \qquad (2.19)$$

where $\boldsymbol{V_{GTG.max}}$- maximum volume of gas used to generate electricity over the past period, m^3;

$N_{\max}$ – number of days of gas consumption by GTG without unscheduled shutdowns and conversions to D/F.

To determine the number of days of GTG operation without unforeseen losses, the days of GTG operation without unscheduled stops and transfers to D/F are selected.

The maximum volume of gas used to generate electricity in the past period is (2.20):

$$V_{GTGmax} = V_{GTG.f} + L_{GTG} \qquad (2.20)$$

The coefficient of GTG operation is determined by the formula (2.21):

$$k_{ex.GTG} = \frac{q_{GTGav.day.f}}{q_{GTGav.day.max}} \qquad (2.21)$$

Volume of gas consumed by GTG during the period of oil shipment to the tanker

During periods of oil shipment to the tanker, gas consumption by GTG increases, according to the actual changes in gas consumption for 2021, the average statistical volume of gas consumed by GTG per full batch of oil (**q**$_s$), equal to about 30,000 m^3 is determined.

To determine the change in the amount of gas consumed by GTG, taking into account oil shipments, it is necessary to determine the number of full batches of oil in the forecast period [36].

$$К_{CB} = \frac{M_o}{67000} \qquad (2.22)$$

where $К_{CB}$ – number of complete batches, pcs.;

M_o – predicted amount of oil production, tons;

67000 – the amount of a full batch of oil loaded into the tanker, tons.

The volume of gas consumed by GTG during the period of oil shipment to the tanker is equal to:

$$V_{GTGs} = \Delta К_{CB} * q_s \qquad (2.23)$$

where $\Delta К_{CB}$ – the difference of the number of full shipments of crude oil in the forecast period to the number of shipments in the previous period. As of 2021, 54 full shipments of crude oil were shipped (2.24).

$$\Delta К_{CB} = К_{CB} - 54 \qquad (2.24)$$

According to the results of actual indicators for 2021:

- Average daily actual gas consumption at GTG including unforeseen losses equals 164,718 m^3/day;
- The coefficient of operation of the GTG is 0.99;
- The average daily forecast gas flow rate at GTG upon completion of well construction is 159,412 m^3/day.

Based on this calculation methodology, we can make Table 2.3, which will show the current and projected volumes of production and consumption of associated petroleum gas [36].

№ n/a	INDICATORS	Unit of measure	2021	2022	2023	2024	2025	2026	2027
			fact	fact	fact/ forecast	forecast	forecast	forecast	forecast
1	**ASSOCIATED PETROLEUM GAS PRODUCTION**	**mln.m3**	**211.503**	**213.982**	**202.018**	**203.458**	**216.368**	**214.134**	**212.261**
2	**USE OF ASSOCIATED PETROLEUM GAS**	**mln.m3**	**67.965**	**69.527**	**68.690**	**64.980**	**69.378**	**69.169**	**67.146**
2.1	**Technological losses total**	**mln.m3**	0.008	0.008	0.007	0.007	0.007	0.007	0.007
	Technological loss norm	%	0.004	0.004	0.003	0.003	0.003	0.003	0.003
2.2.	**Commercial gas delivery,total**	**mln.m3**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**
2.3.	**Gas consumption for own needs, total**	**mln.m3**	**67.957**	**69.519**	**68.6825**	**64.9729**	**69.3707**	**69.1625**	**67.1399**
2.3.1.	Gas consumption for own fuel needs	**mln.m3**	**66.849**	**68.652**	**67.8218**	**64.1617**	**68.5031**	**68.2949**	**66.2723**
2.3.1.1.	For oil treatment technology	mln. m3	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.3.1.2.	For heat production (boiler houses)	mln. m3	11.010	13.185	11.952	11.779	11.736	11.736	11.736
2.3.1.3.	For heat production (heat generators, methanol regeneration, etc.)	mln. m3	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2.3.1.4.	For electricity generation	mln. m3	55.840	55.467	55.869	52.382	56.767	56.558	54.536
2.3.2.	Gas consumption for own non-fuel needs	**mln.m3**	**1.1075**	**0.8676**	**0.8608**	**0.8112**	**0.8676**	**0.8676**	**0.8676**
2.3.2.1.	On regulated combustion (purging, backpressure, standby combustion)	mln. m3	1.1075	0.8676	0.861	0.811	0.868	0.868	0.868
3	**ROUTINE COMBUSTION**	**mln.m3**	**143.5387**	**144.4552**	**133.3287**	**138.4782**	**146.9901**	**144.9646**	**145.1145**
3.1	- including HPT	mln. m3	118.783	121.354	110.956	115.231	122.313	120.628	120.753
3.2	- including LPT	mln. m3	24.7557	23.1012	22.372	23.248	24.677	24.337	24.362
4	**ASSOCIATED PETROLEUM GAS UTILIZATION**	%	**32.134**	**32.492**	**34.002**	**31.938**	**32.065**	**32.302**	**31.634**

Table 2.3 – Current and projected volumes of APG use

CHAPTER 3: Technological scheme of APG utilization on the Prirazlomnaya Platform

Based on the above calculations of consumption and combustion of associated petroleum gas, it was proposed to use the existing scheme of enhanced oil recovery and utilization of associated petroleum gas.

To carry out the calculations, the technological scheme with the use of ejectors, developed on the basis of patent No. 2293178, presented in figure 3.1, was chosen. [38]

A brief description of this circuit

There is a description of the device for the impact on the formation of the water-gas mixture, which includes lines of water, gas and surfactants (surfactants), as well as an ejector and a line of water-gas mixture injection [19]. However, this device is limited in its functionality and application due to the inability to create high pressures of water-gas mixture injection using the ejector.

There is also a system for influencing the reservoir with water-gas mixture, which includes a power pump, jet device, booster pump, injection wells, a tank with foaming surfactants, adjustable valves, water supply line to the power pump, water injection line, gas pumping line, surfactant supply line and water-gas mixture injection line [20]. However, this system also has low efficiency and limited application area due to the inability to operate at high gas flow rates.

Thus, the proposed devices for the impact on the reservoir water-gas mixture have their limitations and do not provide the necessary efficiency at high injection pressures or gas flow rates.

The main purpose of this invention is to increase efficiency and expand the field of application of water-gas impact on the deposit by increasing gas productivity and efficiency factor (coefficient of performance) with increasing pressure at the intake of the jet device.

To achieve higher efficiency and expand the field of application of the system for water-gas impact on the reservoir, it is proposed to use the following configuration. The system includes a production well separator, which separates products into oil, gas and water, and a gas injector. The inlet port of the gas injector is connected to the gas outlet line of the separator, and its outlet line is connected to the intake of the jet.

In the first version of the system that was proposed for the calculation, the gas injector has a design that combines a liquid-gas separator and an ejector. The ejector is placed so that the gas from the separator flows to its inlet, and then the ejector blows a mixture of water and gas into the liquid-gas separator. The liquid-gas separator forms a closed circuit to circulate water and heats this water, gas and water-gas mixture.

Thus, the proposed invention improves efficiency and expands the field of application of the system for water-gas stimulation by using a special configuration of the product separator and gas injector.

This invention achieves increased efficiency and extends the scope of the system for water-gas stimulation by using several improvements [21].

In order to achieve increased efficiency of the system, the power pump water supply line is connected to the production well separator water discharge line and/or to the water intake well through a liquid-gas separator. A booster pump is installed in the separator water discharge line and a submersible pump is installed in the intake well. In addition, the liquid-gas separator is equipped with a condensate drain line. The condensate drain line can be connected to the receiving chamber of the jet unit, power pump intake, oil pipeline or cylinder filling line [22].

A dosing pump can be installed on the surfactant (surfactant) supply line. A multistage centrifugal pump as a booster pump is used to pressurize the system. Such a pump can be installed horizontally driven by a surface motor or vertically in a sump driven by a surface or submersible motor. The pump motors can be connected to frequency converters.

Thus, the proposed invention involves a number of improvements, including connecting the water supply and discharge lines, using a booster and submersible pump, using a liquid-gas separator with a condensate drain line, and installing a multistage centrifugal pump with frequency converters to increase system efficiency (Figure 3.1).

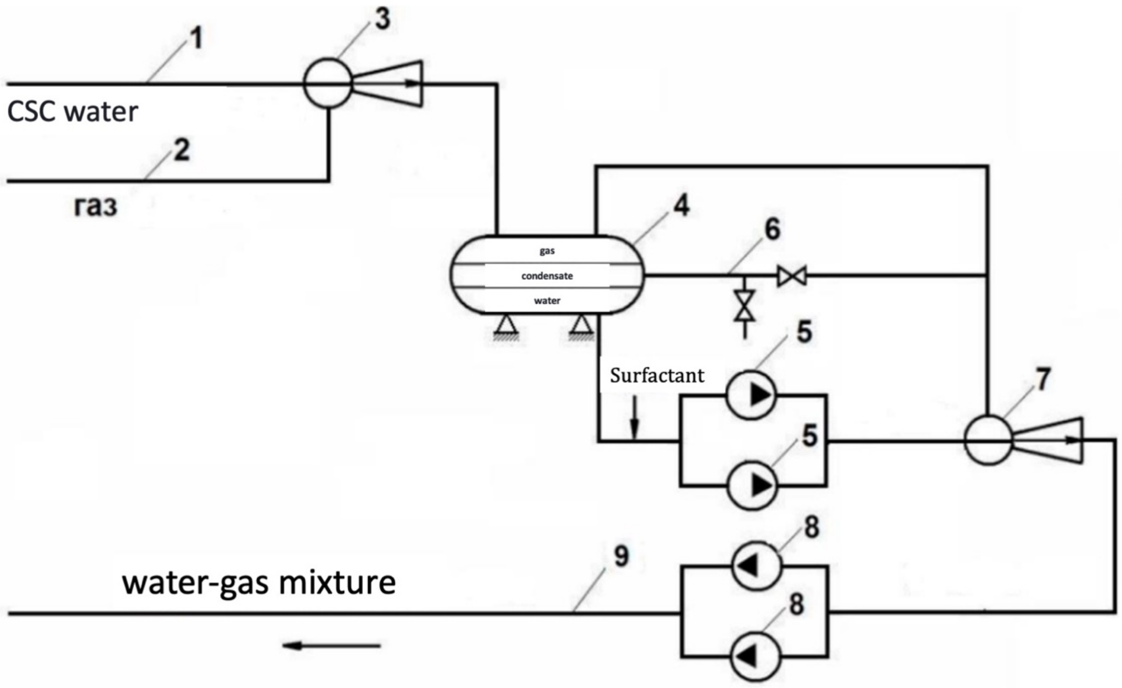

Figure 3.1 – Process diagram of pump-ejector system for water-gas impact

1 - water from the cluster pump station, 2 - low pressure gas line from booster pump station, 3 - ejector of the first compression stage, 4 - separator, 5, 8 - multistage pumps, 6 - condensate discharge line, 7 - ejector of the second compression stage, 9 - water line to the injection wells

Initial data

As a baseline, let's consider one of the injection wells at Prirazlomnaya (Table 3.1), since all injection wells have similar characteristics (Figure 3.2).

Name	Identification	Value
Gas content of the mixture in formation conditions	α	25%
Water density under standard conditions	ρ_w	1008
Gas density at standard conditions	ρ_g	1,224
Injection wellhead pressure during gas injection	P_{wh}	26 MPa
Pumped water volume	Q_w	420 m^3/h
Well depth	H_w	5835
Inside diameter of tubing	d_t	140 mm

Gas consumption under standard conditions	$Q_{g\ st.c.}$	1300 m^3/hour
Gas pressure at intake	P_{int}	0,3 MPa

Table 3.1 – Initial data for calculation

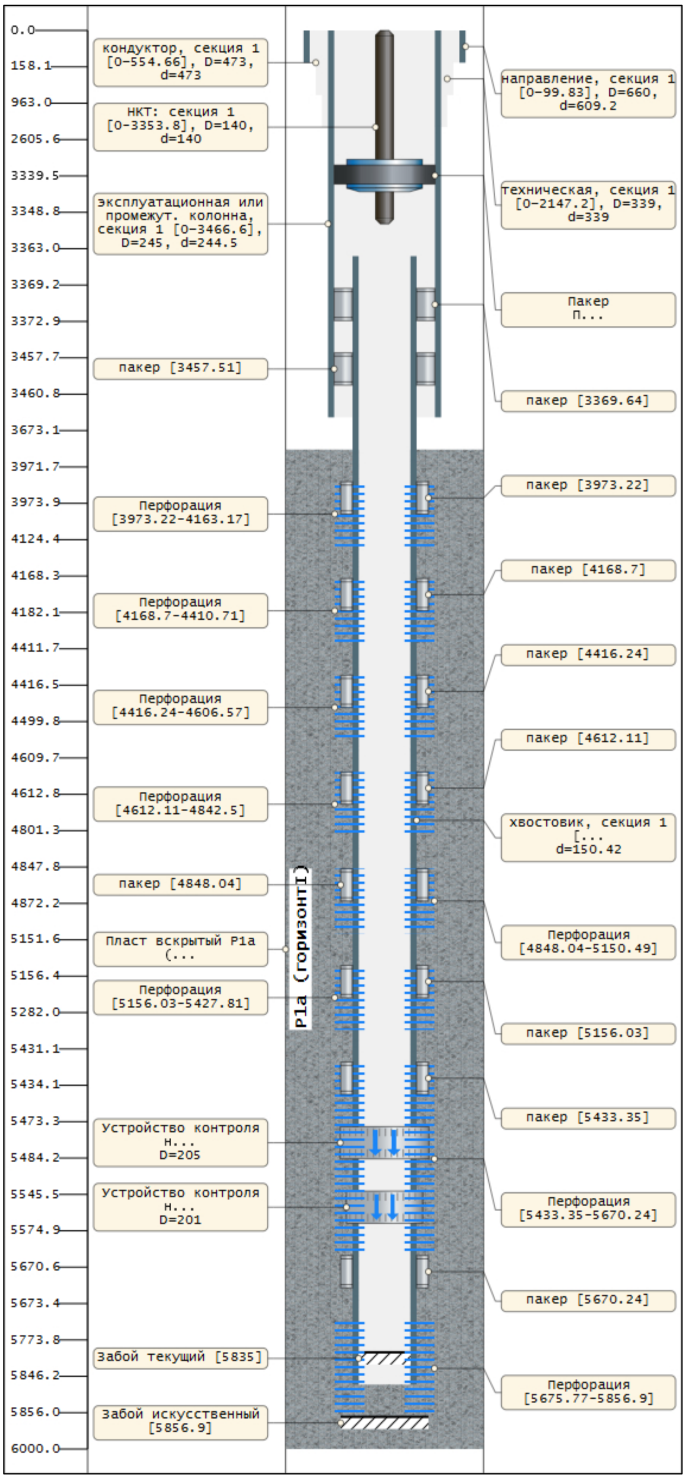

Figure 3.2 – Production well design

Calculation of hydrostatic pressure at the bottom hole (3.1):

$$P_{hyd} = \rho_w \times g \times H_w \quad (3.1)$$

$$P_{hyd} = 1008 \times 9{,}81 \times 5835 = 57{,}7\ MPa$$

Calculation of water velocity (3.2):

$$v_w = \frac{Q}{S} = \frac{Q_w \times 4}{t \times \pi \times d_t^2} \quad (3.2)$$

$$v_w = \frac{10080 \times 4}{86400 \times \pi \times 0{,}140^2} = 7{,}58\ \frac{m}{s}$$

Calculation of Reynolds number (3.3):

$$Re = \frac{v_w \times d_t \times \rho_w}{\mu} \quad (3.3)$$

$$Re = \frac{7{,}5 \times 0{,}14 \times 1008}{10^{-3}} = 1058400$$

The obtained value corresponds to the turbulent mode $Re > 10000$.

