A Discourse on Unconventional Reservoir Engineering – The State of the Art after a Decade

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Abstract

Proven economic success of production from ultra-tight unconventional resource plays in the US has opened a new frontier for the oil and gas industry. This so-called "unconventional reservoir revolution" has been usually attributed to new discoveries and technological developments in the areas of horizontal well construction and staged hydraulic fracturing. Despite the impressive technological advances to develop tight unconventional resources, after a decade, our understanding of the physical mechanisms of fluid production from these reservoirs has been limited. This paper presents the state of the art in unconventional reservoir engineering through the eyes of its author and discusses the new directions for future developments.

Introduction

In the last decade, shale-gas, tight-oil, and liquid-rich unconventional resource plays have become important sources of domestic oil and gas production in the US. Similar to any emerging resource, unconventional reservoirs became a viable source of energy when new technologies removed the technical and economic barriers for the exploitation of these resources [Holditch, 2006]. Contrary to the common thought, however, favorable oil prices had a limited role in the emergence of unconventional reservoirs; instead, the development of the tight unconventional resources should be viewed as a response of the oil and gas industry to the challenges of the reserve replacement problem coupled with the problem of finding new resources that are abundant, have longer life expectancy than the conventional reserves, and make economic sense when compared with the other conventional and unconventional energy sources. Analyses of economic scenarios (Fig. 1) have indicated that for optimum reserve replacement, switching to unconventionals is inevitable (curiously enough, the switch to unconventionals was required much earlier for the low-price scenarios) [Ozkan et al., 2012].

As indicated by Fig. 1, despite the fact that the largest revenue will still be obtained in the future from the production of the existing conventionals, due to increased scarcity, exploration and development of new conventionals will be associated with higher costs and will tend to provide smaller profit margins; eventually dropping to negatives by the mid 2020s. On the other hand, pursuing unconventional reservoir development options will provide the industry with better prospects and maintain a positive profit margin [Ozkan et al., 2012].

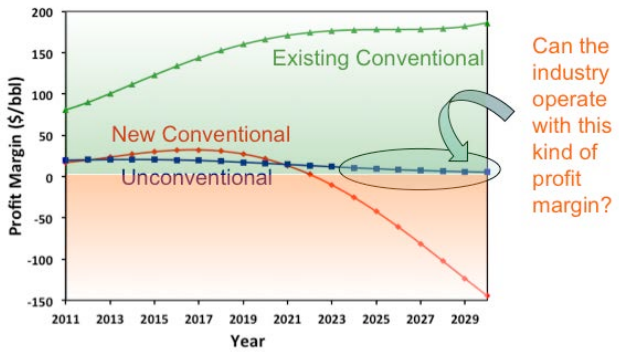


Figure 1 – Profit margins of the existing conventional reserves, conventional replacement, and unconventional replacement for the low-price scenario [Ozkan et al., 2012].

The implications of these predictions are widespread. On one side, hydrocarbon-poor or depleted countries will intensify their efforts to utilize unconventional resources to reduce their dependence on foreign energy and improve their energy security. On the other side, traditionally oil-rich countries will try to develop and utilize unconventional gas resources for their increasing domestic consumption and save the conventional oil for export. An examination of the recent emphasis of the private and national oil companies on unconventional resource development justifies these predictions [e.g., Buchan, 2013, Makan and Crooks, 2013, and Hall, 2013]. However, the long-term profit margin shown in Fig. 1 for unconventional oil is predicted to be small ($2-5). Even if the resource scarcity creates an upward price trend in the long term, because the oil companies cannot control prices, their best option will be to lower the extraction and development costs by using better technologies and more efficient reservoir management. This discussion warrants a critique of the options available for the industry to create a positive economic impact by new technology applications.

Figure 2, shows the differences between the production decline characteristics of a 10,000-ft Bakken-field horizontal well with 30 frac stages [Mason, 2012] and an average vertical well in conventional US plays [Auzanneau, 2012]. The steep production decline of the fractured horizontal well at early times shown in Fig. 2 has sometimes been cited as a discouraging factor for the development of unconventional resource plays. However, the high decline rate of the horizontal well at early times should not be confused with the boundary-dominated production decline of conventional wells. Whereas the former signifies the accelerated production under transient flow conditions, the latter indicates the accelerated depletion under the effects of the boundaries. Therefore, it is more appropriate to designate this flow period as accelerated production before a stretched linear-flow dominates the long-term productivity of the well.

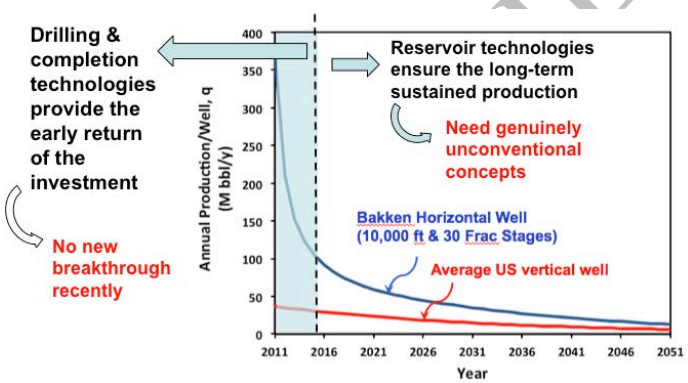


Figure 2 – Production decline trends for wells in conventional and unconventional plays.

A decade of production from unconventional plays has shown that the high project costs are compensated by the accelerated production at early times (the shaded area in Fig. 2 is roughly the pay-back period for unconventional wells in the US). It must be emphasized that the high initial production (IP) of wells in unconventional resource plays is a result of more efficient flow convergence toward the well, removal of flow impediments, and more efficient communication with natural fractures in the near field (vicinity of the well and hydraulic fractures), which are mandated by advanced (and expensive) well construction and stimulations technologies. Although the accelerated production contributes immensely to project economics, its impact on long-term productivity is limited as the long-term productivity is mainly governed by the flow conditions in the far field and highly dependent on good reservoir management, which requires good understanding of reservoir flow mechanisms.

Tight nano-porous resources are usually labeled "unconventional" due to their limited flow capacity associated with their very low permeability. As shown in Fig. 3, for example, shale plug permeabilities are too small to measure (apparent effective permeabilities estimated from desorption vs. time plots are in 10's of nanoDarcies, and pulse decay permeabilities from powdered samples are in the range of 10^{-3} to 10^{-12} milliDarcy) [Cluff et al., 2007]. The hydrocarbons are stored in pore spaces from a few nanometers to a few hundred nanometers in radius [Curtis et al., 2010], leading to intricate rock-fluid interactions, complex flow and phase behavior, low production rates, and small ultimate recovery factors. It is estimated that nearly 90% of tight-oil [Chaudhary et al., 2011] and 65% of unconventional gas [Dong et al., 2013] will be left in the reservoir using the existing methods of production. How to properly manage these resources to achieve long-term sustained production and improved recovery is a problem of significant interest. Despite the impressive technological

advances to develop tight unconventional resources, our ability to characterize and model production from these fractured nano-porous reservoirs has been limited.

