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Summary

With a view to energy security of the world, unconventional energy resources - coalbed methane (CBM), methane gas hydrate, shale gas, basin centred gas, tight gas, oil shale and heavy oil- exploration and exploitation is a pertinent task for geoscientists. Shale gas is natural gas from shale formations which acts as both the source and the reservoir for the natural gas. Each shale gas reservoir has unique characteristics. Shale has low matrix permeability. So, gas production in commercial quantities requires fractures to provide permeability. For a given matrix permeability and pressure, the gas production is determined by the number and complexity of created fractures, their effective conductivity, and the ability to effectively reduce the pressure throughout the fracture network to initiate gas production. Understanding the relationship between fracture complexity, fracture conductivity, matrix permeability, and gas recovery is a fundamental challenge of shale-gas development. Shale gas reservoirs almost always have two different storage volumes (dual porosity) for hydrocarbons, the rock matrix and the natural fractures. Because of the plastic nature of shale formations, these natural fractures are generally closed due to the pressure of the overburden rock. Consequently, their very low, matrix permeability, usually on the order of hundreds of nanodarcies (nD), makes unstimulated, conventional production impossible. Almost every well in a shale gas reservoir must be hydraulically stimulated

(fractured) to achieve economical production. These hydraulic fracture treatments are believed to reactivate and reconnect the natural fracture matrix. Shales and silts are the most abundant sedimentary rocks in the earth's crust. In petroleum geology, organic shales are source rocks as well as seal rocks that trap oil and gas. In reservoir engineering, shales are flow barriers. In drilling, the bit often encounters greater shale volumes than reservoir sands. In seismic exploration, shales interfacing with other rocks often form good seismic reflectors. As a result, seismic and petrophysical properties of shales and the relationships among these properties are important for both exploration and reservoir management. Another key difference between conventional gas reservoirs and shale gas reservoirs is adsorbed gas which is gas molecules attached to the surface of the rock grains. The nature of the solid sorbent, temperature and the rate of gas diffusion all affect the adsorption. Presently, the only method for accurately determining the adsorbed gas in a formation is through core sampling and analysis. Understanding the effects of adsorption on production data analysis increases the effectiveness of reservoir management in these challenging environments. They contain natural gas in both the pore spaces of the reservoir rock and on the surface of the rock grains themselves that is referred to as an adsorbed gas. This is a complicated problem in that desorption time, desorption pressure, and volume of the adsorbed gas all play a role in how this gas affects the production of the total system. Adsorption can allow for significantly larger quantities of gas to be produced. Shale gas reservoirs present a unique problem for production data analysis. The effects of the adsorbed gas are not clearly understood except that it tends to increase production and ultimate recovery. The phenomena of gas storage and flow in shale gas sediments are a combination of different controlling processes.

1.1 Global Shale Gas Initiative (GSGI)

The GSGI uses government-to-government policy engagement to bring the U.S. federal and state governments' technical expertise, regulatory experience and diplomatic capabilities to help selected countries understand their shale gas potential. U.S. government agencies that partner with the Department of State under GSGI include: the U.S. Agency for International Development (USAID); the Department of Interior's U.S. Geological Survey (USGS); Department of Interior's Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE), the Department of Commerce's Commercial Law Development Program (CLDP); the Environmental Protection Agency (EPA), and the Department of Energy's Office of Fossil Energy (DOE/FE). A benefit of this government-to-government cooperation is the potential for establishing and strengthening long-term working relationships at the technical and ministerial levels. The ultimate goals of GSGI are to achieve greater energy security, meet environmental objectives and further U.S. economic and commercial interests (see http://www.eia.gov/analysis/studies/worldshalegas/; and http://www.adv-res.com/unconventional-gas-literature.asp). Countries have been selected to participate in GSGI based in part on the known presence of natural gas-bearing shale within their borders, market potential, business climates, geopolitical synergies, and host government interest (Figure 1). To date, partnerships under GSGI have been announced with China, India, Jordan and Poland, with bilateral agreements possible with several other additional countries. South American countries that participate in GSGI include Argentina, Chile, Colombia, Peru, and Uruguay. According to geologists, there are more than 688 shales worldwide in 142 basins. Shale gas exploitation is no longer an uneconomic venture with availability of improved technology as the demand and preference for this clean form of hydrocarbon have made shale gas, an energy in demand. The reserve accretion, production and development of shale gas from one basin to another around the world are rapidly increasing.

