Unconventional Reservoirs Require Unconventional Thinking: Using Fracturing Model as an Example

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Abstract. The current widely adopted Discrete Fracture Network (DFN) model has its obvious flaws. This paper presents a conceptual model which may lead us having a fresh view on the mechanical and fluid flow mechanisms during and post fracturing. The proposed Fracturing Impacted Volume (FIV) model allows us not only to avoid the inputs data setting up blindingly with the DFN model but also to think the unconventional object in an unconventional way which we are not seeing that with the concept of DFN model. Instead, FIV model emphasizes both the fracturing fluid penetration and fracture initialization as well as propagation at equal weight rather than focusing on mechanically fracturing. Through a serial comprehensive analysis of all sorts of data including core testing and field observation and testing e.g. DFIT data published and unpublished, a conceptual model, namely FIV has been proposed in this paper. From this conceptual model point of view, the entire fracturing is a process of the reservoir system (microfracture and matrix) pressurization along with fracturing in unconventional reservoirs. This paper demonstrates a good correlation between reservoir permeability or leak off and reservoir effective pressure change through a serial core samples tests of tight sandstone and shale, and field observations which include the result of DFIT and other diagnostic tests. According to the proposed model, a different interpretation of shale fracturing fluid flow mechanism is presented in this paper. Finally, based on the concept of FIV model, a couple real cases have been studied and considerable positive results have been achieved with this model. The FIV model could provide alternative solutions to problems that the DFN models have run into. With the basic concept in this FIV model, fracturing simulation will become much effective, and production simulation results will be more consistent with field history data because the conceptual model provides a better angle for us to understanding what an unconventional reservoir may have been through and changed during the fracturing, post fracturing and to the production period down the road. It is truly fresh air for us in unconventional fracking and production simulation arena. It is the time for us going back to the fundamental and basics on this.

Keywords: Fracture impacted volume · Dynamic properties · Flow and fracturing mechanism · Pressure dependent permeability

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1 Introduction

There are significant differences between of unconventional and conventional reservoirs as is known. This paper will focus those factors which distinguish it from conventional reservoir such as pressure dependent permeability/leak off and etc. and the conceptual model from fracturing design and simulation point of view. Some people view that fracture network are formed through the hydraulic fracture propagating and encountering natural fractures [1], which is considered as a very similar concept as SRV back to 20,006 or so. This is not uncommon view on this. Then a common seen conceptual model, the Discrete Fracture Network (DFN) or fracture network model has been used for simulation purpose. Even though the fracture network model was not well defined, many scholars tend to quantitatively describe the existing DFN model. Where as in unconventional reservoir, the concept of the limited in number and spatially distributed sizable natural fractures intersecting with the hydraulic fractures and creating either regular or irregular shaped fractures, DFN or fracture network is adopted by many. However, in practice, this model uses finite number of natural fractures which must be less than numerical grid numbers; and it uses the dual-porosity dual-permeability model for fluid flow mechanism, which has been implemented for conventional reservoirs for a few decades. The imperfect in using both the fracture network model and the concept is so obvious, and caution must be taken while applying this technique.

The unavoidable fact in using DFN model is that one has to face many unknown parameters in the model such as the size, total number and distribution, conductive and connectivity of natural fractures among others. Scholars tend to deliberately define those parameters randomly with very little or no data. Some use the rock outcrop to define the natural fracture geometry for reservoir; some others interpret from the microseismic event cloud, counting the number and location to interpret as reopened natural fractures. But neither of the methods can overcome the blindness or the randomness of the natural fracture distribution. Outcrop can be used to observe many geological properties of the rock, but not for fractures because the rocks had gone through totally different orogeny movement in geological history between the two, outcrop and reservoir, evidently. Microseismic was used as another tool to locate natural fractures. The large number of non-calibrated microseismic events would introduce numerous errors and quite low accuracy, which was used in interpreting the fracture network and discrete fracture as SRV [2, 3]. The less credibility model introduces its unavoidable and unconquerable problems to the fracture interpretations and its related computations. And some may take micro-fissures data from cores or image logs which are in very small/micro scale and drag them to numerical grid scale in their numerical model which is in macroscale.

Furthermore, conventional dual-porosity dual-permeability mode is also debatable for unconventional reservoir because the fluid flow mechanisms difference between the shale/tight sandstone reservoirs and the conventional reservoirs like in carbonate reservoirs. Erdal Oskan (2012) indicated that, while the matrix absolute permeability is lower than 10–6 mD, the contributions of natural fracture network is close to none [4], the dominate factor is the flow within the matrix. Ian Walton (2017) has summarized from 2000 wells in Barnett shale with its production history profile for a conclusion: Natural Fracture Add Little to Shale Gas Reservoir Productivity [5]. Similarly, massive matched production history from unconventional reservoir suggests that, the error in used permeability is easily in 2–4 order of magnitude [6]. In the application side of DFN, there are contradictory results between fracture network data and other parameters. Mayerhofer (2014) uses the SRV model to investigate inter-well relationship between a fracturing well and a producing well in Marcellus shale reservoir, and there is an extensive un-matching result; comparing to the better matching results with the simple fracture model. There are numerous examples of un-consistency of production data matching or sometime contrary with this fracture network model.