Calculation of zone boundaries (3.4, 3.5):

$$Lower\ boundary = 10\frac{d_t}{\Delta} = 10\frac{140}{0{,}1} = 14000 \quad (3.4)$$

$$Higher\ boundary = 500\frac{d_t}{\Delta} = 500\frac{140}{0{,}1} = 700000 \quad (3.5)$$

Calculation of the hydraulic resistance coefficient of the 2nd region of turbulent mode (3.6):

$$\lambda = 0{,}11 \times (\frac{68}{Re} + \frac{\Delta}{d_t})^{0{,}25} \quad (3.6)$$

$$\lambda = 0{,}11 \times (\frac{68}{1058400} + \frac{0{,}1}{140})^{0{,}25} = 0{,}672$$

Calculation of friction head losses (3.7):

$$h_{fr} = \lambda \times \frac{Hw}{d_t} \times \frac{v_w^2}{2g} \quad (3.7)$$

$$h_{fr} = 0{,}672 \times \frac{5835}{0{,}14} \times \frac{7{,}5^2}{2 \times 9{,}81} = 80{,}2\ m$$

Calculation of water pressure loss by friction (3.8):

$$P_{fr} = \rho_w \times g \times h_{fr} \quad (3.8)$$

$$P_{fr} = 1008 \times 9{,}81 \times 80{,}2 = 7{,}93 \times 10^5\ Pa$$

Calculation of total bottom hole pressure (3.9):

$$P_{wb} = P_{hyd} + P_{fr} + P_{wh} \quad (3.9)$$

$$P_{wb} = 57{,}7 + 0{,}793 + 26 = 84{,}4\ MPa$$

So that the injectivity of the well, when using as a working agent gas-liquid mixture instead of water, did not change the pressure at the bottom of the well must remain at the same level and equal to 84.4 MPa. Gas-liquid mixture flow rate remains equal to water flow rate, i.e. 10080 m3 /day. It is necessary to recalculate hydrostatic pressure at the bottom hole.

Calculation of gas flow rate at reservoir pressure of 26.23 MPa (3.10):

$$Q_{g.res} = Q_w \times \alpha \tag{3.10}$$

$$Q_{g.res} = 10080 \times 0{,}25 = 2520\ m^3/day$$

Calculation of necessary water consumption (3.11):

$$Q_w = Q_w - Q_{g.res} \tag{3.11}$$

$$Q_w = 10080 - 2520 = 7560\ m^3/day$$

Recalculation of gas flow rate for bottom hole pressure of 84.4 MPa:

$$Q_{g.wb} = 1230\ m^3/day$$

Calculation of gas content at the bottom hole (3.12):

$$\alpha_{wb} = \frac{Q_{g.wb}}{Q_{g.wb}+Q_w} \tag{3.12}$$

$$\alpha_{wb} = \frac{1230}{1230 + 7560} = 14\%$$

Calculation of mixture density at the bottom hole (3.13):

$$\rho_{mix\ wb} = \rho_{wb} \times (1 - \alpha_{wb}) + \rho_g \times P_{wb} \times \alpha_{wb} \tag{3.13}$$

$$\rho_{mix\ wb} = 1008 \times (1 - 0{,}14) + 1{,}224 \times 844 \times 0{,}14 = 954{,}5\ \frac{kg}{m^3}$$

Calculation of pressure losses due to friction forces for the water-gas mixture (βz=14%) begins with the calculation of the mixture velocity (3.14):

$$v_{mix} = \frac{Q_w+Q_{g.wb}}{S} = \frac{(Q_w+Q_{g.wb})\times 4}{t\times\pi\times {d_t}^2} \tag{3.14}$$

$$v_{mix} = \frac{(7560 + 1230) \times 4}{86400 \times \pi \times 0{,}140^2} = 2{,}87\ \frac{m}{s}$$

Calculation of the Reynolds number for the water-gas mixture (3.15):

$$Re = \frac{v_{mix}\times d_t\times \rho_{mix.wb}}{\mu} \tag{3.15}$$

$$Re = \frac{2{,}87 \times 0{,}14 \times 954{,}5}{1{,}41 \times 10^{-3}} = 3057120$$

Calculation of the hydraulic resistance coefficient (3.16):

$$\lambda = 0{,}11 \times (\frac{68}{Re} + \frac{\Delta}{d_{\text{НКТ}}})^{0{,}25} \qquad (3.16)$$

$$\lambda = 0{,}11 \times (\frac{68}{3057120} + \frac{0{,}1}{140})^{0{,}25} = 0{,}772$$

Calculation of friction head losses (3.17):

$$h_{fr1} = \lambda \times \frac{Hw}{d_t} \times \frac{v_m^2}{2g} \qquad (3.17)$$

$$h_{fr1} = 0{,}772 \times \frac{5835}{0{,}14} \times \frac{2{,}87^2}{2 \times 9{,}81} = 50{,}2\ m$$

Calculation of pressure losses (3.18):

$$P_{fr1} = \rho_m \times g \times h_{fr} \qquad (3.18)$$

$$P_{fr1} = 1008 \times 9{,}81 \times 50{,}2 = 5{,}9 \times 10^5\ Pa$$

Now we need to set the wellhead pressure, take 32 MPa, and calculate the gas flow rate at it:

$$Q_{g\ Pwh32} = Q_{g.wb} \times \frac{P_{wb}}{P_{wh32}} \qquad (3.19)$$

$$Q_{g\ Pwh32} = 1230 \times \frac{84{,}4}{32} = 1983\ m^3/day$$

Calculation of gas content at the wellhead at 32 MPa (3.20):

$$\alpha_{wh32} = \frac{Q_{gPwh32}}{Q_{gPwh32} + Q_w} \qquad (3.20)$$

$$\alpha_{wh32} = \frac{1983}{1983 + 7560} = 19\%$$

Calculation of water-gas mixture density at the wellhead at 32 MPa (3.21):

$$\rho_{m\,wh} = \rho_w \times (1 - \alpha_{wh32}) + \rho_g \times P_{wh32} \times \alpha_{wh32} \qquad (3.21)$$

$$\rho_{m\,wh} = 1008 \times (1 - 0{,}19) + 1{,}224 \times 320 \times 0{,}19 = 834{,}6\ \frac{kg}{m^3}$$

Calculation of hydrostatic downhole pressure during water-gas mixture injection at 32 MPa wellhead pressure (3.22):

$$P_{hyd\ m32} = \frac{\rho_{m\,wb} + \rho_{m\,wh}}{2} \times g \times H_{wh} \qquad (3.22)$$

$$P_{hyd\,m32} = \frac{954{,}5 + 834{,}6}{2} \times 9{,}81 \times 5835 = 47{,}8\,MPa$$

Calculation of water-gas mixture pressure loss due to friction (βwh=19 %).

Calculation of mixture velocity at 32 MPa wellhead pressure (3.23):

$$v_m = \frac{Q_w + Q_{gPwh32}}{S} = \frac{(Q_w + Q_{gPwh32}) \times 4}{t \times \pi \times {d_t}^2} \tag{3.23}$$

$$v_m = \frac{(7560 + 1983) \times 4}{86400 \times \pi \times 0{,}140^2} = 3{,}95\,\frac{m}{s}$$

Calculation of Reynolds number at a 32 MPa orifice pressure (3.24):

$$Re = \frac{v_{m2} \times d_t \times \rho_{m.wh}}{\mu} \tag{3.24}$$

$$Re = \frac{3{,}95 \times 0{,}14 \times 834{,}6}{1{,}683 \times 10^{-3}} = 2159134$$

Calculation of the hydraulic resistance coefficient at the 32 MPa wellhead pressure (3.25):

$$\lambda = 0{,}11 \times \left(\frac{68}{Re} + \frac{\Delta}{d_t}\right)^{0{,}25} \tag{3.25}$$

$$\lambda = 0{,}11 \times \left(\frac{68}{2159134} + \frac{0{,}1}{140}\right)^{0{,}25} = 0{,}872$$

Calculation of friction losses at 32 MPa wellhead pressure (3.26):

$$h_{fr2} = \lambda \times \frac{Hwh}{d_t} \times \frac{v_{m2}^2}{2g} \tag{3.26}$$

$$h_{fr2} = 0{,}872 \times \frac{5835}{0{,}14} \times \frac{3{,}95^2}{2 \times 9{,}81} = 63\,m$$

Calculation of pressure friction losses at 32 MPa wellhead pressure (3.27):

$$P_{fr2} = \rho_{m\,wh} \times g \times h_{fr2} \tag{3.27}$$

$$P_{fr2} = 834{,}6 \times 9{,}81 \times 63 = 6{,}5 \times 10^5\,Pa$$

Calculation of average friction pressure losses at a 32 MPa wellhead pressure (3.28):

$$P_{fr32} = \frac{P_{fr1} + P_{fr2}}{2} \tag{3.28}$$

$$P_{fr32} = \frac{5{,}9 \times 10^5 + 6{,}5 \times 10^5}{2} = 6{,}2 \times 10^5\,Pa$$

Calculation of full downhole pressure at 32 MPa wellhead pressure (3.29):

$$P_{wb32} = P_{hyd\,m\,32} + P_{fr\,32} + P_{wh\,32} \qquad (3.29)$$

$$P_{wb32} = 47{,}8 + 0{,}62 + 32 = 80{,}42\ MPa$$

Wellhead pressure of 32 MPa is considered satisfactory, because it is less bottomhole pressure than water alone (84.4 MPa)

Next, proceed to the calculation and selection of the necessary process equipment for the pump-ejector system.

Calculation of gas consumption at the inlet of the first stage ejector (3.30):

$$Q_{g\ int\ 1} = \frac{Q_{g\ st.cond} \times P_{g\ st.cond.}}{P_{int1}} \qquad (3.30)$$

$$Q_{g\ int\ 1} = \frac{31200 \times 0{,}1}{0{,}3} = 7800\ \frac{m^3}{day}$$

Calculation of the Injection Coefficient of the First Stage Ejector:

$$K_{e1} = \frac{Q_{g\ int\ 1}}{Q_w} \qquad (3.31)$$

$$K_{e1} = \frac{7800}{10080} = 0{,}77$$

Set the pressure of the mixture after the ejector of the first stage equal to 1.6 MPa.

Efficiency of ejectors, according to studies, we take equal η=0,35 for the ejector of the first stage and η=0,45 for the ejector of the II compression stage.

Calculation of fluid working pressure upstream of the first stage ejector nozzle (3.32):

$$P_{op1} = P_{m1} + \frac{K_{e1} \times P_{int\ 1} \times ln\frac{P_{m1}}{P_{int1}}}{\eta} \qquad (3.32)$$

$$P_{op\ 1} = 1{,}6 + \frac{0{,}77 \times 0{,}3 \times ln\frac{1{,}6}{0{,}3}}{0{,}35} = 27{,}54\ MPa$$

The pressure at the inlet of the II stage ejector is 3 MPa.

Calculation of gas consumption at the intake (3.33):

$$Q_{g\ int\ 2} = \frac{Q_{g\ st.cond} \times P_{g\ st.cond.}}{P_{int2}} \qquad (3.33)$$

$$Q_{g\ op1} = \frac{31200 \times 0{,}1}{3} = 780\ \frac{m^3}{day}$$

Calculation of the II-stage ejector injection coefficient (3.34):

$$K_{e2} = \frac{Q_{g\ int\ 2}}{Q_w} \qquad (3.34)$$

$$K_{e2} = \frac{780}{10080} = 0{,}077$$

The pressure of the water-gas mixture after the ejector of the II compression stage is taken as 4.5 MPa.

Calculation of gas inlet to pumps (3.35):

$$Q_{g\ int} = \frac{Q_{g\ st.cond} \times P_{g\ st.cond.}}{P_{int\ 1}} \qquad (3.35)$$

$$Q_{g\ int} = \frac{31200 \times 0{,}1}{4{,}5} = 5790\ \frac{m^3}{day}$$

Calculation of the gas content of the mixture αinlet at the pump inlet (3.36):

$$\alpha_{int} = \frac{Q_{g\ int}}{Q_{g\ int} + Q_w} \qquad (3.36)$$

$$\alpha_{int} = \frac{5790}{5790 + 10080} = 0,36$$

Gas content is within allowable limits for modern centrifugal pumps. Calculation of liquid working pressure before the ejector nozzle II stage (3.37):

$$P_{op\ 2} = P_{m2} + \frac{K_{e2} \times P_{int\ 2} \times ln\frac{P_{m2}}{P_{int2}}}{\eta} \qquad (3.37)$$

$$P_{op\ 1} = 1{,}6 + \frac{0{,}077 \times 1{,}6 \times ln\frac{4{,}5}{1{,}6}}{0{,}45} = 31{,}6\ MPa$$

Calculation of the ejector pump pressure of stage II (3.38):

$$P_{pump2} = P_{op2} - P_{int2} \qquad (3.38)$$

$$P_{pump2} = 31{,}6 - 1{,}6 = 30\ MPa$$

To ensure the required technological parameters of the operating mode of equipment, it was selected two pumps type CNS-300-600, which at a supply of 10080 m^3/ day will provide the required head of 2600 m total power N-pumps, consumed pumps will be 2.4 MW

Pump operation parameters after the II stage ejector: P1=4,5 MPa, α_{int}=0,36, Q_w=10080 m^3/day, P2=32 MPa.

Calculation of gas supply (3.39):

$$Q_{g\ av} = \frac{Q_{g\ st..cond.} P_{g\ st.cond.}}{P_2 - P_1} \times ln\frac{P_2}{P_1} \tag{3.39}$$

$$Q_{g\ av} = \frac{31200 \times 0{,}1}{32 - 4{,}5} \times ln\frac{32}{4{,}5} = 7200\ \frac{m^3}{day}$$

Calculation of pump flow for mixture (3.40):

$$Q_{av} = Q_{g\ av} + Q_w \tag{3.40}$$

$$Q_{av} = 10200\ \frac{m^3}{day}$$

Calculation of the mass flow rate of the mixture (3.41):

$$M_{qm} = Q_w \times \rho_w + Q_{g\ st.cond.} \times \rho_g \tag{3.41}$$

$$M_{qm} = 10800 \times 1008 + 31200 \times 1{,}224 = 10{,}1 \times 10^6\ \frac{kg}{day}$$

Calculation of average mixture density (3.42):

$$\rho_{m\ av} = \frac{M_{q\ m}}{Q_{av}} \tag{3.42}$$

$$\rho_{m\ \text{средняя}} = \frac{10{,}1 \times 10^6}{10200} = 983\ \frac{kg}{m^3}$$

Calculation of the average head of the mixture pump (3.43):

$$h_{av} = \frac{P_2 - P_1}{\rho_{m\ av} \times 10} \tag{3.43}$$

$$h_{av} = \frac{(32 - 4{,}5) \times 10^6}{983 \times 10} = 2797\ m$$

To ensure the required technological parameters of the equipment operation mode, the pump of ECN-1340-1280 type was selected, developing at the supply of 10080 m 3 / day, the head of 2797 m. Power consumption on water is equal to 800 kW. Calculation of power at mixture (3.44):

$$N_{pump\ m} = \frac{N_{pump} \times \rho_{m\ av}}{1000} \tag{3.44}$$

$$N_{pump\ m} = \frac{0{,}8 \times 983}{1000} = 0{,}78\ MW$$

During the calculations, the necessary technological equipment for the system of pumping-jet stimulation in order to increase the efficiency of oil production and utilization of associated petroleum gas was determined [23].