Gas flows through a network of pores with different diameters ranging from nanometres (nm = 10^{-9}m) to micrometres (μm = 10^{-6}m). In shale gas systems, nanopores play two important roles (Figure 2). Petrophysical imaging employs first, second and third generation wavelet to delve deep into complex shale gas reservoirs. Nanoscale gas flow in shale gas sediments has scope to cope with research on dry nanotechnology (smartfluid/nanofluid). Anisotropy in sediments may develop during deposition or post deposition. In clastic sediments, anisotropy can arise both during and after deposition. In carbonates, anisotropy is controlled mostly by fractures and diagenetic processes, and so tends to arise after deposition. For anisotropy to develop during deposition of clastics, there needs to be an ordering of sediments-in essence, some degree of homogeneity, or uniformity from point to point. If a rock were heterogeneous in the five fundamental properties of its grains- composition, size, shape, orientation and packing- anisotropy cannot develop because there would be no directionality intrinsic to the material. Anisotropy at the bedding scale that arises during deposition therefore may have two causes (Thomsen, 2002; Britt and Schoeffler, 2009). One is a periodic layering, usually attributed to changes in sediment type, typically producing beds of varying material or grain size. Another result from the ordering of grains is induced by the directionality of the transporting medium. Anisotropy is therefore governed not only by variation in the type of material but also by variation in its arrangement and grain size.

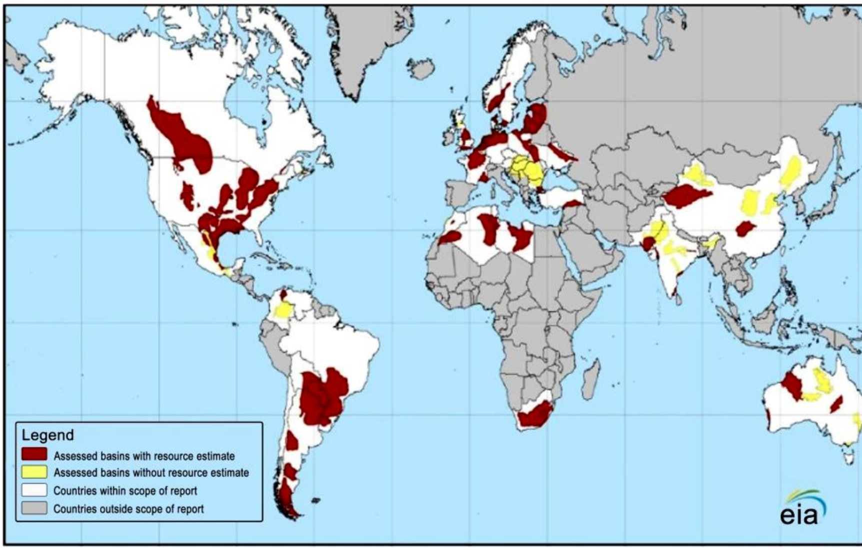

Figure 1. *Initial assessment of shale gas resources in 48 major shale basins in 32 countries indicates a large potential (Source: U.S. Energy Information Administration, Richard Newell, Paris June 2011, from: http://www.eia.gov/pressroom/presentations/newell_06212011.pdf).*

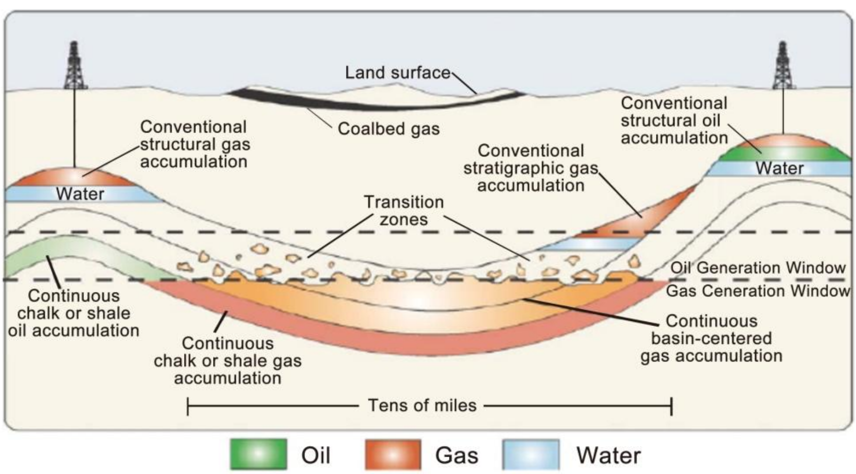

Figure 2. *Diagram showing the area of occurrence of shale gas (Source: United States Geological Survey).*