Hence, to overcome the above limitation from the current fracture network model and to avoid further problems, a novel conceptual model is presented in this paper. It is needed to overcome the mentioned flaws and be more practical and certainly will lead more robust and/or improved unconventional oil and gas fracturing and developing models. An important parameter of this new model discussed in this paper is the concept of permeability is a pressure dependent variable, or the Pressure-Dependent Permeability (PDP) [7]. Warpinski [8] uses summarized the data collected at northwestern Colorado low permeability gas sandstone shows similar relationship in the following figure.

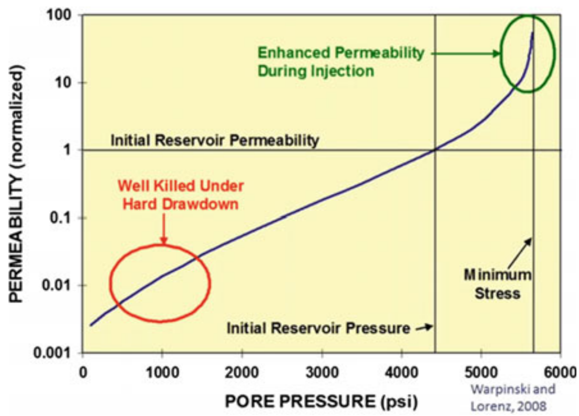

Fig. 1 Normalized permeability is a function of pore pressure [8]

Mittal [9] states that the permeability of the natural fracture increases during the hydraulic fracturing operation. When the pressure reaches the critical point, the permeability increases rapidly. Of course, similar phenomenon have been found from the lab testing and in the field observation as green circle shows in Fig. 1. Even though those investigations were made for tight sandstone reservoirs, it is believed to be true for as shale as well.

Many reservoir simulating models assume the permeability of the reservoir does not change, but it is no longer the case for unconventional modeling. Mohammad [10] proposed that there is an exponential relationship between permeability and reservoir pressure of the induced-fractured zone and hydraulic fractured-zone. The hydraulic fracture and the induced fractures have high geomechanics impacts as of other parameters, and it is even more sensitive to induced-fracture (i.e. the natural fracture is not been propped).

2 Fracturing Impacted Volume (FIV)

To overcome the imperfect and impractical fracture network model like DFN, a model to take two objects in a reservoir into account becomes necessary at certain degree so that the model can be applied much more effective and easier without losing much accuracy; and those two objects in a reservoir are: (1) the sizable fracture such hydraulic made ones or identifiable ones by some mean in the field in the scale like feet or meters, (2) countless microfractures, natural fissures, organic or inorganic pores, clay mineral dewatering microcracks/pore and the matrix—lump sum as the reservoir system with a localized or nonuniform permeability, Ks depend upon the data availability. This paper presents the conceptual model of FIV with the said features. More calculation and model details are to be presented in later articles with more data and investigation works come out.

2.1 FIV Model

From the laboratory observation, shale or tight sandstone reservoir usually fill with numerous naturally fissures. The existence of fissure in shale reservoir is important in shale reservoir, since fissures are proposed as the primary contributor to principle pore and permeability network [11]. It is important to understand that we are talking the micro-scale rather than large scale in term of nature fractures in unconventional reservoirs. It is because the numbers of those micro-scale fracture/fissures are so huge and they are also widely spread or distributed in the reservoir, actually they are the major part of the so-called matrix, and they are the major storage of the oil and gas in the unconventional reservoir, and they are the main fluid flow pathways as well at microscale level. Therefore, the correctly understanding of scale for nature fissure become so important in term of fracturing and reservoir simulation model. As D. Willis, an expert from Oil and Gas in Google Cloud pointed out during ATCE panel speeches in 2018, many of our problems we are facing in oil E&P are because of the misuse of scales. In this section we will present some lab testing and flied observation results for the tight sandstone and shale reservoirs, which demonstrated the correlation between the reservoir permeability and the pressure for shale reservoir system and even tight sandstone reservoir, and presents the view point on fracture mechanism from the proposed conceptual model, FIV.

Significance of natural microfractures in unconventional shale reservoirs is important because microfractures are commonly proposed as a principal pore and permeability network in the production of hydrocarbons from mudrocks (shale) according to Loucks and etc. [11] (Fig. 2). In microscale of observation, microfractures are primarily dominated intensive distributed, at least are much larger (a few orders of magnitude higher) in number and wider in distribution than those in the DFN model. These types of microfracture can not only be the gas/oil storage, but also be the fluid flow paths. For such a huge number of fissure and micro-pores, addressing unconventional reservoir stimulation with slickwater, the adjacent area near the main fracture is energized by the stimulation process, and the pressure within the naturally or induced fissure/fractures and micro-pores rapidly increase triggered by the pumping fluid. This spatial volume that is energized by the stimulation process, which is defined as Fracturing Impact Volume (FIV) and the corresponding model is defined in later part in this article.

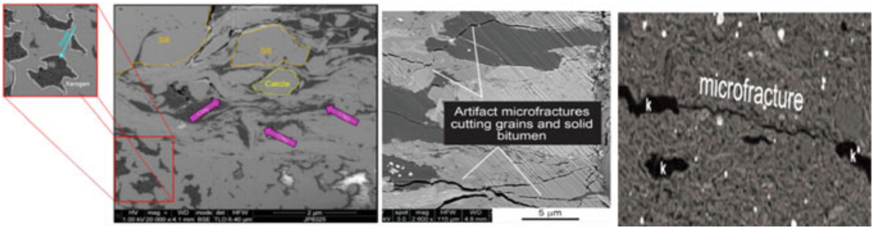

Fig. 2 Fissures in unconventional reservoir

The FIV model takes fully consideration of the pressure dependence reservoir system permeability and fluid loss. The micro discrete structural changes during the pore pressure charging process, which increases the connectivity of inter fissures, and between the fissure and the formation. The pressurized fracturing fluids (slickwater) enter the matrix which accommodate a lot micro fracture (fissure) and creates the FIV, and FIV is equivalent of increasing pore pressure and the initial production pressure difference. This is another mechanism of the unconventional reservoir stimulation.

