Master’s Degree in Petroleum and Mining Engineering

Politecnico di Torino

Multistage hydraulic fracturing

Final qualification project

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1. Hydraulic fracturing as a preferred stimulation technique

Hydraulic fracturing was first applied in the late 1940s to increase production from poorly producible wells in Kansas (figure 1). Following the explosive growth in the practice of this technique in the mid-1950s and a significant spike in activity in the mid-1980s, hydraulic fracturing developed into the dominant stimulation method, primarily for low-permeability reservoirs in North America. By 1993, 40 percent of new oil wells and 70 percent of gas wells in the United States were fractured.

Figure 1 — An early hydraulic fracture performed in 1949

With the current increased capabilities of hydraulic fracturing technology, as well as the development of fracturing technology for high-permeability formations, which in professional jargon has come to be called “frac & pack”, hydraulic fracturing has further spread and has become the preferred stimulation technique for all types of wells in the United States but especially in gas wells (figure 2).

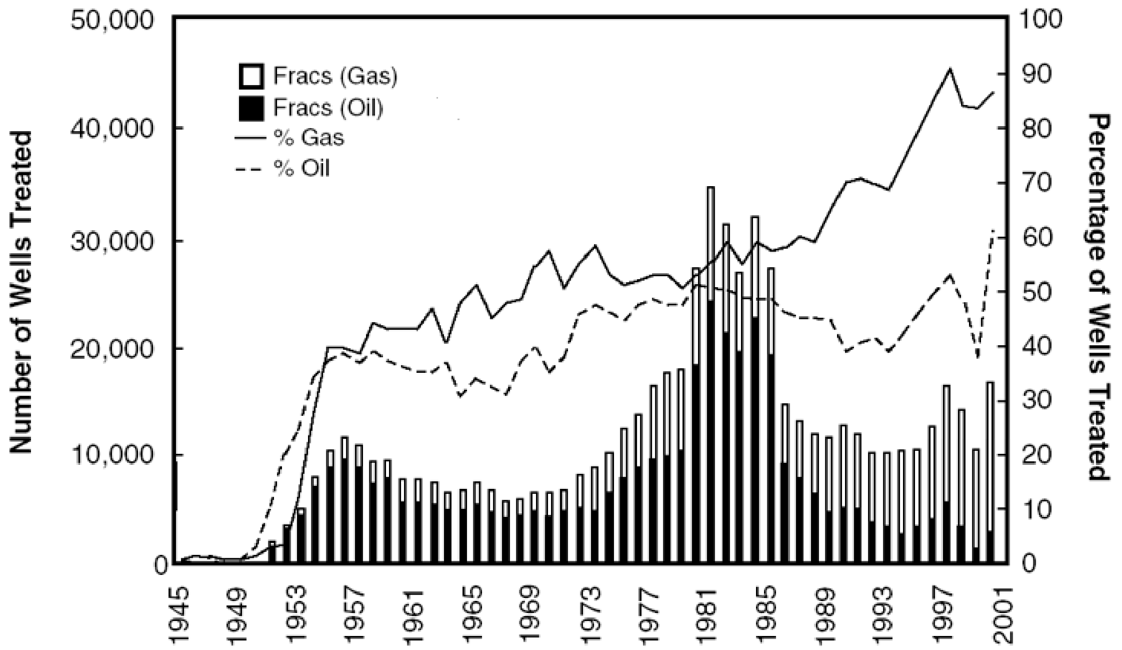


Figure 2 – Historical data concerning hydraulic fracturing

Nowadays, the fact that the benefits of hydraulic fracturing in most wells are enormous has become quite common. Even close to water or gas contacts that were considered "death" for hydraulic fracturing, fracturing in high-permeability formations is now finding use as it offers controlled fracture propagation and limits drawdown [Mullen et al., 1996; Martins et al., 1992].

Rapid growth in the number of hydraulic fracturing operations in highly permeable formations - from a few unrelated operations in 1993 [Martins et al., 1992; Grubert, 1991; Ayoub et al., 1992] to about 300 hydraulic fracturing per year in the USA alone in 1996 [Tiner et al., 1996] was only the beginning of the period when highly permeable hydraulic fracturing is becoming the dominant tool for optimizing well development and production. It is now considered one of the most significant recent developments in oil production.

There is significant room for additional fracturing growth in the global oil and gas industry, as well as in other industries. It is estimated that in a number of countries fracturing can provide additional production from existing wells of several hundred thousand barrels per day.

This can be achieved if the process is taken seriously and consistently, since the efficiency of energy resources production determines the cost of processing and therefore the economy as a whole.

There are two common obstacles to hydraulic fracturing applications:

1. There is a widespread misconception that this process is only intended for reservoirs with low permeability (e.g. less than 1 mD), or that it is a last technique for stimulation of production or injection, which should be applied only when all else fails. It is often caused by the

fears that hydraulic fracturing is dangerous, that it anticipates water breakthrough to the well, that it increases the water cut of the product or leads to the appearance of crossflows, and so on. Much more serious problem is that using hydraulic fracturing as a last approach, sometimes reckless, means poorly planned stimulation, which can be associated with a number of problems (such as failure to account for well deviation or inappropriate perforation), which, in turn, can almost guarantee disappointing results. And the last of the problems in this regard is opinion that hydraulic fracturing of highly permeable formations is used only for such reservoirs in which it is necessary to control sand production. This is clearly not the case, and fracturing in reservoirs with a permeability of several hundred millidarcy is currently a daily practice.

2. Hydraulic fracturing is a large operation with a very wide set of equipment, complex and requiring large volumes of fluids and proppants, as well as significant costs of qualified engineering labor and auxiliary labor costs, with high requirements for the organization of work. The costs of separate, unrelated jobs, say, one to three operations every three to six months, are excessively high. And in combination with the occasional unsuccessful treatments, this occasional fracturing application will definitely lead to economic failure and lack of motivation to use hydraulic fracturing in the future.

Almost no other type of work in the oil and gas industry differs in cost so significantly between regions where it is widespread and applied on a large scale - such as North America and the offshore fields in the North Sea, and elsewhere. In North America, more than 60 percent of oil wells and 85 percent of gas wells are fractured, and this percentage continues to rise. For example, the cost of hydraulic fracturing with the injection of 100 tons of proppant in the United States is at least 10 times cheaper than the exact same hydraulic fracturing, with the same equipment and carried out by the same service company, say, in Venezuela or Oman.

At the same time, almost no other technology in the oil and gas industry provides the same high economic return. The world production growth from hundreds of thousands to millions of barrels per day is predicted based on the assumption that the percentage of existing wells with hydraulic fracturing will reach the value of 60 per cent, and the increase in production from one well will be only 25% of production before hydraulic fracturing. And this is based on a very modest assumption that all existing wells will continue to produce oil, and hydraulic fracturing will give an easily achievable reduction of the "skin" to a value equal to –2. In fact, the possibility of obtaining additional production from a massive fracturing campaign, with adequate equipment and well-trained personnel, seems to be quite high.

2. Fundamentals of hydraulic fracturing

During the operation of wells after drilling in the reservoir, oil and gas under high pressure in the pore space move to the well and then rise to the surface. One of possible modes in which the flow of fluid to the well occurs is called radial (Figure 3).

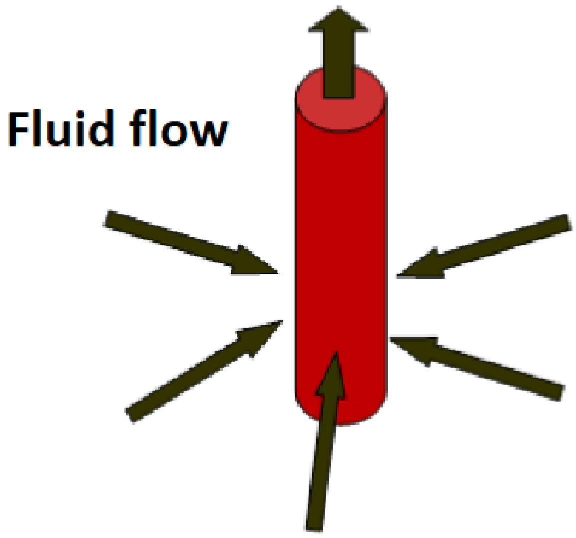


Figure 3 – Radial flow to the well

In case of fluid flow to the well under radial conditions, productivity of a well depends on the pressure drop ΔP created between the formation and the well and the reservoir capacity kh.

The production well inflow can be significantly increased by means of hydraulic fracturing (fracking). During hydraulic fracturing, a liquid (gel) is injected into the well at a pressure higher than the fracture pressure. With further injection of fluid into the formation, a highly permeable fracture is created, the created fracture is then propped open by the proppant. Further, the fluid flow first occurs from the formation into the fracture, similar to radial, and then linear fluid flow in the fracture to the well. The fracture created by means of hydraulic fracturing, unlike other stimulation methods, significantly increases the drainage area by increasing the drainage radius related now to the length of the fracture and provides a linear inflow to the well. Fluid in the fracture is shown in the figure 4.

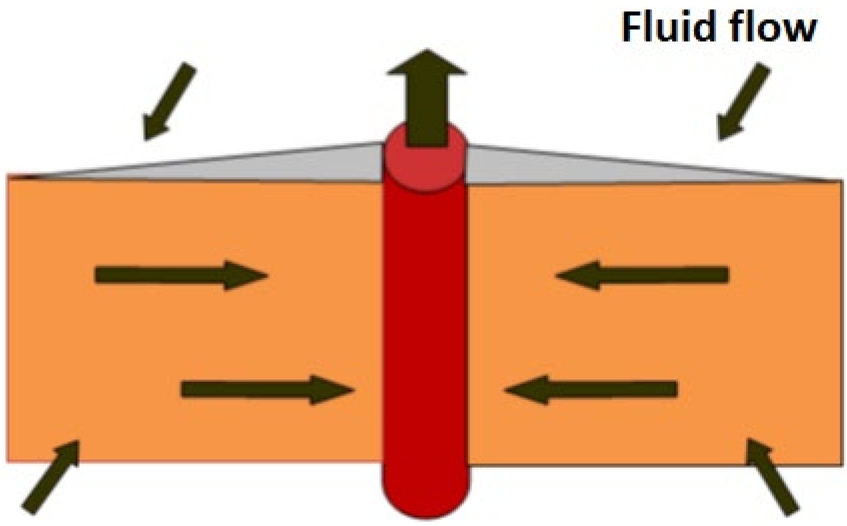


Figure 4 – Linear fluid flow in a fracture

The creation of a linear flow leads to an increase in the rate of fluid production from the formation. The areal contact of the high-permeability fracture with the formation gives a noticeable increase in inflow from the low-permeability formation. In the fracture, additional pressure losses are significantly reduced due to high conductivity during fluid flow from the formation to the well, the rate of production is accelerated, and, accordingly, the balance reserves can be recovered in a shorter period of time. Hydraulic fracturing is used mainly in low-permeability reservoirs, but it can be also applied in highly-permeable reservoirs. Hydraulic fracturing has the following main goals:

1) increase the productivity of the well by increasing the effective drainage radius of the well related to the parameters of the fracture;

2) create a channel for fluid inflow into bottom-hole region from a remote formation zone through the near-wellbore low-permeability zone.

Hydraulic fracturing is the process of using hydraulic pressure to create new artificial fractures or expand existing fractures in a formation. Fractures grow in length, height and width by injecting a gel mixture of fluid and proppant under high pressure, maintaining the fractures open after the decrease in well pressure. The ability of a fracture to increase production from the formation depends on three main characteristics of the fracture geometry: height (h_f), width (w_f) and effective length (l_f). These parameters are interrelated and determined by the rock stresses. A scheme of a fracture kept open by proppant is shown in figure 5.

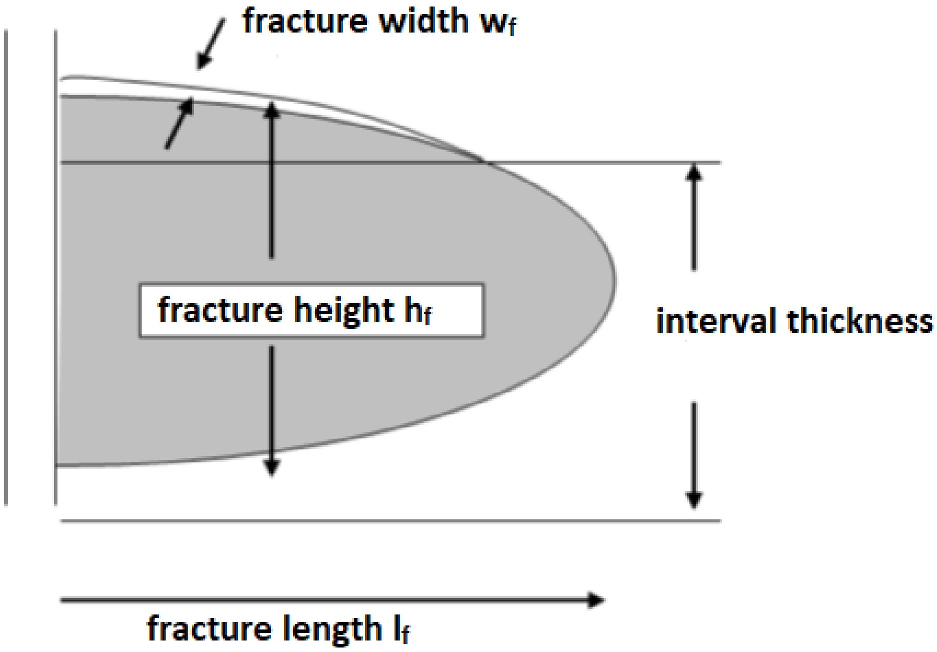


Figure 5 – Fracture geometry

Figure 3 represents only half of the complete fracture geometry. In this case, the fracture length actually represents its half-length, since it is assumed that there is always a mirror reflection of this fracture on the other side of the wellbore with the same width, height and length. This fact should always be taken into account during the analysis of the impact of a fracture on well productivity. With regard to the geometry of the fracture, we can say that the width of the fracture w_f is very important, since its product by the fracture permeability k_f determines its conductivity wf * kf or in other words its ability to conduct fluids to the well. The fracture height is important from the point of view of its relation to the effective thickness of the reservoir.

The excessive fracture height limits the fracture length that could be achieved for a given injection volume. Fracture length L_f is the degree of fracture development deep into the reservoir. The length of the fracture is an important parameter, as it determines drainage area for formation fluid. As a result of hydraulic fracturing, the production rate of producing wells or the injection rate of injection wells are increased dramatically due to the decrease in hydraulic resistance in the bottom-hole zone and an increase in drainage area. Moreover, an increase in recovery factor is obtained as low-permeability zones and layers become producible. Hydraulic fracturing technologies differ, first of all, in the volumes of injected fluid and proppant and, accordingly, in the size of the created fractures. The general scheme of hydraulic fracturing is shown in figure 6.

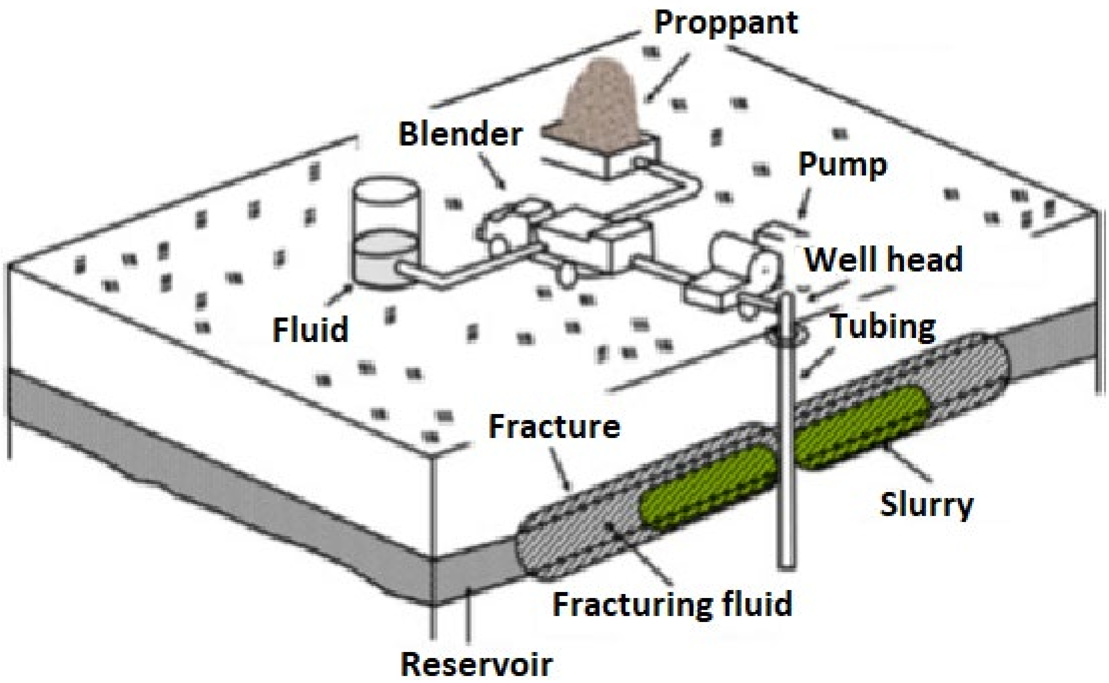


Figure 6 – Hydraulic fracturing scheme

Hydraulic fracturing with the formation of extended fractures not only leads to an increase in the permeability of the bottomhole zone, but also involves additional oil reserves in the production and increases oil recovery in general. At the same time, it is possible to reduce the current water cut of the produced products. The optimal length of a propped fracture with a formation permeability of 0.01-0.05 μm2 is usually 50-80 m, and the injection volume is from tens to hundreds of cubic meters of fluid and from units to tens of tons of proppant.

To create a fracture during hydraulic fracturing, it is necessary to overcome the fracture strength of the rock. The direction and development of the crack depends on the natural stresses of the rocks. The crack will develop in a direction perpendicular to the minimum rock stress. For example, if σ_x is the smallest normal stress, then the crack will develop in a plane perpendicular to this stress, as shown in figure 7.