Shale, with its inherent heterogeneity and anisotropy, has always been problematic in many operations ranging from seismic exploration, well-log data interpretation, well drilling and well-bore stability problems, to production (Figure 3). Research works focus on bridging the gap between invariant characteristics at nanoscale of sedimentary rocks and their macroscopic properties. The 3D seismic is receiving an increasing interest in unconventional resources exploration. In contrast with the other techniques, it has a high potential to depict fracture and fault trends in subsurface.

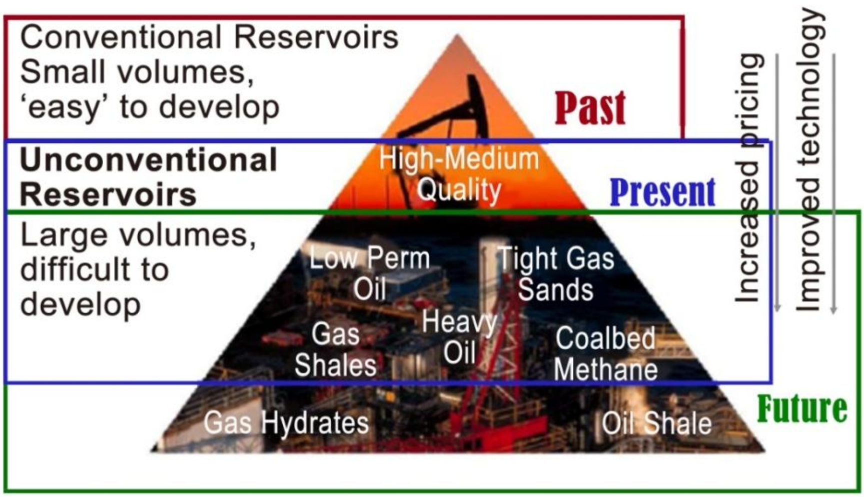

Figure 3. *The resource triangle unconventional resources (Holditch, 2006).*

Geologically complex and low permeability reservoirs, from which hydrocarbons may be sourced ,which require special evaluation and technology ,and some form of stimulation for economical production , in particular tight sand, shale and coal (Figure 4).

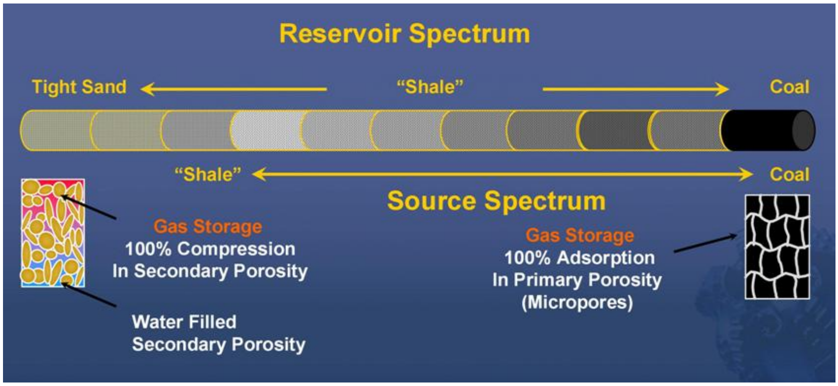

Figure 4. *Geologically complex and low permeability reservoirs (Hashmy and Jonkers, 2011).*

