KHAZAR UNIVERSITY

Specialty: Petroleum Engineering

Faculty: Graduate School of Science, Art, And Technology

Master Thesis

Theme: Development scenarios and risk assessment of "Neft Dashlari" field

Student: Huseyn Novruzov

Supervisor: Elvin Ahmadov (PhD in Earth Sciences)

Baku – 2022

XƏZƏR UNİVERSİTETİ

İxtisas: Neft-qaz Mühəndisliyi

Fakultə: Təbiət elmləri, Sənət və Texnologiya yüksək təhsil fakültəsi

Magistr Buraxılış İşi

Mövzu: “Neft Daşları” yatağının işlənmə ssenarilərinin tərtibi və geoloji risklərin qiymətləndirilməsi

Tələbə: Hüseyn Novruzov

Elmi rəhbər: Elvin Əhmədov (Yer Elmləri Fəsləfə Doktoru)

Bakı – 2022

I, Huseyn Novruzov, hereby declare that this thesis work submitted is entirely my own. All the works of other authors have been fully acknowledged and clearly cited. I also declare that this work is free from any plagiarism.

Name, Surname:

Signed by:

Date:

Acknowledgements

I would like to thanks to my supervisor, Elvin Ahmadov for his excellent support and help to do this research and improve my research abilities in the best possible. And I am grateful to Mahammad Eldarov who is working in dean office for his support and to helping.

Abstract

Energy is essential for living in the world. There are many energy types exist in the world. Petroleum is also kind of energy in the world. Petroleum is also important in industry. There are a lot of things producing from petroleum. Since ancient time petroleum is important thing and depending on it is also actual. Work of petroleum engineers is producing oil from wells with efficiency way. It is challenge of Reservoir engineers to detect exact oil reserves in every condition. It is not easy that to detect oil in every condition. Because in some condition there is some uncertainties to calculating oil value. It's also important to producing oil as much as possible. It is challenging to produce as much as possible in different scenarios. Depending on situation there are different problems happen both in reserve estimation and production. Problem of uncertainties of reserve estimation is the problem of uncertainties data to calculating reserves. There is also problem to producing oil after pressure drop. There are some impact methods to producing petroleum. Impact methods are changing belonging to reservoir condition. In the world practice, the development of oil fields using the irrigation method is very widespread. Currently, more than 90% of all oil fields are developed using secondary methods. The generalization of the field development experience shows that the results of the application of this method should be widely studied today, despite the fact that the application of the irrigation process has yielded mainly positive results. Incomplete coverage of non-homogeneous strata by the application of the injection process, increasing the volume of difficult-to-extract reserves, complicating the characteristics of the oil-saturated porous reservoir, changing the physical and chemical properties of produced oil in the final stage of development, increasing man-made manifestations in fields, creating difficulties in efficient development In many cases, the recovery of formation energy for the creation of efficient development systems in the fields, the close connection of the injected working agent with the compression of oil in the porous environment of the reservoirs is associated with the optimization of irrigation systems during development. The method of treatment with alkaline solutions forms sodium soaps in the layer, which reduces the surface tension and creates an emulsion of oil in water. The amount of additional oil that can be extracted from the fields depends on the parameters of the emulsion and the distribution of the oil in the formation. Thus, when the layers are exposed to an alkaline solution, a wave of highly dispersed emulsion is formed, which affects the increase in oil recovery. Application of the method in oil and sand-carbonate reservoir fields with oil viscosity up to 100 mPa□s, oil saturation more than 50%, permeability of reservoir rocks greater than 0.1 μm2, oil density 850-980 kg / m3, formation temperature up to 1000C and s. higher effect is obtained when Unfavorable factors are cracking of strata, high clay content and high mineralization of produced waters. It was determined that as a result of injection of alkaline solutions into the reservoirs, it is possible to increase their final oil recovery factor by 5-10%.The efficiency of oil field development depends on the extraction of oil from the pores by various methods. As the viscosity of injected water differs sharply from the viscosity of produced oils, its compressibility is not high: water injected into the reservoir with various modifications does not provide maximum leaching of oil from the porous medium by moving it to working wells with high permeability channels. Therefore, polymers are added to the injected water, which increases its viscosity. As a result, conditions are created for more active washing of produced oil, and the efficiency of the injection process increases.

These uncertainties increase the risks of hydrocarbon reserves in the fields. Thus, uncertainties in the calculation of oil and gas reserves are the main geological risks.

It is clear from the expression that the risks decrease as the probability increases in the case under study. Therefore, first of all, the reliability (probability) of reserves should be determined. This is possible due to the study of the degree of impact of geological and technological factors affecting the volume of reserves in modern times in different ways.

Geological risks can be classified by quantity, quality and area

These parameters have been studied at different levels in individual fields. In this regard, a risk matrix should be developed to assess geological risks so that it is possible to determine the risks according to the degree of impact of geological and mining parameters on the volume of reserves, as well as the level of study of this information. Depending on the geological issue under consideration, a risk matrix of different formats can be compiled. Depending on the degree of study of the complexity of the areas where oil and gas and gas condensate fields are located, structural and tectonic structure, oil and gas saturation of reservoirs, the volume of hydrocarbon reserves, various methods have been developed for geological risk assessment.

Keywords: Impact methods, geological risks, risk matrix, reservoir, techtonic sturucture

Referat

Enerji dünyada yaşamaq üçün vacibdir. Dünyada bir çox enerji növləri mövcuddur. Neft həm də dünyada enerji növüdür. Neft sənayedə də vacibdir. Neftdən çoxlu şeylər çıxarılır. Qədim dövrlərdən bəri neft vacib bir şeydir və ondan asılı olaraq da aktualdır. Neft mühəndislərinin işi quyulardan səmərəli şəkildə neft hasil etməkdir. Hər bir şəraitdə dəqiq neft ehtiyatlarını aşkar etmək anbar mühəndislərinin işidir. Hər vəziyyətdə yağ aşkar etmək asan deyil. Çünki bəzi hallarda neftin dəyərinin hesablanmasında müəyyən qeyri-müəyyənliklər var. Mümkün qədər çox neft hasil etmək də vacibdir. Müxtəlif ssenarilərdə mümkün qədər çox istehsal etmək çətindir. Vəziyyətdən asılı olaraq həm ehtiyatın hesablanmasında, həm də istehsalda müxtəlif problemlər yaranır. Ehtiyatların qiymətləndirilməsinin qeyri-müəyyənliyi problemi ehtiyatların hesablanmasına dair məlumatların qeyri-müəyyənlik problemidir. Təzyiq aşağı düşəndən sonra neft hasil etməkdə də problem var. Neft hasil etmək üçün bəzi təsir üsulları var. Təsir üsulları anbarın vəziyyətinə uyğun olaraq dəyişir. Dünya təcrübəsində neft yataqlarının suvarma üsulu ilə işlənilməsi çox geniş yayılmışdır. Hazırda bütün neft yataqlarının 90%-dən çoxu ikinci dərəcəli üsullarla işlənir. Sahələrin işlənməsi təcrübəsinin ümumiləşdirilməsi göstərir ki, suvarma prosesinin tətbiqi əsasən müsbət nəticələr verməsinə baxmayaraq, bu metodun tətbiqinin nəticələri bu gün geniş şəkildə öyrənilməlidir. Vurma prosesinin tətbiqi ilə qeyri-homogen layların natamam örtülməsi, çətin çıxarılan ehtiyatların həcminin artırılması, neftlə doymuş məsaməli layların xüsusiyyətlərinin çətinləşməsi, son mərhələdə hasil olunan neftin fiziki-kimyəvi xassələrinin dəyişdirilməsi işlənmənin, yataqlarda texnogen təzahürlərin artması, səmərəli işlənmədə çətinliklərin yaranması Bir çox hallarda yataqlarda səmərəli işlənmə sistemlərinin yaradılması üçün lay enerjisinin bərpası, vurulan işçi agentin neftin sıxılması ilə sıx əlaqəsi. su anbarlarının məsaməli mühiti işlənmə zamanı suvarma sistemlərinin optimallaşdırılması ilə bağlıdır. Qələvi məhlullarla müalicə üsulu təbəqədə natrium sabunları əmələ gətirir, bu da səthi gərginliyi azaldır və suda yağ emulsiyasını yaradır. Yataqlardan çıxarıla biləcək əlavə neftin miqdarı emulsiyanın parametrlərindən və neftin layda paylanmasından asılıdır. Beləliklə, laylar qələvi məhlulun təsirinə məruz qaldıqda yüksək dispersli emulsiya dalğası əmələ gəlir ki, bu da neftvermənin artmasına təsir göstərir. Metodun neftin özlülüyü 100 mPas:s qədər, neftlə doyma dərəcəsi 50%-dən çox, lay süxurlarının keçiriciliyi 0,1 μm2-dən çox, neft sıxlığı 850-980 kq/m3, lay temperaturu yuxarı olan neft və qum-karbonat lay yataqlarında tətbiqi 1000C və s-ə qədər. Əlverişsiz amillər layların çatlaması, yüksək gil tərkibi və lay sularının yüksək minerallaşması olduqda daha yüksək təsir əldə edilir. Müəyyən edilmişdir ki, qələvi məhlulların laylara vurulması nəticəsində onların son neftvermə əmsalını 5-10% artırmaq mümkündür. Neft yatağının işlənməsinin səmərəliliyi məsamələrdən neftin müxtəlif üsullarla çıxarılmasından asılıdır. Vurulan suyun özlülüyü hasil edilən neftlərin özlülüyündən kəskin fərqləndiyindən onun sıxılma qabiliyyəti yüksək deyil: laya

müxtəlif modifikasiyalarla vurulan su nefti yüksək keçiricilik kanalları olan işləyən quyulara daşımaqla məsaməli mühitdən maksimum yuyulmasını təmin etmir. Buna görə də vurulan suya polimerlər əlavə edilir ki, bu da onun özlülüyünü artırır. Nəticədə hasil olunan neftin daha aktiv yuyulmasına şərait yaradılır, vurulma prosesinin səmərəliliyi artır. Bu qeyri-müəyyənliklər yataqlarda karbohidrogen ehtiyatları riskini artırır. Beləliklə, neft və qaz ehtiyatlarının hesablanmasında qeyri-müəyyənliklər əsas geoloji risklərdir. İfadədən aydın olur ki, tədqiq olunan halda ehtimal artdıqca risklər də azalır. Ona görə də ilk növbədə ehtiyatların etibarlılığı (ehtimalları) müəyyən edilməlidir. Bu, müasir dövrdə ehtiyatların həcminə təsir edən geoloji və texnoloji amillərin təsir dərəcəsinin müxtəlif üsullarla öyrənilməsi sayəsində mümkün olur.

Geoloji risklər kəmiyyət, keyfiyyət və sahəyə görə təsnif edilə bilər

Bu parametrlər ayrı-ayrı sahələrdə müxtəlif səviyyələrdə tədqiq edilmişdir. Bununla əlaqədar olaraq, geoloji riskləri qiymətləndirmək üçün risk matrisi hazırlanmalıdır ki, geoloji və dağ-mədən parametrlərinin ehtiyatların həcminə təsir dərəcəsinə, habelə bu məlumatların öyrənilmə səviyyəsinə uyğun olaraq riskləri müəyyən etmək mümkün olsun. . Baxılan geoloji məsələdən asılı olaraq müxtəlif formatlı risk matrisi tərtib edilə bilər. Neft-qaz və qaz-kondensat yataqlarının yerləşdiyi ərazilərin mürəkkəbliyinin, struktur və tektonik quruluşunun, layların neft və qazla doyma səviyyəsinin, karbohidrogen ehtiyatlarının həcminin öyrənilmə dərəcəsindən asılı olaraq, riskin geoloji qiymətləndirilməsi üçün müxtəlif üsullar işlənib hazırlanmışdır. .

Açar sözlər: Təsir üsulları, geoloji risklər, risk matrisi, lay, tektonik quruluş

Table of Contents

References

List of figures

List of Tables

İntroduction

The dissertation is devoted to the development of scenarios for the development of the “Neft Dashlari” field and the assessment of geological risks. One of the most important issues in the dissertation work is the determination of geological strata parameters and geological uncertainties that affect the field development scenarios. For this purpose, the existing process, which was first investigated for the development of the field was analyzed. Layer parameters, processing parameters are analyzed on the basis of processing errors on each horizon. We got acquainted with the historical data. After that, the observations on the horizons belonging to the specific field of research were analyzed. Layer parameters affecting the analyzed reserves have been identified, and geological mathematical methods have been used to determine the uncertainty of these layer parameters to determine geological risks. So that, tornado and sensitivity diagrams were first established and then an innovation matrix was developed based on tornado diagrams and a risk matrix has been developed that can have a quantitative effect and based on this risk matrix, the risk levels of the layer parameters that affect the efficient processing of the deposit have been determined. In the end, suggestions were made for the risk levels according to the results of the study.

1. Analysis of the development indicators relating to Neft Dashlari field

The first exploration well in Neft Dashlari fields was started to be drilled in August 1949 and oil extracted with daily production 100 tons from Gala formation during the test held on November 07.

The industrial development of the well commenced in 1951 and 24 oil bearing strata were uncovered in the field’s vertical section. The field has an anticlinal shape stretching from north – west to south – east. The field covers an area with length 10 km and breadth 6 km. The field is divided into 5 tectonic blocks isolated from each other.

There have been 1447 development, 145 exploration, and 133 water injection wells throughout the period when Neft Dashlari field was being developed and the following wells were liquidated in the respective period: for technical reasons – 70 wells, geological reasons – 18 wells, technical reasons when developed – 376 wells, and geological reasons – 802 wells. Oil 164,8 million tons, water 72,5 million tons, and gas 12,8 billion m^3 had been produced from the field by 01.01.2009.

Initial balance oil volume in categories $A+B+S_1$ is 364,8 million tons and the extractable oil volume in the same categories is 182 million tons. Initial balance oil volume in category S_2 is 8,2 million tons and extractable oil volume 3,2 million tons.

At present the extractable oil volume in the field in categories $A+B+S_1$ is 17,2 million tons.

Oil output in the development period was as follows: tectonic block I 992 thousand tons, block VIIa 1834 thousand tons, block II 35485 thousand tons, block III 15772 thousand tons, block IV 31923 thousand tons, and tectonic block V 78809 thousand tons.

Residual extractable oil volume in categories $A+B+S_1$ in block I 97 thousand tons, block VIIa 285 thousand tons, block II 1521 thousand tons, block III 2425 thousand tons, block IV 3799 thousand tons, and block V 9107 thousand tons.

To preserve formation pressure, 263,8 million tons water was injected into the wells with 86,2 million tons of economic oil.

The current well fund is as follows:

Development fund - 347 wells

Operational well fund - 333 wells

Temporarily suspended well fund - 2 wells

Unoperational well fund - 10 well

For development methods: 29 wells are operated by free flow method, 298 wells compressor method, 2 wells depth method and 2 wells by EDN.

The main portion of the residual oil volume in Neft Dashlari field 9107 thousand tons is in block V, GAD (Under Girmaky Formation), GUG (Girmaki Clayey Formation), FLD (Fasila Formation) and Balakhany formation.

Drilling and development of new wells for full exploitation of the Reserve is scheduled in the development project.

Currently, well 2578 are being drilled in ADO 2346 and after the excavation is complete, wells 2575, 2570, 2572, 2571 will be put in operation in GUG horizon. Forecast oil output from each well is estimated to be 10-15 tons. Further, the projected wells 2226 and 2122 are being drilled in ADO 1887, GUG and X horizons.

In general, the plan is to drill 32 development wells in the same ADO and complete exploitation of horizons GUG, FLD, X, IX, VIII.

Construction of ADO 2387 is ongoing and it is scheduled to drill 10 wells from foundation to GUG horizon with estimated output 223 thousand tons.

It is planned to drill 52 development wells from projected ADOs 2415, 2585, 753, 755, 1521.

Construction and drilling works are currently ongoing to drill 76 wells out of 96 to complete development in Neft Dashlari field.

1.1 Geological mining properties of Neft Dashlari field

Reservoirs may be put in 2 classes for the properties of residues in economic strate of the Oil Rock well:

The first reservoir - rocks characterized by deep GP amplitude, poor dampening intensivity and highly driven activeness. It includes horizons V, VI, VII, VIIa, VIII, IX, X horizons and reservoirs of FLD, GUG, and QAD formations.

The second reservoirs – reservoirs characterized by low-inclined GP curve poorly dividing well section into component parts lithologically and with activeness closely driven to clays activeness. It includes sedimentations of GUG, GD and GaD formations.

Reservoirs of Neft Dashlari field are primarily represented by poorly cemented crumbling rocks with sandy – aleurite varieties.

According to the analysis results of core mateirals, mean porosity value of the first class reservoirs 0,26-a and mean conductivity value 0,2 mkm^2. The mean porosity value of the second reservoirs is 0,23 and mean conductivity value 0,15 mkm^2. Nevertheless these formations differ from each other for their conductivities. While conductivity in GD formation is 0,025–0,15 mkm^2, conductivity in GaD formation ranges between 0,11–0,24 mkm^2. The formation with the highest conductivity value among them is GAD and GAD QAD_1 development facility may serve as an example of it.

As far as granulometric composition of the rocks in Oil Rocks field is concerned, the variation interval of sandy fractions in the composition in horizon V was 20-40%, horizon VI 45%, horizon VII 40-46%, horizon VIIa 40-55%, horizon VIII 45-55%, horizon IX 50-60%, horizon X 50-65 %, Fasila formation 60-70%, Girmakiustu formation 56%, Girmakiustu clayey formation 45-50%, Girmaki formation 56-66%, Girmakialti formation 60-70%, and Gala formation 58-66%. In general, clay content in the field ranges between 12-40%.

Rocks conductivity in Neft Dashlari field Girmaky formation considerably differs from other formations as long as the rocks conductivity in this formation is extremely low.

Oil and gas contents in Neft Dashlari field horizons in blocks I, Ia, II, III, IV, V differ from each other. As in other fields, formation of the oil – gas accumulations in Neft Dashlari field is connected with the structural – lithological requirements. Complexity of the geological field structure hugely influences across the section and proper distribution in the field of oil – gas horizons. Therefore no oil – gas shows are encountered in many cases across the section despite availability of structural requirements and reservoirs.

Tectonic block V, covering north – eastern part of the south – eastern periclinical of the fissure, is surrounded by breadthwise and lengthwise fractures. Here, oil bearing horizons are GaLD, GAD, GD, GUG, QUG, "FLD", X, IX, VIII, VII-a, VII, VI, and V.Oil content of the above mentioned formations and horizons has been established based on logging charts and rock samples taken from drilled wells.

GAD may be divided as GAD_3, GAD_2, GAD_1 development facilities following the clay layers and data obtained during development. Girmakialty formations are characterized by high oil yield and their oil loops sharply differ. Gas has been obtained in some wells drilled in the highest section of the structure during the test.

Lack of sufficient data hasn't made it possible to characterize the gas content in tectonic blocks I and Ia. It must also be noted that there are no free gas accumulations in horizons (QaLD bottom, QaLD top, $QaLD_2$).

No water shows have been noted in the territory of the Neft Dashlari field as the field is submerged by sea water. Namely due to this reason water shows were found during well drilling and development. Almost all the formation waters across all horizons were obtained in QD, QAD_1, $QaLD_1$, $QaLD_2$ and $QaLD_3$ when drilling to the well behind loop zones.

1.2 Tectonic and stratigraphic field structure

Field tectonics

Neft Dsahlari field is tectonically a fissure stretching from north – west to south – east direction segregated by a short and shallow saddle like structure from adjacent Palchig Pilpilasi. This fissure relates to the structural line in Khali, Chilov, Palchig Pilpilasi, and Gunashly direction. The fissure length is 11 km and breadth 6 km.

Neft Dashlari fissure is of asymmetric shape with varying sloping angles of its wings (fig. 1.2).Its south – western wing has a sloping angle 36-44^o, while north – eastern wing 40-50^o. North – western periclinal of the fissure is short and shallow with sloping angles 18-19^o. South – eastern periclinal is compounded by breadthwise and lengthwise faults having a greater stretch and characterized by sloping angle 13-14^o. Difference between QaLD ceiling values in periclinals reaches up to 2800 m. The existence of the fault crossing breadthwise is manifested by the sharp change in the sloping angle of the rocks. So sloping angle of the formations in the area where wells 1 and 6 are located reaches 70-72^o. Normal slope for a portion of the fissue is not greater than 50^o. This conventionally is a sign of the breadthwise fault. Presence of this fault has been once again proven as a result of the drilling process. According to data obtained from wells 56 and 275, it was established that the fault crossing in breadthwise direction is of multiplying nature. Fault plane slopes towards south – western direction. Multiple fractures cut the fissue in breadthwise and lengthwise directions further compounding it.

Neft Dashlari fissure divides into 5 tectonic blocks (I, Ia, II, III, IV, V) on account of above mentioned breadthwise and lengthwise fractures. Difference in the sloping angle and varying stretch azimuths of the formations were noted in the region of well 6 in the south – western wing of the fissure. It also points to existence of breadthwise fracture with I-Ia and for tectonic properties the fracture is of free air type. That is why the south – eastern part of the structure is fairly depressed relative to the north – western part. Here the sliding amplitude is 120 m, while sliding surface is depressed towards south – eastern direction with sloping angle 70-80^o.

Breadthwise fracture II-II is located in south – eastern direction and identified based on structural maps built following wells 1835, 1678 and change in the oil – gas content loops of the same named horizons.

Breadthwise fracture III - III was identified crossing the whole fissure as a result of orderly location of oil – gas outputs of large rocks crossing from the arc section of the Fissure in south – eastern direction.

Notably, most of the free air and non – free air type fractures cutting the fissure breadthwise that play a major role in distribution of oil bearing area in the field cross in north – eastern and south – western direction and characterized by amplitude 50-100 m and occasionally more than 100 m.

As seen from the structural map, disjunctive fractures divide the fissure into 6 tectonic blocks (fig. 1.1).

Tectonic blocks I, III and V are located in north – eastern wing and VIIa, II, IV in south – western wing.

Growth in the sloping angles of formation is observed towards greater stratigraphic depth and it resulted in change in the thickness from arc section of the structure towards its wings. Arc section of thw wing is composed of Diatom, Maikop and Kaun aged rocks.

Thus, Neft Dashlari field is genetically characterized by “diapir” fissure and morphologically has sloped asymmetric shape.

Field stratigraphy

A stratigraphic sedimentation complex from Kaun (Eocene) to Absheron sedimentations (upper Pliocene) is present in the geological structure of the Oil Rocks field.

Sedimentations of the Productive layer surface up alongisde the sedimentations of Aghjagil and Absheron stages in the arc section of the fissure. Kaun, Diatom and Pont sedimentations present in the field section were uncovered through drilled wells and characterized by alternation of dark – gray clays. Here, the most thoroughly studied sedimenations are the sedimentations of the Productive layer and it is because of the abundance of oil – gas accumulations.

Section of the productive layer is primarily composed of alternation of sands, clays, aleurites and sandstones. Gala, Girmakialti, Girmaki, Girmakiustu sandy, Girmakiustu clayey, “Fasila”, Balakhany, and Surakhany formations are present in the section from bottom to top order (fig 1.1).

Gala formation (QaLD)

This formation is primarily composed of alternation of aleurite and sandy – clayey rocks. Thickness of aleurites and sands occasinally reaches 20-25 m. Here hard cemented sand layers are present alongside big – size sand layers. Sands are primarily of light gray color, small and medium size quartzed, while clays are of gray and brownish color and are poor sanded carbonates. Overall formation thickness ranges between 190-900 m.

According to its geological properties, Gala formation divides into three (blocks I-III), four (blocks I^a-IV block), and two (blocks II-V) oil – gas bearing horizons. Thickness of sandy and clayey horizons and oil saturation rate of the rocks vary across the area. Sandiness increases from the heel to arc of the formation vertically across the section of Gala formation.

Girmakialty formation (QAD)

Overall thickness of Girmakialty formation is 70-135 m and characterized by sandstones and gray quartzed sand layers. Thinner clayers overlay in the bottom section of the formation and sands overlay clay layers in the heel section. For its geologtical nature, the formation divides into horizons QAD_1, QAD_2 and $QAD_{3.}$

Girmaky formation (QD)

Girmaky formation is composed of uniform alternating fine and granular sandstone and sandy – clayey layers. Thickness of sandy layers 4-10 m lay in the bottom section of the formation. For its granulometric content, most QD sands relate to clayey and clayey – sandy aleurites. These have very low resistance below 2 Ohms according to log charts. Bottom sandy part of the formation has relatively higher resistance equaling 15 Ohms. Average formation thickness is 300 m. For its geological nature, Girmaky formation falls under 3 horizons such as $QD_ü$, QD_1, QD_2.

Girmakiustu sandy formation (GUG)

This formation is composed of moderate and small – sized granular sandstone, clayey – sandy layers. Overall formation thickness is 30 m. 70% of the formation content with overal thickness ranging between 15-40 m. Sandy layers primarily cover the mid section of the formation.

Girmakiustu clayey formation (QÜG)

With mean thickness 150 m, Girmakiustu clayey formation is composed of alternation of clay and sandstones, sandy aleurite layers. For log charts, overall thigkness of the formation characterized by 10-20 Ohms ranges between 90-220 m.

"Fasila" formation (FLD)

Composed of sands, primarily moderate and small sized granular sandstones and occasional clay layers, overall thickness of Fasila formation ranges between 56-130 m and mean formation thickness is 80 m.

1.3Analysis of hydrocarbon reserves in the fields

Volumetric method is one of the most common methods of estimating oil reserve. This method is a universal method and is applied regardless of the stage and regime of a field. The following formula is used for this purpose.

$Q_{i.b.} = F \cdot h_{ef} \cdot m_{ac} \cdot K_n \cdot \beta_n \cdot \theta$; thousant tons, here,

$Q_{i.b.}$ -initial balance reserve, thousand tons;

F - oil bearing area, м^2, or щ;

h_{ef} - effective thickness of layers saturated by oil, м;

m_{ac} - open porosity ratio;

K_n -oil saturation ratio;

β_n -oil thickness, g/cм^3, кg/м^3;

θ - estimation coefficient ($\frac{1}{b}$ -layer oil's volumetric ratio).

Initial and residual reserves, including oil yield ratios of QD and GUG and other horizons of "Neft Dashlari" field analyzed in the thesis have been estimated and presented in respective table (table 1.3).

Table 1.3

Horizon	Initial balance reserve	Initial extractable reserve	Aggregated production	Residual balance reserve	Residual extractable reserve	Oil recovery factor	
	thousand tons					final	Current
Block III							
GUG	3923	1977	1734	2189	243	0,50	0,44
-u	361	40	22,5	338,5	17,5	0,11	0,06
QD-1	777	377	290	487	87	0,49	0,37
QD-2	3222	989	441,9	2780,1	547,1	0,31	0,14
Block IV							
QUQ	12177	6090	4665	7512	1425	0,50	0,38
QD-ц	78	23	0,2	77,8	22,8	0,29	0,003
QD-1	1808	543	405,9	1402,1	137,1	0,30	0,22
QD-2	5311	2602	2229,1	3081,9	372,9	0,49	0,42
Block V							
QUQ	25060	12530	11681,2	13378,8	848,8	0,50	0,47
QD-u	57	12	8	49	4	0,21	0,14
QD-1	2988	597	457,2	2530,8	139,8	0,20	0,15
QD-2	6250	2813	2501,2	3748,8	311,8	0,45	0,40

As mentioned in Section 2.2, the values of the following formation metrics are used when estimating the oil reserve by volumetric method: oil bearing area, effective formation thickness, porosity and oil – gas saturation ratios of rocks, special oil weight and estimation coefficient.

These indicators fall under two groups `such as variables and fixed indices for their areal variability nature.

First group of indicators include effective thickness, porosity and oil saturation ratios and the second group oil thickness and estimation coefficient. As far as the oil bearing area is concerned, this indicator is indeed subject to change. In this case, mean value of fixed metrics and well data of variables must be used to determine distribution of the reserve in any field over its area.

This way values of well metrics are obtained and their variability over the field is established through a new methodological – kriging analysis. The newly developed methodology is realized through special algorithm and program and contains the followings:

- distribution of the initial balance oil reserve taking into account values of the well metrics;

- areal distribution of oil output across operated wells;

- areal distribution map of the residual oil reserves.

Areal distribution map of reserve in GUG GD1 and GD2 facilities was drawn up and analysis conducted on the studied facilities of the Oil Rocks field in the thesis using the Statistical Kriking mapping method.

Block III

Well data in GUG formation

Table 1.3.1

Item No	Well No	x	y	Initial balance reserve	Initial extractable reserve	Aggre gate produ ction	Residual balance resource	Extractable reserve
1	2	3	4	5	6	7	8	9
1	1758	3,1	4,5	170121	85061	15268	154853	69793
2	1764	5,5	5,2	208990	104495	11600	197390	92895
3	613	7,1	5,0	148777	74388	10900	137877	63488
4	532	9,5	5,5	165118	82559	9147	155971	73412
5	547	11,0	8,0	175911	87956	13467	162444	74489
6	434	9,9	3,7	104256	52128	18121	86135	34007
7	555	11,5	3,5	163545	81773	11760	151785	70013
8	424	13,5	4,8	137199	68600	13286	123913	55314
9	2326	15,3	8,7	191160	95580	6148	185012	89432
10	654	14,9	9,8	164403	82201	12224	152179	69977
11	559	14,0	9,1	144973	72486	15468	129505	57018

Reserves distribution map was drawn up based on data from 11 wells in block III horizon GUG in the “Neft Dashlari” field in Table 1.3.1 (figure 1.3.1).

If we were to look at the initial balance distribution map, the area with largest initial balance reserve is the zone around well 1764 in the west of the area, where reserve is more than 208 thousand tons, the second local area is the zone around well 2326 in north – eastern portion.

There is the same oder in the initial extractable reserve distribution map in Figure 2.2.1. Here the two main areas is the zone around well 1764 in – west (here initial extractable reserve is more than 104 thousand tons), the second area is the zone around well 2326, where reserve is more than 95 thousand tons.

The most reserve bearing areas in the aggregate production map is the well 434 in the south (with 18 thousand tons oil production), well 559 in north east (with 15,4 thousant tons oil production), well 1758 in the west (with with more than 15,2 thousand tons oil production).

Finally, as far as the distribution of residual balance reserve is concerned, two local areas is the zone around well 1764 with residual volume 92 thousand tons and the zone around well 3236 in north – east with residual balance reserve 89,4 thousand tons.

Horizon QD1.