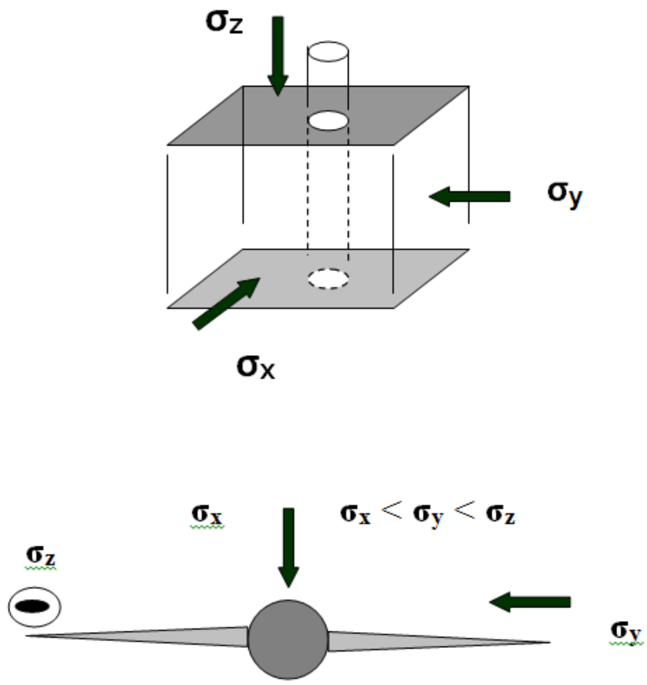


Figure 7 – Image of a vertical fracture perpendicular to σ_x

If the vertical stress σ_z is the smallest, then the created crack develops in the horizontal plane. Experience shows that horizontal cracks occur at shallow depths, where the pressure of the overlying strata σ_z is minimal. Of course, in regions with abnormal rock stresses due to folding and the formation of reverse faults and normal faults, it is possible to create inclined cracks and other deviations. However, in most cases in the fields of Western Siberia, we deal with vertical fractures. Many technical advances in modeling and analyzing fracture behavior and fracture pressures are based on a vertical fracture system.

During the implementation of hydraulic fracturing, the only available way to observe and control fracture development in real time is to interpret the pressure record. Knowledge of the pressures corresponding to certain stages of the process is critical to the successful design and execution of hydraulic fracturing. In most cases, before the main hydraulic fracturing, an injection test is carried out to clarify information about the formation, which is called Mini-frac Test (informational hydraulic fracturing). It shows how the formation will behave during the main hydraulic fracturing. In addition, during the injection test, information about the pressure loss in the perforations and the bottomhole zone, as well as the probability of creating multiple cracks, can be obtained. Figure 8 shows an example of recording bottomhole pressure during informational hydraulic fracturing. This figure illustrates what information can be obtained from an injection test.

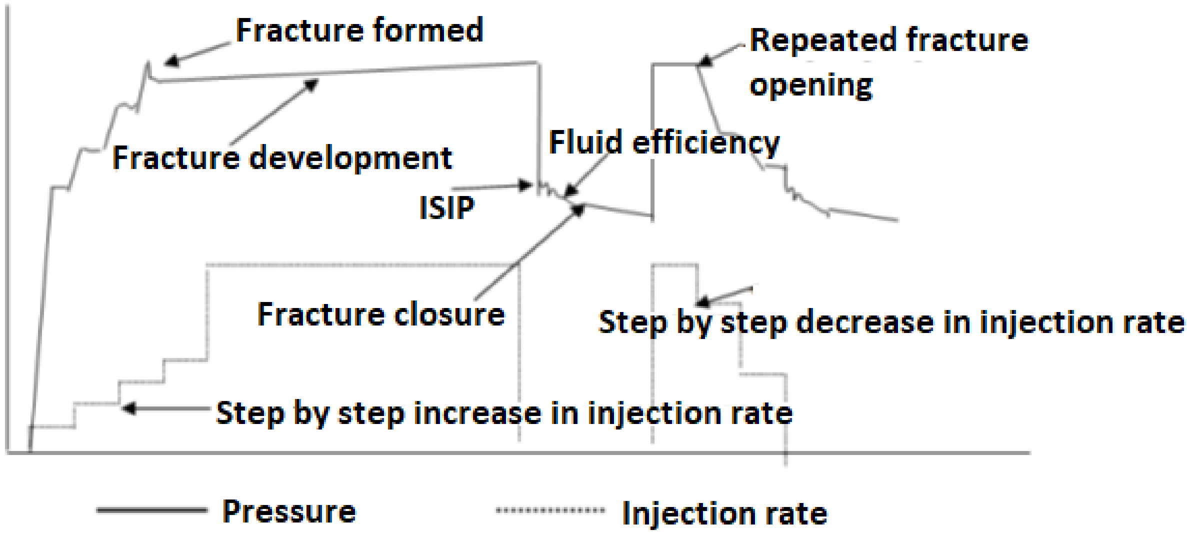


Figure 8 – Bottomhole pressure record during Mini-frac Test

The main factors affecting the fracture geometry are the permeability of the formation k, natural stresses of rocks, and formation pressure. The amount of fluid filtered into the formation during hydraulic fracturing will depend on the properties of the fluid itself and on the permeability of the formation. When the filtration of the fracture fluid into the formation is large, the fracture length decreases and the fracture becomes narrower. In addition, fracture width depends also on natural stresses of rocks (minimum rock stresses).

The fracture height is controlled by the formation boundaries (top and bottom) and the magnitude of the main stresses of the rocks. The crack width is inversely proportional to the Young's modulus of elasticity of the rocks. For example, the higher Young's modulus, the narrower the crack. Other rock properties such as Poisson's ratio and system compressibility also affect fracture geometry, but to a much lesser extent. The fracture gradient (used to determine the amount of pressure required to fracture the rock) depends on the formation pressure.

Basically, the higher the fracture gradient, the higher the pressure that needs to be generated during fracturing. In some cases the working pressure reaches the maximum allowable pressure (for wellhead and manifolds) and further proppant injection cannot proceed safely. This situation can be related to the poor filtration in near-wellbore zone caused by premature proppant package. It is obvious that stopping the process will be premature when only a part of the planned amount of proppant has been injected into the formation, which can greatly limit the geometric parameters of the fracture (height, width, and length) obtained as a result of the stimulation.

Familiarization with the variable parameters of hydraulic fracturing design (type and volume of fluid, type and concentration of proppant, injection rates, operating pressures and reservoir data) gives us the opportunity to consider the performing of hydraulic fracturing design. Theoretically, the process of fracking can be designed using specialized software. The purpose of the design is to analyze the feasibility of hydraulic fracturing in specific conditions and obtain information for the development of procedures for its implementation in the conditions characterizing the specific reservoir.

Fracturing design requires a large amount of input data. Since the calculation of a 3D fracture model involves the application of many theoretical relationships to simplify computer calculations, its results should be interpreted as a theoretical approximation of the fracture geometry. Fracture design calculation assists in decisions regarding fluid selection, injection volume, injection rate, etc. and is a useful tool for creating a hydraulic fracturing plan in the field (Figure 9).

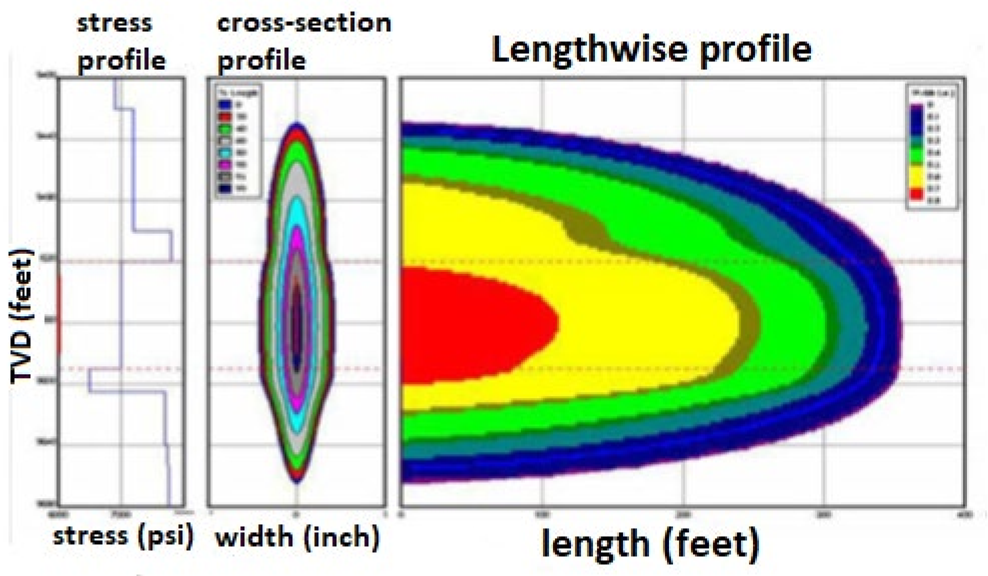


Figure 9 – Fracture model example

The figure shows the stress profiles of rocks, the length, width and height of the fracture. Information on proppant concentration in the fracture and other parameters are also available during the design phase of fracturing. MFrac software (MinFrac and MView) also enables real-time acquisition and processing of mini-frac data. This information can be very useful for determining fracture development pressure, fracture closure pressure and time, fracture efficiency, etc. Values obtained from MinFrac and MView can be used to redesign a fracture if significant difference between measured and predicted values is observed. The assessment of the performed impact using real data obtained from the main hydraulic fracturing provides an excellent opportunity to study the effect of real values on the result of theoretical design.

2.1 Equipment for hydraulic fracturing

When hydraulic fracturing is being performed, the wellhead is equipped with special wellhead fittings with three branches. By means of 50-mm flexible metal pipelines these branches are connected to a collector, to which, in turn, the outlets of pumping units are connected. The following underground equipment is used for hydraulic fracturing: tubing string with an inner diameter of 76 mm; packer; stinger. Tubing hanger with design maximum pressure up to 72 MPa. The layout scheme for hydraulic fracturing is shown in figure 10.

Packer is used during hydraulic fracturing to separate the filtration zone of the wellbore and its upper part. Wellhead fittings are used for connecting wellheads with pumping units during hydraulic fracturing. In addition, the hydraulic fracturing equipment includes an adjustable safety valve that is installed on the casing and serves to prevent casing rupture when fracturing pressure is applied in case of a tubing hanger break. An electronic safety device is used to prevent tubing breakage, destruction of injection lines and damage to pumping units in case of a sharp increase in hydraulic fracturing pressure when filling the well with proppant. Hydraulic pressure sensors are also installed on the main discharge line, which are connected to a hydromechanical pressure recorder.

The main surface equipment used to perform hydraulic fracturing, includes a mixing unit (sand mixer (blender), a vehicle for transporting and feeding proppant to the mixing unit (sand truck), a vehicle for transporting chemicals, pumping units, a unit for maintaining pressure in the annular space, a computer center for controlling the hydraulic fracturing process (control and monitoring station), as well as tanks with hydraulic fracturing fluid located on the surface. During the production of hydraulic fracturing, there are at least two fire trucks at the well pad. In order to provide medical assistance in case of an accident, there is also an ambulance car with qualified medical personnel at the well site.

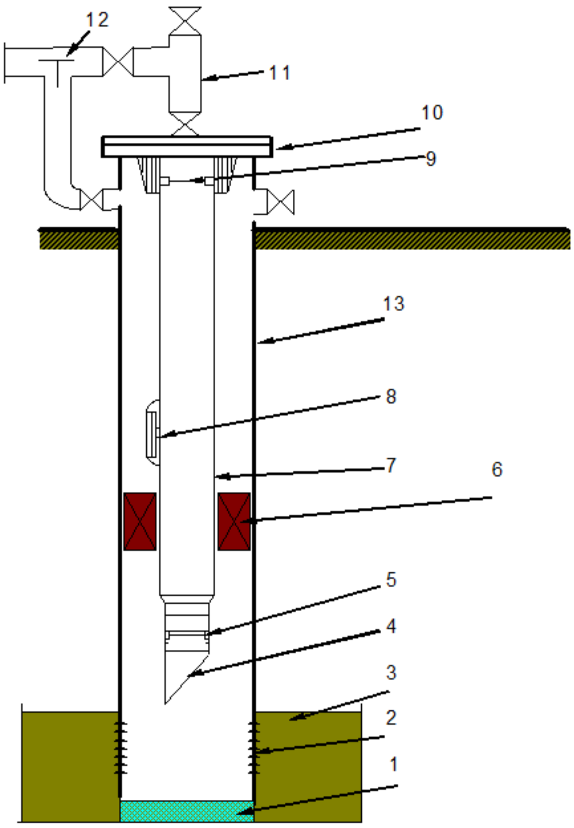


Figure 10 – Subsurface equipment for hydraulic fracturing:
1 – bottom hole; 2 – perforated interval; 3 – reservoir; 4 – stinger; 5 – nipple (for fishing);
6 – packer; 7 – tubing; 8 – safety valve; 9 – preventing device; 10 – tubing head;
11 – wellhead fittings; 12 – pressure relief valve; 13 – production casing

The mixing unit (sand mixer (blender)) by Stewart and Stevenson on the Kenworth chassis designed for the preparation of hydraulic fracturing fluid is shown in figure 11

Figure 11 – Example of a mixing unit (blender)

The mixing unit is equipped with two main pumps: suction - for taking fluid from tanks with hydraulic fracturing fluid and injection - for returning the prepared fluid to hydraulic fracturing bullets during its circulation during preparation, as well as for supplying fluid to pumping units during hydraulic fracturing. The mixing unit is also equipped with two manifolds: suction and discharge, the first of which is designed to take liquid from the tank, the second is to supply the prepared fracturing fluid (gel) to the pumping units. The preparation of the hydraulic fracturing fluid (gel) is carried out in a mixing tank, where a slurry containing water, proppant and chemicals is obtained.

To maintain the correct liquid level in the mixing tank during the preparation of the fracturing fluid, control valve is used. This valve is also remotely controlled from the operator's cab. To ensure control over the parameters of the process, the following instrumentation is installed in the operator's cab of the mixing unit: pressure gauge for suction of liquid from a tank; pressure gauge for fluid supply to pumping units; pressure gauge in the main discharge line; liquid supply indicator; pressure gauge in the hydraulic system; blender speed indicator.

Pumping units are a system that includes a pump, a propulsion system and a gearbox. Pumping units of the Nyuko company during hydraulic fracturing are shown in figure 12.

Figure 12 – Pumping units for hydraulic fracturing

The characteristic features of hydraulic fracturing pumping units are: a) high engine power (up to 1000 kW); b) high performance of the pump at high pressures (up to 1.5 m3 / min at a pressure of 35-40 MPa); c) the ability to develop high pressures at low injection rates (up to 100 MPa). In order to ensure the operator's safety, the hydraulic fracturing pumping unit is controlled from a remote control panel, which is usually installed at a safe distance from the injection lines and the wellhead. The remote control panel includes: throttle regulator; speed controller; engine rotational rate indicator; injection speed indicator; indicators for low oil pressure and high engine temperature; emergency engine switch.

The sand truck is designed to deliver the required amount of proppant to the well pad and to feed it into the mixing unit at a rate determined by the hydraulic fracturing program. Structurally, a sand truck is a tanker on a truck chassis. Its capacity may vary, but the most widespread are sand trucks with a capacity of 18-22 tons of proppant. Sand truck is equipped with a lifting hydraulic cylinder that serves to raise the bunker to the working position. The proppant is fed into the mixing unit by means of a conveyor driven by a hydraulic motor. Since compliance with the proppant concentrations specified in the fracturing program is extremely important, and the proppant concentration in the fracturing fluid directly depends on the fluid flow rate, the rotation speed of the conveyor and, accordingly, the proppant feed rate must be carefully controlled.

Usually, the transportation of liquid chemicals is carried out in barrels, therefore, the body of a corresponding truck is equipped with special devices for their reliable fastening. Special vehicle equipment includes pumps for supplying chemicals to the mixing unit. The manifold unit is designed for connecting the outlet lines of several high-pressure pumping units and connecting them to the wellhead fittings. The manifold unit is transported on a specially adapted platform of corresponding vehicle, the set includes:

1) pressure manifold made of a steel box with six outlets for connecting six pumping units with a pressure of 70 MPa. It has a central pipe with pressure sensors, a density meter and a flow rate meter, with remote registration at control and monitoring station. The pressure manifold is connected to the wellhead using high pressure lines;

2) distribution manifold, designed for a pressure of 2.5 MPa, serves to distribute working fluids between pumping units. It has a large flow area (100 mm), provides the ability to connect ten lines and is equipped with a 2.5 MPa safety valve;

3) set of auxiliary pipelines, consisting of 23 high-pressure pipes with a nominal diameter of 50 mm and a set of quick-detachable swivel joints, also designed for high pressure.

For remote monitoring of the process, a special monitoring and control station on a vehicle is used, equipped with the necessary control and measuring and recording equipment, as well as amplifiers and loudspeakers for sound and telephone communication with individual units and operators.

To measure and record the pressure during hydraulic fracturing, indicating and recording pressure gauges are connected to the manifold unit or wellhead equipment. They are located away from pumping units, pressure lines and manifolds at a safe distance. To measure the fluid flow rate and its total volume during hydraulic fracturing, each reservoir for fracturing fluids is equipped with float level indicators. The instantaneous fluid flow rate during fracturing is also determined by summing the injection rate of each pumping unit. The proppant concentration in the slurry is calculated as a quotient from dividing the proppant feed into the mixer by the total pumping unit injection rate. In this case, the proppant feed is determined by the performance of the sand mixing unit, taking into account its rotation speed. As an example, hydraulic fracturing for 500 tons of proppant was performed in 2007 at the Priobskoye field. The general layout of equipment for large-volume hydraulic fracturing is shown in figure 13.

Figure 13 – General layout of equipment for large-volume hydraulic fracturing

2.2 Fluids and chemicals applied for hydraulic fracturing

The most important factor of hydraulic fracturing success is the quality of the fracturing fluid and proppant. The main purpose of the fracturing fluid is to transfer energy from the surface to the bottom hole of the well, which is necessary to open the fracture, and to transport the proppant along the entire fracture. According to their purpose, fluids are divided into three categories: fracturing fluid, sand carrier fluid, and displacement fluid.

