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Dynamic Fluid Pulsation: A Novel Approach to Reservoir Stimulation Improves Post-Stimulation Gains

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Abstract

One of the major challenges to maximizing recovery of reserves is that every oil or gas reservoir rock is more or less heterogeneous at all scales (micro, mega, and pore) which leads to disproportionate production and injection outcomes. Generally, the higher the level of reservoir heterogeneity the more difficult it becomes to achieve maximum fluid distribution or conformance. Improving conformance in a non-homogenous material such as a hydrocarbon reservoir inherently means improving flow through lower permeability regions. Ideally, during a conventional well stimulation using a treatment fluid such as acid, we wish to move the fluid through the majority of the rock volume but the physical constraints of fluid flow negatively impact that ideal outcome.

Dynamic fluid pulse technology provides for high inertial fluid momentum which improves the flow efficiency of fluids injected into the wellbore, the near wellbore region, and the reservoir. The nature of fluid displacement energy ensures that pulsed fluid will penetrate the matrix proximal to where the tool is placed thus achieving enhanced fluid distribution. Prior to a stimulation operation a dynamic mathematical model associated with fluid pulse technology is employed to generate a precise well program (pumping schedule) to maximize the contact volume of the treatment fluid along the completed interval. Compared with conventional stimulation dynamic fluid pulsation has been demonstrated to bring significant financial benefits to well stimulation without impacting results including: reduced chemical costs; improved post-stimulation sustainability; and, better overall post-stimulation well performance as a greater volume of the completed interval hence matrix is contacted by the treatment fluids.

Introduction

It is well known that the purpose of well stimulation is to remove wellbore “damage” or “skin” to restore a well’s productivity or injectivity. It has been postulated that the depth of radial damage that

may occur in a formation can extend to 20 ft. (~6 m) and can emanate from drilling, completions, workovers, other stimulation procedures as well as production, water or gas injection, EOR activities, pressure changes in the reservoir, mobilizing solids, asphaltene, waxes, swelling clays etc.

Every oil reservoir rock is more or less heterogeneous at all scales of (micro, mega, and pore). Generally, the higher the level of reservoir heterogeneity the more difficult it becomes to achieve maximum fluid distribution or conformance. Improving conformance in a non-homogenous material such as an oilfield reservoir inherently means improving flow through lower permeability regions. Ideally, during a well stimulation using a treatment fluid such as acid, we wish to move the acid through the entire rock volume but the physical constraints of fluid flow negatively impact that ideal outcome. First, injecting a low-viscosity fluid (i.e., acid) into a higher viscosity fluid (i.e., oil) results in the formation of viscous instabilities ("fingering"). Second, because of heterogeneity fluid flow will concentrate in the higher permeability zones (i.e., the path of least resistance) leaving the lower permeability zones virtually unswept by the injected fluid.

Stimulations are accomplished through a variety of techniques but most commonly chemicals are injected to treat existing conditions in the reservoir with an attempt to achieve better well outcomes. In carbonates, matrix acidizing with HCl is widely used to enhance permeability by creating "wormholes." In sandstones mud acids (HCl and/or HF) may be used to dissolve damage in the near wellbore region. In heavy oils, diluents (e.g. naphtha), dissolving agents (e.g. xylene) or other fluid constituents are used for a variety of reasons to enhance well productivity.

The use of chemicals in treating wells has greater efficacy when the fluids are placed along the completed interval with both maximum distribution and depth of penetration. Conventional steady-state injection methodologies as well as jetting tools, acoustic tools or fluidic oscillators with chemicals are limited in their effectiveness to achieve these attributes because those approaches do not have the capacity to overcome difficult reservoir conditions such as low permeability streaks, very viscous oil, and sometimes even worse, the presence of fractures, fissures, and thief zones. Such formation characteristics reduce treatment effectiveness as the chemicals merely follow the pre-established flow pathways. To combat preferential flow often mechanical packer isolation or chemical diverts are used to try to "force" treatment fluids into lower permeability flow zones. The latter may lead to further damage in the reservoir while the former has limited effectiveness in the open hole or completed intervals.

Dynamic fluid pulsing works effectively as a reservoir stimulation method primarily because it forces injection fluids outside the path of least resistance through a dispersion process. The waveform associated with a purpose-created fluid pulse, Figure 1, has a saw-tooth shape providing several benefits over other established stimulation methods. The sharp change in pressure (amplitude) in a very short period of time (rise time) directs flow radially into the formation; inducing fluid dispersion which includes deeper penetration and more uniform distribution of treatment fluids and has shown to overcome the difficult reservoir conditions previously mentioned. However, it is important to note that the difference in pressure is only a small piece of the puzzle; how the change in pressure is created is a differentiating characteristic of dynamic fluid pulsing versus acoustic, sonic, and jetting approaches and ultimately the reason for fluid dispersion into the reservoir.

Dynamic fluid pulses are highly effective as a fluid placement technique because:

- The pressure gradients involved in normal flow of fluids through the reservoir are generally very small when viewed at the pore scale, yet small differences between these pressure gradients determine the path of least resistance that governs normal flow of fluids. Typical amplitudes associated with dynamic fluid pulsing alter local pressure gradients and completely dwarf those associated with normal fluid flow in the reservoir causing accurate fluid placement throughout the

entire interval even through zones of high resistence to flow;

- Dynamic fluid pulsing forces fluid into the spaces between the grains of rock or sand, causing a very small, and completely harmless, expansion and contraction of this pore space and thereby giving rise to an improved dynamic permeability;
- The increase in dynamic permeability and the fluid displacement pulses allow fluids to travel more uniformly through the reservoir; and,
- Typical radius of influence (as penetration depth depends on volume of fluid injected at a single point) of dynamically placed treatment fluid is ~ ≥3 ft (~1 m).

History of Dynamic Fluid Pulsing

Dynamic fluid pulsing is not new to the oil and gas industry. Its origins date back to the late 1990's and the technique has been subject of numerous Canadian academic engineering masters' degrees, a PhD degree (Samaroo, 1999; Wang, 1999; Zschuppe, 2001) as well as numerous patents on the process and tools associated with the technique. Furthermore, dynamic fluid pulsing has been extensively used in waterflooding applications to improve sweep efficiency, reduce water cut, and improve estimate ultimate oil recovery (Avagnina et al., 2013; Avagnina et al., 2015). More recently an intensive effort has been made to move fluid pulsing technology from the longer-term applications of permanently installed tools to shorter-term applications such as coiled tubing (CT) matrix stimulation.