Using methods of analysis and modeling, calculations were made to determine the suitable equipment for the implementation of the system of stimulation. This equipment is able to provide the required parameters and processes to achieve the objectives of the system, such as enhanced oil recovery and associated petroleum gas utilization.

The results of the calculations allowed us to choose the optimal technological equipment, taking into account the given parameters and requirements for the system of formation stimulation. This allows the efficient use of resources and achieve the desired results in the process of oil production and gas utilization, contributing to more efficient operation in the field.

The necessary equipment is:

- first compression stage ejector with an injection ratio of 0.77;
- second stage ejector with an injection coefficient of 0.077;
- pump type CNS-300-600;
- ECN-1340-1280 type pump.

Liquid flow rate is 10080 m^3/day, gas flow rate under standard conditions is 31200 m^3/day, pressure at the wellhead of the injection well is 32 MPa. Total power consumed by the pumps is 3.2 MW.

This scheme can be applicable only in case of complete technical redesign of the pumping equipment on the platform, since the current pumps, which are functioning today, do not provide for the use of this technological scheme. Also, this technological scheme requires quite a large working area, which in the conditions of the operating production platform is extremely critical. The entire working space on the platform is used at 100%.

In this regard, a scheme was developed and proposed using the current pumping equipment as well as an additionally designed ejector and an additional booster pump, manufactured by the Russian company Novomet Perm. "Novomet Perm" is a Russian company that has considerable experience in utilization of associated petroleum gas and development of relevant equipment.

Novomet Perm specializes in creating innovative solutions for the efficient utilization of associated petroleum gas, which used to be frequently flared, causing significant environmental and economic damage. Thanks to the development of new technologies and the use of advanced approaches, the company enables the maximum use of this gas by offering solutions that facilitate its collection, purification and subsequent use in various processes.

One of the key advantages of Novomet Perm is the development of specialized equipment capable of efficiently handling associated petroleum gas. This includes gas pumping units, gas purification systems, gathering and transportation systems, as well as engineering solutions for optimal integration of equipment into production processes (Figure 3.4).

The equipment developed by Novomet Perm is characterized by high efficiency and reliability, as well as compliance with modern norms and standards of environmental safety. It makes it possible to significantly reduce greenhouse gas emissions into the atmosphere, reduce losses of valuable energy resources and provide economic benefits to oil companies (Figure 3.7).

The experience of Novomet Perm in utilization of associated petroleum gas and development of relevant equipment makes it a leading player in the Russian market and allows it to actively implement its technologies at oil fields, helping to reduce the negative impact on the environment and increase the energy efficiency of the industry [9].

Today Novomet has a line of equipment for transportation and utilization of APG, CO2 (Figure 3.3, Table 3.2).

Purpose:

- Pumping gas-liquid mixture and CO2
- (free gas content up to 95%)
- Delivery of crude products from the well to the collection point
- Transportation and utilization of associated petroleum gas

- Injection of a gas-liquid mixture into the formation

Benefits:

- Field service and repair capability
- Automatic control when connected to a control station
- Energy Efficiency
- Low cost of ownership

Application:

- Oil and Gas Industry
- Heat power
- Metallurgy and Mining
- Chemical industry

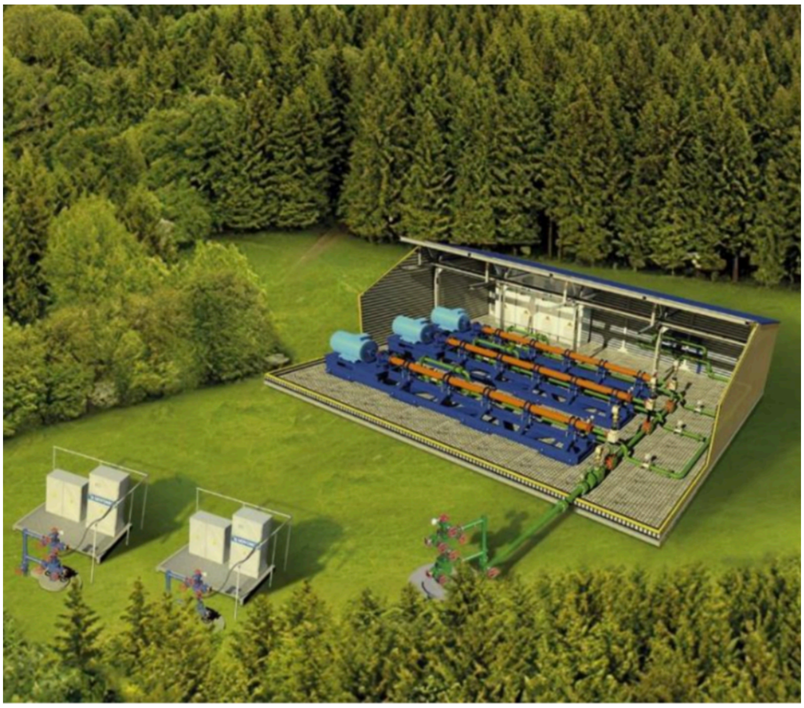

Figure 3.3 – Block pumping station

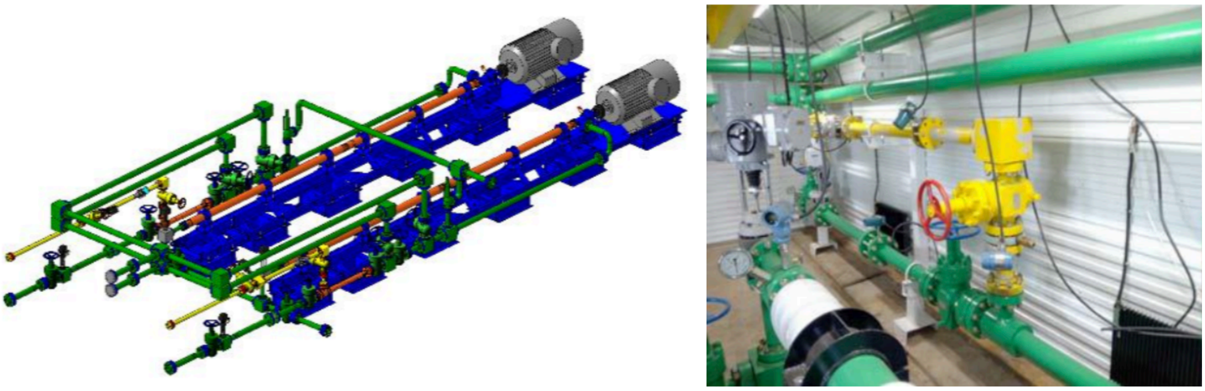

Figure 3.4 – Implemented gas utilization project by ORENBURGNEFT, 2014

The key parameters of the ORENBURGNEFT project installation (Figure 3.4):

- Inlet gas content 73.5%
- Fluid supply 1340 m^3/day
- Associated gas supply up to 3,720 m^3/day
- Pressure generated by the unit 350 m

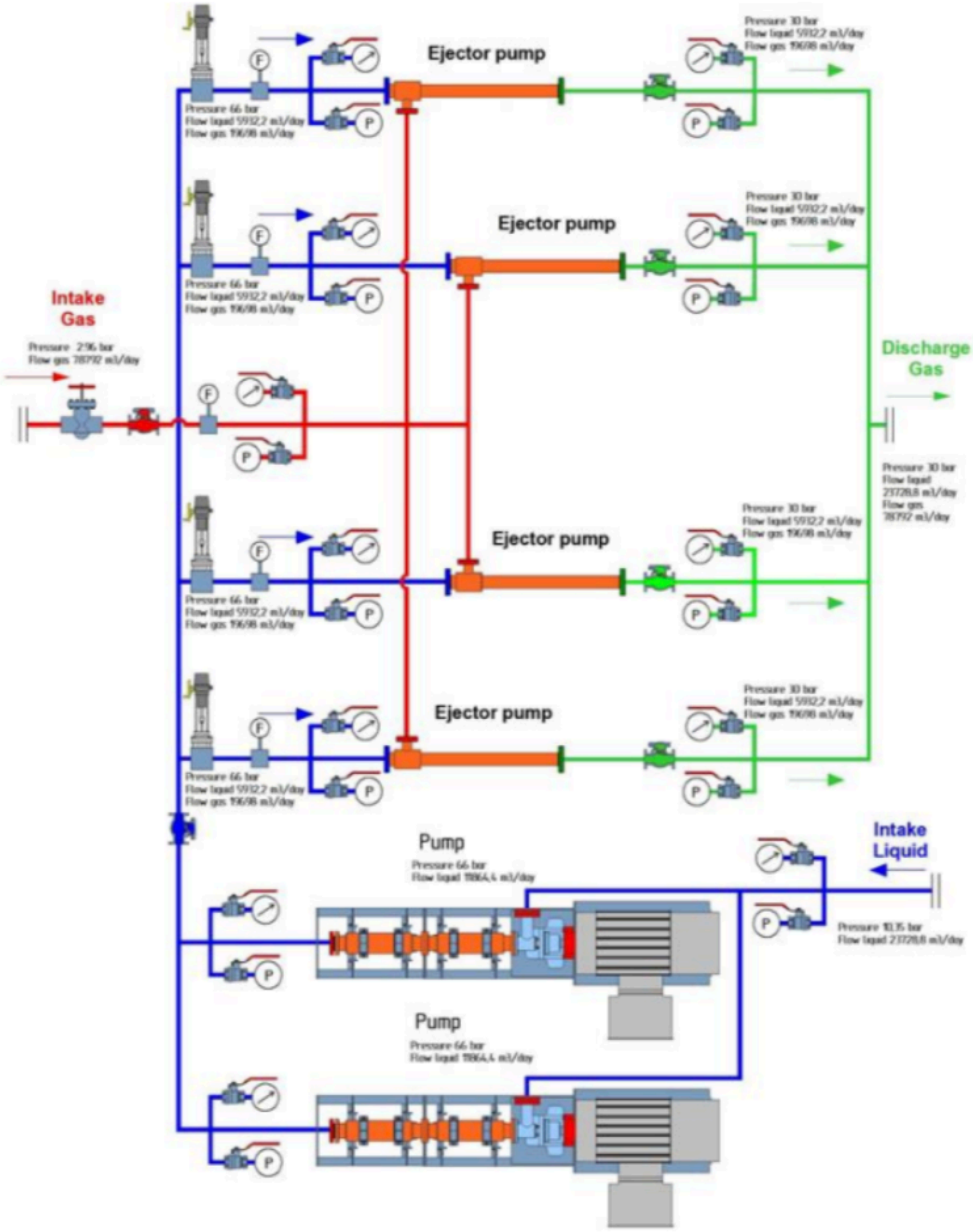

Figure 3.5 – Project implementation: gas utilization for geothermal project. Turkey - current project

Key characteristics of the installation implemented in Turkey (Figure 3.5):

- Inlet gas content 76.9%
- Liquid supply 23,729 m^3/day
- Liquid pressure 10.35 atm
- Associated gas supply up to 78,792 m^3/day
- Gas pressure 3 atm
- Pressure produced by the unit, 30 atm

Development of the scheme for enhanced oil recovery and APG utilization at the Prirazlomnaya Platform

Indicator	Value
Head pressure, (P_h)	26-32 MPa
Water supply, (Q_w)	10080–16500 m^3/day
Water pressure, (P_w)	3–4,5 MPa
Gas supply, (Q_g)	31200–104880 st.m^3/day
Gas pressure, (P_g)	0,3–0,45 MPa

Table 3.2 – Initial parameters for installation selection

At the moment the platform has a pump type CNS16-670, which has the following characteristics (Table 3.2.):

The main function of this pump is to increase the pressure of water from the pumping station for its further supply to the pipeline of the RPM. The daily water flow rate is 12000 m^3/day, the water comes to it with a pressure of 0.7 MPa. At the outlet pressure is 3 MPa.

I propose at this stage of the technological scheme to introduce an ejector, which will perform the main function - mixing of water and purified gas for further injection of gas-liquid mixture into the manifold (distributor) of injection wells.

Before calculating and selecting the required ejector, it is necessary to get acquainted with the principle of jet pump (ejector) operation.

Operation of liquid-gas ejector is based on the following principle, illustrated in Figure 3.6: active flow, having high speed, is directed from the nozzle device 1 to the receiving chamber 2, simultaneously with it the passive flow, which has lower pressure, is drawn. Then the active and passive flows mix in the mixing chamber 3, where they are intensively mixed. Before entering the mixing chamber 3, the flow appears as a liquid jet surrounded by gas and may partially or completely break up into droplets. The process of splitting the liquid jet into droplets and their interaction with the ejected air occurs as it moves along the working chamber, also known as the displacement chamber, and leads to a uniform distribution of gas bubbles in the flow after the working chamber, representing it in the liquid phase state as in Figure 3.7 [24].