2.2.1 Fracturing fluids

Fracturing fluids must have sufficient dynamic viscosity to create high conductivity fractures due to their large opening and efficient proppant filling; have low filtration leaks to obtain cracks of the required size with minimal fluid consumption; provide a minimum decrease in the permeability of the formation zone in contact with the fracturing fluid; ensure low pressure losses due to friction in pipes; to have sufficient thermal stability for the treated formation and high shear stability, i.e. shear stability of the fluid structure; easy to remove from the formation and hydraulic fracture after stimulation; be technologically advanced in preparation and storage in field conditions; have low corrosiveness; be environmentally friendly and safe to use; have a relatively low cost.

The fracturing fluid must penetrate well into the formation or into a natural fracture, but at the same time have a high viscosity, since otherwise it will dissipate in the volume of the formation without causing the necessary development of initiated fracture.

According to their physicochemical properties, fracturing fluids are divided into hydrocarbon-based fluids and water-based fluids.

Liquids of the first type include hydrocarbons thickened with naphthenic acids and napalm, "refined oils", which are a mixture of heavy oil fractions, crude oils, naphta residue or its mixture with lighter hydrocarbons, diesel fuel, etc.

Typically, oil-based fluids are used for hydraulic fracturing in production wells in case of reservoir formed by rocks sensitive to water. Such kinds of rock contain a high percentage of clays that can migrate or swell in the presence of water or brine. Petroleum based fluids do not adversely affect formation clays and, from this point of view, are considered non-damaging.

Liquids of the second type include water, an aqueous solution of sulfite-cellulose liquor, solutions of hydrochloric and hydrofluoric acids, as well as the so-called "thickened water" and "thickened acid".

Water-based fluids can be used as fracturing fluids for injection wells, production wells in reservoirs formed by rocks with no sufficient sensitivity to water (no clay swelling effect) but also in case proper chemical agents are introduced to reduce clay swelling effect.

The choice of fracturing fluid depends on the temperature of the formation undergoing fracturing, since the viscosity of the fluid, the stability of the gel and emulsion, as well as other physicochemical properties depend on the temperature. In this regard, there are recommendations for the use of fracturing fluids. So, at a bottomhole temperature below 60 ° C, the use of viscous oil and mineral oils is allowed. Napalm-type gels can be used at all bottomhole temperatures. The same applies to emulsions.

To increase the viscosity and reduce the filtration of fluids used in fracturing, appropriate additives are used. Such thickeners for hydrocarbon fracturing fluids are salts of organic acids, high molecular weight and colloidal compounds of oils, for example, bitumen, asphaltite, oil tar or oil refinery residues. As fracturing fluids for oil wells, emulsions of such types as acid or water in hydrocarbons have become widespread, which can be ranked as both the first and the second type based on the fact what is dispersed phase and dispersing medium.

2.2.2 Sand carrying fluids

Fracturing fluids are linear gel solutions, while sand carrier fluids are polymeric crosslinked fluids with very high viscosity and forming an almost ideal suspension with proppant, which allows the proppant to fill the entire volume of the fracture.

Sand carrier fluids can also be oil- and water-based. For them sand-holding capacity and low filtration are important.

Sand-holding capacity is critical to sand carrying fluid to provide the condition of sufficient filling of formed fractures by proppant to be able to rich the required fracture geometry.

With high filtration properties, the transfer of sand into the fracture by the liquid deteriorates, since flow rate along the fracture becomes zero quite soon, and the development of hydraulic fracturing finishes in vicinity of the wellbore.

High sand-carrying capacity and low filtration properties are achieved in practice both by increasing the viscosity and by imparting structural properties to the fluid.

Emulsions have good sand-carrying capacity, especially acid-kerosene emulsions, which are highly resistant, do not break down in hot weather and withstand long-term transportation with filler.

Known difficulties can happen during the injection of a sand-carrying fluid.

High wellhead pressures arise due to the high viscosity, the presence of sand and the need to maintain a high rate of injection. In this condition, the pumping units, although they are made in a wear-resistant design, wear out quickly.

Additional issue in this regard is the fact that due to friction the pressure from the wellhead is transmitted to the bottomhole only partially. To reduce the pressure loss due to friction by 12-15%, chemical additives (soap-based solutions) have been developed, which from one hand, increase the viscosity, and from the other hand, reduce the friction when the fluid moves along the tubing. Heavy, high molecular weight hydrocarbon polymers are another type of such additives.

Initially, viscous petroleum-based fluids were used to reduce fluid loss and improve the sand carrying properties of these fluids. With the development and improvement of hydraulic fracturing technology, by means of an increase in injection rate of pumping units, it became possible to ensure the necessary costs and sand-carrying capacity with low-viscosity water-based fluids. The transition to water-based fluids led to the fact that the hydrostatic pressures due to the increase in the density of these fluids increased, and the friction losses in the tubing decreased. This, in turn, reduced the wellhead pressures required for hydraulic fracturing. The low cost of water, its availability, its properties of a good solvent with the introduction of various additives have led to the fact that nowadays about 90% of hydraulic fracturing operations are carried out using water-based fluids.

2.2.3 Displacing fluids

Dispacing fluids are pumped into the well in order to bring the sand carrier fluid to the bottom of the well. The volume of the displacement fluid is equal to the volume of the tubing. The volume of the annular space between the tubing shoe and the upper holes of the filter is added to the calculated volume of the tubing.

Almost any comparably cheap liquid available in sufficient quantity can be used as a displacement fluid. Most often water is used as a displacement fluid, in some cases a working fluid (linear gel).

2.2.4 Proppant

There are known facts of effective hydraulic fracturing without the use of a filler, but in these cases the effect is shorter. The filler, when filling the crack, perceives the load from the rock pressure after the fluid pressure is reduced. As a result, it is partially destroyed and partially pressed into the rock of the facture walls. Therefore, it must have a high crushing strength. Ideally, the filler should have a density equal to that of the sand carrying fluid. In this case, transporting it along the fracture and filling it would be most successful. The size of the filler grains should ensure its penetration into the most distant parts of the fracture and their high permeability during the subsequent operation of the wells.

Artificial proppant is used for propping of fractures. Synthetic proppants made of modern materials of medium and high strength with a grain size of 0.6-1.2 mm. During hydraulic fracturing, usually a finer fraction (0.5-0.8 mm) is mixed in the first portions of the sand carrier fluid, and larger fractions are used in the subsequent portions. The physical properties of proppants that affect fracture conductivity include strength, grain size and particle size distribution, grain shape (sphericity and roundness), and density. The first and most widely used fracture-propping material is sand, which has a density of approximately 2.65 g / cm^3. Sands are usually used for hydraulic fracturing of formations in which the compressive stress does not exceed 40 MPa. Medium-strength are ceramic proppants with a density of 2.7-3.3 g / cm^3, used at a compression stress of up to 69 MPa. Ultra-strong proppants such as bauxite and zirconium oxide are used at compressive stress up to 100 MPa, the density of these materials is 3.2-3.8 g / cm^3. Synthetic resin-coated proppants are also produced and used (figure 14).

Figure 14 – Proppant

As previously said, pure quartz sand can be used as material of proppant. This solution is quite common in practice. However, sand has a very high density (2650 kg / m^3), which is very different from the density of liquid used for carrying of sand, which contributes to sand precipitation from the liquid stream and makes it difficult to fill fractures. In addition, in some cases, its resistance to crushing is insufficient. In this regard, in the world practice, glass beads, as well as grains of agglomerated bauxite of the appropriate size and ground walnut shells, have recently been used as a filler. The density of glass beads is approximately equal to that of quartz, i.e. 2650 kg / m3, but they have more strength and are less pressed into the rock. The density of the agglomerated bauxite powder is 1400 kg / m3. Industrial tests of a filler made of extra strong artificial polymeric substances with a density close to that of a sand carrying liquid (1100 kg / m^3).

2.2.5 Additives to fluids for hydraulic fracturing

Water-gelling agents.

Water-gelling agents thicken fresh water and mild brines to improve proppant transfer. In the formed gels, cross-links (crosslinks) arise, which increases the amount of proppant retained by them.

High temperature stabilizers for water gels.

Gel stabilizers are used when high fracture bottom temperatures limit the life of a particular gelling agent. The decrease in viscosity due to an increase in temperature, resulting in more rapid sand precipitation, can be delayed by the use of these products. It is necessary to use gel stabilizers at temperatures of 66 ° C and above.

Breakers for water gels.

The correct selection of breakers for a specific gel is important when performing hydraulic fracturing operations. The highly viscous working fluid must gradually degrade to maintain normal outflow rates and cause minimal damage to the formation.

Biocides.

Bactericidal compounds are used to combat microorganisms, which include sulfur-reducing bacteria, mucus-forming bacteria, and algae. Microorganisms and their metabolic products decompose and destroy hydraulic fracturing fluids.

Additives fluid loss reduction.

The fracture geometry depends on several parameters, one of which is the degree of fluid loss. To create acceptable fracture penetration into permeable rock, special additives are often required to control leakage. When selecting suitable additives, consideration should be given to product particle size, solubility, and possible damage to the proppant layer and conductivity disturbances.

Friction reducing additives.

Friction reducing additives are usually emulsions of high molecular weight polymers of acrylamide in oil. They can partially hydrolyze and react with other chemicals to form cations and anions. Effectively used to relieve frictional pressures in all types of fluids, from acids to hydrocarbons. Reduction of friction pressure reaches 80%.

2.2.6 Foaming additives.

Foam is a dispersed system of liquid and gas, with gas as the internal phase and liquid as the external phase. Low pressure formations are often slow in stimulation and may require well swabbing. Foamed fracturing fluids are a proposed solution to this problem. The foam has a low liquid content, excellent filtration control results and better well flow due to the expansion of the gas phase. The main liquid can be water, acid, aqueous methanol, diesel fuel, kerosene, or crude oil.

2.3 Important parameters of hydraulic fracturing design

Currently, modern technology and the fluids used allow successful injection with an average sand concentration in fluid of about 200 kg / m^3. However, both higher and lower concentrations are used. According to Haliburton, the amount of sand injected, consumed for the hydraulic fracturing operation, has been increased to 22.5 tonnes by now, and the amount of injected fluid on average (fracturing fluid + sand carrier fluid) is up to 151.4 m^3.

The required amount of sand (proppant) is determined in accordance with the calculated optimal fracture length. According to the regulations, the amount of sand (proppant) in tones can be determined from the ratio:

$$V_p = 10^3 \times V_f \times C, \quad (1.1)$$

where: V_f – volume of sand carrying fluid, m^3;

C – concentration of proppant in sand carrying fluid, kg/m^3.

The relative concentration of proppant in the sand carrier fluid is determined empirically. The sand concentration determined on the basis of experiments carried out at the fields of the Nizhnevartovsk region using hydraulic fracturing is recommended in the range from 100 kg / m^3 at the beginning of the operation, to 1500 kg / m^3 at the end of hydraulic fracturing. In each case, the amount of sand, its concentration in the liquid are determined by calculation. To calculate the sand requirement for the entire hydraulic fracturing operation, it is recommended to take an average value of the sand concentration of 450 kg / m^3.

To prepare the sand-liquid mixture and supply the working fluid to the pumping units during the hydraulic fracturing process, one sand mixing unit (blender) is used. Sand is transported by a sand truck with a certain lifting capacity (for example, Stuart & Stevenson sand truck on a Kenworth chassis has a capacity of 20 tons). The required number of sand trucks is determined by the ratio of the required mass of sand to the mass capacity of one sand truck. Propping is required to maintain the permeability created by fracturing. Hydraulic fracturing is carried out at pressures up to 100 MPa, with a high flow rate and using a complex and diverse equipment. A force related to the weight of the overlying rocks acts on the porous formation in the vertical direction. Fracture permeability depends on a number of interrelated factors:

1) type, size and homogeneity of the proppant;

2) degree of its destruction or deformation of proppant;

3) amount and method of the proppant transportation.

Some of the most common proppant sizes are shown in Table 1.

Table 1 – Proppant particles size

Sieve size	Size of proppant particles, mm
100	0,150
40-60	0,419-0,250
20-40	0,841-0,419
12-20	1,679-0,841
8-12	2,380-1,679

The average density of sedimentary rocks is usually taken equal to 2300 kg / m3. Then the overburden pressure will be equal to:

$$P_o = \rho_b g H \qquad (1.2)$$

Since the density of water is 1000 kg / m3, the overburden pressure P_0 is approximately 2.3 times higher than the hydrostatic pressure at the same depth H. For the formation of a horizontal crack in the reservoir, it is necessary to create a pressure P_{fr} inside the porous space, exceeding the rock pressure by the value of the temporary resistance of rocks to rupture σ_z, since it is necessary to overcome the cohesion forces of the rock particles, i.e.

$$P_{fr} = P_o + \sigma_z \qquad (1.3)$$

However, the actual fracture pressures is often less than the rock pressure, i.e. unloading areas are created in the bottomhole zone, in which the internal stress is less than the overburden pressure P_o. This may be due to reasons of a purely geological nature, for example, in the process of rock formation not only compression of rocks could occur, but also their extension. Bottomhole pressure, at which hydraulic fracturing (fracking) occurs is called the fracture pressure P_{fr}. Initially, fracturing fluid is injected through the tubing with the set packer in volumes necessary to obtain the bottomhole pressure sufficient to fracture the formation. The moment of rupture at the surface is noted as a sharp increase in fluid flow rate (huge increase in filtration intensity in near-wellbore zone) at the same wellhead pressure or as a sharp decrease in wellhead pressure at the same flow rate. A more objective indicator characterizing the moment of hydraulic fracturing is the injectivity index:

$$II = Q / (P_e - P_{wf}), \qquad (1.4)$$

where: Q – injection rate;

P_e – reservoir initial pressure;

P_{wf} – flowing bottomhole pressure.

During hydraulic fracturing, there is a sharp increase in II. However, due to the difficulties associated with continuous monitoring of the value of P_{wf}, and due to the fact that the pressure distribution in the formation is not a substantially steady process, the moment of fracture occuring is identified by the conditional coefficient k.

$$k = Q / WHP, \quad (1.5)$$

where: WHP – well head pressure.

A sharp increase in k during injection is also interpreted as the moment of fracture occuring. There are devices for this value recording.

After fracturing the formation, a sand carrier fluid is injected at pressures that keep the fractures occured in the formation open. It is a more viscous liquid, mixed (180-350 kg of sand per 1 m3 of liquid) with sand or other kind of proppant. Sand is injected into the open cracks to the greatest possible depth to prevent the cracks from closing during the subsequent release of pressure and putting the well into production. Sand carrier fluids are displaced into the tubing and into the reservoir by the displacement fluid. For the design of the hydraulic fracturing process, it is very important to determine the fracture pressure P_{fr}, which must be created at the bottom of the well.

A large statistical material regarding the magnitude of the fracture initiation pressure of the formation P_{fr} has been accumulated for various fields of the world and at different depths of wells, which indicates the absence of a clear relationship between the depth of the formation and the fracture pressure. However, all actual values of P_{fr} lie within the range between the values of the total overburden and hydrostatic pressures. Moreover, at shallow depths (less than 1000 m) P_{fr} is closer to overburden pressure, and at large - to hydrostatic pressure.

Based on these data, the following approximate values for fracture initiation pressure can be recommended:

for shallow wells (up to 1000 m)

$$P_{fr} = (1{,}74 – 2{,}57)\ P_{st},$$

for deeper wells (H > 1000 m)

$$P_{fr} = (1{,}32 – 1{,}97)\ P_{st},$$

where: P_{st} – the hydrostatic pressure of the liquid column with the height equal to the formation depth.

The tensile strength of rocks is usually small and lies within the range σ = 1.5-3 MPa, therefore, it does not significantly affect P_{fr}.

The fracture pressure at the bottomhole P_{fr} and the pressure at the wellhead (WHP) are related by an obvious relationship:

$$P_{fr} = WHP + P_{st} - P_{loss}, \quad (1.6)$$

where: P_{loss} – frictional pressure loss in tubing.

From equation (1.6) follows:

$$WHP = P_{fr} + P_{loss} - P_{st}, \quad (1.7)$$

P_{st} – static pressure is determined according to the inclination:

$$P_{st} = \rho_{liq}\, gH \cos\beta, \quad (1.8)$$

where: H – depth of a well;

β – inclination (average);

ρ_{liq} – density of a liquid in a well.

If the fluid in the well contains filler (sand, glass spheres, polymer powder, etc.), then the density is calculated as a weighted average:

$$\rho = \rho_{liq}\,(1 - n/\rho_{filler}) + n, \quad (1.9)$$

where: n – mass of filler in 1 m^3 of liquid;

ρ_{filler} – density of filler (for sand ρ_{filler} = 2650 kg/m^3).

Friction loss is more difficult to determine, since the fracturing fluids sometimes have non-Newtonian properties. The presence of filler (proppant) in the liquid increases frictional losses.

$$P_{fr} = \lambda\ H\ w2\rho\ g\alpha\ /\ 2dg, \quad (1.10)$$

where: λ – friction coefficient determined according to Reynolds number;

w – linear velocity of liquid in tubing;

d – internal diameter of tubing;

ρ – liquid density;

H – length of tubing;

g = 9.81 m/s^2;

α – coefficient, taking into account concentration of filling agent (for pure water α = 1)

Hydraulic fracturing is preferable stimulation techniques for the wells that meet the following criteria:

1. Effective reservoir thickness is not less than 3 m;

2. The reservoir subjected to hydraulic fracturing is hydraulically separated from other reservoirs by impermeable barrier with a thickness of more than 5 m;

3. The actual recovery factor for the well should not exceed 20%;

4. The well must be technically ready for operation, both the state of the production casing and the adhesion of the cement to the casing and the rock must be satisfactory in the interval 50 m above and below the filter;

3. Standard technological process of hydraulic fracturing and its design

3.1 Hydraulic fracturing procedure

Hydraulic fracturing plan.

1. Shut off the well.
2. Conduct logging to determine the state of the production casing and the inflow profile.
3. Carry out scraping and flushing.
4. Install the fracturing wellhead.
5. Run the packer on tubing and unpack it.
6. Pressurize the annulus to the proof-test pressure of the production casing.
7. Prepare the site and connecting equipment for hydraulic fracturing.
8. Perform hydraulic fracturing.