During the stimulation, increase the micro-fracture and micro-pore pressure is easier than creating additional fracture, and the process happens earlier and lasts longer. As the fluid pressure within the pore gradually increase, the effective stress act on matrix frame work decrease, the connectivity in micro-fracture and micro-pore increases but the pressure is not exceeding the critical failure stress. In other word, there is initial fluid loss, but due to the limited contact area at early time, the fluid loss is small. With the initiation and propagation of fracture, the contact area increases. This increases the fluid loss to the matrix formation. During the stimulation process, because the fracturing fluid (slickwater) flows easily, it enters the formation matrix rapidly under greater pressure difference and break the pressure balance of the original formation; on other hand, the matrix-system which contains massive micro-fracture (fissure) was pressurized by stimulation, which increases the permeability and energize the formation in the FIV domain.

Figure 3 is the sketch for Fracturing Impacted Volume concept model, injecting with the better penetrability fluid and the hydraulic fracture is shown within the two solid red lines in very middle. The pressure difference increases as the pore pressure increase, fracturing fluid enters micro fractures to form the energized pressure zone (purple line in figure). This volume is the Fracture Impacted Volume. Micro-Fracturing Impacted Volume is related with micro-fracture density. The more of micro-fracture, the larger of FIV, and vice versa.

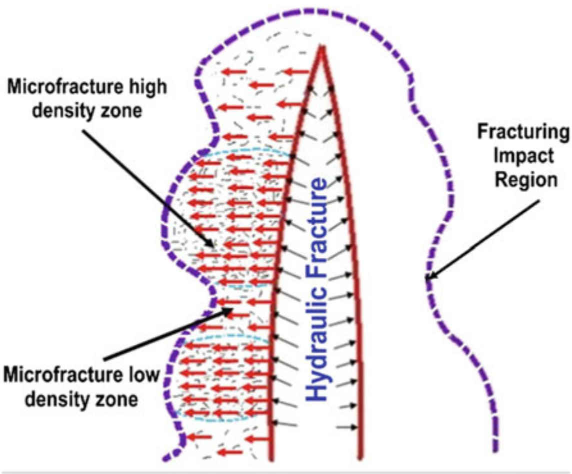

Fig. 3 Sketch for fracture impacted volume

Theoretically, SRV, is created by the fracture net pressure, which is the fluid pressure minuses the minimum horizontal stress/closure pressure. When the net pressure is equal to zero, the fracture closes.

$$P_{net} = P_{frac} - \sigma_{\min} \tag{1}$$

$$P_{net} > \sigma_{\min} \tag{2}$$

FIV is different than SRV. It is the pressure transfer with in the liquid system, the pressure difference between the fluid within the fracture and the pore pressure, ΔP. During the stimulation, the matrix system energized by fracture fluid. The system permeability increases before it reaches the critical failure pressure. In unconventional reservoir stimulation, before the rock breaks, the average pressure is Pt, which is pressure of the area of reservoir system fluid loss increase rapidly. The initial reservoir pressure is Pi, ΔP is the additional pressure increase, as in equation:

$$\Delta P = P_t - P_i \tag{3}$$

$$\sigma_{eff} = \sigma - P_{pore} \tag{4}$$

In the above equation, σ_{eff} is the effective stress acing on the matrix frame. The dispersion process with in the microfracture and micro-pore provides additional driving force for flow back. It is believed that this driving mechanism is the most outstanding and unique parameter in unconventional reservoir. After/during rock failure.

$$\Delta P_{flu} = P_{frac} - P_i \tag{5}$$

$$\Delta P_{flu} > P_{net} \tag{6}$$

where ΔP keeps increasing and reaches the maximum value, ΔP_{eff}, the fracture starts to initiate. The pressure in fracture, P_{frac}, is just a little higher than the pressure in reservoir pore pressure during penny fracture phase and then increase significantly while the fracture keeping growth. When the fracture propagates, it becomes the fracture extension pressure. It is worth noting that, during the whole process of pressure rising from original pore pressure to fracture initiation pressure, all liquids are a loss into the formation rather than creating fracture. The fracturing impacted volume FIV discussed in this paper is mainly referring to the system of reservoir rock prior fracture and during the fracturing process, the formation system of micro-fracture and micro-pore diffusion dominated pressurized on both sides of the fracked fracture. In other words, due to the influence of the changing the micro-pore and micro-fracture pressure during fracturing, part of fracturing increased production is mainly contributed due to the process of micro-fracture and the system pressurization, and the range of increasing production is the FIV-affected volume of fracturing which associate with the model of FIV.

2.2 Model Rationality

Because the penetration of fracturing fluid (most of the cases with slickwater) forms the pressurized zone around the main fracture in the reservoir system, which is the volume of FIV at that moment. Why the FIV model can be used to interpret what may happen during hydraulic fracturing than the Fracture Network/DFN will be mainly discussed from the following aspects.