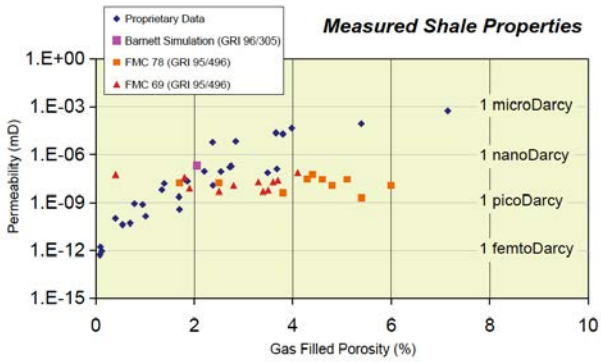


Figure 3 – Permeability of shales [Cluff et al., 2007]

This paper brings the state of the art in unconventional reservoir engineering into focus and discusses the new directions for future developments. However, because unconventional designation is mostly contextual, before delving into the details, we clarify what we mean by unconventional reservoir engineering in this communication.

What is Unconventional in Unconventional Resource Plays?

The definition of "unconventional reservoir" varies by time, location, and discipline. Until mid 1970s, the exploration geologists in the US considered sub-economic or marginally economic gas resources as unconventional. However, the market-based rate regulation and the passage of National Gas Policy Act changed the economic environment for the exploration and production of some of these unconventional natural gas resources [Law and Curtis, 2002].

Some geologists used the distinctions of geologic characteristics to define unconventional gas resources in the early 2000s. They noted that unconventional gas resources are regionally pervasive accumulations, which are mostly independent of structural and stratigraphic traps and not buoyancy driven [Law and Curtis, 2002, and Law, 2002]. The definition of unconventional gas resources as continuous accumulations has led to the concept of sweet spots (localized areas with more favorable reservoir characteristics) or the conclusion that the variations in productivity are due to the variations of drilling and completions technologies. This geology-based definition has been challenged by the demonstration that, although at different scales, most known tight and shale-gas accumulations display the characteristics of conventional petroleum systems [Shanley et al., 2004]. This has led to a newer definition of unconventional (shale) gas plays based on very fine-grain rock texture, gas storage, and flow characteristics, which are uniquely tied to nano-scale pore throat and pore size distribution, and organic and clay content that serve as gas sorption sites.

Although more comprehensive, the definition of unconventional gas accumulations based on complex and unusual petrophysical properties may still not be sufficient for every discipline. For example, from reservoir engineering perspective, unless the geological, geochemical, and petrophysical complexities do not lead to unconventional flow mechanisms, the challenges of unconventional resource plays may be simplified to the incorporation of heterogeneity and small scales of properties into conventional tools, models, and procedures. Therefore, to have a more comprehensive definition, well-completion challenges and flow-mechanism "oddities" must be included in the list of characteristics. Recently, flow mechanism "oddities" have been more often recognized as the root cause of the reservoir engineering challenges. Therefore, in this communication, the challenges of unconventional reservoir engineering will be addressed mainly from the perspective of unconventional flow mechanisms.

Unconventional Reservoir Characterization and Engineering Challenges

Nano-porous unconventional reservoirs often exhibit a variety of heterogeneities, such as fractures, fissures, micro, macro, and inter-aggregate pores, and the conglomerations of organic matter. These properties pose challenges to our ability to characterize the formation and fluid phase behavior. Establishing a reservoir-engineering framework for unconventional shale-oil reservoirs requires a multi-scale understanding of dynamics

of fluid flow coupled with phase behavior starting from the very fundamental pore-level.

The heterogeneity of the microscopic structures in shales and other nano-porous formations causes preferential flow at the macroscopic level by creating a highly nonuniform velocity field. Preferential flow in the nonuniform velocity field leads to nonequilibrium conditions with respect to pressure and concentrations of hydrocarbon components, which further complicate our ability to model and predict flow and transport in such heterogeneous media. What separates these characterization and modeling challenges from those in conventional reservoirs is the lack of a clear scale separation in unconventional reservoirs.

Models of flow and transport in porous media traditionally rely on the validity of continuum methods, which assume small or finite spatial correlations of process variables. The premise that a scale separation exists imposes certain constraints on the rock properties and process parameters. The constraints of the continuum assumption become dubious not only because of the types of heterogeneity caused by the varying scales of pores and the contrast between the matrix and fracture characteristics, but also due to the strong scale dependency of the phase behavior and local gradient of the mean process variables in nano-porous unconventional reservoirs. Yet, the unconventional reservoir characterization challenges were taken, initially, as an issue of scale and tool sensitivity. Similarly, the industry took a pragmatic approach to manage these resources with the existing conventional understanding and tools. From that perspective, some of the biggest challenges of the practicing reservoir engineers have been the use of conventional characterization tools and the sources of data, definition of drainage area, and the implementation of conventional production decline analysis to unconventional resource plays.

Petrophysical complexities of unconventional resource plays, such as extreme heterogeneity, mixed pore-size and pore-throat geometries, and the complex mineral content of mudrocks complicate the use of conventional characterization approaches in unconventional resource plays. Moreover, unaccustomedly small scales of porosity and permeability cause problems in measurements and raises concerns in interpretations. However, the protocols used by the industry do not considerably differ from those used for the petrophysical characterization of conventional reservoirs. For example, the current approach to characterize unconventional formations by the conventional notion of Darcy flow leads to the obscure designation of "nano-Darcy formation," despite the practical non-existence of Darcy flow at such low magnitudes of permeability. One of the consequences of this contradiction is the dubious permeability estimates from different sources. Similarly, inability to establish undoubted lab protocols cause inconsistency in nano-porosity characterizations (Fig. 4) [Apaydin, 2012].

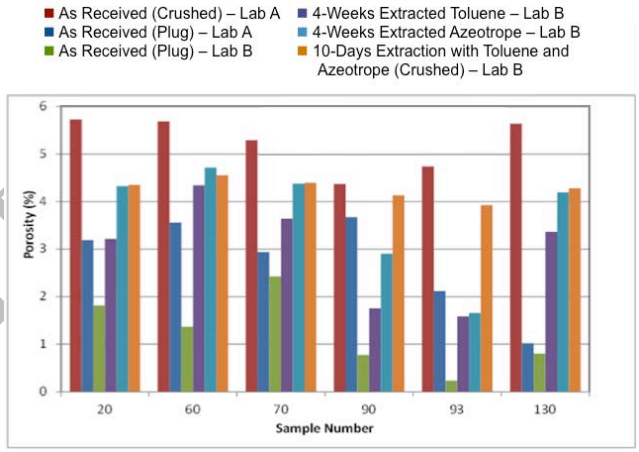


Figure 4 – Extended extraction measurements from a Niobrara core [Apaydin, 2012)

Another major challenge faced in practical reservoir management is the use of production decline analysis. Production decline models are preferred because they are zero-dimensional; they do not require specific information about reservoir characteristics and detailed description of flow in the reservoir. Often times, the application of conventional production decline analysis to unconventional resource plays has been addressed as a problem of processing the data to follow the assumptions of the conventional decline models (these include generating liquid-equivalent gas production data, removal of the effects of variable rate and production, incorporation of fractures and horizontal well, etc.). However, the conventional boundary-dominated production-

decline analysis is based on material balance considerations and requires the knowledge of the drainage area and average pressure.