Hydraulic fracturing should be carried out only during daylight hours.

The head of the hydraulic fracturing unit provides instructions on the safe conduct of work, including:

- procedure for pressure testing of the discharge line;
- work procedure during hydraulic fracturing, design parameters of hydraulic fracturing;
- fire safety issues;
- order of actions in case of emergency or fire;
- indication of ways to evacuate people and equipment in an emergency;
- reporting the number of people present at the hydraulic fracturing;
- clarification of the location of workplaces and responsibility for facilities;
- clarification of the questions that have arisen.

3.2 Criterions of a proper post-fractured well performance

Post-fractured well performance can be described in a variety of ways. One of the most commonly used methods is to predict oil, gas and even water production as a function of time elapsed after hydraulic fracturing. However, post-treatment production is influenced by many decisions that are not critical to the actual hydraulic fracturing design. For example, the production pressure may or may not be the same as the pre-fracturing pressure and may or may not be kept constant over time. Even if, purely for the sake of evaluation, someone tries to set all the operating parameters the same both before and after fracturing, comparison over time will still be complicated due to the fact that the formation is being produced at a higher rate after fracturing.

Therefore, during the phase of preliminary sizing and optimization, some simple performance metric must be used to describe the expected and actual well performance improvement as a result of stimulation.

For this reason such parameters as fracture length and dimensionless fracture conductivity are introduced. They are the two main variables that control the productivity index of a well draining fractured formation. Dimensionless fracture conductivity is a measure of the relative ease with which produced fluids flow within the fracture, compared to the formation's ability to release fluids into the fracture. It is calculated as the product of the fracture permeability and fracture width divided by the product of the formation permeability and the length (by agreement, half-length) of the fracture.

In low-permeability reservoirs, the fracture conductivity is indeed high, even if a narrow propped fracture is created and a significant fracture length is required. The skin factor after stimulation can reach such large negative values as –7, which leads to a new well productivity index that is several times higher compared to the same well before stimulation.

For proper fracture performance in highly permeable reservoirs, it is critical to achieve a large fracture width. In recent years, a technique known as tip screenout (TSO) has been developed. This technique allows us to stop the lateral growth of a fracture deliberately and then increase its opening to achieve as high value of conductivity as possible.

Considering fixed proppant volume in the formation, the maximum flow rate from the well or the rate of injection into it will be provided if the dimensionless fracture conductivity is close to 1. In other words, a dimensionless fracture conductivity of about 1 (or more accurately 1.6) is the physical optimum, at least for hydraulic fracturing not associated with extremely large quantities of proppant. Larger values of the dimensionless fracture conductivity would mean that its length is relatively lower than optimal, and, therefore, there would be an additional restriction to the flow of fluid from the formation into the fracture. Values of dimensionless fracture conductivity less than 1 would mean that the fracture width is less than optimal, that would also an obstacle to optimal production.

There is a set of secondary issues that complicate the task - transient flow regime at early times, the effects of reservoir boundaries, the effects of flow deviating from Darcy's law, and proppant embedment, and only a few of them are mentioned. Nevertheless, these effects can be correctly taken into account only if there is a clear understanding of the role of the dimensionless fracture conductivity.

It is quite possible that under certain combinations of conditions, the practical optimum may differ from the physical optimum. In some cases, the geometry of the fracture predicted by the theory will be difficult to achieve due to physical constraints imposed either by the available equipment, the marginal characteristics of the materials used in the fracturing, or the mechanical properties of the rocks in which the fracturing is performed. However, the aim to maximize the productivity or injectivity of the well is a highly advisable first condition in hydraulic fracturing design.

3.3 Size determination and optimization

The term "optimum" (or "optimal"), as used above, means maximizing the productivity of a well, within the constraints of a particular formation size. Therefore, the decision on the size of the hydraulic fracture should precede optimization process based on the criterion of dimensionless fracture conductivity (or be performed simultaneously).

For a long time, specialists have considered fracture half-length as a convenient variable characterizing the size of the fracture created. This tradition arose because it was impossible to change the length and width of the fracture independently, and also because length is the main factor affecting productivity in low-permeability reservoirs. In a unified fracture design, where both low-permeability and high-permeability formations are considered, the best single variable that characterizes the size of the created fracture is the volume of proppant placed in the reservoir.

Obviously, the total volume of proppant placed in the target interval is always less than the total amount of proppant injected. From a practical point of view, determining the volume of hydraulic fracturing means deciding how much proppant is required for injection. When determining the volume of hydraulic fracturing, the engineer must understand that an increase in the proppant injected volume by a certain value x will not necessarily mean an increase in the amount of proppant that has reached the productive interval by the same exact value of x. We consider the ratio of the two proppant volumes (i.e., the volume of proppant placed in the reservoir divided by the total volume of proppant injected into the well) as the volumetric efficiency of the proppant.

However, the most critical factor in determining the proppant volumetric efficiency is the ratio of the created fracture height to the effective reservoir thickness.

The intense height growth limits the volumetric efficiency of the proppant, which is something we generally try to avoid as much as possible. (The possibility of a fracture crossing OWC is another important reason to avoid excessive fracture height growth.)

In fact, the choice of the amount of proppant to be injected is mainly based on economical issues, particularly taking into account such parameter as net present value (NPV). As with most engineering projects, costs increase almost linearly with the size of processing, but after a certain point, the revenue of a process doesn`t show any significant increase. Thus, there is some optimal fracture size - this is the point at which the NPV of additional revenue, correlated with stimulation costs, is the maximum.

Optimal sizing can be determined if some method for prediction of the maximum achievable productivity growth for a given amount of proppant is available. This fact is widely used in the unified fracturing design, provided that the maximum achievable productivity growth is already determined by the volume of proppant in the reservoir. The basic fracturing sizing solution already includes many details of the technology, making it possible to carry out a simple but proper design process.

Therefore, the concept of "proppant volume reached the reservoir", or simply "propped volume in the reservoir", is widely used as a key variable in the process of fracturing sizing decision making in the procedure of unified fracture design. To carry out this stage correctly, it is necessary to determine the amount of proppant to be injected and the volumetric efficiency of the proppant.

3.4 Connectivity between fracture and a well

As the maximum achievable increase in productivity is determined by the volume of proppant in the reservoir, several additional conditions must be met in order to realize this potential increase. One of the critical factors is the need to find an optimal compromise between length and width (or deviate from the optimum only as much as necessary, if technological constraints require it). As explained earlier, the optimal dimensionless fracture conductivity is the variable that helps us to find this compromise. However, there is another equally important condition. This is fracture-to-well connectivity.

The reservoir at depth is in a mechanically stressed state, which can be characterized by three main stresses: one vertical, which in almost all cases of deep formations (at depths over 500 m, 1500 ft) is the largest of these three, and two horizontal, one minimum and the other maximum. The hydraulic fracture will be directed along the normal to the lowest stress, as a result, in almost all cases in the oil industry, the fractures are vertical. The direction of these fractures is predetermined by the natural state of stresses in the subsurface environment. Therefore, horizontal or deviated wells, that are candidates for hydraulic fracturing, must be drilled taking into account a possible direction of a fracture. Vertical wells, obviously, naturally coincide with the plane of the crack.

If the borehole azimuth does not coincide with the plane of the fracture, then the fracture will most likely originate in one plane and then bend to reach its final azimuth - normal to the direction of the minimum stress, which will create significant "tortuosity" on the way to this final azimuth ... Vertical wells with vertical fractures or ideally horizontal wells drilled deliberately in the direction of the expected fracture plane create well-fracture systems with the best mutual orientation. Other fracture-well configurations are subject to "choke effects" unnecessarily reducing the productivity of the fractured well. Perforations and their orientation can also be a source of problems in hydraulic fracturing, which include the initiation of multiple fractures and premature screenouts caused by tortuosity effects.

The dimensionless fracture conductivity in low-permeability reservoirs is naturally high, so that the negative influence of the above-described choke effects is usually minimized; to avoid tortuosity, a point source fracturing is often used.

Currently, fracture-to-well connectivity is generally considered as a critical success factor for fracturing in high permeability formations, which frequently contols the azimuth of the well (eg, drilling S-shaped vertical wells), or forces horizontal wells to be drilled along the direction of the fracture. Reperforation is often done. Moreover, in the most advanced practices hydro-jetting of slots is also considered. Although some computer models include complex well-fracture geometries with choke effects and other effects, there are many uncertainties that prevent us from proper prediction of well performance in these cases. More precisely, we are limited to explain well performance when post-fracturing test and production information become available. During the design phase, we try to make decisions that minimize the likelihood of such unnecessary reductions in productivity.

3.5 Calculation of the main hydraulic fracturing characteristics

Practical case of the calculation of main characteristics of hydraulic fracturing process is presented below.

As an example a production well with a depth of 3250 m is considered. Producible formation thickness h is assumed to be 16 m. Fracturing is performed along the tubing with a packer, thickened Cenomanian water with a density of 1020 kg / m^3 and a viscosity of 0.225 Pa s is used as a fracturing fluid and sand carrier. It is assumed that 7 tonnes proppant consisting of grains of 1 mm in diameter will be pumped into the well. We take the injection rate Q equal to 0.015 m^3 / s. The unit 4AH - 700 is used for injection. The initial data are given in Table 2.1.

Calculation:

1. Vertical component of overburden pressure:

$P_{ov} = \rho_r\, g\, L_w\, 10^{-6} = 2550 * 9.8 * 3250 * 10^{-6} = 81.3$ MPa;

2. Assuming ν = 0,28, horizontal component of overburden pressure:

$P_{oh} = P_{ov} * \nu / (1 - \nu) = 81.3 * 0.28 / (1 – 0.28) = 31.617$ MPa

Table 2.1 – Input data for calculation of hydraulic fracturing parameters

Parameters of a well	Value
Depth of a well, m	3250
Penetrated formation thickness, m	16
Inner diameter of tubing, mm	62
Production casing outer diameter, mm	114
Rock density, kg/m^3	2550

3. According to overburden pressure, bottomhole pressure required for fracturing can be calculated according to the following formula:

$$\frac{Pfr}{Poh}\left(\frac{Pfr}{Poh}-1\right)^3 = 5.25\frac{1}{(1\ -\ \nu^2)^2}\left(\frac{E}{Poh}\right)^2\frac{Q\mu}{Poh}$$

where: E – Young modulus (E = $1 \cdot 10^4$ MPa).

Therefore, bottomhole pressure required for fracturing is the following:

$P_{fr} = 32.839$ Mpa;

4. Volume concentration of proppant in sand carrying fluid:

$$\beta = \frac{C/\rho}{\frac{C}{\rho}+1} = \frac{500/2450}{\frac{500}{2450}+1} = 0.1695 \text{ kg/m}^3$$

where: C is assumed to be 500 кг/м^3, proppant density = 2450 kg/m^3

5. Density of sand carrying fluid with proppant inside:

$\rho_{sf} = \rho_f(1- \beta) + \rho\, \beta$;

$\rho_{sf} = 1020 * (1- 0.1695) + 2450 * 0.1695 = 1262.385$ kg/m^3;

6. Viscosity of sand carrying fluid with proppant inside:

$\mu_{sf} = \mu_f * \exp(3.18 * \beta)$;

$\mu_{sf} = 0.225 * \exp(3.18 * 0.1695) = 0.3857$ Pa*s;

7. Reynolds number:

$Re = 4 * Q * \rho_{sf} / (\pi * d * \mu_{sf})$;

$Re = 4 * 0.015 * 1262.385 / (3.14 * 0.062 * 0.3857) = 1008.72$;

8. Friction factor:

$\lambda = 64 / Re$;

$\lambda = 64 / 702.71 = 0.063$;

9. Frictional losses:

$P_{friction} = 8 * \lambda * Q^2 * L_c * \rho_{sf} / (\pi^2 * d^2)$;

$P_{friction} = 8 * 0.091 * 0.015^2 * 3250 * 1262.385 / (3.14^2 * 0.062^2) = 12.363$ MPa;

10. Taking into account increase in frictional losses 1.52 times in case of Re > 200:

$P^*_{friction} = 1.52 * P_{friction}$

$P^*_{friction} = 1.52 * 12.363 = 18.791$ MPa

11. Wellhead pressure required for fracturing:

$WHP = P_{fr} - \rho_{sf} * g * Lw + P^*_{friction}$;

$WHP = 32.839 – 1262{,}385 * 9.8 * 3250 * 10^{-6} + 18.791 = 11.423$ MPa;

12. The unit at a speed develops an operating pressure (Pop) of 32.4 MPa, and an operating flow rate (Qop) of 0.017 m^3 / s, therefore, the required number of units will be equal to:

$N = WHP*Q/(Pop* Qop * K)+1$

where K is the coefficient of the technical condition of the unit (K = 0.5);

$N = 11.423*0.015/(32.4*0.017*0.5)+ 1 = 2$ units

13. Calculation of volume of displacing fluid

$V_{df} = 0.785*ID_{tubing}^2*h_{well}$

$V_{df} = 0.785*0.062^2*3250=9.807 m^3$

14. Calculation of liquid required for hydraulic fracturing:

$V_{fr} = 7000/500 = 14$ m^3

15. Total time of 1 unit operation at 4th speed:

$t = (V_{fr}+V_{df})/Q_{op}$

t = (14+9.807)/0.017 = 1400 sec = 24 min

16. Geometry of fractures:

1. Length of a vertical fracture:

$$L_{fr} = \sqrt{\frac{Vfr*E}{5.6*(1-\nu^2)*h(Pfr-Poh)}}$$

$$L_{fr} = \sqrt{\frac{14*10^4}{5.6*(1-0.28^2)*16(32.839-31.617)}} = 37.245 \text{ m}$$

2. Width of a fracture:

$$Wfr = \frac{4*(1-v^2)*L_{fr}*(P_{fr}-P_{oh})}{E}$$

$$Wfr = \frac{4*(1-0.28^2)*37.245*(32.839-31.617)}{1*10^4} = 0.0168 \text{ m} = 1.68 \text{ cm}$$

Therefore, as a result of this particular hydraulic fracturing there will be formation of a vertical fracture with a length of about 37 m and a width of about 1.7 cm.

3.6 Factors determining the success of hydraulic fracturing procedure

The main factors that determine the success of hydraulic fracturing are the correct choice of an object for operations, the use of hydraulic fracturing technology that is optimal for these conditions, and a competent selection of wells for treatment.

The decision to carry out hydraulic fracturing in each case is carried out taking into account geological conditions. However, as a rule, when analyzing the geological and physical properties of a potential object, the following features are taken into account:

1. heterogeneity of the reservoir along strike and dissection in thickness, ensuring high efficiency of hydraulic fracturing due to involvement in the development of zones and interlayers that were not previously drained;
2. reservoir permeability, which usually should not exceed 0.03 μm^2 with oil viscosity up to 5 mPa-s and 0.03-0.05 μm^2 with oil viscosity up to 50 mPa-s (In higher permeability formations, local hydraulic fracturing is effective, which gives a significant effect mainly as a means of treating the bottomhole zone.);

3. thickness and consistency of impermeable formations separating the reservoir from gas or water-saturated reservoirs, which should be at least 4.5-6 m;
4. the depth of the formation, which, as a rule, should not exceed 3500 m and determines the requirements for the hydraulic fracturing technology, in particular for the strength of the proppant used;
5. reservoir energy and effective oil-saturated thickness of the reservoir, sufficient for a significant and long-term increase in well production rate after hydraulic fracturing and, therefore, providing a return on the cost of hydraulic fracturing;
6. Recovery factor, which, as a rule, should not exceed 30%.

Research regarding hydraulic fracturing technology, that take into account primarily the selection of proppant and fracturing fluid, determination of the required amount of these agents and the conditions for their injection, are currently being actively pursued.

The highest hydraulic fracturing efficiency can be achieved if the selection of wells for treatments and the optimization of fracture parameters, ensuring a balance between the filtration characteristics of the formation and the fracture, are carried out taking into account the geological and physical properties of the object, the distribution of stresses in the formation that determines the orientation of the fractures, the waterflooding system and the placement of wells.

The effect of hydraulic fracturing is varying from one well to another one, therefore, it is necessary to consider not only the increase in the flow rate of each well due to hydraulic fracturing, but also the influence of the mutual arrangement of wells, the specific distribution of reservoir heterogeneity, the energy capabilities of the object, etc. Such an analysis is possible only on the basis of mathematical modeling of the process development of a section of a reservoir or an object as a whole using an adequate geological production model that identifies the features of the geological heterogeneity of the object.

4. Hydraulic fracturing in horizontal wellls

Hydraulic fracturing technologies are constantly being improved, also in horizontal wells drilled in a low-permeability reservoir. When carrying out multistage hydraulic fracturing, it is possible to perform continuous hydraulic fracturing separately in each interval. In field practice, there are several types and technologies of interval hydraulic fracturing in horizontal wells: installation of interval sand bridges; use of interval plugs; use of liquid packers; the use of frac sleeve; burst port system. In the field, there are various methods of isolating formations in an open horizontal hole: use of hydraulically activated packers (such as ARES ™ produced by Weatherford), swellable packers and inflatable packers. Depending on the reservoir isolation technology, certain proppant injection systems are used to selectively separate reservoirs during hydraulic fracturing. There are multiple action systems that open by pressure and ball drop, and closed by moving the sleeve. The well completion scheme for multistage hydraulic fracturing is shown in figure 15.