The phenomena of dynamic fluid pulsing and the benefits arising from its applications do not fall within the "conventional" view of porous media mechanics. The mechanics involved in the application of systematic dynamic fluid pulsing are not radical, yet industry accepted porous mechanics models cannot correctly account for the dynamic effects associated with its outcomes.

Scientists and engineers working in fluid flow have been taught that the steady-state Darcy flow paradigm ($q \propto \partial p/\partial \ell$), where gradient is a macroscopically defined quantity ($\partial p/\partial \ell = (p_1/p_2)/\ell$), is a sufficient theory for porous media flow over a wide range of conditions. Perhaps some inability to correctly predict flow rates or dispersion behavior in clays, shale's or fractured media is admitted, but otherwise Darcy theory is accepted uncritically.

Similarly, geophysicists working with porous media wave mechanics have been taught that Biot-Gassmann theory is sufficient to describe porous media wave propagation, given a wavelength much greater than the particle size.

Neither of these "fundamental" theories is complete, although each may be sufficient for practical purposes under certain restrictive conditions.

Dr. Tim Spanos, Professor Emeritus, the University of Alberta developed a rigorous theory of porous media mechanics which fully describes the dynamic fluid flow characteristics associated with dynamic fluid pulsing. The Spanos fluid flow theory is more thermodynamically sound than either Darcy theory for non-dynamic flow, or Biot-Gassmann theory for wave propagation (de la Cruz, 1985; Geilikman et al, 1992; Spanos, 2001; Spanos and Udey, 2017).

Darcy theory is a steady-state theory, and contains no inertial terms. Thus, when liquid or solid phase accelerations are important with respect to the system flow velocity, one may expect effects that cannot be quantitatively explained. This does not invalidate the Darcy paradigm within the restrictive conditions for which it was stipulated (i.e. no inertial effects). However, it does mean that Darcy theory is incapable of predicting or quantifying the effects of dynamic fluid pulsing.

The Biot-Gassmann theory of wave propagation in porous media is to wave mechanics what Darcy theory is to flow mechanics, yet Biot-Gassmann theory is based on a set of assumptions that have recently been shown to be inadequate. The two most important flaws are the following:

- Porosity is assumed to be a constant scalar quantity; and,

- The energy in a porous medium can be described by a single-valued function.

As noted, Darcy theory does not include inertial effects. For example, it is known to be inapplicable to flows involving turbulence where internal energy dissipation from inertial effects is important. During large amplitude excitation applied to test cells in laboratory experiments, inertial effects, sudden acceleration and deceleration of the pore fluid, dominate the flow regime. To overcome this limitation of Darcy flow theory, the Spanos flow theory includes inertial effects formulated at the correct scale from fundamental physical principles.

Similarly the theory of wave propagation in porous media developed by Spanos overcomes the limitations associated with the restrictive assumptions in the Biot-Gassmann theory. The basic characteristics of the theory include inertial mass coupling between the phases, porosity as a variable, energy dissipation because of phase compression, and rigorous incorporation of the dilatational behavior of all phases.

Porosity Variation during Dynamic Fluid Pulsing

It is well established that a major contributor to the ability of fluids to flow in the ground is the size of the pore spaces within rocks and soils: “porosity”. It is also well established that the greatest obstacle to overall fluid injection and fluid recovery is related to pore space size and how efficient fluids flow in interconnected pore pathways: "permeability". If pore space size and pore interconnectivity govern fluid flow when extracting a liquid such as the case in oil production then those same characteristics also govern how well a fluid can be injected and distributed into the ground. Hence, porosity and permeability control both fluid extraction and fluid injection.

Assume acid is going to be injected into a formation under constant pressure for the purpose of enhancing permeability. This is referred to as "steady-state or quasi-static injection". Nature has set up a system of pores and pore interconnectivity. This can be somewhat altered by processes such as fracturing or tectonic activity (earthquakes) but all things being equal it is a pre-determined system. Flow rate and the distribution of the acid injected into the rock or soil is dominated by that pre-determined system. The easiest explanation is the path of least resistance. It is difficult to alter the path of least resistance simply by increasing the pressure by which the liquid is injected. Furthermore, it is almost technically impractical for that acid to be distributed outside the path of least resistance. The term used in the oil industry referring to the efficacy of how injected liquid is distributed is "sweep efficiency". Why does the path of least resistance dominate? The answer is quite simple. Pore space size and pore interconnectivity remain the same throughout the entire process.

Now assume acid is going to be injected into the formation under constant pressure but an intermittent dynamic force is superimposed on that process. This is termed "dynamic enhancement" or "dynamic flow". The magnitude and duration of the dynamic force is calculable for every given rock or soil. Dynamic fluid pulsing intermittently changes both the size of the pore space and pore interconnectivity through the applied dynamic force. How is this accomplished? Dynamic fluid pulsing relies on the elastic properties of rocks and soils. When a dynamic fluid pulse is applied through the injected liquid it dilates the pore space through an elastic response. This in turn causes not only the pre-determined pore network to increase in size and interconnectivity but also opens up additional pore spaces to flow. Hence, dynamics governs how flow occurs because it overcomes the path of least resistance. The result is greater sweep efficiency. This represents a greater overall volume of the formation coming into contact with the acid.

As noted above the waveform associated with dynamic fluid pulsing and its properties are predicted by the physical theory that describes multiphase flow and seismic wave propagation in porous media. Within the constructs of the physical theory lay equations that allow for the calculation of porosity

changes as a function of pulse amplitude and formation depth. Figures 2 through 5 present base cases for magnitude of reversible porosity changes at an originating porosity value of 5% and 20% respectively. As shown porosity changes are quite negligible at a single pore space however when occurring simultaneously over millions of pores the net effect is large-scale dynamic flow which has the beneficial attributes of improved sweep and deeper fluid penetration.

Modeling a Dynamic Fluid Pulse Well Stimulation

To effectively plan a dynamic fluid pulse well stimulation a mathematical model of dispersion is required to compute the saturation profile of the injected treatment fluid for a given injection volume. In addition, the mathematical model allows for a comparison of fluid dispersion by dynamic pulsing versus the saturation profile of a conventional well stimulation based on static flow parameters. In the mathematical model it is assumed that conventional well stimulation is dominated by viscous fingering, hence an empirically based model for the viscous fingering curve has been implemented.