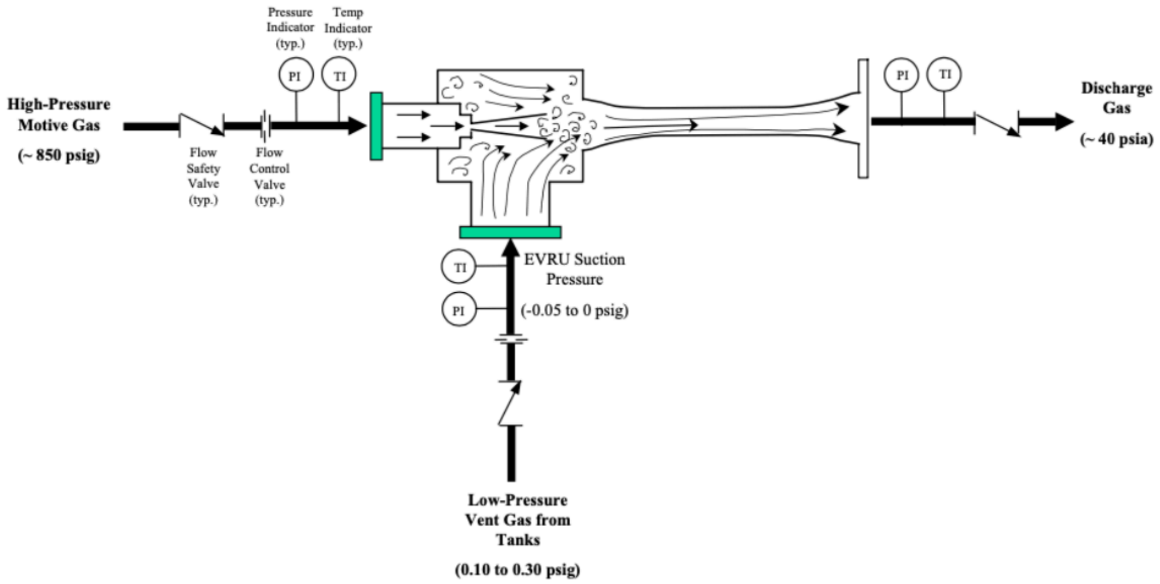

Figure 3.6 – Ejector operation principle

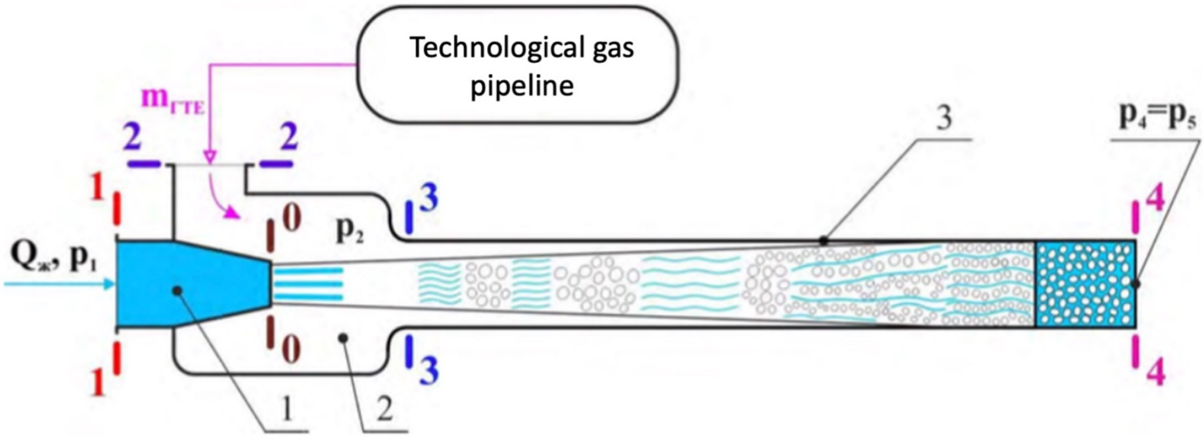

Figure 3.7 – Traditional ejector design

It is important to note that the velocity epureure at the entrance to the mixing chamber of the liquid-gas ejector is non-uniform. Close to the wall of the mixing chamber the minimum value of velocity is observed, while at the boundary of the liquid jet the maximum velocity is reached (Figure 3.8) [25].

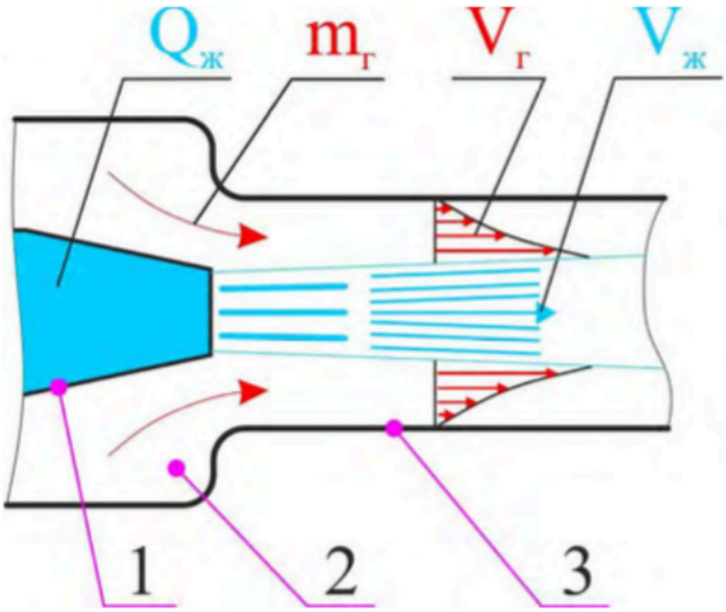

Figure 3.8 – Epureure of gas flow velocity at the entrance to the fluid working chamber.

Indicator	Value
Active flow pressure (water)	3 MPa
Active flow rate	12000 m^3/day
Passive flow pressure (gas)	0,45 MPa
Passive flow temperature	40 (degrees Celsius)

Table 3.3 – Input data for the ejector calculation

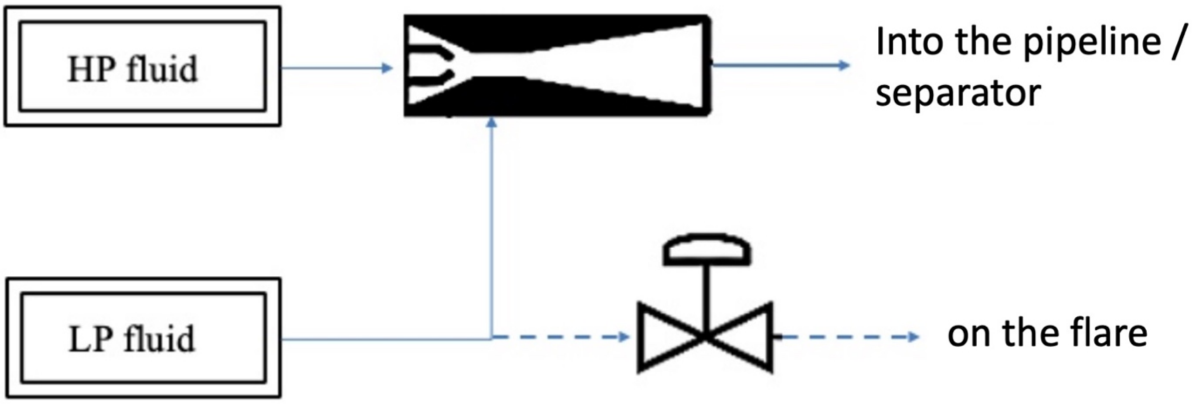

Figure 3.9 – Ejector connection diagram

Calculation of the ejector characteristics (Table 3.3)

Let's find the ratio of pressures at the nozzle device by the formula (3.45):

$$\varepsilon_{12} = \frac{P_1}{P_2} \tag{3.45}$$

$$\varepsilon_{12} = \frac{3}{0,45} = 6,42$$

where $P_1 = 3\ MPa$ – supply pressure (active pressure flow in front of the nozzle).

Then the compression ratio is determined by the formula (3.46):

$$\varepsilon_{52} = \frac{P_5}{P_2} \tag{3.46}$$

$$\varepsilon_{52} = \frac{0,101}{0,45} = 0,244$$

where $P_5 = P_{atm} = 0,101\ MPa$ – *backpressure.*

The jet parameter is found by the following formula (3.47):

$$\Gamma = 2 \times \varphi^2(\varepsilon_{12} - 1) \tag{3.47}$$

$$\Gamma = 2 \times 0,96^2(6,42 - 1) = 9,99$$

where $\varphi = 0,96$ – nozzle velocity factor.

The next step is to find the fluid flow rate at the outlet cross-section of the nozzle device (3.48):

$$u_w = \sqrt{\frac{P_2 \times \Gamma}{\rho_w}} \tag{3.48}$$

$$v_w = \sqrt{\frac{0{,}45 \times 9{,}99}{1008}} = 0{,}1\ \frac{m}{s}$$

where ρ_w - active flow fluid density (water).

Change of the fluid velocity at the nozzle device cut-off as a function of pressure P_2, is insignificant (Figure 3.8). As a percentage, this difference is 0.21%. Then the area of the outlet cross section of the nozzle orifice is found (3.49):

$$S_0 = \frac{Q_w}{v_w} \tag{3.49}$$

$$S_0 = \frac{0{,}14}{0{,}1} = 0{,}0005\, m^2$$

The shape of the nozzle is a tapering cone, so the area of the jet is equal to the area of the nozzle opening (3.50):

$$S_0 = S_n = 0{,}0005\ \ m^2 \tag{3.50}$$

The next step is the fluid velocity at the inlet to the working chamber (3.51):

$$v_{w3} = \frac{Q_w}{n} \tag{3.51}$$

$$v_{w3} = \frac{0{,}14}{0{,}0005} = 0,18\ \frac{m}{s}$$

The velocity of the air flow at the inlet to the working chamber is determined by the formula (3.52):

$$v_{g3} = \phi \times v_{w3} \tag{3.52}$$

$$v_{g3} = 0{,}9 \times 0{,}18 = 0{,}97\ \frac{m}{s}$$

where $\phi = 0{,}9$ – slip coefficient.

The coefficient of hydraulic friction we take $\lambda = 0{,}015$

Extreme characteristics indicating the limit modes of operation are shown in Figure 3.10.

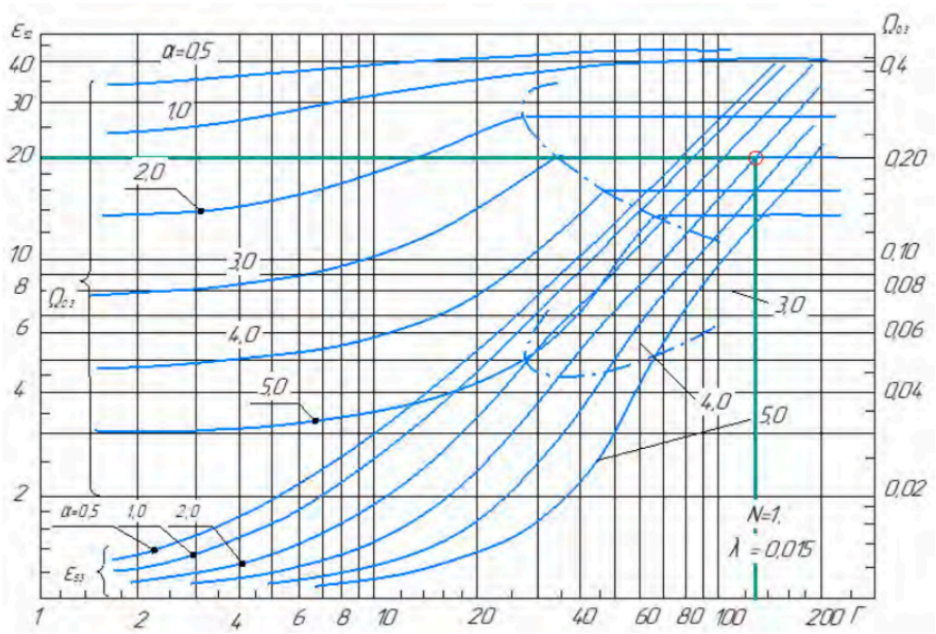

Figure 3.10 – Ejector characteristics

According to Figure 3.10, we determine the volumetric induction coefficient $\alpha = 2{,}5$ and the relative nozzle area $\Omega = 0{,}4$

Then the cross-sectional area of the working chamber is specified (3.53):

$$S_3 = \frac{S_n}{\Omega} \tag{3.53}$$

$$S_3 = \frac{0{,}0005}{0{,}4} = 0{,}0012$$

The diameter of the ejector nozzle orifice is according to formula (3.54):

$$d_0 = \sqrt{\frac{4 \times S_0}{\pi}} \tag{3.54}$$

$$d_0 = \sqrt{\frac{4 \times 0{,}0005}{3{,}14}} = 0{,}025\ m$$

The nozzle has a conical shape, therefore, the jet has the same shape and size, the diameter of the jet is equal to the diameter of the nozzle (3.55).

$$d_0 = d_n = 0{,}025\ m \tag{3.55}$$

Then we find the diameter of the working chamber (3.56):

$$d_3 = \sqrt{\frac{4 \times S_3}{\pi}} \tag{3.56}$$

$$d_3 = \sqrt{\frac{4 \times 0{,}0012}{\pi}} = 0{,}04\ m$$

The volume flow rate of the ejected gas is found by the formula (3.57):

$$Q_g = \alpha \times Q_w(13) \qquad (3{,}57)$$

$$Q_g = 2{,}5 \times 0{,}17 = 630\ \frac{m^3}{h}$$

The density of the ejected gas in the displacement chamber is determined by the formula (3.58):

$$\rho_{g2} = \frac{P_2}{R \times T} \qquad (3.58)$$

$$\rho_{g2} = \frac{0{,}45}{283 \times 313} = 1{,}224\ \frac{kg}{m^3}$$

where $P_2 = 0{,}45\ MPa$ – suction pressure (in the suction chamber)

$R = 287\ \frac{J\,K}{kg}$ – universal gas constant

$T = 313\ K$ – temperature of the ejected gas

The mass flow rate of the ejected gas is found by formula (3.59):

$$m_g = \rho_{g2} \times Q_g \qquad (3.59)$$

$$m_g = 1{,}224 \times 630 = 7000{,}43\ \frac{kg}{h}$$

The length of the working chamber is determined by the formula (3.60):

$$L_{34} = 28\left(1 - 0{,}2\frac{P_2}{P_5}\right) \times d_3 \qquad (3.60)$$

$$L_{34} = 28\left(1 - 0{,}2\frac{0{,}45}{0{,}101}\right) \times 0{,}04 = 0{,}5\ m$$

Specify the length of the working chamber by the formula (3.61):

$$L_{34} = d_3 \times \frac{c \times \alpha}{\Omega} \qquad (3.61)$$

$$L_{34} = 0{,}04 \times \frac{12 \times 2{,}5}{0{,}4} = 1{,}5\ m$$

where $c = 11..12$ – factor of proportionality.

Since the ratio of the length of the working chamber L_{34}, to the diameter of the working chamber d_3 is in the range of 5...10, then the result of formula (17) is the most preferable, т. е. $L_{34} = 0{,}5\ m$

Calculation of the nozzle device: Let's determine the necessary size of the nozzle device. With the known value of the nozzle orifice diameter, the length is determined by the formula (3.62):

$$\frac{l_0}{d_0} = 1..2 \qquad (3.62)$$

Considering The nozzle cut-off distance from the working chamber (return distance) is determined by the formula (3.63) the average value of the sample:

$$l_0 = 0{,}04 \times 0{,}5 = 0{,}02\ \text{м}$$

The nozzle cut-off distance from the working chamber (return distance) is determined by the formula (3.63):

$$l_c \leq 2d_0 \qquad (3.63)$$

Take the values of the nozzle angle constriction $\theta = 16°$

The next step is to find the total pressure of the fluid flow before the nozzle device in the inlet nozzle (3.64):

$$\overline{P_1} = P_1 + \frac{\rho_w \times v_w^2}{2} \qquad (3.64)$$

$$\overline{P_1} = 3 \times 10^6 + \frac{1008 \times 0{,}1^2}{2} = 4{,}5\ MPa$$

The gas density at the end of the working chamber is found by the formula (3.65):

$$\rho_{g5} = \frac{P_5}{R \times T} \qquad (3.65)$$

$$\rho_{g5} = \frac{101000}{287 \times 313} = 1{,}124\ \frac{kg}{m^3}$$

The volumetric gas flow rate at the end of the working chamber is calculated by formula (3.66):

$$Q_{g5} = \frac{m_g}{\rho_{g5}} \qquad (3.66)$$

$$Q_{g5} = \frac{7000{,}43}{1{,}124} = 4000\ \frac{m^3}{h}$$

The density of the entire mixture at the end of the working chamber is found by the formula (3.67):

$$\rho_m = \frac{\rho_{g5}Q_{g5}+\rho_w Q_w}{Q_g+Q_w} \tag{3.67}$$

$$\rho_m = \frac{1{,}124 \times 1{,}1 + 1008 \times 0{,}14}{1{,}1 + 0{,}14} = 889{,}4\ \frac{kg}{m^3}$$

The volume flow rate of the mixture is calculated by the formula (3.68):

$$Q_m = Q_{g5} + Q_w \tag{3.68}$$

$$Q_m = 1{,}1 + 0{,}14 = 1{,}24\ \frac{m^3}{s}$$

The velocity of the mixture at the end of the working mixture is found by the formula (3.69):

$$v_m = \frac{Q_m}{S_3} \tag{3.69}$$

$$v_m = \frac{1{,}24}{0{,}0012} = 1{,}2\ \frac{m}{s}$$

Use the following formula to find the total pressure of the mixture at the end of the working chamber (3.70):

$$\overline{P_5} = P_5 + \frac{\rho_m \times v_m^2}{2} \tag{3.70}$$

$$\overline{P_5} = 0{,}101 \times 10^6 + \frac{889{,}4 \times 1{,}2^2}{2} = 1{,}3\ MPa$$

The final step is to find the efficiency (efficiency factor) of the liquid-gas ejector by the formula (3.71).

$$\eta = \frac{m_g \times R \times T \times \ln\left(\frac{P_5}{P_2}\right) + k_{res} \times (\overline{P_5} - P_2)}{Q_w \times (\overline{P_1} - P_2)} \tag{3.71}$$

$$\eta = \frac{26{,}43 \times 287 \times 313 \times \ln\left(\frac{0{,}101}{0{,}45}\right) + 1 \times (1{,}3 - 0{,}45)}{0{,}14 \times (4{,}5 - 0{,}45)} = 0{,}301$$

где $k_{res} = 1$ – coefficient of useful use of residual energy of the active flux.