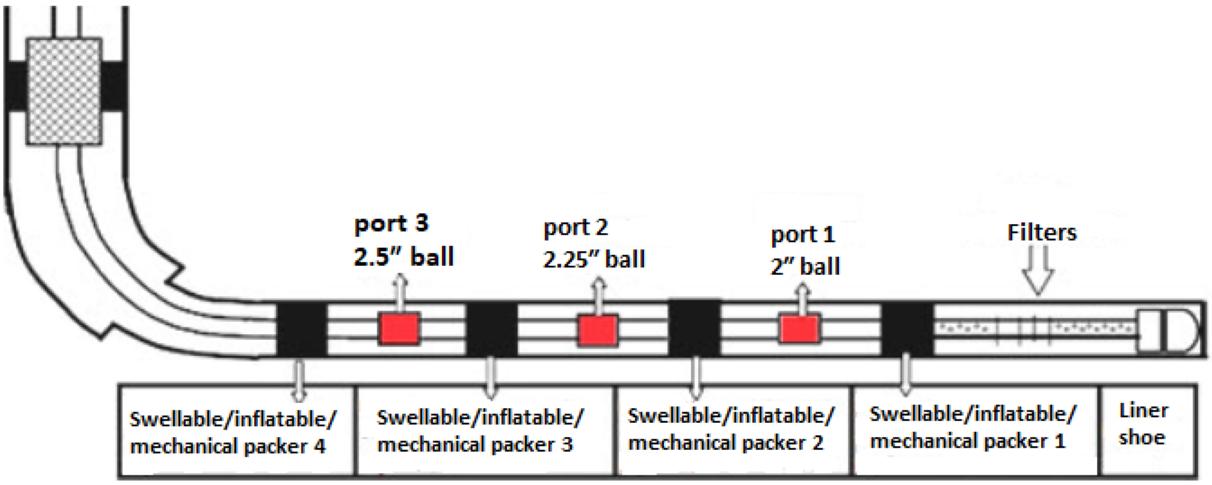


Figure 15 – General completion scheme for multistage hydraulic fracturing

A single-action system with frac sleeve activated by ball drop is one of the most popular techniques used for multistage hydraulic fracturing (figure 16)

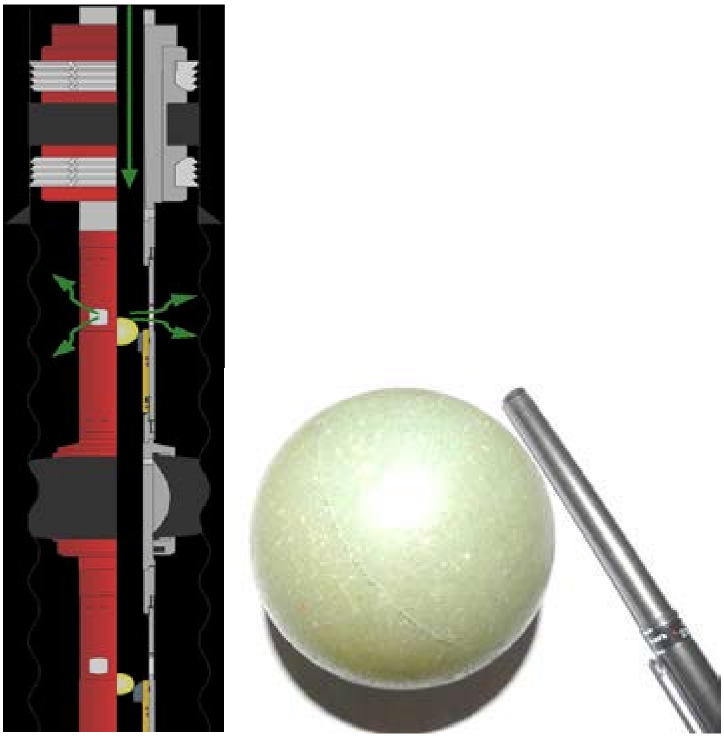


Figure 16 – Single-action system with frac sleeve activated by ball drop

Single-action injection system allows multiple proppant injections in one round trip. The frac sleeve opens once. Dropping balls are designed to ensure complete sealing and prevent them from getting stuck in the seat, therefore they can be pumped out of the well. Composite coating of the working parts of the frac sleeve and balls prevents the system from mechanical impurities coming from the outside.

For example, in the wells of the Koshilskoye field, multistage hydraulic fracturing was performed using activated drop balls of the FracPORTS type. Three-stage hydraulic fracturing was carried out on three wells, initially the ball of the smallest diameter was thrown out. The dropped ball hits the seat of the frac sleeve and, under the pressure generated from above, pushes the inner bushing down and opens the port. The ports will then maintain open thanks to a special mechanism. After opening the port, fracturing fluid was injected with mini-frac and the subsequent main frac. After the three-stage hydraulic fracturing, coiled tubing was run in hole, cleanout was performed and the balls were then extracted or drilled out. In well No. 902b, during the first hydraulic fracturing, proppant 16/20 was injected in the amount of 25 tons and the following pressures were obtained, maximum pressure up to 40 MPa, average pressure 20 MPa, final pressure 17 MPa. In the second hydraulic fracturing, 17 tons of proppant were injected with pressures, the maximum one was 29 MPa, the average was 20 MPa, and the final was 18 MPa. In the third hydraulic fracturing, 31 tons of proppant were injected with pressures, maximum up to 28 MPa and final up to 26 MPa. According to the calculation, at each stage of hydraulic fracturing, cracks with a width of up to 2.4 mm, a height of up to 31 meters and a length of up to 110 meters were obtained. This made it possible to achieve an increase in the oil production rate of wells by 4 and 3.3 times, respectively.

Based on the results of three-stage hydraulic fracturing in the wells of the Koshilskoye field, the specialists observed that the use of the systems with ball-activated frac sleeves has certain advantages. Firstly, it was possible to control the development of a hydraulic fracture (fracture initiation point, volume of injected fluid), it was possible to increase the concentration of proppant at the bottomhole, it was possible to use large proppant fractions and not to limit the proppant mass, previously stimulated zones are securely isolated.

4.1 Multistage hydraulic fracturing

At the moment, many fields worldwide are at the late stages of exploitation, which is associated with a constant decline in the rate of oil production and the producing well stock. In this regard, in multilayer fields, it becomes relevant to involve tight oil reserves (unconventional oil reserves) in the production by carrying out enhanced oil recovery techniques. Traditional methods do not allow to comprehensively and effectively solve the problem of tight oil production.

Therefore, it was proposed to solve this problem by increasing the drainage zone of one well by drilling a horizontal end followed by multi-stage hydraulic fracturing (MHF).

Multistage hydraulic fracturing technology involves running a special assembly (liner) into the well, separating the horizontal wellbore into isolated sections, where hydraulic fracturing is performed section by section.

Nowadays, multi-stage hydraulic fracturing technology with the use of separating swellable packers and special frac sleeves has become widespread in the world.

The idea of the multistage hydraulic fracturing operation in this case is that at the initial moment, the run-in liner is sealed and there is no communication between the downhole space and the annulus. During hydraulic fracturing, balls of various diameters, starting with the smallest one, are directed into the fluid flow at the stage of displacement, which drop to special seats attached to the frac sleeves. Each dropped ball, acting on the seat, allows isolating the previous interval and opening the frac sleeve, thereby achieving communication with the formation for the next stage of multistage hydraulic fracturing. The sequence of stages is set from the bottom of the well.

The selection of the optimal length of the horizontal part and the number of hydraulic fracturing stages is performed on the hydrodynamic model and depends on the reservoir properties of the stimulated formation. The main guiding parameters for selection of the intervals for installing the packers and the location of the frac sleeves were:

- no increase in the radius of the well according to caliper data in the intervals of swellable packers;

- uniform distribution of frac sleeves along the horizontal wellbore for efficient involvement of the entire drainage zone associated with this well and interference effect elimination;

- the location of frac sleeves should be as close as possible to the areas with the best reservoir properties and equidistant from the nearest isolation packers.

The process of preparing the well and flow initiation after multistage hydraulic fracturing has a number of important features, in contrast to the procedures required in a standard hydraulic fracturing operation.

4.2 Special characteristics of subsurface equipment for multistage hydraulic fracturing

To carry out standard hydraulic fracturing, a tubing string is run into the well with a packer installed at a distance of 10-50 m above the perforation interval of the stimulated formation to prevent the impact of high pressure on the production casing. Before the operation of Multistage Hydraulic Fracturing, a special tool called stinger, which is hermetically fixed to the liner hanger of the multi-packer assembly and thus excludes the effect of high pressure on the main production casing during the operation (Figure 17.)

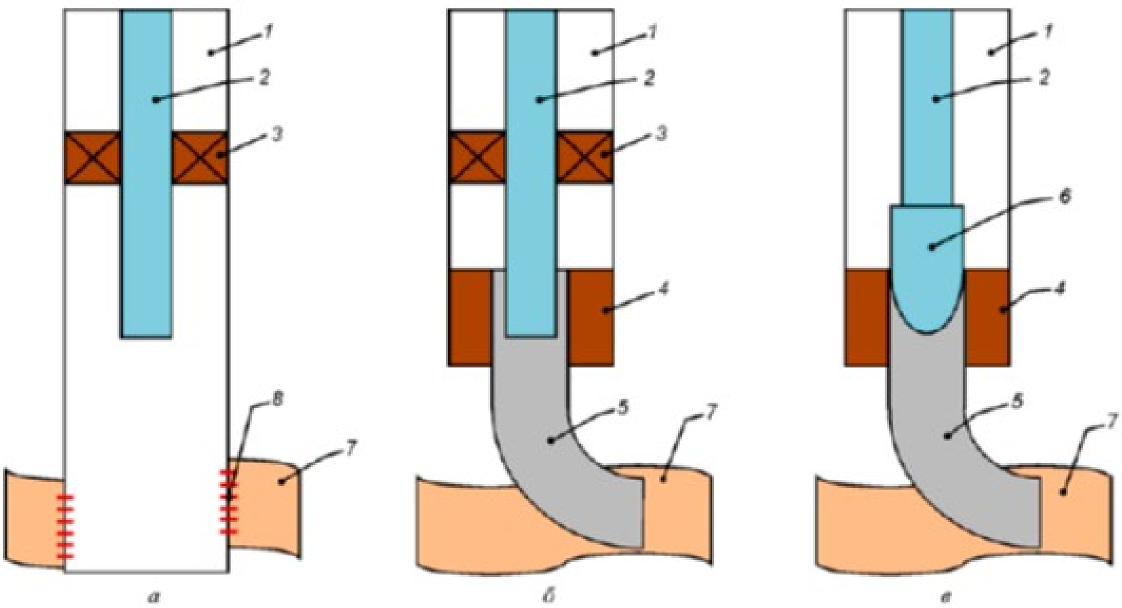


Figure 17 – Scheme of underground equipment for hydraulic fracturing:

The figure shows the schemes of underground equipment for three different cases:

(a) standard hydraulic fracturing in case of a deviated well

(b) standard hydraulic fracturing in case of a horizontal well

(c) multistage hydraulic fracturing in case of a horizontal well

Where:

1. production casing;
2. tubing string;
3. packer;
4. liner hanger;
5. liner;
6. stinger;
7. reservoir;
8. perforated interval.

4.3 Special technological aspects of multistage hydraulic fracturing procedure

Technologically, the multistage hydraulic fracturing process differs from the standard hydraulic fracturing process by the need for systematic ball dropping during the stimulation operation. This procedure is implemented by installing, in addition to the main high-pressure line, a special auxiliary line for launching balls into the well (Figure 18).

Figure 18 – Auxiliary line for launching balls into the well

Mentioned line includes:

1 - a device for launching a ball into a line;

2 - auxiliary line back pressure valve;

3 - valves of the auxiliary line;

4 - valve of the main line;

5 - main line back pressure valve;

6 - main line pressure sensor;

The ball drop procedure is taken into account when developing the hydraulic fracturing injection program. For this, the volume pumped into the well from the beginning of the dispacing stage to the moment the ball is launched must correspond to the volume of proppant that is still not displaced into the formation from the well. Also, in order to avoid automatic shutdown of the pumps, it is recommended to reduce the injection rate to 1.5 m^3 / min when the remaining volume of injection fluid is 2 m^3. This reduces the amplitude of the pressure spike that occurs when the ball lands in the seat and the next frac sleeve is opened. The moment the ball is launched is accompanied by a characteristic metallic sound and is recorded by an external observer at the wellhead. The ball must be launched into a crosslinked polymer system to reduce the amplitude of oscillation during pumping under the influence of gravitational forces, and only then is it allowed to switch to a linear system to complete the displacement stage. After the completion of the pumping stage without stopping the injection, you can immediately start the injection test of the next stage of multi-stage hydraulic fracturing through the opened frac sleeve.

Unlike standard hydraulic fracturing operations, multistage fracturing does not involve the use of proppant with a special coating (RCP), which is sintered under the action of the formation temperature and prevents the proppant from being carried into the wellbore after the operation is completed. This technological solution is due to the fact that the area of communication between the horizontal wellbore and the formation by means of frac ports is insignificant and the use of RCP proppant in this case is considered inappropriate, since it carries additional risks of premature shutdown and complicates the injection process.

Particular attention should be paid to the hydraulic fracturing design of its first stage. This operation is carried out at the farthest point from the wellhead and, as a result, is associated with high pressure losses due to friction in the tubing string, liner and perforated filter acting as the first frac port. To reduce technological risks, the injection program provides for a reduction in the maximum proppant concentration (800-900 kg / m3) and a more gentle rate of increase in this concentration relative to the injection programs of subsequent stages. In case of high pressure losses in the holes of the perforated filter, it is also possible to use proppants of fine fractions (30/50 or 30/60) at the stage of mini-fracturing to solve this problem.

Moreover, the organization of mixing the linear gel directly on the well pad is also an important issue. The system of preliminary mixing is extremely undesirable, since in this case after each stage it will be necessary to clean the containers from gel residues to maintain required quality of hydraulic fracturing fluid. This procedure requires a certain amount of time and delays the performance of the multistage hydraulic fracturing operation. The most reasonable choice in this case is the use of a blender to mix the linear gel directly during injection. This solution allows using tanks only for water and not cleaning them after each stage of multistage hydraulic fracturing.

4.4 Flow initiation after multistage hydraulic fracturing

Usually, upon completion of a standard fracturing operation, forced closure of the fracture happens due to well fluid release to a special tank with a flow rate of around 50 l / min. After multi-stage hydraulic fracturing, it is recommended to keep the well under pressure until the gel completely distracts. This time depends on the polymer system used and, as a rule, varies from 12 to 24 hours. Next, the well is released to a tank equipped with a special trap at the inlet of the line coming from the well to catch the balls. When the flow is initiated, the dropped balls can be thrown to the surface and fixed in this trap. It should be noted that the balls can remain in the well even in case of free-flow production from a well, since the formation energy is not enough to throw them to the surface along with the formation fluid flow.

If the reservoir pressure is not enough for initiation of free flow from the well, the balls and ball seats are drilled out, followed by well flow initiation using gas (e.g. nitrogen) lift technology and coiled tubing (CT).

The result of a comparative analysis of production data showed that the efficiency of the multistage hydraulic fracturing in a horizontal well is 2.5 times higher than the efficiency in a deviated well with a standard hydraulic fracturing operation. Here we should make a conclusion that introduced multistage hydraulic fracturing technology for horizontal wells demonstrated its high technical and economic efficiency, thereby making quite promising the involvement of tight oil to production in order to maintain high rates of total oil production.

However, all set of advantages and disadvantages of this technology should be taken into account (table 2). Moreover, the following issues must be also considered:

1. Risk of using swellable / hydraulic packers

- Insufficient swelling of packers in assemblies with burst port system (risk of fracturing fluid crossflows between sections, uncontrolled leaks and unplanned shutdowns during fracturing);

2. Correspondence of the diameters of balls and ball seats (human factor during installation at the wellhead)

- installation of a hydraulic fracturing sleeve with a ball seat diameter lower than that one of a ball planned for dropping (risk: overflow of proppant into the formation, decrease in the conductivity of the hydraulic fracture);
3. The correct sequence of balls (human factor during hydraulic fracturing) requires constant monitoring;
4. Timely ball drop (short time interval for an operation, human factor during hydraulic fracturing); risks of hydraulic fracturing at the next sleeve;
5. Fracture initiation through the ports not intended for hydraulic fracturing
6. Hydraulic fracturing with marked proppant through a port, not intended for hydraulic fracturing;
- Increased pressure loss → "STOP",
7. Closure of ports with an increase in water cut from the fracture;
- The equipment used is not intended to close the ports in case of an increase in water cut;
- Lack of experience in port closure work;
8. The expected high cost of work and the absence of a guaranteed result;
9. Drilling out balls with coiled tubing:
Risks:
- possibly longer well flow initiation process;
- decrease in fracture conductivity;
- decrease in expected oil production rates;
- probable problems during workover, geophysical surveys, etc.
10. Stinger (sealing unit) retrieval after hydraulic fracturing
- Risks of equipment being stuck.
11. Liner deformation (completion assembly equipment)
- Probable risk of equipment deformation during fracture propagation along the wellbore and “breakthrough of the fracture behind the packer” into the interval of adjacent sections.
12. Use of composite and / or aluminum balls
- Possible solution to the problem of drilling out;
- The technology has been field tested;
13. Impact of acids on equipment, well completion assemblies, hydraulic fractures and formation rocks;
14. Incomplete decomposition / dissolution of ball materials;

4.5 Multistage hydraulic fracturing with ball-activated frac sleeves

4.5.1 Advantages and disadvantagies of multistage hydraulic fracturing with ball-activated frac sleeves

Advantages	Disadvantages
- Control over the development of a hydraulic fracture (fracture initiation point, displacement volume); - Isolation of previously stimulated areas; - Mechanical reliability in case of following regulations, rules and taking into account best engineering practices; - Potential ability to isolate flooded intervals by closing ports.	- The complexity of equipment layout; - Complexity of well completion; - Risk of insufficient isolation provided by installed packers (crossflows between zones); - The number of ports is limited by the inner diameter of the casing liner, the sizes of the seats and the sequence of balls with increasing sizes; - Risk of multi-fracture development; - Risk of fracture breakthrough between sections; - Complexity of wellbore cleanout; - Human factor, engineering errors (selection of equipment, dropping of balls) - High cost of equipment.

4.5.2 The example of implementation of multistage hydraulic fracturing with ball-activated frac sleeves

One of the technologies for running a multisection assembly with ports (frac sleeves) for pumping proppant separated by packers in the annulus was selected as the basic technology for multistage hydraulic fracturing in horizontal wells at Tsvetnoye field.