Fundamentally, if boundary dominated flow prevails in the reservoir, processing and transforming the data should suffice for the application of conventional production decline models to unconventional reservoirs. However, unlike most conventional wells, where physical depletion of the drainage volume dictates the end of the project, for long fractured horizontal wells in unconventional resource plays, economic depletion comes before the physical depletion of the play. Therefore, production data analysis in unconventional reservoirs requires transient flow considerations and detailed modeling of flow convergence around the well and in the reservoir. To rephrase the problem, the efforts to implement conventional production decline analysis and refrain from detailed flow modeling have not provided acceptable solutions. Furthermore, in the absence of consistent and coherent rock and fluid characterization and a well-defined framework of flow in fractured nano-porous reservoirs, "detailed" simulation studies are unlikely to yield satisfactory results.

Perceptions of Flow in Unconventional Reservoirs and Their Implications

The conventional definition of transport in porous media is phenomenological [Prat, 2010]. Our perceptions are such that the porous medium forms a continuum, saturation, pressures, etc., are volume-averaged quantities, and the relation of fluxes to gradients is through empirical coefficients. Consistent with these perceptions, we define phenomenological constitutive relationships, such as Darcy's law (or Fick's law), relative permeability, macroscopic capillary pressure, etc. In this context, the objective of the fluid and flow domain (porous rock) characterization is the quantification of the constitutive relationships (such as the physical properties and phase behavior of the reservoir fluids, magnitudes and directions of permeability, capillary pressure vs. saturation curves, etc.).

When the perception of flow and transport changes, new constitutive relations are required to fit the new perception. Accordingly, the objectives of reservoir characterization (in other words, the parameters to be described and quantified) may change. Considering the fact that the flow-mechanism oddities in most unconventional reservoirs are fundamentally related to the small pore and pore-throat sizes, what seems to suit better is "nano-porous" reservoir designation, rather than "nano-Darcy" reservoir, for these reservoirs. It is, then, only natural to reconstruct the perception of flow and its constitutive relations starting from the appropriate definition of the nano-porous flow domain. From this perspective, our current approach to define the flow domain based on the pre-assigned perception of flow is upside down.

Models of flow and transport in porous media traditionally rely on the validity of continuum methods, which assume small or finite spatial and temporal correlations of process variables. This perception permits the use of gradient-based flux relations, such as Darcy's or Fick's law, as constitutive relations together with the appropriate conservation equations. The premise that a certain scale and time separation exists, however, imposes constraints on the rock properties and process parameters. As indicated by Knudson [1909] flow regimes in Fig. 5, the assumptions of Darcy flow (continuum flow, no-slip boundary condition, etc.) are more likely to be met at conventional, micrometer range pore sizes. For gas flow in nanopores, for example, the Knudsen number may become larger than 10^{-3} at low pressures (as the effective distance between the gas molecules becomes larger) and it may be more appropriate to use the slip flow conditions [Ozkan et al., 2010]. This downsizing of the pore channels brings about not only a drastic change in the perception of flow (from Darcy flow regime to diffusive flows) but also in the characterization of the fluid and the flow domain.

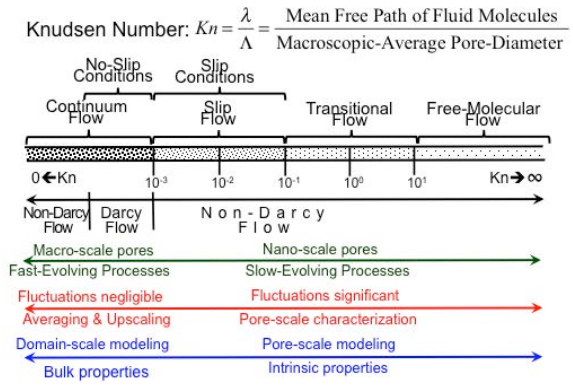


Figure 5 – Knudsen [1909] flow regimes and comparison of flow characteristics of conventional (micro-porous) and unconventional (nano-porous) reservoirs.

In macroscopic systems, flow and transport behaviors are reproducible and fluctuations (deviations from the typically observed, average behavior) are small. This establishes the basis of the continuum assumption. As a system's dimensions decrease, fluctuations away from equilibrium begin to dominate its behavior. Such systems are not appropriately characterized by using the continuum assumption; that is, by using properties averaged (upscaled) over control volumes (such as the permeability, diffusivity constant, etc. used in the flux laws defined based on the local gradients of the process variables) [Fomin et al., 2011] or by assuming bulk or equilibrium conditions (such as the phase behavior from PVT cell experiments, which ignore pore proximity effects, or based on classical equilibrium thermodynamics) [Firincioglu et al., 2012, Firincioglu, 2013, and Nojabaei et al., 2013]. In nanoporous unconventional reservoirs, the constraints of the continuum assumption become dubious not only because of the types of heterogeneity caused by varying scales of pores and contrast between the matrix and fracture characteristics (Fig. 6), but also due to strong pore-scale dependency of the phase behavior and non-local gradients of the mean process variables.

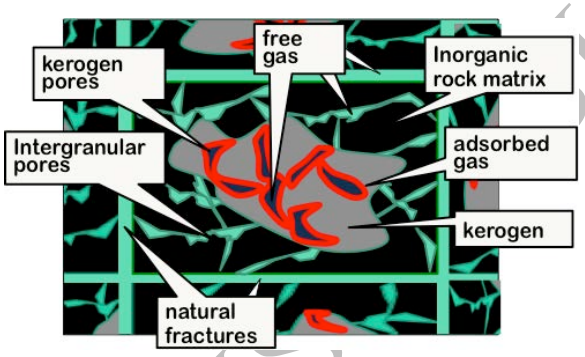


Figure 6 – Schematic of the storage media and pore structure in shale-gas plays.

Recent research [e.g., Javadpour et al., 2007, Javadpour, 2009, Ozkan et al., 2010, Kang et al., 2011, and Akkutlu and Fathi, 2012] has indicated that nanoporous unconventional resource plays possess multiple flow mechanisms at different spatial and temporal scales. For shale gas, for example, these mechanisms are a result of the gas storage in multiple media (Fig. 7); free gas in natural fractures, intergranular micro and nanopores of the inorganic matrix, and the pores (cavities) of the organic material (kerogen), adsorbed gas at the surfaces of the kerogen pores, and soluble gas in the organic material. In this context, it is useful to discuss the two perceptions that highlight the current unconventional flow models discussed in the literature.

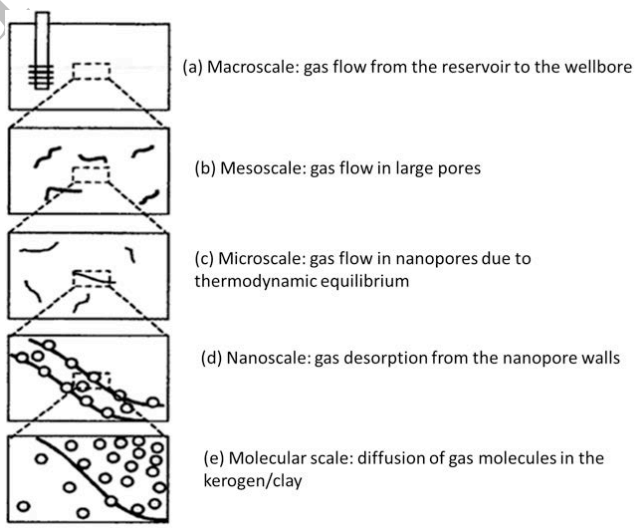


Figure 7 – Gas flow mechanisms at different scales [Javadpour et al., 2007].