Theoretical derivations (Udey, 2009; Udey, 2012) and laboratory studies confirm that that dynamic fluid injection generates dispersion. Dispersion is the flow process where some of the injected fluid bypasses the in-situ fluid. The main feature of dispersion is that the speed of a given saturation point on a saturation profile moves at a constant speed.

In the dynamic flow model this dispersion curve is represented by a spline curve. Given this curve, the saturation profile of the injected treatment fluid for a given injected volume can be computed. The initial profile is a vertical line at a radius equal to the well radius $r = r_w$. Since the curve is a cubic spline, integration under the curve is used to determine the displaced pore volume.

As mentioned the shape of the dispersion curve is based on the speed of the saturation contours. Each saturation contour propagates as a wave. These waves increase in speed monotonically with decreasing water saturations, with the greatest changes in velocity occurring at very high and low water saturations. Permeability, viscosity, surface tension affect the magnitude of the velocities but do not change the general shape of the dispersion curve. Here the shape of the curve is caused by the passing porosity waves.

Volumetric sweep efficiency, E_v, associated with dynamic fluid pulsing is determined using the reference dispersion curves. From the model the dispersion curves have this same shape across a broad range of formation parameters and fluid pulse rates. Any variations in the shape due to variations in the formation parameters like porosity and permeability are quite small and for all well stimulation comparisions a theoretical dispersion curve based on porosity and permeability employed; and for these curves the computed value of E_v is approximately 40%.

In the mathematical model of dynamic fluid pulsing, the viscous fingering curve used for comparative purposes is an empirically based piecewise polynomial curve (Figure 6).

For a typical fluid displacement undergoing viscous fingering, 4 zones can be defined:

Zone 0: $r \in [r_w, r_o)$; *Zone* 1: $r \in [r_o, r_1)$; *Zone* 2: $r \in [r_1, r_2)$; *Zone* 3: $r \in [r_2, r_3]$

Zone 0 is the region next to the injection point $r = r_w$ where the injected fluid has completely displaced the in-situ fluid. The saturation profile is modelled as a flat profile with $S_i = max(S_i) = 1 - S_{wc}$ where the connate water saturation is S_{wc}.

Zone 1 is a transition zone where the saturation drops down from $max(S_i)$ to $S_i = E_v$ where E_v is the selected volumetric sweep efficiency of the viscous fingered displacement. In this zone the saturation profile is modelled by a Bezier cubic with zero slope at the beginning and end points. The cubic is designed to mimic the dispersion curve.

Zone 2 is the fully developed fingered zone. The curve is modelled as a flat profile with $S_i = E_v$.

Zone 3 is the transition zone from the fully developed fingered zone to the leading edge of the fingers. The curve is modelled by a Bezier cubic that drops from $S_i = E_v$ to $S_i = 0$. The curve has zero slope at the beginning with a slight 1.1 degree slope at the end.

In the mathematical model, the viscous fingering curve is specified by the properties of a layer (well radius, porosity, connate water saturation), the sweep efficiency of the viscous fingered displacement (typically 10% to 35%, shown here as 15%), and a reference volume per unit length of fluid V_O/h (default value is 0.5 *US gal/ft*). Initially, the volume of Zone 0 is zero, but can slowly increase. A logarithmic growth formula is employed in the model. Initially the volume of Zone 1 is 90% of the reference volume, while the remaining 10% is allocated to Zone 3. For a given volume per unit length V_i/h, the viscous fingering curve algorithm distributes the volume into the various zones. For large volumes, most of the volume is in Zone 2.

Although the algorithms associated with the mathematical model are too complex to discuss in detail here, it is much simpler than a finite difference, finite element, or finite volume simulation of viscous fingering. Nevertheless, the model captures the essential features of the average saturation profile of viscous finger dominated fluid displacement.

In the model E_v, for the static flow condition may vary from 10% to 35% (or more) depending on the thickness of the fingers and density of the fingers (i.e. the distance between fingers). For all comparisons E_v = 20% is used for comparative purposes. This choice represents the most commonly reported value in the literature and is consistent with results obtained in laboratory experiments.

Tools and Procedures

Dynamic fluid pulse stimulation is a two-step process. Step one is a wellbore cleaning process to remove any scale or flow impediments within the wellbore using a cavitation-based pulsing tool that creates a water hammering affect to remove detritus materials. Step two is the main treatment and employs a magnetic-based flow driven device that operates entirely on a pressure differential where the opening and closing of a downward shifting piston allows fluid to exit the tool at high acceleration.

Why a two-step process? While the pressure differential flow driven works effectively as a matrix stimulation method to force injection fluids outside of the path of least resistance and deep into the reservoir it is not well suited to scale and fill removal. This is because the energy content, or waveform, generated by the tool is that of a high-amplitude; low frequency saw-tooth wave. In contrast, devices that generate higher frequencies and lower amplitudes having a sinusoidal waveform are more conducent to the removal of scale, etc. Hence, the cavitation-based pulsing tool is used to remove detritus material from the wellbore and near wellbore region to prepare the well and formation for matrix stimulation via the pressure differential flow driven device.

The cavitation-based tool (Figure 7) deployed to prepare or clean a wellbore prior to matrix stimulation relies on a steady state turbulent flow of fluid entering the tool through an inlet pipe; moving to a large fluid chamber where it undergoes a sudden enlargement (Figure 8). The fluid flow in the corners of the chamber near the inlet is small, and consists of small eddies and vortices. A large shearing action and shear layer is induced by the difference in flow rate between the fluid in the chamber corners near the inlet and the fluid exiting the inlet. Consequently, vortex rings are created in the shear layer and travel from the inlet to the edge of the outlet pipe where it connects with the chamber. The collision of a vortex ring with this edge converts a large part of its energy into a wide range of pressure waves, i.e. the self-excited pressure oscillation. The remainder of the energy remains

with the flow and is split between the flow towards the chamber wall and the flow into the outlet pipe. The large pressure oscillations of the pressure waves cause the output flow to be interrupted and subsequently converted into an oscillating or pulsating jet of fluid producing the water hammer and cavitational vaporization effects.

