HYDRAULIC FRACTURING: BASIC INFORMATION ABOUT JOB SELECTION AND DESIGN EXECUTION

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ABSTRACT

When it comes to hydraulic fracturing, there are a lot of factors that are involved into the design, job selection/preparation and execution. This paper will discuss the basic information that goes into most designs with regards to fluids, proppant and equipment requirements. In addition, basic calculations, quality control and additional requirements for job preparation will be discussed. By having a basic understanding of what goes into a "frac" job, this will aid in successful job completion.

INTRODUCTION

We've come a long way in stimulation. In the 1890's, the first stimulation technique was explosive fracturing. Liquid and solid nitroglycerin was pumped and then ignited. The first hydraulic fracturing job was performed in Grant County, KS in July, 1947. The well was the Klepper Gas Unit #1 in the Hugoton Gas Field. The treatment was 1000 gals of napalm-thickened gasoline followed by 2000 gals of gasoline containing 1% of a cationic emulsion breaker. This treatment was applied to four limestone pay zones. Post-treatment analysis showed minimal productivity improvement. Although minimal, this helped pave the way for hydraulic fracturing to become a favorite method of stimulation. Early treatments used gelled hydrocarbon fluids for stimulation with minimal amounts of proppant. Currently, water-based gels are used on ~95% of all stimulation treatments, with an emphasis on the remaining fracture conductivity. This focus leads to the pumping of high concentrations of proppant, and sometimes the application of higher strength ceramic proppants instead of the less expensive quarried sand proppants.

Productivity increase is the main reason we use hydraulic fracturing. The primary mechanism that improves production from a fractured well is the change in flow pattern within the reservoir. Instead of a radial flow pattern as in natural completion or matrix-acidized wells, flow periods of linear and bi-linear flow occur prior to pseudo-radial flow. The most common condition used to analyze flow is the pseudo steady-state condition. This assumes a closed reservoir boundary with the pressure drawdown having reached the boundary so that the future rate of change of pressure is a constant for a given drawdown rate. In very-low perm formations (i.e. tight gas sands), the well may never reach pseudo steady-state conditions. There are several calculations that go into calculating productivity. The two calculations used to analyze productivity are the productivity index (J) and undamaged productivity index (Jo). There are several factors that go into these calculations. The predominant factors are fracture conductivity, drainage area, and permeabilities. These two values are then used with the McGuire & Sikora chart to calculate the productivity index ratio, (PIR or J/Jo), which describes the increase of productivity through fracturing. Another type of analysis is using pressure transient analysis. There are three types: uniform flux, infinite conductivity, and finite conductivity. Due to the complex nature, we will not go into full detail of these options.

As we generate fractures through hydraulic fracturing, we care most about the ones that stay open and allow for enhance productivity. We call these the "conductive" fractures. Through the years, the term fracture dimensionless conductivity (Cfd) was born to evaluate a hydraulic fracture's success. When talking about the fracture's conductive length, we assume that it consists of two equal half-lengths (xf, in feet) going in opposite direction from the wellbore. When defining fracture dimensionless conductivity, we also need to know the fracture width (w) in feet, fracture permability (kf) in millidarcies and reservoir permeability (k) in millidarcies. Therefore, we use the following equation:

$Cfd = (kf * w)/(k * xf)$

Going forward, we will be discussing the information needed to help in designing a frac job which includes reservoir and rock properties. From there, we will dive into the materials (additives, fluid systems and proppant) and parameters needed to design a frac job. We will conclude with quality control, job execution and basic calculations needed.

RESERVOIR AND ROCK PROPERTIES

The most important aspect when looking at fracture stimulation is the formation to be treated. You have to know its physical properties to provide optimal and accurate stimulation.

Physical Properties

One of the first things to know about a formation is its porosity and permeability values. Porosity refers to the percentage of the pore volume with respect to the bulk volume. In un-consolidated formations, porosity depends on grain size distribution, not on absolute grain size. It will be high, in the range of 35% to 40%, if all grains are close to the same size. It will be lower, down to 15%, if there is a wide range of grain sizes such that small grains fill the pore spaces between large ones. The effective porosity is the porosity not filled with clay or the total storage capacity of a rock. The fraction of pore space containing water is termed the water saturation, Sw. Part of this water Swirr (irreducible volume of water) is bound by surface tension on grain surfaces, at grain contacts and in the smallest interstices. Permeability is the relative ability of flow (gas, oil and water) through a porous media under a specified pressure gradient. In contrast with porosity, permeability depends greatly on grain size of the rock.

Reservoir Area

Another key aspect of hydraulic fracturing is related to the volume of the reservoir. Volume of the reservoir is calculated through the drainage area and the reservoir height. Drainage area refers to the area that the reservoir is draining from, typically given in acres. Height of the reservoir is typically calculated through evaluating multiple logs (discussed below).

Geology

The crucial part of understanding how to fracture a zone is to understand the geology of the formation. You have to know what are the lithology, matrix character, clay content and mineralogy.

The lithology tells you a little bit of how the formation will react; whether it is limestone, dolomite, consolidated sandstone, consolidated sandstone, shaly sand, shale or coal. It is also important to know if the formation is homogenous or heterogeneous or if the formation is naturally-fractured.

Matrix character also will allow you discern how to go with the fracture design. There are different types of porosity and cement that define the formation. This will tell you if the formation is a consolidated or unconsolidated formation. The different types of formation porosity to understand are: intergranular, intragranular and transparticle. Intergranular porosity means that there is pororsity between the matrix grains. Intragranular porosity is when there are void spaces dissolved from within the grains (diagenetic). Transparticle porosity exists when void spaces are dissolved crossing between grain boundaries. The two main formation cements we are concerned with are rim cements and occluding cement. Rim cements are cements occurring on the surface of the grains or pore throat linings. There can be some that have low surface area (Quartz, Plagioclase or Orthoclase) or high surface area(Illite, Mixed-layer Smectite/Illite, Aragonite, Chlorite). Occluding cements are cements occurring in the pore throats thus shutting-off or obstructing the flow path (Calcite, Pyrite, Dolomite, Siderite, Ankerite and Kaolinite).