Consequently, the efficiency factor:

$$\eta = 30{,}1\ \%$$

Based on the calculations, two ejectors were selected: NSN-3500 and NSN-6000. Then it is necessary to test these ejectors to compare their parameters and choose the best option that will satisfy the requirements for gas-liquid mixture injection at Prirazlomnaya OIRSP [26].

The tests will be carried out on a specialized stand (Figure 3.11).

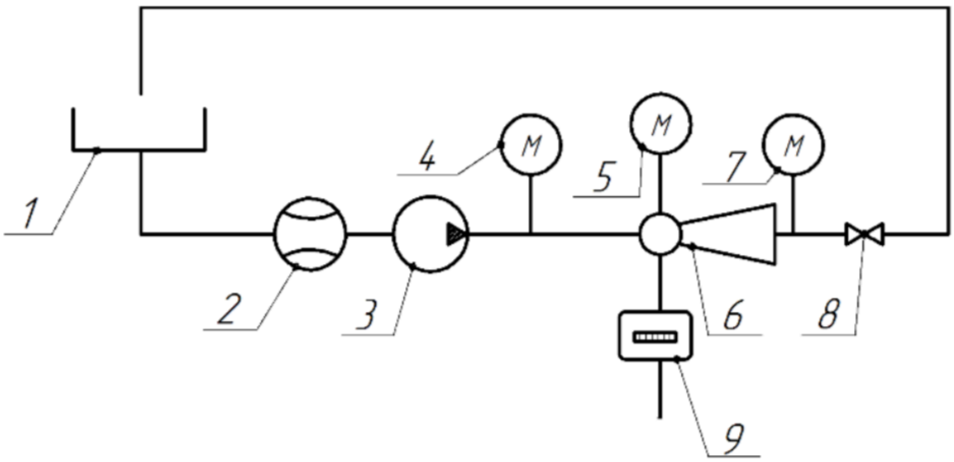

Figure 3.11 – Ejector test bench

1 - tank with liquid; 2 - liquid flowmeter; 3 - booster pump (ESP7A-2250); 4 - pressure sensor at the inlet of jet pump; 5 - pressure sensor in gas line (manovacuometer); 6 - jet pump NSN-3500; 7 - pressure sensor at the outlet of jet pump; 8 - high pressure valve (gate valve); 9 - gas flowmeter [9].

The main characteristic of a jet pump is the dependence of the dimensionless head Pr on the induction coefficient.

The dimensionless head **Pr** is calculated using the following formula (3.72):

$$P_r(h) = \frac{P_{out}-P_g}{P_{in}-P_g} \qquad (3.72)$$

where P_{out} – pressure at the outlet of the jet pump, atm;

P_g - pressure in the gas line, atm;

P_{in}- water pressure at the inlet of the jet pump.

The volumetric induction coefficient u is calculated by the following formula (3.73):

$$u = \frac{Q_g}{Q_w} \tag{3.73}$$

where Q_g – gas supply, m^3/day;

Q_w- water supply, m^3/day.

Indicator	**NSN-3500**	**NSN-6000**
Nozzle diameter, d_n	21, 8 mm	28,3 mm
Mixing chamber diameter, D_c	35 mm	48,1 mm
Distance from nozzle to mixing chamber, L_{n-c}	38, 2 mm	38,2 mm
Mixing chamber length, L_{cm}	500 mm	500 mm
D_c /d_n*	1,606	1,700
L_{n-c} / d_n**	1,752	1,350
L_{cm} / D_c***	14,29	10,40
Water supply, м3/сут	1670	2880
Max. gas supply, m^3/day	3860	7516
Max. EFFICIENCY	27,7 %	28,1 %
Max. Pr	0,71	0,67
Max. u	2,31	2,6
Max. P_{out} , atm	12,8	12,1
h when max EFFICIENCY	0,37	0,34

Table 3.4 – Comparison of jet pump parameters

** Optimal diameter ratio Dc/dn 1,6-2,3.*

*** For water the optimal ratio is 1.5, for gas you need to look for more information.*

****Optimal ratio Lcm/Dc Based on the literature sources 15-20.*

During tests of jet pumps the dependence of the dimensionless head on the induction coefficient is observed (table 3.4). The ejection coefficient determines the ratio between the volume of ejected liquid and the volume of injected energy [27].

When the ejection coefficient increases, i.e. the volume of ejected liquid increases, the dimensionless head also increases. This is due to an increase in ejected fluid flow, which creates more force and energy to deliver fluid to the pump outlet. The increase in the dimensionless head in this case indicates the increased efficiency of the pump.

On the other hand, when the ejection ratio decreases, that is, the volume of ejected fluid decreases, the dimensionless head also decreases. This is due to the reduced flow of the ejected fluid and, consequently, the reduced force and energy transferred to the fluid supply. A decrease in the dimensionless head indicates a decrease in pump efficiency at a given value of the induction coefficient (figure 3.12).

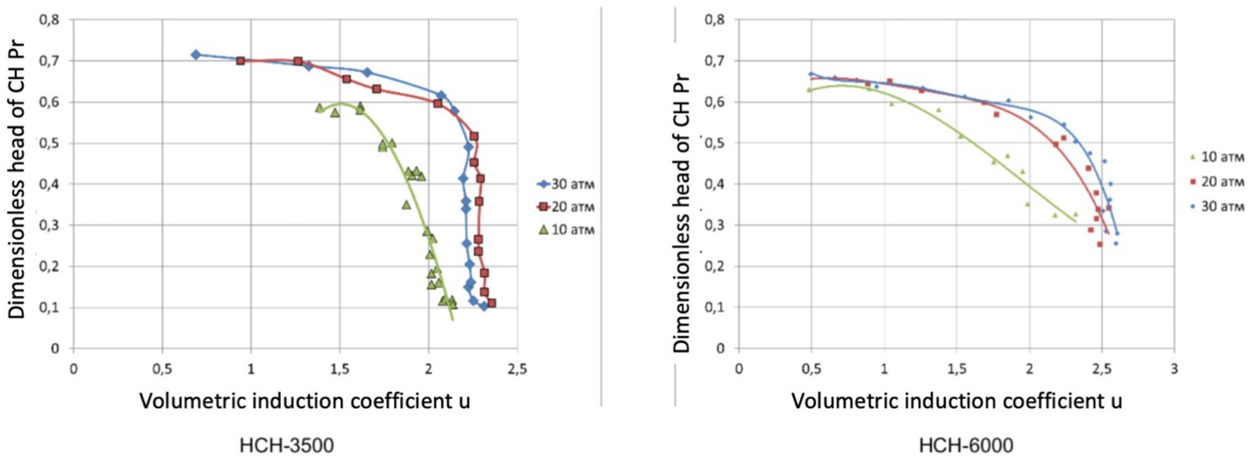

Figure 3.12 – Dependence of dimensionless head on the induction coefficient

Indeed, with further increase in the induction coefficient, the dimensionless head may begin to decrease. This is explained by peculiarities of operation of jet pumps and interaction between ejected liquid and input energy.

At the beginning, as the ejection ratio increases, the dimensionless head also increases, as more fluid is ejected from the pump, resulting in an increase in the force and energy generated. However, when a certain value of the induction coefficient is reached, the pump switches to flow separation mode [9].

In flow separation mode, as the induction coefficient increases, more of the ejected fluid begins to form a separate jet, which deviates from the main flow of energy input. This leads to a decrease in the efficiency of energy transfer to the fluid supply, and hence a decrease in the dimensionless head.

Thus, dependence of dimensionless head on ejection coefficient during tests of jet pumps is not directly proportional, and at a certain stage, increase of ejection coefficient may lead to decrease of dimensionless head due to transition of pump into flow separation mode (figure 3.13). This phenomenon is manifested in the change of character of interaction between the ejected liquid and the input energy inside the pump [28].

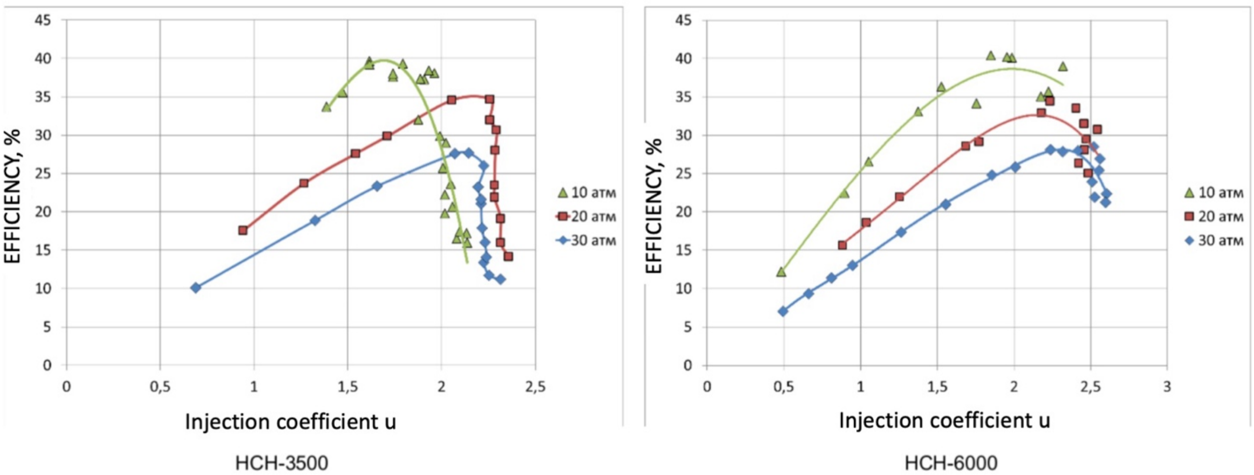

Figure 3.13 – Efficiency dependence on the induction coefficient

The dependence of efficiency (coefficient of performance) on the induction coefficient when testing jet pumps can have several variants. In general case, the change in efficiency can manifest itself as follows:

1. Increasing efficiency with increasing induction coefficient: In some cases, pump efficiency can increase with increasing induction coefficient. This may be due

to improved flow hydrodynamics, better transfer of pump energy to the fluid and the ejected jet, as well as an optimal ratio between energy supply and ejected fluid.

2. Efficiency decreases as the induction ratio increases: In other cases, as the induction ratio increases further, pump efficiency may begin to decrease. This may be due to increased energy losses because of flow separation, turbulence formation or sub-optimal ratio between ejected fluid and energy input [29].

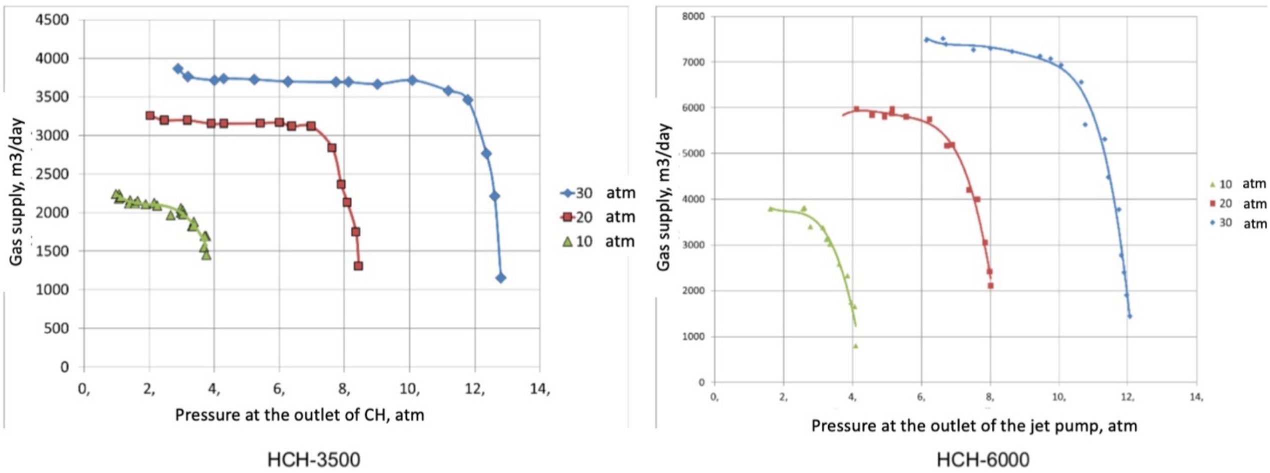

Figure 3.14 – Dependence of gas supply on CH outlet pressure

The dependence of the gas flow rate on the pressure at the outlet of a jet pump can be described by Bernoulli's law and the continuity equation (Fig. 3.14).

According to Bernoulli's law, when gas passes through a constriction or nozzle, there is a pressure difference. In this case, in general, as the pressure at the outlet of the pump increases, the gas flow rate will decrease. This is because an increase in pressure is accompanied by an increase in the force required to overcome that pressure, which reduces the velocity of the gas and hence the flow rate.

However, there may be exceptions to this general rule under specific jet pump operating conditions. For example, by using special designs, special nozzles, or operating modes, it is possible to achieve an inverse relationship in which an increase in pressure at the pump outlet is accompanied by an increase in gas flow rate.

In general, as the relative head in the ejector increases, the efficiency may change. However, the exact relationship can vary depending on a variety of factors, including ejector geometry, fluid properties (e.g., density and viscosity), operating conditions and other parameters.

Usually, when the relative head in the ejector increases, there is an increase in efficiency [30]. This is due to the fact that at a higher head the energy efficiency of the ejection process increases, which leads to a more efficient use of energy to move the working medium.

However, it should be noted that dependence of efficiency from the relative head may not be linear and may have certain features, such as the presence of a peak of efficiency under certain conditions or the presence of a limit value of efficiency, after which a further increase in the relative head leads to a decrease in efficiency (Figure 3.15).