When the cavitation-based cleaning tool is deployed in a well, the repeated pulsed water hammer effect and cavitational vaporization zones produced by the tools act on tubulars or enter the reservoir through the well perforations and impact the near well bore region. The strong oscillatory motions of the fluid in the near well bore zone are strongly coupled to deformations of the reservoir matrix in a complex non-linear manner. The net effect near the well bore is a strong agitation or "churning" effect—called the "Laundry Effect" (Figure 9) that breaks down sand bridges, loosens particles, and removes blockages from tubulars, perforations, liners, and pore throats (Escobar et al, 2014).

Operationally the cavitation-based cleaning tool has two operating modes: extended and retrieved (Figure 10). In the extended mode the tubulars and wellbore are subject to 360^0 of fluid flow through twelve fluid ports: 4 ports in the nose cone and 8 ports in the main body. The two flow structures are joined by a slider that is fully extended in its base condition allowing for all 12 ports to expel fluid. As the cleaning procedure continues all 12 ports will continue to expel fluid with strong oscillatory motions as the coiled tubing or jointed pipe ingresses into the wellbore. If a fluid blockage or "tag" is encountered the weight placed on the tool by the coiled tubing or jointed pipe will move the slider to the retrieved position. The retrieved position disengages flow in the main body and now all flow is directed downward through the 4 ports in the nose. As the waterhammer effect initiated by the cavitating action of the tool impacts the blockage a process referred to as, "cavitation erosion" occurs and erodes the blockage. As the blockage is removed the fluid pressure in the coiled tubing or jointed pipe begins the re-engage the slider until it is fully extended and all 12 ports are again expelling fluid. This process may repeat throughout a cleaning operation depending on the number of tags that are encountered.

Once stage 1, the preparation stage, is complete the coiled tubing is tripped out of the well and the pressure differential flow driven device (Figure 11) attached to the coiled tubing for the main treatment. Current versions of the magnetic-based flow driven device have differential pressures rated from 300 psi to 1,200 psi at flow rates up to 2.0 barrels of fluid per minute (bpm). A higher flow rate, 3 bpm tool sufficient to deliver a minimum 1,200 psi dynamic fluid pulse is currently under development.

Model Example

Figure 12 presents data representing model inputs for a vertical water injector in a sandstone reservoir having a range of porosity from 9.79% to 24.58% and a permeability range from 0.96 mD to 2,787mD.

With this data the dynamic fluid pulsing stimulation model was used to evaluate both the Radius of Influence ["ROI"] (Figure 13) versus measured depth as well as the Extra Pore Volume ["EPV"] (Figure 14) of the rock matrix that is in contact with the stimulation fluid. In this example EPV occupied by dynamic fluid pulsing for a treatment volume of 19,200 gals of HCl/HF mud acid is 1,335.5 ft^3 when compared with viscous fingering model associated with conventional steady-state injection through open coil. In the graph PW Overflow ("PWO") represents the volume of fluid that freely moves up or down the completion at the onset of a dynamic fluid pressure pulse initiated by tool. PWO is pseudo-dynamic fluid dispersion.

From the model flows a coiled tubing well program defining a step-by-step, layer-by-layer guide for stage 1, the clean-out procedure; stage 2, the pre-flush; stage 3, the main acid treatment; and, stage 4, the post flush. Stage 1 is completed using the cavitation-based cleaning tools while stages 2 to 4 utilize

the dynamic fluid pulsing tool.

This well is slated for stimulation therefore no pre and post stimulation comparison is available. As with all models matching history with predictions allows the model to become more robust thus providing for better future outcomes. Though numerous dynamic fluid pulse models have been run and wells stimulated the availability of precise fluid distribution outcomes via ILT or PLT logs remains few hence model improvements will step-wise updates as critical data becomes available. For those wells where ILT or PLT logs that have been run but unavailable for publication due to confidentiality there has been seen definitive changes in fluid distribution associated with dynamic fluid pulsing albeit optimization of the entire dynamic fluid pulsing approach remains to be further optimized.

Selected Stimulation Outcomes

As discussed a dynamic fluid pulse matrix stimulation is a two step process however to understand the capabilities of the cavitation-based cleaning tool and its importance in preparing the wellbore for the dynamic fluid pulse stage case examples of the tool used solely for the purpose of wellbore and near wellbore cleaning are presented.

Case 1 is a horizontal well in North Africa. The objective of the clean-out was the removal of 500m (~1,640ft) of a hard consolidated sand plug consisting of a 20/40 mesh sand from 2,630m to 3,131m (~8,626ft to ~ 10,270ft) after an initial attempt utilizing a standard jetting nozzle failed. The oil producing well had a 4.5” tie back liner in a 7’’casing. 1.5”cavitation-based tool was run on 1.5” coiled tubing and nitrified gelled water used as the cleaning fluid.

The 500 m sand plug was removed effectively in a single run saving time and money for the customer. The cavitation erosion effect generated by the tool with the associated self-adjusting future combined with highly nitrified fluid eroded the entire hard sand plug as the tool was run into the well where an initial attempt to remove the sand plug using an alternative approach failed.

Case 2 is a horizontal well in North Africa. The well stimulation operation was completed with 2⅞” coiled tubing. The objective of the clean-out was to clean the horizontal section from miscellaneous deposits, sediments, oil residues, and fines migration obstructing the oil producing reservoir. 1.5”cavitation-based tool was run on 1.5” coiled tubing and 7½% HCL + nitrified treated water used as the cleaning fluid

The miscellaneous materials impeding oil production were successfully removed and oil production approximately doubled from 3.89m^3/hr to 6.75m^3/hr (~795bbls/day to ~1381bbl/day).

Case 3 is a deviated observation well in the Middle East used to monitor saturation changes in a producing reservoir. The well was completed across three reservoirs to a depth of 10,066ft (~3.069m) between water injectors and oil producers. Due to the existence of unspecified solids fill well clean-out was required as logging and drifting tools could not go past a depth of 9,523ft (~2,903m).

The clean out operation was started at depth of 9,688ft (~2,954m) where the drifting tool reached prior to the operation. The cavitation-based tool was run into the well at 20fpm. During the clean-out, 50ft (~15m) “bites” into the fill were taken while pumping 5bbl of gel and 5bbl of fresh water every 100ft (~30m). Once the TD was reached, the coiled tubing was pulled back to 10,055ft (~3,066m) and 10bbl of gel followed by 160bbl of inhibited fresh water was pumped. Sampling of the returns was conducted every 15 minutes and showed solids removal. As pumping continued, a great reduction in solids percentage was noticed from 30% to 0.5% indicating an efficient clean-out operation.