Unconventional reservoirs need a stimulation to achieve commercial production. Shale gas reservoirs necessitate fracture stimulation to release gas from very low-permeability formations. Since fracture stimulation is a capital issue in well completions, production companies explore fractures to get important information about their characteristics (dimensions, type, direction of fracture propagation, etc.). In this view, seismic is used to give such information and to guide drilling and completions (Hashmy and Jonkers, 2011). Three types of information derived from seismic data are of high importance in optimizing drilling locations: fracture characterization, geomechanical properties, and principle stress measurements (vertical maximum and minimum horizontal stresses). Given the target depth of formations in shale gas basins that are being exploited today, the maximum principle stress is vertical, giving rise to HTI (horizontal transverse isotropy) (Thomsen, 2002; Yenugu, 2010). This means that the fracture system is comprised of vertical fractures which cause anisotropic effects on seismic waves as they pass through. These anisotropic effects are observed on 3D seismic data as changes in amplitude and travel time with azimuth. In multicomponent data shear wave splitting can be observed. The relationship between changes in P-wave amplitude with azimuth in anisotropic media is used to invert the observed seismic response and predict fracture orientation and intensity. This information is of great value to production companies because it indicates the optimum horizontal drilling azimuth and offers the prospect of subsequent fracture stimulation as a solution to tap into existing natural fracture systems.A clear understanding of the geomechanical properties and their distribution explains the reservoir heterogeneity and thus the variation in economic ultimate recovery (EUR) between wells. Geophysicists derive a host of geomechanical properties from migrated CDP gathers, including Young’s Modulus, Poisson’s Ratio, and shear modulus, by first inverting the data for P- and S-wave velocities and density. With this information, fracture dimensions can be predicted and wells drilled in the most brittle rock. Linear Slip Theory for geomechanical properties is used to calculate stress values.

1.2 Nonlinear Seismic Imaging

In a nonlinear elastic system, the principle of superposition does not hold and the frequency mixing, the harmonic generation, and the spectral broadening take place. These changes that add new frequencies to the frequency spectrum provide us with a means of measuring the elastic nonlinearity parameter of the reservoir rocks. This elastic nonlinearity parameter is unique, and can be effectively used as a seismic attribute to map the rock properties of the reservoirs for improving the results of the exploration and exploitation efforts. The sensitivity of the nonlinear response to the porosity, fracturing, and pore fluids of the reservoir rocks is relatively larger than the linear measurements being used today. Industry needs to take advantage of this additional seismic attribute to reduce the ambiguity of the seismic-based geologic interpretation. Nonlinear seismic imaging enables the end-user to retain the conventional linear seismic images and provides additional nonlinear seismic images that identify the porous and fractured reservoir rocks. In areas where the current seismic fails to map the stratigraphic or fractured hydrocarbon traps, nonlinear seismic technology can provide the useful reservoir information.

1.3 Shale-Inherent Heterogeneity and Anisotropy

3D seismic is becoming successful because of the ability to identify fracture and fault trends. Surface geochemistry cannot identify in the subsurface where the frac or fault systems will be intersected by the drill bit. This is why 3D seismic is now being used aggressively and successfully. Unconventional reservoirs require some forms of stimulation to obtain commercial production. Shale gas reservoirs require fracture stimulation to unlock gas from extremely low-permeability formations. As fracture stimulation is an important aspect of well completions, production companies need to know basic information about fractures. Three types of information extracted from seismic are useful in optimizing drilling locations: fracture characterization, geomechanical properties, and principal stress measurements (vertical maximum and minimum horizontal stresses). Anisotropic effects are marked on 3D seismic data by variations of amplitude and travel time with azimuth. Besides, shear wave splitting can be observed in multicomponent data (Thomsen, 2002).

When geophysics met geomechanics: imaging of geomechanical properties and processes using elastic waves. The focus is primarily on geophysical imaging using elastic waves, whose propagation is controlled by a material's elastic properties and density (Prasad et al., 2009). The former can be thought of as the summation of contributions over a range of length scales: grains, discontinuities (including cemented or uncemented grain contacts), inter- or intra-granular cracks, fractures and layers, which can all be anisotropic or can produce an anisotropic aggregate material. Geophysicists obtain geomechanical properties from migrated CDP gathers, including Young' s Modulus, Poisson's Ratio, and shear modulus. The derived information allows to accurately predict fracture dimensions and to correctly choose the drilling locations of wells in the most brittle rock.