First, from the whole system point of view, the proportion of fracturing fluid flowback in unconventional reservoirs is relatively low or quite low comparing with conventional ones, which is the basic fact. Based on this fact, where does the fracturing fluid go during a few hours of fracturing? There are two proposed different explanations: one is that fracturing fluids are all or most of them creating fractures to form fracture networks. That is, in addition to creating hydraulic fractures, it is to open natural fractures with relatively large scale (in feet or meters), so that macroscale model can be used. Another explanation is believed that big portion of fracturing fluids—slick water penetrates a considerable part of the reservoir system alone the hydraulic fractures. This should be a reasonable interpretation of why slickwater does not any other fluid, and why nanoscale permeability rock can produce unbelievable amount of oil and gas from the unconventional rock which were believed impossible. Is this all because the fracturing creates limited large-scale fracture intersecting with sizable nature fracture. If so, it will leave more questions than answers. If is not because the connectivity of microfractures and micropores with large cardinal number and wide distribution in the reservoir through the stimulation, it is non-explainable that millions barrels of oil in the microscale storage space can be produced. Based on this conceptual model, we can certainly have wide open mind to interpret what may have been happened during and after fracturing.

In addition to the above basic scientific and logical analysis, more rationality is to present as following paragraph. The rationality of the FIV model is discussed from the aspects of the field test data, the core experiment in the laboratory and the simulation results of the field DFIT diagnostic tests.

Warpinski and Lorenz field test shows result from many wells in the Piceance basin of low permeability sandstone gas in 2008 [8], with the increase of pore pressure, the permeability increases exponentially with increasing pressure; just open the existing micro-fractures, and did not create new cracks, just to improve the connectivity between micro-fracture and micro-pores, the system permeability in the reservoir increased significantly. These findings and technical ideas of this paper are common.

The Core Experiment Proves the Rationality. Figures 4 and 5 present the results of PDP (Pressure Dependent Permeability)/PDL (Pressure Dependent Leakoff core experiments. Figure 4 shows the relationship between effective fluid pressure difference (the difference between injection fluid pressure and original pore pressure) and fracture surface area water absorption under different confining pressures. The correlation between these two parameters is a simple reflection of permeability. Under different confining pressures, the water absorption per unit surface area is less affected by confining pressure when the confining pressure is above a certain level. However, with the increase of the effective fluid pressure difference, the water absorption capacity of the unit surface area increases gradually. When the effective fluid pressure difference reaches 5 MPa, the water absorption capacity of the unit surface area increases dramatically. In Fig. 5, the relationship between dimensionless fluid pressure difference and dimensionless permeability is obtained by using the derivative of red curve in the left diagram, and it is obvious that with the increase of fluid pressure difference, the connectivity between micro-fractures improves and the effective permeability increases.

As a result of liquid injection, the pore pressure increases and the effective pressure of the reservoir system (the overlying rock pressure or the difference between the

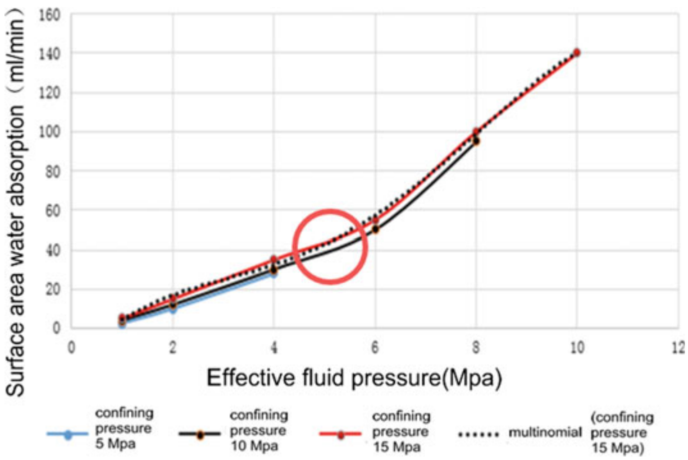

Fig. 4 Relationship between effective fluid pressure difference and surface water absorption. (Modified from [12])

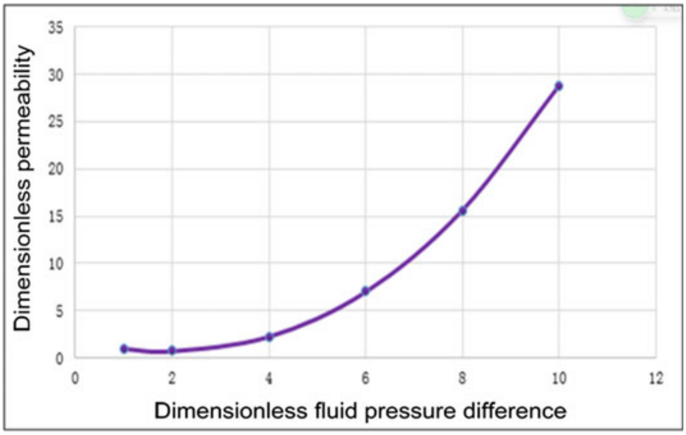

Fig. 5 Relationship between dimensionless fluid pressure difference and dimensionless permeability

confining pressure and the pore pressure in the rock) decreases, in reservoir system, the compressibility between grains decreases and the tension between particles increases, and the connectivity of tiny pores and fine fractures in rock becomes better, which leads to the increase of permeability, and the change of permeability will inevitably lead to the change of permeability of the whole system. According to many core experiments, it is found that there is an exponential relationship between core permeability and effective pressure difference:

$$K = K_i e^{d_f \Delta p} \tag{7}$$

Here K Is the reservoir system efficiency permeability, K_i is the initial reservoir system permeability, and ΔP is the effective fluid pressure difference ($P\text{-}P_{\mathrm{initial}}$), and d_f is the exponential decay constant, which is defined by the particle size, sorting, and compaction of the rock. Need to note that the effective fluid pressure difference is not the effective stress, the effective fluid pressure difference is the difference between the injection fluid pressure and the original pore pressure, and the effective stress (the force loaded on the rock frame) is the difference between the stress and the pore pressure. The relationship between effective stress and system permeability is discussed below.