Following the cleaning procedure using the cavitation-based tool the drifting tool was rigged up and succeeded in reaching the TD without any restrictions.

As effective and beneficial as the cavitation-based cleaning tool is in cleaning the wellbore and near

wellbore region of great importance to production and reservoir engineers is maximizing matrix stimulation outcomes. Dynamic fluid pulsing sets out to accomplish this objective.

Figure 15 presents the results of four dynamic fluid pulse stimulations completed in a sandstone reservoir in the Middle East. Two stimulations, denoted as P-1 and P-2, were completed on oil producing wells. Two stimulations, denoted as INJ-1 and INJ-2, were completed on water injection wells in a waterflood.

Well P-1 had a range of porosity from 25% to 30%; a minimum formation permeability of 400mD; and, a Static Bottom Hole Pressure (SBHP) of 5000KPa (~725psi). Stage 1 of the stimulation consisted of wellbore preparation using the cavitation-based cleaning tool on coiled tubing with a 7% KCl fluid. Following wellbore preparation Stage 2, the dynamic stimulation, commenced with the fluid pulsing tool. Stage 2 consisted of a pre-flush using a 15% HCl solution; a main mud acid treatment (7% HCl &1.5% HF); and, a post-flush using a 15% HCl solution.

Prior to the dynamic fluid pulse stimulation well P-1 had gross fluid production of 4.17m^3/day (~26bbls/day) with net oil production of 3.97m^3/day (~25bbls/day) at a base solids and water (BS&W) content of 4.76%. Post-dynamic fluid pulse stimulation in well P-1 gross fluid production increased by an approximate factor of 8 to 31.77m^3/day (~200bbls/day) with net oil production increasing by an approximate factor of 5.5 to 22.53m^3/day (~141bbls/day) at a BS&W of 29.65%.

Well P-2 had a range of porosity from 22% to 30%; a permeability range from 400mD to 1000 mD; and, a SBHP of 3750KPa (~544psi). Stage 1 of the stimulation consisted of wellbore preparation using the cavitation-based cleaning tool on coiled tubing with a 7% KCl fluid. Following wellbore preparation Stage 2, the dynamic stimulation, commenced with the fluid pulsing tool. Stage 2 consisted of a pre-flush using a 15% HCl solution; a main mud acid treatment (7% HCl &1.5% HF); and, a post-flush using a 15% HCl solution.

Prior to the dynamic fluid pulse stimulation well P-2 had gross fluid production of 9.69m^3/day (~61bbls/day) with net oil production of 8.33m^3/day (~52bbls/day) at a base solids and water (BS&W) content of 14%. Post-dynamic fluid pulse stimulation in well P-2 gross fluid production increased by an approximate factor of 2 to 21.06m^3/day (~132bbls/day) with net oil production increasing by an approximate factor of 2.25 to 19m^3/day (~117bbls/day) at a BS&W of 29.65%.

INJ-1 and INJ-2 shared the same reservoir properties having a porosity range from 8% to 32%; a permeability range from 95mD to 572mD; and, a SBHP of 5550 KPa (~798psi). Stage 1 of the stimulation consisted of wellbore preparation using the cavitation-based cleaning tool on coiled tubing with a 7% KCl fluid. Following wellbore preparation Stage 2, the dynamic stimulation, commenced with the fluid pulsing tool. Stage 2 consisted of a pre-flush using a 15% HCl solution; a main mud acid treatment (7% HCl &1.5% HF); and, a post-flush using a 15% HCl solution.

Prior to the dynamic fluid pulse stimulation INJ-1 had an injection rate of 57m^3/day (~359bbls/day) while INJ-2 had an injection rate of 50m^3/day (~314bbls/day). Post-dynamic fluid pulse stimulation the injection rate increased to 130m^3/day (~817bbls/day) or an approximate factor of 2.3 and the injection rate on INJ-2 increased to 150m^3/day (~943bbls/day) or a factor of 3.

Figures 16 and 17 show pre and post PLT log data as received from the client for a sandstone water injector located in California, USA. The well was cased-hole perforated with the target treatment zone from 6,411ft (~1,955m) to 6,760ft (~2,161m).

Due to certain logistical and cost constraints the client could not carry-out Stage 1, the wellbore cleaning procedure therefore Stage 2, the dynamic stimulation, immediately commenced with the fluid pulsing tool. Stage 2 consisted of 15% HCl; 7.5% HCl; 1.5% HF; and, 5% NH_4Cl being sequentially placed in multiple passes of the dynamic fluid pulsing tool.

As shown in the PLT log (Figure 16) prior to the dynamic fluid pulse stimulation the water injection

rate was 798bbl/day (~127m^3/day) spread across five intervals however two intervals received more than 90% of the inflow. Figure 17 shows a PLT log taken 90-days post-dynamic fluid pulse stimulation. Water injection rate increased approximately 4.6 times pre-stimulation rates to 3,692bbl/day (~587m^3/day). Moreover, twelve zones were accepting fluid post-stimulation versus five zones pre-stimulation with the upper zone decreasing in contribution from 76% to 30%. This outcome demonstrates how dynamic fluid pulse technology may beneficially improve both fluid distribution and placement without the need for mechanical or chemical diversion techniques.

Summary

Dynamic fluid pulsation is a game changing approach for the placement of fluids during well stimulation or EOR activities where traditional, conventional approaches are ineffective or marginally beneficial. The flow processes associated with dynamic fluid pulsation are predicted by a strong physical theory that describes multiphase flow and seismic wave propagation in porous media and is supported by academic study and field evidence over the past 20 years. The economic and production/injection benefits of dynamic fluid pulsation are related to the application of long-wavelength displacement waves (porosity dilation waves) that bring dynamic energy to fluids at the pore scale, overcoming flow barriers and dispersing fluids deeper and more uniformly throughout the reservoir matrix.