1.4 Azimuthal Anisotropic Seismic Signal Processing

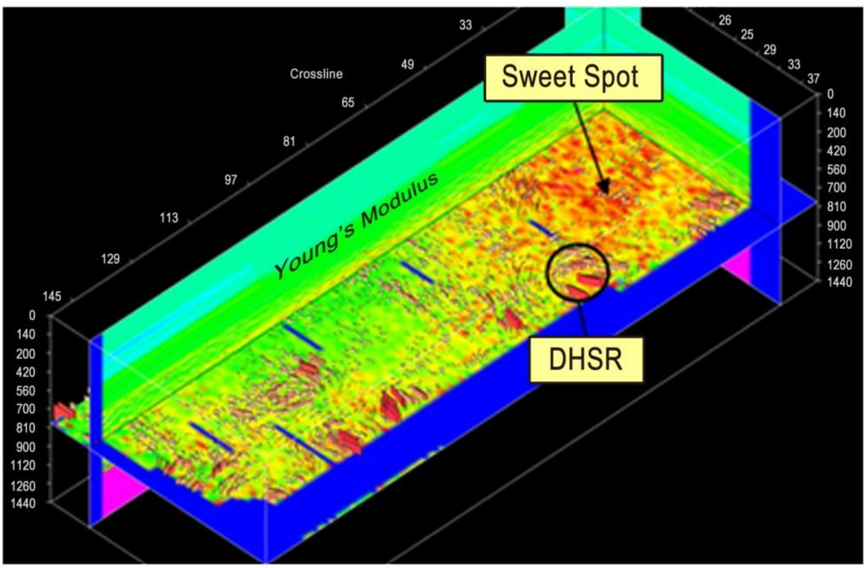

Figure 5. *Large plates correspond to large values of DHSR. The prospect locations are where Young's Modulus values are high (rock is most brittle) and DHSR plates are small (fracture swarms will form) (Image courtesy of CGGVeritas).*

Linear Slip Theory for geomechanical properties is used to calculate stress values. Generally, the stress state is anisotropic leading to the estimation of both the minimum and maximum horizontal stress. As the seismic data measure dynamic stress, results are then calibrated to the static stress that is effectively borne by the reservoirs at depth, making it possible to predict the hoop stress and the closure stress as key elements defining the type and motion of fractures. At locations where the differential horizontal stress ratio (DHSR - the ratio of the difference between the maximum and minimum horizontal stresses to the maximum horizontal stress) is low, tensile fractures will be formed in any direction, creating a fracture swarm (Figure 5). If the maximum horizontal stress is much greater than the minimum, then fractures will be formed parallel to the direction of maximum horizontal stress (Gray, 2010; Schmid et al., 2010).

1.5 Hydraulic Fracturing

Hydraulic fracturing is a process that results in the creation of fractures in rocks, whose goal is to increase the output of a well (Kundert and Mullen, 2009) (Figure 6). The hydraulic fracturing is used to increase or restore the rate of fluid flow within the shale reservoir and horizontal drilling creates maximum borehole surface area in contact with the shale. Hydraulic fracture complexity is the key to unlocking the potential of shale plays. Microseismic monitoring suggests that the complex fracture network can be developed in some shale plays (Warpinski, 2008). Microseismic monitoring is a proven technology and has been widely used to monitor and evaluate the effectiveness of hydraulic fracture treatments in various formations, including shale. Theoretically, in shale plays, a complex fracture should produce better compared to bi-wing planer fractures as a result of an increased fracture surface area. The value of the microseismic data is that it provides operators with 3D visualization of where the hydraulic fracture process is impacting the rock in the reservoir (Britt and Schoeffler, 2009). When real-time monitoring is used, the microseismic information can be used to prevent fracture growth out of zone. Microseismic hydraulic fracture monitoring is another of these new technologies. One of the principal costs in extracting natural gas is the hydraulic fracture process. The rock must undergo extensive fracturing to create the permeability required to allow gas to flow into the wellbore. Microseismic methodologies arguably offer industry the best method to determine the efficiency of the fracture stimulation process, as it applies to making contact with the gas resource locked in the rock (Warpinski et al., 2005).