The first perception is based on the assumption that the organic material is elongated along laminations (Fig. 8) and connected in the entire flow domain (forms a continuum) [Loucks et al., 2007, Javadpour et al., 2007, Javadpour, 2009, Kang et al., 2011, and Akkutlu and Fathi, 2012]. Because of the considerably larger sizes of the kerogen pores (left behind from the conversion of kerogen to hydrocarbons by thermal maturation) than the nanopores of the inorganic matrix, flow in the nanopores of the inorganic matrix is neglected. Therefore, the flow mechanism consists of the production of the free gas in kerogen pores, desorption of the gas at the surface of the organic pores, and concentration driven diffusion of gas from the bulk of the kerogen to its pore surfaces (Fig. 7). Naturally, these models emphasize desorption and diffusion in long-term productivity. Because of higher effective permeabilities based on larger pore size and the contribution of desorption and diffusive flows, existence of a natural fracture network is not usually essential to match the production data with these models either.

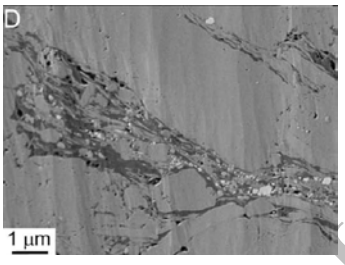


Figure 8 – Organic material elongated along laminations in Bakken shale sample [Loucks et al., 2007].

The second perception considers isolated pockets of organic content embedded in the nanoporous inorganic shale matrix (Fig. 9). Because the organic material is not in direct communication with the well, flow has to start in the inorganic pores first. However, due to the tightness of the inorganic matrix, flow cannot permeate into reservoir without the existence of a dense natural fracture network. As shown in Fig. 10 and demonstrated by simulations [Ozkan et al., 2010], even with natural fractures, flow in the inorganic matrix blocks is confined to a relatively thin surface layer. As a consequence, except when the natural fractures intercept the kerogen bodies, free gas flow, desorption, and diffusion in organic material do not considerably contribute to flow.

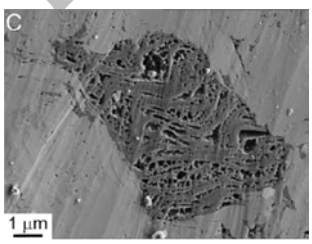


Figure 9 – Organic material embedded in the inorganic shale matrix [Loucks et al., 2007].

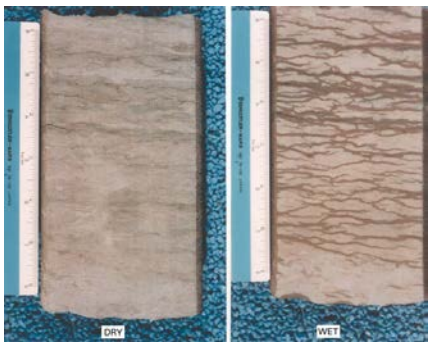


Figure 10 – Bakken core sample showing limited penetration of fluid from microfractures into shale matrix [Pitman et al., 2001].

It is possible to find examples of both perceptions in shale samples (although the size of the sample has a significant impact on the interpretations) and it is likely that nuances of both perceptions may be applicable. The author of this communication favors the second perception; thus, the rest of this discourse primarily builds upon the premises of the second perception. However, in the general context of flow in heterogeneous, fractured, nanoporous media, most of the discussions should be applicable to the first perception also.

With the basis of the discussion set as above, we can now scrutinize the flow mechanisms in unconventional reservoirs. Among multiple flow mechanisms, advection (Darcy flow) is the fastest; it dominates flow in fractures but its contribution is minimum in nano-porous matrix. In matrix nanopores, much slower diffusive flows are dominant. Of these mechanisms, diffusion caused by concentration gradients, such as Knudson diffusion [Ozkan et al., 2010] and diffusive flow in kerogen [Javadpour et al., 2007, Javadpour, 2009, Kang et al., 2011, and Akkutlu and Fathi, 2012], are well documented and included in some reservoir flow models.

It had been discussed in the literature that, Darcy's Law alone could not describe the fluid flow in weakly permeable media demonstrating membrane behavior [Revil and Pessel, 2002]. Recently, Firincioglu et al. [2012] have pointed out that thermodynamics in nano-porous media can also lead to different molecular compositions of the gas and liquid phases in different-size nano-pores. If the pore-throat sizes approach the scale of membrane pores, osmosis can take place. In fact, the behavior of argillaceous low-permeability media has been described as analogous to semipermeable membranes due to the membrane properties of shale layers [Kemper and Rollins, 1966; Olsen, 1969; Horseman and McEwen, 1996, and Neuzil, 2000].

The membrane properties of the weakly permeable media are associated with the existence of the gradient-driven coupled flows [Katchalsky and Curran, 1967; Bolt, 1979; Revil, 1999]. As the main coupled flow, chemical osmosis has been the subject of many studies of argillaceous media [e.g., Kemper and Quirk, 1972; Keijzer et al., 1999; Neuzil, 2000; Malusis and Shackelford, 2002; Gonçalvès et al., 2004; Gonçalvès et al., 2007]. One of the main areas of research in the literature is the estimation of the chemical-osmosis coupling coefficient, which is defined as the capacity of the membrane to behave as a semipermeable boundary. We conclude this discussion on osmosis by emphasizing that because diffusion and osmosis take place in opposite directions with respect to the concentration gradient, it is important to know the prevailing mechanism at a given point to determine the correct direction of transport.

Non-Local Anomalous Diffusion in Nano-Porous Unconventional Reservoirs

In the last two decades, non-local, memory-dependent descriptions of flow and transport have gained notable popularity among scientists, engineers, and mathematicians focusing on applications in various forms of nano-porous systems [Gorenflo et al., 2001]. These efforts have not attracted much attention in the oil-field applications due to the dominance of advective (Darcy) flow in conventional reservoirs. In unconventional shale-gas reservoirs, on the other hand, diffusive flow mechanisms have been recently incorporated into flow models due to their considerable contribution to flow in shale matrix [Javadpour et al., 2007, and Kang et al., 2011, Apaydin et al., 2011, Clarkson et al., 2012]. In these works, the advective and diffusive mechanisms were assumed to be independent of each other and locally defined based on the corresponding gradients of the process variables (pressure and concentration); an assumption that presumes linearly additive fluxes and permits the use of the classical diffusion equation. However, there has been enough evidence in the literature [Metzler, et al., 1994, Fomin et al., 2011] that classical diffusion is a special case, not a norm, in heterogeneous nanoporous media.