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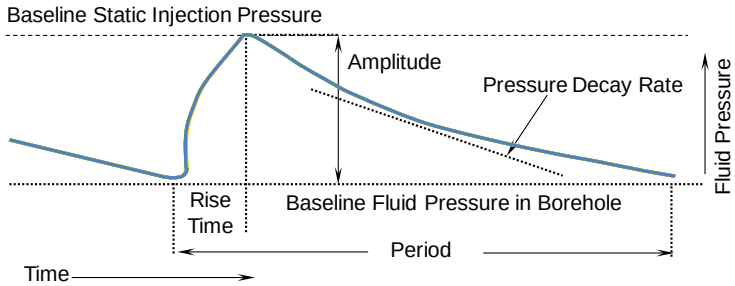
Figures



Rise-Time. This refers to the time frame in which the maximum amplitude of the fluid impulse occurs. Rise-time triggers elastic deformations of the matrix. It is desirable to optimize rise-time based on formation permeability.

Amplitude. This refers to the magnitude of the impact of the fluid impulse on the onset of the tools piston shifting open. Amplitude dictates inflow of fluids into the porous medium. In almost all cases due to instantaneous displacement efficiency the fluid pulse amplitude does not exceed the local fracture pressure of the porous medium. Displacement efficiency is defined as the percentage of net fluid volume entering the medium relative to the volume injected during a pulse.

Pressure Decay Rate. This refers to the pressure bleed off rate of the formation. For low permeability formations the bleed rate tends to be longer hence the number of pulses per minute reduced. Conversely for higher permeability formations where bleed off is quick the number of pulses per minute increases.

Period. This refers to the time between successive fluid pulses generated by the dynamic fluid pulsing tool.

Fig. 1—Theorectical waveform associated with dynamic fluid pulsing.

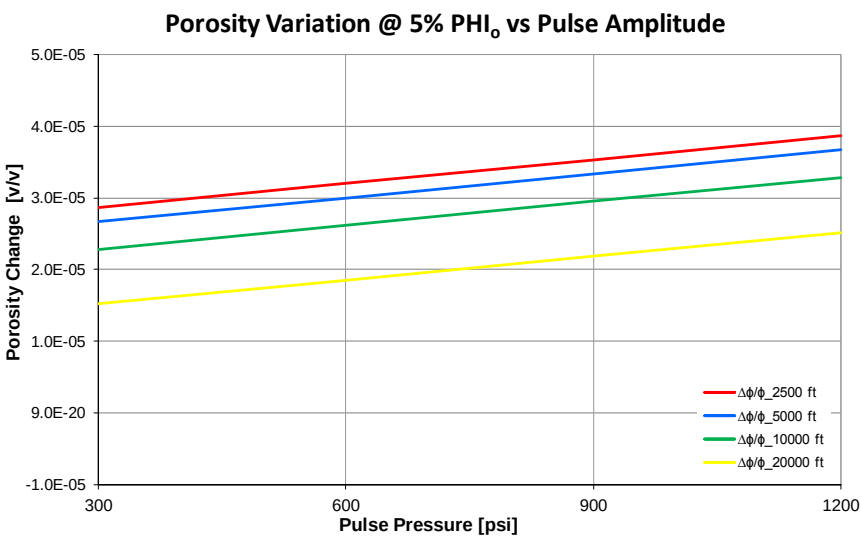


Fig. 2—Porosity change versus pulse amplitude during dynamic fluid placement.

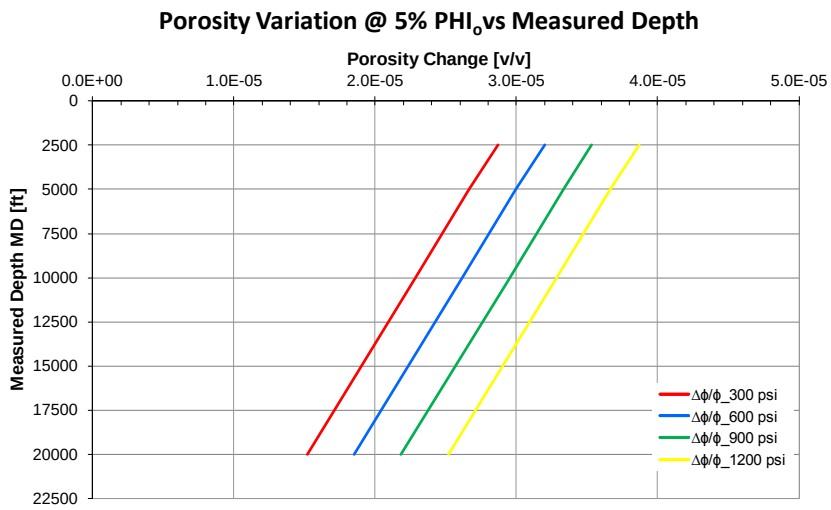


Fig. 3—Porosity change versus measured depth during dynamic fluid placement.

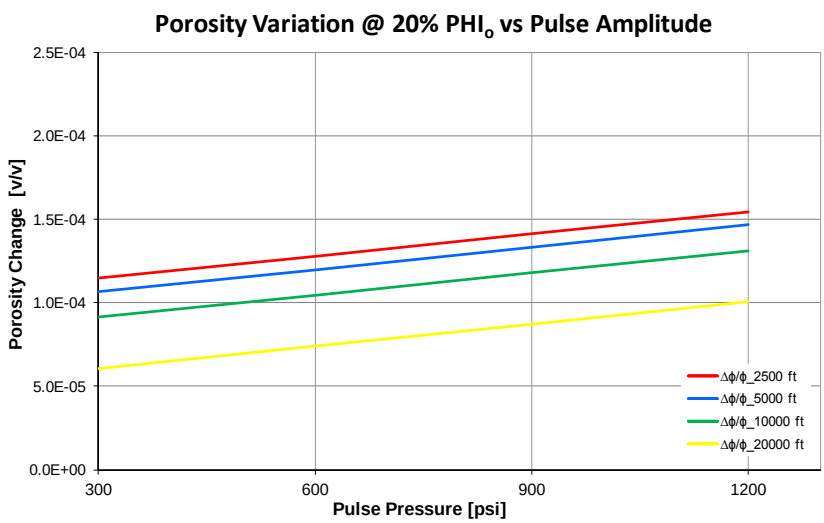


Fig. 4—Porosity change versus pulse amplitude during dynamic fluid placement.