There are several types of formation clays found in formations. All clays are capable of migrating when contacted by injected fluids which alter the ionic environment. This accounts for why filtrate from drilling mud, cement, completion and stimulation fluids can have such an impact on formation permeability. This is a significant problem when in the presence of swelling clays like smectite and mixed-layer clays which will expand significantly thus generating an increased reduction in permeability. The four most common clays found in formations are kaolinite, smectite (montmorillonite), chlorite and illite. Chemically, kaolinite is a very stable clay. The crystal within the lattice are held together tightly by the hydrogen bonds. This aids in the prevention of water into the lattice. Smectite (Montmorillonite) has weak bonds between the crystals which permit water molecules to enter and expand the distance between clay crystals. Complete hydration will occur in the presence of excess water, especially in sodium is present. If in the presence of excess potassium, it can convert to Illite. KCl brines can shrink smectite clay. It can ionically bond to alcohol, glycol and other organic acids. It is the primary cause of cation exchange because of the high negative charge density on the faces of the crystals. Hydrated clay is stress sensitive having the potential to relase water. It is somewhat HF reactive, but not HCl. Chlorite is diagenetically stable although strong HCl can leach ferrous iron and leave an amorphous silica residue which may be incompatible with some surfactants. Illite–It is HF reactive. In structure it is a very fine, fibrous material that is extremely sensitive to shear. Mixed-layer clays are composed of more than one clay mineral. The most common combination is smectite and illite. As well as swelling problems due to the presence of smectite, the weak smectite crystal can also result in the mixed clay breaking up and causing pore throat plugging.

Mineralogy is important to know so that you can prepare for possible precipitates and incompatible fluids. Quartz is highly reactive with HF (slightly with HCl) and diagenetically alterable. Calcite is reactive and soluble with HCl; reactive and forms insoluble precipitates with HF; diagenetically alterable. Feldspar is reactive to HF; in presence of excess potassium and metal anions (Ca, Na, Mg, Fe, Al) forms mixed-layer smectite/illite; in acidic environment with a surplus of K goes directly to illite. Iron-bearing Carbonates (Evaporites) are sources of free ferrous iron (Fe^{2+}) radicals to form iron hydroxide precipitates (Ankerite and Siderite). Iron Sulfide is pyrite and relatives (FeS).

Formation stresses

The determining factors of a fracture's growth are in relation to the stresses that the formation can endure. These stresses are Young's Modulus, Poissons Ratio, Bulk Modulus and Shear Modulus.

Young's Modulus (E): Young's Modulus is the ratio of stress (σ) to strain (ε) under conditions of uniaxial stress. This value is generated through core testing. The importance of Young's Modulus is that it defines the "stiffness" of the formation and will greatly influence the width of the created fracture for a given fluid injection pressure. Young's Modulus is calculated with the following equation:
$E = \Delta\sigma/\Delta\varepsilon$
Typical Young's Modulus values:
Partially-consolidated sandstone: $<0.5*10^6$ psi Sandstone: $2\text{-}6*10^6$ psi Limestone: $6\text{-}8*10^6$ psi

Poisson's Ratio (ν): Poisson's Ratio is the ratio of the lateral expansion to longitudinal contraction of a rock under conditions on uniaxial stress. This value is typically generated through core testing by calculating the lateral (ε_r) and axial (ε_y) strain of the rock under compression. Poisson's Ratio is important because it defines the amount of overburden stress that is translated into the horizontal stress. A variation in this value controls the fracture height growth. Poisson's Ratio is calculated with the following equation:
$\nu = -\varepsilon_r/\varepsilon_y$
Typical Poisson's Ratio values:
Sandstone: 0.20-0.25 Shale: 0.25-0.30

Bulk Modulus (K): Bulk Modulus is the ratio of hydrostatic pressure to the volumetric strain it produces. To calculate Bulk Modulus, use the following equation.
$K = E / \{3*(1- 2\nu)\}$

Shear Modulus (G): Shear Modulus is often used interchangeably in fracture models with Bulk Modulus. To calculate Shear Modulus, use the following equation:
$G = E / \{2*(1+\nu)\}$

Reservoir Fluids

What type of reservoir fluids are there? Is there water, oil, gas (wet or dry) or condensate? In the oil, are there asphaltenes, paraffin, iron, etc.? What's the viscosity of the oil? What are the densities of the reservoir fluids? What's the make-up of the gas (any CO_2 or O_2)? These all play factors into what goes into our fluid system and how we design a treatment for a frac job.

Logging

Well logging (aka borehole logging) is where you penetrate the wellbore and make a detailed record (well log) of the wellbore. This aids particularly in determining the formations and their depths in the wellbore. It also helps indicate the formations where hydrocarbons are present. There are many types of logs including: spontaneous potential, gamma ray, neutron, density, sonic and magnetic resonance imaging. Typically wireline is conveyed in the wellbore with specific tools to collect the log data.

Spontaneous potential occurs any time an electrically conductive fluid is in the hole at the time the open hole surveys are recorded. This helps in rock characteristic identification by seeing if there is shale/clay present.

Gamma ray measurement is a result of measuring the naturally occurring gamma radiation from the rock formations penetrated by the borehole. The radiation level is due primarily to the radioactive isotopes of uranium, potassium and thorium. These isotopes are usually more concentrated in shales and clays than in sandstones or limestones. Neutron logs are mainly an indication of hydrogen. They relate to hydrogen in the water molecules whether the hydrogen is in bound formation water or movable formation water. The presence of hydrocarbons generally decreases the apparent neutron porosity. For example, there are less hydrogen atoms in rock filled with natural gas than with formation water because the gas density is so much less. Oil has the same effect but to a much lesser degree. This is why neutron logs are used in conjunction with density logs to identify hydrocarbon bearing zones. Density logs calculate the bulk density of the formation. We assume sandstone equals 2.65 grams per cubic centimeter, limestone equals 2.71 grams per cubic centimeter, dolomite equals 2.87 grams per cubic centimeter, water equals 1.0 gram per cubic centimeter and gas equals 0.3 grams per cubic centimeter.

Sonic logs measure a formation's capacity to transmit seismic waves. This can be used to help identify some of the mechanical properties (Young's Modulus, Poissons Ratio, Bulk Modulus and Shear Modulus) of the formation. The sonic tool response, like the neutron, reads both bound water and free water as porosity. The difference between the two is the presence of hydrocarbons. Sound waves in fluid slow down as the fluid density goes down. Thus the presence of hydrocarbons tends to raise the apparent sonic porosity.