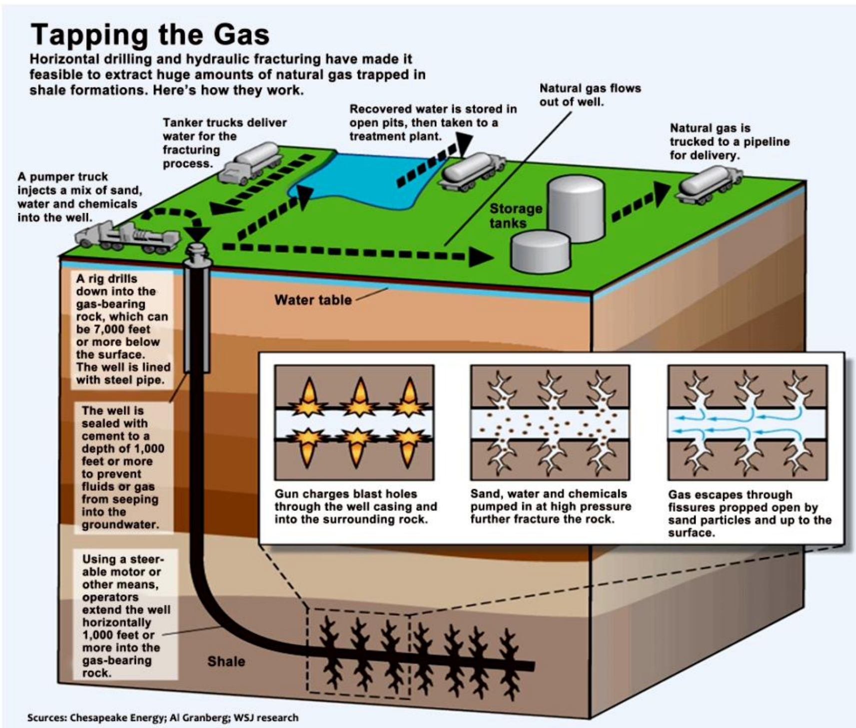

Figure 6. *Introduction of horizontal drilling and hydrofracturing in shale.*

Nanoscale imaging visualizes shale gas plays - nanoscale gas flow in shale gas sediments. Diameter of pores in shale gas sediments ranges from a few nanometres to a few micrometres. In shale gas systems, nanopores play two important roles. First, for the same pore volume, the exposed surface area in nanopores is larger than in micropores, probing nanoscale forces/mechanochemistry: AFM (Atomic Force Microscopy) to study interactions of nanoscale particles with fluid mixtures. The ability of the AFM to create three-dimensional micrographs with resolution down to the nanometer and Angstrom scales has made it an essential tool for imaging surfaces in applications. In addition to this topographical imaging, however, the AFM can also probe nanomechanical and other fundamental properties of sample surfaces, including their local adhesive or elastic (compliance) properties.

1.6 Nano-Proppants Applications in Hydraulic Fracturing

Hydraulic fracturing is a well-stimulation process technique which consists of drilling and injecting fluid into the ground at a high pressure so as to fracture shale rocks to release natural gas inside. It is frequently applied to wells for shale gas, tight gas, tight oil, and coal seam gas, and successfully used to increase flow rates. The used fluid contains water, sand, and chemicals. Proppant suspended particles in the fracturing fluid are used to hold fractures open after a hydraulic fracturing treatment, thus producing a conductive pathway that fluids can easily flow along (Rahm et al., 2011). Naturally occurring sand grains or artificial ceramic material are common proppants used. Nano-proppants OxBall and OxFrac are light, high-strength ceramic proppants. OxBall is heavier and slightly larger, and OxFrac is lighter and smaller. As per applications requisition nano-proppants are used. For example, OxBall is more suited for west Texas type oil and OxFrac for shale gas like the Barnett. OxBall is currently being used to enhance production from the deeper Haynesville and Eagle Ford plays. Spaces exist where the surfaces do not touch (see http://www.epmag.com/tech-watch-highly-conductive-nanostructured-proppants-boost-recovery-647956). The balls are all uniform size, so they pack uniformly and create porosity providing significant space for all and gas to flow. In contrast, if the proppant being used has particles of varying shapes and sizes, such as the grains in commonly used, relatively inexpensive sand, they pack tighter, and the rate at which oil and gas come out of the well is slower. The flow rate with same-size proppant particles can be as much as 100 percent higher than using traditional ones.

Another consideration is downhole injection where fluid is pumped down the borehole with varying-sized proppant particulates, their tendency to aggregate will limit how far down they can be pumped.