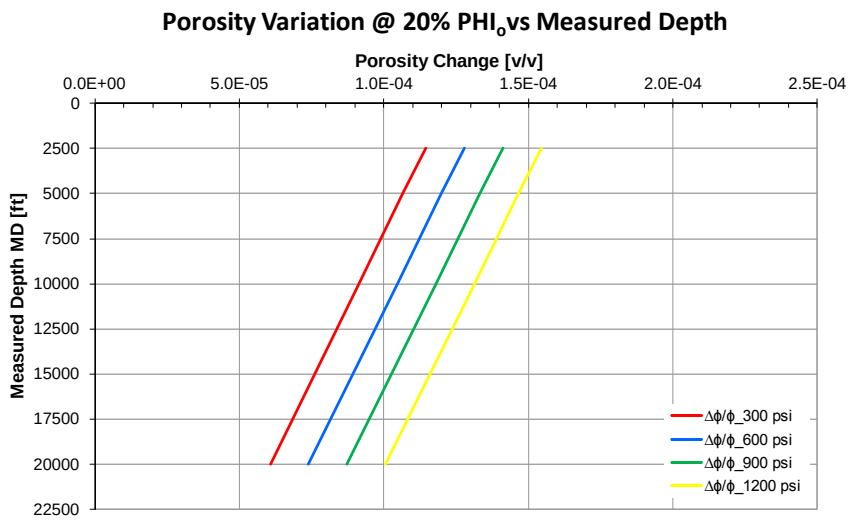


Fig. 5—Porosity change versus measured depth during dynamic fluid placement.

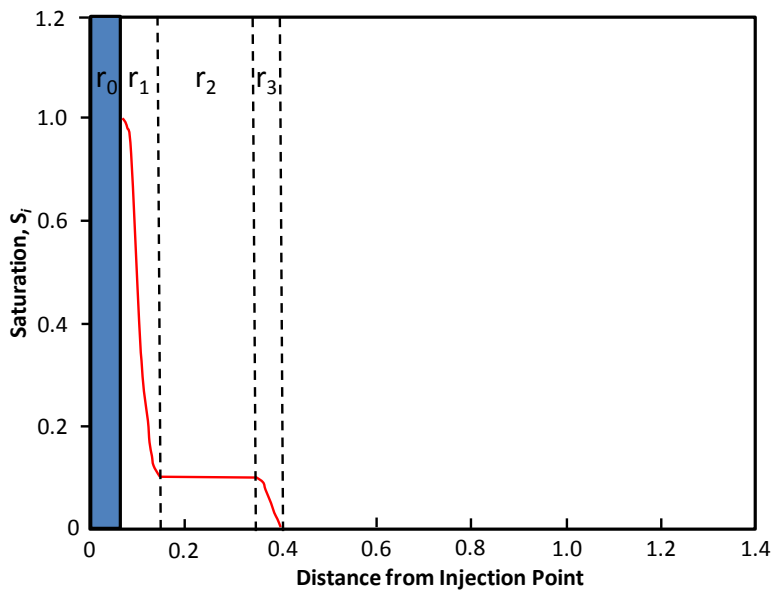


Fig. 6—Viscous fingering curve used in the dynamic fluid pulsing model.

Fig. 7—Cavitation-based cleaning tool side view.

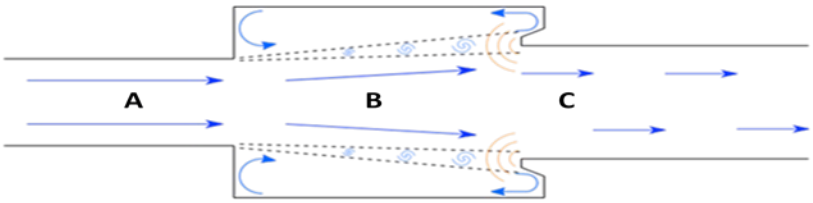


Fig. 8—Cavitation-based cleaning tool operational principles.

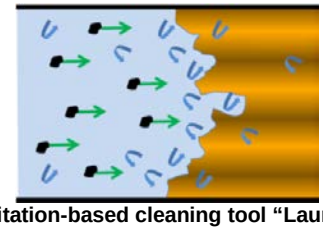


Fig. 9—Cavitation-based cleaning tool "Laundry Effect".

Fig. 10—Operational modes of a cavitation-based cleaning tool.

Fig. 11—Magnetics-based dynamic fluid pulsing tool.

Well Information	
Well Type	Vertical Water Injector
Completion Type	Perforated Liner
Treatment Intervals:	9824 – 9838, 9843 – 9856, 9865 – 9879 9884 – 9937, 9940 – 9959, 9971 – 10050 ft MDKB
Treatment Interval TVD	9824 – 10050 ft TVDKB
Treatment Interval Length (net)	192 ft
Production Liner	5.5"
Prod. Tubing	4.5" & 3.5"
SIWHP	0
Reservoir Information	
Formation Type	Sandstone
SBHP	3,800 psi @midpoint of target zone
BHT	202°F (94.5°C)
Permeability	0.96 – 2787.3 mD
Porosity	9.79 – 24.58 %
Fracture pressure gradient	0.82 Psi/ft
Tool Information	
Cavitation-Based Cleaning Tool	2.0" Model 2
Dynamic Fluid Pulsing Tool	1,200 psi tool

Fig. 12— Middle East well 1 details for modeling.

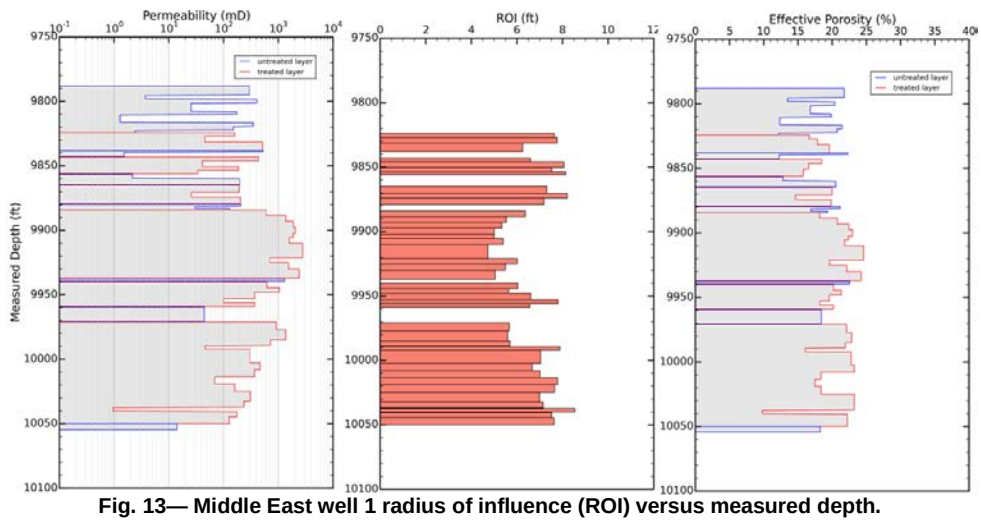


Fig. 13— Middle East well 1 radius of influence (ROI) versus measured depth.