With magnetic resonance imaging, magnetic waves are used to align hydrogen molecules in the near wellbore. The apparent change in movement of the hydrogen molecules can aid in calculating bound water and relative permeability. Typically, service companies have software packages that analyze the collected data and interpret for you. It is important to understand as much about the reservoir as we can and the formation(s) to stimulate.

MATERIALS

We've talked about determining the location of the formation to stimulate. Now we will discuss the materials used in a frac job. These materials include the different additives, fluid systems and proppants utilized.

Additives

There are several additives that are used in the fracturing fluid system which are included based on reservoir characteristics, reservoir fluid characteristics and rock properties. Here are several different types of additives and their applications:

Acid crosslinkers are used to increase the viscosity of gelled acid by hooking the long linear molecules together much like truck tire chains compared to a long chain. The increase in viscosity allows for a wider fracture to be created, thereby giving more acid at the fracture face to dissolve limestone. The increase in viscosity also provides improvement in leak-off control. The use of a crosslinker is much more economical than increasing the gellant loading in increasing viscosity

Acid retarders are chemicals used to give the acid greater penetration into the formation. They work by temporarily plating out an anionic surfactant on the formation (used in carbonates, i.e. dolomites and limestones) and then being removed by the acid. They do not change the actual reaction rate of the acid, but change the apparent reaction rate. Since acid retarders are anionic they stick onto the matrix. Over time the acid leaches those off the formation, therefore the acid still spends at the rate it is supposed to. They do not help create additional fracture width during an acid fracturing operation because it does not increase viscosity.

Antifoamers are used in two applications. They can be used to prevent foam from occurring, or as defoamers to break existing foam. As antifoamers, they can be used with certain other specialty surfactants that may foam as a side effect to their intended use or they may be blended with cement slurries to break bubbles and enhance slurry density. They can be used as defoamers to break existing foams after the foam is no longer required. They're useful (EX: Back in the old days there was a surfactant that also foamed, so if you were gelling up a frac tank, the first thing you knew, you had foam coming out the tank). If you do a foam frac and have a stiff foam, when you flow back you can use it.

Antisludge additives (ASA) are used during the acidizing process to prevent sludge formation from crudes containing asphaltenes and ferric iron (Fe^{3+}), which occurs when asphaltenes and iron are encountered or introduced through the treatment. The low pH from the Hydrochloric Acid (HCl) gets those together and the ferric iron reacts with the asphaltenes to make sludge. The ASA will prevent the iron from reacting with the asphaltene. If sludge is made, use aromatic solvents like xylene and preferably toluene (benzene is banned because it is more soluble in water than xylene and toluene; benzene is also a carcinogen) to dissolve the sludge. If you can keep the iron from reacting with the asphaltene, then you prevent the sludge. Sometimes you can get citric or acetic acid to chelate the iron; if they don't chelate the iron, then go to EDTA. If the iron is ferric, use sodium erythorbate or erythorbic acid. Stannous Chloride is a last resort to reduce the iron due to cost but is the most effective.

Asphaltene solvents solubilize deposits. We usually use aromatic solvents, xylene and toluene to dissolve asphaltenes. There are also inhibitors available to aid in the prevention of those deposits.

Biocides are used in the fracturing process to prevent gel degradation and formation contamination. Gellants used in the fracturing process are food sources for a host of bacteria. They must be eliminated in order to preserve the gellant. Enzymes excreted must also be denatured. Both anaerobic and aerobic bacteria are of concern. The biocide must also be compatible with the base fluid and the rest of the fracturing additives. When enzymes are used as low temperature breakers, biocides that denature are not recommended. Biocides that chelate cannot be used with crosslinked fluids.

Buffers help in the gelling process by creating the correct pH levels to correctly crosslink the fluid for the application.

There are two general types of clay stabilizers in use. One is considered to be short term but temporary, only used to make sure frac fluid won't hurt formation. The other is long term, not permanent, works about 3-5 yrs if well is producing water. These chemicals provide protection against formation swelling due to the treatment fluid during the procedure and while the load fluid is being recovered. Materials in general use for this type are KCI (Potassium Chloride), NH_4CI (Ammonium Chloride) and TMAC (TetraMethylAmmoniumChloride). High molecular weight (MW) polymers are used to provide long-term protection against shale and clay swelling. There are also low-weight molecular polymers available that can be used in lower permeability formations and still provide long-term protection similar to the larger molecules. The long term chemicals are higher molecular weight polymers (1000-2MM). The advantage of the low MW (1000-10,000) is that you can get those into a small pore throat. If you have high perm and porosity the higher MW stabilizers are better. Clay stabilizers are not compatible with anionic chemicals. All coagulants are clay stabilizers.

Corrosion inhibitors that will prevent corrosion from O2, CO2 and H2S are available. These are usually found in the packer fluid section. Acid corrosion inhibitors are a separate topic. H2S inhibitor takes a film-forming amine (oil-based amine to plate out on metal). CO2 corrosion control reacts with CO2 to make a carbonate. O2 scavenger reacts with O2 to change the sulfides into sulfates. H2S scavenger reacts with the H2S and changes the sulfides into sulfates. All aldehydes and aldehyhde-release agents are H2S scavengers. Halliburton has a lot of patents on H2S stuff.

Acid corrosion inhibitors (ACI) are used to prevent the acid from reacting with the transport equipment and the well tubulars. They are designed to make a package to put in our acid, but can't be completely soluble in acid (need it to be dispersible); otherwise it won't get on tubular. ACI's are film formers, they move to the surface of the acid to stick to the metal. Most inhibitors don't stick as temperature increases, therefore intensifiers are needed to plate out acid onto the metal.

Dispersants are used to keep one phase, product or material dispersed within another one. Paraffins and asphaltenes can be dispersed. Hydrocarbons can be dispersed in water or acid base fracturing fluids, and chemicals can be dispersed to prevent their separation when added to a base fluid.

Emulsifiers are designed to put a discontinuous phase inside a continuous outer phase. You can put water droplet or acid droplet inside oil and vice versa. Emulsifiers are used in acidizing for two primary purposes. First, they are used to put the hydrocarbon phase on the outside so it will come in contact with the limestone first and then remove heavy hydrocarbon deposits on the matrix. Second, they create viscosity for acid fracturing so one can achieve greater fracture widths thereby etching a wider fracture. One emulsion we use all the time is foam; nitrogen bubbles with the water phase on the outside.