Well data from horizon QD1ы   Table 1.3.2

Item No	Well No	x	y	Initial balance reserve	Initial extractable reserve	Aggregate production	Residual balance resource	Extractable reserve
1	2	3	4	5	6	7	8	9
1	1743	4,6	3,1	53295	26114	1148	52147	24966
2	1755	6,5	4,3	30861	15122	1941	28920	13181
3	1771	3,4	4,0	33210	16273	8271	24939	8002
4	528	12,1	10,5	6919	3390	254	6665	3136
5	457	13,8	7,5	31365	15369	14144	17221	1225
6	434	13,9	2,5	28597	14013	1764	26833	12249
7	1759	9,0	3,1	28216	13826	1510	26706	12316
8	652	17,5	4,6	27771	13608	12604	15167	1004
9	203	17,8	1,7	49814	24409	1189	48625	23220
10	490	14,6	2,9	33210	16273	2487	30723	13786
11	1744	6,0	2,5	32107	15733	3510	28597	12223
12	477	15,9	5,0	33813	16569	7418	26395	9151
13	438	13,1	3,5	39764	19484	4466	35298	15018
14	598	17,5	6,5	28294	13864	5376	22918	8488
15	1754	9,9	3,8	29687	14546	7611	22076	6935
16	1772	3,5	4,1	36548	17909	8746	27802	9163
17	1882	17,0	1,2	39863	19533	5373	34490	14160

Data from 17 wells has been used for this facility (table 1.3.2).

The following areas have been delineated following distribution of the initial balance reserve in the area: first the zone around well 1743 in south west (here the initial balance reserve - 53 thousand tons); second –south – east area where wells 203, 1882 are located with initial balance reserve between 39-49 thousand tons; third area- the zone around well 438 in the center with initial balance reserve 39 thousand tons. There are 26 thousand tons of extractable oil in the zone around well 1743, second – zone around wells 208, 1882 with extractable reserve 24-19,5 thousand tons, third area – 19,4 thousand tons (zone around well 438)..

As for the aggregate extraction map (figure 1.3.2), the most productive oil reserves is the area around wells 457 and 652 in central – eastern part (12-14 thousand tons of oil has been produced from these wells) and the area in south - west where wells 1772 are located. Here, more than 8 thousand tons of oil has been produced from this well.

As for the residual reserves well (figure 2.2.2) here three main local areas are delineated: first – the zone around well 1743 with residual reserve more than 52 thousand tons in south west; second – well 203 with residual reserve more than 48 thousand tons, including well 1882 with residual oil reserve 34 thousand tons. Third area – the zone where well 438 is located and here the residual oil reserve is around 35 thousand tons.

Horizon QD2. Here data from wells 10 has been used in the horizon. Figure 1.3.3 presents map of initial balance distribution map. There is more than 348 thousand tons of initial balance reserve around well 1990 in south – east. The second area is the zone around well 1757 in south – weste where the initial balance reserve volume equals 352 thousand tons. The reserve volume in well 1756 in the center and well 457 in the north is 337 thousand tons. In the distribution map of initial extractable reserve, there is 109 thousand tons of oil in well 1757, 108 thousand tons in well 1990, 105 thousand tons in well 2040, and 104 thousand tons in wells 1756 and 457. The same situation is observed in the aggregate production map (except only well 1990). Let's look at the distribution map of the residual balance reserve. Here the first area is the zone around well 1990 located in south – east of the territory (here residual reserve is 344 thousand tons), second area – west of the area – 2091 and the area where wells 1757 are located with residual reserve 327-332 thousand tons. The third area is the zone around well 1756 in the center with residual reserve 316 thousand tons.

Data from well in horizon QD2   Table 1.3.3

Item No	Well No	x	y	Initial balance reserve	Initial extractable reserve	Aggregate production	Residual balance resource
1757	4,1	3,0	352052	109136	25044	327008	84092
2091	2,6	2,7	337177	104525	4325	332852	100200
2097	3,0	3,3	317503	98426	24746	292757	73680
537	9,0	4,6	318722	98804	5674	313048	93130
446	10,9	5,0	285608	88539	10945	274663	77594
1756	10,7	3,0	337177	104525	20905	316272	83620
457	13,8	7,2	337177	104525	21112	316065	83413
2040	15,0	6,0	341488	105861	23018	318470	82843
475	18,2	7,8	314928	97628	4674	310254	92954
1990	17,9	1,5	348850	108144	4416	344434	103728

Block IV-

Data from well in horizon GUG   Table 1.3.4

Item No	Well No	x	y	Initial balance reserve	Initial extracta ble reserve	Aggregate productio n	Resi- -dual balance resourc e	Extractabl e reserve	
1	2	3	4	5	6	7	8	9	
1	113	6,0	8,1	401450	200725	37750	363700	162975	
2	1650	9,4	8,9	364954	182477	70077	294877	112400	
3	1721	4,1	12,6	391231	195615	2224	389007	193391	
4	1885	3,1	13,2	194156	97078	3476	190680	93602	
5	1933	7,0	11,9	150501	75250	70588	79913	4662	
6	2054	7,0	6,9	234332	117166	1907	232425	115259	
7	2074	2,5	12,7	211771	105885	1192	210579	104693	
8	2198	9,8	7,0	297803	148901	5042	292761	143859	
9	2209	14,5	8,7	33984	169923	115525	224320	54398	
10	2214	9,0	10,1	259170	129585	3296	255874	126289	
11	2215	8,4	10,8	255468	127734	1228	254240	126506	
12	1587	16,5	7,5	214073	107036	4419	209654	102617	
13	2174	12,8	6,5	215799	107899	1356	214443	106543	
14	699	12,6	4,5	332108	166054	7714	324394	158340	

Areal distribution map of the reserves in GUG formation has been drawn up using data from well 14 in block IV. As seen from table 1.3.4, the first area is the zone around well 1721 in the east with initial balance reserve around 400 thousand tons. The second area is the zones around wells 113 and 1650 with the volume of initial balance reserve between 360-400 thousand tons. The third area is the zone around well 2209 in the east and relatively, the zone around well 699 in the south. There is balance reserve 332 thousand tons in the same wells.

The same order is observed in the distribution map of the first extractable reserve (table 1.3.4). So, the extractable reserve in the west is around 200 thousand tons. The second is the central part with extractable reserve between 180-200 thousand tons (wells 113 and 1650). Third area is the well 2209 in the east and and the volume of initial extractable reserve in well 699 is 160 thousand tons (table 1.3.4). The most reserve extracted area in the aggregate production map is the well 2209 located in the east of the area with produced oil more than 115 thousand tons. Other wells are wells 1650 and 1933 with more than 70 thousant tons of oil production.

Finally, let's look at the distribution map of residual reserves. Here the first area is well 1721 in n the north – west of the area (here volume of residual reserve is 389 thousand tons) and the areas where wells 113 are located in the center (here residual reserves 363). Second area is the zone around well 699. The residual reserve estimated in this well is 363 thousand tons.

Let's analyze the distribution maps of the residual reserves without attending to the initial and aggregate production maps drawn up for horizons QD1 and QD2. Two local reas in horizon QD1 are the well 267 in the center and the zone around well 197 with more than 27 thousand tons of residual reserve. Second area the wells 1730 and 739 in the north. Here, volume of available residual reserves is 24-25 thousand tons.

Data from well in horizon QD1 Table 1.3.5

Item No	Well No	x	y	Initial balance reserve	Initial extractable reserve	Aggregate production	Residual balance resource
197	10,0	7,1	30372	9112	2951	27421	6161
243	8,7	7,0	25699	7710	7562	18137	148
267	9,5	6,7	28718	8615	1019	27699	7596
1730	8,0	11,0	27813	8344	3233	24580	5111
2197	14,5	6,0	21843	6553	1061	20782	5492
2199	14,4	6,6	19555	5866	5538	14017	328
1593	4,8	7,0	23597	7079	2810	20787	4269
1693	3,1	11,4	26671	8001	3316	23355	4685
739	7,8	9,2	32708	9813	7534	25174	2279
2005	4,1	8,0	25788	7737	2994	22794	4743
514	12,0	3,0	31388	9416	9251	22137	165
323	15,8	5,5	22395	6719	6163	16232	556

Here the zone is located around wells 1678, 1676, 1675,270 stretching arcform in north – western direction in terms of distribution of residual reserves in operation facility QD 2 (table 1.3.6) with volume of residual reserve between 530-750 thousand tons. The second area is the zone around well 468 in south east with residual reserve 492 thousand tons.

Data from wells in horizon QD2 Table 1.3.6

Item No	Well No	x	Y	Initial balance reserve	Initial extractable reserve	Aggregate production	Residual balance resource
1	2	3	4	5	6	7	8
147	12,5	8,0	382067	187213	106919	275148	80294
312	11,6	7,4	472374	231463	93001	379373	138462
401	9,8	6,5	479321	234867	182296	297025	52571
1628	10,0	10,2	457111	223984	18008	439103	205976
1675	11,0	8,0	618841	303232	25258	593583	277974
1676	11,8	7,6	578195	283316	5976	572219	277340
1678	10,1	7,5	780768	382576	22673	758095	359903
1798	13,9	8,4	459068	224943	15885	443183	209058
1860	14,6	8,5	505950	247915	37624	468326	210291
1949	16,8	7,7	437778	214511	103512	334266	110999
1674	4,5	8,5	413386	202559	55667	357719	146892
1806	5,5	12,4	569709	279158	77145	492564	202013
270	5,4	10,0	551331	270152	23298	528033	246854
468	13,5	2,2	511276	250525	19044	492232	231481
749	20,5	5,0	400686	196336	28150	372536	168186
1890	5,8	13,0	399434	195723	6346	393088	189377

Following data from 25 wells in GUG formation in ***block V*** (table 1.3.6), initial and residual balance reserves have been estimated and their areal distribution map drawn up (table 1.3.7).

Data from wells in horizon GUG Table 1.3.7

Item No	Well No	x	Y	Initial balance reserve	Initial extractable reserve	Aggregate production	Residual balance resource
1	2	3	4	5	6	7	8
501	4,7	10,6	1220931	610466	137402	1083529	473064
637	3,6	12,7	1534189	767095	80835	1453354	686260
802	12,2	2,1	1612511	806256	6936	1605575	799320
879	12,4	3,4	1464636	732318	145669	1318967	586649
908	13,2	8,3	1628741	814370	9721	1619020	804649
939	13,5	10,5	1315609	657804	52238	1263371	605566
951	3,0	10,4	1313045	656522	191328	1121717	465194
977	16,0	6,0	1335802	667901	68860	1266942	599041
984	14,5	11,9	1193808	596904	8431	1185377	588473
1538	7,7	13,6	990914	495457	2228	988686	493229
1557	19,5	14,2	1363917	681959	207552	1156365	474407
1559	21,7	11,0	1108992	554496	294	1108698	554202
1579	17,2	11,5	1030595	515298	46207	984388	469091
1621	19,0	16,1	1517425	758713	14914	1502511	743799
1624	17,6	9,7	1438226	719113	13622	1424604	705491
1645	6,3	1,5	1436748	718374	43798	1392950	674576
1656	21,1	15,7	1057793	528896	86007	971786	442889
1651	22,7	9,5	1438226	719113	18639	1419587	700474
1705	3,5	6,0	1226660	613330	78250	1148410	535080
1700	10,0	3,6	1471547	735773	2699	1468848	733074
1781	11,4	5,1	1515909	757955	23	1515886	757932
1830	21,0	11,6	1419010	709505	89330	1329680	620175
1910	24,7	11,0	1311373	655687	141274	1170099	514413
1918	26,0	11,1	829232	414616	164005	665227	250611
1946	7,5	11,8	827686	413843	58227	769459	355616
1806	5,5	12,4	569709	279158	77145	492564	202013
270	5,4	10,0	551331	270152	23298	528033	246854
468	13,5	2,2	511276	250525	19044	492232	231481

Let's now look at the distribution map of the initial balance reserve drawn up for GUG formation in **block V**. As seen here, the first wells calling attention are wells 802 and 908 located in the center. The initial balance reserves estimated across wells are more than 162 thousand tons. Still another area is the well 1621 in the north and 637 in the west with initial balance reserves more than 150 thousand tons (table 1.3.7). Another area is the zone around wells 1651 and 1624 in the central – eastern part with reserve around 140 thousand tons. As for the aggregate production distribution map, the production here has been from wells in western and eastern parts in the distribution map of the initial balance reserve. As for the central part, here 6-8 thousand tons of oil has been produced.

Namely because of it the order from the distribution map of the residual reserve has been as follows:

First local area – the zone around wells 908, 802, 1781 in the center of the area with residual balance reserve equaling 150-160 thousand tons;

Second local area – zone around well 1621 in the north of the area with volume of residual balance reserve 150 thousand tons;

Third local area- the zone around well 637. It is in the west of the area.

Finally, fourth local area are the areas around wells 1651 and 1624 with residual reserve 140 thousand tons.

Let’s look at the distribution maps of the residual reserves without analyzing the initial and aggregate production maps in horizons QD1 and QD2. The following local areas have been delineated in the distribution map of the residual reserves across 9 wells (tables 1.3.8 and 1.3.9): first local area – the area where wells 1790,2320,2332 area located in north - west (here residual reserves are between 145-151 thousand tons); second area – the zone around well 721 in the south – east with residual reserve 149 thousand tons.

Data from wells in horizon QD1 table 1.3.8

Item No	Well No	x	Y	Initial balance reserve	Initial extractable reserve	Aggregate production	Residual balance resource
1	2	3	4	5	6	7	8
2332	5,9	9,5	167062	33412	19757	147305	13655
2318	4,8	9,9	166643	33329	25303	141340	8026
1790	2,0	7,5	174396	34879	23130	151266	11749
825	7,5	7,6	156621	31324	10112	146509	21212
375	7,4	2,0	161360	32272	11764	149596	20508
2032	9,5	1,1	149279	29856	22640	126639	7216
503	13,7	3,1	129527	25905	7114	122413	18791
721	13,9	1,0	154135	30827	4899	149236	25928
2320	3,0	9,0	164452	32890	18661	145791	14229

Distribution map of the residual reserves in horizon QD2 is diverse (table 1.3.9). So, in the map drawn up based on wells 18, several local zones have been delineated: the first area in the south is the well 2051 (553 thousand tons), second area in the north – 2397 and well 618 (501-507 thousand tons), well 1932 in south – east (498 thousand tons), well 728 in the east (470 thousand tons), wells 596 and 384 in north – east (448-464 thousand tons).

Data from wells in horizon QD2 Table 1.3.9

Item No	Well No	x	Y	Initial balance reserve	Initial extractable reserve	Aggregate production	Residual balance resource
1752	6,9	4,1	399675	179854	41359	358316	138495
1875	8,5	5,5	407777	183500	31989	375788	151511
1932	15,3	2,1	539658	242846	41036	498622	201810
1965	12,6	4,0	454489	204520	165782	288707	38738
2051	8,5	3,4	567281	255276	13542	553739	241734
2314	11,8	11,5	383514	172581	22331	361183	150250
2397	7,8	11,6	506786	228054	5150	501636	222904
596	2,0	9,1	476044	214220	11060	464984	203160
384	1,8	6,6	472353	212559	23640	448713	188919
618	8,4	8,4	522973	235338	15501	507472	219837
849	14,2	8,2	394518	177533	14223	380295	163310
721	17,3	3,0	405200	182340	44662	360538	137678
1791	5,6	10,9	377219	169748	17618	359601	152130
1981	3,6	4,5	448678	201905	28880	419798	173025
1696	6,8	8,5	486310	218839	98101	388209	120738
728	16,0	6,3	493089	221890	22614	470475	199276
431	1,5	5,0	416538	187442	58901	357637	128541

Thus, the thesis contains estimation of reserves in GUG, GD1 and GD2 formation in the Oil Rocks field, differentiation of the reserves across blocks has been conducted, and prospective zones have been determined across the facilities for realization of the reserves of which it might be more appropriate to consider the order of priority given above.

2. Regulation of the field development and geological rationale for new development scenarios.

It is commonly known that the fields development process comprises the following phases:

Phase I field development period is characterized by drilling of the main well fund. The industrial oil is extracted namely during these years and the wells are primarily operated by flow method.

Phase II covers stable years of oil output and is distinguished for 10% drop in the maximum production value. In this period reserves wells fund is being drilled and different methods and measures are taken to increase oil yield from the field.

Phase III is characteirzed by sharp decline in oil output and end of the phase is estimated as 2% rate of the development rate. Here, the wells operated by flow method transition into mechanical development method. The field is subject to watering and consequently,several wells are put out of operation.

Phase IV is characterized by value less than 2% of the development rate. All possible measures are taken in this phase to prevent drop in the production rate.

Development phase V has been suggested by prof. B.A. Baghirov. Results of the broad-scale scientific – research works have shown that it is appropriate to delineate phase V after the final development phase. While IV phase is ongoing, the value of the development rate may be raised above 2% as a result of any action, which may be defined as phase V.

2.1 Development phases have been delineated and their analysis presented below by drawing development curves of horizons GUG and QD lower stratum of the productive layer in Neft Dashlari field we have studied in the thesis.

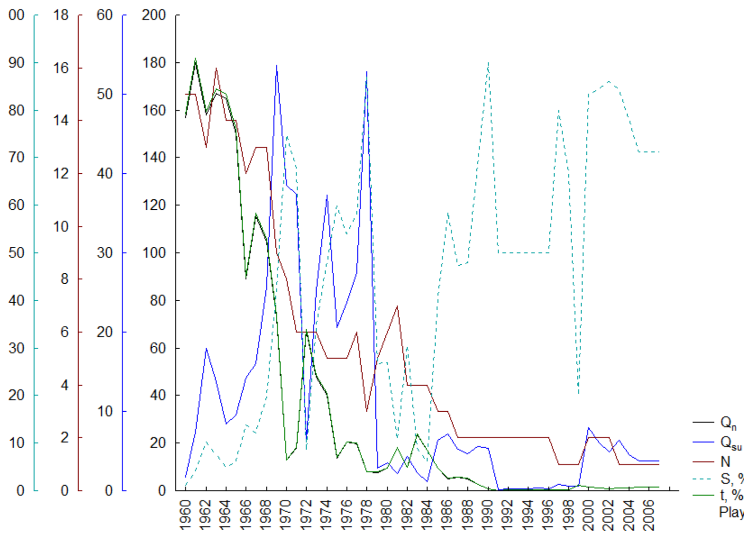
Block III.

GUG development facility (figure 2.1.1) this block was first placed in development in 1960. Oil 156,7 thousand tons and water 1,7 thousand tons have been output from 15 wells developed in the same period. The first layer pressure equaled 7,3 МПа. Despite the stable number of wells in 1961, the first oil output increased and reached 179,8 thousand tons. The same period may be qualified as the development phase I (figure 2.1.1). In this phase water output increased and reached 7,4 thousand tons. Production in the years 1962-1964 made up 167-164 thousand tons, while water output was between 18-8 thousand tons. The facility is assumed to be developed in phase II in those years.

Number of developed wells began to drop as from 1965 and a consequent drop in the oil output was observed. This case has also affected the development rate. There was a sharp decline in the number of wells beginning from 1969. So while wells number was 14 in 1965, this number fell down to 9 in 1969. Oil output was 73 and water output53,6 thousand tons respectively in the same year. Number of wells dropped down to 6 in the years 1971-1973. Years 1965-1974 cover development phase III (figure 2.1.1).

Development curves of Neft Dashlari field block III horizone GUG

Figure 2.1.1



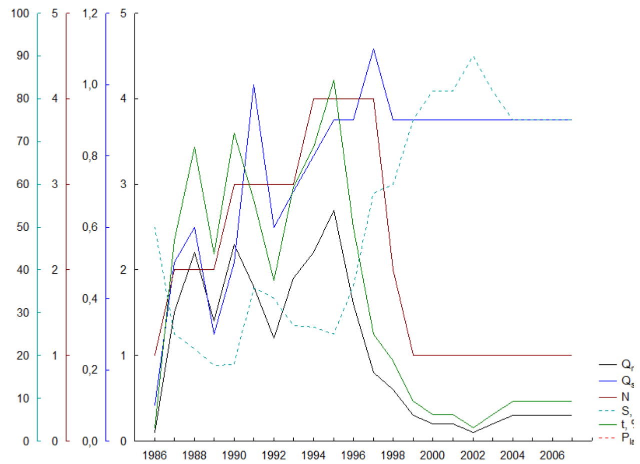
In phase IV (covers years 1974-2007) the number of wells fell down to 5 in the years 1974-1976, which in its turn, affected oil output rate. While oil output was 67-40 thousand tons in 1972-1974, this indicator dropped down to 20-13 thousand tons in 1975-1977. Production in 1978-1982: oil dropped down to 7,9-18 thousand tons and water 52,8-4,3 thousand tons. Production sharply declined beginning from 1985. In the year number of wells dropped down to 3 and 2 in 1987-1996 and was just 1 well in 1997. Oil output also began to decline beginning from 1985 due to decline in the number of operated wells. While oil output was 9-5 thousand tons in 1985-1988, production was below 2,6 thousand tons beginning from 1989. As for the water output, this was 7-4,7 thousand tons in 1985-1990 with sharp decline also in water output beginning from 1991. Number of wells from 2003 until present is 1. Oil and water output values have been stable over the last three years (2005-2007): oil- 1,5 thousand tons and water 3,7 thousand tons.

There has been oils 1734,6 thousand tons and water 532,8 thousand tons output from the facility until present. Value of current oil yield value in the facility equals 0,44. The reason of it is because of the high development rate in the initial development period. Notably, value of development rate in the years 960-1965 was between 9-7%.

Oil Rocks field ***horizon QD**$_{top}$* put in operation in 1986. Oil 0,1 thousand tons and water 0,1 thousand tons has been produced from 1 operated well. Initial value of the layer pressure equaled 7,9 MПa. Number of wells increased up to 2 in 1987 and consequently, annual oil output increased up to 1,5 thousand tons with water output making up 0,5 thousand tons. Number of wells made up 2 in 1990. Oil output in the years 1988-1989 was 2,2-1,4 thousand tons and water output 0,6-0,3 thousand tons (Figure 2.1.2).

Development curves of Neft Dashlari field block III horizon QD-u

Figure 2.1.2



Number of wells increased again as from 1990 with oil 2,3 thousand tons and water 0,5 thousand tons from 3 wells. Production watering was 17,9 %. Value of the development rate made up 5,75%.Annual oil output declined in 1991 with oil output1,8 thousand tons, water output1 thousand tons, production watering 35,7% and development rate was 4,5%. (table 2.1.1).There was a repeated decline in production in 1992, with oil output1,2 thousand tons and water output 0,6 thousand tons. Development indices of block III horizon QD-u

Table2.1.1

Years	**Well number**	**Annual oil production, thousand t**	**Annual water production, thousand t**	**Watering %**	**Development rate %**	**Reservoir pressure MPa**
1986	1	0,1	0,1	50,0	0,25	7,9
1987	2	1,5	0,5	25,0	3,75	
1988	2	2,2	0,6	21,4	5,50	
1989	2	1,4	0,3	17,6	3,50	
1990	3	2,3	0,5	17,9	5,75	
1991	3	1,8	1	35,7	4,50	
1992	3	1,2	0,6	33,3	3,00	
1993	3	1,9	0,7	26,9	4,75	
1994	4	2,2	0,8	26,7	5,50	
1995	4	2,7	0,9	25,0	6,75	
1996	4	1,6	0,9	36,0	4,00	
1997	4	0,8	1,1	57,9	2,00	
1998	2	0,6	0,9	60,0	1,50	
1999	1	0,3	0,9	75,0	0,75	
2000	1	0,2	0,9	81,8	0,50	
2001	1	0,2	0,9	81,8	0,50	
2002	1	0,1	0,9	90,0	0,25	
2003	1	0,2	0,9	81,8	0,50	

2004	1	0,3	0,9	75,0	0,75	
2005	1	0,3	0,9	75,0	0,75	
2006	1	0,3	0,9	75,0	0,75	
2007	1	0,3	0,9	75,0	0,75	

began to increase from 1994 and it was most probably because of the increase in the number of developed wells.

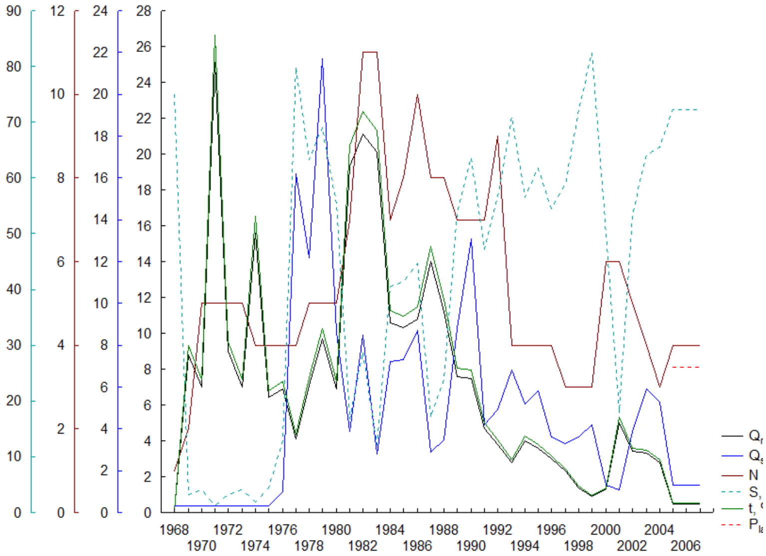
Oil output reached its peak in 1995. Annual oil output from 4 wells was 2,7 thousand tons with water output 0,9 thousand tons, and production watering 25%. There were 4 wells in operation. Development rate made up 6, 7% and years 1986-1995 are qualified as development phase I in the facility.

Phase III covers years 1996-1997. There were 4 wells in operation in this phase with annual oil output between 1,6-0,8 and water output 0,9-1,1 thousand tons. Production watering was 36-58 %.

Number of wells declined to 2 as from 1998. Consequently, oil output declined down to 0,6 thousand tons and water output 0,9 thousand tons. Watering rate was 60%. Sharp decline was observed in the number of wells beginning from 1999. By now number of wells in operation is 1. Oil output was 0, 3 thousand tons and water output 0, 9 thousand tons in 1999. Oil output was 0, 1-0,2 in the years 2000-2003 and 0,3 thousand tons in 2004. Water output from 2000 until present has remained unchanged with stable 0, 9 thousand tons. The facility is operated in phase IV from 1998 until present. Aggregate oil output from 1986 until present has been 22, 5 thousand tons. It means the reserve has been used 6%.

Substratum of the production layer ***development facility QD1*** (figure2.1.3) was put in operation in 1968. 1 operated well yielded oil 0,1 thousand tons and water 0,3 thousand tons. Wells number increased and made up 2 as from 1969. In this connection, initial oil output increased by8,8 thousand tons water output remained unchanged making up 0,3 thousand tons. Wells number increased by 5 as from 1970. The maximum oil output was observed in 1971 making up development phase I. Annual oil output in this phase was25,1 thousand tons and water output 0,3 thousand tons with development rate 6,6% (Figure 2.1.3).

Figure 2.1.3

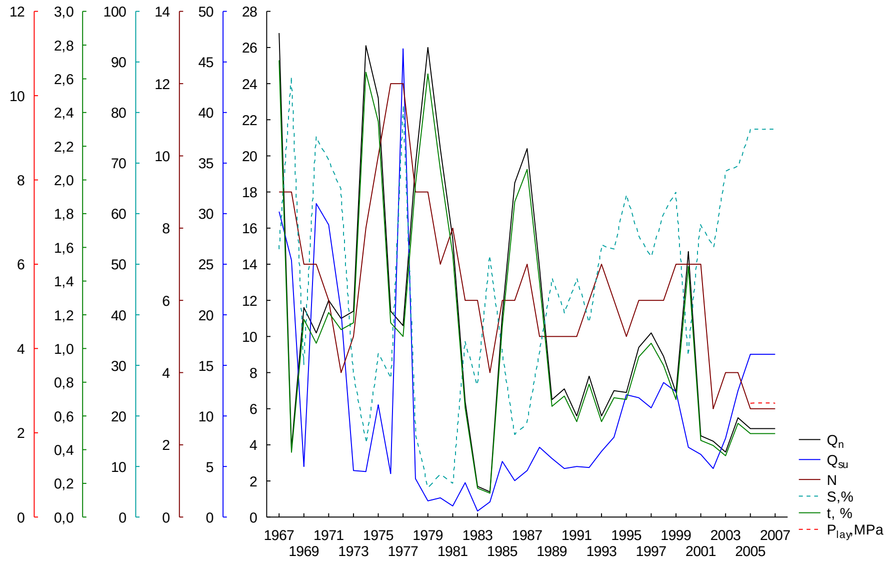


Phase III in the facility covers years 1972-1989. Notwithstanding availability of 7 wells in the period, the annual productions number was low: oil-7,6 thousand tons and water- 8,8 thousand tons. Value of development rate made up 2,02%. Facility transitioned into phase IV in connection with decline in oil output and value of development rate below 1,8% beginning from 1990. Wells number in this phase in 1992 was 9. However it didn’t influence oil output altogether. Wells number began to decline from 1993. Generally, wells number in this phase was between 5-3 and hence annual productions declined as well. Currently there are 4 wells being operated in the facility with annual oil output 0,5 thousand tons and water output 1,3 thousand tons. Production watering is 72%, current layer pressure equals 2,6 МПа. Aggregate production from 1968 until present is 290 thousand tons. Here reserves usage rate is 37%.

Neft Dashlari field ***horizon QD2*** (Figure 2.1.3a)

Figure 2.1.3a

Development curves of “Neft Dashlari” field block III horizon QD-2



This well was put in operation in 1967 and wells number equaled 9. Annual oil output from the same well was 26,8 thousand tons and water output 30,2 thousand tons. Value of current layer pressure was 10,7 MPa. Maximum value of the annual oil output namely coincides with this year. North withstanding that the number of wells remained stable in 1968, there was a marked decline in annual oil output and itt is most probably due to lower oil output from each well. Value of water output in the same year made up 25,4 thousand tons (Table2.1.2).

Table 2.1.2

Years	Well number	Annual oil production, thnsd t thousand tones	Annual water production, thousand t thousand tones	Watering %	Development rate %	Layer pressure MPa
1967	9	26,8	30,2	53,0	2,71	10,7
1968	9	3,8	25,4	87,0	0,38	
1969	7	11,6	5	30,1	1,17	
1970	7	10,2	31	75,2	1,03	
1971	6	12	28,9	70,7	1,21	
1972	4	11	20,3	64,9	1,11	
1973	5	11,4	4,6	28,8	1,15	
1974	8	26,1	4,5	14,7	2,64	
1975	10	23,2	11,1	32,4	2,35	
1976	12	11,4	4,3	27,4	1,15	
1977	12	10,6	46,3	81,4	1,07	
1978	9	19,5	3,8	16,3	1,97	
1979	9	26	1,6	5,8	2,63	
1980	7	20,4	1,9	8,5	2,06	
1981	8	15,4	1,1	6,7	1,56	
1982	6	6,4	3,4	34,7	0,65	
1983	6	1,7	0,6	26,1	0,17	
1984	4	1,4	1,5	51,7	0,14	
1985	6	11,2	5,5	32,9	1,13	
1986	6	18,5	3,6	16,3	1,87	
1987	7	20,4	4,6	18,4	2,06	
1988	5	13,8	6,9	33,3	1,40	
1989	5	6,5	5,8	47,2	0,66	
1990	5	7,1	4,8	40,3	0,72	
1991	5	5,6	5	47,2	0,57	
1992	6	7,8	4,9	38,6	0,79	
1993	7	5,6	6,5	53,7	0,57	
1994	6	7	7,9	53,0	0,71	
1995	5	6,9	12,1	63,7	0,70	
1996	6	9,4	11,8	55,7	0,95	
1997	6	10,2	10,8	51,4	1,03	
1998	6	8,9	13,3	59,9	0,90	
1999	7	6,9	12,4	64,2	0,70	
2000	7	14,7	6,9	31,9	1,49	
2001	7	4,5	6,2	57,9	0,46	
2002	3	4,2	4,8	53,3	0,42	
2003	4	3,6	7,8	68,4	0,36	
2004	4	5,5	12,5	69,4	0,56	
2005	3	4,9	16,1	76,7	0,50	2,7

table 2.1.2

Wells number declined in the years 1969-1970 dropping down to 7, 6 wells in 1971, and 5 in the subsequent year. Oil output was 12-10 thousand tons over the years. Value of water output was as follows: 31 thousand tons in 1970 and 28,9 thousand tons in 1971.