Figure 6 shows the core experimental data of several unconventional oil and gas fields from the Barnett and Utica sandstone gas fields, Eagle Ford and Marcellus shale

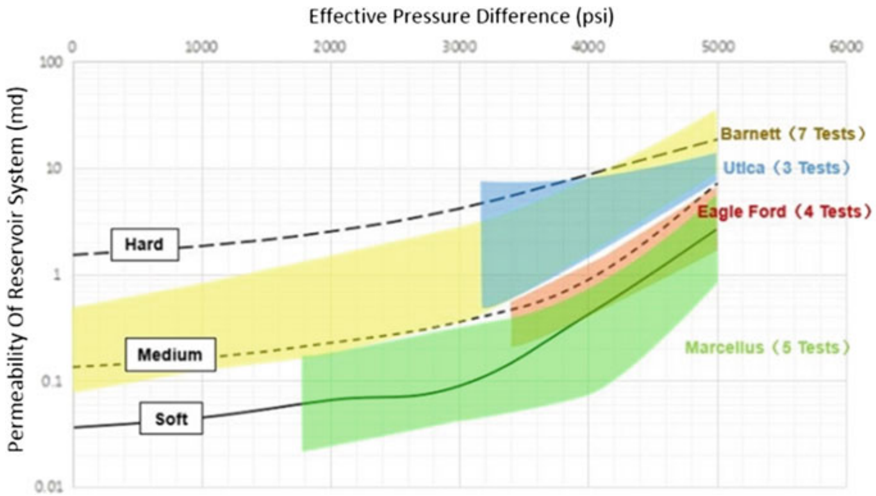

Fig. 6 Relationship between the permeability of reservoir system and effective pressure difference in unconventional oil and gas fields [13]

basins, to determine the relationship between the reservoir system permeability and the effective stress difference. There is an exponential relationship between them. With the increase in effective pressure difference, the effective stress decreases, and the system permeability increases. The reason is that when the effective pressure difference increases, the effective stress of the rock frame of the micro-fracture decreases, the connectivity of the micro-fracture is improved, and the effective permeability of the system is improved. With the decrease in effective stress, the system permeability of Utica sandstone gas reservoir in the blue area increases one order of magnitude, showing a decreasing exponential decreasing relationship. The results show that this type of sandstone reservoir has a good effect of micro-fracture and micro-pore pressure leading diffusion, and other shale reservoirs also have a similar relationship, which is a significant negative correlation between system permeability and effective stress, and a positive correlation between system permeability and effective fluid pressure difference.

In the diagram, the reservoir rock changes from soft to hard from bottom to top, and when the lithology is soft, the brittle index is lower, the density of micro-fracture is smaller, the less the total amount of fracturing fluid (slick water) enters the reservoir micro-fracture, the smaller the pressurization area controlled by micro-fracturing is. Therefore, the volume FIV affected by fracturing in green area is relatively small. For hard lithologic such as Barnett shale, brittleness index is higher, micro-fracture density is larger, and the pressurized area of microfracture density becomes larger, for example, the volume FIV of Barnett shale affected by fracturing in yellow area will also become larger. It should be noted that when shale and ultra-low permeability sandstone are separated from the high-pressure reservoir and fluid saturation environment, many micro-fractures will be completely closed and can no longer be energized or reopened.

Therefore, the relationship between the injection pressure or effective pressure difference measured in laboratory and the permeability of reservoir system is generally low. Normally, the permeability measured in laboratory is not more than two orders of magnitude with the increase of injection pressure difference, but most should be in one order of magnitude.

Field Diagnostic Test Proves the Rationality. The proposed Fracturing Impacted Volume model for micro-fracture and micro-pore pressurization can be verified by field test. Figure 7 shows a monitored pressure fitting curve in the DFIT diagnostic test of Vaca Muerta unconventional reservoir gas wells [14], the permeability of the DFIT diagnostic test is one order of magnitude greater than the core test. The black line represents the original monitored pressure. The blue line represents the pressure curve fitted using DFIT pore pressure and DFIT permeability. The red line represents the pressure curve fitted with low pore pressure and core permeability. The green line represents a pressure curve fitted using low pore pressure and DFIT permeability.

The blue line fits the best, while the green line fit the worst. Because the pore pressure of blue line is the higher DFIT pore pressure, the permeability is the permeability is obtained by DFIT; As the pore pressure increases, the effective stress decreases, the connectivity between micro-fractures and micro-pores improves, and the effective permeability increases. The pore pressure and effective permeability increase simultaneously. Only by considering the both changes at the same time, we could become more reliable to the underground, and we can fit the monitoring pressure curve better.