This technology guarantees a possibility to perform multistage hydraulic fracturing in the open hole of the horizontal section. The duration of working operations, depending on the hydraulic fracturing design, can range from several days to several hours. The ability to selectively control the opening of ports allows isolation of intervals with high water-cut, increasing the duration of the waterless well operation period. Well design is shown in figure 19.

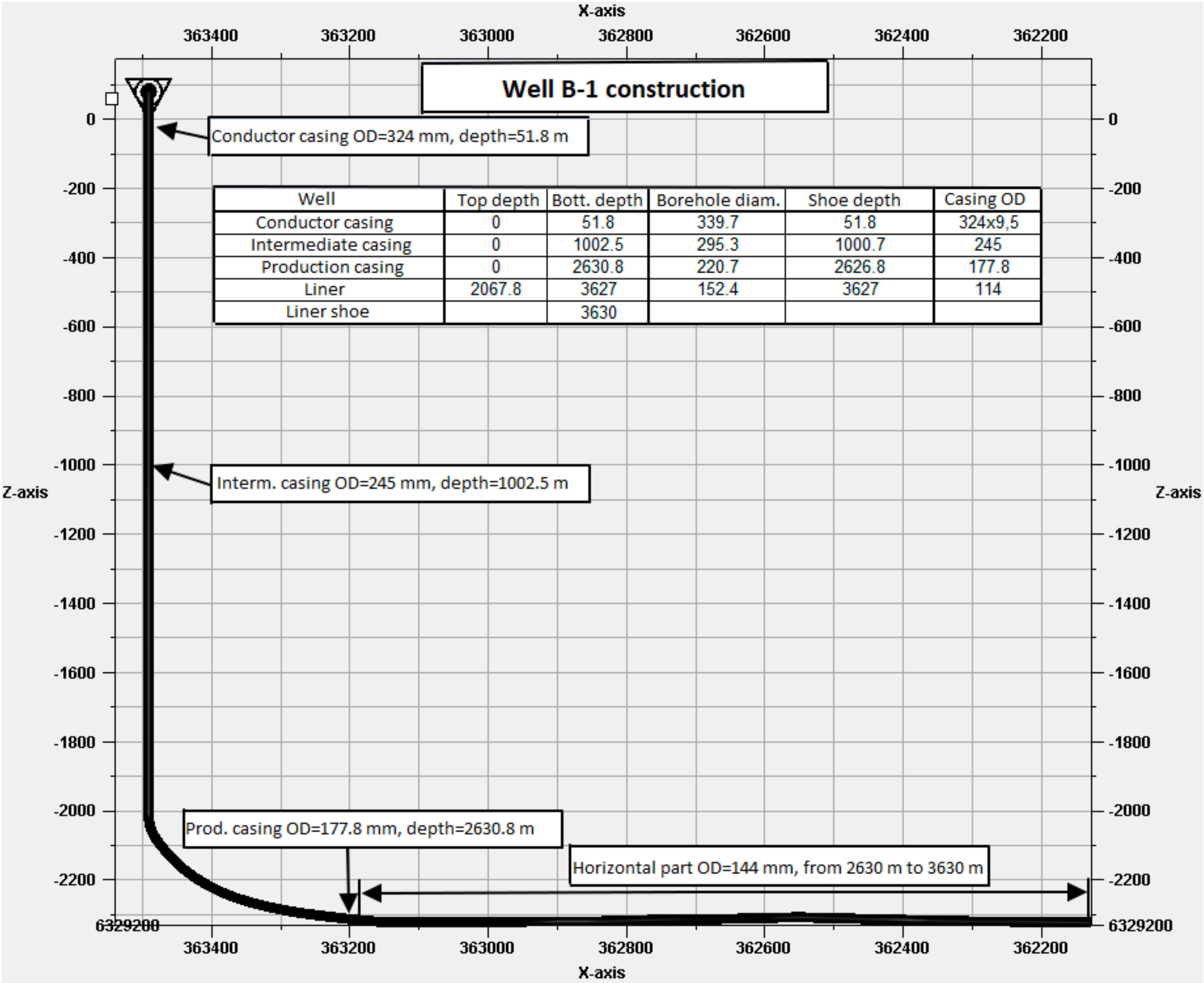


Figure 19 – Well B-1 construction

The process of hydraulic fracturing (prod. casing OD = 177.8mm) includes:

1. Mini frac, V fluid = 70m^3.

2. Proppant stage for cleaning perforations - 1 tonne of proppant, concentration 30kg / m3, V liquid = 50m^3.

3. Initial stage, V liquid = 105m^3.

4. Water-based proppant stage - proppant 40/70 - 19tn, concentration 60-90kg / m^3, proppant 30/50 - 5tn, concentration 90kg / m^3, liquid V = 230m^3.

5. Flushing stage - pumping water-based hydraulic fracturing fluid, V fluid = 75m^3.

6. Water-based proppant stage - proppant 30/50 - 17tn, concentration 60-90kg / m^3, V liquid = 210m^3.

7. Flushing stage - pumping of water-based hydraulic fracturing fluid, V fluid = 75m^3.

8. Water-based proppant stage - proppant 30/50 - 18tn, concentration 60-120kg / m^3, V liquid = 200m^3.

9. Displacement stage.

A special liner was run into the well. Its construction is shown in figure 20.

Liner components:

1. Liner pipe 114 mm.
2. Swellable packers (distance ~ 70-100m)
3. Isolated sections.

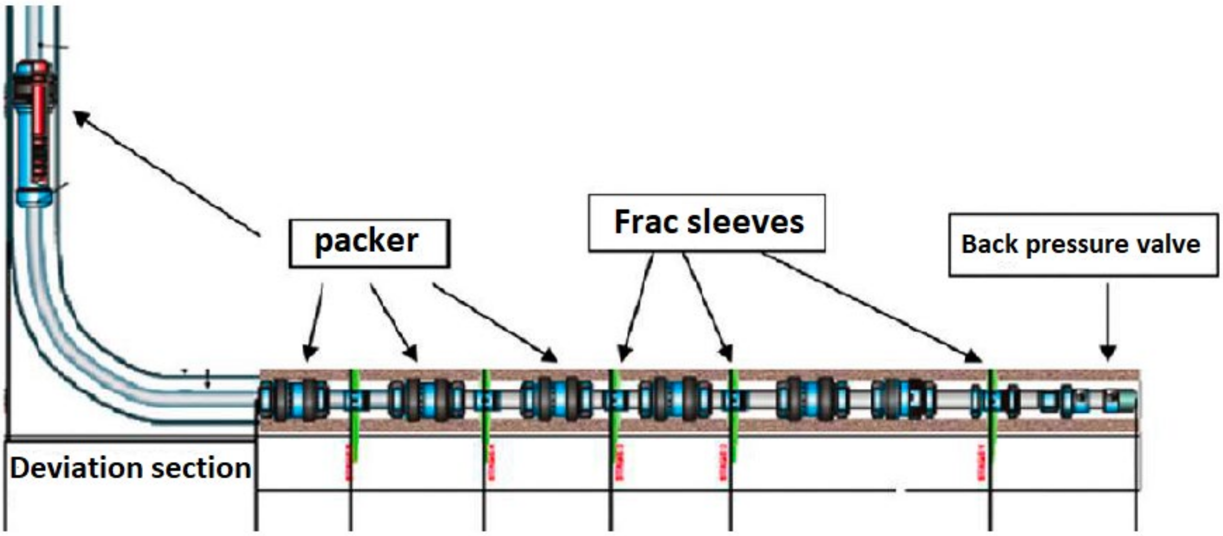


Figure 20 – Liner scheme

After all stages of hydraulic fracturing, balls were drilled out using coiled tubing technology.

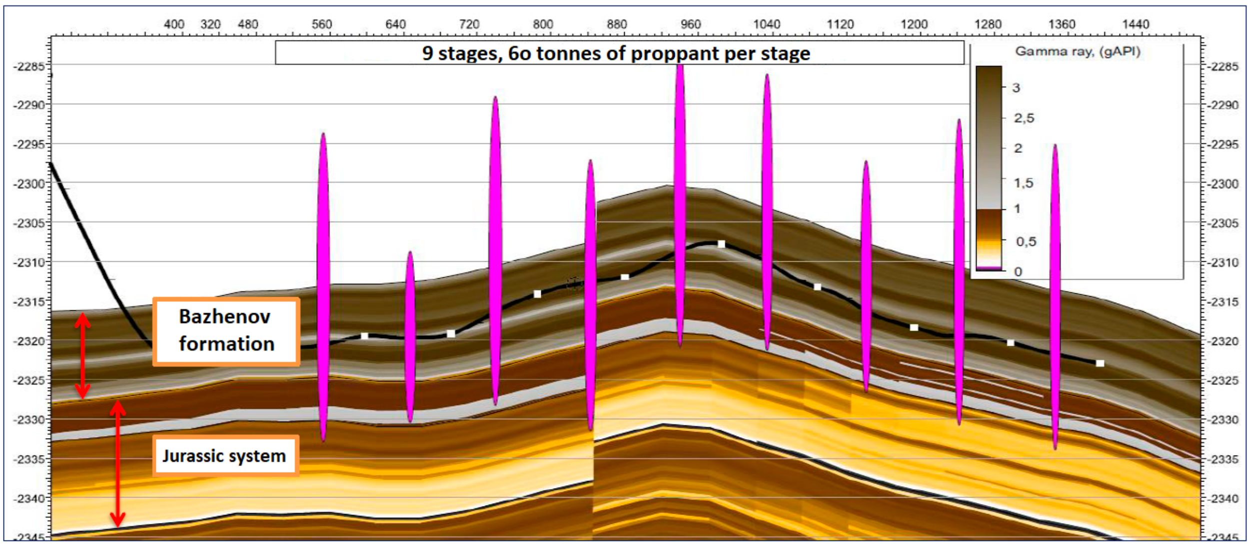


Figure 21 – Geologic cross-section and hydraulic fracturing stages

Upon implementation of multistage hydraulic fracturing for well B1, significant oil production increase was achieved, however, at the same time a sharp growth of water cut was also detected. According to the performed analysis, this fact is associated with water breakthrough behind a casing. Two most probable directions of water breakthrough to a well B1 were identified. Their contribution to total increase of water cut are considered as 85 and 15 per cent, respectively.

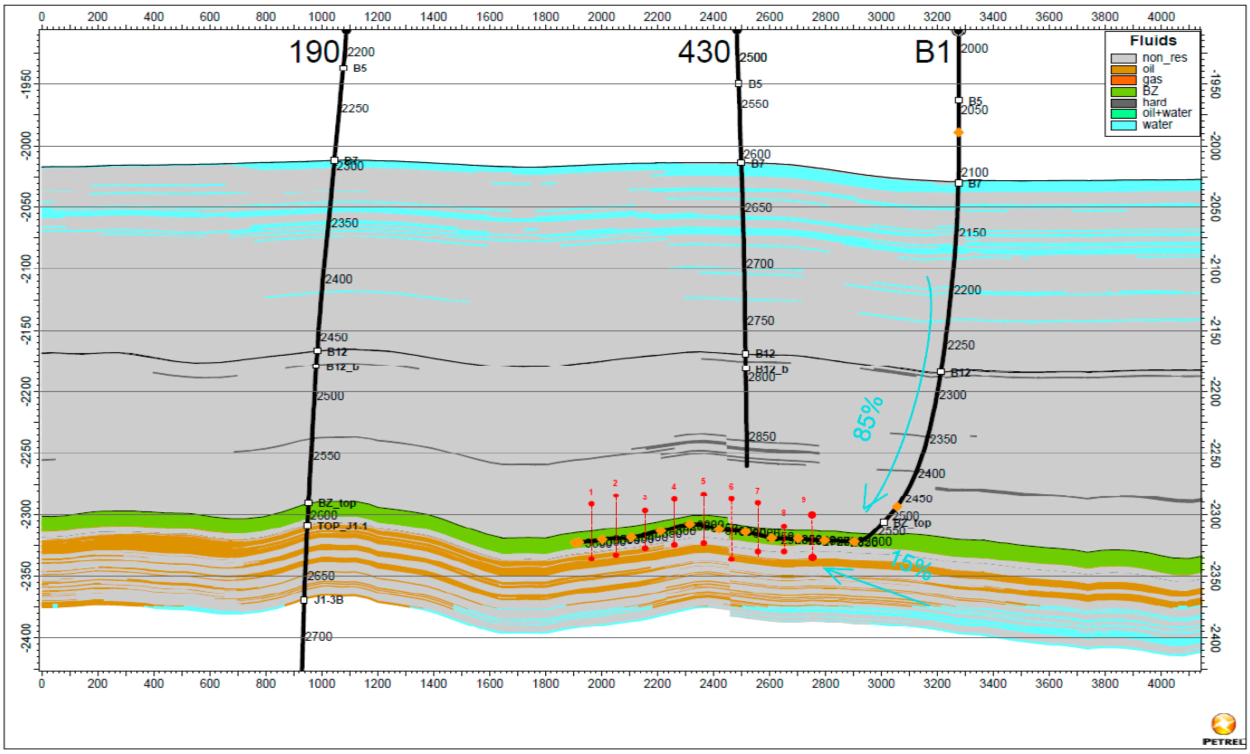


Figure 22 – Geologic cross-section with possible directions of water breakthrough

5. Multistage hydraulic fracturing as a part of well completion

Well completion in simple words means preparing the well for production after drilling operations. Well completion is wanted only when the well has sufficient amount of oil and gas to be commercially viable. The open hole where wireline tests and coring were conducted can now be cased and cemented to become a closed hole. When we talk about running casing in well completion we are only referring to the casing that incases the zone or zones of interest in the open hole. This casing string is referred to as production casing.

Production casing only run when the well shows promise of becoming a producing oil well. Running and cementing this casing are a part of the first steps in well completion. Well completion, however, involves more than running casing and cementing. To complete the well after the casing is run and cemented the set of the following procedures can be performed:

1. Running and cementing production casing
2. Perforation (for cased hole completion)
3. Stimulation (e.g. hydraulic fracturing)
4. Sand control (gravel packing)
5. Equipment of a well with tubing, packers and Christmas tree to control the flow of fluids to the surface

Moreover, depending on the fact if the production casing is run along the entire length of the well and through the reservoir or is run through the wellbore until it sits directly on top of the reservoir, but the freshly drilled hole is left 'uncapped' at the bottom, the type of well completion will be called cased hole completion and open hole completion, respectively.

Open hole completions are often favored in horizontal wells, where running a production casing along the entire length of the well might be too expensive, or technically unfeasible. Cased hole completions, on the other hand, might be the better option for vertical wells when there is low formation integrity. There is also an alternative type of completion that is really similar to open hole completion (casing is also run through the wellbore until it sits directly on top of the reservoir) but in this case a well is also equipped with special tubing called liner that is hanged on internal surface of production casing (figure 23).

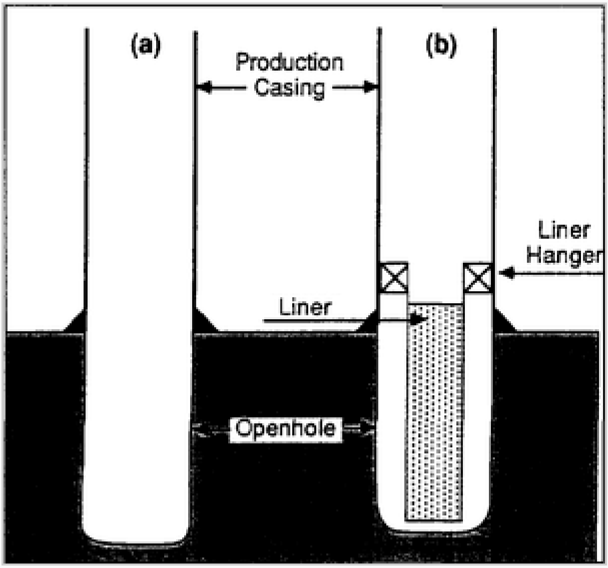


Figure 23 – Open hole completion (a) and liner completion (b)

Nowadays, especially for the conditions of Western Siberia, the majority of newly drilled wells are presented by horizontal wells. Moreover, multistage hydraulic fracturing in many cases is considered not just as a possible stimulation technique but as an integral part of horizontal well completion. Therefore, it is the most relevant to discuss horizontal well completion with multistage hydraulic fracturing. The stages of horizontal well completion with multistage hydraulic fracturing are considered below.

5.1 Stages of horizontal well completion with multistage hydraulic fracturing

As mentioned previously, running and cementing production casing is the first step in well completion. Afterwards the following procedures are also applied in case of horizontal well completion with multistage hydraulic fracturing:

1. Running the liner to the project depth on drill pipes
2. Activation of hydraulic setting tool (HST)
3. Retrieval of drill pipes with HST
4. Running a stinger and its attachment to the top of liner
5. Performing hydraulic fracturing
6. Retrieval of stinger
7. Equipment of a well with tubing and Christmas tree

5.1.1 Running the liner to the project depth on drill pipes and HST activation

After production casing is run and cemented and the next hole with lower diameter is drilled, the liner has to be run to the project depth. In order to process this activity the customer (oil producing company) in conjunction with drilling company and service company confirm a special document called action plan. The action plan for running the liner and completion equipment activation for a real practical example is described in details below. Also the technical description of utilized completion equipment is provided.