In statistical physics, diffusion is the result of the random Brownian motion of individual particles. Classical diffusion is usually associated with homogeneous porous media. It is a special case where the random Brownian motion of the diffusing particles is governed by a Gaussian probability density whose variance is proportional to the first power of time; that is the mean square displacement of a particle is a linear function of time:

$$\sigma_r^2 \sim Dt \tag{1}$$

However, a convincing number of works have indicated anomalous diffusion in which the mean square variance grows faster (superdiffusion) or slower (subdiffusion) than that in a Gaussian diffusion process. Thus, a general relationship between the mean square variance and time is given by

$$\sigma_r^2 \sim Dt^{\alpha} \quad \text{where} \begin{cases} \alpha = 1 & \text{Normal Diffusion} \\ \alpha \neq 1 & \text{Anomalous Diffusion} \\ \alpha > 1 & \text{Superdiffusion} \\ \alpha < 1 & \text{Subdiffusion} \end{cases} \tag{2}$$

The disordered structure of naturally fractured unconventional nanoporous media is more in line with the anomalous diffusion models where the geometric complexity of the medium slows down the particle motion in random walk (subdiffusion) [Park et. al., 2000] and the variance of the evolution equations becomes proportional to the fractional power of time (Eq. 2). In addition, transport pathways created by the natural and induced fractures in porous media have been shown to be fractal objects [Sahimi and Yortsos, 1990]. Transport in disordered systems often involves long-range correlations, which is another fundamental characteristic of fractal systems. Furthermore, the local gradients of the mean diffusion process variables depend on the global pressure field governed by advective flows and lead to a non-local anomalous diffusion process. Thus, in unconventional reservoirs, it is important to consider non-local diffusion in matrix nano-pores under the global influence of the pressure field dominated by the advective flow in fractures. This issue lends itself to a non-local, scale- and memory-dependent flow and transport formulation.

Fractional diffusion formulations have the potential of non-local modeling of flow with long-range interactions in nano-porous unconventional reservoirs. Many approaches have been proposed to derive a fractional diffusion equation that honors the non-Gaussian diffusion process signified by the relationship in Eq. 2 [Metzler et al., 1994, Metzler and Nonnenmacher, 1997, Park et al., 2000]. For the purpose of demonstration, here we will consider the following 1D fractional diffusion equation [Fomin et al., 2011]:

$$\frac{\partial^{\gamma} C}{\partial t^{\gamma}} = \frac{\partial}{\partial x}\left(D_{f\gamma\beta} \frac{\partial^{\beta} C}{\partial x^{\beta}} \right) \tag{3}$$

The fractional diffusion equation in Eq. 3 is obtained by using the following non-local flux relation (constitutive relation) in the continuity equation:

$$J_C = D_{f\gamma\beta}\, \partial_t^{1-\gamma}\left(\frac{\partial^{\beta} C}{\partial x^{\beta}} \right), \qquad 0 < \gamma, \beta < 1 \tag{4}$$

Note that for $\gamma = \beta = 1$, Eqs. 3 and 4 default to normal diffusion equations (Fick's second and first laws, respectively).

As opposed to the local-gradient based Darcy's or Fick's law, the non-local flux defined in Eq. 4 is proportional to the fractional temporal and spatial gradients of concentration of order $1-\gamma$ and β, respectively. In Eqs. 3 and 4, Caputo [1967] definition of the spatial and temporal fractional derivatives is given by

$$\partial_{\upsilon}^{\beta} C = \frac{\partial^{\beta} C}{\partial \upsilon^{\beta}} = \frac{1}{\Gamma(1-\beta)} \int_0^{\upsilon} (\upsilon - \xi)^{-\beta} \frac{\partial C}{\partial \xi} d\xi; \quad \upsilon = x \text{ or } t \tag{5}$$

Because the fractional derivative in Eq. 5 is a convolution, it depends on the values of $C(\upsilon)$ much farther away from υ. This signifies the spatial and temporal non-local perception of diffusion and constitutes a major shift from the conventional perception of local-gradient driven diffusion described by the Fickian flux (Eq. 4 with $\gamma = \beta = 1$) and the corresponding continuity equation (Eq. 3 with $\gamma = \beta = 1$).

Other considerations used in the fractal definition of the flow medium and in the construction of the constitutive relation lead to different representations of fractional diffusion equation. In petroleum engineering, fractal formulation of diffusion has been used to account for the stochastic character of natural fractures [Chang and Yortsos, 1990, Acuna and Yortsos, 1995, Camacho-Velázquez et al., 2008], reservoir heterogeneity [Beier, 1990 & 1994], and hydraulically fractured wells [Raghavan and Chen, 2013].

Chang and Yortsos, [1990] and Acuna and Yortsos [1995] defined a flux relationship in the following form (simplified here to 1D)

$$J_C = -D_f x^{-\theta} \frac{\partial C}{\partial x} \tag{6}$$

and then used the following diffusion equation

$$\frac{\partial C}{\partial t} = \frac{\partial}{\partial x}\left(D_f x^{-\theta} \frac{\partial C}{\partial x} \right) \tag{7}$$

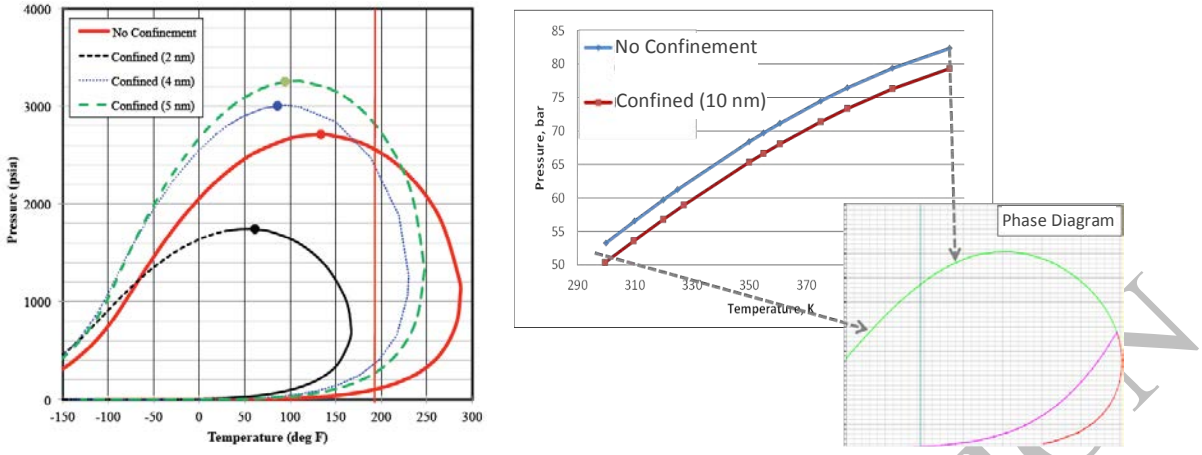
where θ is the index of anomalous diffusion determined by the fractal dimension of the medium This formulation, based on the results of O'Shaughnessy and Procaccia [1985], uses a steady-state conductivity and does not consider the memory of fluid flow (the flow path variations are entered into the formulation by a space dependent conductivity in the form of $D_f x^{-\theta}$). The same general formulation was used by Beier [1990] with different fractal parameters as he considered other forms of reservoir heterogeneity (combination of permeable and impermeable rocks). Beier [1994] later extended his solution to a vertically fractured well in a heterogeneous reservoir with radial geometry. Camacho-Velázquez et al. [2008] used the same flux relationship as Chang and Yortsos, [1990] and Acuna and Yortsos [1995] (Eq. 6) for a naturally fractured reservoir but utilized the memory dependent diffusion equation proposed by Metzler et al. [1994] in the form of Eq. 3.

Raghavan and Chen [2013] have recently presented a study of fractured well performance under anomalous diffusion. Their work considers a hydraulic fracture in an otherwise homogeneous reservoir. They focused on the development of appropriate forms of diffusivity equation to model diffusion in fractal reservoirs, particularly in the absence of radial symmetry. This point is important especially if we are interested in generalizing the formulations to multiple wells, non-uniform source strengths (finite-conductivity wells and fractures) and bounded reservoirs. Finally, in a slightly different context, Cossio et al. [2013] have explored the connection between the radial and linear forms of diffusion equation through the concept of fractals.