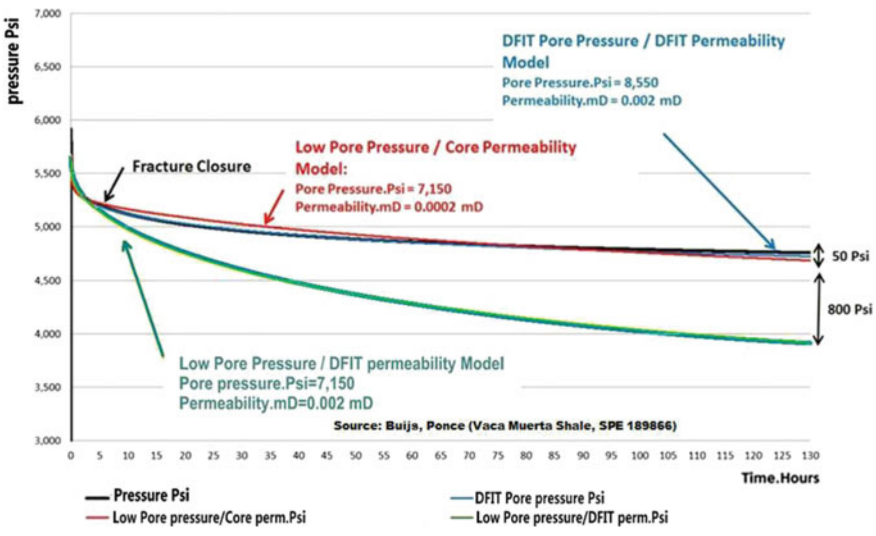

Fig. 7 Pressure fitting curve for monitoring a gas well [14]

The red curve in Fig. 7 seems to be not too bad in term of history matching of pressure. But in this paper, Buijs also compares the G-function curves in two cases

[14]. However, the interpretation of permeability measured by core and pore pressure measured by gas display, G function is completely wrong, while using both the permeability and pore pressure obtained by DFIT and the closed pressure explained by G function of that pore pressure are in very shape.

This case study shows that permeability obtain by other means is at least one magnitude lower than one obtained with DFIT, similar trend to the pore pressure. This shows the validity of the fracturing impact the permeability and pore pressure even with very small amount of water. The matrix is energized and activated, and the effective permeability increases due to increment of pore pressure. It is absolutely not ignorable if 75,000 barrels of water/fluid injected into reservoir within one stage of fracturing. What we have done to the wide distributed formation beyond creating some fractures. If that amount of water all used for creating fractures, our fracture space will not be just a few meters in spacing. **This is so obvious, and so basics**.

Because of the strong positive correlation between reservoir filtration and system permeability, in the initial stage of fracture closure, reservoir filtration shows pressure dependence, which also shows pressure dependence of system permeability. In the process of fracture main fracture opening and extending, fracture rock micro-fracture, micro-pore pressing, make the micro-fracture connectivity in the reservoir become better; At this time, no matter whether micro-cracks have micro-opening or slippage, there exists the phenomenon of increasing permeability and filtration loss, which increases the driving mechanism in subsequent production. Driving mechanism provides energy for subsequent fracturing.

2.3 The Role of FIV Model in Fracturing

Because of the filtration effect of fracturing fluid, a pressurized zone is formed around the fractures in the reservoir system, that is, fracturing affects the volume of FIV. The rationality and applicability of this interpretation is not only to avoid the trouble of distinguishing matrix from natural fracture in the calculation of fracture mesh model, but also to put forward a new way of thinking about fracturing model. The effect of micro fracture on the whole fracturing effect is considered more than the previous double porosity and double permeability model. For the productivity calculation model, the great effect of micro fractures (or capillary fractures) on the productivity after fracturing is fully considered. The change of conceptual model, many working ideas should also change with it.

Fracture mesh model is a common model for unconventional oil and gas fracturing, in which the volume of fracturing modification and the flow conductivity of fracture net are the key indexes to evaluate the effect of fracturing operation. In this model, the geometric parameters of the fracture mesh are obtained by simulating the expansion law of the fracture net and the flow of fracturing fluid and the movement of proppant in the fracture mesh, and the fracturing operation scheme is selected. Shale with natural fractures is the key point of fracture mesh fracturing. The model holds that the smaller the horizontal stress difference is, the easier it is to form fracture mesh, the larger the operation discharge is, the larger the total amount of fracturing fluid is, the larger the volume range of reservoir reconstruction is. The higher the seams' diversion capacity, the higher the productivity.

Obviously, under the influence of fracturing volume FIV model and the whole flow system combination model, the existence of fracture network is not the key and focus of the problem. Fracturing influence volume model is a new idea of unconventional fracturing. The goal of fracturing is different from fracture mesh model (whether to form fracturing standard for fracture net and so on) and to pursue optimal production. The model does not think that the larger the displacement, the larger the liquid scale, the better the fracturing effect is. Due to the slow process of micro-fracture and micro-pore pressure leading diffusion, the model usually uses small displacement and fluid flow to fracture, which does not require formation of fracture network, but increases pressure in micro-fractures and micro-pores. Thus, the microstructure of reservoir rock is improved, and its connectivity is improved (I.E. the matrix is punched and activated), the effective permeability of reservoir is increased, and the filtration is increased. In addition, the parameters optimization of fracturing design and fracturing operation for well spacing, fracture spacing and so on are also different from the fracture mesh model.

In a word, the influence volume model of fracturing has fundamentally changed the guiding ideology of unconventional fracturing and put forward different requirements for the optimum design and production mode of fracturing.

3 Application Example

To investigate the rationality of the above theory and method, a horizontal well fracturing in a gas field is applied and calculated. The horizontal section of the well is 500 m long, fracturing is divided into four sections, and the depth is about 2000 m. The specific physical parameters of the reservoir are shown in the Table 1.