Action plan on running the liner

This document has the following content (the example of Prirazlomnoye field, Russia well №5500):

1. ***Data concerning the well***

- *Bottom hole depth:*

measured depth (MD), m	*4486*
true vertical depth (TVD), m	*2588*

- *Actual well construction*

	OD, mm	*Wall thickness, mm*	*ID, mm*	*Depth*
Surface casing	*324*	*9,5*	*305*	*52*
Intermediate casing	*244,5*	*7,92*	*228,66*	*1267,3*
Production casing	*177,8*	*9,2*	*159,4*	*3099*
Liner	*114*	*7,4*	*99,2*	*4473*

- *Production casing shoe*

Depth of production casing shoe, m	*3099*

- *Liner hanger*

Depth of liner hanger installation, m	*3024*

- *Liner shoe*

Depth of liner shoe, m	*4473*

- *Open hole*

Nominal diameter of open hole, mm	*155,6*

- *Productive formation*

Name	*Bazhenov formation*
Top of formation, m	*2581*

- *Formation conditions*

Formation pressure, atm	*300*
Formation temperature, °C	*78*
Cavernosity coefficient	*1.08*

- *Well profile features*

Well type	*horizontal*
The highest inclination, deg.(at depth, m)	*89.19 (3253.54)*

- *Drilling mud parameters*

Mud type	*Bipolymeric inhibited*
Density, kg/m^3	*1270*

- *Characteristics of tubes*

Interval		*Section Length*	*Type of tubes*	*Required torque*
Shoe, m	*Top, m*	*m*	*-*	
4473	*3024*	*1449*	*Liner*	*0.46-0.61t_f*m*
3024	*2494*	*530*	*Steel drill pipe*	*2.2t_f*m*
2494	*1494*	*1000*	*Heavyweight drill pipe*	*2.2t_f*m*
1494	*0*	*1494*	*Steel drill pipe*	*2.2t_f*m*

- *Packers specifications*

№ of packer	*Installation depth, m*	*Depth variation tolerance, m*

1	*4379*	*±5*
2	*4233*	*±5*
3	*4086*	*±5*
4	*3938*	*±5*
5	*3789*	*±5*
6	*3645*	*±5*
7	*3501*	*±5*
8	*3355*	*±5*
9	*3207*	*±5*
10	*3122*	*±5*

- *Frac ports specifications*

№ of packer	*Installation depth, m*	*Depth variation tolerance, m*
1	*4448*	*±1*
2	*4310*	*±2*
3	*4156*	*±5*
4	*4015*	*±5*
5	*3860*	*±5*
6	*3718*	*±5*
7	*3572*	*±5*
8	*3430*	*±5*
9	*3280*	*±5*
10	*3134*	*±5*

Note: 1st port has to be located at least 20 meters far from liner shoe

2. Preoperational activity

Equipment delivery to drilling rig has to be performed not later than 1 day before running the liner. All equipment has to be certified with corresponding passports that have to be attached to the equipment. Equipment without a passport is not valid for operation. All of this is controlled by customer`s supervisor.

Equipment name	*Amount/ length, m*	*Responsible party*
Liner tube	*1521 m*	*Customer(oil prod.comp.)*

Float shoe with a check valve	*1*	*Service company*
Locking ball landing collar	*1*	*Service company*
Toe sleeve	*1*	*Service company*
MultiShift (Ball-activated frac sliding sleeve)	*1*	*Service company*
Hydro mechanical packer	*1*	*Service company*
Liner hanger (BlackCat packer)	*1*	*Service company*
SSU (Service Seal Unit)	*1*	*Service company*
Hydraulic setting tool	*1*	*Service company*
Centralizer	*1*	*Service company*
Cementing unit	*1*	*Cementing service comp.*
Elevator for 114 mm OD tubing (for liner)	*1*	*Drilling company*
Elevator for 89 mm OD tubing (for HST)	*1*	*Drilling company*
Elevator for 89 and 102 mm OD drill string	*1*	*Drilling company*
Pneumatic power slips	*4*	*Drilling company*
Drift mandrel (tubing OD =114mm, 102mm,)	*4*	*Drilling company*
Pipe tong	*1*	*Drilling company*
Hydraulic tong unit	*1*	*Drilling company*
Landing joint	*3*	*Drilling company*
Salt solution (density =1270 kg/m^3)	*38m^3*	*Drilling company*
Christmas tree	*1*	*Customer (oil producing company)*
Geology-technological survey station	*1*	*Customer (oil producing company)*
Thread lubricant	*50 kg*	*Drilling company*
Adapter from HST to drill pipe	*1*	*Service company*

Action plan during preoperational phase:

1. *Drilling master has to ensure that all the surface equipment is ready for operation:*

- *Geology-technological survey station (check and correction of all readings of sensors)*
- *Electronic weight indicator (ensure that readings are correct)*
- *Pneumatic power slips (check the availability of slips)*
- *Hydraulic tong unit (check the availability of jaw)*
- *Torque sensor on hydraulic tong unit (check the availability and readings accuracy), to calibrate make up torque*
- *Power tong (check operability of control station, availability of jaws etc.)*
- *Drilling rig (check operability and u centering)*
- *Handling winch (check operability)*
- *Drilling pumps (check operability, report a diameter of barrel of a pump and type of a pump)*
- *Trip tank (to ensure fill-up of liner and column)*
- *Shale shaker, mud desander, gas separator, etc. (check operability)*
- *Top drive (check operability)*
- *Preventor (check operability of valves, condition and diameter of sealing units of preventor). In case of any of equipment is not ready for operation, it has to be fixed or in case if it is impossible, this fact has to be reported in a corresponding document and a represe tative of a customer has to be informed.*

2. *Drilling master completes a special document reporting the fact that surface equipment is ready for operation. Customer`s supervisor is included in this document.*
3. *Drilling master completes a special document reporting the fact that wellbore is ready for running the liner.*
4. *At planned depth of liner hanger the following parameters have to be measured: torque (in case of rotation (with rotational speed of: n=5 rotation/min and n=10 rotation/min), surface pressure and weight of a column while tripping in/out.*
5. *Customer`s supervisor provides column weight report**.** Such data as weight of a column while running in production casing (each 100m) and weight of a column while running in open borehole (each 50m) have to be reported in this document.*
6. *Mud engineer ensures that parameters of a mud correspond to planned ones. The fact of this correspondence is reported in a special document signed by mud engineer, drilling master and customer`s supervisor. The sample of drilling mud is retrieved and kept until liner is run to a final depth.*

7. Drilling master insures the completion of the following procedures:

- *Liner pipes (OD = 114mm) are put on pipe rack with boxes located towards drilling rig*
- *Visual inspection regarding defects is performed*

8. Drilling engineer ensures the following:

- *The length of each liner pipe is measured and reported in a special list*
- *The number of each liner pipes is written 0.5 m far from a nipple.*
- *Pipe cap is disconnected, the thread is checked and cleaned and then pipe cap is connected again*
- *Defected liner pipes are taken away and indicated specially*

9. Completion engineer:

- *Upon arrival to a drilling rig completion is obliged to perform health and safety training and put a signature in a corresponding record book*
- *Together with customer`s supervisor and drilling master check the correspondence of liner equipment with an approved list*
- *Check the availability of technical passports for equipment and the fact that all equipment correspond to its passports*
- *Check the condition of threads, lengths and diameters listed in passports*
- *Verify the possibility of centralizer installation on liners pipes*
- *Perform the measurement of ID of centralizers*
- *Check the correspondence of balls to frac ports*
- *Check the number of operations of HST and ensure that after each second operation, a special defect inspection is performed.*
- *Complete a special equipment inspection report*
- *Complete the liner scheme according to geometrical characteristics of all components of a liner (such as liner pipes, shoe, packers, ports etc.). This scheme is completed corresponding to the customer`s intervals mentioned previously.*

3. Assembling and running the liner in a production casing

1. Assembling of a liner is performed in a strict correspondence with the liner scheme prepared by a completion engineer and approve by the customer.

2. Coupling of completion equipment (packers, ports etc.) with liner pipes is primarily performed manually with pipe tongs on pipe rack and then the required torque will be applied with hydraulic tong unit

3. Assembling of liner components is performed gently not allowing any mechanical damage

4. Thread lubricant is put only to nipple part of pipes

5. Mandrel drifting of each liner pipe is performed on pipe rack

6. While running the liner, a proper fill-up is ensured (the level of drilling mud up to the rotary table level has to be kept). Fill-up operation is performed only with a special line through a special filter. Fill-up with top drive is forbidden.

7. During running the liner a special tool to avoid foreign objects entering the well has to be used

8. Before running operations a special orientation meeting is organized to discuss detailed plan of action and safety measures

9. After first 8 liner pipes are run, a circulation is maintained to check the operability of a special float shoe containing a check valve that prevents fluids from entering the casing while the pipe is lowered into the hole enabling circulation down through the casing. In case no circulation is maintained or it is impossible to rise injection rate up to 6 l/sec keeping the inflow pressure below 40 atm, running the liner out is performed for its revision.

10. 2 centralizers are installed on each liner pipe not more than 6 meters far one from another.

11. First 20 pipes are run in usinf 2nd elevator.

12. Fill-up is performed into each liner pipe using a special filter.

13. Running a liner in is performed with a speed of 0.1 m/sec after a packer or a port are connected to a liner.

14. Assembling and running a liner in is performed according to a scheme prepared by a completion engineer until liner hanger (connected to hydraulic setting tool)

15. Before connecting liner hanger to a liner, double fill-up of a column is performed

16. Before connecting liner hanger to a liner, an elevator has to be changed to the one suitable for hydraulic setting tool (elevator for 89 mm OD tubing)

17. HST (hydraulic setting tool) connected with liner hanger are lifted to the rotary table, unpacked and inspected by a completion engineer

*18. HST is taken with an elevator and connected to a liner using pipe tong then a required torque (0.46-0.61 ton_f*m) is obtained with Hydraulic tong unit*

19. With closed Pneumatic power slips the column has to be lifted 2 meters up to check if HST stands the weight of a full column and that all details are connected in a proper way

20. If the test is successfully passed, Pneumatic power slips can be open and changed to the one suitable for OD=89mm tubing

21. *HST is held in Pneumatic power slips*

22. *If necessary, an elevator is changed to be suitable for drill pipes*

23. *Fist pipe stand is connected to HST top*

24. *HST and first pipe stand are run in and fill up is performed*

25. *Well circulation is maintained with mud flow rate 2-3 l/sec, in case a circulation is reached, well cleanout is performed with mud flow rate up to 6 l/sec and pressure below 50 atm*

26. *Mud volume required for cleanout is equal to internal volume of a liner plus 10 %*

27. *Weighing of a liner is performed with a liner run in and out, these two weights are recorded.*

28. *Subsequent weighing of a liner is performed each 100 meters reporting the values to a corresponding document.*

29. *Speed of running in cannot exceed 4 m/sec*

30. *Fill-up overflow is performed for each pipe stand. Breaking this rule can lead to early HST hydraulic activation*

31. *HST turning is forbidden due to the possibility of early HST mechanical activation*

32. *Hook load reduction cannot exceed 3 tonnes while running the column in*

33. *When the liner is run in to the level of production casing shoe, the circulation is maintained with mud flow rate of 2-3 m/sec*

34. *After the circulation is reached, cleanout is performed with max mud flow rate of 6-8 l/sec and maximum flowing pressure of 60 atm*

35. *Weighing of a column is performed with a liner run in and out, these two weights are recorded.*

4. Running the liner in open hole

1. *Customer`s supervisor controls the weight of a column (the weight is recorded each 50 meters).*
2. *During liner running in open hole a supervisor, drilling engineer and completion engineer have to be on the rig.*
3. *When a liner shoe and firs liner pipe reach the shoe of production casing, the speed of running cannot be higher than 0.1 m/sec, after the shoe of production casing is passed, hook load reduction cannot exceed 5 tonnes.*
4. *Each pipe stand has to be filled-up with drilling mud, otherwise, hydraulic activation of HST can happen.*

5. *The pause in running the Liner in open hole cannot exceed 3 minutes. In case it happens, the column has to be run out (the length of drilling pipe) and run in again.*
6. *Pipe stand have to be run in gently without any quick starts and stops.*
7. *Hook load reduction cannot exceed 8 tonnes in case of running in open hole.*
8. *In case of running the liner in open hole before closing in pneumatic power slips, the column has to be run out until the hook load stabilizes.*
9. *Run the column until it reaches the depth of 4473 m.*
10. *Connect the top drive and reach mud circulation starting from mud flow rate of 2-3 l/sec.*
11. *When the circulation is maintained, mud flow rate can be increased until 6-8 l/sec with maximum flowing pressure of 80 atm.*
12. *The cleanout with mud volume equal to annular space from liner shoe to the surface (+10%) is performed.*

5. *Activation of completion equipment*

1. *Drilling mud replacement by salt solution is performed with salt solution volume equal to annular space in open hole. The density of salt solution has to be equal to the density of used mud (±0.03g/cm^3).*
2. *Completion equipment activation can be performed only under control of a completion engineer.*
3. *A possibility to monitor the working parameters of cleanout and activation phases has to provided in cementing unit.*
4. *Cementing unit has to overcome a pressure test with pressure equal to maximum operational pressure multiplied a special coefficient (1.4).*
5. *The column has to be lifted until hook load is stabilized.*
6. *2 m^3 of water have to be pumped to the column, then 1 inch OD ball is thrown to the column (the fact that a ball disappears in a column has to be ensured) and pumped with salt solution (volume is equal to inner space from liner shoe to liner head) that is followed by mud (volume is approximately equal to inner space from liner head to the surface but in any case corresponds to the volume that was pumped until the ball reaches its seat) until indication of the ball reaching its seat is recorded. The indication is a sharp increase in flowing pressure (immediate pressure growth from operational pressure of about 80 atm to 100 atm).*

7. *With ball reached a seat near liner shoe, the system cementing unit/liner has become a system hydraulically disconnected from the reservoir, therefore, further pumping will lead to increase in flowing pressure in a liner.*
8. *The flowing pressure in a liner has to be increased until 240 atm with steps of 35 atm to activate liner hanger.*
9. *The system has to be completely depressurized.*
10. *Liner hanger activation is controlled by:*
    - *moving the column down (until hook load is equal to the weight of a column while running in production casing shoe interval minus 10 tones)*
    - *moving the column up (until hook load is equal to the weight of a column while running out in production casing shoe interval plus 10 tones)*
    - *pressure test (reaching the pressure in annular space of 140 atm by steps of 35 (for water density) recalculated according to mud density) of 30 mins duration*
11. *The annular space has to be completely depressurized.*
12. *Hydraulic HST activation:*
    - *The column must be moved in such a way to maintain a hook load equal to the weight of drilling column while running out in the interval of liner head minus 5-7 tones (running out after drilling operations)*
    - *reaching the pressure in inner space of 300 atm by steps of 35 atm*
13. *The inner space has to be completely depressurized.*
14. *Trial of HST disconnection from the column:*
    - *lifting the column either until the hook load is stabilized on full column weight minus the weight of a liner or until hook load is equal to full column weight + 25 tonnes (further lifting is forbidden)*
15. *In case the hook load is stabilized on full column weight minus the weight of a liner, probable successful HST disconnection from the liner is controlled by lifting the column 2.5 meters and verifying the stabilization of hook load. If in this case hook load is stabilized, hydraulic activation of HST and its disconnection were successfully performed.*
16. *In case hook load during HST disconnection trial reaches full column weight and continues to grow until full column weight + 25 tonnes, further lifting is forbidden and hydraulic HST activation process with further disconnection trial have to be repeated again (maximum 4 times). In case disconnection was not achieved, HST mechanical activation process has to be performed.*

17. *Mechanical HST activation (in case HST activation was not achieved hydraulically):*
    - *The column is moved in such a way to get hook load equal to an average between the weight of drilling column while running out at the interval of liner head and running in at the same interval (running out/in after drilling operations)*
    - *Rotate the column 6 times, then it is run in and lifted to the same position again and rotated other 6 times with further running in*
    - *Lift the column and check HST disconnection from the liner with previously mentioned method*
18. *When activation of HST and its disconnection from the liner is performed, the mud in inner and annular space above the liner head is replaced by water (the volume of water has to be equal to 1.5 cycles).*
19. *The column (HST+drill pipes) disconnected from the liner have to be run out*
20. *When HST lifted to the surface it is inspected and a corresponding document is filled.*

Technical description for utilized completion equipment during liner run in phase

As mentioned previously, the completion equipment (in case of Weatherford service company) utilized during liner run in phase is the following:

- *HST (hydraulic setting tool)*
- *Packer BlackCat (liner hanger)*
- *Polish Bore receptacle (liner head)*
- *Packer ARES (interval isolation packer)*
- *MultiShift (ball activated frac sliding sleeve)*
- *Toe sleeve*
- *KLC (Locking ball landing collar)*
- *Float shoe equipped with check valve*

As a whole, this set of equipment in case of Weatherford oil service company is called Weatherford ZoneSelect System. The description of this equipment is provided below.

In addition to ZoneSelect System, another important equipment called Stinger has to be described. Stinger is used in well completion during multistage hydraulic fracturing phase. Stinger description is also provided below.

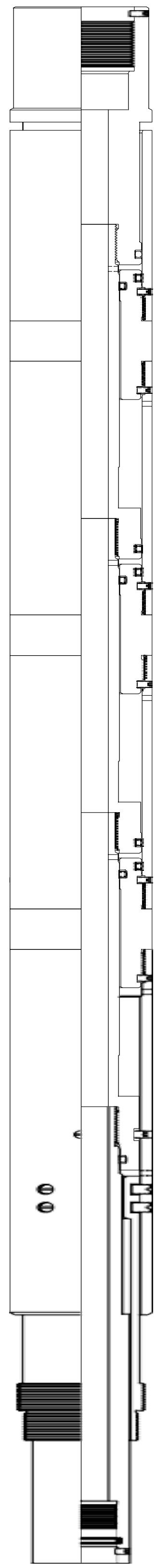
1. HST (hydraulic setting tool)

The Weatherford WFX Hydraulic Setting Tool is a specialized setting tool designed and constructed as the core component to Weatherford's WFX Sand Control System. Used in conjunction with the Weatherford WFX Crossover Tool it is intended to set specific versions of Weatherford's BlackCat Retrievable Seal Bore Packer. This setting tool comes with some special and unique features that are required to achieve full functionality from the WFX system.

The WFX Hydraulic Setting Tool is a heavy duty setting tool, designed to handle the pressure and flow requirements of extreme sand control techniques, such as frac packing. It also has high tensile ratings necessary to carry in long screen assemblies and accompanying washpipe. While designed to be a heavy duty tool, it will serve as the standard setting tool for our weight down gravel pack system.