In principal, the existing work on reservoirs with fractal geometry may provide a stepping stone but the application of more general, non-local anomalous diffusion concepts to nano-porous unconventional reservoirs should require a significant effort. Furthermore, a crucial question yet to be investigated is the implications of non-local, fractional diffusion model on the characterization of nano-porous unconventional reservoirs. In a broad sense, the objective of characterization is to provide data for modeling studies. However, the existing approaches to characterization/modeling studies are based on the premise that the rock and fluid properties are locally defined and form a continuum. This permits, for example, the local gradient-based estimations of the diffusivity constant (or the permeability) from flux relations such as Eq. 6, and thus, enables various forms of upscaling. The ensuing ramifications of the fractional definition of the constitutive (flux) relation as in Eq. 4, however, are non-trivial and may require a complete overhaul of the conventional reservoir characterization approaches. Specifically, the interpretation of the fractional derivatives in Eq. 4 as convolution assigns a spatial and temporal non-local meaning to the diffusion coefficient, $D_{f\gamma\beta}$. As a result, a new approach to reservoir characterization with repercussions on upscaling concepts should be required.

Phase Behavior in Unconventional Reservoirs

Recent research [Firincioglu et al., 2012, Honarpour, et al., 2012, Sapmanee, 2011, and Devegowda et al., 2012] has shown that conventional PVT cell descriptions are inapplicable to phase behavior in nano-porous media. One of the consequences of the small pore confinement is the shift of the phase envelope and the suppression of the bubble-point as shown in Fig. 11.



A. Eagle Ford Gas Condensate **B. Bakken Fluid Sample**

Figure 11 – Phase diagrams of confined and unconfined fluids: A. Eagle Ford gas-condensate mixture [Sapmanee, 2011, Devegowda et al., 2012], B. Bakken fluid sample [Firincioglu et al., 2012, Firincioglu, 2013].

Two approaches have been reported in the petroleum engineering literature to deal with the bubble-point suppression issue. One of the approaches [Sapmanee, 2011, and Devegowda et al., 2012] aims at using conventional black-oil simulators with the modification of the pseudo-critical properties of the fluid. Although it is not possible to completely account for the phase behavior change under confinement with this approach, it has the promise of extending conventional black-oil simulators to unconventional resource plays. The other approach [Firincioglu et al., 2012, and Firincioglu, 2013] performs vapor-liquid equilibrium (VLE) calculations by also accounting for the capillary and surface forces. This yields gas and oil pressures separated by capillary pressure and surface forces when the first gas bubble appears. Then correlations are developed to relate the liquid and gas phase pressures to the bubble-point pressure obtained from bulk-fluid (PVT cell) experiments. This approach provides higher accuracy in phase behavior calculations (near to that of compositional simulators) but requires a special black-oil simulator to work with different phase pressures and correlations to relate the phase pressure in confinement to the PVT-cell estimate of the bubble-point pressure.

Following Firincioglu et al. [2012], to demonstrate the effect of confinement on phase behavior, we consider the relationship between the wetting and non-wetting phases in a pore space given by the following relationship:

$$p_{non-wetting} - p_{wetting} = \frac{2\sigma}{r} + \Pi \tag{8}$$

where σ is the interfacial tension, r is the radius of curvature of the interface, and Π is the surface forces (van der Waals, structural, electrostatic, and adsorptive forces). In a PVT cell, the capillary ($2\sigma/r$) and surface (Π) forces are negligible (because of the large curvature radius between the two phases and the small contact surface of the fluid with the container compared with its volume); thus, $p_{non-wetting} = p_{wetting}$. This leads to a bubble-point pressure concept where the wetting and non-wetting phase pressures are equal at the moment of appearance of the first gas bubble. In the Bakken field, however, 80% of the pores have a diameter less than five nano-meters [Bruner and Smosna, 2011]. Because the largest radius of a gas bubble in pore confinement is the radius of the pore, as the pore size decreases, the capillary forces may no longer be negligible. Furthermore, at small pore sizes, surface forces become comparable to capillary forces [Firincioglu et al., 2012]. Thus, the right hand side of Eq. 8 is nonzero and, when the first gas bubble forms, $p_{non-wetting} \neq p_{wetting}$.

The relationship between the liquid and gas pressures can be shown in terms of their chemical potentials as a function of pressure as in Fig. 12. When the first gas bubble appears, the chemical potentials of the gas and liquid phases should be the same. As shown in Fig. 12, the pressures and chemical potentials of the liquid and gas phases are the same if the capillary pressure is negligible (for the sake of discussion, we are neglecting the surface forces). This is the bubble point obtained from bulk fluid experiments in a PVT cell. In other cases, the liquid (wetting) and gas (non-wetting) phase pressures will be suppressed as shown, respectively, by

$$p_{liquid} = p_b - \left(p_c + p_e\right) \tag{9}$$

and

$$p_{gas} = p_b - p_e \tag{10}$$

where p_b, p_c, and p_e denote, respectively, the bubble-point pressure from PVT cell (bulk fluid) experiment, capillary pressure, and the excess suppression amount shown in Fig. 12. This indicates that for black oil simulations commonly used for unconventional reservoirs, not accounting for the bubble-point suppression may lead to significant underestimations of recovery.

To have a sense of the magnitude of error, let us compare the pressures of the liquid (wetting phase) in a Bakken fluid sample under confined (pore space) and unconfined (PVT cell, bulk fluid) conditions. In Fig. 13, $r_p = \infty$ corresponds to bulk fluid measurements taken in conventional PVT cells and $r_p = 10$ and 1 nano-meter cases consider the effect of pore confinement on bubble-point pressure of the liquid phase. Bubble-point suppression amount ranges from 4 bars for 10-nano-meter pores to 81 bars for 1-nano-meter pores. The corresponding effect of confinement on the formation volume factor is shown in Fig. 14 for the $r_p = 10$ nano-meter case. As expected, Fig. 15 highlights the significant prediction errors caused by the use of bulk-fluid measurements of PVT experiments in black-oil simulators.

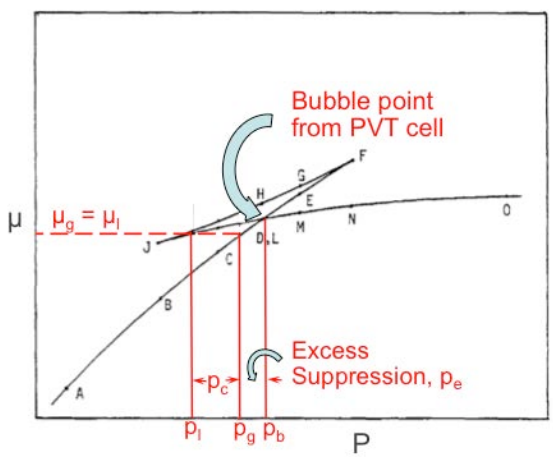


Figure 12 – Liquid and gas chemical potentials as a function of pressure [Udell, 1982, Firincioglu, 2013].