Wells number was 4-5 in the years 1972-1973 and it began to increase beginning from 1974. While value of this indicator was 8 in 1974, it increased up to 10 in 1975 and equaled 12 in 1976-1977. Annual oil output increased alongside increase in the wells number. So, while oil output was 11,4 thousand tons in1973, this indicator doubled in 1975 making up 26 thousand tons. The production dropped in 1976-1977 making up 11,4 -10,6 thousand tons. There was an increase in oil output observed notwithstanding decline in the wells number in 1978 (Table 2.1.2). Oil output in the same year was 19,5 thousand tons and 26 thousand tons in 1979. Wells number gradually declined beginning from 1980. Notably, value of water output was very low in the years 1979-1980 (1,9-1,1 thousand tons).

While value of development rate was 2% in the years 1974-1980, there was a marked decline in this rate beginning from 1981.

As seen from table 2.1.2, wells number declined to 6 in the years 1982-1983. However while the annual production from 6 wells made up 6,4 thousand tons in 1982, it made up 1,7 thousand tons in 1983. In these years water output equaled 3,4 and 0,6 thousand tons respectively. Wells number sharply declined to 4 in 1984 with oil output1,4 thousand tons and water output1,5 thousand tons. Annual value of the oil output in1985-1986 ranged between 11-18 thousand tons and water output 5,5-3,6 thousand tons. Number of operated wells in the years 1988-1991 was 5. Oil output ranged between 13,8-5,6 thousand tons and water output 6,9-5 thousand tons. Wells number in the years 1991-2001 changed between6-7. As for oil production, its change interval was 5,6-14,7 thousand tons and 13-6 thousand tons. There was a marked decline in the wells number beginning from. 2002 (between 3-4). Consequently, oil output made up 3,6-4,9 thousand tons and water output 4,8-16 thousand tons.

Currently there are 3 operational wells in the facility with annual oil output 4,9 thousand tons and water output 16,1 thousand tons and current reservoir pressure 2,7 Mpa.

Notably, there has been oil 442 thousand tons produced from the well as from the start of operation (beginning from 1967). Rate of reserve usage is 14%. It should be noted that the development rate here is characterized by very low numbers and here the highest rate was 2,7% (in 1967).

Block IV

GUG development facility (Table 2.1.2a) was put in operation in 1955. Development indicators of block IV GUG horizon

Table 2.1.2a

Years	**Wells number**	**Annual oil production** **thousand tones**	**Annual water output** **thousand tones**	**Watering,** **%**	**Development rate** **%**	**Layer** **pressure,** **MPa**	**Gas factor** **м3/tone**
1955	1	9,1	0,9	9,0	0,15	13,1	
1956	1	11,2	0,9	7,4	0,18	13,1	
1957	1	11,2	0,9	7,4	0,18	13,1	
1958	18	92,3	0,9	1,0	1,52	11,2	
1959	25	317,9	0,9	0,3	5,22	7,9	
1960	24	183,5	0,9	0,5	3,01	7,1	80
1961	21	211,5	0,9	0,4	3,47	7,6	78
1962	22	269,7	1,3	0,5	4,43	8	52
1963	19	288,8	12,2	4,1	4,74	8,7	60
1964	18	317,4	32,6	9,3	5,21	8,3	64
1965	22	231,1	31,3	11,9	3,79	7,9	64
1966	28	293,6	30,5	9,4	4,82	7,5	92
1967	25	327,3	29,8	8,3	5,37	7,5	143
1968	26	212,3	62,5	22,7	3,49	7,3	191
1969	28	152,3	80,1	34,5	2,50	7,3	97
1970	26	105	72	40,7	1,72	7,8	135
1971	24	82,7	59,6	41,9	1,36	7,3	178
1972	25	84,1	6,3	7,0	1,38	7,3	229
1973	24	67,2	12,6	15,8	1,10	13,1	472
1974	18	48	22,9	32,3	0,79	12,9	371
1975	15	33,7	19,6	36,8	0,55	12,7	371
1976	14	51,4	25,3	33,0	0,84	124,5	260
1977	18	49,7	19	27,7	0,82	13,2	220
1978	18	58,8	15,6	21,0	0,97	13,3	160
1979	16	49	32,2	39,7	0,80	13,2	160
1980	20	94,6	15,8	14,3	1,55	13,2	160
1981	19	109	42,6	28,1	1,79	6,6	55
1982	17	96,2	57,9	37,6	1,58	6,6	60
1983	17	40,8	24,6	37,6	0,67	6,6	60
1984	20	73,1	38	34,2	1,20		
1985	18	65	24	27,0	1,07		
1986	17	77,9	36	31,6	1,28		
1987	17	58,3	32,7	35,9	0,96		
1988	21	53,7	9,7	15,3	0,88		
1989	21	34,6	45,9	57,0	0,57		
1990	20	42,1	30,9	42,3	0,69		
1991	18	20,6	20,2	49,5	0,34		
1992	15	15,7	19,7	55,6	0,26		
1993	11	22,4	17,4	43,7	0,37		

1994	14	22,3	14,6	39,6	0,37		
1995	14	24,2	16	39,8	0,40		
1996	12	19,8	14,7	55,0	0,33		
1997	10	16,7	10,6	38,8	0,27		
2000	13	23,8	17,4	42,2	0,39		
2001	13	23,6	19,1	44,7	0,39		
2002	11	22,2	14,6	39,7	0,36		
2003	10	19,8	14,4	42,1	0,33		

Table 2.1.2 a

Oil 9,1 thousand tons and water 0,9 tons were output from 1 well in operation. First layer pressure was 13,1 МПа. There was an observed increase in wells number beginning from 1958 that reached 18 (Table2.1.2a). Increase in wells number also influenced annual oil production. So oil output in the respective year equaled 92,3 thousand tons and wells number was 25 as from 1959. Oil output increased and made up 317,9 thousand tons. Water output remained unchanged in the years 1955-1961. Maximum value of oil output in the facility was 327,3 thousand tons (1967) and it makes up development phase I. Water output in the respective period was 29,8 thousand tons and development rate 5,3 %. Oil output began to decline from 1968 and notably, phase III here covers years 1968-1969. The facility transitioned into phase IV beginning from 1970. Value of oil output in the years 1968-1973 ranged between 212,3- 67,2 thousand and number of developed wells between 26-24. Wells number declined in the years 1974-1979 making up 18-16 with consequent drop in oil output (58-48 thousand tons) and water output 22-32 thousand tons.

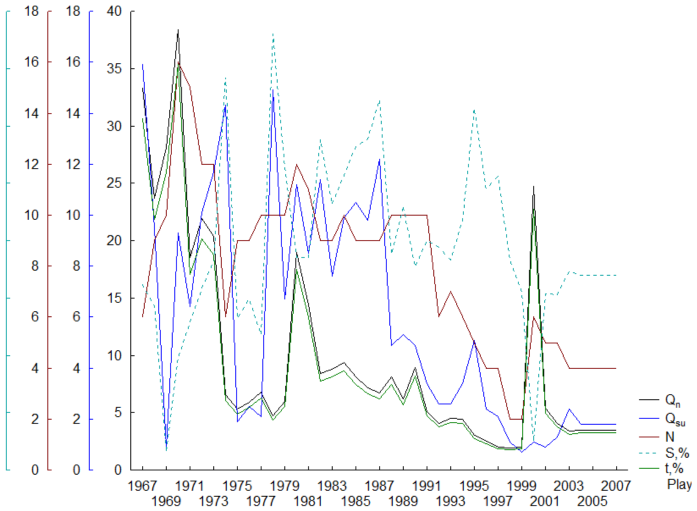
Wells number increased in the interval of years 1980-1981, 1984-1985 and 1988-1990 (18-21). There was a marked increase in oil output in the years 1980-1986 (figure2.1.4a).

Production in 1991 relative to 1990 dropped double. Production gradually declined beginning from 1992. Annual oil output has fluctuated around 22 thousand tons from 1992 until present. There is also no change in the wells number in the respective period. Wells number ranged between 15-12. There are currently 12 wells operational in the facility. Annual oil output is 21,3 thousand tons, water output 26,1 thousand tons and layer pressure 3,6 МПа.

There has been oil 4665 thousand tons and water 1234,4 thousand tons output from the facility until present with reserve usage rate 38%.

Development of ***horizon QD$_{top}$*** ин block IV coincided with 1998. There was only 1 well in operation with annual oil output 0,2 thousand tons and water output 0,7 thousand tons. Currently the facility is not in operation and reserve usage rate being very low equaling 0,003.

QD1development facility (figure2.1.4a)



The facility was put in operation in 1967 with 6 developed wells. Annual oil output was 33,3 thousand tons and water output15,9 thousand tons. Value of development rate equaled 32%. Wells number began to increase beginning from 1968. But this case had no influence on increase in oil production. The production increased and made up 23,7 thousand tons relative to 1967. Wells number reached 10 in 1969 and 16 in 1970. Annual oil output reached its peak and equaled 38,4 thousand tons in its development period in 1970. Years 1967-1970 make up development phase I with development rate of 7% (Table 2.1.3)

Table 2.1.3

Years	**Wells number**	**Annual oil production thousand т**	**Annual water yield thousand т**	**Watering, %**	**Development rate %**	**Reservoir pressure, MPa**	**Gas factor m3/tone**	
1967	6	33,3	15,9	32,3	6,13	11		
1968	9	23,7	9,5	28,6	4,36			
1969	10	28,1	0,9	3,1	5,17			
1970	16	38,4	9,3	19,5	7,07			
1971	15	18,5	6,4	25,7	3,41			
1972	12	21,9	10,1	31,6	4,03			
1973	12	20,4	11,7	36,4	3,76			
1974	6	6,6	14,3	68,4	1,22			
1975	9	5,3	1,9	26,4	0,98			
1976	9	5,9	2,5	29,8	1,09			
1977	10	6,8	2,1	23,6	1,25			
1978	10	4,7	14,9	76,0	0,87			
1979	10	6	6,7	52,8	1,10			
1980	12	19	11,2	37,1	3,50			
1981	11	14,4	8,5	37,1	2,65			

1982	9	8,4	11,4	57,6	1,55			
1983	9	8,8	7,6	46,3	1,62			
1984	10	9,4	9,9	51,3	1,73			
1985	9	8,1	10,5	56,5	1,49			
1986	9	7,2	9,8	57,6	1,33			
1987	9	6,7	12,2	64,6	1,23			
1988	10	8,1	4,9	37,7	1,49			
1989	10	6,2	5,3	46,1	1,14			
1990	10	8,9	4,9	35,5	1,64			
1991	10	5,1	3,4	40,0	0,94			
1992	6	4,1	2,6	38,8	0,76			
1993	7	4,5	2,6	36,6	0,83			
1994	6	4,4	3,4	43,6	0,81			
1995	5	3	5,1	63,0	0,55			
1996	4	2,5	2,4	49,0	0,46			
1997	4	2	2,1	51,2	0,37			
1998	2	1,9	1,1	36,7	0,35			
1999	2	2	0,7	31,0	0,37			
2000	6	24,7	1,1	5,0	4,55			
2001	5	5,4	0,9	30,8	0,99			
2002	5	4,1	1,3	30,5	0,76			
2003	4	3,4	2,4	34,6	0,63			
2004	4	3,5	1,8	34,0	0,64			
2005	4	3,5	1,8	34,0	0,64			
2006	4	3,5	1,8	34,0	0,64			
2007	4	3,5	1,8	34,0	0,64		52	

Table 2.1.3

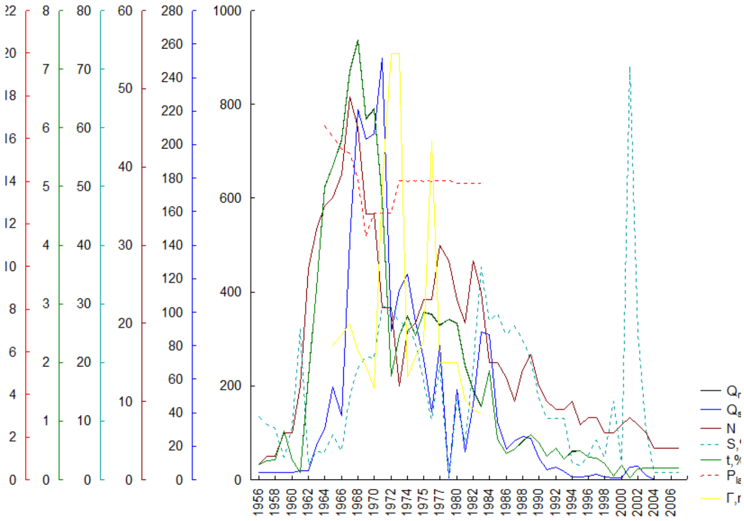
Years 1971-1981 make up development phase III. Annual oil output was low notwithstanding that the wells number ranged between 15-9 in this phase. Oil output ranged between 20-6 thousand tons and water output 14,9-2 thousand tons in the respective period.

The facility made a transition into phase IV beginning from 1982 with wells number between 9-10 in 1982-1992. Oil output in the respective period declined from 9 to 5 thousand tons and water output from 11 to 2,6 thousand tons. Wells number was 6-5 in the years 1992-1995 and 5-4 in the years 1996-2002. Increase in oil output (24,7 thousand tons) was observed in connection with drilling of new wells in the facility in 2000. In this connection, value v of the development rate made up 4,5%. The year may be seen as development phase V.

Wells number dropped to 4 beginning from 2003. Annual oil output in the respective years was 3,4 thousand tons and water ield 1,8 thousand tons. Oil 405,9 thousand tons and water 238,7 thousand tons have been output from the facility until present. Reserve usage rate is 22%.

Development of ***horizon QD2***(figure2.1.5) in block IV

It entered in 1954. Annual oil production from two wells is 20,3 thousand tons, water production is 1,5 thousand tons, the first reservoir pressure is 11,7mPA, the price of gas factor was 75 m3/t. Beginning in 1956, the number of wells began to increase . In 1956, wells were operating while in 1957 their number was 9. According to the increase in the number of wells, annual oil production is 44,4thousand tons, it was equal to 120,7 thousand tons. Namely, 1957 covers the development stage. (Figure2.1.5)



Phyase III covers 1958-1972 (chart 2.1.7). In 1958 the wells number declined to 6 with annual oil output from 6 wells 104,2 thousand tons and water output 1,5 thousand tons. Notably, water output remained stable and made up 1,5 thousand tons from the beginning of development until 1963. Value of gas factor in the years 1956-1958 was 105-135 м^3/т. Despite increase in wells number in 1959, oil output was 83,5 thousand tons. It ranged between 86-83 thousand tons in 1959-1961. Wells number increased up to 10 in 1963. Oil output increased and made up 102,5 thousand tons in the respective year. Wells number began to increase as from 1964 reaching 18 in 1967. Wells number doubled and made up 32 in 1971. Oil output ranged between 90-112 thousand tons in 1964-1970 with water output 9-38 thousand tons. As for the gas factor, the peak value of this indicator coincides with 1968 (358 м^3/т) . Value of development rate in 1958-1972 was 4-2%.

The facility has been operated in phase IV from 1973 until present. Wells number was 17,21 in 1973-1974. Oil output in the same year was 35,7-30,4 thousand tons with water output ranging between 21,5-23,5 thousand tons. Wells number in 1978-1992 ranged between 20-10 with oil output 43-10 thousand tons and wells number between 12-9 in 1993-2003. As for the oil output there was a marked decline in it beginning from 1991 (below 10 thousand tons) with water output ranging between 18-8 thousand tons (chart 2.1.7).

Years	Wells number	Annual oil output thousand tones	Annual water yield thousand tones	Watering %	Development rate %	Layer pressure MPa	Gas factor m3/tone
1956	2	33,8	4,1	10,8	0,27	20,5	
1957	3	39,8	4,1	9,3	0,32		
1958	3	42,8	4,1	8,7	0,34		
1959	6	104,1	4,1	3,8	0,83		
1960	6	42,8	4,1	8,7	0,34		
1961	12	16	5,5	25,6	0,13		
1962	27	218	5,6	2,5	1,74		
1963	32	407,4	20,5	4,8	3,25		
1964	35	623,3	30	4,6	4,97	16,6	
1965	36	669	55,3	7,6	5,34	16,1	143
1966	39	725,3	38	5,0	5,79	15,5	155
1967	49	871,6	143,1	14,1	6,96	15,3	166
1968	45	936,8	220,8	19,1	7,48	14,1	137
1969	34	770,3	203,1	20,9	6,15	11,4	121
1970	34	790	206,6	20,7	6,30	12,5	97
1971	22	596,9	251,7	29,7	4,76	12,5	314
1972	22	220,5	88,8	28,7	1,76	12,5	454
1973	12	307,2	113,4	27,0	2,45	14	454
1974	19	349,3	122,4	25,9	2,79	14	109
1975	20	307,4	94,3	23,5	2,45	14	132
1976	23	357,3	71,9	16,8	2,85	14	147
1977	23	352,9	40,3	10,2	2,82	14	361
1978	30	330	80	19,5	2,63	14	125
1979	28	341,9	1	0,3	2,73	14	125
1980	23	333,8	53,7	13,9	2,66	13,9	125
1981	20	243,5	16,5	6,3	1,94	13,9	85
1982	28	191,3	44,9	19,0	1,53	13,9	75
1983	24	155,4	88,3	36,2	1,24	13,9	70
1984	15	232,7	86,4	27,1	1,86		
1985	15	87,1	34,5	28,4	0,70		
1986	13	56,4	18,5	24,7	0,45		
1987	10	65,7	23,4	26,3	0,52		
1988	14	81,8	25,7	23,9	0,65		
1989	16	96	24,7	20,5	0,77		
1990	12	78,8	13	14,2	0,63		
1991	10	50,2	5,9	10,5	0,40		
1992	9	67	7,8	10,4	0,53		
1993	9	43,8	5,1	10,4	0,35		
1994	10	60,7	1,8	2,9	0,48	20,5	
1995	7	62	1,5	2,4	0,49		
1996	8	48,2	2,1	4,2	0,38		
1997	8	45,8	3,3	6,7	0,37		
1998	6	35,4	1,4	3,8	0,28		

1999	6	7,1	1,1	13,4	0,06		
2000	7	30,8	1	3,1	0,25		
2001	8	3,1	7,4	70,5	0,02		
2002	7	23,8	7,9	24,9	0,19		
2003	6	26,1	2,5	8,7	0,21		
2004	4	25,3	0,3	1,2	0,20		
2005	4	25	0,3	1,2	0,20		
2006	4	25	0,3	1,2	0,20		
2007	4	25	0,3	1,2	0,20	5,8	

Number of developed wells from 2003 until present is 9 with annual oil output 15, 2 thousand tons, water output14,3 thousand tons and current layer pressure 8,4 MПa.

So, aggregate output from horizon QD 2 in block IV until present has been 2229 thousand tons. As compared to block III, here reserve usage rate was thrice more making up 42%. It may be noted, following the development analysis result, that the reason for 42% reserve usage rate here may be explained by 1,5 times greater development rate (as compared to block III) equaling 4,64. Further, considering the facility is operated in gas solved in oil, gas factor has also had a role as an informative indicator here (ranged between 75-358 $м^3/т$). Average value of this indicator equals 140 $м^3/т$ in block IV, while it is 52 $м^3/т$ in block III.

Block V

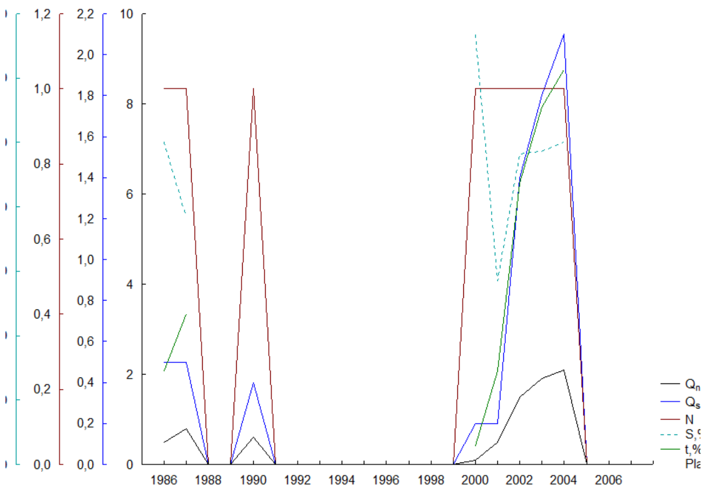
Development of ***GUG formation*** (Figure2.1.5) in block III coincides with 1956. 2 wells were put in operation in the respective year with annual oil output from 2 wells 33,8 thousand tons, water output 4,1 thousand tons, and initial layer pressure 20,5 MПa. Wells number began to increase beginning from 1957. Annual oil output from 3 wells in the year increased and made up 39,8 thousand tons, while water output remained stable. Wells number increased reaching 6 in 1959 and doubled in 1962 making up 27. Oil output increased correspondingly.

In 1963, oil 407,4 thousand tons and water 20,5 thousand tons were output from 32 wells. Output in 1964 increased up to 623,3 thousand tons, 669 thousand tons in 1965, 725,3 thousand tons in 1966, and 871,6 thousand tons in 1967. Water output increased from 30 thousand to 143 thousand tons correspondingly. Increase in the wells number is also observed in the respective years (chart 2.1.8). Maximum value of annual oil output in the facility is observed in 1968. Years 1956-1968 make up development phase I of the facility. In this period, annual oil output was 936,8 thousand tons, water output 220,8 thousand tons, and value of development rate 7,5%. Number of developed wells equaled 45 (chart 2.1.8).

Phase III in the facility covers 1969-1980. Wells number dropped down to 34 in 1969 with corresponding decline in oil output 770,3 thousand tons. Oil output declined and made up 597 thousand tons in 1971, water output 251,7 thousand tons and number of developed wells 22. Oil output began to decline beginning from 1973 (307 thousand tons). In general, annual oil output ranged between 307-357 thousand tons in the years 1973-1980 with number of development wells between 12-30.

The facility has been operated in phase IV from 1981 until present. Wells number in 1981-1983 was between 20-28. Annual oil output in the respective years ranged betwen 243-155 thousand tons and water output16-88,3 thousand tons. Wells number dropped as from 1984 with corresponding gradual decline in oil output. Sharp increase in the wells number started from 1995. There were 7 wells in operation in that year with annual oil output 62 thousand tons and water output1,5 thousand tons. As seen from chart 2.1в, oil output began to decline beginning from 1996. Wells number dropped down to 4 in 2004. There are currently 4 operational wells in the facility with oil output 25 thousand tons, water output 0,3 thousand tons, and current layer pressure 5,8 МПа. There has been oil 11681 thousand tons and water 2292 thousand tons output from the facility from 1956 until present. Current oil yield rastio is 0,47. It must also be noted that the peak value of development rate here was 7,4%. As seen from above, the reserve usage rate in this block is higher as compared to block IV and it may naturally be explained by high development rate as well.

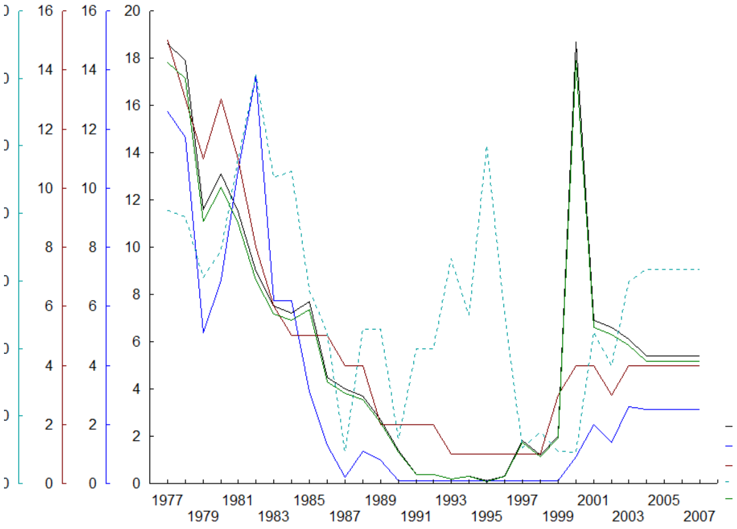
In figure2.1.6 **Development curves in horizon *QDüst* is presented**



Development curves in horizon ***QDüst*** is presented. This facility was out in operation in 1986. Oil 0,5 thousand tons and water 0,5 thousand tons were output from 1 well in operation in the respective year. Output increased and made up 0,8 thousand tons notwithstanding that the wells number remained stable in 1987. Wells operation halted in the years 1988-1989 and 1 well was put in operation again in 1990. Its annual oil output was 0,6 thousand tons and water output 0,4 thousand tons. After the interval continuing until 2004, the annual oil output in the same year made up 2,1 thousand tons and water output 1,8 thnsd tons with production 48,6 % and development rate

17,5%. Aggregate output made up 8 thousand tons as the facility's development period was short. Notably, the value of reserve usage rate in this block is higher as compared to developed QDtop facility making up 14%.

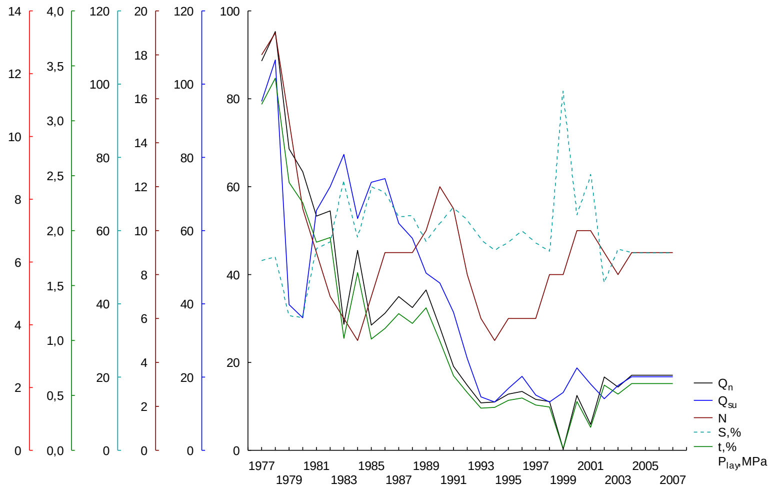
Development of ***horizon QD1***(figure2.1.7)



coincides with 1977. Annual oil output from 15 wells was 18,6 thousand tons and water output 12,6 thousand tons. This year may be qualified as development phase I. Wells number dropped down to 13 beginning from 1978. Oil output made up 17,9 thousand tons and water output 11,7 thousand tons in the respective year. Years 1978-1980 make up development phase III. Number of developed wells in this phase was 13, annual oil output 13,1 thousand tons and water output 6,9 thousand tons with development rate 2,19%.

Currently, annual oil output is 5,4 thousand tons, water output 2,5 thousand tons with production watering 31%. There has been oil 457,2 thousand tons and water 97,5 thousand tons output from the facility from 1977 until present. Reserve usage rate is 15%.

In this block, development of ***horizon QD2*** (figure 2.1.8)



coincides with 1977. Oil 88,6 thousand tons and water 95,3 thousand tons have been output from 18 wells in operation. Development phase coincides with years 1977-1978. Number of developed wells in the respective period was 19, annual oil output 95,3 thousand tons and water output 106,6 thousand tons. The facility was operated in phase III in the years 1979-1980. Wells number in the respective period was 15,11. Annual oil output ranged between 68,6-63,4 thousand tons and water output 39-38 thousand tons. As for the development rate, it equaled 2,4-2,3% (chart 2.1.11).

Years	**Wells number**	**Annual oil output thousand tone**	**Annual water output thousand tone**	**Watering,**	**Development rate %**	**Layer pressure MPa**	**Gas factor m3/tone**
1977	18	88,6	95,3	51,8	3,1	12,5	
1978	19	95,3	106,6	52,8	3,4		
1979	15	68,6	39,8	36,7	2,4		
1980	11	63,4	36,2	36,3	2,3		
1981	9	53,3	65,5	55,1	1,9		
1982	7	54,5	72	56,9	1,9		
1983	6	28,7	80,8	73,8	1,0		
1984	5	45,5	63,3	58,2	1,6		
1985	7	28,5	73,2	72,0	1,0		
1986	9	31,2	74,2	70,4	1,1		
1987	9	35	62	63,9	1,2		
1988	9	32,5	57,9	64,0	1,2		
1990	12	28	45,7	62,0	1,0		
1991	11	19,1	37,7	66,4	0,7		
1992	8	14,8	25,1	62,9	0,5		
1993	6	10,8	14,6	57,5	0,4		
1994	5	11	13,2	54,5	0,4		
1995	6	12,8	16,9	56,9	0,5		
1996	6	13,4	20,2	60,1	0,5		
1997	6	11,6	15,1	56,6	0,4		

The facility made a transition into phase IV in connection with the value of development rate equaling 1,9% beginning from 1981. The wells number began to decline as from 1981 (their number was 9). Wells number ranged between7-10 in the year 1982 -1989. Value of annual oil output ranged between 54-28 thousand tons and water output 48-72 thousand tons.

Wells number began to decline from 1992 and their number equaled 8. Wells number ranged between 8-6 in 1998. There was a marked decline in oil output in connection with drop in wells number (ranged between 11-14,8 thousand tons). Wells number from 2002 until present has been 9. Currently, the oil output is 17,1 thousand tons, water output 20 thousand tons, development rate 0,6 %, and current layer pressure value 4,1 МПа. Oil 2501 thousand tons has been output from this facility until present. Its reserve usage rate is 40%. Here reserve usage rate as compared to block IV is relatively low. This figure is threefold greater than in block III (here, reserve usage rate is 14%). Its most probable reason is that the development rate as compared to block IV (the highest value 3,4%) is lower than block IV and greater than block III.

2.2 Geological substantiation of waterflooding and new impact methods

In the world practice, the development of oil fields using the irrigation method is very widespread. Currently, more than 90% of all oil fields are developed using secondary methods. The generalization of the field development experience shows that the results of the application of this method should be widely studied today, despite the fact that the application of the irrigation process has yielded mainly positive results. Incomplete coverage of non-homogeneous strata by the application of the injection process, increasing the volume of difficult-to-extract reserves, complicating the characteristics of the oil-saturated porous reservoir, changing the physical and chemical properties of produced oil in the final stage of development, increasing man-made manifestations in fields, creating difficulties in efficient development.

In many cases, the recovery of formation energy for the creation of efficient development systems in the fields, the close connection of the injected working agent with the compression of oil in the porous environment of the reservoirs is associated with the optimization of irrigation systems during development.