According to the above test parameters, a model of 300, 300 and 100 m is established for long, wide and high respectively, wherein the interlayer is respectively 25 m and the gas layer is selected to be 50 m, combined with the above fracturing effect volume FIV model, considering the dependence of permeability on effective pressure difference, the reservoir numerical simulation method is used to simulate the horizontal well fracturing.

Table 1 Physical parameters of rock in a horizontal well

	Young modulus/GPa	Poisson ratio	Mean porosity/%	Mean permeability/mD
Interlayer	5.65	0.24	0.17	/
Air layer	15	0.21	0.17	0.001

When shale gas is produced, the production is defined in the inner side, the pressure is defined outside, and the pressure relief radius is the distance to which the pressure disturbance propagates at the current moment, the conditions for the solution are as follows:

$$\Psi|t = 0 = \Psi_i(p = p_i) \tag{6}$$

$$r\frac{\partial \Psi}{\partial r}\bigg| r = r_w = \frac{q_{sc}p_{sc}T}{\pi K_o h Z_{sc} T_{sc}} \tag{7}$$

$$\Psi|r = r_c = R(t) = \Psi_i(p = p_i) \tag{8}$$

Through the pressure distribution formula of unsteady seepage reservoir and MATLAB programming, the distribution curve of formation pressure in different time is obtained. As the production time increases, a pressure drop funnel is formed from the wellbore to the far end. According to the distribution of formation pressure at different production times and different distances from the wellbore (Fig. 8), combined with the change of reservoir permeability and pressure difference mentioned above, reservoir permeability distribution at different distances from wellbore and different production times can be obtained.

Figure 9 shows the permeability field of reservoir system in the early stage of fracturing production. Permeability changes in the near well zone after fracturing. According to the model of fracturing effect volume, the permeability of reservoir system increases because of the better connectivity between micro-fractures and micro-pores after fracturing. The closer it is to the well, the better the diffusion effect is, and the more obvious the permeability is. With the increase of distance, the diffusion effect of micro-fracture and micro-pore pressure leading to diffusion decreases gradually, and the increase of permeability becomes smaller.

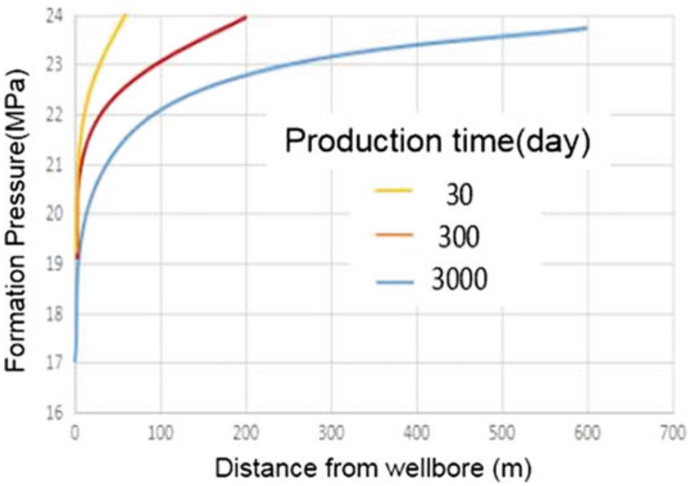

Fig. 8 Distribution of formation pressure at different distances from the well

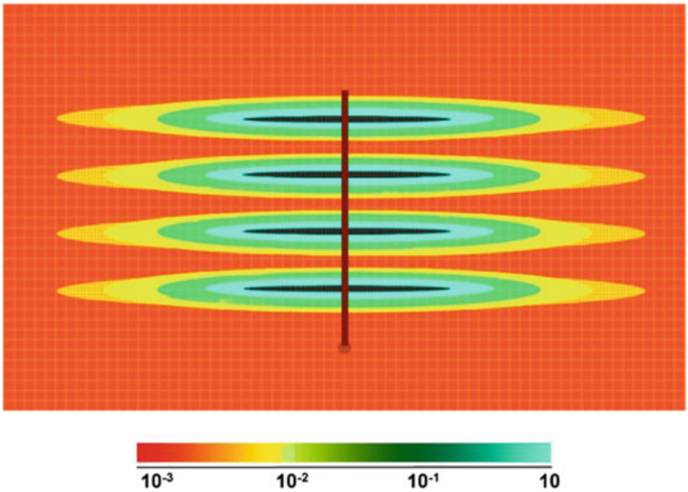

Fig. 9 Distribution of reservoir permeability at different distances from the well

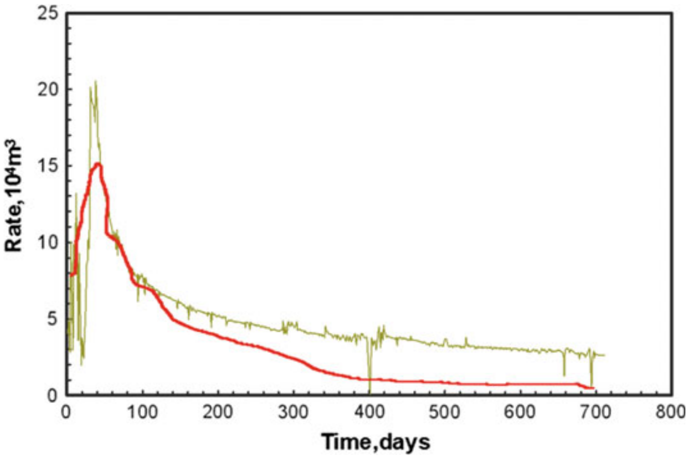

Fig. 10 Production fitting without considering the effect of fracturing on volume FIV effect