Stabilizing fines in place or removing them from the formation can aid in fines control. The choice of fines control is based on the origin of the particles. If the fines are created out in the matrix, then you want to leave them where they are so they do not decrease permeability. If they are created within the fracture, then you want to disperse them and flow them out of the formation. During fracture, anionic or nonionic, after they acid is spent, you want it to be cationic to grab onto the fines and flow out of the well.

Fines migration additives are patented organosilanes that bond silica fines together to slow or prevent fines migration, especially in high rate wells and where water breakthrough occurs.

Fluid loss additives are used to prevent fluid from leaking into the matrix from the fracture and to help in the prevention of wormhole growth. The material is usually a solid or liquid, but foams also help provide leak-off control. If you're using a frac fluid that doesn't have a lot of viscosity, you can use a solid fluid-loss additive (FLA) to get the leakoff control. You can use hydrocarbon dispersion for fluid loss control. For really clean fluids, use a liquid FLA. Use foams for any application

Foam stabilizers are typically the polymers used in providing viscosity. Lower molecular weight polymers can be used for this application. Typically, foam stabilizers are required in higher temperature applications.

Foamers are used in acidizing to help reduce the hydrostatic head caused which in turn reduces load recovery time and on occasion, creates stiff foams for fracturing. Hydrostatic head is caused by minimizing volume of liquid and the load recovery time is due to energy. Stiff foams are typically used to create fracture width and length by providing viscosity and leak-off control when the fractures provided by gelled acid would create greater width than would be economical. A typical foam would have a 10 minute half-life. A stiff foam would have a minimum of 70 minute half-life.

Friction reducers are used when pump rates are required that would cause the fluid to be in turbulent flow, resulting in high friction pressure and higher horsepower. Friction reducers extend the fluid velocity before reaching that transition. High molecular weight polymers are made for this application. Several polymer types and charges are available to match particular job requirements. These polymers allow for higher pump rates at the same pressure or lower horsepower at the same rate. If using a high density clear brine (mainly CaCl and CaBr) the friction reducers will have little effect. The Ca reacts with the polymers and causes the structure to coil into a ball instead of extend like limbs of a tree.

Gellants are used to viscosify the base fluid. Water gellants are typically guar, guar derivatives and synthetics. These base fluids are used because of proppant transport and leak-off control. Friction reducers also become gellants as the loading is increased. Gellants are used in acid fracturing to provide viscosity and leak-off control. Wider fractures can be created to allow more acid to be spent in place, which yields greater etched fracture conductivity. Leak-off control helps to minimize wormhole growth and keeps more of the live acid in the fracture.

Mutual solvents are chemcials that are soluble in hydrocarbons, acid and water. The primary example used in the oilfield is EGMBE (EthyleneGlycolMonoButylEther). It is also called Dowanol EB by Dow Chemical and Butyl Cellosolve by Exxon. These products are used as non-emulsifiers and demulisfiers as well as penetration aids. Any chemicals that are soluble in both an aqueous phase and a hydrocarbon phase is known as a mutual solvent.

Non-emulsifiers (or demulsifiers). Non-emulsifiers prevent the formation of emulsions between treatment fluids and reservoir fluids. The particular non-emulsifying agents (NEA) for the treatment have to be effective with live acid, spent acid, reservoir fluids and formation fines. The catch is that an ounce of prevention is worth a pound of cure.

Oil gel breakers are used to reduce the viscosity of gelled oil after the proppant has been put in place, then to recover the treatment fluid. Any additives that will change the pH.

Oil gellants are used to increase the viscosity of hydrocarbons, allowing proppant transport and placement while improving leak-off control. The most commonly used oil gellants are phosphate esters.

The most common oil crosslinkers are aluminum and iron. These trivalent metals tie the phosphate esters together to provide significant increase in fluid viscosity.

Paraffin solvents are used to remove existing deposits. Solvents are generally used with acid/oil clean-out or hot oil treatment. Inhibitors can be used in the prepad of a fracturing treatment. Paraffin solvents solubilize deposits. There are also inhibitors available to aid in the prevention of those deposits. Usually use xylene, toluene, diesel or kerosene.

Scale control products dissolve scales, and some products will inhibit the deposition of most scale. Effective life of the treatment is a function of placement technique. One of the things good for calcium and magnesium scales is EDTA, as long as the scale is not barium sulfate. Some of the polyacrylates are good scale inhibitors. They work by preventing agglomeration.

Silt suspenders are used to carry the HCI insoluble debris left behind during the acidizing process back to the surface so they are not deposited in the formation. If the fines are created out in the matrix, then leave them where they are so they don't decrease permeability. If they are created within the fracture, then you want to disperse them and flow them out of the formation. During fracture anionic or nonionic, after the acid is spent, you want it to be cationic to grab onto the fines and flow out of the well.

Solvents include: solvents, mutual solvents, micellar solvents and surfactants that provide greater efficiency. Typically people are thinking of toluene, xylene and EGMBE.

Surface tension reducers and interfacial tension reducers are used for increased penetration and more rapid return of the treatment fluid.

Surfactant really means surface active agent. Normally when we use the term surfactant, we mean a surface tension reducer or flowback additive. Surface active molecules that do not have properties listed under other specific names, e.g. foamers, de-mulsifiers, emulsifiers, mutual solvents, surface tension reducers and micellar additives will be listed here. This also includes acid gelling surfactants and amphoteric additives.

Water crosslinkers are used to tie large molecules together to yield huge viscosity increases above the base gel. The most common ones are boron, titanium, zirconium and aluminum. Boron is best when you can use it. Zirconium is not worm-proof, too finicky (below ph 3, instant crosslink, 3-5 delayed crosslink, above 5.3 you can't crosslink. You could crosslink titanium at high and low ph, perfect transport system (problem is , there are more goobers left with the titanium). Once you think aluminum is good enough, the aluminum would more or less break out. But you could use a two-part system with aluminum and blends with titanium and zirconium.

Water gel breakers are used to break the viscosity of the fracturing fluid after the proppant is in place. This is normally done with enzymes at the lower temperatures and oxidizers at elevated temperatures. The challenge has been adding sufficient breakers to provide a complete break while being able to place the proppant before breaking begins.