In Azerbaijan, the United States, Canada, Russia, Saudi Arabia and other countries, the injection process has been intensively used in the development of oil fields.
The relative simplicity of irrigation technology, high efficiency, availability of water source and inefficiency of the working agent have given impetus to the widespread use of this method.
The long-term application of irrigation in different geological conditions has led to the creation of various modifications. They are:

Pumping behind the contour. In this way, water is pumped behind the water-oil contour of the field. The water injected into the formation by this method has a positive effect on the hydrodynamic conditions of the field when the degree of geological diversity in the formation is low, the permeability of the formation rocks is high, and the viscosity of the oil is low. The width of the field should be about 5 km, and when it is larger, its central parts are excluded from the impact of the injected water.

Pumping next the contour.

The conditions required for the application of this method are analogous to the conditions of application of back-contour irrigation. The only distinguishing feature here is the relatively low permeability of the layers in the water-oil contour zone. Therefore, the placement of injection wells away from the water-oil circuit and the injection of water into the field through them reduces the efficiency of the process. In such cases, the placement of injection wells on the water-oil contours (internal and external) eliminates this complexity.

Internal Contour (field) pumping. This method is sometimes called "field irrigation" modification. As its name suggests, this method involves the placement of injection wells in the oil field of the field. The following geological factors must be present in the field for the effective application of field irrigation modification: the oil content of the field is large, the geological diversity of the formation is high, the permeability of the rocks is relatively low, and the viscosity of the oil is high.

The above methods of irrigation are given in general. Against the background of this division, irrigation is carried out with different investments depending on the geological structure: irrigation in the arch part of the field, irrigation cutting off the oil field, irrigation in the direction of the structure, etc.

The effectiveness of the irrigation system is influenced by various geological and mining factors. Without taking these factors into account, it is difficult to determine the measures that will ensure the effectiveness of the irrigation process.

It should be noted that the effect of formation parameters when applying the injection process should be studied in a complex way, not separately. Multidimensional statistical models are used to study the combined effect of geological and mining factors on irrigation.

In order to effectively carry out the process of artificial impact in the fields, the solution of the following problems must be reflected:

1. Watering start time. It is known from world oil production experience that it is advisable to start the pumping process shortly after the start of field development - when there is a small amount of degassing in the formation, when the formation pressure drops 10-20% below the oil solubility pressure. After this period, the movement of water in the formation can be controlled. However, the subsequent degassing of the formation has a negative impact on the full development of the field's reserves. In this case, the viscosity of the oil increases, it is very difficult to accelerate its movement through the water injected into the reservoir, and this problem can be solved by the application of the third type of impact methods.

In some fields, irrigation started at the time of commissioning, which creates favorable conditions for achieving high oil recovery rates.

In other cases, the application of irrigation was started long after the development of the fields, and the application of irrigation is relatively effective. Long-term development processes prior to the introduction of the injection process lead to uneven development of the initial resources of the formation, the reduction of formation energy at different rates in the field. In such cases, the water injected into the formation moves unevenly, which can lead to the formation of "water tongues" of different scales.

2. Well placement system. It is known that the efficient development of oil and gas fields depends on the density of the well network and the placement system. This dependence is more pronounced when the development process is carried out by injection. When the area of the field is small, the contour perimeter or contour irrigation method is applied to its development system. The number and density of injection and production wells depend on the geological and hydrodynamic properties of the formation.

In the case of highly permeable and geologically homogeneous strata, a post-contour modification of the injection is applied and it is assumed that the injected water will move freely in the stratum. Otherwise, the injection wells should be located close to the water-oil contour and the distance between them is determined as a result of geological and hydrodynamic surveys.

If the field is characterized by high geological heterogeneity, high oil viscosity, poor permeability of the rocks, the series of injection wells should be alternated with production wells, which is called a single-row injection system. If the geological and hydrodynamic environment of the formation is considered satisfactory, two-, three- and five-row systems can be applied. The latter system can be applied only when the field is characterized by an ideal feature for development, which means that the water injected into the reservoir will penetrate all its parts.

3. Watering rate. The volume of water injected into the fields during the injection process should be 10-20% more than the volume of the total fluid (oil and water) produced in the field. When the volume of injected water is less than the volume of fluid extracted from the formation, it does not completely displace the oil deposits in the rock pores, which leads to an unequal zonal distribution of residual reserves in the developed formation.

4. Stopping the watering process. In the process of contouring or contouring, the injection wells should be maintained gradually when the percentage of water in the fluid extracted from the working wells located around the contour of the field reaches a very high level (80-90% and more).

In the case of field irrigation, in the event of a sharp increase in production in the field, some injection wells should be stopped to prevent the formation of "water tongues". In all cases, the direction of movement of water injected into the formation must be determined by geological-mining methods (based on production, formation pressure, etc.).

5. Predicting the efficiency of the irrigation process. Like all geological and technical measures applied in the development of fields, the effectiveness of the irrigation process must be predicted. To solve this problem, specific layer parameters must be determined that affect the efficiency of the process.

The generalizations show that the parameters that most affect the injection process are: permeability, sandyness, hydroconductivity, oil viscosity, water and oil viscosity ratio, well network density, irrigation system and development rate. Based on this information, the efficiency of irrigation can be determined by applying statistical and dynamic models.

The injection process has been used in the Oil Rocks field (Block V) since 1962 (Table 2.2).
199,000 m3 of water is being pumped into VII, VIIa, VIII, X and FLD in tectonic block V this year.
At IX, QUQ, QD-2, QA-1 production facilities, water supply processes were stopped at different times due to technical problems. It is clear from the analysis of the development that the effect of the seam acceptance and pumping process was satisfactory.

Table 2.2

Dynamics of water injected along the horizons in the tectonic block of the “Neft Dashlari” field.

Horizons	Number of	Liquid	Number	Watering	Volume	Current	Total

	production wells	production in the current year, thousand tons	of injection wells	history (*-Continue)	of water injected in the current year, thousand m3	injection coefficient	volume of injected water, thousand m3
VII	5	19,2	1	1974-*	11,4	0,59	4385
VIIa	8	21,1	2	1968-*	55,9	2,65	10392
VIII	25	113,5	1	1970-*	15,0	0,13	16341
IX	19	66,3		1971-2006			3872
X	38	199,5	2	1962-*	92,7	0,46	25918
FLD	32	179,0	1	1962-*	24,2	0,14	22012
QÜQ	20	108,0		1962-1994			11127
QD-2	4	22,4		2005-2006			43
QA-1	8	42,4		1962-1997			9670
Sum	159	771,4	7		199,2	0,26	103760

However, due to technical problems near the end of the development, the volume of water pumped and the network of wells were reduced. Therefore, optimization of irrigation remains a topical issue. Using the available technical capabilities, it is important to increase the number of injection wells to optimize the injection process at the above-mentioned development facilities and to increase the injection volume and injection ratio to restore the full impact on production wells. In addition, the application of new methods for geological and mining indicators of facilities was considered.

One of the modern requirements for the efficient development of oil and gas fields is to achieve a high oil recovery factor. In conditions of complex geological environment (high heterogeneity of strata, low permeability of rocks, high oil viscosity, etc.) it is impossible to achieve high oil recovery coefficients by traditional methods. This requires the application of advanced scientific methods in experimental work, as a result of which the efficient development of fields is possible. At present, the scope of application of new methods (3rd method of influence) is constantly expanding. This is due to the fact that with traditional technology it is not possible to ensure a sufficiently active movement of high-viscosity oils to the bottom of the well in layers with a conductivity of less than 0.1 μm2. Therefore, extensive scientific and experimental work has been carried out in such fields and modern oil extraction methods have been proposed. At present, these methods are grouped into the following groups: physico-chemical, physico-hydrodynamic, thermal, gas, microbiological, acoustic, combined methods, etc. The following is a brief description of the general characteristics of these methods (Table 2.2.1).

1.Physical – chemical impact methods.

Method of interaction with surfactants .

The addition of surfactants to the water injected during the extraction process reduces the surface tension at the oil-water boundary. As a result, the movement of oil in the formation conditions is activated and favorable conditions are created for the improvement of compression .

Table 2.2.1

Geological conditions of effective application of new methods.

NEW METHODS		Geological and mining indicators										
		Viscosity of produced oil, mPa · s	Oil saturation, %	Lay temperature, 0C	Layer conductivity, 10-3 mkm2	Depth , m	Thickness, m	Type of collector	Clay, %	Mineralization of water, mq/l	Gas cap	Increase in final oil yield,%
Physicochemical	Surfactants	<3-5	>50	<70	≥0.1	No solution	3-12	Sandy	<10	20	weak	2-3
	Alkaline solutions	10-100	>50	<100	≥0.1	-"-	No solution	-"-	<10	<20	-"-	5-10
	Polymer solutions	10-100	>50	<90	>0.1	-"-	3-6	-"-	<10	20	-"-	7-10
	Biopolymer	10-100	>50	<90	>0.1	-"-	3-6	-"-	<10	20	-"-	5-10
	Micellar solutions	<15	>25	<90	>0.1	-"-	<25	-"-	weak	<5	-"-	8-15
	Foam effect	1-100	>50	<90	>0.05	-"-	Up to 20	-"-	-"-	<20	-"-	3-4
	"Polymerized" water	1-100	>50	<90	>0.1	-"-	No solution	-"-	-"-	20	No solution	5-10
Physico-hydrodynamics	Watering from time to time	<25	60	No solution	>0.05	-"-	<20	No solution	-"-	No solution	No solution	3-5
	Water-gas mixture with periods	<25	>60	-"-	>0.05	-"-	3-25	-"-	No solution	-"-	weak	5-6
	Low mineralized water	<25	60	-"-	>0.05	-"-	<25	Sandy	weak	<5	No solution	5-15
Thermal	Layer internal combustion	>10	>40	-"-	≥0.1	≤2000	2-30	No solution	No solution	No solution	weak	20
	Steam effect	>10	>40	-“-	≥0.1	≤1800	>6	-"-	5-10	-"-	-"-	20
	Exposure to hot water	5	>50	-"-	≥0.1	<1500	10-100	-"-	5-10	-"-	No solution	4-10
gas	Effects with CO2	<10-15	>40	-"-	<0.1	≤1200	10-15	-"-	weak	-"-	weak	10-15
	High pressure gas injection	<10	>60	-"-	<0.1	≤1200	<10	-"-	-"-	-"-	-"-	10-15
	Effect of nitrogen	<10	>65	-"-	>0.3	>1200	10-15	Carbonate	-"-	-"-	-"-	20
	Dactive gas	<10	>60	-"-	<0.1	≤1200	<10	No solution	-"-	-"-	-"-	10-15
Combined methods	Effects with water and gas	-	>60	-"-	>0.05	No solution	<25	-"-	No solution	-"-	-"-	5-10
MICROBIOLOGY		<10	>30	<75	>0.05	≤1800	8-10	-"-	weak	-"-	-"-	14-19
ACOUSTIC		-	50	-	<0.1	-	No solution	-"-	-"-	-	-"-	2-7

In addition, the wetting of the rocks improves: water penetrates into the pores and facilitates the movement of oil, increasing the coefficient of compression. The addition of even small amounts of surfactants to the injected water activates this process. The effective application of this method is in the case of non-homogeneous reservoirs with a thickness of 3-12 m, permeability of rocks 0.03-0.04 μm2, formation temperature up to 70 0C, oil saturation coefficient more than 50% and salinity of formation water 20 mg / l. effect.

OP-10 is one of the most widely used surfactants in the oil industry. Data from the operation of oil fields show that the surfactants added during the injection process improve the washing properties of the oil and increase the final oil recovery factor by up to 3%.

Method of exposure to alkalis.

The method of treatment with alkaline solutions forms sodium soaps in the layer, which reduces the surface tension and creates an emulsion of oil in water. The amount of additional oil that can be extracted from the fields depends on the parameters of the emulsion and the distribution of the oil in the formation. Thus, when the layers are exposed to an alkaline solution, a wave of highly dispersed emulsion is formed, which affects the increase in oil recovery. Application of the method in oil and sand-carbonate reservoir fields with oil viscosity up to 100 mPa□s, oil saturation more than 50%, permeability of reservoir rocks greater than 0.1 μm2, oil density 850-980 kg / m3, formation temperature up to 1000C and s. higher effect is obtained when Unfavorable factors are cracking of strata, high clay content and high mineralization of produced waters. It was determined that as a result of injection of alkaline solutions into the reservoirs, it is possible to increase their final oil recovery factor by 5-10%.

Method of interaction with polymers .

The efficiency of oil field development depends on the extraction of oil from the pores by various methods. As the viscosity of injected water differs sharply from the viscosity of produced oils, its compressibility is not high: water injected into the reservoir with various modifications does not provide maximum leaching of oil from the porous medium by moving it to working wells with high permeability channels. Therefore, polymers are added to the injected water, which increases its viscosity. As a result, conditions are created for more active washing of produced oil, and the efficiency of the injection process increases.

Application of the method When the viscosity of oil in sand and carbonate-type reservoirs is 10-100 mPa · s, the oil saturation of the rocks is more than 50%, the permeability of the reservoir rocks is more than 0.1 μm2, formation temperature is up to 900C, clay is weak (8-10 up to%). Unfavorable factors are the fracture of the strata, high clay content in the rocks and the hardness of the water. It was determined that as a result of injection of polymer solutions into the layers, it is possible to increase their final oil recovery factor by 7-10%.

Method of action with micellar solution.

As it is known, it is very difficult to achieve a smooth form of sectoral oil displacement in the process of field development: there are residual oil zones in the field, which are distributed irregularly in different forms. The reason for their formation is the viscosity of the oils located in the pores of the rock, capillary and surface-molecular forces, etc. factors. In this case, it is necessary to reduce the impact of these forces to ensure the uniform movement of oil. For this purpose, the layers are treated with micellar solutions. The use of micellar solutions in the irrigation process has a good effect at all stages of field development.

Application of the method in sandy reservoirs, layer thickness up to 25 m, oil viscosity less than 15 mPa · s, oil saturation more than 25%, rock permeability greater than 0.1 μm2, formation temperature up to 70-900C, salinity 5 mg / gives a high effect when l. Unfavorable factors include the cracks in the collectors and the hardness of the water. The application of micellar solutions in the irrigation process can increase the final oil recovery factor of the fields by 8-15%.

Foam effect method.

Adding foam to the layers reduces their water permeability and improves the oil's ability to compress. The main result of foaming in a porous environment is a significant reduction in the water permeability of the layers. The foam consists of an emulsion gas in liquid form. The liquid phase of the foam can be one of water, acid, or hydrocarbons, while the gas phase usually consists of nitrogen and, in some cases, CO_2. The application of the method gives a high effect when the effective layer thickness is up to 20 m, oil viscosity 1-100 mPa · s, in heterogeneous reservoirs, fractured rocks, the conductivity of collector rocks is 0.05 μm2, oil saturation is more than 50%, formation temperature is up to 900C. There is no limit to the depth of deposition of foam in the application of foam. In addition, the method can be applied in fields with low formation pressure and high irrigation content. As a result of applying the method, it is possible to increase the final oil recovery factor of the layers by 3-4%.

Method of treatment with "polymerized" water.

This method restricts the movement of water in the reservoirs, reduces sharp wetting, improves oil displacement. The chemical composition of the modified water increases the viscosity during the movement in the formation and limits the movement of the formation water. Increases oil recovery ratio up to 10%. One of the advantages of the method is that it does not require time in production and is used in conjunction with other physical and chemical methods. The method has been used in many onshore and offshore oil and gas fields in the United States and has yielded satisfactory results.

2. Methods of physical and hydrodynamic effects.

These methods are aimed at increasing the coverage of the reservoirs with the oil extraction process by commissioning low-permeability layers and undeveloped areas in the fields. The essence of physical-hydrodynamic methods of impact is to create a change in pressure drops between zones of different permeability and oil content. Changes in pressure drops allow to obtain a smooth shape of the oil and water contour of the field.

Methods of physical and hydrodynamic effects can be used in all geological and physical conditions of the fields. These methods include periodic irrigation and periodic water-gas mixture effects

Periodic watering method .

The main purpose of the periodic method is to artificially change the formation pressure over the area of a non-homogeneous deposit. To achieve this, the volume of water injected is changed or the amount of fluid production on working wells is increased or decreased. As a result, the formation pressure changes over time, affecting the fields in different w54ays. This process leads to the movement of oil from the high oil saturation zones in the field to the less saturated zones. The method gives higher efficiency when the effective layer thickness is 3-25 m and the viscosity of the oils is up to 10 mPa · s. Layer cracking, on the other hand, reduces the efficiency of the process. Application of the method can increase the final oil recovery factor of the fields by 3-5%.

Method of water-gas effect with periods .

The alternating injection of water and gas into the reservoirs facilitates the smooth flow of oil from oil-saturated areas to the working well zones. Effective application of the method is possible in non-homogeneous fractured layers with a permeability of more than 0.05 μm2, oil viscosity between 10-25 mPa · s, oil saturation more than 60%. One of the factors complicating this process is the cracking of the layers and the presence of free gas accumulations. Application of this method allows to increase the final oil recovery factor of the layers by 5-6%.

Method of exposure to less managed water.

The chemical composition and physical parameters (mineralization, pH, etc.) of the injected water are of great importance for increasing the oil recovery factor. The impact on the formation with low mineralized water is 10% more effective than the traditional irrigation process. As a result of applying the method, it is possible to increase the oil recovery factor by 5-15%. This method works better in sandy and terrigenous collectors. This method is widely used in Russian and Canadian oil fields.

3. Thermal methods .

Thermal methods that increase the oil yield of the fields include in-bed combustion, oil compression by steam, injection of hot water into the reservoirs and their combination. These methods are mainly used in the development of high-viscosity oil fields. It is known that the high viscosity of oil is one of the main factors influencing its poor mobility in the formation. Extensive application of thermal methods has shown that the viscosity of oil is significantly dependent on temperature, and when heated from 20-250C to 100-1200C, its viscosity can decrease from 100-500 mPa□s to 5-20 mPa□s. also significantly increases its mobility in porous media.

The following is a brief description of the individual heating methods that increase the oil yield of the reservoirs.

Layer internal combustion method.

Studies have shown that hydrocarbons can be used to extract heat energy from oil fields by using their ability to react exothermically with oxygen (generating heat energy as a result of the reaction). The basis of the method is that part of the oil in the porous medium burns and activates its non-combustible fraction. With the help of special equipment, a certain temperature level is created at the bottom of the well. The process is then continued in an independent mode by regularly injecting air into the wells. As a result, the temperature of the combustion zones is higher than the saturation temperature of water vapor and varies between 400-6000C.

In-bed combustion is mainly used in heavy oil fields. The application of the method is suitable for deposits with a bed depth of up to 2000 m. The thickness should be 3-25 m to conduct combustion within the layer. Residual oil saturation should not exceed 50-60%, irrigation should not exceed 40%. Factors that negatively affect the application of the method include the cracking and high heterogeneity of the layers, the presence of a gas cap, the high clay content of the rocks and the low thickness of the cover layers. The internal combustion method allows to increase the final oil recovery coefficient of the reservoirs by up to 20%.

Method of exposure to water vapor .

This method involves injecting water vapor under high pressure into high-viscosity (40-50 mPa□s and more) oil reservoirs. As a result, a large amount of heat energy enters the layer and heats it. In this case, the viscosity of the oil decreases and its mobility in the porous medium increases.

It should be noted that the application of this method is more effective when applied in the early stages of development. Method terrigenous reservoirs Depth of formation up to 2000 m, density of oils 820-1000 kg / m3, oil viscosity more than 40-50 mPa□s, effective thickness 10-40 m, porosity of rocks 15-35%, permeability of rocks 0 , 5 μm2, gives a higher efficiency when the oil saturation is more than 40%. The presence of a gas cap and high clay content in the layers reduces the efficiency of the process. It has been determined that it is possible to increase their final oil recovery by up to 20% as a result of steam injection into the reservoirs.

Method of exposure to hot water .

This method is widely used in the development of fields with high viscosity and paraffin oils. In this case, the temperature of the water injected into the formation must be higher than the temperature of the formation. Depth of the method operation facility is up to 2000 m, permeability of collector rocks is more than 0.1 μm2, porosity is more than 18%, oil saturation is more than 50%, oil viscosity is more than 10 mPa□s, layer thickness is 10 At - 100m, it gives more efficiency. It was determined that it is possible to increase the final oil recovery factor up to 10% as a result of injecting hot water into the reservoirs.

4. Methods of exposure to gas

Method of interaction with carbon dioxide (CO_2).

Injecting CO_2 into the reservoirs is one of the most effective ways to increase their oil yield. CO_2 provides a high oil recovery process as hydrocarbon solvents. The principle of application of the method is that the CO_2 injected into the reservoir as a solution in oil increases its volume ratio by up to 50%; reduces surface tension at the oil-water boundary, reduces oil viscosity and increases its velocity. This method can be more effective when the depth of formation is 1000-1200 m, thickness 10-15 m, oil viscosity 10-15 mPa · s, oil saturation coefficient more than 40%, and formation pressure 8-9 MPa. It should also be noted that when it is not possible to apply the injection process in low-permeability reservoirs, the method of exposure to carbon dioxide is the main method of compressing the reservoir oil. Among the factors complicating the application of the method are the following: the heterogeneity of the layers, cracks, the presence of asphalt and resin in the oil, the presence of a gas cap in the field. If this method is applied effectively, it is possible to increase the final oil recovery factor of the field by 10-15%.

High pressure gas method.

Compression of oil with gas in the formation is aimed at maintaining the formation pressure of the field, as well as reducing the strength of capillary forces in the formation rocks. As a result of this process, the rate of oil production in a porous environment increases. Favorable geological conditions for injection of gas into the field at high pressure are as follows: formation thickness 10-50 m, formation pressure more than 20 MPa, oil saturation

60-70%, oil density 825 kg / m3, viscosity less than 10 mPa · s, poor conductivity of rocks. However, cracks in the layers and the presence of a gas cap may complicate the application of this method.

As a result of applying the method, it is possible to increase the final oil recovery factor of the layers by 10-15%.

Method of exposure to nitrogen (N2).

The application technology is analogous to gas methods. It is mainly effective in carbonate, low-viscosity oil fields with a permeability higher than 0.3 mD. One of the main conditions is the presence of a gas cap. As a result of applying the method in the mentioned geological conditions, it is possible to increase the oil recovery factor by 20%.

Method of exposure to reactive gas.

This method is used in collectors where the water basin is not very active. The gas is injected into the reservoir at intervals. Due to the expansion of the volume, the moving gas reduces the viscosity of the oil and allows the oil to be squeezed into the formation. Therefore, the method is called the method of exposure to lazy gas. As a result of the application of the method, the oil recovery factor can increase by 10-15% under appropriate geological conditions.

5. Combined impact methods.

These methods are used in oil and gas fields characterized by different geological conditions. The combined methods include water-gas, foam-water-gas, application of polymer silicates, etc. includes. The mixture of polymer and silicate was first applied in Russia in 1980 and achieved high results. Combining foam and water-gas mixture has been applied in the dry lands of Azerbaijan (Siyanshor and Sulutepe) in recent years and has increased oil production.

Method of exposure to water and gas

This method is used by the world's leading oil companies Statoil, Bp, ExsonMobil and others. It is used in oil and gas fields operated by In particular, the Azeri field has this experience. In the oil layer, both the water injected from the back of the contour and the gas pumped from the arch of the structure are compressed. In order to maintain the hydrodynamic balance in the field, well studies are constantly carried out and, if necessary, the productivity of the percussion agent is limited at intervals. Depending on the geological conditions, it is possible to increase the oil recovery factor by 5-10% [49].

6. Acoustic methods.

As a result of acoustic exposure to oil layers, the viscosity of oils decreases, the thermal conductivity of rocks increases. As a result, the flow of oil to the wells is accelerating. This method is more effective when applied in oil layers containing asphalt, resin and paraffin and allows to increase the final oil yield by 2-7%.

7. Methods of microbiological action .

Microbiological methods are based on the intensification of the vital activity of bacteria in the layer and are aimed at the use of nutrients that contain components necessary for cell structure. In addition to organic matter, it requires important biogenic elements (S, K, Mg, etc.), as well as substances and vitamins that support cell growth.

The main preconditions for the use of microorganisms are that bacteria secrete SO2, bio-SAM and organic acids as a result of their vital activity. Bio-SAM forms a microemulsion with produced oil and water, where the viscosity of the microemulsion sharply reduces the viscosity of the produced oil. The decrease in oil viscosity, in turn, is accompanied by an increase in the volume of produced oil due to SO2, which increases the mobility of oil in the formation.

Implementation of the method in collectors of carbonate and weakly cemented sand at a depth of 1700-1800 m, layer thickness more than 8 m, permeability of collector rocks greater than 0.05 μm2, oil saturation more than 30%, oil viscosity greater than 10 mPa□s , density 820-950 kg / m3, gives high efficiency when the formation temperature is less than 750C.

Negative indicators in the application of the microbiological method include the high heterogeneity of the layers, the presence of high levels of Ca and Na salts in the formation waters and the presence of a gas cap. As a result of applying the method, the final oil yield of the reservoirs can be increased by 14-19%.

8. Geological conditions of drilling horizontal wells.

It is known from world oil and gas production experience that horizontal wells are widely used to increase the efficiency of field development [74]. In recent years, the operation of wells drilled in this way is usually reflected in the project documents. In addition to newly discovered mines, horizontal wells are also used to rehabilitate long-developed deposits.

The concept of a horizontal well does not mean that the wellbore is necessarily horizontal; Depending on the shape and oil saturation of the field, its body can be oriented as desired.

The geometric condition of the horizontal wells provides for the involvement of the field in the oil-saturated area to increase the drainage zone and to develop it by opening the productive layers not covered by the development. Therefore, the production capacity of such wells is much higher than that of conventional (vertical) wells, but due to the high economic performance of drilling and operation of horizontal wells, a responsible approach to their drilling is required.

It should be noted that this drilling method is more important in the development of deposits located in the sea area. Thus, as a result of their application, the number of marine foundations is reduced.

In general, the development of fields with horizontal wells allows to increase the final oil recovery factor, leading to the active development of their reserves. From this point of view, it is expedient to include the method of exploitation with horizontal wells in the set of methods that increase the oil yield of the reservoirs.

Horizontal wells have a number of advantages over conventional vertical wells:

- substantial increase of drainage zones as a result of changing the condition of the wellbore in the geological space;
- change of flow direction of liquid (oil) in the formation;
- two or more cuts of the ceiling (heel) depending on the distribution of oiliness (water content) in the volume of the productive layer;
- Involvement of adjacent blocks of the field, limited by screen-type fractures, for simultaneous development;
- Significant reduction in the intensity of sand plug formation during development in

weakly cemented collectors.

The high production obtained from the development of fields with horizontal wells is considered to be an economically viable method of development, as it completely covers the costs of drilling them.

Substantiate the application of methods to increase oil recovery.

As mentioned above, there is no universal method to increase oil production. Any method can give high efficiency only under certain geological conditions. In other cases, the method is less effective. Therefore, the effectiveness of the new methods depends on the correct selection of the appropriate field for this purpose.

A table has been compiled summarizing the effects of the above-mentioned geological conditions for the effective application of methods to increase the oil yield of reservoirs (Table 2.2.2). As can be seen, a large number of layer parameters affect the effective application of individual methods.

Table 2.2.2

Geological conditions of effective application of new methods .

New methods		Geological and mining indicators										
		Viscosity of produced oil, mPa · s	Oil saturation, %	Layer temperature, 0C	Layer conductivity, 10-3 mkm2	Depth , m	Thickness, m	Type of collector	clayiness, %	Suyun minerallaşması, mq/l	Qaz papağı	Son neftveriminin artımı, %
Physical chemicals	Surfactants	<3-5	>50	<70	≥0.1	no solution	12-Mar	Sandy	<10	20	Zəif	3-Feb
	Alkaline solutions	10-100	>50	<100	≥0.1	-"-	no solution	-"-	<10	<20	-"-	10-May
	Polymer solutions	10-100	>50	<90	>0.1	-"-	6-Mar	-"-	<10	20	-"-	10-Jul
	Biopolymer	10-100	>50	<90	>0.1	-"-	6-Mar	-"-	<10	20	-"-	10-May
	Micellar solutions	<15	>25	<90	>0.1	-"-	<25	-"-	weak	<5	-"-	15-Aug
	Foam effect	1-100	>50	<90	>0.05	-"-	Up to 20	-"-	-"-	<20	-"-	4-Mar
	"Polymerized" water	1-100	>50	<90	>0.1	-"-	no solution	-"-	-"-	20	Məh. yox	10-May
physical hydrodynamics	Watering from time to time	<25	60	no solution	>0.05	-"-	<20	no solution	-"-	no solution x	Məh. yox	5-Mar
	Water-gas mixture with periods	<25	>60	-"-	>0.05	-"-	25-Mar	-"-	no solution	-"-	Zəif	6-May
	Low mineralized water	<25	60	-"-	>0.05	-"-	<25	sandy	weak	<5	Məh. yox	15-May
THERMAL	Lay internal combustion	>10	>40	-"-	≥0.1	≤2000	Feb-30	no solution	no solution	no solution	Zəif	20
	Steam effect	>10	>40	-‘‘-	≥0.1	≤1800	>6	-"-	10-May	-"-	-"-	20
	Exposure to hot water	5	>50	-"-	≥0.1	<1500	10-100	-"-	10-May	-"-	Məh. yox	10-Apr
GAS	Effects with CO2	<10-15	>40	-"-	<0.1	≤1200	15-Oct	-"-	weak	-"-	Zəif	15-Oct
	High pressure gas injection	<10	>60	-"-	<0.1	≤1200	<10	-"-	-"-	-"-	-"-	15-Oct
	Effect of nitrogen	<10	>65	-"-	>0.3	>1200	15-Oct	carbonate	-"-	-"-	-"-	20
	Dactive gas	<10	>60	-"-	<0.1	≤1200	<10	no solution	-"-	-"-	-"-	15-Oct
COMBINED METHODS	Effects with water and gas	-	>60	-"-	>0.05	no solution	<25	-"-	no solution	-"-	-"-	10-May
Microbiological		<10	>30	<75	>0.05	≤1800	10-Aug	-"-	weak	-"-	-"-	14-19
Acoustic		-	50	-	<0.1	-	no solution	-"-	-"-	-	-"-	7-Feb

The benefit of applying the method is calculated as follows:

$$Q_{səmarə} = Q_{qbe} \cdot E_{ef} / 100$$

Here, Qsamara is the efficiency obtained after the application of the method, Qqbe is the residual balance reserve, Eef is the efficiency of the method,%.

Substantiation and forecasting of the effectiveness of geological-mining measures depends on the accuracy of formation and fluid parameters in the fields. In this regard, for the application of new methods, layer and fluid parameters (permeability, oil viscosity, oil saturation, effective thickness, sand, clay, etc.) should be specified, the risks of the minimum and maximum limits on the parameters should be assessed. In addition to geological-mathematical models, it is important to build hydrodynamic models for the fields. Layer and fluid parameters are simulated in the model and results are obtained.