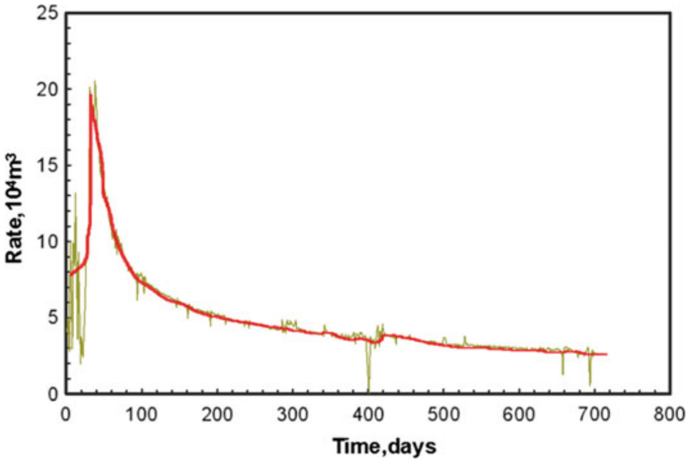

Fig. 11 Production fitting considering the effect of fracturing on volume FIV

Figure 10 shows the production matching of not considering Fracturing Impacted Volume effect, the curve trend and numerical has not been fitting. In early stage of opening the well for production, due to not considering Fracturing Impacted Volume effect, pore pressure and system permeability are overall low, lead to the single well production cannot be matched. Such as at the initial production stage, the average formation pressure of near wellbore area is 18 MPa, average permeability of near wellbore area is about 0.001 mD. When considering FIV effect, it must be considered fully the increasing condition of pore pressure and system permeability after the formation was stamped, the average formation pressure of near wellbore area is 20 MPa, average permeability of near wellbore area is about 0.01 mD. The parameter setting is more suitable for the real underground situation after fracturing. Figure 11 shows the production matching of considering Fracturing Impacted Volume effect (fixed permeability near wellbore area), the production curve matching is good.

As Cluff, etc. pointed out in their article of 2007, there is a minimum representative volume element in a fracturing simulation. The smallest representative volume unit is obviously larger than the minimum representative volume unit of the conventional reservoir, because the latter considers the existence of micro-cracks. The numerical modeling requires 2–4 magnitude orders of the system permeability of the gas permeability to match the flow rate and the final increasing. It is necessary to have a higher permeability pathway through the shale [6]. The example above is also fully showing that existing the phenomenon of matrix stamping activation, the connectivity of micropores is better and the system permeability increases, which was evidenced in the capacity simulation. The concept of Fracturing Impacted Volume model is consistent with the fitting results of actual production data, also indirectly shows that significance guiding of the model proposed in this paper of future fracturing and productivity evaluation.

4 Conclusion

Tremendous numbers of horizontal wells have been fractured and huge amount of production data are available with over decade production history of unconventional reservoirs. We have a lot of more information that we had a decade ago. It is no supervise for us to have some new understanding on the unconventional reservoir fracturing and production related simulation.

The drawbacks in using Discrete Fracture Network (DFN) or fracture network model are so obvious and unavoidable as discussed in this paper, an alternative mode is certainly necessary. We all know that we cannot get those parameters properly for the DFN model as discussed above in this paper, and trial and error method is not feasible neither due to the unlimited possibilities.

On the other hand, in the FIV model, regardless the size, number of the nature fractures and drilling/hydraulic induced fractures, all those non-quantitively characterized micro and macro fractures can be treated as the reservoir system properties, which may be measured through DIFT or other means including simulation method to estimate the alone with the main fracture created hydraulically. This is what has been called "the greatest truth for complicated things is simple, and most likely it is the best answer" as an old saying.

In the fracturing process, a large amount of slickwater was used as pad fluid to enhance the original permeability and the leak off increasing significantly, which increases the additional driving mechanism for subsequent production and provides additional potential energy and activation very localized pore/fracture space of the rock in the microscale of the reservoir. In this paper, the concept of FIV model and its flow system composite model is hinted. With this model and its related concepts, certainly the fracturing design and production mode can be improved significantly for unconventional reservoir development and EOR as well.

In terms of the mechanism of unconventional fracturing: FIV model and its concept are different from the concept and model of fracture network fracturing or DFN, the latter over emphases the importance of fracture networks or complex fractures and needs to quantitatively define them. That is an obvious and old pitfall as in conventional reservoir for decades—detailed static parameters characterization dilemmas because the so-called static parameters are not never static in many cases. It is believed that dynamic is always the prevailed factor for those parameters from the beginning to nowadays when the fracturing is implemented. In the FIV region, the reservoir permeability is enhanced and microcracks/micropores are activated through pressurization of fracturing, which stimulates oil and gas in microscale alone the main hydraulic fractures. That may be the most important mechanism of the fracturing all about for unconventional reservoirs.

In terms of fracturing simulation and production model: In the framework of in using FIV model, people don't need to puzzle their brains about how to set the amount of natural fracture, the position, the scale and their conductivity of nature fractures in the model, and it is not necessary and no way to distinguish which inch of the pay is the matrix and which microfracture/fissures are the natural ones or induced ones in the mesh model calculation. In this paper, FIV fracturing simulation and reservoir simulation model and its associated concepts are considered irreplaceable role.

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