Acid

The two most utilized acids in hydraulic fracturing are hydrochloric and hydrofluoric. Hydrochloric acid (HCl) is used to dissolve most scales, including but not limited to: iron sulfide, iron oxide, and all carbonates (i.e. limestone, dolomite). It can also be used to dissolve hematite. The most important thing to remember when trying to dissolve hematite is that you cannot use an inhibitor package in the acid because the inhibitor will plate out on the hematite, thus not allowing the HCl to dissolve the hematite. Barium sulfate cannot be dissolved with HCl, it has to be mechanically taken off the wellbore either by a sonic tool, mill or casing scraper. Other typical applications of HCl are: performation cleanup, spearhead, fracturing and matrix acidizing. Matrix acidizing is designed to remove damage from the wellbore and within the formation. The key to executing this technique is to pump the acid at a bottomhole pressure less than the fracture gradient. This should allow the acid to flow radially out from the wellbore, thereby reacting with damage-causing foreign materials and the formation. Acid fracturing is used to create a fracture in the formation and aid in increased fracture conductivity. This is best utilized in limestone formation (with HCl) and to some degree dolomite. The acid etches the formation which creates wormholes/conductive channels. The length of the conductive fracture can be calculated with the leaf-off rate and acid reaction rate. This technique cannot be used with HF in a sandstone formation. The reaction rate is too slow.

Acid wash/Perforation wash is used to help remove damage in the producing interval, perforation tunnels and the near-wellbore area. Coiled tubing is the preferred execution with this treatment where acid can be placed at the specified perforations/depth. Acid soak is used to remove damage (i.e. scale) from the tubing and/or casing in a producing interval. The acid is allowed to sit and then flowed back.

Hydrofluoric acid (HF) is typically used in conjunction with HCl to make mud acid. What the hydrofluoric does is dissolve any mud debris left in the wellbore (i.e. bentonite, kaolinite and other fines found in drilling mud) and silicates while the HCl works on the iron oxides and other dissolvable materials. Hydrofluoric or mud acid should not be used in any formations with limestone because the calcium detaches and forms goobers by attaching to the HF and can block pore throats and perforations as well as remain in the wellbore.

Fluid Systems

Depending on reservoir characteristic and intended fracture zone will aid in determining the fluids to be utilized in the frac process. Here are some typical fluid systems with their advantages, disadvantages and typical formations to be utilized in.

Cross-linked fluids are a highly viscous fluid (usually guar-based gel) with a cross-linking agent (typically borate or zirconate). The advantage of cross-linked fluids is that they have increased viscosity. This viscosity in turns gives us better frac width, more efficient proppant transport, allows us to pump more proppant, and works as a great leak-off control. The fluid stays in the fracture instead of “leaking-out” into formation. The main disadvantage is that it costs more than slickwater fracs. Also, if the breaker schedule is not performed correctly, un-broken gel can be left on the formation; therefore decreasing productivity. Typical formations to be used in are: shales, tight sands and consolidated sandstones.

Foam is an emulsion with the gas (nitrogen, carbon dioxide or binary) as the discontinuous phase and a viscous fluid as the continuous phase. A foaming agent is also needed to generate foam. Stiff foam is when there is a 70 minute half-life or greater. The main advantage of foam is that it minimizes water contact (less formation damage in clay-sensitive zones). It aids in increasing the drive energy of the zone. There is also great leak-off control and a stiff foam can almost be a perfect proppant transport. The disadvantage with foam is that you lose hydrostatic head; therefore, you will have higher pump pressures. You have to manipulate concentrations at blender to what they will be downhole. Typical formations to be used in are: low bottom-hole pressure formations (low fracture gradient) and clay-sensitive zones.

Linear gel is a viscous fluid, typically a guar-based gel (Guar, HPG and CMHPG). The main advantage is that the viscosity gives us better frac width, more efficient proppant transport, and allows us to pump more proppant. Its main disadvantage is that it does not have the great leak-off and proppant transport properties like cross-linked gel systems. It doesn’t give as good of frac width or proppant transport as cross-linked gel and it costs more than slickwater fracs. Typical formations to be used in are: fractured zones where you have proppant pack from the bottom down, formations with either small natural fractures or high permeability (permeability that is high enough where cross-linked fluids will leak-off).

Gelled carbon dioxide is liquid carbon dioxide with a viscosifying agent. An advantage is that the viscosity gives us better frac width, more efficient proppant transport, and allows us to pump more proppant. The disadvantage is that you can’t get enough proppant into the container to do an effective frac job. Typical formations to be used in are: shales, high clay-content formations and water-sensitive zones.

Slickwater is originally a trademarked name created by DOW Well. It is a fluid with a friction-reducing agent. This can either be a true friction reducer or gel can be used. The trick is to use lots of water and lots of rate. The main advantage of slickwater is that it is cheaper than gel. In high naturally-fractured zones, the cross-linked gel system does not buy anything. The main disadvantage is that you don't get the proppant transport capabilities as you do with a linear gel or cross-linked gel system. The typical formation to be used in is a high naturally-fractured zone.

Proppant

Proppant is used in the fracturing process to allow for increased productivity of the well. You have made this fracture and now you need to be able to keep this fracture propped. Proppant selection is primarily based on the closure stress of the formation. The closure stress will affect the fracture conductivity of the proppant selected. There are a variety of proppants to accommodate all types of formation environments. There are regular sands (Ottawa and Brady), intermediate strength proppants, high strength proppants, ceramics and resin-coated proppants. Proppants also come in various mesh sizes as well and have a direct affect to the fracture conductivity.

Closure stress is the effective stress on the proppant pack, i.e. the total stress closing the fracture less the fluid pressure in the fracture (usually taken as the BHFP). The deeper the well, the higher the closure stress (applicable in most applications). In higher stress environments you need to find a proppant that can handle the stress and still give acceptable permeability/fracture conductivity.

Typically, a larger proppant size will result in greater permeability at lower closure stress. As the closure stress increases, the effect of particle size becomes less due to increased crushing of the larger proppant size. Although a large proppant size might give more conductivity, it also requires a larger fracture width to enable it to be effectively transported without "bridging out". A "bridge out" condition is said to exist when proppant is prevented from being carried further down the fracture. Typical width and proppant size diameters where this will occur is if the maximum proppant particle size is greater than one-half the fracture width.