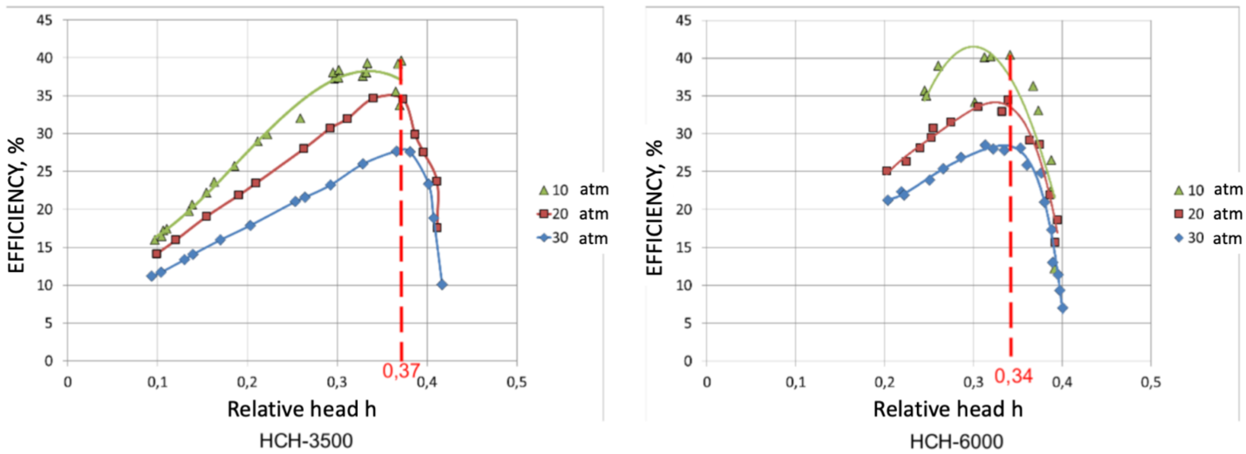

Figure 3.15 – Efficiency vs. relative head

From the results of research it is clear that the maximum efficiency of the pump for each design does not change when changing the inlet water pressure. However, for each design it is different, so for NSN-3500 relative head h is 0.37, for NSN-6000 relative head h is 0.34.

In general, when increasing the pressure drop across the nozzle of the jet pump, the water supply may increase. This is because a higher differential pressure creates a stronger force that acts on the water and accelerates its movement through the nozzle. This results in an increase in water flow.

It should be noted, however, that the dependence of water delivery on pressure drop may not be linear. In some cases, nonlinear behavior can be observed, because various factors, such as compression and expansion of the flow, friction and energy losses, can affect the exact dependence [31] (Figure 3.16).

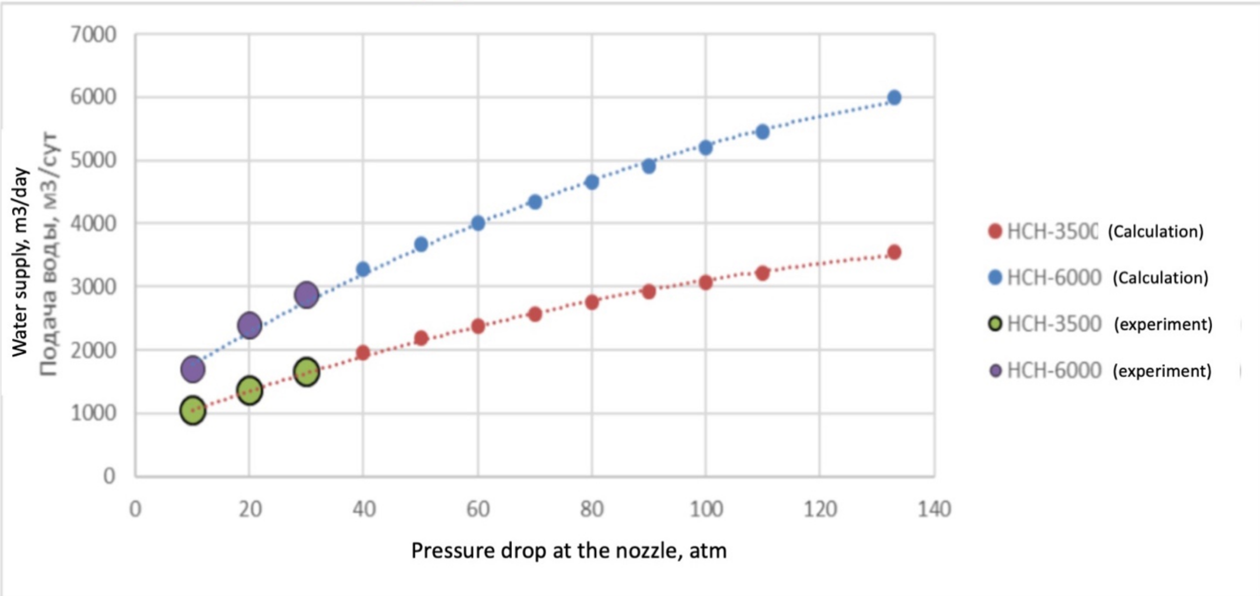

Figure 3.16 – Dependence of water supply on differential pressure at the jet pump nozzle

Nozzle diameter: NSN-3500 has 21.8 mm, NSN-6000 has 28.3 mm. As can be seen from the dependence, the pressures obtained experimentally and by computational method agree. It is possible to achieve the declared flow rates of both jet pumps at a pressure drop of 133 atm, while the nozzle velocity will be equal to 110 m/s. According to literary sources, speed in the nozzle should not exceed more than 100 m/s, because at high speeds greatly increases abrasive wear of the nozzle.

Method for determining pressures in a jet pump

Objective: Determine how the pressure at the outlet of the jet pump will change if you increase the gas pressure at the inlet to 4.5 atm.

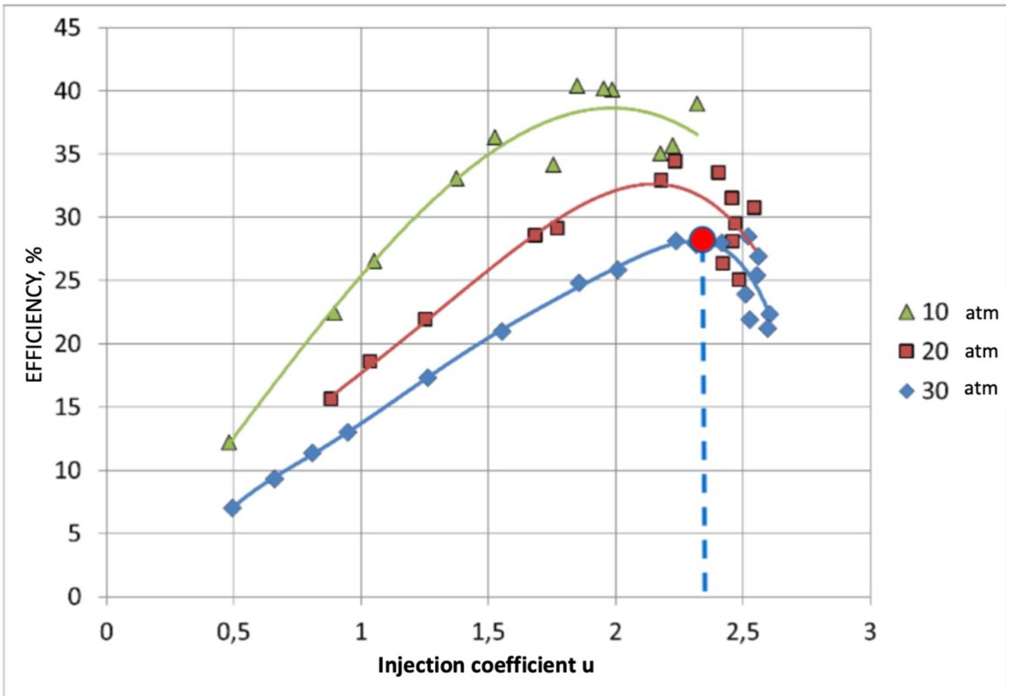

Figure 3.17 – Ejector efficiency vs. induction coefficient **u**

From the dependence above, for the required pressure (for example, we take 30 atm) determine the point of maximum efficiency (Figure 3.17). Maximum efficiency is reached at **u** equal to 2.4.

Methodology for selecting a jet pump

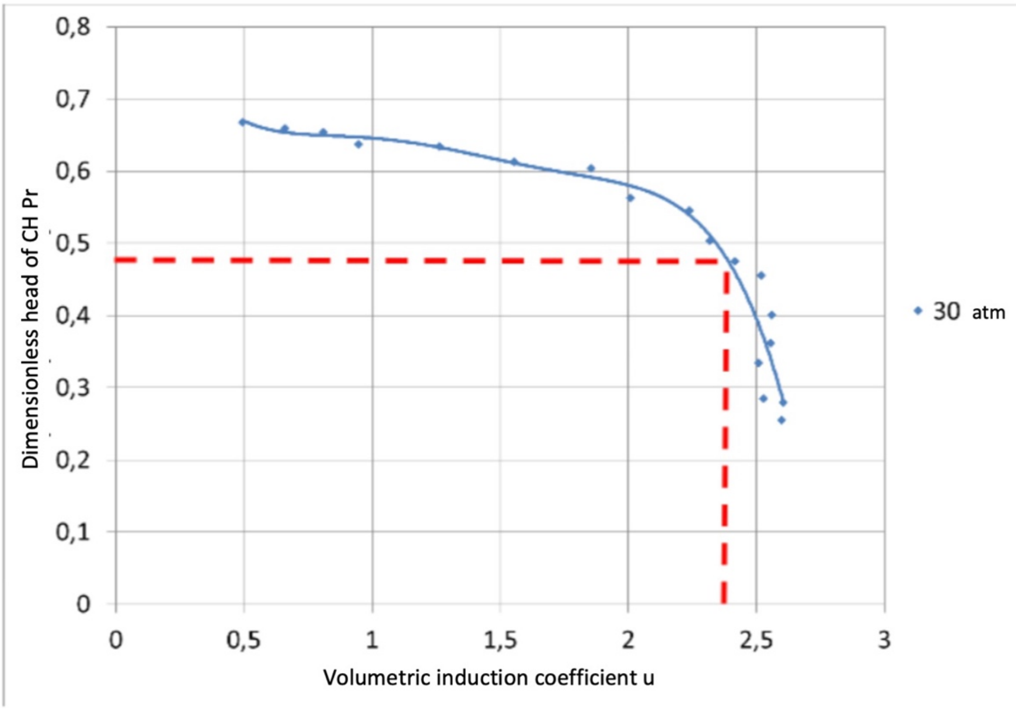

Figure 3.18 – Dependence of dimensionless head on the induction coefficient **u**

1) It is known that the maximum efficiency is achieved at an ejection coefficient of 2.4 (Figure 3.18).
2) From the basic dimensionless characteristic - let's determine the value of dimensionless head Pr. Pr = 0.48.
3) 3) From formula (3.74) express the pressure at the outlet of the jet pump and substitute the obtained values:

$$P_{out} = \frac{P_r \times P_{in} + P_g}{P_r + 1} = \frac{0{,}48 \times 30 + 4{,}5}{0{,}48 + 1} = 12{,}7 \text{ atm} \qquad (3.74)$$

That is, if you increase the gas pressure at the inlet to the jet pump from 0 to 4.5 atm, the pressure at the outlet of the jet pump will increase from 10 to 12.7 atm with the same coefficient of ejection.

CHAPTER 4: Analysis of the Results

4.1 Analysis of the results

As a result of the study the following results were obtained:

1. During tests of NSN-3500 and NSN-6000 jet pumps at active medium (water) pressures of 10, 20 and 30 atmospheres, the results were obtained. Atmospheric air was used as a passive medium.
2. The minimum induction ratio is 1.5 for the NSN-3500 jet pump and 2 for the NSN-6000 jet pump. These values indicate the minimum ratio between active and passive media flow in the system.
3. The maximum induction coefficient increases for both pump types as the pressure of the active medium increases. At a maximum pressure of 30 atmospheres the ejection coefficient reaches values of 2.25 for NSN-3500 and 2.5 for NSN-6000. This indicates the possibility of more effective energy transfer from the active medium to the passive medium at higher pressures.
4. The efficiency of the developed jet pumps reaches the value of 28% at the pressure of the active medium at 30 atmospheres. This means that the percentage of energy transferred from the active medium to the passive medium is 28% of all available energy.
5. The relative head, which reflects the pressure drop factor, is independent of the active medium pressure and is 0.37 for NSN-3500 and 0.34 for NSN-6000. This indicates the relative efficiency of the pumps in creating pressure in the system.
6. The issue of elaboration arises due to the impossibility of testing at passive medium pressures higher than 4.5 atmospheres. Further investigation and characterization of pumps at higher passive medium pressures require additional study and analysis.

The topic of selecting a powerful ejector for efficient injection of associated petroleum gas into the reservoir is a complex task that requires consideration of many parameters and factors. Research results and practical experience show that choosing a suitable ejector is a non-trivial process, depending on several key factors [32].

First and foremost, the effectiveness of an ejector system depends on the characteristics of the reservoir itself, including its geological properties, permeability, reservoir pressure and gas composition. Consideration of these parameters makes it possible to determine the necessary volume and intensity of gas injection to achieve the desired results.

An important factor is also selecting the optimal pressure of the active medium, in this case water, which provides gas injection. This pressure must be sufficient to ensure efficient gas movement through the system, but must not exceed the limits determined by the ejector design and other technical constraints.

In addition, the selection of a powerful ejector requires consideration of such parameters as the ejection ratio, geometric features of the ejector system, the degree to which operating conditions match the operating range of the selected ejector and other factors affecting the efficiency of the gas injection process.

To achieve optimal results in selecting a powerful ejector, it is necessary to use a comprehensive approach, including mathematical modeling, testing of pumping systems of different capacities, as well as analysis and comparison of the obtained data [33]. Consideration of all the above factors and their interaction requires specialized knowledge and experience in the field of gas dynamics and petroleum engineering.