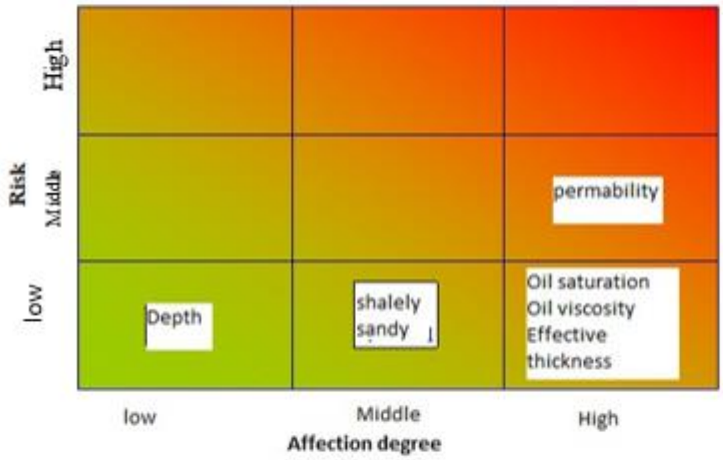


Figure . 2.3 Geological risk assessment matrix.

The geological risk assessment for the application of the method was based on the results from the diagrams. For this purpose, a matrix for risk assessment was created (Figure 2.3).

The matrix identifies the class to which the relationship between the layer and the degree of influence of fluid parameters on the effectiveness of the method and the parameters and geological risks. The degree of impact of geological risks and parameters on the effectiveness of the method was assessed at three levels (low, medium, high).

As can be seen from the matrix, the permeability of the field was assessed as a medium risk parameter. Therefore, it is proposed to apply new methods after a complete refinement of the conductivity in the field.

The application of new methods for the efficient development of residual resources in the Gunashli and Neft Dashlari fields is based on technical (surface operation equipment, transmission lines, systems for the application of new technologies, etc.) and economic indicators. Using the classification model of the developed new methods, it is proposed to apply surfactants along with water injection to the existing technical system in the Oil Rocks field (V tectonic block). As a result of the application of the method, it is possible to increase oil production by 2-3%, which can increase the remaining recoverable reserves by 1675-2513 thousand tons (Table 2.2.3). The application of microbiological methods is proposed to the GUG formation, and as a result of the impact, the increase in oil reserves is projected at 1758-2386 thousand tons.

In the Gunashli field, as a result of the application of surfactants to the new system IX, X and FLD, the residual oil reserves are projected to increase by 3867-5801 thousand tons. As a result of the application of microbiological methods in the FLD, the growth of oil reserves is projected at 17319-23505 thousand tons.

It is known from the experience of the gas injection process in the Azeri field that if the Gunashli field is affected by high-pressure gas from the arch of the structure, it is possible to increase oil production by 10-15%. An economic analysis is needed to establish this system.

Table 2.2.3

Schedule of projected total oil production after application of new methods.

Development objects	Residual balance reserve, thousand tons	Method to be applied	The effectiveness of the method, %	Increase in oil reserves, min ton
Oil Rocks field on V tectonic block				
VII	4059	Surfactants	2-3	81-122
VIIa	7197			144-216
VIII	10130			203-304
IX	9161			183-275
X	14694			294-441
FLD	17536			351-526
QÜQ	12558			251-377
QD-2	3675			74-110
QA-1	4752			95-143
Total	83762			1675-2513
QÜQ	12558	Microbiological methods	14-19	1758-2386
On a Gunashli field				
IX	15712	Surfactants	2-3	314-471
X	53950			1079-1619
FLD	123709			2474-3711
Total	193371			3867-5801
FLD	123709	High pressure gas injection	10-15	12371-18556
FLD	123709	Microbiological methods	14-19	17319-23505

2.3 Geological risk assessment

The term "risk" was first used by Portuguese sailors in times of danger. After that, as in other industries, it was developed in the oil and gas industry. Risk is understood as a factor that indicates the likelihood of encountering adverse events as a result of uncertainties. The probability of not getting the desired result, the risk of facing a difficult situation, the risk of loss instead of profit are the main factors. The risk factor and its assessment are very important in decision making. It is possible to face risk in all areas of industry. At present, it is impossible to imagine that risks are not taken into account in the management of the industry. The oil industry is one of such areas].

Depending on the level of risk, there are different ways to manage it. The choice of the optimal risk management strategy depends on the direction of statistical analysis. That is, the right strategy creates an image of optimal decisions, ensures that risk is balanced or managed. U.S. scientists Zvi Bodi and R.K. Merton have commented extensively on the importance of investing in uncertainty risk. The risk management process must go through the following five stages:

- risk detection;
- risk assessment;
- selection methods of risk management;
- implementation of selection methods;
- Evaluation of results.

The risk factor is one of the most studied issues in the oil and gas industry recently. From the exploration and exploration of oil and gas fields to the final stage of development, there is a risk of risk in the process. However, reliable risk management depends mainly on the quality and quantity of geological-geophysical and mining data obtained from exploration wells. When the results of exploration drilling are in line with forecasts, it is considered expedient to continue the next stages. Depending on the causes, the risks are classified according to the following scheme (Figure 2.3.1).

Research in the field of oil and gas geology, which is related to the geological basis of oil and gas field development and covers a wide range, is characterized by significant uncertainties, and as a result, these features create geological risks associated with the calculation of reserves. Geological uncertainties mainly depend on the structural and tectonic characteristics of the field under study, the type and shape of the trap, the degree of change in the characteristics of the reservoir on the cross section and area of the field, the degree of study of formation fluids. Once these uncertainties have been studied and the probabilities determined, the risks of the process are assessed. Depending on the research area, different methodologies have been developed for risk assessment.

In order to study uncertainties and reduce risks, research should be carried out in accordance with standard procedures from the beginning to the end of the exploration process (Figure 2.3.1).

These procedures are not fully implemented for various reasons.

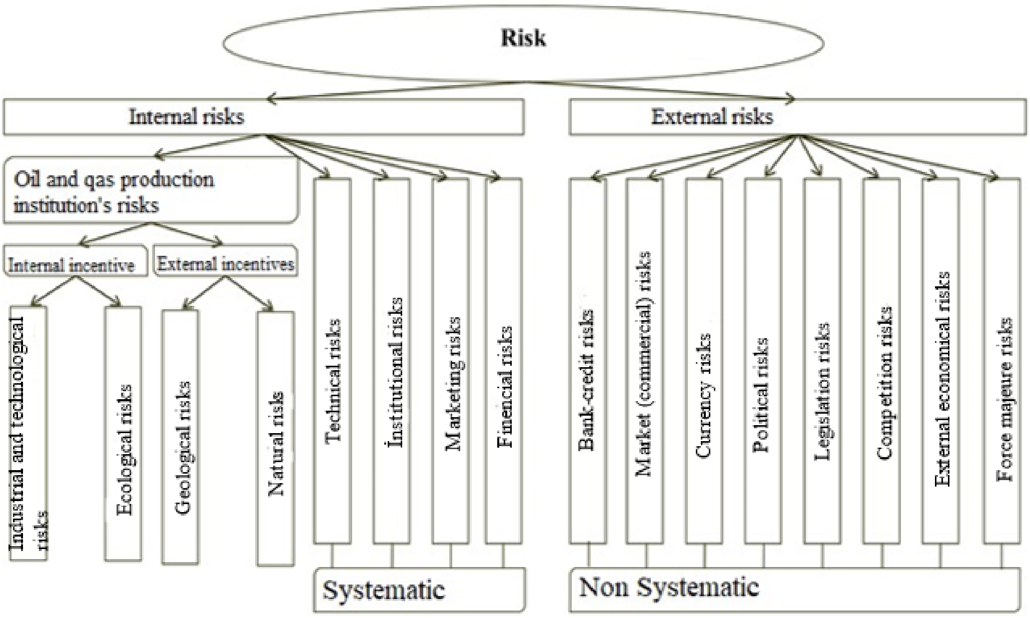


Figure 2.3.1. Risk classification scheme.

For example, some important geological, geophysical, hydrodynamic surveys of the Azerbaijani oil and gas fields during exploration and testing cannot be carried out in full compliance with the procedures due to technical, economic and other factors.

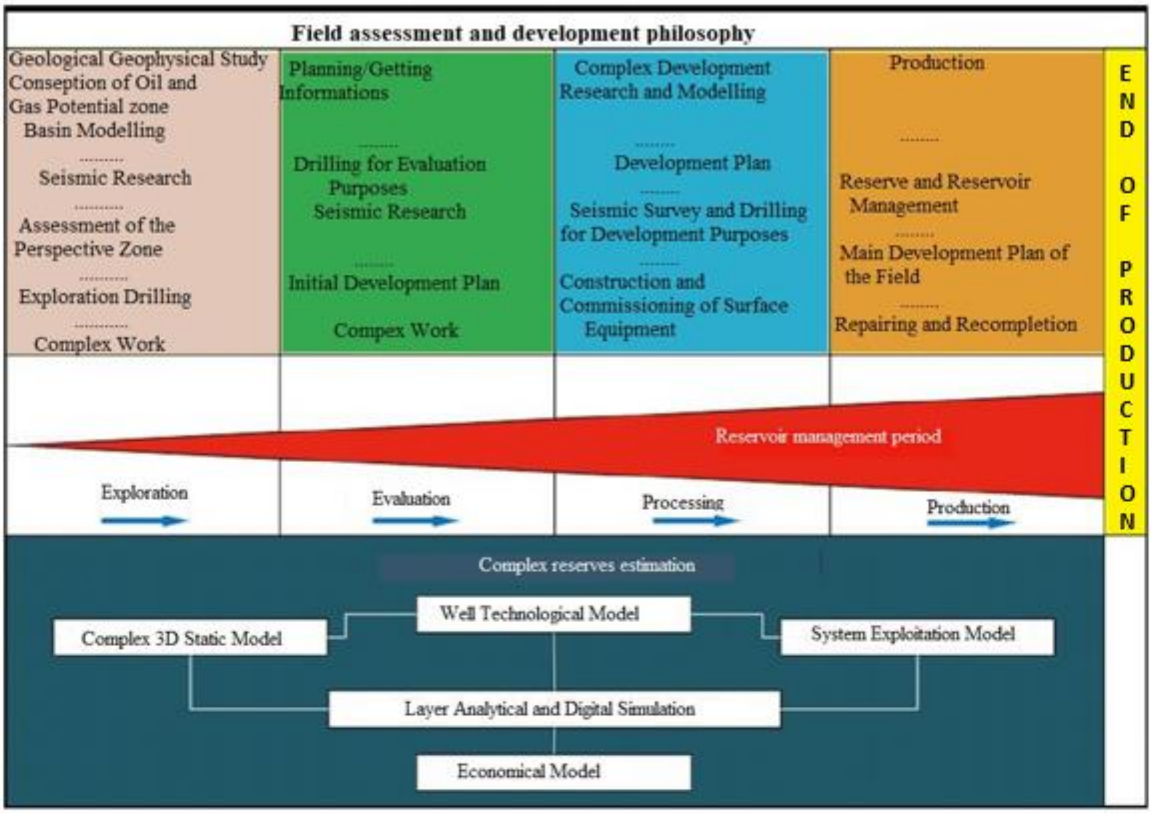


Figure 2.3.2. Scheme of assessment and development of hydrocarbon potential of deposits.

Such delays are particularly pronounced in the onshore fields (due to the start of exploration in the 19th century). The main research and development stages in the onshore fields of the republic, especially the oil and gas fields of the Absheron oil and gas region, coincided with the period of World War II [1, 4]. The geological, geophysical, hydrodynamic, and hydrogeological studies required to meet the high demand for oil and gas in these fields have not been fully conducted, and the existing uncertainties and risks have not been fully assessed. This results in certain difficulties during the future development of oil and gas fields (optimal selection of the well network, installation of surface infrastructure, accurate calculation of reserves, preliminary assessment of impact methods projects, forecasting, etc.). Therefore, the re-assessment of geological risks in oil and gas fields after the exploration phase was considered relevant. From the above, it can be concluded that in order to assess geological risks, the quantity and quality of seismic, geological-geophysical, test data obtained during the exploration, testing and exploitation of the fields must be determined.

Thus, the main geological risks are classified according to the following scheme (Figure 2.3.3) .

1. Scope of research:

- incomplete field and depth seismic surveys in accordance with the procedures, uncertainty in the assessment of oil saturation of productive reservoirs;

- uncertainty caused by insufficient study of seismic, mining-geophysical and other geological-geophysical data;

- uncertainty due to incomplete coverage of core data by area and cross section;

- inaccurate definition of stratigraphic boundaries, uncertainty of collector characteristics;

- Uncertainty of skin effect when opening horizons.

2. Interpretation of the results of geological and geophysical research:

- uncertainties in the separation of productive strata;

- Uncertainty of lithofascial properties of collectors.

3. Uncertainty of the scale (grid) - the network of wells is due to sharp differences between the thickness of the reservoir layers and the scale in the geological model. In such cases, it is difficult to reflect small-scale vertical heterogeneity and to model the movement of formation fluids correctly.

These uncertainties increase the risks of hydrocarbon reserves in the fields. Thus, uncertainties in the calculation of oil and gas reserves are the main geological risks.

The determination of geological risks to assess the reliability of reserves can be expressed mathematically as follows:

$$R = 100 - E$$

Here , R – risk, E – is probability, % .

It is clear from the expression that the risks decrease as the probability increases in the case under study. Therefore, first of all, the reliability (probability) of reserves should be determined. This is possible due to the study of the degree of impact of geological and technological factors affecting the volume of reserves in modern times in different ways.

Geological risks can be classified by quantity, quality and area.

Quantitative and qualitatively assessed geological risks - is the quantification of the overall risks of any project.

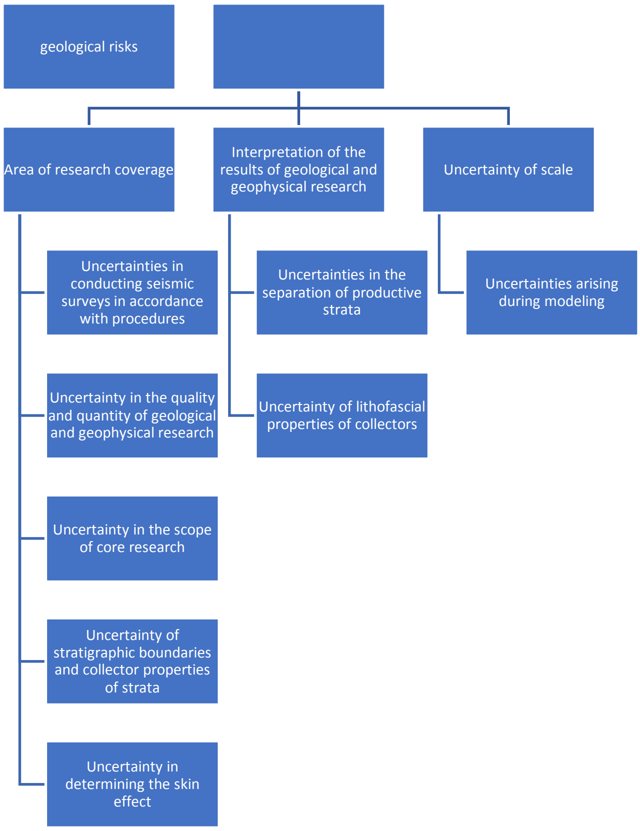


Figure 2.3.3. Geological risk classification model .

After assessing the geological risks in different areas, the nature of the changes in these objects is described on the maps. These maps are called risk maps. They are compiled using simple field mapping methods based on quantitative or qualitative assessments of risks. Over time, risk maps are updated and project effectiveness is assessed.

Azerbaijan's main oil and gas reserves are concentrated in offshore fields, and research, as well as the development of proven reserves in accordance with the existing development project, requires several times more investment than onshore fields. In this regard, the uncertainties and risks that may arise during the exploration and development stages of offshore fields should be assessed more accurately.

Initially estimated oil and condensate reserves and prospective resources (C2 + C3) are 24% in offshore fields and 9% in onshore fields (Figure 2.3.4). Gas reserves of the same category are 31% in offshore fields and 2% in onshore fields. The mentioned hydrocarbon reserves are an important part of the country's energy resources. In this regard, the assessment of geological risks is urgent.

The following uncertainties affect the assessment of geological risks in Azerbaijan's oil and gas fields:

- complexity of structural-tectonic structure of deposits (mud volcanoes, tectonic faults, lithological or stratigraphic fault zones) and deep deposition;

- hydrocarbon filling coefficient or oil and gas field of structures;

- oil and gas saturation coefficient of collectors;

- layer parameters (collector and thermobaric properties);

- fluid parameters (density, viscosity, etc.).

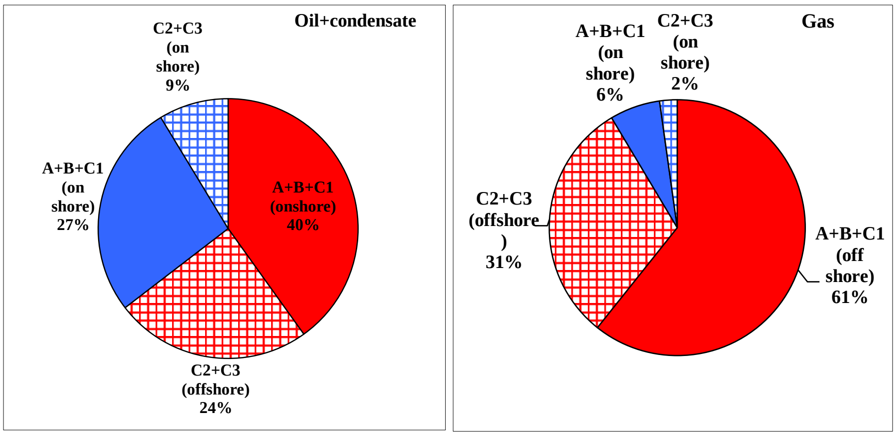


Figure 2.3.4. Proportion of geological reserves and resources of Azerbaijani fields.

These parameters have been studied at different levels in individual fields. In this regard, a risk matrix should be developed to assess geological risks so that it is possible to determine the risks according to the degree of impact of geological and mining parameters on the volume of reserves, as well as the level of study of this information. Depending on the geological issue under consideration, a risk matrix of different formats can be compiled. Depending on the degree of study of the complexity of the areas where oil and gas and gas condensate fields are located, structural and tectonic structure, oil and gas saturation of reservoirs, the volume of hydrocarbon reserves, various methods have been developed for geological risk assessment. Such methods are analogous, logical, geological-mathematical, etc. an example can be given. The most commonly used methods for assessing geological risks in the oil and gas industry are as follows :

An analogous method. In this way, it is possible to predict geological risks in the uncertain structures of the oil and gas region, where the risks have already been assessed in one or more fields. In this way, geological risks can only be determined. Experts use this method only when other methods are not available to assess the geological risks of hydrocarbon deposits with very little geological-geophysical and mining data. It is not possible to quantify geological risks in this way.

Logical method. This method has similarities and differences to a similar method. Geological risks can be assessed qualitatively, not quantitatively, using the method. However, unlike the similar method, this method is used to assess the geological risks of hydrocarbon deposits with a certain amount of geological-geophysical and mining data..

Geological-mathematical methods. Unlike both methods, this method allows to assess geological risks both qualitatively and quantitatively. To do this, it is necessary to fully study some of the geological-geophysical and mining parameters of the studied field. Depending on the field of study, geological, geological-mathematical or hydrodynamic models are developed to evaluate the process. With the help of these models, the impact of geological factors affecting the process is assessed. After assessing the degree of study of these parameters in the studied field, an existing or completely new risk matrix is compiled. All calculations are performed on a mathematical basis. With this procedure, the risks of any geological issue can be assessed. However, there are logical aspects of the method, which are studied in different approaches to solving such problems. To assess the geological risks of each process in the oil industry, the reliability and quantity of the geological and mining data of the field or development being studied must be examined. Depending on the results, a method is selected to assess geological risks. Suppose that a geological risk assessment is required to determine the reliability of a hydrocarbon resource in a field. For this purpose, first of all, the quantity and quality of geological-mining parameters affecting the hydrocarbon resources of the studied field are clarified. The degree of study of these parameters in the field is studied. For this purpose, multidimensional mathematical and statistical analysis is carried out. If uncertainties in the field prevail, analog or logical methods are used, and vice versa, geological-mathematical methods. Similar and logical methods are usually used in the initial exploration phase of fields or oil and gas fields.

Although various methods have been developed for the assessment of geological risks, the effective solution of this problem in the oil and gas and gas condensate fields of Azerbaijan often requires a specific approach. The combination of existing methods and the use of special logistics methods were considered expedient. A new method has been developed to more reliably assess geological risks. The method was developed in accordance with international standards and research was performed in the following sequence (Figure 2.3.5):

- Geological and mining data of the fields were collected, systematized and statistically analyzed;

- Sensitivity analyzes of these parameters affecting the process were carried out on geological-mathematical models;

- As a result of sensitivity analyzes, the degree of impact of geological-mining parameters on the process was assessed by tornado diagrams;

- geological risks were assessed using the results obtained from tornado diagrams (the level of impact of the parameters on the process) and a new risk matrix compiled according to the degree of study of these parameters in the field.

Thus, the procedure for geological risk assessment with a more modern methodological approach was developed in the above sequence and applied to hypothetical hydrocarbon deposits located in the offshore sector of Azerbaijan.

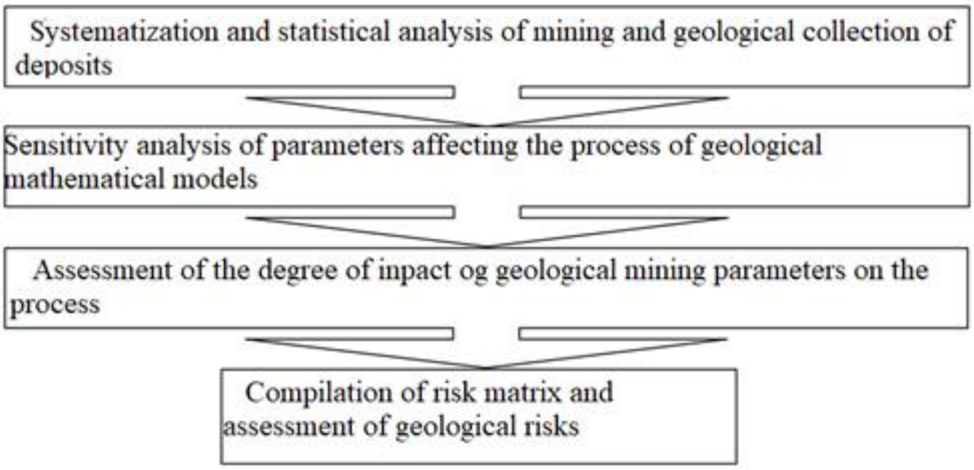


Figure 2.3.5. Scheme of the procedure for geological risk assessment.

One of the most pressing issues related to the rapid development of the oil and gas industry is to ensure the reliability of reserves, along with traditional methods, to calculate and assess the risks in accordance with international standards.

The main goal of this study is to assess the geological risks involved in the calculation of hydrocarbon reserves by international standards.

Currently, various classifications are used to assess reserves. SPE standards, one of the modern classification models, are used to solve this problem and are interpreted as follows.

Proved reserves (P90) are reserves that can be extracted in the current economic and technological conditions, provided that the probability that the accumulated production during the use of probabilistic models is higher or equal to the estimated reserves is 90%.

- Approved operating reserves are those that have been discovered and can be removed from the development area at the time of valuation.

- Approved non-developed reserves are reserves of the area where there are non-perforated and closed wells.

- Approved non-drilled field reserves are the reserves of areas where new wells are to be drilled and financial costs are expected.

Probable reserves (P50) are unconfirmed reserves that are expected to be extracted based on geological data. The recoverable reserve has a probability of being equal to or greater than the approved and probable reserve of 50%.

Potential reserves (P10) - unapproved reserves that are less than the probable reserve and have a probability of withdrawal of 10%.

The procedure for estimating reserves in accordance with the standards of modern classification models can be explained by the example of a hypothetical gas-condensate field. The studied gas-condensate field is located in the Azerbaijani sector of the Caspian Sea (Figure 2.3.6). The north-western part of the field is under development. In this area, 5.2

million m3 of gas and 92 tons of condensate are produced daily from 38 wells with 38 development facilities..

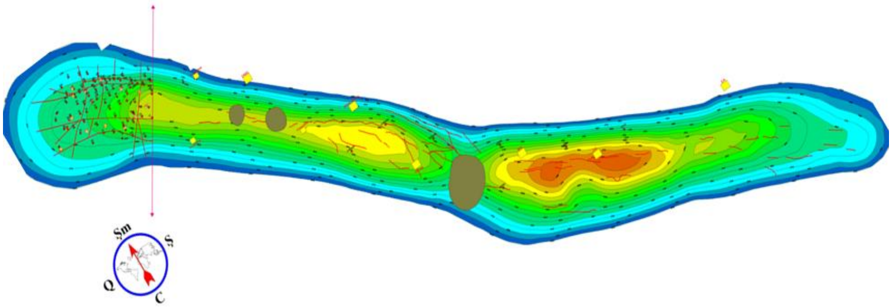


Figure 2.3. 6. Structural map of the field.

Initial balance reserves in the undeveloped field of the field by traditional methods: gas 253 billion m3, condensate 35.7 million. tons were estimated. 8 exploration wells were drilled in these areas. Along with these wells, geological-geophysical and mining data of wells drilled in the north-western area were used in the assessment of reserves according to international standards.

It is known that the uncertainty of layer and calculation parameters is taken into account in the calculation of reserves. From this point of view, first of all, it is necessary to determine the minimum and maximum values of the layer parameters used in the calculation of reserves and to study the distribution patterns.

The stratum parameters used for field development A were studied and illustrated in Figure2.3.6 Values of geological-mining parameters used in the calculations Table 2.3. Given in 1.

The gas field was determined based on data from the developing part of the field and exploration wells. The minimum cost of the gas field of the field was taken with an optimistic approach 10% less than the base price (Table 2.3.2).

To calculate the effective thickness, data from 24 wells on the total field were used and the statistical distribution was studied. As can be seen from Figure 2.3.7, the fashion price is 26 m, and the minimum and maximum prices are 24 and 35 m, respectively .– +

Gas saturation and porosity coefficients were determined by core and well geophysical surveys (KGT).

The formation pressure was determined based on the test data of exploration wells operating in the north-western part of the field and drilled in other areas, and the base value was taken as 40 MPa. Other fluid parameters were determined based on PVT surveys of production wells.

Table 2.3.1.

Prices of geological-mining parameters on an object.

No	Wwell No	Effective thickness, m	Porosity,%	Gas saturation,%	Layer pressure, MPa
1	1	25	20	67	40
2	2	24	21	70	40
3	3	25	21	67	40
4	4	28	22	67	
5	5	26	21	69	42
6	6	28	23	70	39
7	7	30	22	70	
8	8	26	22	69	39
9	9	26	22	69	40
10	10	26	22	69	42
11	11	29	22	70	
12	12	30	22	63	
13	13	26	24	65	
14	14	24	24	69	35
15	15	28	23	70	
16	16	29	21	63	40
17	17	32	21	67	
18	18	35	20	69	40
19	19	31	23	69	39
20	20	26	23	70	
21	21	31	23	65	39
22	22	26	20	65	
23	23	25	20	67	
24	24	29	24	69	
Average	28	22	68	40	
Maximum	35	24	70	42	
Minimum	24	20	63	35	
Model	26	22	69	40	

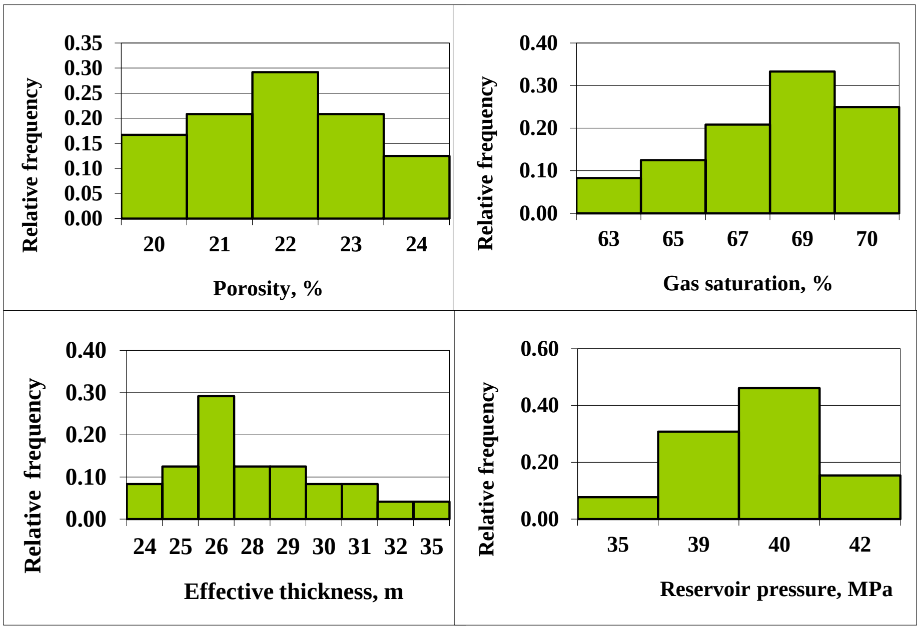


Figure 2.3.7. Distribution histograms of layer parameters.

Thus, using the complex geological-geophysical and mining data systematized M-Ball software pokent, the basic version of the report was compiled using the Monte Carlo method.

Table 2.3.2

Estimates of geological and mining parameters used in the reports

Price	**Gas area, thousand m2**	**Effective thickness, m**	**Gas saturation, %**	**Prosity, %**	**Layer pressure, MPa**	**Layer temperature, °C**	**Gas density, kq/m^3**	**Density of condensate, kg / m3**	**Amount of condensate in the gas, g / m3**
Minimum	124419	24,0	63	20	35	70	0,730	730	125
Base	138244	26,0	69	22	40	75	0,735	735	137
Maximum	138244	35,0	70	24	42	80	0,740	740	140

The essence of the Monte Carlo method is as follows.

It is necessary to find the value of a certain quantity studied. For this, a random quantity X is taken so that the mathematical expectation of this random quantity is equal to a:
M(X)=*a*

In practice, this happens as follows: n units are tested and the result is a random quantity X, n is a possible value; their algebraic mean is calculated and it is assumed that a is taken as x as the value of a * of the sought number:

$$a \simeq a^* = \bar{x}$$

The Monte Carlo method is often called the statistical test method because it requires experiments with large numbers of numbers. The theory of this method shows how to find the possible value of a random quantity X by choosing it very wisely. In particular, the method of reducing the variance of a random quantity is used, and as a result, the number of errors decreases when the desired mathematical expectation a is replaced by its value a *.

The Monte Carlo method calculates the probabilities of the results by determining the statistical distribution regularities of the parameters with the following options:

1. Based on the measured values of the fixed parameters;

2. Based on the minimum and maximum values of the set of parameters;

3. Based on minimum, maximum and fashion values of multidimensional parameters;

4. Based on average price and parameter variance;

5. Methods of calculation based on logarithmic values of parameters.

One of the above calculations is optimally selected, the probable values of the reserves are calculated, and the results are obtained in the form of histograms. [23].