1.7 Viscous Flow and Diffusion

Discrimination between pressure-driven volume flow (Darcy flow) and diffusive transport through the water-saturated pore system or organic matter, constitutes a problem in laboratory experiments on rocks with low to extremely-low permeability. Both transport processes may result in similar flow rates at the cm to mm sample length scale. Nominal permeability coefficients derived from steady state or non-steady state flow tests for initially water saturated shales after gas breakthrough may be as low as 10^{-25} m^2. Diffusion of gases through the water-saturated pore space and the organic matter of carbonaceous rocks (and coals) may result in observed fluxes of the same order under these experimental conditions (gas pressure gradients: 1-10 MPa/cm; 10^8-10^9 Pa/m) (Figure 7). In analogy to heat transport, the dimensionless Peclet number (Pe) may be used to express the ratio of convective to diffusive transport (Pe=system length x fluid velocity/diffusion coefficient). While Pe values >>1 indicate predominance of advective transport (pressure-driven volume flow), for Pe << 1, diffusion will be the dominating process. For the experimental conditions stated above, Peclet numbers around 1 and lower are commonly encountered when effective permeability coefficients are less than 10^{-22} m^2. The composition of gas produced from tight gas and shale gas reservoirs varies with time for a variety of reasons. The cause of flowing gas compositional change typically cited is selective desorption of gases from the surface of the kerogen in the case of shale. However, other drivers for gas fractionation are important when pore throat dimensions are small enough. Pore throat diameters on the order of molecular mean free path lengths will create non-Darcy flow conditions, where permeability becomes a strong function of pressure. At the low permeabilities found in shale gas systems, the dusty-gas model for flow should be used, which couples diffusion to advective flow.

Configurational Diffusion occurs when the molecules flowing through a porous medium are similar in size to the pores of the porous medium. This phenomenon is considered to be important in transport through zeolites, and in biological systems, and is substantially complicated by issues of surface chemistry. Configurational diffusion effects are unlikely to be important in the specific case examined in this work, i.e., flow of light hydrocarbon gases through shale. This is because the shale pores which are believed to transport and store gas, are far larger than the light hydrocarbon gas molecules flowing through them. Even small kerogen pores possess dimensions of 50nm while a methane molecule has a diameter of 0.38 nm.

Surface Diffusion occurs where molecules are adsorbed to the surface of the porous medium and move along that surface. Shale is known to contain a quantity of adsorbed gas on its kerogen and clay surfaces, so adsorption is certainly an important contributor to total gas storage (SEG, 2013).

Liquid Diffusion is the transport of molecules through a liquid with concentration gradient as the driving force. In this case, we are particularly interested in the transport of dissolved gas molecules through the liquid phase.

Estimates of liquid diffusion coefficients are typically orders of magnitude lower than gas-phase diffusion coefficients for any given light gas molecule at the same thermodynamic conditions. In addition, solubility of hydrocarbon gases in liquid water is not high. Gas diffusivity of methane into methane (self-diffusivity) is 2.5 × 10-1 cm^2/s at atmospheric pressure while the diffusivity of methane in water is 1.88 $\times 10^{-5}$ cm^2/s. At a high pressure 50MPa, the self-diffusivity of methane is 4.55 $\times 10^{-3}$ cm^2/s. Consequently, total hydrocarbon flux caused by liquid diffusion will be orders of magnitude lower than flux caused by gas diffusion. Both tight gas and shale gas reservoirs are known to contain water, but the water is typically found at saturations below the irreducible saturation. In other words, water will not flow, but may serve as a substrate for diffusion. A liquid hydrocarbon phase may be present in tight gas or shale gas reservoirs. This phase coexistence may be due to thermodynamic equilibrium or capillary condensation and the composition of the liquid hydrocarbon phase will vary significantly with pressure and temperature.