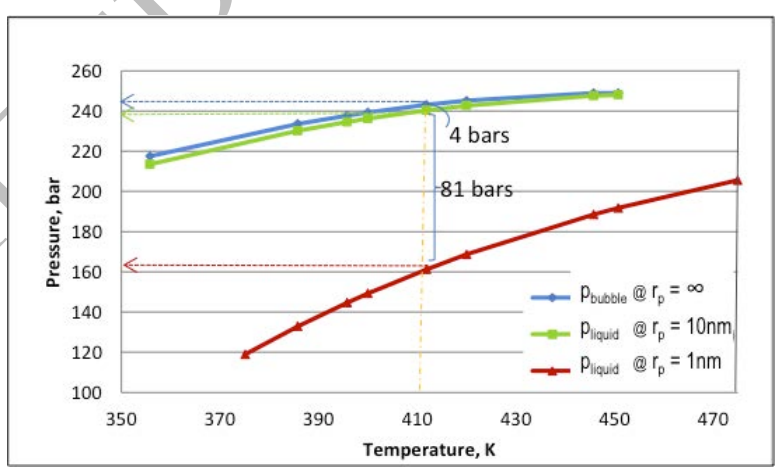


Figure 13 – Suppression of bubble-point pressure due to pore confinement; Bakken fluid sample [Firincioglu et al., 2012].

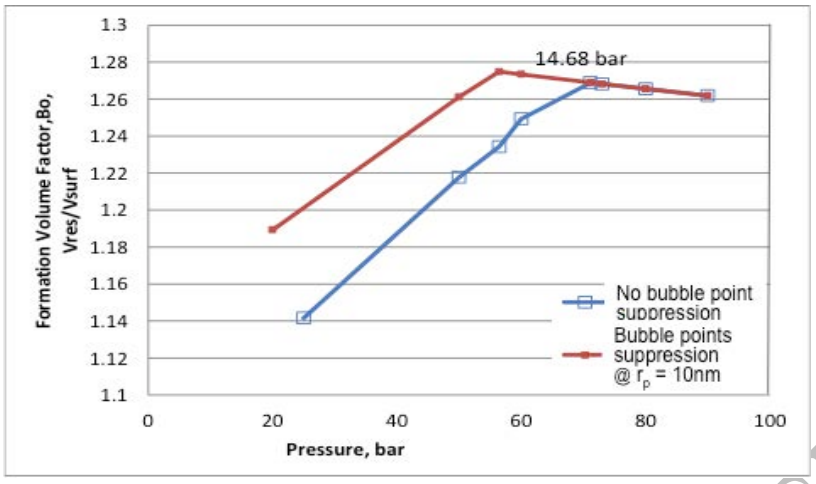


Figure 14 – Effect of bubble point suppression on formation volume factor; Bakken fluid sample [Firincioglu et al., 2012].

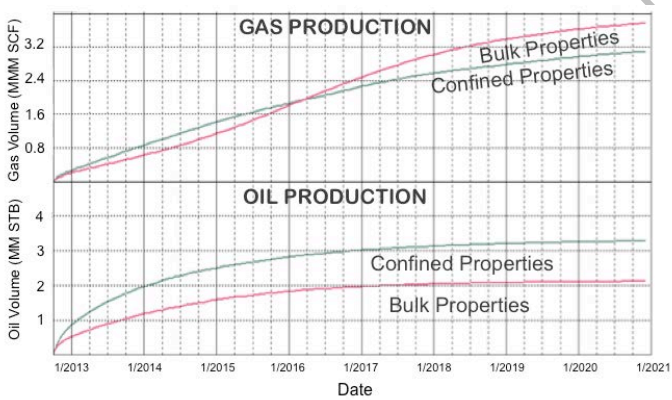


Figure 15 – Effect of bubble-point suppression on predictions by black-oil simulation; Bakken example [Firincioglu, 2013].

As a final remark on the effect of confinement on fluid properties, we note the possibility of other flow regimes in heterogeneous nano-porous formations. Figure 16, taken from Firincioglu et al. [2012], shows the effect of supersaturation (bubble-point suppression) on C1 and C7+ mole fractions. Having different liquid pressures at bubble point as a function of varying pore sizes indicates the possibility of concentration driven fluid flow in nano-porous formations.

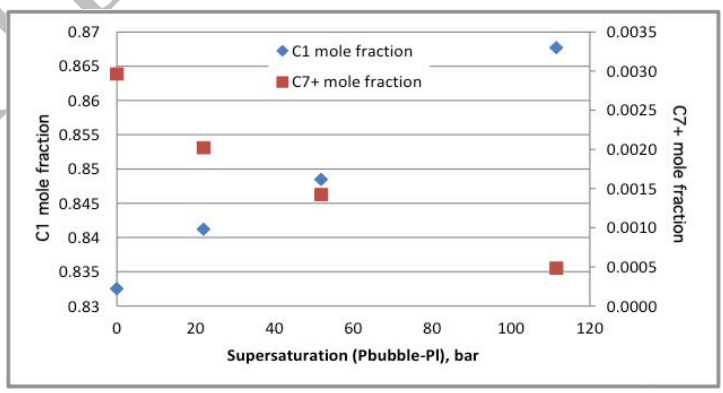
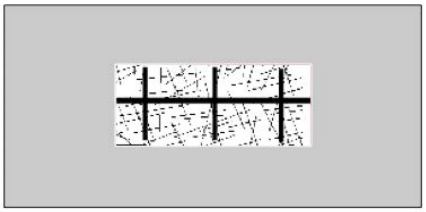


Figure 16 – Effect of supersaturation on fluid composition (Firincioglu et al., 2012).

Drainage Area Issues in Unconventional Reservoirs

Another important issue with the perceptions of flow in tight unconventional reservoirs is the definition of the flow domain. Because the initial interest and success of the industry came from the application of fractured

horizontal wells in shale-gas plays, the stimulated reservoir volume (SRV) concept has been usually affixed to flow domains in all tight formations (Fig. 17 A). However, the SRV concept is strictly tied to the perception that hydraulic fracturing in shale gas plays rejuvenates the existing healed (cemented) natural fractures (Fig. 17 B) in a local volume comprising the well and the hydraulic fractures. Beyond the tips of the hydraulic fractures and the horizontal well, the formation is assumed to consist of unfractured shale matrix. This perception appears to be supported by the concentration of microseismic events around the well during hydraulic fracturing.



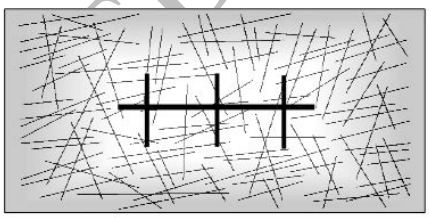
A. Stimulated reservoir volume (SRV) for shale-gas wells

B. Healed fractures in organic-rich shale

Figure 17 – Stimulated reservoir volume (SRV) for a fractured, horizontal shale-gas well (A) and healed natural fractures in organic-rich Woodford shale (B) [Guo and Marfurt, 2011].

The SRV concept, however, may not be applicable to unconventional liquid-rich and tight-oil plays mainly because of the different architecture of the fracture networks in these formations. In organic-rich shale formations, origins of invasive microfractures are usually associated with the maturation process; these fractures are assumed to be healed and cemented through subsequent events. Some larger and conductive tectonic fractures may also exist in the system with varying degrees of contribution to flow. If the density of the conductive macrofractures is low, then commercial production may be possible if hydraulic fracturing rejuvenates the healed microfractures around the well to create a stimulated reservoir volume (Fig. 17 A).