The M-Ball software package is a convenient tool to address these issues. With this program, the Monte Carlo model is selected from the Tool menu to estimate resources. Then select the system of units of geological-mining parameters used in the calculations, including the Units menu (Figure 8). In the Options tab, you can enter general information about the bed and the object to be processed (Figure 9). To save operations, press the Done button in the window and the Cancel button.

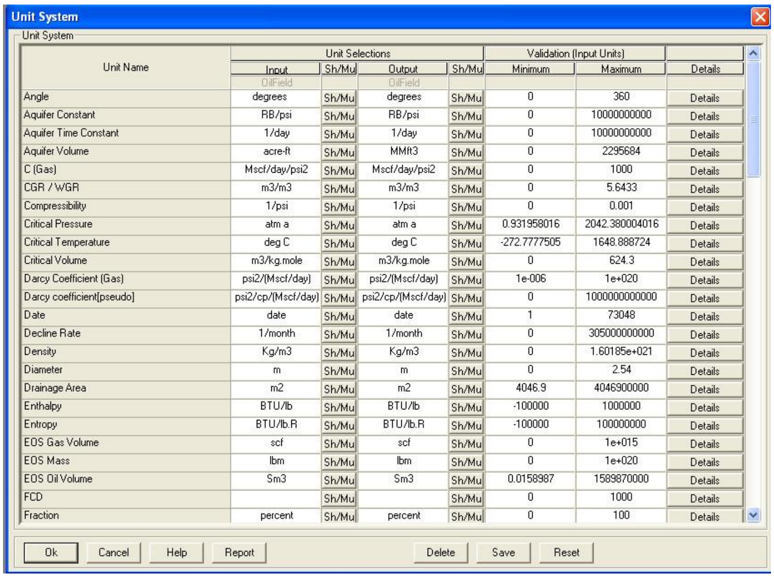


Figure 2.3.8. Units system selection window.

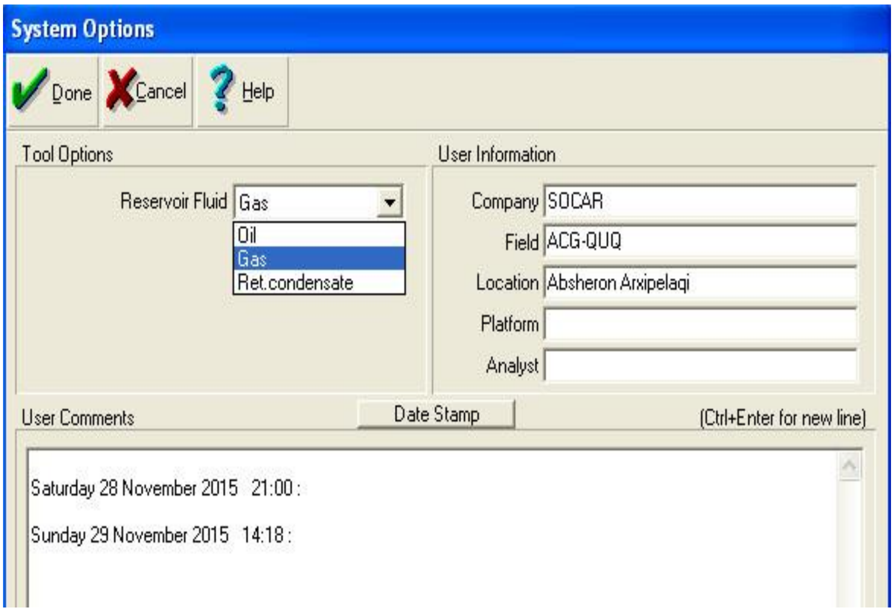


Figure 2.3.9. General information window.

To enter PVT data into the program, select the "Fluid properties" line from the "PVT" menu. In the window that opens, information about the requested physical properties of PVT and fluid is entered into the program (Figure 10). This information should be included more accurately in the calculation of gas-condensate reserves. For calculations, press the "Calc" button, and in the newly opened window will be asked the pressure and temperature range. After entering this information, press the "Calc" button. As a result, in the newly opened window, the volume dependences of the mining parameters, depending on the pressure and temperature, are tabulated. In this window, you can follow the curves by clicking the "Plot" button to get a graphical representation of these dependencies..

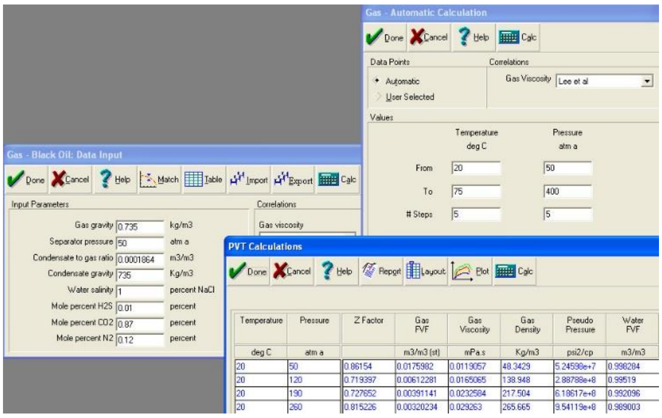


Figure 2.3.10. Window for entering fluid data and calculations.

To start the calculation operations, select Distributions from the Input menu, enter the resource calculation parameters in the opened window and press the Calc button for calculation (Figure 11). Then

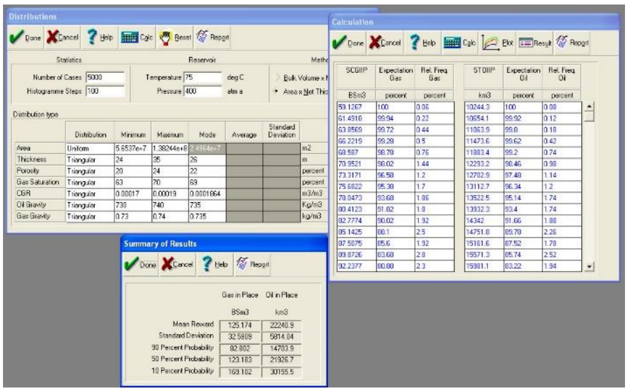
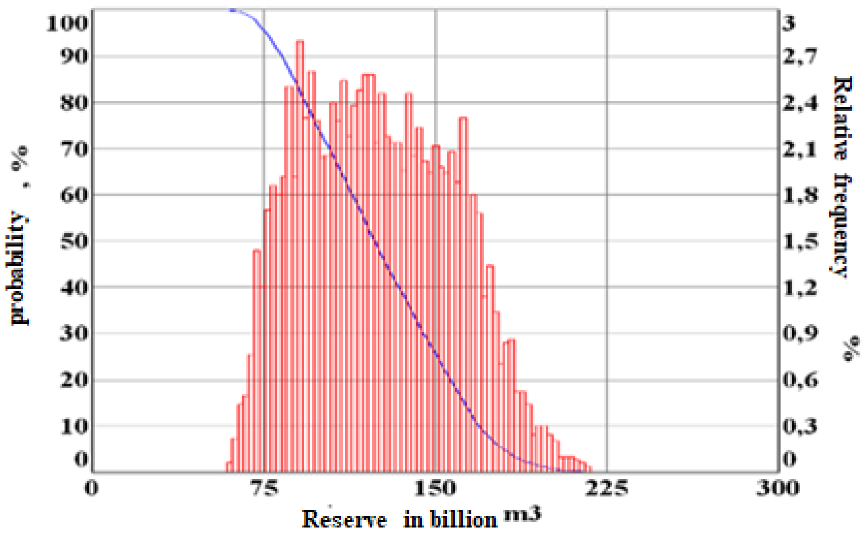
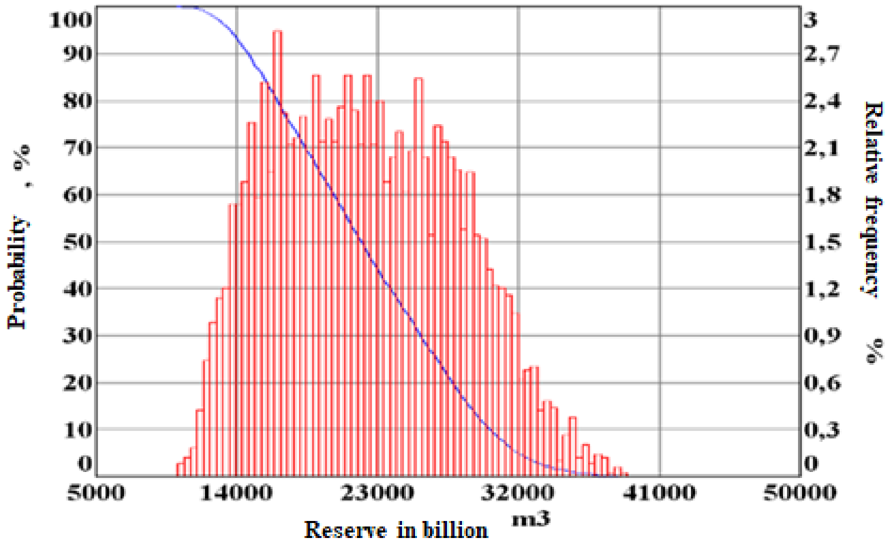


Figure 2.3.11. Transaction execution windows .

You can then view the histograms on the screen by pressing the Plot button in the new window that opens (Figure 2.3.12).



a



b

Figure 2.3.12. Monte Carlo histograms. a - gas, b - condensate reserves.

The results of the Monte Carlo calculation of gas and condensate reserves in the studied field are given in Table 3. Gas and condensate reserves were calculated for P90, P50, P10 categories at A and B facilities of the field. The total gas reserves of facility A (P10 category) are 169.1 billion m3, condensate reserves are 22.1 million. tons, total gas reserves of object B 84.4 billion m3, condensate reserves 11.1 million. tons were calculated. In general, 253.5 billion m3 of gas and 33.3 million tons of condensate were estimated at the two facilities..

Table 2. 3.3

Gas-condensate reserves calculated by the Monte Carlo method

Categor y	**Initial balance reserves**		
	gas, billion m3	**condensate, min m3**	**condensate, min ton**
A reserve on an object			
P90	82,8	14703	10807
P50	123,2	21927	16116
P10	169,1	30156	22165
B reserve on an object			
P90	31,4	5583	4104
P50	55,4	9916	7288
P10	84,4	15090	11091
Total reserve			
P90	114,2	20286	14910
P50	178,6	31843	23405
P10	253,5	45246	33256

In order to study the uncertainties in these calculations and the degree of their impact on the results, multivariate sensitivity analyzes were performed on statistical models (Monte Carlo models) based on the minimum, maximum and fashion values of geological-mining parameters. Sensitivity analysis refers to the effect of the values of these geological and mining parameters on the results, which is very important for risk assessment.

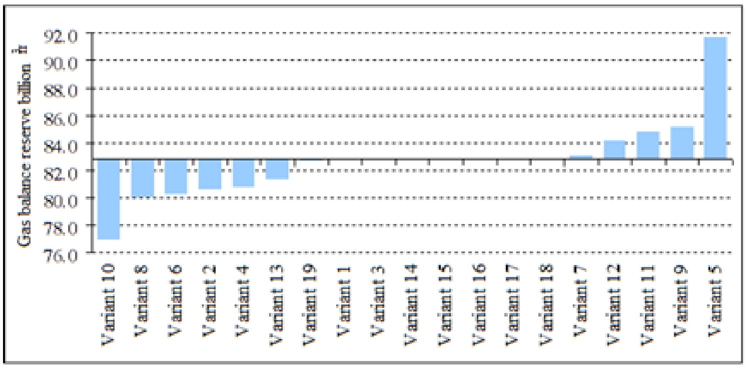
To test the sensitivity of the developed geological-mathematical models with geological-mining parameters, research was conducted with the following logical approach (Figure 2.3.13).

Results

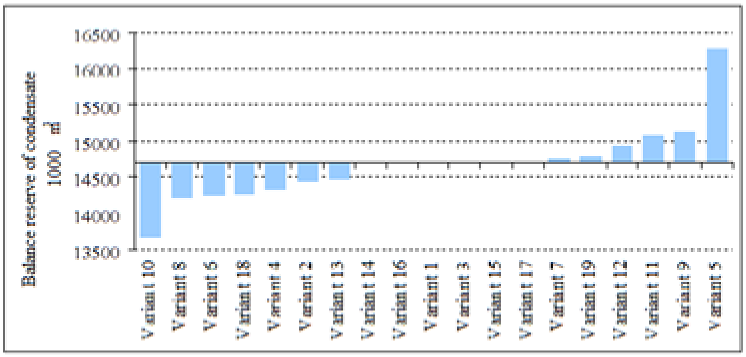
	Gas in place	Effective thickness	Gas saturation	Permability	Reservoir pressure	Reservoir temperature	Gas density	Condensate density	Amount of Codensate in gas
variant 1	base	base	base	base	base	base	base	base	base
variant 2	minimum	base	base	base	base	base	base	base	base
variant 3	maximum	base	base	base	base	base	base	base	base
variant 4	base	minimum	base	base	base	base	base	base	base
variant 5	base	maximum	base	base	base	base	base	base	base
variant 6	base	base	minimum	base	base	base	base	base	base
variant 7	base	base	maximum	base	base	base	base	base	base
variant 8	base	base	base	minimum	base	base	base	base	base
variant 9	base	base	base	maximum	base	base	base	base	base
variant 10	base	base	base	base	minimum	base	base	base	base
variant 11	base	base	base	base	maximum	base	base	base	base
variant 12	base	base	base	base	base	minimum	base	base	base
variant 13	base	base	base	base	base	maximum	base	base	base
variant 14	base	base	base	base	base	base	minimum	base	base
variant 15	base	base	base	base	base	base	maximum	base	base
variant 16	base	base	base	base	base	base	base	minimum	base
variant 17	base	base	base	base	base	base	base	maximum	base
variant 18	base	base	base	base	base	base	base	base	minimum
variant 19	base	base	base	base	base	base	base	base	maximum

Figure 2.3.13 Options for sensitivity analysis.

Sensitivity analysis was performed on 19 variants in accordance with the scheme, of which the first variant was calculated for the base, and the others for the minimum and maximum values of each of the geological-mining parameters. It is also possible to increase the number of these options. The results of the calculation of gas-condensate reserves by options are given in Figure 14..



a



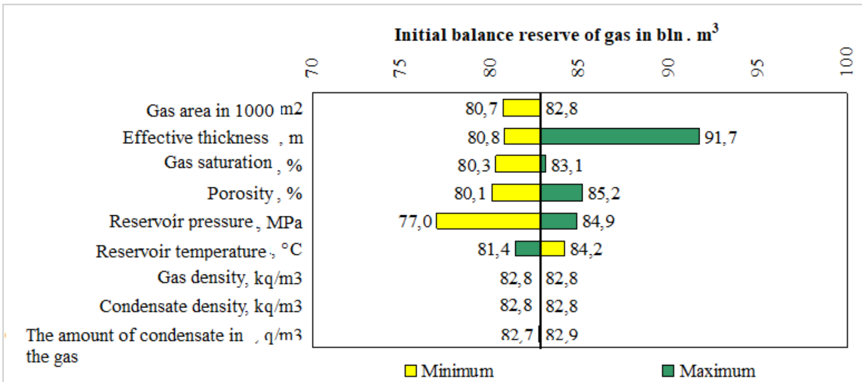
b

Figure 2.3.14. Results of sensitivity analyzes. a - gas reserves, b - condensate reserves .

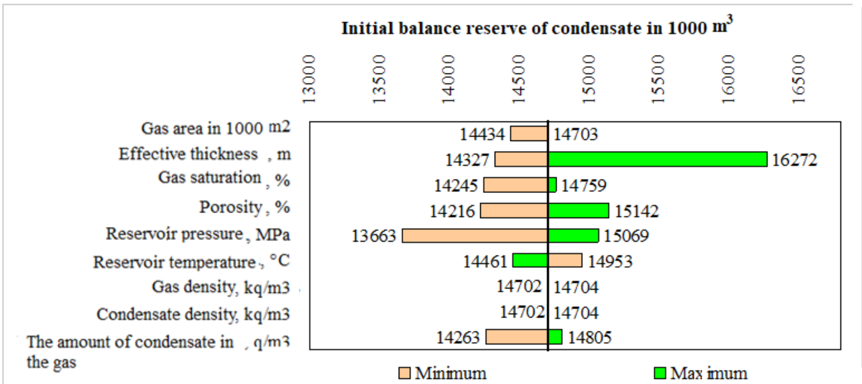
As can be seen from the graphs, in the base variant (variant 1) gas reserves are 82.8 billion m3, condensate reserves are 14703 thousand m3. In Option 10, the gas condensate reserves receive a minimum value, which is related to the minimum formation pressure (350 atm), respectively. The probability of formation pressure at 350 atm is 8% in the field. In Option 5, the reserves were calculated at maximum. This was due to the maximum value of the effective thickness on the object to be processed. In this variant, the effective thickness was assumed to be 35 m with a probability of 4%. Options 3, 7, 14, 15, 16, 17 are more similar to the base version. This is justified by the weak geological and mining parameters.

Tornado diagrams were developed to assess the impact of geological and mining parameters on gas and condensate reserves (Figure 2.3. 15).

Using these diagrams, the degree of impact of geological and mining parameters on the volume of reserves was assessed. As can be seen from the diagram (a and b), the initial balance reserves of gas in the base variant were estimated at 82.8 billion m3, and condensate reserves at 14,703,000 tons. Depending on the minimum cost of the gas field, there is a risk of reduction of gas reserves to 80.7 billion m3, and condensate reserves to 14,434,000 tons. The parameter that most affects the reserves is the formation pressure, which is associated with the recording of a minimum value of 350 atm. With this procedure, tornado diagrams were analyzed and the impact of geological-mining parameters on gas-condensate reserves was estimated as a percentage..



a



b

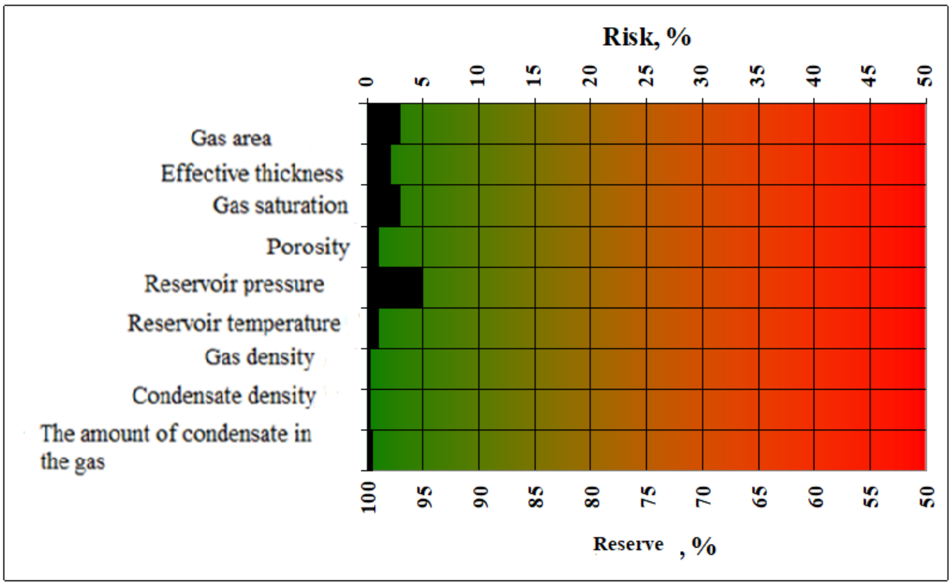
Figure 2.3.15.Tornado diagrams. a - for gas reserves and b - for condensate reserves.

As the probability increases in the case under study, the risks decrease. That is, the reliability of resources increases. The probability depends on the intervals of change of geological-mining parameters on the field or objects. So, if there is a big difference between the minimum and maximum values of geological and mining parameters and the fashion price, then the probability of reserves will decrease. It is possible to follow this process in tornado diagrams.

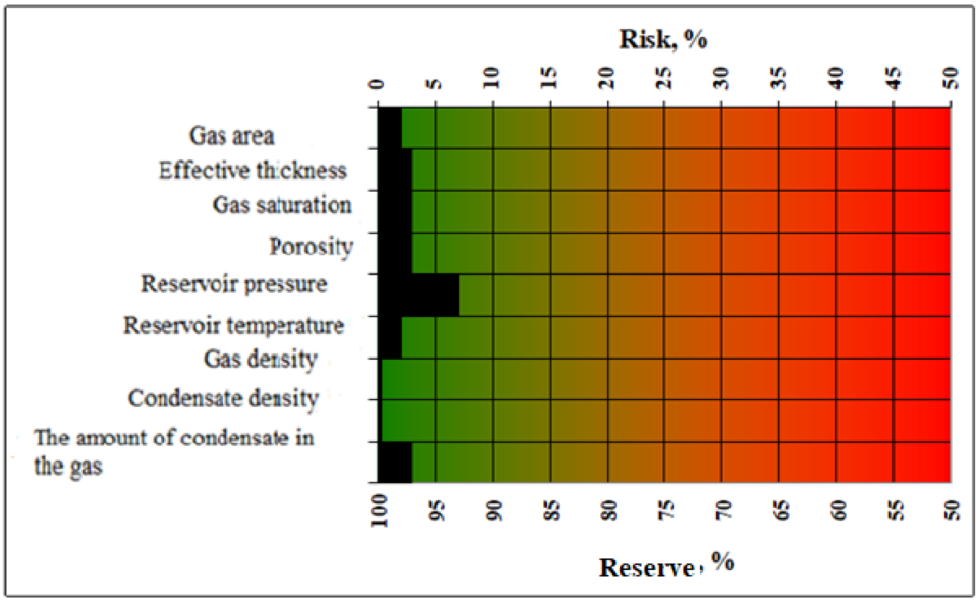
Risks in the calculation of reserves can be called geological risks because they are related to geological criteria (parameters). In the final stage of the study, diagrams were developed to assess the degree of impact of these criteria on reserves and the dependence of risks on geological risks (Figure 2.3.16). In the charts, the risks are rated very high at 0-5% very low, 5-10% low, 10-20% medium, 20-30% high, and above 30%..

As can be seen from the diagrams, the greatest risk (5-7%) in the calculation of gas-condensate reserves is due to the uncertainty of the formation pressure. Gas field, effective thickness, gas saturation and porosity ratios were assessed as very low risks in the calculation of reserves by this statistical method..

Although this matrix is sufficient to assess the geological risks in the calculation of reserves, a more optimal matrix is needed in some uncertain fields and other geological-technological processes. In these cases, a matrix should be designed so that geological risks can be assessed according to the degree of impact of geological and mining parameters on the process, as well as their level of study by field or object. For this purpose, a universal risk matrix was developed (Figure 2.3.17).



a



b

Figure 2.3.16. Geological risk assessment diagrams. a - for gas reserves and b - for condensate reserves.

Degree of learning parameters	**Degree of impact**				
	Very weak	**weak**	**average**	**High**	**Very high**
high (fully studied in the field)	**A1**	**A4**	**A6**	**B4**	**B5**
average (studied in some areas)	**A2**	**A5**	**B2**	**C1**	**C3**
Low (very little has been learned in the field)	**A3**	**B1**	**B3**	**C2**	**C4**
Risk degree	**A (low)**		**B (average)**		**C (high)**

Figure 2.3.17. A new matrix for risk assessment.

In the matrix, the degree of influence of the parameters on the process was assessed at 5 levels, and the degree of study in the field was assessed at 3 levels. In the matrix, geological risks are assessed at three levels (low, medium, high). Depending on the degree of impact and the study of factors, the parameters are placed in the appropriate cells. The lowest risk threshold is defined as the cell with the lowest degree of influence of geological-mining parameters on the process, the highest degree of study (A1), and the highest risk threshold with the highest degree of influence of parameters, the lowest level of study (C4).

In order to assess the geological risks in the calculation of gas-condensate reserves of the studied development object, first of all, the degree of influence of geological-mining parameters on the volume of reserves was determined by analyzing the results of Tornado diagrams. Layer pressure, average effective thickness, gaseous area, porosity and gas saturation are weak, and other parameters are observed as very weakly affected parameters. As these parameters fully cover some areas, the study rates were rated at an average level. The results of geological risk assessment under these conditions are given in Table 2.3.4..

Thus, the assessment of geological risks in the calculation of reserves by the proposed procedures has fully allowed to determine their reliability and design measures to ensure them..

The proposed procedure covers exploration work, development process, etc. it is possible to assess the reliability of geological projects. Suppose that in a hypothetical oil and gas field, it is necessary to assess the geological risks of the process of high-pressure gas injection..

Table 2.3.4

Geological risk assessment schedule

Geological-mining parameters studied	Degree of learnin	Degree of impact	Location	Risk
Gas area	average	weak	A5	down
Effective thickness	average	average	B2	average
Gas saturation	average	weak	A5	down
Porosity	average	weak	A5	down
Reservoir pressure	average	average	B2	average
Reservoir temperature	average	very weak	A2	Down
Density of gas	average	very weak	A2	Down
Condensate density	average	very weak	A2	Down
The amount of condensate in the gas	average	very weak	A2	Down

Table 2.3.5

Geological and technological parameters of the object

Version	Depth, m	Sandiness, %	Clay ness, %	Oil saturation, %	Effective thickness, m	Viscosity of oil, mPas	Conductivity, mD
Minimum (50%)	1333	24	6	34	12	0,5	49
Base (100%)	2666	47	12	68	24	0,9	97
Maximum (150%)	3999	71	18	102	36	1,4	146

For this purpose, sensitivity analyzes are performed on the geological-hydrodynamic model of the field to study the degree of impact on the effectiveness of the method. In general, the geological and technological parameters affecting this process will be as follows (Table 5).

As can be seen, the base prices of geological and mining parameters affecting the gas injection process have been reduced and increased by 50%. Sensitivity analyzes were performed on the hydrodynamic model of the field in multidimensional variants according to the minimum, base and maximum values of the parameters, and the degree of impact on the efficiency of the gas injection process was determined (Figure 2.3.18).

As can be seen from the tornado diagram, the main geological and mining parameters that affect the projected efficiency of the field gas injection process are permeability, oil viscosity, effective thickness and oil saturation. With the exception of permeability, other parameters have been studied at a high level in the field. Conductivity field studies were rated moderate. Referring to the risk matrix, the risk of this parameter was assessed at a high level (C3) .

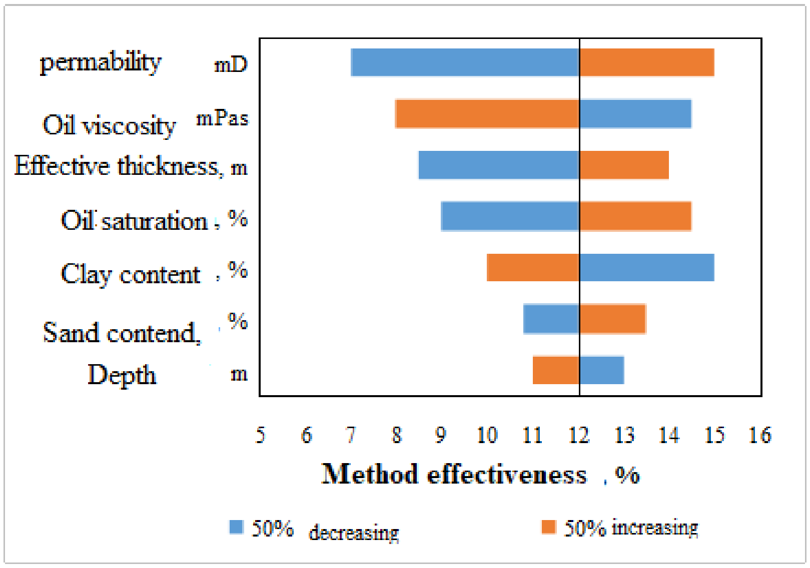


Figure 2.3.18. Tornado diagram for the gas injection process.

In order to reduce the geological risk of the Laya high pressure gas injection project, it is proposed to develop a full area permeability distribution map as a priority measure.

Thus, this approach, which is considered a geological-mathematical and logical method, differs in its universality for assessing the risks of geological, technological, technical, environmental, and economic projects within the norms of international standards.

Risks are characterized four categories. They are attached below:

Low risks which are till 1%

Medium risks which are 1-5 %

High risks which are 5-20%

Very high risks which are up to 20%

. Table 2.3.6 shows IV horizon's table. In here we have horizon and we made tornado and risk matrix for it.

Initial balance reserves of oil, min ton	**Price**	**Oilness Area , min m^2**	**Effective Thickness , m**	**Porosity %**	**Oil saturation %**	**Volume coefficient**	**Density of oil,q/sm^3**
IV	minimum	180	6.0	22	75	1.111	0.900
	base	180	11.0	25	78	1.111	0.900
	maximum	200	11.0	25	78	1.111	0.900

Table 2.3.6

Figure 2.3.19

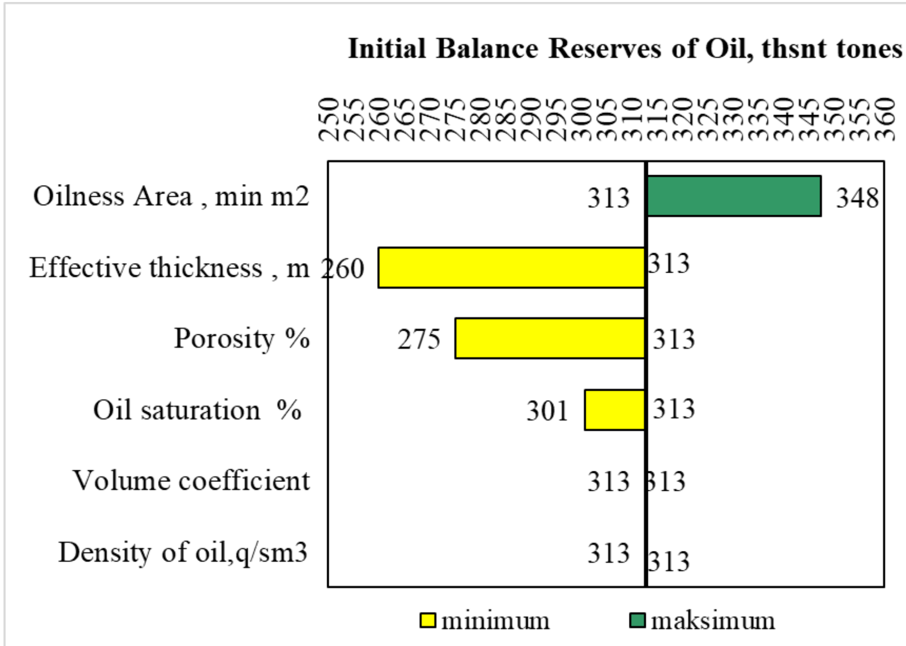


Figure 2.3.19 shows IV tornado diagram. As seems to this diagram we can see the first big affection to production is uncertainties of effective thickness. It decreases from 313 to260 like 83 % reserve and 17 %e risk. Second affection is porosity. Uncertainty of porosity decreases production from 313 to 275 like 88%reserve 12 %risk. Third affection is oil saturation. Uncertainties of oil saturation is decreases oil production from 313 to 301. It is 96 % reserve 4 % risk. Figure 2.3.20 shows risk matrix of grid block.