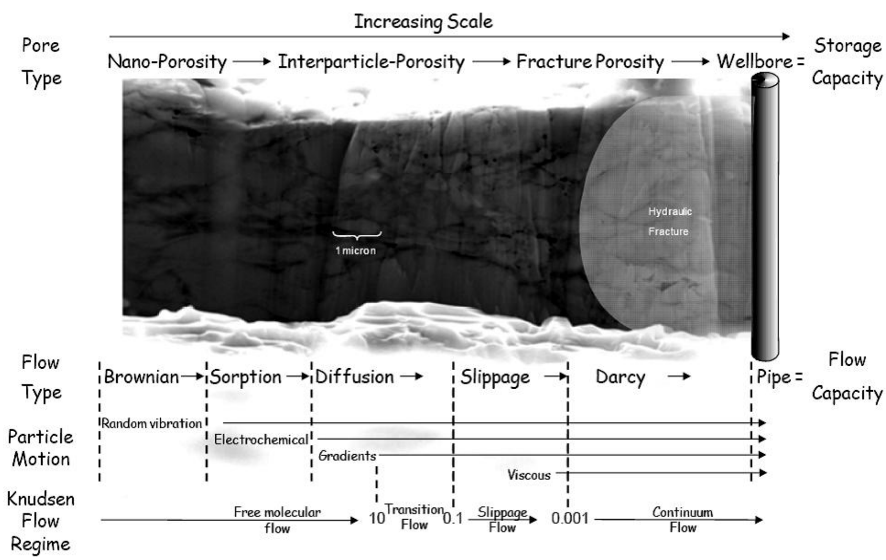

Figure 7. *Gas shale storage and flow capacity diagram showing pore type, flow type, dominant particle motion within a given flow regime.*

Permeability measures the ability of fluids to flow through rock (or other porous media). The Darcy is defined using Darcy's law, which can be written as:

$$v = \frac{k\Delta P}{\mu \Delta x}$$

where v is the superficial (or bulk) fluid flow rate through the medium, κ is the permeability of a medium, μ is the dynamic viscosity of the fluid, ΔP is the applied pressure difference, and Δx is the thickness of the medium.

Navier-Stokes equation Incompressible flow

$$\rho = \left(\frac{\partial v}{\partial t} + v.\nabla v\right) = -\nabla p + \mu\nabla^2 v + f$$

Navier-Stokes equation, Compressible flow

$$\rho = \left(\frac{\partial v}{\partial t} + v.\nabla v\right) = -\nabla p + \mu\nabla^2 v + \left(\frac{1}{3}\mu + \mu^v\right)\nabla(\nabla. v) + f$$

Fick's first law $J = -Dgrad\Phi$

Fick's Second Law $\frac{\partial \emptyset}{\partial t} = D\nabla^2\emptyset$

The description of matrix flow by considering diffusive (Knudsen) flow in nanopores. When Darcy flow becomes insignificant due to nanodarcy matrix permeability, Knudsen flow takes over and contributes, substantially, to the transfer of fluids from matrix to fracture network (Rahm, 2011).

Knudsen flow describes the movement of fluids with a high Knudsen number, that is, where the characteristic dimension of the flow space is of the same or smaller order of magnitude as the mean free path.

The Knudsen number is a dimensionless number defined as: $\frac{\partial \emptyset}{\partial t} = D\nabla^2\emptyset$ $\kappa_n = \frac{\kappa_B T}{\sqrt{2}\pi\sigma^2 pL}$, for an ideal gas.

For particle dynamics in the atmosphere, and assuming standard temperature and pressure, i.e. 25 ℃ and 1 atm, we have $\lambda \approx 8 \times 10^{-8}$ m, or approximately 2.6×10^{-9} ft.

Therefore, incorporating Darcy and diffusive flows in the matrix and stress-dependent permeability in the fractures, we develop a dual-mechanism dual-porosity naturally fractured reservoir formulation and derive a new transfer function for fractured shale-gas reservoirs.

1.8 Conclusions

According to geologists, there are more than 688 shales worldwide in 142 basins. Shale gas exploitation is no longer an uneconomic venture with availability of improved technology as the demand and preference for this clean form of hydrocarbon have made shale gas, an energy in demand. The reserve accretion, production and development of shale gas from one basin to another around the world are rapidly increasing. Real-time monitoring of microseismic events allows operators to immediately optimize the hydraulic stimulation process by modifying the fracture stage design while pumping into the formation. The operator used the real-time data to experiment with how different perforation patterns impacted fracture propagation. The firm also used the data to make real-time changes in the fracture program. At one point, the data showed an absence of growing microseismic activity geometry, alerting the operator to stop pumping proppant and flush the well with water to avoid a potentially costly sanding-off of the fractures. Recording microseismic events to monitor rock fracturing in 3D space and time during the stimulation process allows operators to confirm the rock volume and formation geometry being stimulated. As a result, operators can optimize future well placement and completion designs, for cost-effective drainage of unconventional reservoirs.

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