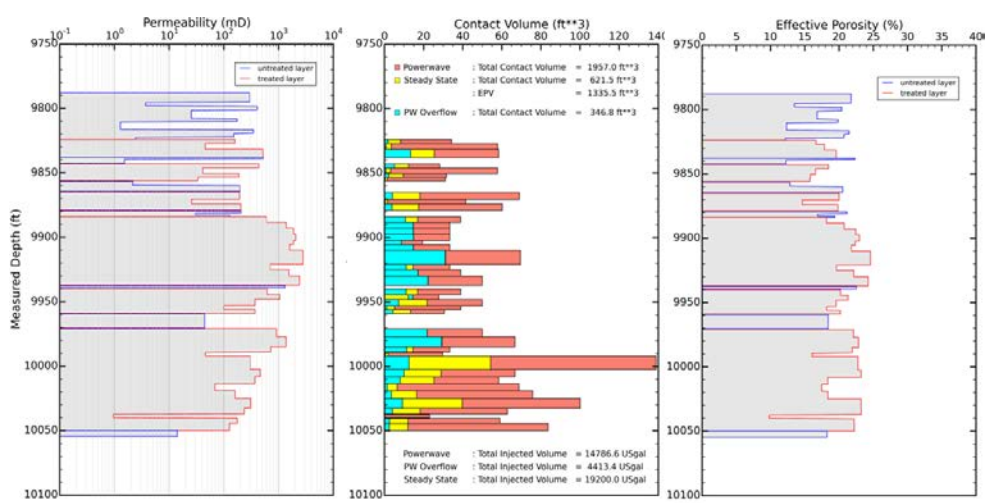


Fig. 14— Middle East well 1 fluid contact volume as a function of porosity and permeability.

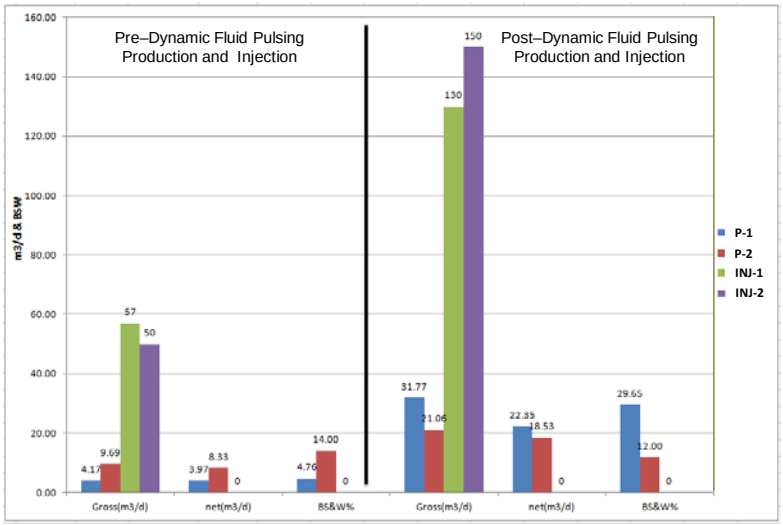


Fig. 15— Pre and post dynamic fluid pulse stimulation results for two oil producers and two water injectors.

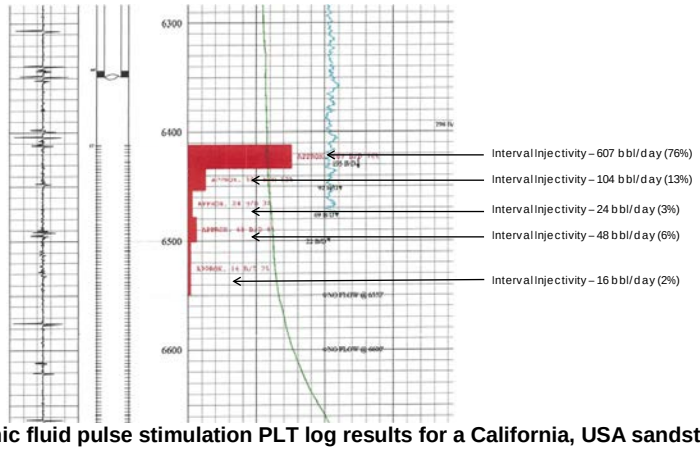


Fig. 16— Pre-dynamic fluid pulse stimulation PLT log results for a California, USA sandstone water injection well.

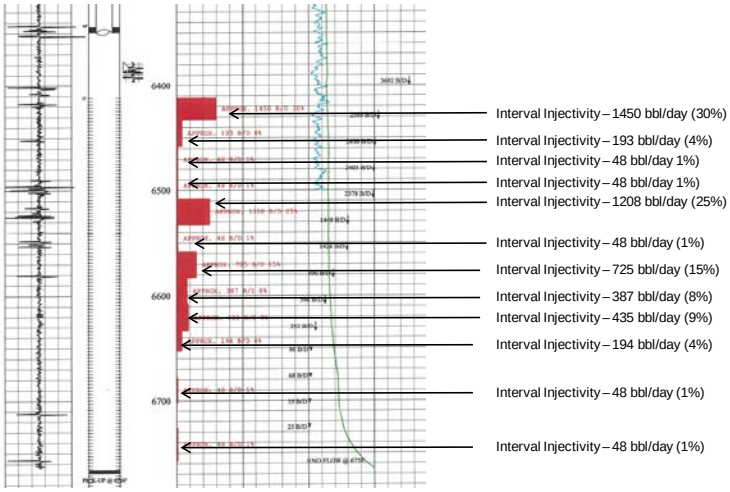


Fig. 17— Post-dynamic fluid pulse stimulation PLT log results for a California, USA sandstone water injection well.