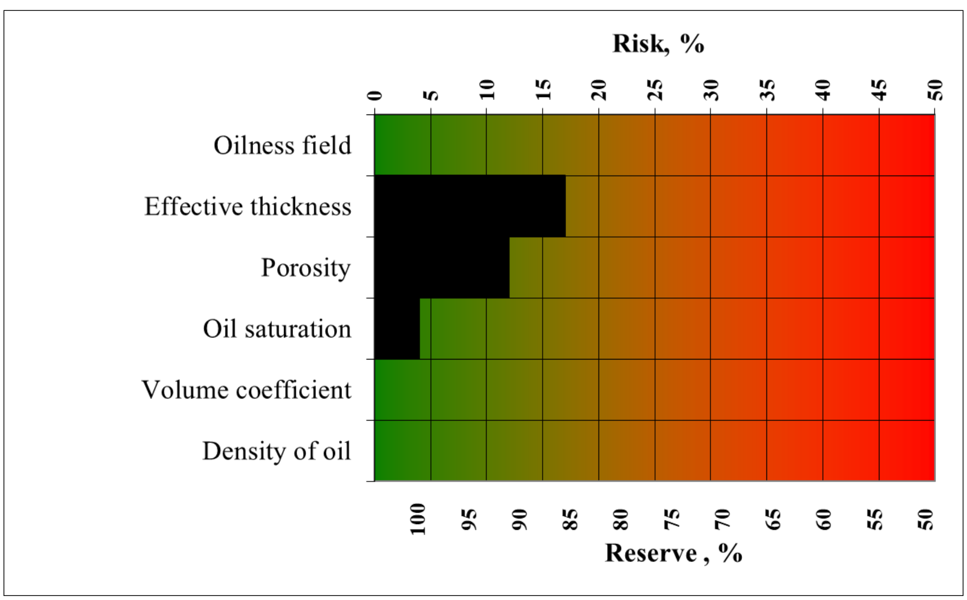


Figure 2.3.20 shows IV risk matrix

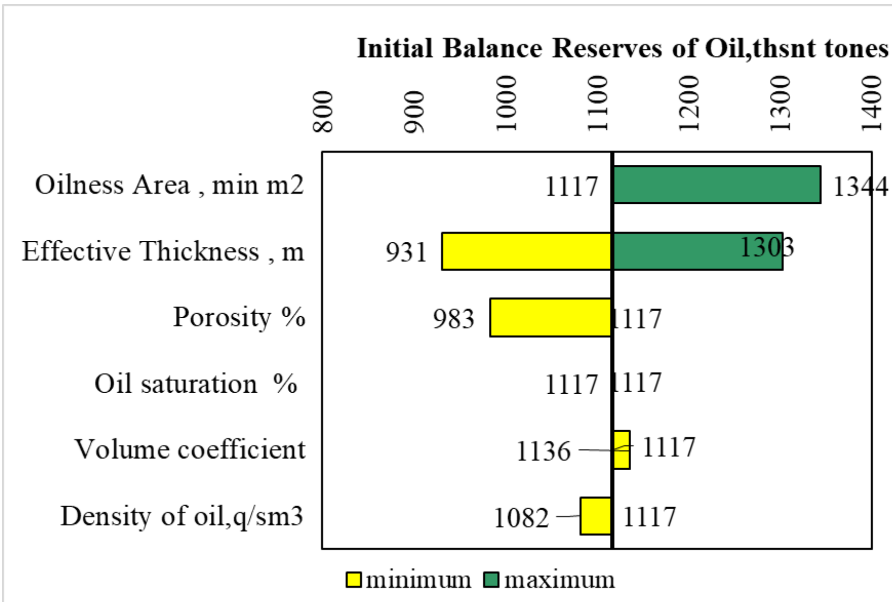
According to this matrix we have high risk uncertainties of effective thickness, and porosity. We have middle risk uncertainty of oil saturation. But others we have no risk.

Table 2.3.7 shows V horizon parameters

Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
V	minimum	590	10.0	22	75	1.073	0.889
	base	590	12.0	25	75	1.091	0.918
	maximum	710	14.0	25	75	1.091	0.918

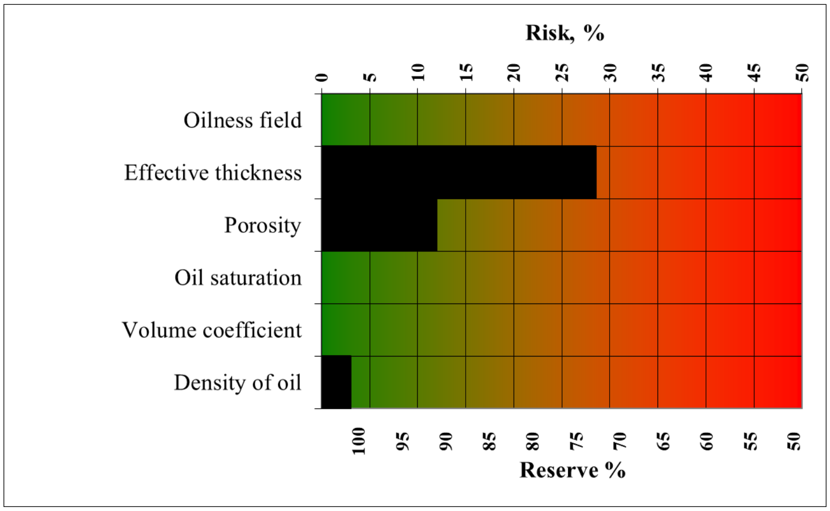
Table 2.3.7

Figure 2.3.21 shows tornado chart



According to this diagram we can see that the biggest affection of reserve estimation is uncertainties of effective thickness. Changing amount of it decreases production from 1117 to 931. It is 83% reserve and 17% risk. Second big affection is porosity. Uncertainty of it decreases reserve from 1117 to 983. It is 88 % reserve 12% risk.

Figure 2.3.22 shows risk matrix of V horizon

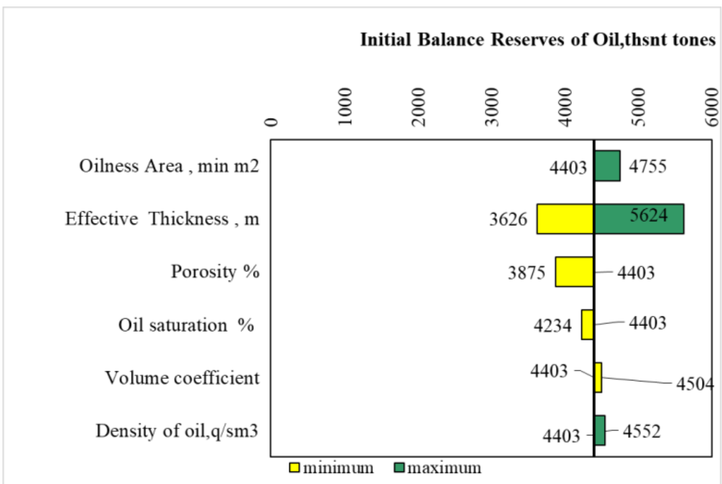


According to figure 2.3.22 we can see there is very high risk is uncertainty of effective thickness. The high risk is uncertainty of porosity, and we have low risk in uncertainties of density of oil.

Table 2.3.8 shows VI horizon's table

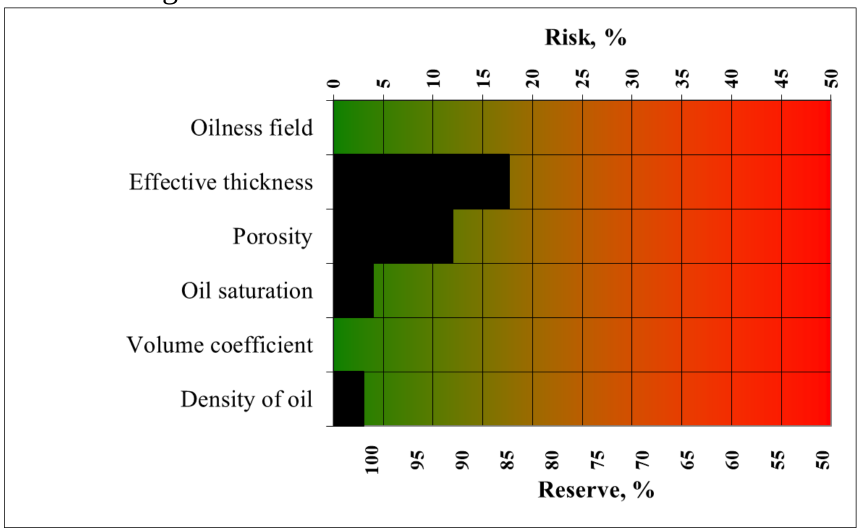
Object	Price	Oilness Area, min m^2	Effective Thickness, m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
VI	minimum	1750	14.0	22	75	1.140	0.885
	base	1750	17.0	25	78	1.166	0.885
	maximum	1890	21.0	25	78	1.166	0.915

Figure 2.3.23 shows tornado chart of VI horizon



According to figure 2.3.23 we can see that the biggest affection of reserve estimation is uncertainties of effective thickness. Changing amount of it decreases reserves from 4403 to 3626. It is 82.35% reserve and 17.65% risk. Second big affection is porosity. Uncertainty of it decreases reserves from 4403 to 3875. It is 88 % reserve 12% risk.

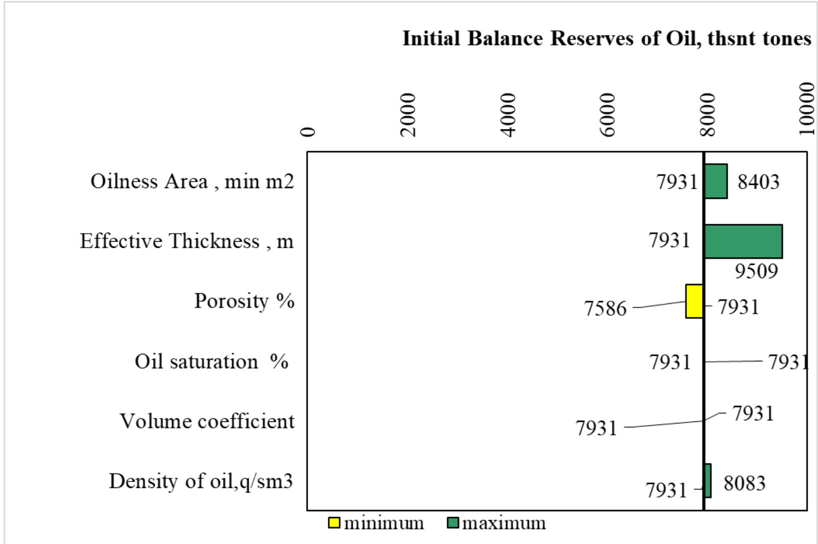
Figure 2.3.24 shows risk matrix of VI horizon



According to figure 2.3.24 we can see there is very high risk is uncertainty of effective thickness. The high risk is uncertainty of porosity, and we have middle risk in uncertainties of oil saturation and density of oil.   Table 2.3.9 shows VII horizon's table

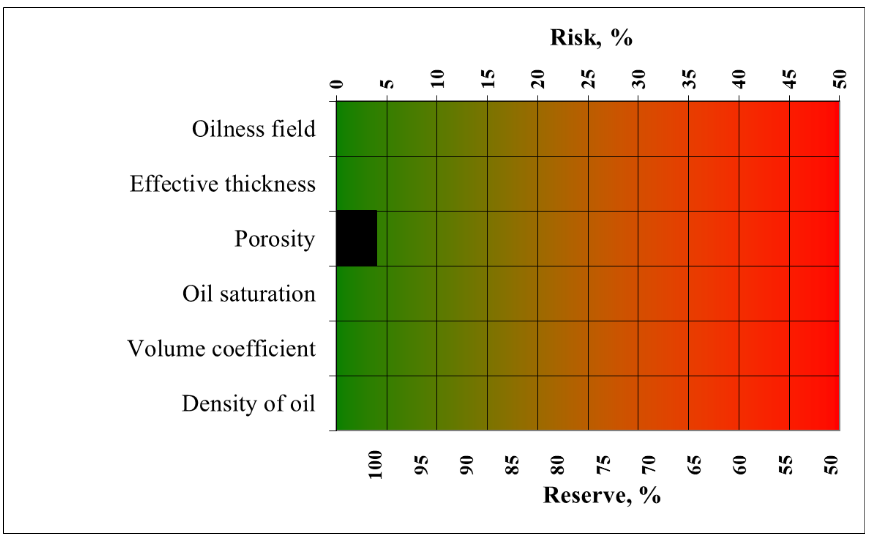
Object	**Price**	**Oilness Area , min m^2**	**Effective Thickness , m**	**Porosity %**	**Oil saturation %**	**Volume coefficient**	**Density of oil, q/sm^3**
VII	minimum	3530	17.0	22	71	1.096	0.887
	base	3530	17.0	23	71	1.096	0.887
	maximum	3740	20.0	23	71	1.096	0.904

Figure 2.3.25 shows tornado chart of VII horizon



there is only porosity uncertainty effects amount of the reserve. It changes from 7931 to 7596 and it is 96% reserve 4 % risk

Figure 2.3.26 shows risk matrix of VII horizon

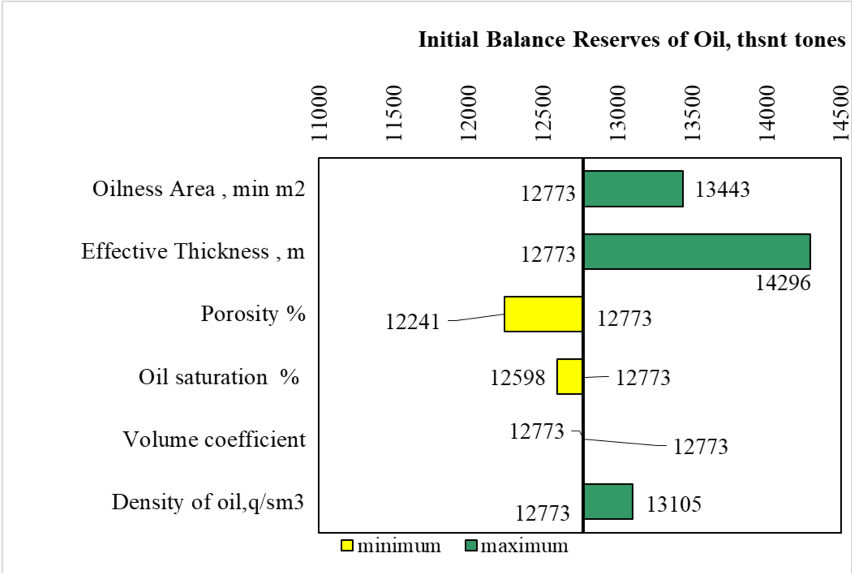


According to figure 2.3.26 we can see we have only porosity middle risk.

Table 2.3.10 shows VIIa horizon's table

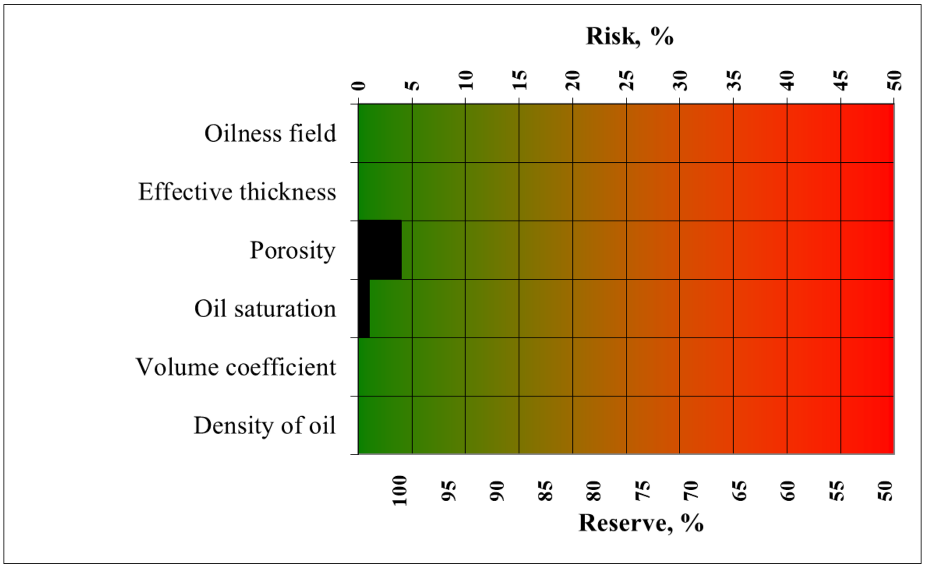
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
VIIa	minimum	8780	11.0	23	72	1.175	0.887
	base	8780	11.0	24	73	1.175	0.887
	maximum	9240	12.0	24	73	1.175	0.910

Figure 2.3.27 shows tornado chart of VIIa horizon



According to figure 2.3.27 there are 2 affections to reserve estimation. Porosity decreases reserve from 12773 to 12241. It is 96 % reserve 4% risk. Oil saturation decreases from 12773 to 12598. It is 99% reserve 1 % risk.

Figure 2.3.28 shows risk matrix of VIIa horizon

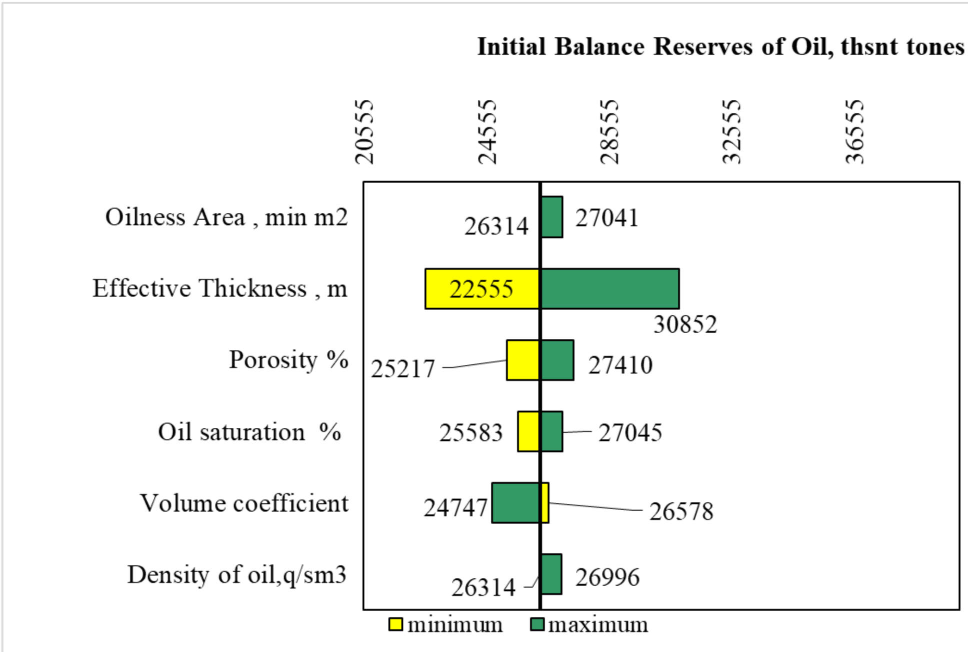


According to figure 2.3.28 we have middle risk for changing value of porosity and oil saturation.

Table 2.3.11 shows VIII horizon's table

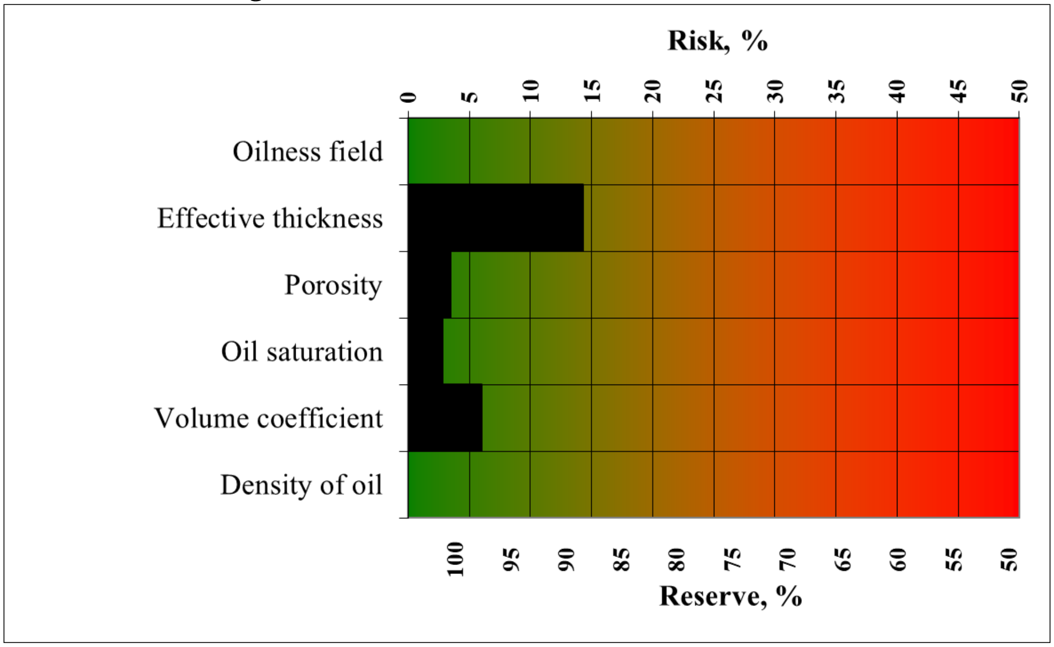
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
VIII	minimum	10850	15.0	23	70	1.095	0.887
	base	10850	17.5	24	72	1.106	0.887
	maximum	11150	20.0	25	74	1.176	0.910

Figure 2.3.29 shows tornado chart of VIII horizon



According to figure 2.3.29 we can see that the biggest affection of reserve estimation is uncertainties of effective thickness. Changing amount of it decreases reserves from 26314 to 22555. It is 85.7% reserve and 14.3% risk.

Figure 2.3.30 shows risk matrix of VIII horizon

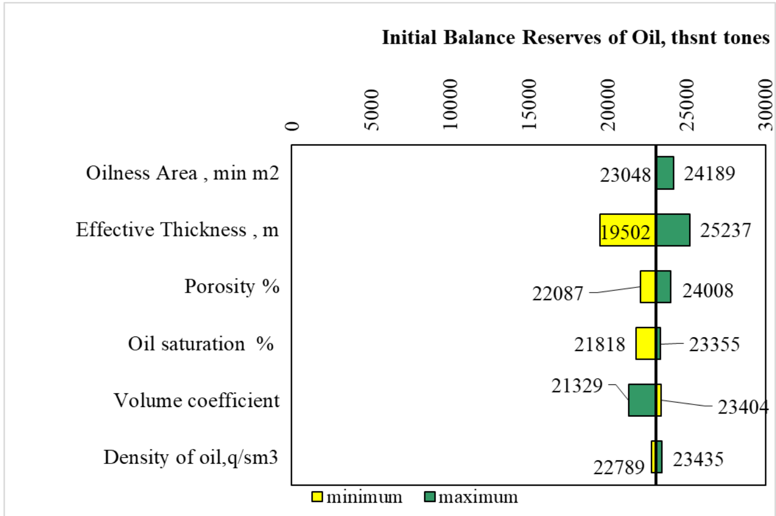


According to figure 2.3.30 we have very high-risk uncertainties of effective thickness. High risk is volume coefficient and middle risks are oil saturation and porosity.

Table 2.3.12 shows IX horizon parameters

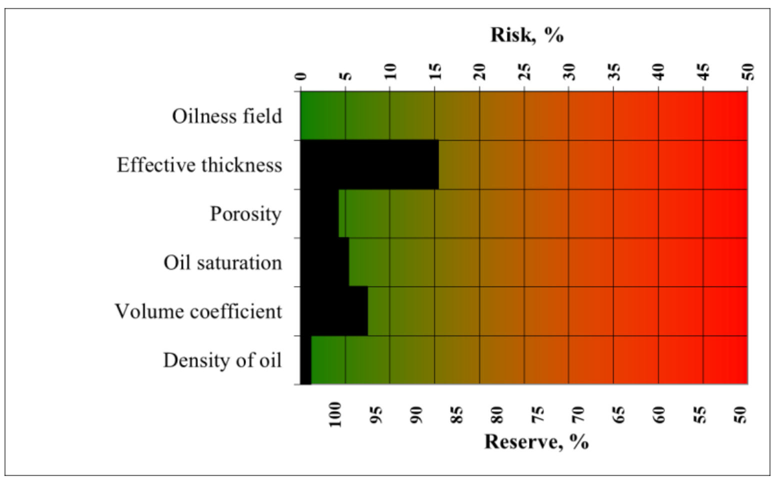
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
IX	minimum	12320	11.0	23	71	1.100	0.883
	base	12320	13.0	24	75	1.117	0.893
	maximum	12930	14.0	25	76	1.207	0.908

Figure 2.3.31 shows tornado chart of IX horizon



According to figure 2.3.31 we can see that the biggest affection of reserve estimation is effective thickness. Uncertainty of it decreases reserves from 23048 to 19502. It is 84.6% reserve and 15.4%risk.

Figure 2.3.32 shows risk matrix of IX horizon

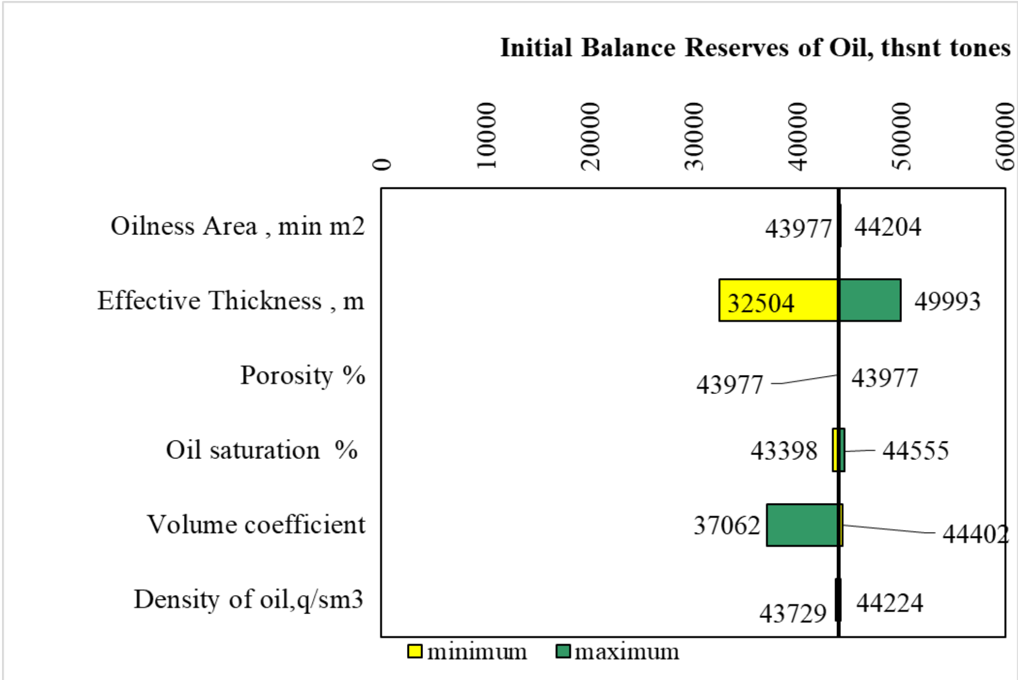


According to figure 2.3.32 seems that the high risks are effective thickness and volume coefficient and oil saturation. Middle risks are porosity and density of oil.

Table 2.3.13 shows X horizon parameters

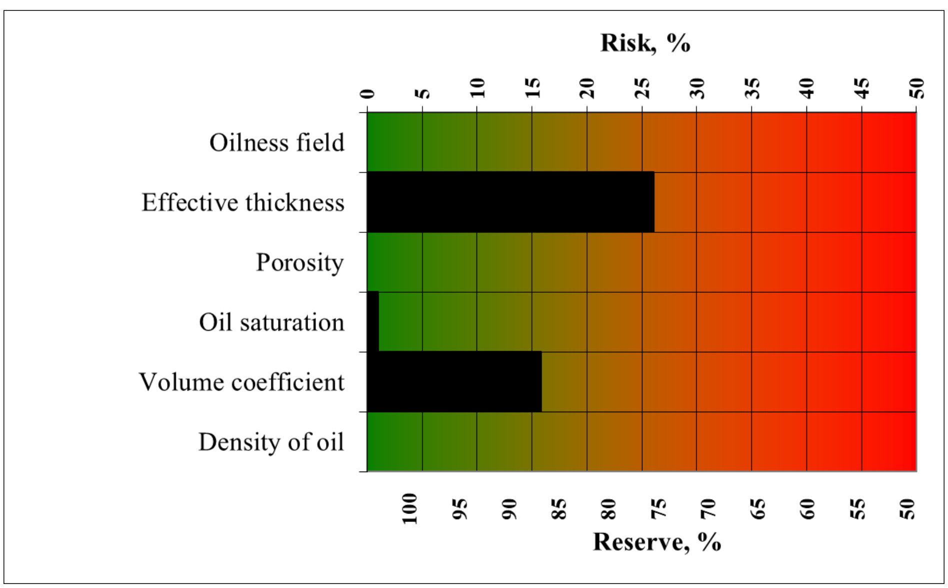
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
X	minimum	13540	17.0	24	75	1.136	0.883
	base	13540	23.0	24	76	1.147	0.888
	maximum	13610	26.0	24	77	1.361	0.893

Figure 2.3.33 shows tornado chart of X horizon



According to figure 2.3.33 we can see that the biggest affection of reserve estimation is effective thickness. Uncertainty of it decreases reserves from 43977 to 32504. It is 73.9% reserve and 26.1%risk.

Figure 2.3.34 shows risk matrix of X horizon

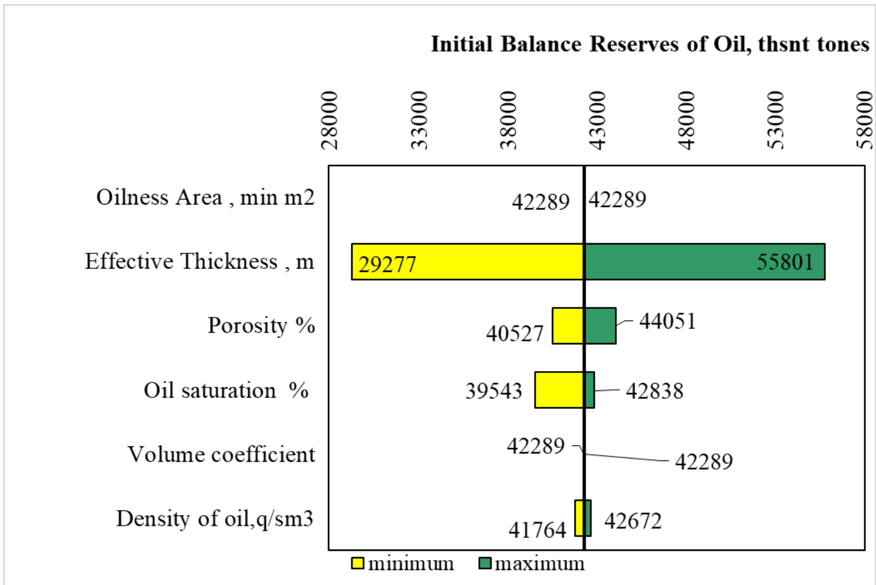


According to the figure 2.3.34 we can see that there is very high risk is uncertainty of effective thickness. High risk is volume coefficient, and low risk is uncertainty of oil saturation.