4.2 Technological scheme and equipment

Equipment

The following equipment will be used to create an effective technological scheme for enhanced oil recovery and associated gas utilization [9]:

CNS 16-670 (figure 4.1)

Characteristics:

- Pump length 1 m
- Pump pressure 47 atm at rated flow
- Pump efficiency 80% (figure 4.2)
- Motor length 3 m.
- Motor power 800 kW
- Total length of pump with motor 4 m

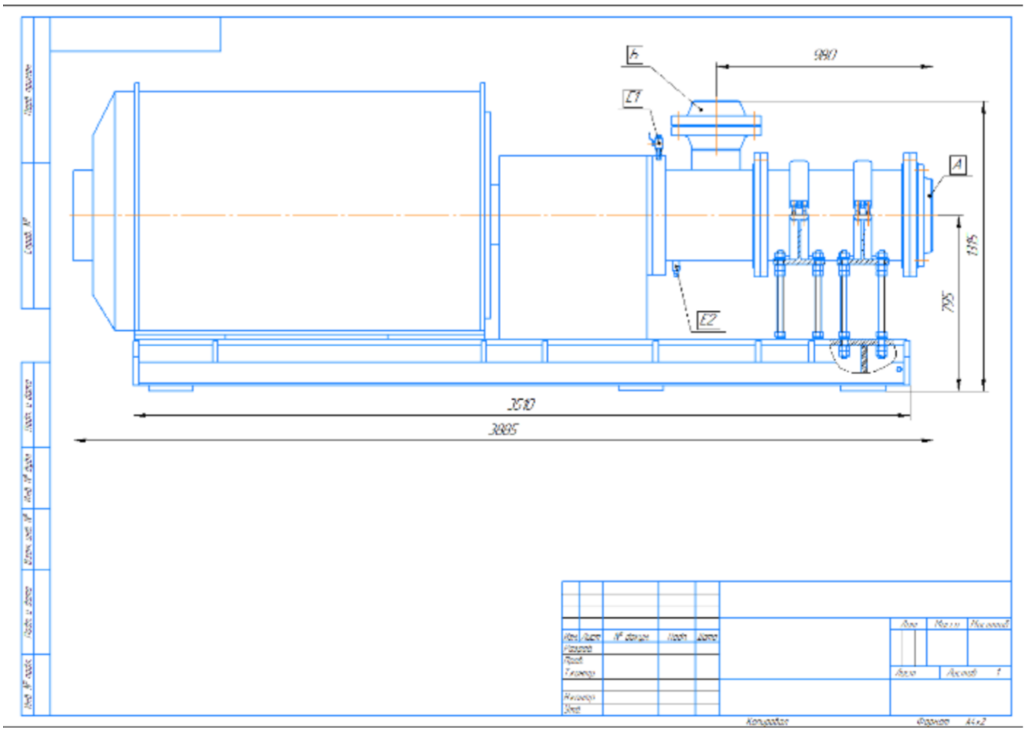

Figure 4.1 Diagram of the CNS16-670 with indication of all dimensions

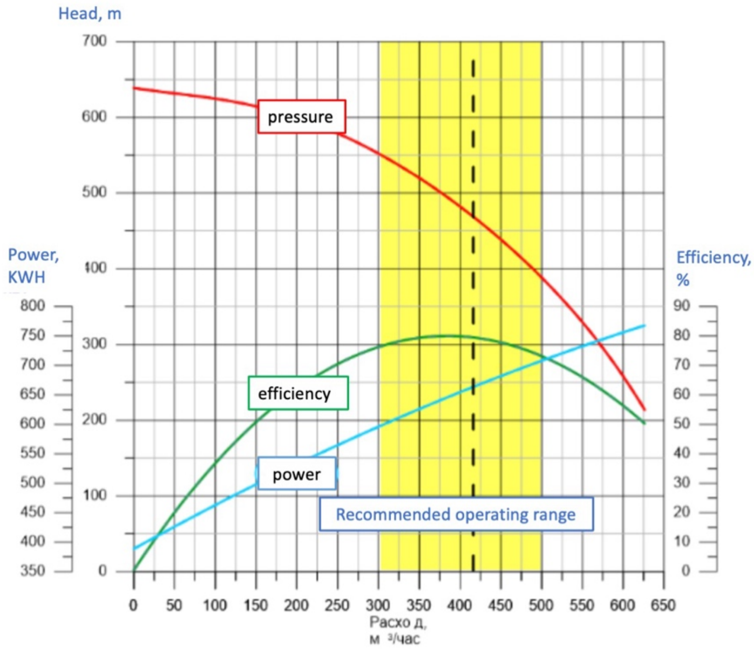

Figure 4.2 Diagram of the optimal operating range of the CNS16-670

NSN-6000 (Figures 4.3 and 4.4)

Characteristics:

- Jet pump length 1.7 m
- Height 0.6 m (at gas flange)
- Diameter of water inlet line 150 mm
- Diameter of gas inlet pipe 126 mm
- Injection coefficient (maximum) 2.4-2.5
- EFFICIENCY 28%

Figure 4.3 – 3-D model of the NSN 6000

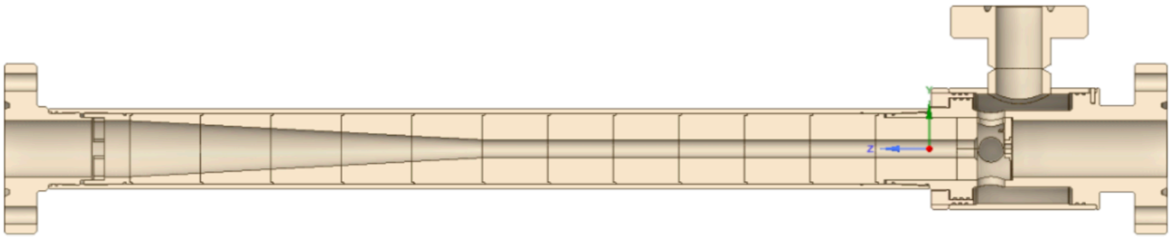

Figure 4.4 – Sectional view of the NSN 6000

CNS 500-2400 (figure 4.5)

Characteristics:

- Pump length 3.5 m
- Pump pressure 240 atm
- Pump efficiency 80% (figure 4.6)
- Engine length 4 m
- Motor power 4,5 MW
- Total length 7,5 m

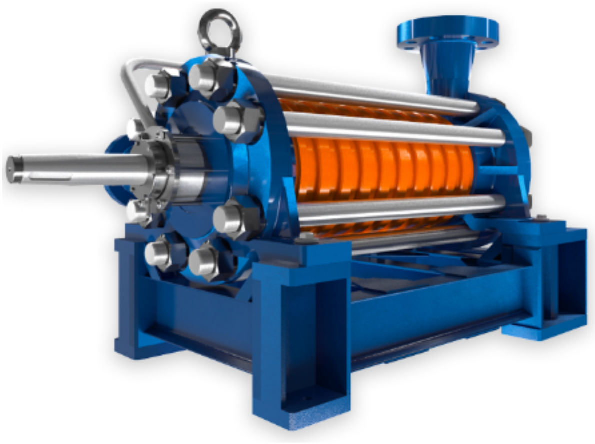

Figure 4.5 – CNS500-2400 version

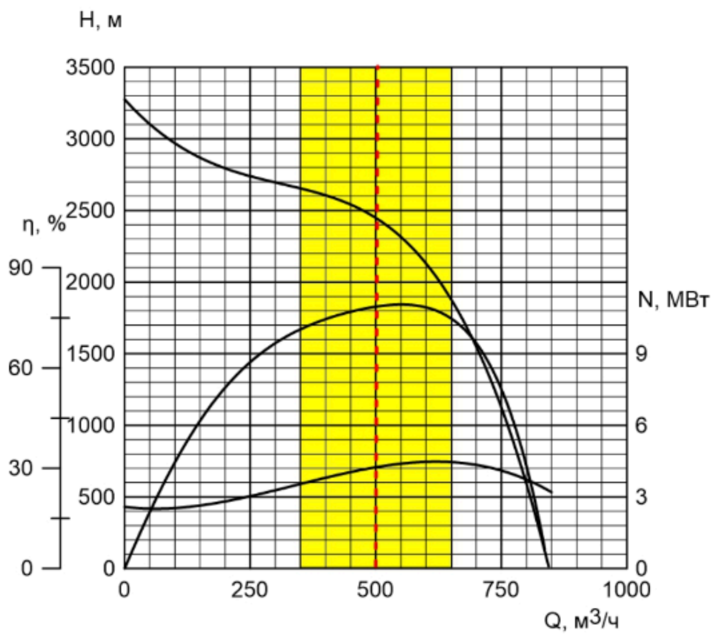

Figure 4.6 Diagram of the optimal operating range of the CNS500-2400

Technological scheme (Figure 4.7)

1) Water under pressure of 0.7-1.3 MPa enters CNS16-670 for injection before ejection. At the outlet water pressure is 3-4.5 MPa

2) The gas enters the ejector under pressure of 0,3-0,45 MPa after the separator of the second stage. The gas must necessarily be purified from hydrogen sulfide and have a low percentage of methane (not more than 50%). This is a mandatory

geological requirement, which is due to the fact that in the case of high methane content, there is a risk of insolubility in the formation.

3) After that, water and gas through the appropriate supply pipes fall into the ejector, where they are mixed.

4) At the outlet of LOS, the pressure of gas-liquid mixture is insufficient for further injection into the reservoir. It is 1.35–1.6 MPa.

5) In this connection, the water-gas mixture further enters the pump to pressurize the outlet pressure to 26-32 MPa. For this function the pump CNS 500–2400 was chosen.

6) After that the pressurized gas-liquid mixture enters the common manifold and only after that it is injected into the wells. The condition of using the common manifold is mandatory, as all wells at Prirazlomnaya IBSF are productive and therefore the risk of gas caps, "breakthroughs" and uneven distribution front should be excluded. Otherwise, it is fraught with catastrophic consequences.

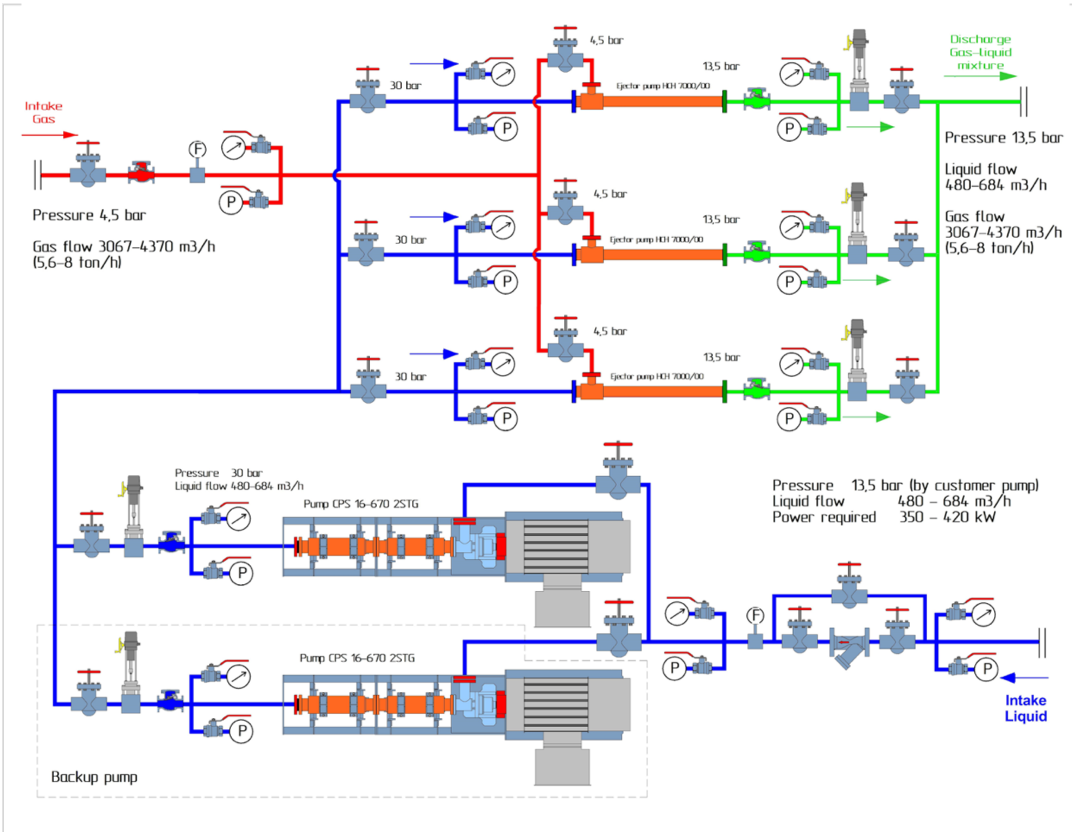

Figure 4.7 Technological scheme of APG utilization at Prirazlomnaya Platform

Characteristics of this technological scheme:

- Water supply: 10080-16416 m^3/day
- Water pressure: 30-45 bar
- Gas supply: 31200 – 104880 st.m^3/day (13383 - 19069 m^3/day)
- Gas pressure: 3-4.5 bar (overpressure)
- Pressure at the outlet of the jet pump: 13.5 - 16 bar

At these pressures the NSN-6000 jet pump is capable of pumping:

- Water supply: 2900 m^3/day
- Gas supply: 6900 m^3/day

The installation diagram is as shown in Figure 4.8:

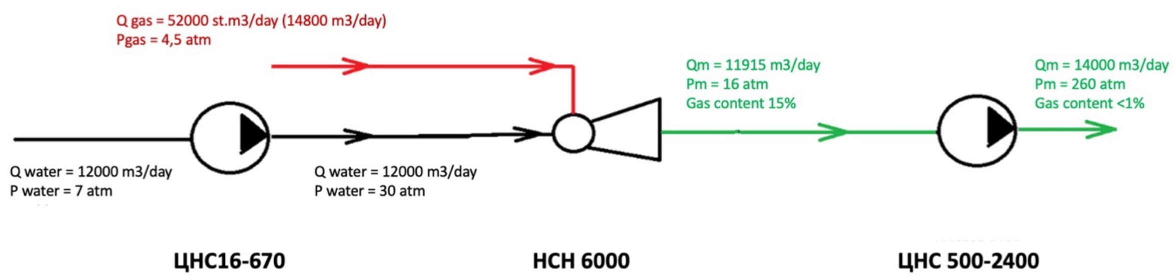

Figure 4.8 Installation diagram of pumps and ejector

The unit consists of three devices (figure 4.9):

- CNS 16-670 (required to create water pressure before the jet pump) in quantity of 4 pcs.
- NSN-6000 (ejector for mixing water and gas flows). To pump the entire volume of water, 6 jet pumps will be required, and their potential gas supply, which it will be able to mix at the given pressures, will be 41400 m^3/day.
- CNS500-2400 (required to create the required outlet pressure 260 atm) in the amount of 4 pcs.

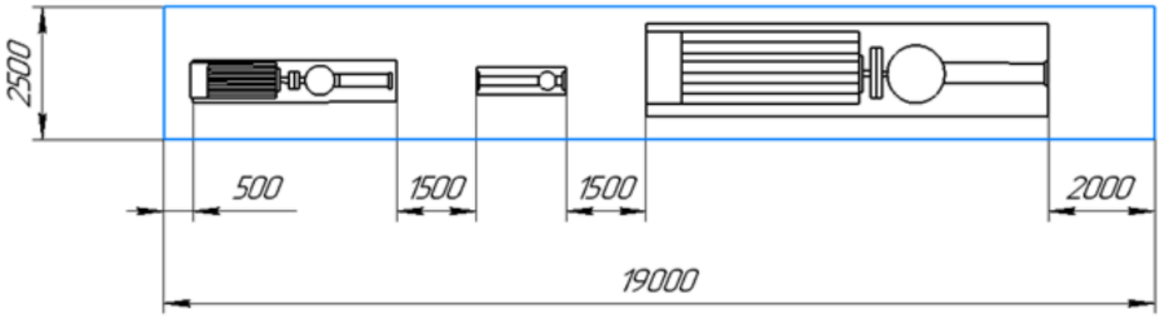

Figure 4.9 Relative overall dimensions of the equipment

Thus, this technological scheme will make it possible to utilize more than 60% of the currently flared associated petroleum gas (Fig. 4.10)

Figure 4.10 Prirazlomnaya Platform

4.3 Advantages and disadvantages of water-gas ejection technology for APG utilization

1. *Utilization efficiency:* The water-gas ejection method provides high efficiency in the utilization of associated petroleum gas. The ejectors can effectively mix the associated gas with water to form a gas-liquid mixture, which can then be routed into the reservoir. This makes it possible to extract a large portion of the energy from the associated gas and utilize it as an additional source of energy for oil

production. The ejectors use the energy of the water jet to create a vacuum that causes the associated gas to be ejected into the reservoir. Thus, there is a useful use of gas, which contributes to the energy efficiency of the process and reduces the loss of resources [34].