The proppant concentration refers to the mass of proppant per unit area of fracture placed by the treatment (typically laboratory-tested as 2 lb/ft2). In our design we show it as pounds of sand per gallon of fluid (ppg). The higher the concentration, the higher the fracture conductivity. High permeability fracturing where fracture conductivity is of primary concern will seek a higher proppant concentration.

Fracturing of deeper formations requires the use of stronger proppant materials. There are now ceramic proppants and bauxite that are applicable for high pressure environments. In formations where sand sloughing occurs, resin-coated proppants may be applicable.

DESIGN

Now that we have a basis for how a formation to fracture is identified and the materials used, we can begin to discuss how a design can be prepared. We have different "stages" within the fracture treatment. Typically, the initial fluid pumped into the reservoir (either through perforations, holes from sliding sleeves or open hole) is designated as "pad". This initial "pad" aids in the initiation of the fracture before we pump the proppant-laiden fluid called "slurry". The slurry is what also dictates fracture geometry and the proppant within it allows the created fracture to stay open and produce. The well will dictate what to use for your design. Here are some typical rules of thumb from past experience and other methods for job design.

Basic Designs

It you have a consolidated sandstone and it is not high naturally-fractured and it is on 160 acre spacing or greater use:
1) at least a 25 ppg gel
2) 2000 gals of fluid per ft of gross frac height (If in a horizontal well, use 200-500 gals/ft)
3) use ~ 22% fluid for pad, distribute the rest with 1,2,3 and 4 ppg fluid (less flush volume)
If you have 40 acre spacing use 1000 gals of fluid per ft of gross frac height

If you have a high naturally-fractured zone use:
1) slickwater fluid
2) 2000 gals of fluid per ft of gross frac height (If in a horizontal well, use 200- 500 gals/ft)
3) use ~ 22% fluid for pad, use rest with .25 ppg sand (less flush volume)

Some people do Keel fracs. This is where you use 4200 gals/ft. You pump for a long, shut down and immediately flow the well back for an hr, then you repeat the process. The theory is that you're creating a new fracture to flow in. If you use path of least resistance (which you should) then this method does not make sense to use.

It you have a really bad shale problem or a highly water-sensitive zone, gelled diesel is probably the best treatment. Otherwise use water with a lot of clay stabilizer in it. For shale use:
1) one of the aforementioned fluids
2) 2000 gals of fluid per ft of gross frac height (If in a horizontal well, use a max of 500 gals/ft)
3) use ~ 22% fluid for pad, distribute the rest with 1,2 and 3 ppg fluid (less flush volume)

If you have a dolomite or limestone, use an acid. This volume is dependent on the feet you want to get out into the zone. Typically, use 1000 gallons of gelled acid per foot for a 10-20 ft zone and 40-acre spacing. If your acre spacing is ≥160 acres, use 2000 gals of gelled acid per ft.

If the zone is a low-pressured zone (i.e. frac gradient < .433 psi/ft) then the design will have to use foam. Stiff foam with a 75 Quality Downhole is ideal for proppant transport. Try to avoid using CO2 for a foam or a binary system. The problem is you don't know exactly when the CO2 changes phases downhole from a liquid to a gas.

Pressures and Stresses

There are additional parameters that affect the treatment design such as pressure and in-situ stresses. There are several pressure calculations in fracturing. As with all fluids flowing through any media, there is friction associated with the fluid with respect to the media and flow rate. Two of the most important calculated friction pressures are that with respect to the tubulars and the perforations. To calculate friction pressures in tubulars, you need to either have previous field data for the fluid or lab-tested data. Since most fracturing fluids are power law fluids, you can't use moody friction charts to calculate friction pressures. To calculate perforation friction (Pperf) you need to know flow rate (Q) in bbl/min, fluid density (ρ) in lb/gal, number of perforations (#perf), peforation diameter (Dperf) in inches, and discharge coefficient (Cd). For the discharge coefficient, use 0.60 for either new perforations or perforations with jagged edges. After flowing fluid through the perforations, you can use 0.80 as the coefficient. To calculate Pperf use the following equation:

$$\text{Pperf} = .2369 * \{[Q^2 * \rho] / [\ \#\text{perf}^2 * \text{Dperf}^4 * \text{Cd}^2]\}$$

Hydrostatic pressure (Phyd) is the pressure in psig exerted by a column of fluid with respect to the true vertical depth (TVD) in footage. To calculate the hydrostatic pressure, use the following equation:

$$\text{Phyd} = \rho f * .052 * \text{TVD}$$

When dealing with fluids, density (ρ) is a critical component. It is used to aid in the calculation of pressures. There are typically two forms density is presented. The first is in a force-volume ratio, usually in pounds per gallon (lb/gal). Another is in specific gravity (γ) which is a fluid's density ratio with respect to water. At standard conditions (14.72 psia and 60^0F), water has a density of ~8.337 lb/gal. To calculate density of a fluid (ρf) in lb/gal with respect to specific gravity (γf) use the following equation:

$$\rho f = \gamma f * 8.337$$

Oil is usually represented in ^{0}API. For reference, water has an API value of 10, therefore all oil has a value greater than 10^{o}API. The higher the API units, the lower the specific gravity, which means lighter crude.To calculate oil density (ρo) in lb/gal with API units use the following equation:

$\rho o = \{141.5 / (131.5 + {}^0API)\} * 8.337$

With regards to in-situ stresses, at shallow depths (~1500 ft) the minimum stress is the overburden depth stress. Since the fracture will propagate perpendicular to the minimum principal stress it can be inferred that hydraulic fractures induced in shallow formations will be horizontal in nature. At greater depths (>1500 ft) the minimum stress will be one of the horizontal principal stresses. Fractures at these depths will tend to be vertical. It's important to realize that this is a generalization. There are several studies showing various orientations. What are the stresses at depth? The vertical stress (σv) or overburden is the weight of the overlaying formations. Note, by convention, compressive stress is taken as positive and tensile stress is negative (we look at these differently in coiled tubing and snubbing, i.e. tension as positive and compression as negative). In practice, vertical stress is determined from integrating the density log from surface to the depth at interest. Typically this is in the range of 1.0-1.1 psi/ft. The problem is, this value is the total vertical stress. To find the effective vertical stress (σv'), we simply subtract the pore pressure (pr) at depth from σv. This value is the portion of the overburden being supported by the rock matrix. The problem with using the calculation above to find effective vertical stress is that it assumes no flow through the formation. To take into account fluid movement through the formation we use the poreoclastic constant, also known as Biot's constant (α), this describes the efficiency of the fluid pressure in counteracting the total applied stress. To calculate α we need to know the undrained bulk modulus (K) in psi and the bulk modulus of the matrix material (Km) in psi. Use the following equation:

$\alpha = 1 - (K/Km)$

Typically, for petroleum reservoirs, α is 0.7. To apply this in calculating σv' use the following equation:

$\sigma v' = \sigma v - (\alpha * pr)$

The magnitude of the effective horizontal stress can range from one-third to three times the effective overburden stress. Typically, a state of normal stress exists in the ground where both the maximum and minimum horizontal stresses are less than the vertical stress (i.e. σH-min < σH-max < σv). The most common model used for calculating the stress with depth is the plane strain model. For the constraint of zero strain at the limits of x and y, the induced horizontal stress may be calculated from poisson's ratio (ν), overburden and pore pressure:

$\sigma H = \{[\nu/(1-\nu)]*(\sigma v - \alpha * pr)\} + \alpha * pr$

It can also be represented in respect to effective vertical stress:

$\sigma H = \{[\nu/(1-\nu)]*(\sigma v')\} + \alpha * pr$

The two aforementioned calculations refer to the minimum horizontal stress. Typically σHmin is 0.6-0.7 times that of the overburden. Note, there can also be an additional tectonic component in areas of regional or localized movement. Regionally this can occur in an overthrust belt or anywhere there is tectonic activity. There are more complex models to calculate the horizontal stresses, but the industry standard is the aforementioned calculation.

Design Evaluation

Now that we have discussed the basics of making a frac job design, there are several ways to do a pre-job evaluation to insure the induced fracture geometry stays in the desired formation. There are a lot of complex calculations that go into calculating fracture growth/geometry. There are three categories that fracture modeling are placed: 2D Models, Pseudo-3D Models and 3D Models. Since there is such a huge amount of data computations, pseudo-3D has become the workhorse in the industry for fracture modeling.

Two-dimensional models of fracturing were developed in the 1950's & 1960'sbecause the fracture extension due to fluid injection could be solved using closed from analystical solutions. This is possible if you assume one of the fracture dimensions is constant – the fracture height. Two mutually exclusive fracture models were developed and are used in the industry. The first, referred to as KGD model (Kristianovich, Geertsma & De Klerk model) has

application where the fracture height is significantly greater than the fracture width. The width of the fracture at a given distance from the wellbore is a constant for all values of height. Such a situation will only exist if there is slip at the top and bottom of the fracture although, as stated above, the model will have application where the height of the facture is significantly greater than the length. The cross section in the horizontal plane is approximately elliptical.
The KGD model expresses the fracture width (w) as a function of the fracture length (X_f), fluid pressure (p) and Young's Modulus (E):
$w \propto (X_f * p) / E$
The pressure in the fracture is given as :
$p \propto \{(E^3 * \mu * Q * X_f)^{1/4}\} / h_f$
What this tells us is that the fluid pressure in the fracture will decrease as the fracture grows longer and higher.

The other two-dimension model is the Perkin and Kern (PKN) model gives width as the below function:
$w \propto (h_f * p) / E$
The pressure in the fracture is given as :
$p \propto \{(E^3 * \mu * Q)^{1/4}\} / (h_f^{1/2} * X_f^{1/2})$
This tells us the fluid pressure in the fracture will decrease as height increases, but increases as it grows longer.

In the pseudo-3D model, the fracture is divided into a number of discrete elements to solve the governing equations of elasticity (which define the crack opening as a function of the fluid pressure), equations of fluid flow in the fracture (which define the pressure gradient in the fluid) and equations of rock failure (which define the extension of the fracture up). The four most widely-used programs are: FracPro (Pinnacle Technologies), StimPlan (NSI), MFRAC (Meyers), and Gohfer (Stimlab). Each program has differences in the simulations. You need to be aware of these differences when utilizing the modeling software to accurately analyze your formation/reservoir. Just like the typical saying, "Garbage In – Garbage Out." The model is only as good as the data that is input. It is not an exact science when delegating the dynamics of the frac design, but it definitely helps when analyzing a design to see if it can be completed. The most important way to analyze a frac design, is to keep track of historical designs and to refine accordingly. You can learn a lot from past mistakes or successes. Then, by correlating treatment designs, and productivity increase, design refinement can be attained.

JOB PREPARATION AND EXECUTION

A design has now been formulated, now we will discuss what goes into the preparation of the frac job. We will talk about the equipment selection, quality control and safety precautions that go into a frac job. Then, we will conclude with what to look while executing the frac job.

Equipment Selection

We now have a job design in place, now we need to make sure that we have the proper equipment to execute the job. The first piece of equipment to look at is the fracturing pump to pump the fluid rate designed. When determining the pump selection you need to know the maximum treating pressure. To calculate this, you need to know the hydrostatic pressure (Phyd), perforation friction pressure (Pperf), pipe friction pressure (Pfric) and bottomhole fracture pressure (BHFP). The bottomhole fracture pressure is the point at which the rock fractures. To calculate this number you need the true vertical depth and the fracture gradient (FG) in psi/ft.
BHFP = FG x TVD
From this, we can now calculate surface treating pressure:
Psurf = BHFP – Phyd + Pperf + Pfric
The other limiting factor for maximum treating pressure is in reference to the wellbore. Whatever the maximum allowable pressure is for the tubulars needs to also be considered. To calculate the horsepower (HHP) required you need the maximum treating pressure (Psurfmax) and the maximum pump rate (Qmax).
HHP = (Psurfmax * Qmax) / 40.8

So, typically the pumps used (especially in horizontal completions) are 2250 HHP quinitplex pumps. To assure enough HHP is on location to complete the job, a typical rule of thumb is 1500 HHP is useable. Therefore, if a job requires ~6000 HHP, you should have at least four pumps. Even though you could get away with three, it is good to have backup and to compensate for pump inefficiencies. Other equipment to consider while preparing for a frac job are: hydration unit, blender, chemical additive unit, high pressure manifold. For the above equipment, make sure that they can withstand the flow rate and the pressure rating.