Table 2.3.13 shows FLD horizon parameters

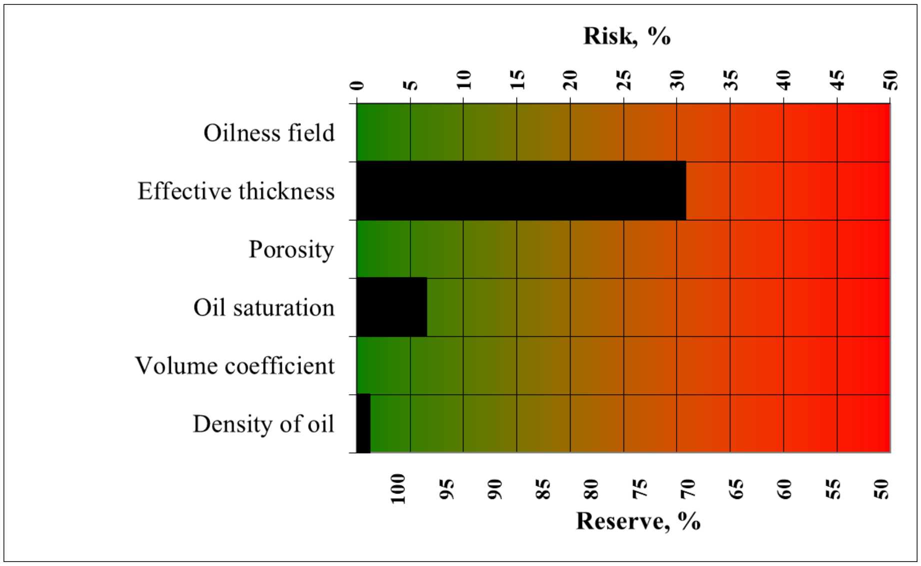
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
FLD	minimum	10880	18.0	23	72	1.094	0.874
	base	10880	26.0	24	77	1.094	0.885
	maximum	10880	34.0	25	78	1.094	0.893

Figure 2.3.35 shows tornado chart of FLD horizon



According to figure 2.3.33 we can see that the biggest affection of reserve estimation is Effective Thickness. Uncertainty of it decreases reserves from 42289 to 29277. It is 69.2% reserve and 30.8%risk. The second nig effect is uncertainty of oil saturation. It decreases from 42289 to 39543. It is 93.5 % reserve 6.5% risk. Third big effect is Oil saturation it decreases from 42289 to 39543. It is 93.5% reserve 6.5 risk.

Figure 2.3.36 shows risk matrix of FLD horizon.

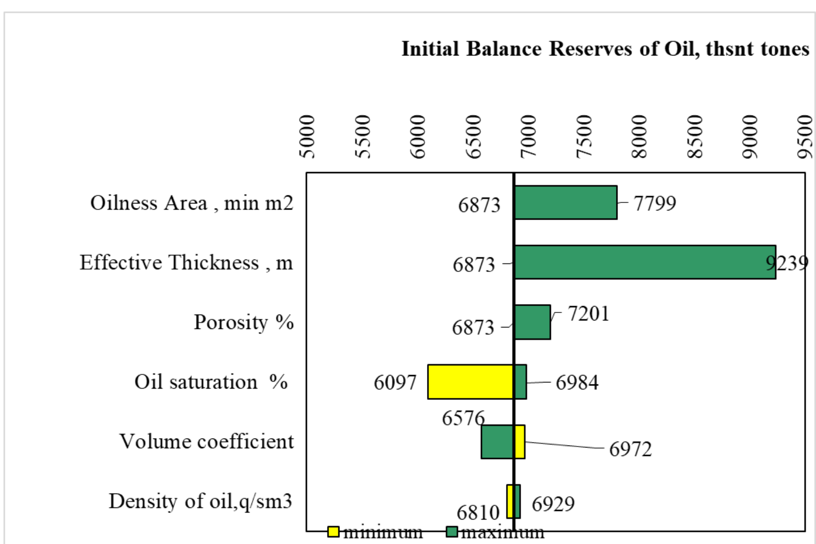


According to figure 2.3.36 seems that there is very high risk on effective thickness. There is high risk on uncertainty of oil saturation and medium risk on density of oil.

Table 2.3.14 shows QUG horizon parameters

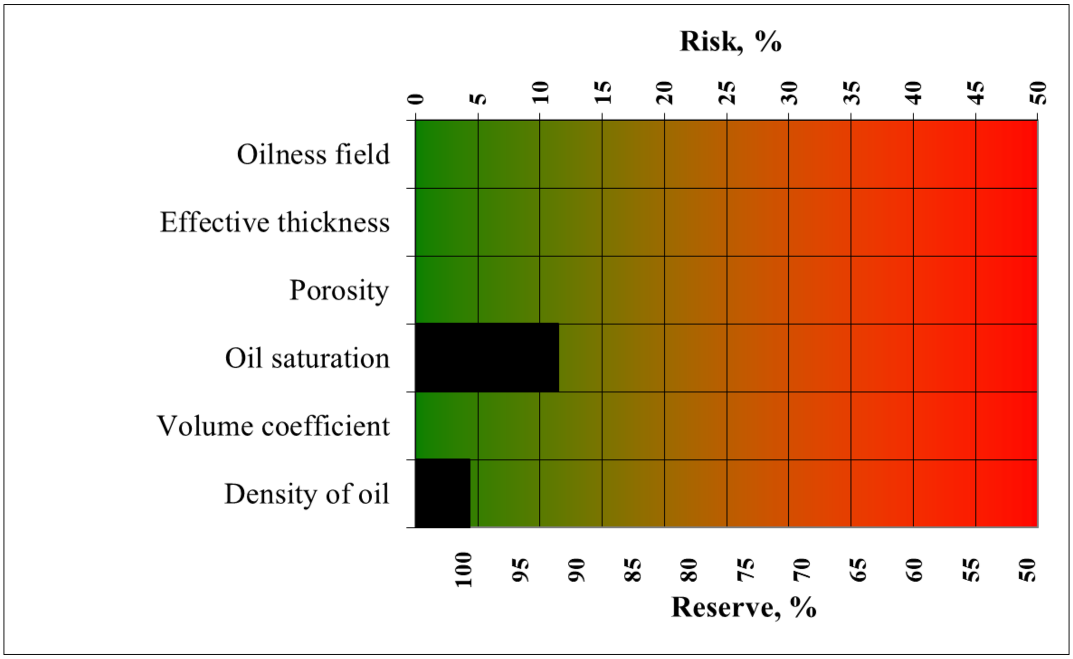
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
QUG	minimum	10840	6.0	21	55	1.047	0.854
	base	10840	6.0	21	62	1.062	0.862
	maximum	12300	8.0	22	63	1.110	0.869

Figure 2.3.37 shows tornado chart of QUG horizon



According to figure 2.3.37 seems that the big affection of reserve is uncertainty of oil saturation. It deceases from 6873 to 6097 it is 88.56% reserve and 11.44% risk.

Figure 2.3.38 shows risk matrix of QUG horizon.

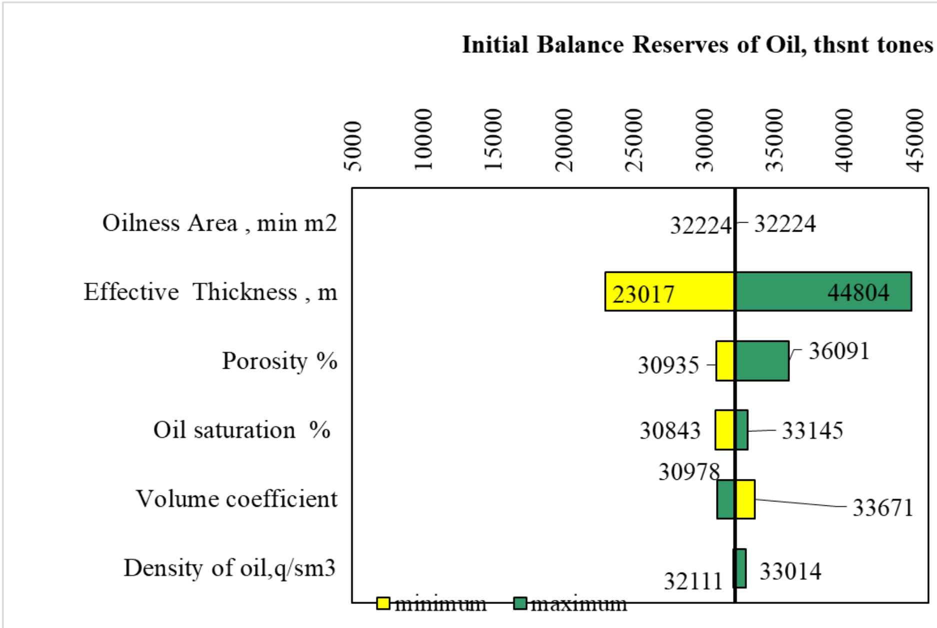


According to risk matrix seems that high risk on oil saturation. And there is medium risk on density of oil.

Table 2.3.15 shows QUQ horizon parameters

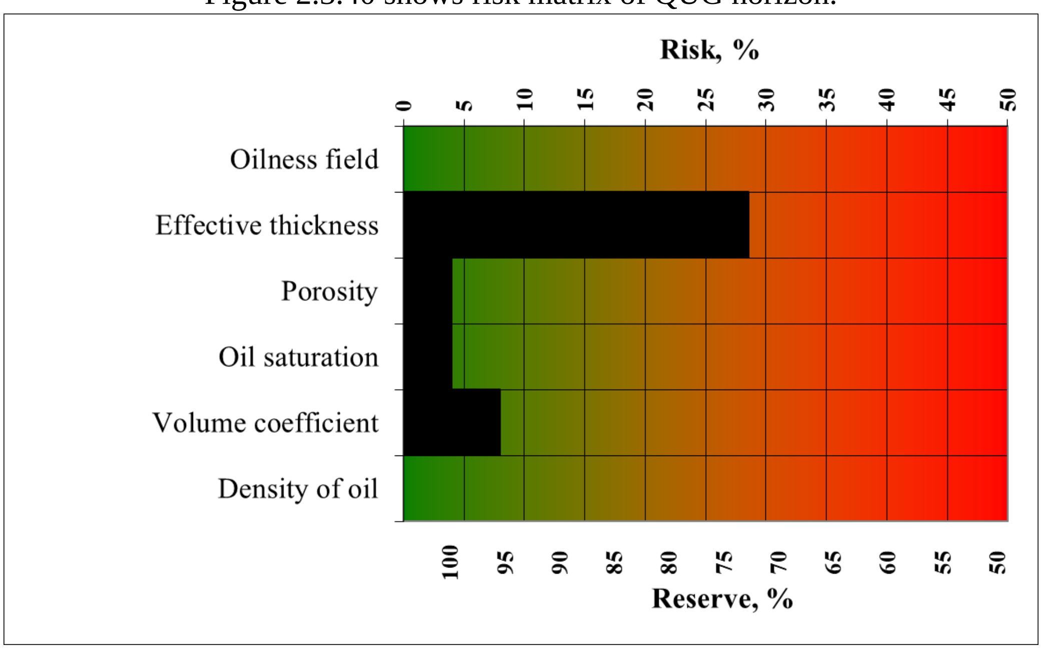
Object	**Price**	**Oilness Area , min m^2**	**Effective Thickness , m**	**Porosity %**	**Oil saturation %**	**Volume coefficient**	**Density of oil, q/sm^3**
QUQ	minimum	16790	10.0	24	67	1.047	0.854
	base	16790	14.0	25	70	1.094	0.857
	maximum	16790	19.0	28	72	1.138	0.878

Figure 2.3.39 shows risk matrix of QUG horizon.



According to figure 2.3.39 it seems that the big affection of reserve estimation is changing of effective thickness it decreases from 32224 to 23017. It is 72.428% reserve and 28.572% risk.

Figure 2.3.40 shows risk matrix of QUG horizon.

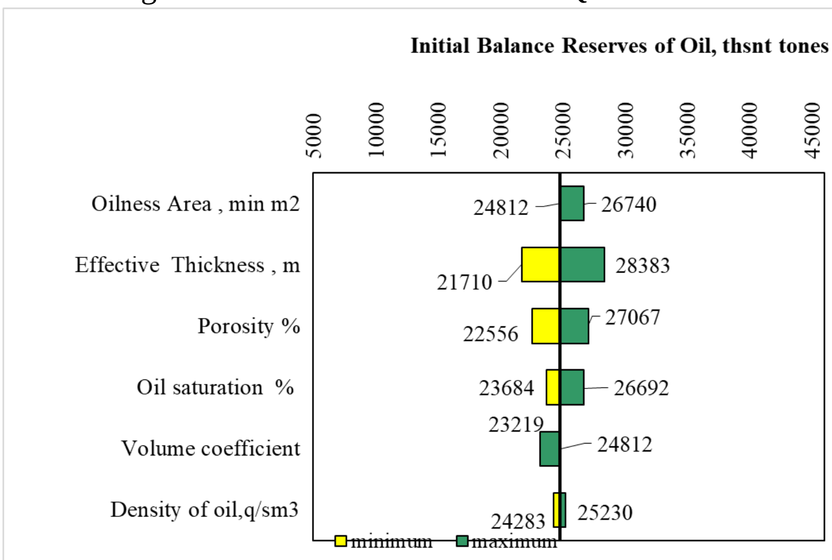


According to figure 2.3.40 it seems that there is the very high risk on uncertainties of effective thickness. There is high risk on volume coefficient, and middle risks on oil saturation and porosity.

Table 2.3.16 shows QD horizon parameters

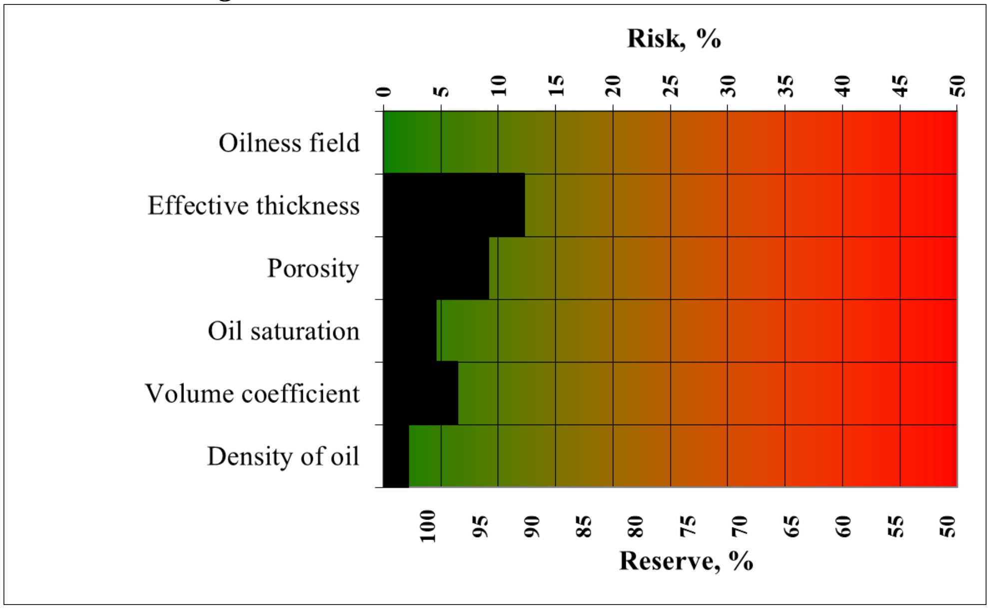
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
QD	minimum	25867	7.0	20	63	1.079	0.872
	base	25867	8.0	22	66	1.079	0.891
	maximum	27877	9.0	24	71	1.153	0.906

Figure 2.3.41 shows risk matrix of QD horizon.



According to the figure 2.3.41 it seems that the biggest affection of reserve estimation is uncertainty of effective thickness. It decreases from 24812 to 21710 like 87.75% reserve 12.25% risk. The second big affection is porosity. It decreases from 24812 to 22556. It is 90.9% reserve 9.1% risk.

Figure 2.3.42 shows risk matrix of QD horizon.

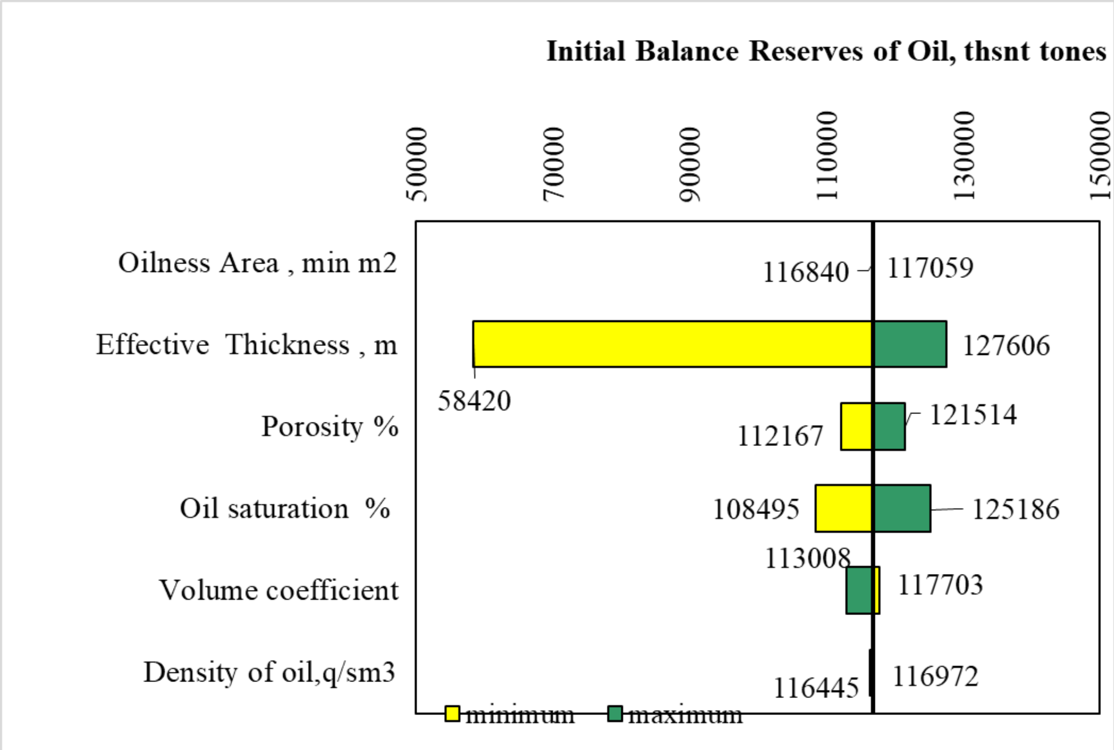


According to figure2.3.42 high risks are uncertainties of effective thickness, volume coefficient and porosity. Middle risks are uncertainties of oil saturation and oil density.

Table 2.3.17 shows QA horizon parameters

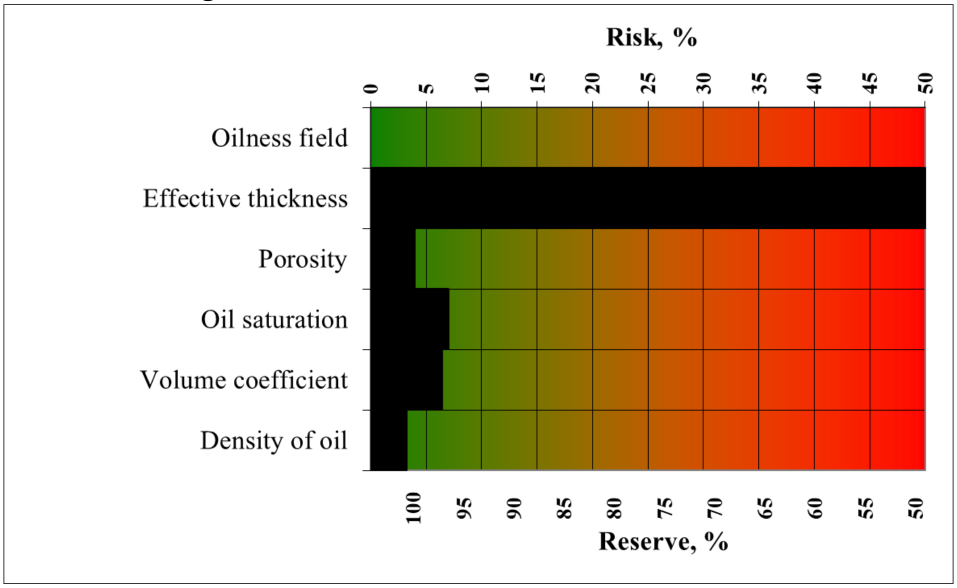
Object	**Price**	**Oilness Area , min m^2**	**Effective Thickness , m**	**Porosity %**	**Oil saturation %**	**Volume coefficient**	**Density of oil, q/sm^3**
QA	minimum	37370	11.0	24	65	1.083	0.883
	base	37370	22.0	25	70	1.091	0.886
	maximum	37440	24.0	26	75	1.128	0.887

Figure 2.3.43 shows risk matrix of QA horizon.



According to the figure 2.3.43 it seems that the biggest affection of reserve estimation is uncertainty of effective thickness. It decreases from 116840 to 58420. It is 50% reserve 50% risk.

Figure 2.3.44 shows risk matrix of QA horizon.

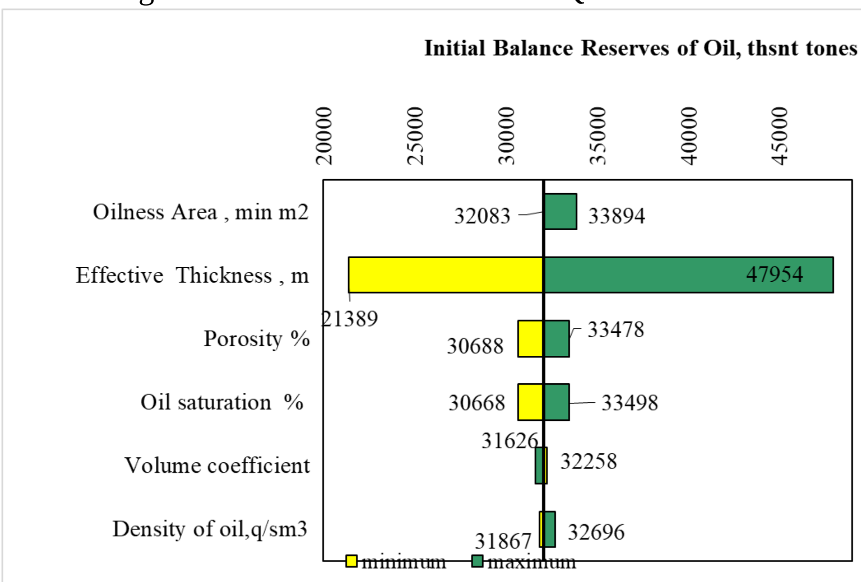


According to figure 2.3.44 it seems that there is very high risk to uncertainty of effective thickness. There are high risks on oil saturation and volume coefficient. And there is middle risk on density of oil.

Table 2.3.18 shows QaLD horizon parameters

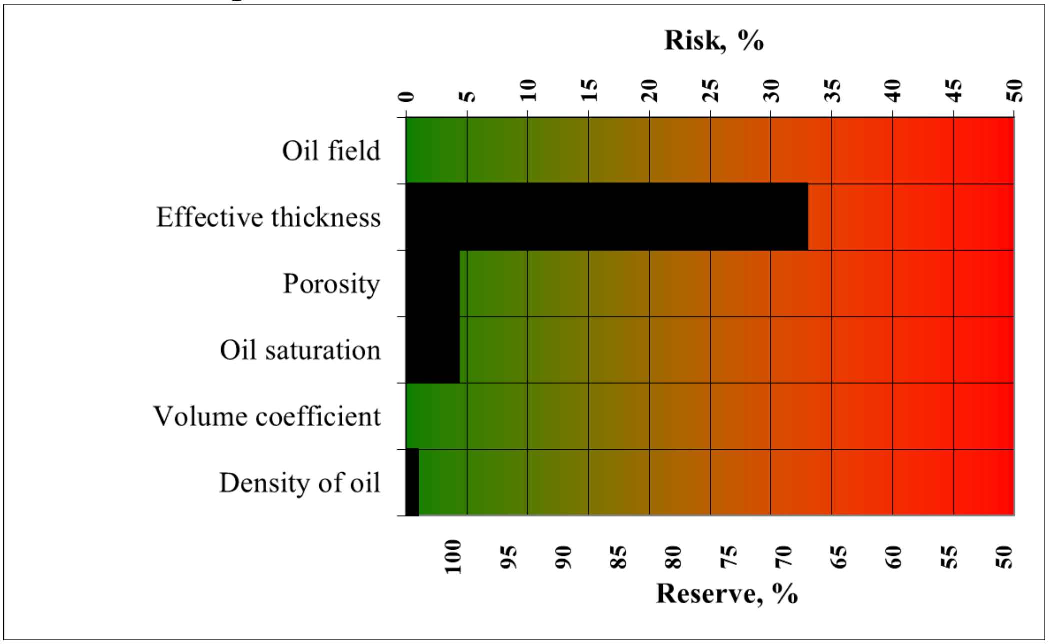
Object	Price	Oilness Area , min m^2	Effective Thickness , m	Porosity %	Oil saturation %	Volume coefficient	Density of oil, q/sm^3
QaLD	minimum	17010	10.0	22	65	1.101	0.884
	base	17010	15.0	23	68	1.107	0.890
	maximum	17970	22.0	24	71	1.123	0.907

Figure 2.3.45 shows risk matrix of QaLD horizon.



According to figure 2.3.45 seems that the biggest affection is changing of effective thickness. It decreases from 32083 to 21389. It is 67% reserve 33% risk.

Figure 2.3.46 shows risk matrix of QaLD horizon.



According to figure 2.3.46 it seems that there is very high risk on uncertainty of effective thickness, porosity oil saturation are medium risks, oil density is low risk.

3 Results and conclusion

Uncertainty of layer parameters was analyzed and these uncertainty rates were assessed by sensitivity analysis to the degree of reserve effect of each parameter and as a result of this assessment, the risk matrix m=is formed. The risk of each parameter has been determined based on a risk matrix that can be quantified. It is proposed that this method be used in the formulation of the specification for processing in the “Neft Dashlari” field. Thus, the uncertainty of these reserves is the first factor that directly affects the accuracy of the scenarios and accurate forecasting. From this point of view, this methodology is of great importance. And it is proposed that the risks in this type of development in the “Neft Dashlari” fields should be determined by this method

References

1. Bağırov B.Ə., Calalov Q.İ., Nəzərova S.Ə. Riyazi geologiyanın əsasları. Bakı: Realkom, 2001, 64 s.
2. Bağırov B.Ə., Həsənəliyev M.Q., Gəncəliyeva A.S. Azərbaycanın dənizdə ehtiyatı çətin çıxarılabilən neft yataqlarında işlənilmənin başa çatdırılmasının səmərəli yolları // Azərbaycan Geoloqu, 2000, №5, s. 87-95
3. Bağırov B.Ə., Nərimanov A.Ə., Nəzərova S.Ə., Salmanov Ə.M. Yataqların çıxarılabilən neft ehtiyatlarının hesablanması. Bakı: ADNA, 2001, 57 s.
4. Bağırov B.Ə., Nərimanov A.Ə. və b. Çoxsaylı neft yataqlarının kəsilişində istismar obyektlərinin ayrılma üsulları. Bakı: ADNA, 2001, 26 s.
5. Əhmədov E.H. Neftin su buxarı ilə sıxışdırılması / XIII Respublika Elmi Tələbə Konfransı. Bakı: 2008, s. 34
6. Əhmədov E.H., Şirinov Ə.T., Rəhimov F.V. Geoloji risklərin qiymətləndirilməsi üçün yeni üsul / AMEA-nın 70 illiyinə həsr olunan gənc alim və mütəxəssislərin "Akademik elm həftəliyi – 2015" adlı beynəlxalq multidissiplinar forum. Bakı: 2015, s. 4-6
7. Əhmədov E.H., Şirinov Ə.T., Rəhimov F.V. Neft-qaz yataqlarında geoloji risklərin qiymətləndirilməsinin yeni metodikası // Gənc Tədqiqatcı, 2015, № 2, s.
8. İskəndərov M.Ə. Neft-qaz mədən geologiyası və neft-qaz yataqlarının işlənməsi. Bakı: Marif, 1968, 399 s.
9. Qasımov Ə.Ə., Zeynalov N.V. Layların neftverimini artıran üsulların səmərəliliyinin qiymətləndırılməsi // Azərbaycan Neft Təsərrüfatı, 2002, №2, s. 6-8
10. Salmanov Ə.M., Kərimov N.S., Əhmədov E.H. Neft Daşları yatağında Qırməki lay dəstəsi obyektlərində suvurmanın nəticələri // Azərbaycan Ali Texniki Məktəblərinin Xəbərləri, 2012, №5, s. 20-25
11. Абасов М.Т., Алияров Р.Ю., Гулиев И.С. О геологических проблемах развития нефтегазодобычи в Азербайджане // Известия НАН Азербайджана. Серия Наук о Земле, 2003, №3, с. 110-123
12. Абасов М.Т., Багиров Б.А., Гусейнов А.Н. Исследование структуры запасов с целью перспективного планирования методов повышения нефтеотдачи // Азербайджанское нефтяное хозяйство, 1983, №1, с. 1-4
13. Багаров Т.Ю. Статистические методы оценки запасов нефти. Баку: Элм, 1978, 100 с.
14. Багиров Б.А., Аллахвердиев И.М, Салманов А.М., и др. Прогнозирование эффективности заводнения нефтяных залежей // Известия Высших Учебных заведений, 1995, №2, с. 9-12
15. Багиров Б.А., Аллахвердиев И.М., Салманов А.М. Моделирование нефтеотдачи залежей с трудноизвлекаемыми запасами нефти / Материалы Международного симпозиума Геологические

аспекты разработки залежей. Баку: 1995, с. 60-61

16. Багиров Б.А. Геологические основы доразработки месторождений нефти и газа. Баку: Элм, 1986, 111 с.

17. Багиров Б.А. Геологические проблемы разработки нефтяных месторождений Азербайджанской республики / Международная Конференция по формированию залежей УВ. Пекин: 2006, Апрель, с. 127-140

18. Ahmadov E.H. Estimation of oil and gas reserves applying various mathematical and geological methods / II Итоговая Международная (заочная) научно-практическая конференция по всем наукам «Интеграция мировых научных процессов как основа общественного прогресса». Казань: 2014, с. 21-25

19. Ahmadov E.H. Study of water injection efficiency through modern geological-mathematical models in Guneshly field // Journal of Environmental Science and Engineering, 2013, № 10, pp. 574-577

20. Ahmed T., McKinney P.D. Advanced reservoir engineering. New-York: GPP, 2011, p. 424

21. Risk and uncertainty. Awareness Seminar / BpAmoco, 1999, 170 p.