If the density and conductivity of the tectonic fractures are sufficiently high, then hydraulic fracturing is not expected to create (or rejuvenate) new fractures; instead, hydraulic fractures improve productivity by intersecting existing natural fractures in the global system (Fig. 18). In the well-known cases of liquid-rich and tight-oil production from Bakken and Eagle Ford, the producing layers are fractured carbonates or shales with high carbonate content. Although being in contact with (or in close proximity of) a source rock adds some additional features, at least for the drainage area considerations, all tight carbonates produce because of the existence of a global fracture network (Fig. 18 A). Particularly, because they do not possess the thermal maturation related, healed micro fractures, hydraulic fracturing in these formations intercepts the existing open fractures (Fig. 18 B) but does not create a new fractured zone (SRV) around the well.



A. Fractured horizontal well in a globally fractured tight-oil play

B. Open fractures in producing formation

Figure 18 – Fractured horizontal well in a globally fractured tight-oil play (A) and open fractures in Woodford shale [Guo and Marfurt, 2011].

Fractured horizontal wells in shale-gas and tight-oil plays display various production decline characteristics depending on whether the natural fracture network is localized (SRV) or global (Fig. 19). For shale-gas wells with an SRV, physical depletion (boundary dominated production decline) follows the end of formation linear flow between hydraulic fractures because the region beyond SRV does not contribute (Fig. 19). For tight-oil systems, after the depletion of the internal region between hydraulic fractures, a compound linear flow period develops because of the global extent of the natural fractures. Depending on the ratio between the horizontal-well length and reservoir dimension, a pseudoradial flow period may prevail before eventually reaching the physical depletion behavior (Fig. 20).

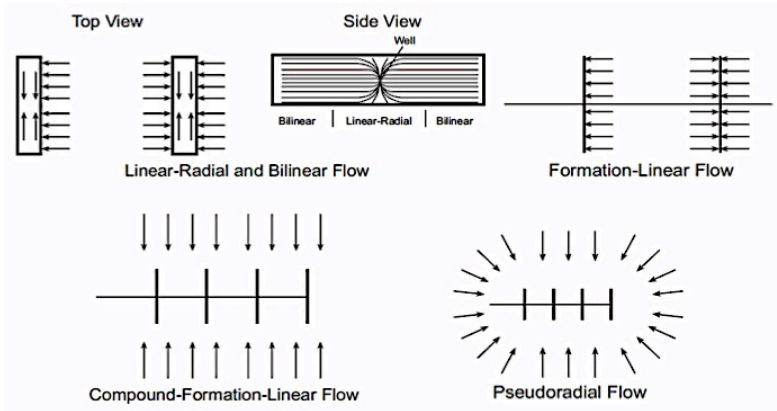


Figure 18 – Potential flow regimes for fractured horizontal wells [Raghavan et al., 1997, Kamal, 2009]

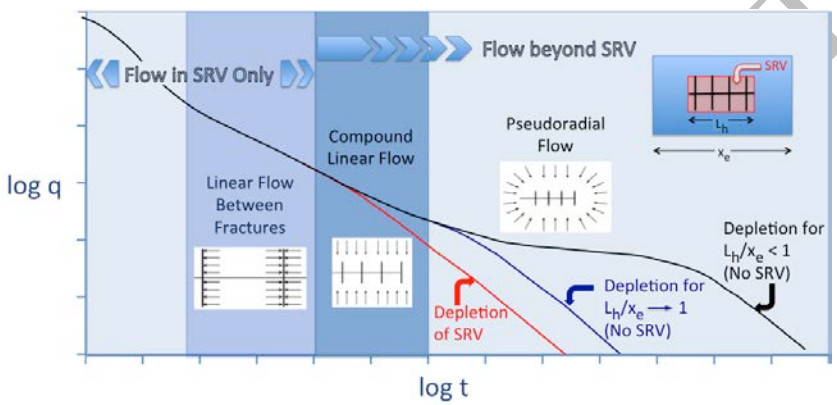


Figure 20 – Production decline characteristics for fractured horizontal wells

As shown in Fig. 20, if the horizontal well length approaches the extent of the reservoir ($L_h/x_e \rightarrow 1$), physical depletion follows the linear flow behavior with or without an SRV. In these cases, the use of the SRV concept for tight-oil systems underestimates the drainage volume of the well. Furthermore, in any system, the productive life of the well ends when an economic depletion rate is reached. In more conventional systems, economic depletion coincides with the physical depletion of the drainage area (boundary dominated production decline). In tight systems, economic depletion may be reached before the physical depletion of the reserves (before the well feels the physical boundedness of the drainage area). However, the common wisdom from conventional reservoirs usually associates any depletion with a physical or flow boundary (such as interference between wells). In shale-gas systems, the boundary of the SRV serves as a physical boundary and may lead to the physical depletion of the system. In tight carbonates, on the other hand, depletion occurs only when the existing energy of the system becomes insufficient to bring economically sufficient fluids to the well from beyond a distance. Because the wells in both systems usually reach depletion under economic restrictions, the actual conditions of the boundary may become irrelevant.

Concluding Remarks

A decade ago, reservoir engineers felt more comfortable dealing with unconventional resource plays as the industry initially conceived the unconventional-reservoir-engineering as an issue of using conventional concepts with nano-scale reservoir properties and incorporating multiple hydraulic fractures into flow models. This approach became inadequate as the long-term reservoir-management concerns offset the initial hype about unconventional shale-gas and liquids-rich reservoirs. Consequently, the interests in genuinely unconventional reservoir-engineering understanding and practices have started growing. After a decade, the challenges of unconventional reservoir engineering have only grown bigger, proportionally to our understanding that sustainable success in unconventional resource plays requires a major shift from the conventional perception of flow and transport in porous media.

This communication has not provided a complete review of the developments in unconventional reservoirs nor has it been intended as a comprehensive discussion of the challenges of unconventional reservoir engineering. Such a task would be daunting considering the wide variety of the imminent problems and the limitations of the author's command beyond areas of personal expertise. An effort, however, has been made to highlight the remarkable diversion from conventional reservoir engineering while discussing the state of the art in specific focus areas of unconventional reservoir engineering. Facts supported by data and evidence should be indisputable; the opinions and interpretations noted here, however, are author's own and inherently open to criticism.

Nomenclature

B_o : Formation volume factor, m^3/sm^3
C : Concentration, mol/m^3
D_f : Diffusion constant, m^2/s
$D_{f\gamma\beta}$: Anomalous diffusion coefficient, m^β / s^γ
J_c : Flux, $mol/m^2\text{-}s$
Kn : Knudsen number
p : Pressure, *Bar*
p_b : Bubble-point pressure, *Bar*
p_c : Capillary pressure, *Bar*
p_e : Excess suppression, *Bar*
p_g : Gas pressure, *Bar*
p_l : Liquid pressure, *Bar*
q : Flow rate, m^3
r_p : Pore radius, *m*
SRV : Stimulated reservoir volume
t : Time, *s*
x : x-coordinate (linear distance), *m*
Γ : Gamma function
∂_υ^β : Caputo derivative
θ : Index of anomalous diffusion
Λ : Macroscopic average pore diameter, *m*
λ : Mean free path of fluid molecules, *m*
μ_g : Chemical potential of gas, *Joule/mol*
μ_o : Chemical potential of oil, *Joule/mol*
Π : Surface forces, N/m^2
σ : Interfacial tension, *N/m*
σ_r : Mean displacement, *m*

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