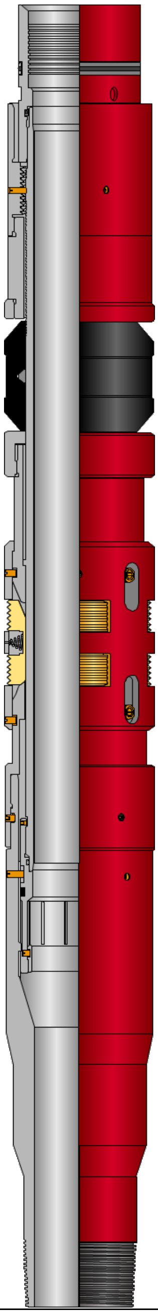
Multiple sizes of this tool are designed in order to maximize flow and pressure ratings. The WFX setting tool is a multi-piston tool to keep setting pressures low. On conventional jobs without the presence of high horsepower sand control pumps, achieving setting pressures with rig pumps should not become an issue. A torque through feature has been incorporated into the WFX setting tool. Torque can be transmitted from the workstring and setting tool into the BlackCat Packer. Special drive sleeves in the setting adapter kits have a profiled bottom edge to mate with the setting sleeve of corresponding packers to transfer torque to the packer assembly.

The setting tool has a unique decommissioning feature. Once setting pressure is reached; pins are sheared so setting force is no longer transmitted to the packer. The shear value must be matched to recommended setting force for the specific packer. This was incorporated into the tool so hydraulic force from sand control and stimulation treatments did not act to move associated crossover tools run below the setting tool eliminating



the chance of damaging the interface between the drive and setting sleeves. *The WFX setting tool is designed with a Stub Acme assembly thread in the top. The appropriate top sub must be ordered and installed before using the tool.* *Top subs with common tubing and drillpipe threads are offered and can be changed as needed.*	

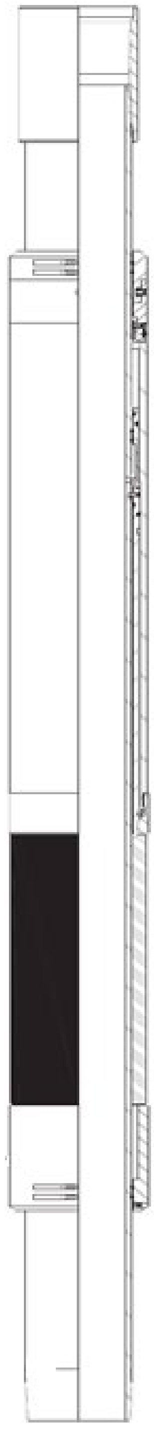
2.Packer BlackCat (liner hanger)

The Weatherford BlackCat downhole packer is an enhanced version of the reliable and field-proven BlackCat retrievable isolation packer. The BlackCat packer is specially designed for today's and future well completion technologies. The packer can be used in the process of production, injection, tubing perforation with pumping fluid from the wellbore, well testing, installation of stand-alone filters, gravel packing and for running multistage hydraulic fracturing assemblies. As standard, the packer is equipped with a PBR (Polish Bore receptacle) installed in the upper part of the packer. The packer is run and activated by means of a hydraulic setting tool (HST). Once the stinger has been run and connected with the BlackCat packer, the system has a full bore diameter for unrestricted well intervention. The BlackCat packer is equipped with the patented ECNER system, which provides highly effective isolation and prevents the piston effect. These high-tech packers meet the stringent requirements of ISO 14310. The packers are retrievable with the standard BlackCat tool. This packer is equipped with the same accessory used for the Weatherford UltraPak ™ Fixed Packer.	

3. Polish Bore receptacle (liner head)

The Polish Bore receptacle (PBR) is a component of the BlackCat packer and serves as a seat for the sealing unit - stinger. The inner surface is polished to ensure a hermetic stinger seal during hydraulic fracturing operations. The length of the Polish Bore receptacle provides free axial movement of the stinger in the event of a buoyancy force at high pressures inside the tubing, it can be used in conjunction with a hydraulic anchor.	

4.Packer ARES (interval isolation packer)

The ARES hydromechanical packer can be installed both in the open hole and in the production casing and provides mechanical isolation of the annular space with a high pressure drop by compressing the packer elements by applying hydraulic pipe pressure, eliminating time delay after its installation. Unintentional setting of the packer by applying pulling axial forces or unloading weight is eliminated. The packer is one of the components of the downhole assembly of multi-stage hydraulic fracturing systems, providing inter-interval isolation of ports for hydraulic fracturing and is widely used in horizontal well profiles.	

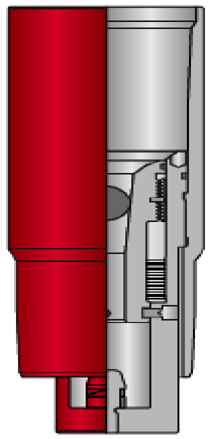
5. <u>MultiShift (ball activated frac sliding sleeve)</u>

The circulation valve of the Multishift type is an element of the downhole equipment for well completion. It is installed and run into the well as part of the liner and provides communication and separation of the inner space with the annular space. The opening (closing) of the circulation valve is carried out by moving the sliding sleeve located inside the valve body. The valve has the form of a branch pipe with holes in the middle part of the body. The valve design allows sequential installation of several valve units for interval and selective communication with the annular space. The ability to communicate with the annulus through a circulation valve of this type is used to produce multistage hydraulic fracturing. The valve is activated by a ball that closes the pipe space after being seated in the seat. To exclude the possibility of damage to the pack of seals when moving the sliding sleeve, one of the holes is equipped with a special flow hole to equalize possible pressure drops.	

6. Toe sleeve

Product installed and run into the well at the bottom of the completion assembly between the packer and shoe. The product can be installed in a production casing, or in an open hole; it is widely used in horizontal well profiles. The first opening of the product is carried out by increasing the hydraulic pressure in the tubing. After opening the sliding sleeve shifts along the flow holes of the body and is fixed by means of the retaining ring. In this case, the screws are sheared. After opening, the product is closed by moving the sliding sleeve using the switching tool. Subsequent switching to the open / closed position is carried out by switching the sleeve of the sliding using the switching tool. Fixation of the position is ensured by the retaining ring. The product provides mechanical isolation of the annular space with a high pressure drop by compressing the packer elements by applying hydraulic pipe pressure.	

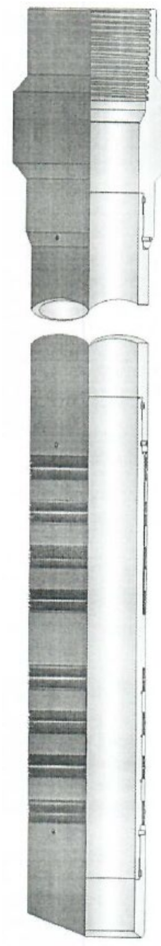
7. KLC (Locking ball landing collar)

KLC (Locking ball landing collar) is utilized in case of completion with liner and is applied for a hermetic seal of inner space. KLC is designed to be installed in conjunction with shoe equipped with check valve. It serves as a long-time barrier of flow from inner space of liner to the reservoir. This is required to be able to activate hydraulically activated completion equipment. *KLC (Locking ball landing collar) allows the flow through the liner at a phase ot liner run in. To be activated, and therefore, to block the flow from the liner to the reservoir, 1 inch OD ball has to be dropped into the column and subsequently reach its seat. In such a way the flow is blocked that leads to growth of pressure and subsequently to activation of hydraulically activated completion equipment such as liner hanger, HST and other.* *Special features:* *1. Reliable flow blocking technology* *2. Availability of circulation during liner run in* *3. Absolute sealing properties*	

8. *Float shoe equipped with check valve*

This shoe has several important roles in the main phase of circulation through the liner. *1. Shoes are most often run with check pressure valves, and they perform the main function of guiding the casing to a predetermined depth, and the shoe also acts as the main check valve when the direct circulation is completed.* *2. Round shoe packing facilitates liner penetration in horizontal and deviated wells. Ideal for low pressure applications where other valves may not close. Withstands long periods of circulation and can be drilled with roller cone bits.* *This 303 shoe has a Sure-Seal 3 poppet spring loaded phenolic valve. This valve has an easy-to-drill non-ferrous metal spring and a flexible seal for low pressures. A solid phenolic seal for high pressures reduces compression and deformation of the resilient seal during critical pressure drops.* *This shoe meets or exceeds API Category IIIC 10F fatigue, pressure and temperature requirements for check valve equipment for casing cementing.*	

9. Stinger

Stinger (tubing seal assembly) of Weatherford service company is a device that is installed on tubing and used for tubing hermetic connecting with liner head for subsequent hydraulic fracturing procedure. Stinger has a constant inner diameter corresponding to ID of a liner hanger (BlackCat packer). Setting of a packer and its connection with liner head is provided by hook load deloading and its retrieval is provided by loading.	

5.1.2 Running a stinger and its attachment to the top of liner

After the liner is run in, HST is activated and retrieved on drill pipes and the well filling with water is performed, running a stinger is initiated.

The procedure is the following:

- A stinger is transported on tubing (OD=89mm or different) column until it reaches the interval corresponding to the liner head.
- Hook load is constantly monitored, due to the fact that then number of tubes in column increases, hook load has to increase constanly.
- When a sharp decrease in hook load is noticed (around 2-3 tones), the column, probably, reached the mentioned interval (the interval corresponding to the liner head) and two different scenarios producing this decrease in hook load can apply:
    1. The stinger touches the liner head that is represented by Polish Bore Receptacle (PBR) but does not enter inside the liner
    2. The stinger enters inside the liner (in particular, inside PBR) and hook load is released by fractional losses appeared due to the contact between bonded seals of a stinger with internal walls of PBR
- Immediately after mentioned hook load decrease, the column has to be lifted until hook load is stabilized on the last value recorded prior to the mentioned sharp decrease.
- Keeping the column away from the interval of liner head but as close to this interval as possible, cleanout has to be performed: reverse circulation (pumping to the annular space) is maintained with water of 1.01 g/cm^3 density. The volume of required water is equal to the volume of inner space from liner head to the surface.
- After cleanout, the column is run in until the same hook load decrease.
- To verify which of mentioned two scenarios producing the decrease in hook load applies, immediately after 2-3 tones hook load decrease is reached again, pressure test in annular space has to be conducted.
- Pressure test 1 in annular space is performed in the following manner:
    1. Preventer is closed
    2. 1.01 g/cm^3 water is pumped to the annular space until the pressure of approximately 70 atm is reached.
    3. In case after 5-10 minutes maintained pressure is kept constant and no inflow from the tubing to the surface is detected, no hydraulic communication between annular and inner space is present that shows that the stinger entered

inside PBR and hook load is released by fractional losses appeared due to the contact between bonded seals of a stinger with internal walls of PBR (scenario 2).

4. In case after 5-10 minutes maintained pressure decreases and/or inflow from the tubing to the surface is detected, the stinger touches the liner head that is represented by Polish Bore Receptacle (PBR) but does not enter inside the liner. In this case further operations have to be performed (scenario 1).

- After the Pressure test 1 in case of scenario 2:
  1. The column is run in until hook load decrease is approximately equal to 15 tones
  2. The place on the tube (N) just above the spider is marked
  3. The column is lifted in such a way to disconnect the mentioned tube (N) and the one just below (N-1) from the column.
  4. The distance from the end of nipple of the tube N to the mentioned mark (this distance is called A) is measured.
  5. The following calculation is performed: $E = A - (B + C) + D$,

  where: B – length of preventer, C – length of spider, D – length of surface sealing unit

  6. The length E corresponds to the length of a tube (composed by several special tubes of reduced length) that is required to be placed on the column instead of the tube N – 1. The tube N – 1 will be placed instead of tube N.
  7. A frac tree is installed on the highest tube (that is now N – 1 tube) and the column is run in on frac tree until frac tree and surface sealing unit are in contact.
  8. If the length of tube E is calculated in a correct way, in a last moment before frac tree and surface sealing unit are in contact, the hook load decrease has to be approximately equal to the initial one (15 tones).
  9. Pressure test 2 in annular space is performed in the following manner: 1.01 g/cm^3 water is pumped to the annular space until the pressure of approximately 100 atm is reached. In case after 30 minutes maintained pressure is kept constant and no inflow from the tubing to the surface is detected, no hydraulic communication between annular and inner space is present that shows that the stinger entered inside PBR and hook load is released by fractional losses appeared due to the contact between bonded seals of a stinger with internal walls of PBR.

10. In case pressure test 2 is successfully performed, running a stinger in is completed and the well is prepared for hydraulic fracturing.

- After the Pressure test 1 in case of scenario 1:
  1. The mark on a tube exactly above a spider is made.
  2. The column is lifted until hook load is stabilized
  3. Several clockwise rotations (e.g. 3) of a column are performed
  4. Run in a column is performed controlling the hook load
  3. If the initiation of hook load decrease is recorded later than before (the mark in this point of time is deeper than previously), the required scenario (The stinger enters inside the liner (in particular, inside PBR) and hook load is released by fractional losses appeared due to the contact between bonded seals of a stinger with internal walls of PBR) happened and Pressure test 1 is repeated again
  4. The mentioned procedures are repeated until Pressure test 1 is successful
  5. Then the procedures from the previous topic (After the Pressure test 1 in case of scenario 2) are applied and the well then is prepared for hydraulic fracturing.

5.1.3 Performing hydraulic fracturing

Hydraulic fracturing in a horizontal well is usually performed by a corresponding service company that play a role of contractor for oil and gas production company. As in case of the considered project (Prirazlomnoye field, Russia well №5500) a service company called Schlumberger acts as a contractor.

Hydraulic fracturing was performed in the following way (only 3 stages out of 10 are considered):

Procedures completed	*Stage*
1.Displacement by linear gel (22m^3) *2. Injection of fracturing fluid (15m^3)+ sand-carrying fluid (22m^3)* *3. $P_{(port1)activation}$ = 620 atm, ISIP = 167 atm* *(port1 was activated by no-ball hydraulic activation)*	*Mini-frac*
1.Injection of fracturing fluid (60m^3)+ sand-carrying fluid (174,3m^3) *2.Injection of 1,47m^3 of water, dropping the ball (Ø 52,02mm) for activation of port2 (Ø 50,37mm)*	*Stage 1*

3.Injection of 21,9 m³ of water for a ball delivery to its seat *4.Port 2 activation (interval 1 isolation + port2 opening)* *5.Displacement by linear gel (10m³)*	
1. 1.Injection of fracturing fluid (60m³)+ sand-carrying fluid (164m³) *2.Injection of 1,1m³ of water, dropping the ball (Ø 54,00mm) for activation of port3 (Ø 52,27mm)* *3.Injection of 21,24 m³ of water for a ball delivery to its seat* *4.Port 3 activation (interval 2 isolation + port3 opening)* *5.Displacement by linear gel (10m³)*	*Stage 2*

The following stages (from stage 3 to stage 10) are performed by means of equivalent procedures.

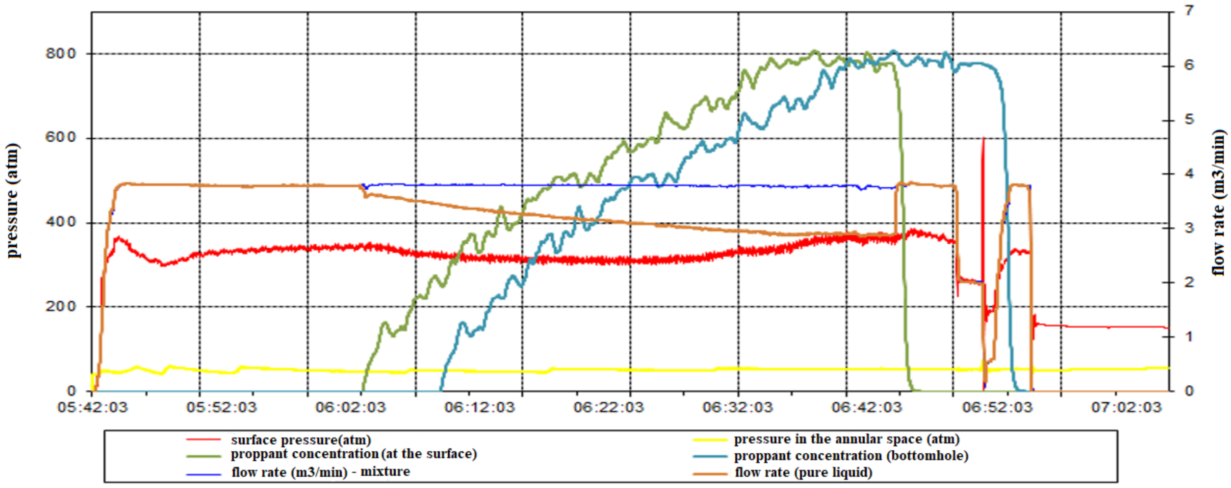


Figure 24 – Graph of Multistage Hydraulic fracturing (stage 2)

5.1.4 Retrieval of a stinger

After hydraulic fracturing is performed, the next stage of well completion follows. It is called retrieval of a stinger.

The procedure of a stinger retrieval is the following:

- Annular space has to be completely depressurized (0 atm)
- A value of hook load during test retrieval (W_{test}) recorded at the phase of stinger setting is considered as an approximate hook load that minimally has to be achieved during stinger run out for its retrieval. However, due to a set of factors in reality hook load sufficient for retrieval is usually a way higher
- When during run in operation W_{test} is reached, each following run in attempt has to be done in such a way to reach additional hook load increase of 5 tones and to make

a pause in run in operation for about 5 minutes. This set of operations is repeated until either a stinger is disconnected (scenario 1) from PBR or until weight limit for workover rig is reached (scenario 2).

- In case of scenario 1, a temporary well kill operation is performed by means of pumping of a fluid of certain density to the annular space.
- In case of scenario 2, either a different workover rig with a higher weight capacity is provided, or additional trials of sharp deloading with subsequent lading of the column are performed to provide a necessary impulse and prevail frictional forces between bonded seals of a stinger and internal walls of PBR taking into account an additional contribution of well impurities affecting friction as well. When stinger disconnection from PBR is finally reached, kill operation mentioned in case of scenario 1 is also performed.

5.1.5 Equipment of a well with tubing and Christmas tree

After the liner is run in, HST is activated and retrieved on drill pipes, running a stinger is performed with subsequent multistage hydraulic fracturing operation completed, a stinger is retrieved and temporary well kill is done, the well has to be equipped with tubing and Christmas tree. When all of the mentioned phases are passed, the horizontal well can be considered completed and ready for initiation of a flow to the well.