2. *Flexibility and adaptability:* The water-gas ejection method is flexible and adaptive, allowing it to be used under different conditions and field types. Ejectors can be tuned for optimal operation depending on associated gas characteristics, reservoir pressure and other parameters. This makes it possible to efficiently utilize associated gas regardless of changing production conditions. It can be used in different conditions and well types, and is suitable for different volumes and compositions of associated gas.

3. *Reducing greenhouse gas emissions*: The use of the water-gas ejection method reduces greenhouse gas emissions into the environment. Associated petroleum gas, which previously might have been incinerated or vented into the atmosphere, can now be utilized as energy, helping to reduce the negative impact on the climate.

4. *Improving economic efficiency*: Water-gas ejection offers a cost-effective solution for the utilization of associated petroleum gas [35]. By using the energy of associated gas for oil production, companies can reduce their operating costs and obtain additional revenues from gas utilization, as well as save on flaring penalties.

5. *Reducing the environmental impact*: Water-gas ejection is a more environmentally friendly method of utilizing associated gas compared to other traditional methods, such as combustion or flaring. In contrast to these methods, water-gas ejection minimizes emissions of harmful substances, including carbon dioxide, nitrogen oxides and other pollutants that can have a negative impact on the environment and human health. In addition, ejectors provide a more controlled associated gas utilization process, which helps reduce the likelihood of accidents or unanticipated emissions.

6. *Increasing oil recovery:* The use of water-gas ejection increases oil recovery. Ejecting associated gas into the reservoir creates additional pressure and transports oil to the well, increasing production. This is particularly useful in the case

of low-permeability or high-viscosity formations, where conventional production methods may be less effective.

7. *Reducing the risk of accidents:* Water-gas ejection is a safe method of utilizing associated gas. Compared to other conventional methods, such as flaring or venting, this method reduces the risk of fires, explosions or environmental contamination. The water used in the ejection process provides cooling and temperature control, which contributes to the safe operation of the system [36].

Thus, the water-gas ejection method has a number of advantages, including enhanced oil recovery. These advantages make it an attractive option for utilizing associated petroleum gas and ensure efficiency and safety in the oil production industry.

Now consider the disadvantages:

1. Ejection of the water-gas mixture requires sufficient water in the system, which can be a problem in areas with limited access to fresh water. Limited access to water resources can limit the application of this method and require additional engineering solutions for water supply.

2. *High energy consumption*: The ejection process requires large energy inputs to create sufficient pressure and water flow. Energy consumption can be significant, especially when working with high ejection coefficients and large volumes of associated gas.

3. *Limited ability to regulate:* Water-gas ejection has limited ability to accurately control process parameters such as pressure and water flow rate. This can make it difficult to optimize the process under different operating conditions and require additional effort to achieve the desired efficiency.

4. *Complexity of design and equipment selection:* Designing and selecting the right equipment for water-gas ejection requires a high degree of technical expertise and experience. Optimal design of an ejection system, including selection of pumps, nozzle devices and other components, can be a complex task, especially when dealing with different reservoir types and production conditions [37].

5. *The need for security:* To operate the ejection system safely, measures must be taken to prevent possible accidents, such as gas leaks or excessive operating pressures. This requires additional safety measures and regular maintenance of the equipment.

6. *Impact on the environment:* The ejection process can affect the environment in the form of greenhouse gas emissions and other harmful substances [38]. Various harmful substances such as hydrogen sulfide (H2S), nitrogen oxides (NOx), heavy metals, and other pollutants can be released during the ejection process. These substances can have a negative impact on air quality, soil and water resources.

7. *Potential pollution of water resources:* Water and gas ejection can cause potential pollution of water resources due to the release of oil components and other harmful substances into water systems. This can have a negative impact on the ecosystems of rivers, lakes, and groundwater.

8. *Noise pollution:* The operation of pumping and ejector systems can be accompanied by high noise levels, especially at high water flow rates and pressures. Noise pollution can have a negative effect on biological organisms, including animals and people living near the place of operation.

The economic component of water-gas ejection in the utilization of associated petroleum gas has its own peculiarities. Here are a few aspects that should be considered:

1. *Investment costs:* Implementing a water-gas ejection system requires significant investment in the purchase and installation of specialized equipment, including pumps, nozzle devices, piping and instrumentation. Because of this, the initial investment costs can be high.

2. *Operating expenses:* Water-gas ejection requires constant operating costs for energy to drive pumps and other devices, and to maintain and service the system. This includes costs for electricity, equipment maintenance and repair, and the purchase of water and other resources.

3. *Water costs:* Water is an integral part of the water-gas ejection process, and its consumption can be significant. Water costs can affect the economic efficiency

of the method, especially in cases where access to fresh water resources is limited or requires transportation over significant distances.

4. *Remuneration and staff training:* Providing competent personnel to operate water-gas systems and perform ejection requires additional training and labor costs. Technical expertise and personnel experience are important factors in ensuring safe and efficient system operation.

5. *Regulation and regulatory compliance:* Water and gas ejection is subject to regulation and regulatory requirements related to safety, environmental protection and compliance with oil and gas production regulations. This may require additional costs for licensing, certification, monitoring and compliance with standards.

First, it should be noted that the decision to implement water-gas ejection is a complex process that requires consideration of various factors, including economic, technical and environmental aspects.

On the economic side, offshore platform companies may be confronted with several factors that make paying penalties for associated gas emissions a better alternative than implementing water-gas ejection.

The first factor is the unevenness of costs. In some cases, the cost of gas emission fees may be relatively low compared to the cost of implementing and operating a water-gas ejection system. This can be a financial incentive for a company to choose to pay penalties, especially if the cost of ejection is significantly higher than expected penalties.

The second factor is uncertainty in future regulatory changes. Due to ever-changing regulatory requirements for gas emissions, companies may face uncertainty in predicting future penalties. This uncertainty makes it difficult to make effective economic calculations and can lead to decisions to pay penalties in the short term [39].

However, it should be noted that economic calculations should not be limited only to a comparison of the cost of gas emission fees and the cost of implementing water-gas ejection. The decision must also take into account other factors, such as the potential economic benefits of implementing water-gas ejection and its impact on the overall performance and competitiveness of the company.

First, the economic calculations must take into account the potential long-term benefits of water-gas ejection. Instead of paying penalties, a company can take advantage of associated petroleum gas utilization opportunities that will reduce the cost of purchasing additional fuel or gas for its operations. This can lead to significant savings in fuel costs and improve the company's financial stability in the long term.

Second, the introduction of water-gas ejection can help reduce operational risks and ensure more reliable and safer offshore platform operations [40]. The costs of preventing and eliminating emergencies associated with gas emissions can be significant. The implementation of an effective gas utilization system will reduce the probability of accidents and reduce the operating costs for equipment repair and recovery.

In addition, the introduction of water-gas ejection can have a positive impact on a company's reputation and social responsibility. In today's society, more and more attention is being paid to environmental and sustainable development issues. Public opinion and legislation are becoming more and more stringent with regard to emissions of harmful substances. When selecting a gas utilization option, a company can count on the support of stakeholders, including government, investors and the public, which can lead to additional economic benefits, such as access to financing or new markets [41].

4.4 Qualitative analysis of operational risks

The HAZID (Hazard Analysis and Identification) risk assessment for the use of the pump and injector system on the Prirazlomnaya platform for associated petroleum gas utilization is as follows:

1. Hazard Identification:

- Identifies the various stages of the associated petroleum gas utilization process using a pump-ejector system, including gas supply, processing, transportation, and emissions.

- Potential hazards such as gas leaks, explosions, fires, environmental and worker health impacts, equipment damage, and technical failures are identified.

2. Assessment of the probability of occurrence of hazards:

- - Each identified hazard is evaluated based on its probability of occurrence. The probability can be estimated on a numerical scale from 1 to 5, where 1 is a very low probability and 5 is a very high probability.

3. Assessing the effects of hazards:

- For each identified hazard, its potential consequences are evaluated. Consequences may include injuries, loss of life, property damage, negative environmental impact, etc. Consequences can also be assessed on a numerical scale of 1 to 5, where 1 is minimal consequences and 5 is catastrophic consequences.

4. Calculation of risks:

- Risk is determined by multiplying the probability and consequences of each hazard. This allows us to estimate the level of risk for each identified hazard.
- - Risk assessment can be presented in scores based on a chosen numerical scale, where a higher score indicates a higher level of risk.

5. Prioritization and risk mitigation measures:

- Hazards with the highest risks are identified. These hazards require closer attention and the development of risk reduction measures.
- Risk mitigation measures are developed and proposed, including technical and organizational measures, training, and safety procedures.

Decisions are made to introduce and implement risk reduction measures based on their effectiveness, affordability and economic feasibility [42] (Table 4.1);

Risk register for the use of the pump-ejector system on the Prirazlomnaya Platform (HAZID)				Initial risk				Residual risk		
№	RISK	REASONS	CONSEQUENCES	Probability	Damage	Grade	Measures to eliminate	Probability	Damage	Grade
1	Hydrogen sulfide leakage	1. Depressurization of the water injection system in the case of H2S-containing gas ejection	1. poisoning of service personnel on the platform; 2. alarm and shutdown of the platform. Financial losses	3	5	15	1. Regularly perform maintenance of equipment and diagnostics of process pipelines of the pump-ejector system; 2. At the stage of equipment design, take into account the corrosion tolerance with appropriate internal coating; 3. Development of corrosion inhibitor supply scheme, determination of the required dosage when performing OPI. 4. Availability of evacuation kits to evacuate all workers at the site; 5. Regular analysis of the air in the air of the working area for the content of H2S and hydrocarbons;	2	3	6
2	Decrease in the oil recovery factor	1. Uncertainties in physics of process of water-gas influence on reservoir; 2. Inhomogeneity of reservoir; 3. Decrease of injectivity of injection wells, limitation on oil production.	1. Lost profit due to reduction of project oil production indicators;	2	5	10	1. Filtration studies of oil displacement by water-gas mixtures on core material; 2. Analysis of the impact of water-gas impact on technological indicators of development and the final oil recovery factor of the Prirazlomnoye field on the hydrodynamic model.	1	5	5
3	APG flaring	1. Failure of pump-ejector system; 2. Internal corrosion of static equipment, including process pipelines; 3. Inconsistency of planned indicators of APG production with actual ones; 4. Decrease of water and gas-liquid mixture injection into the wells of RPM.	1. Negative environmental impact; 2. Reputational risks; 3. Payment of fines for APG flaring;	4	4	16	1. Design of pumping-ejector system with the involvement of experts in the field and operating personnel; 2. Installation of flares designed for flareless combustion; 3. Partial use of APG for own needs (gas turbine generators, fire heaters).	2	3	6
4	Reservoir acidification	1. Injection of H2S containing H2S into the formation;	1. Exceeding the norms of technological mode. 2. Deterioration of reservoir injectivity when injecting water with increased H2S	4	4	16	Assessment of water-gas impact on the hydrodynamic composite model; 2. Develop a scheme of hydrogen sulfide neutralizer injection; 3. Continuous control of the chemical composition of the injected HCS with the help of flow analyzers.	2	4	8

			content. 3. Increased corrosion of downhole and process equipment; 4. Exceeding permissible standards for sulfur and mercaptans content.							
5	Gas breakthrough to the bottom of production wells	1. Inhomogeneity of reservoir; 2. Separation of water-gas mixture in reservoir;	Failure of downhole equipment; 2. The need to replace downhole equipment with more expensive equipment;	3	5	15	1. Lower completion installation with inflow control device; 2. Isolation of horizons with high permeability; 3. Selection of technological mode providing suppression of gas bubbles coalescence.	2	4	8
6	Inconsistency of the actual indicators of technological modes with the design ones	1. Uncertainties in the design of the technology; 2. Lack of experience in the widespread use of the pump-ejector system for WGI.	1. APG combustion; 2. Prolonged system shutdown, prolonged repair; 3. Required level of pumping into APG is not provided, disruption of production program.	3	5	12	1. Development of the project and carrying out pilot testing of the technology in the field of an onshore subsidiary of PJSC Gazprom Neft. 2. Reserving equipment for WGM injection into the reservoir;	2	4	8

Table 4.1 – Risks of using a pump-ejector system on the Prirazlomnaya Platform (HAZID)

CONCLUSION

In this master's thesis the problems and opportunities of water-gas ejection as an effective method of utilization of associated petroleum gas on offshore platforms were investigated and analyzed. The purpose of the work was to study the technical aspects, analyze the application and efficiency of water-gas ejection, as well as to formulate recommendations for optimizing the process for the utilization of associated petroleum gas.

Main conclusions:

1. The current state of the problem of utilization of associated petroleum gas on offshore platforms is analyzed and the efficiency of various existing methods of utilization is evaluated.
2. The study showed that water-gas ejection on offshore platforms has a number of advantages, such as high efficiency in utilization of associated petroleum gas, possibility to use existing infrastructure, as well as reduction of negative environmental impact. It makes it possible to use the energy of the associated gas to create a head and inject the active medium, which helps reduce gas emissions into the atmosphere.
3. The experience of using the pump-ejector system technology on the example of the Samodurovskoye field has shown positive results.
4. The developed technological scheme for utilization of associated petroleum gas on the Prirazlomnaya platform using the pump-ejector system makes it possible to achieve significant volumes of utilization and reduction of emissions into the atmosphere. It includes selection of necessary equipment, calculation of parameters and assessment of the process efficiency. The technological scheme of associated gas utilization on the Prirazlomnaya platform was developed based on the existing NSN-6000 jet pumps and CNS pumps of different capacity. This makes it possible to achieve optimal productivity and efficiency of the utilization process.

5. Selecting and calculating an ejector requires consideration of many factors, such as gas volumes, required head, efficiency and geometric parameters of the system. The interdependence of these characteristics must be taken into account when designing the process flow diagram and selecting the optimal equipment.

6. Analysis of the results showed that water-gas ejection on offshore platforms is a promising and environmentally effective method of utilization of associated petroleum gas. However, for successful implementation of the project it is necessary to consider financial, technical and environmental aspects.

7. In the process of risk analysis using the HAZID system, potential hazards and their probability of occurrence were identified. The risks were assessed in accordance with the applied assessment scale. The results obtained make it possible to take measures to reduce risks and ensure the safety of the associated petroleum gas utilization process on the Prirazlomnaya offshore platform.

8. Water-gas impact technology using a pump-ejector system is applicable to other offshore projects.

On the basis of the study, we can offer the following recommendations:

- When introducing water-gas ejection it is necessary to consider the specifics of a particular platform, conduct additional technical and economic calculations, as well as assess the risks of the HAZID system and take measures to reduce them.
- The results of the study can be used in practical activities of oil and gas companies to optimize the utilization of associated petroleum gas on offshore platforms, reduce gas emissions and ensure the safety of operations.

Based on the above, we can conclude about the importance and relevance of the development and application of water-gas ejection for associated petroleum gas utilization on offshore platforms. This study provides a basis for further research and development in this area, as well as gives practical recommendations for industrial enterprises.

Despite the achieved results, it should be noted the limitations of this study. Further research can be aimed at a more detailed study of the technical aspects of water-gas ejection, economic assessment of the process and its comparison with other methods of utilization. It is also possible to investigate the possibilities of optimizing technological schemes and increasing the energy efficiency of the process of utilization of associated petroleum gas on offshore platforms.

In general, the results of this study contribute to the development of methods of utilization of associated petroleum gas and contribute to solving urgent problems in the oil and gas industry.

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