Quality Control

Now that the equipment has been selected, we need to make sure that the materials are going to withstand downhole conditions (pressure and temperature). Therefore, before the job is performed, lab testing should be done to make sure that the chemicals are compatible with the oil in formation and can withstand the bottomhole temperature. This is really important with regards to crosslinked gel jobs because variances in water (high sulfates and pH) can cause extreme viscosity reduction. Once the chemistry has been checked for compatibility, the water on location needs to be checked to ensure the chemicals are still compatible, since lab tests can vary from conditions on location. Another thing that needs to be checked is the sand. Sand sieve analysis should be used to ensure it is the correct sand size for the job. In tighter formations, a sand size that is greater in volume, such as 20/40 or 16/30, might not be able to enter the induced fracture. Therefore, knowing the sand that is going to be pumped is crucial.

Most importantly, before commencing a job, ensure that the equipment is in working condition. Make sure that the equipment is up to date on maintenance. Ensure that the surface equipment can withstand the anticipated maximum surface treating pressure. When dealing with a well, also be aware of the entire design of the wellbore and all jewelry (i.e. packers, hangers, etc) within it. This will aid in volumetrics to know where fluid and proppant are in the wellbore and aid in any diagnostics.

Safety

Before performing the frac job, a safety meeting should be conducted to discuss any potential safety hazards. Always have the crew make sure they wear the proper personal protective equipment in the appropriate area. Also, test all equipment before job initiation. This includes doing pressure tests, to ensure there will be no leaks during the job.

Job Execution

Now that we have checked quality control, equipment function and safety, it is time to complete the frac job. One of the main things we look at is the treating pressure while performing the frac. One plot we use to measure pressure is the Nolte plot. The Nolte plot is a log-log plot of either bottom-hole pressure or net pressure versus time. The purpose of the Nolte plot is to help determine what is happening at the perforations during the stimulation treatment. If the Nolte plot shows a sizeable decline or a sharp decline in net pressure over time there is either one of two situations happening.

1) This is a naturally fractured zone and all of your fluid is just filling the fractures and not creating a new one
2) You are fracturing outside of the zone that you are in (frac height).

If the Nolte plot shows a sharp increase in net pressure over time you are “screening out” in the zone which means the fracture has been filled with proppant and you are no longer creating an increase in the fracture geometry. If there is a significant delay to what the engineer sees in an increase in pressure to what the treater is seeing for an increase in net pressure, this means that the screenout is occurring farther in the fracture. The only way to overcome screening out is to immediately increase rate to see if you can force the proppant into the formation. If the Nolte plot shows either a gradual increase or a steady net pressure, this indicates that you are not breaking out of the boundaries and are creating fracture length (along with width). This is what you want to see while doing the stimulation treatment. Make sure that the treatment doesn’t exceed the maximum allowable treating pressure.

Another thing to look at is to make sure the sand concentration and flow rates are at the correct value. Typically, a radioactive densometer is used to measure the sand concentration by measuring density fluctuations and flow meters are used to check flow rate. You can verify the sand concentration (Pconc) in lb/gal by back calculating it from the absolute volume of the sand (AV) in gal/lb, clean rate (Qc) in bbl/min and slurry rate (Qs) in bbl/min.

$Qs = Qc \times \{ 1 + (Pconc \times AV) \}$

Therefore,

$Pconc = \{(Qs/Qc) – 1\} / AV$

Ensuring the sand concentration is where it is designed is crucial. The formation's characteristics (stress, porosity, permeability, etc) can limit the concentration a formation can allow before screening out. In tighter formations, if you start ramping sand concentrations in intervals over 1 ppg, you have a tendency to screenout. Also, the maximum allowable concentration may only be 2-3 ppg. An example where this can be prudent is if an accidental increase in sand concentration occurs. This can happen if the sand augers are hit too high into gear or if there's miscommunication between the treater and the blender operator. If not noticed, this can cause a sand slug to hit the perforations and cause a screenout. Another reason to keep in constant view, is if you go for an extended and you do screenout, you might have to use either coiled tubing or regular tubing (stick pipe) to clean the

Keeping track of chemicals and chemical concentrations is another vital operation. For instance, if in a tight formation, you need viscosity to aid in near-wellbore fracture-width growth. This means you have to use a crosslinked fluid system to gain viscosity. If the chemicals that are supposed to be pumped are not at the correct concentrations, you can get a thin fluid (low viscosity) and potentially screenout the formation. We see with quality control that the fluid needs to be monitored (particularly at the blender) to make sure there is a viscous fluid forming. Another example of knowing chemistry is with regards to clay-rich formations. If you need to pump a clay stabilizer and it is not getting pumped, you are highly likely to see the water swell/hydrate the clays and cause a screenout as the pore throats cause restriction in the formation. If chemical tracking is not shown by chemical loading (Conadd, gals/1000 gals of fluid or lbs/1000 gals) you can calculate the chemical concentration by using the clean rate (Qc) in barrels per min to calculate the additive flow rate (Qa) in either gallons per minute or pound per minute.

$Qa = Qc * Conadd * .042$

This way, you can also keep track of the correct chemical injection rate if Qa is given during the treatment and not Conadd.

Volumes are also important to know. Internal capacity(Capint) is critical when calculating flush volume for treatment design. You need to know the length of the tubular (Ltub) being analyzed in feet and the internal diameter (ID) of the tubular in inches. To calculate (Capint) in barrels (bbls) use the following equation:

$Capint = (ID^2 / 1029.4) * Ltub$

Sometimes displacements are used in various applications. For displacements, outside diameter (OD) of the tubular in inches, ID and length are needed.For external displacement (Dispext)in bbls, use the following equation:

$Dispext = (OD^2 / 1029.4) * Ltub$

For incremental displacement (Dispinc) use the following equation:

$Dispinc = \{(OD^2 – ID^2) / 1029.4\} * Ltub$

Flush volume is critical to know because a significant overflush can cause proppant to go further into the fracture and decrease near-wellbore conductivity. Thus, effectively decreasing production. The typical reason overflush is used is to ensure that there is no remaining proppant left within the wellbore (especially in horizontal wellbores) which can cause wireline or other perforating methods to fail. The same can also be said in the sliding sleeves of wellbores, where additional sand near the seat of the sleeve can prevent the ball from fully closing the port and opening the sleeve body.

CONCLUSION

There are several factors that go into a frac job. You have to understand the reservoir and its characteristics. By having a base knowledge of the materials and equipment used this can help prepare oneself to do a frac job. Knowing calculations used during the job and keeping involved during a frac will help in aiding a successful job completion.

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