SOLVING THE CHALLENGES OF PRODUCING LIQUID-RICH SHALE GAS

Shale gas is natural gas that is trapped in shale formations, which are primarily comprised of fine-grained sedimentary rocks, dominated by shales. Natural gas produced from shale is often referred to as "unconventional," which refers to the reservoir in which it is found. Unconventional reservoirs are laterally continuous and regionally extensive hydrocarbon accumulations without an apparent seal or trap and often extend beyond the spill point of conventional structures.

Currently, the production of gas from unconventional resources has surpassed the production from conventional fields in the United States. Approximately 67% of the gas reserves identified in the United States are in unconventional reservoirs. However, the estimated ultimate recovery of the original gas in place is only around 15 to 20%. In addition, the production of unconventional horizontal and multi-staged fractured wells is known to drop by 75% to 90% in the first few years of the life of the well. Liquid loading in the horizontal sections of the well and condensate banking in the reservoir have been identified as the two major causes of declining production rates and limited ultimate recovery.

Liquid Loading

There are many studies published regarding liquid loading for vertical wells. Two commonly quoted liquid loading models were developed by Turner et al. (1969) and Coleman et al. (1991). However, these have proven to be not applicable for horizontal liquid-rich wells. Another study by the University of Tulsa demonstrated the significance of gas velocity in carrying liquids, as well as characterized flow regimes under different velocities and identified 20ft/s as being the critical gas velocity needed to effectively carry liquids along a horizontal well. Studies by Khazam et al. (1994) showed for the first time the impact of increased gas velocity on relative permeability using condensing fluids. This new phenomenon was referred to as the "positive coupling effect" and was attributed to the coupling of the flow of the gas and condensate phases. G.D. Henderson et.al (2010) reported that gas condensate relative permeability will increase with increasing velocity. The laboratory experiment was conducted on different cores at various interfacial tension values and condensate saturations. These results have shown that inertia effect was dominant in cores saturated with 100% gas at the tested conditions. However, as the condensate saturation increased, an improvement in relative permeability due to positive coupling was observed over the entire range of velocities at all the values of IFT tested.

Upwing's SCS can uniquely provide solutions to the combined issues of liquids in the horizontal sections of the well and liquids in the formation. Operation of the SCS in a gas well creates a low-pressure zone at the compressor inlet at the bottom of the wellbore, thus lowering the bottom hole well pressure. This drawdown in the wellbore actively induces more gas flow from the formation to the wellbore. With higher gas flow rates and lower bottom hole flowing pressures, the increase in velocity (e.g. 14ft/s or above) of the gas stream carries more liquids out of the wellbore, thus removing liquids from the vertical and horizontal sections of the well. Brito et al. (2017) studied the liquid film reversal mechanism to develop a model for predicting liquid loading instead of using the liquid droplet mechanism. They postulated that liquid loading occurs when the shear stress exerted by the gas flow at the liquid-gas interface is insufficient to generate enough drag force to carry the liquid film surrounding the pipe wall. Experimental results depicted in Figure 1 highlight the transition region from unstable to stable flow above critical velocity, which defines the onset of significant liquid accumulation in the lateral section. Figure 1 also shows the percentage increase in back pressure against the formation with decreasing gas velocities.

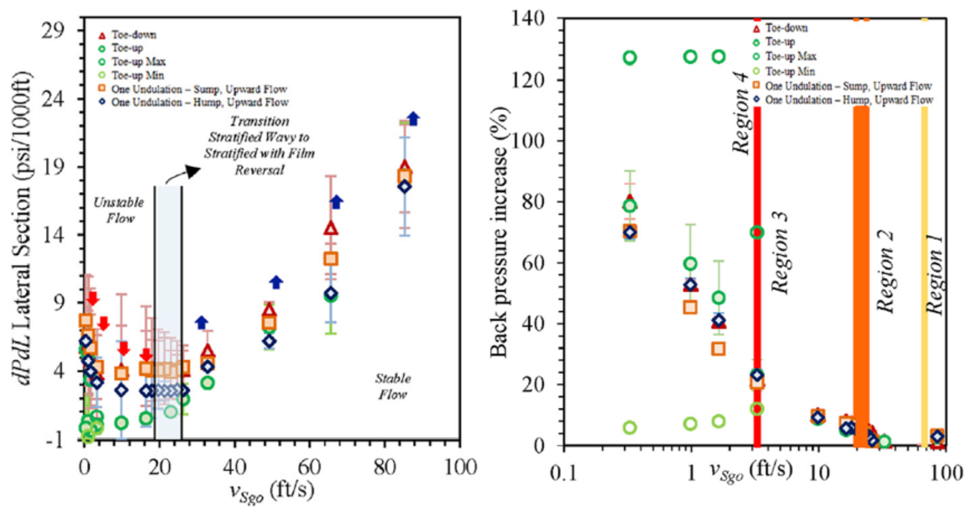

Figure 1. Pressure gradient and back pressure vs. superficial gas velocity.

Beyond the suction effects mentioned above, the boosting effects with the higher discharge pressure from the compressor will overcome the pressure losses along the pipe and increase the wellhead pressure to flow the gas into the surface gathering system. With both the suction effects and the boosting effects of the subsurface compressor at work, the well can still produce gas from the formation under the lowest possible downhole pressure or even vacuum, while forcing the produced gas up hole.

The current artificial lift methods include: using mechanical pumps to transport liquids from the vertical section of the well; reducing the liquid column density by surfactants; and installing a velocity string to increase gas velocity by reducing the diameter of the flow area to carry more liquid. However, they all have limited capabilities on how much liquid can be removed from a gas well. For example, a rod pump can reduce the height of the hydrostatic column but not eliminate it; surfactant can reduce the density of the liquid column but a certain amount of back pressure still remains; and the smaller cross-section area of the velocity string can increase the gas velocity to carry more liquids but with higher friction losses due to a smaller pipe diameter. In addition, all these artificial lift methods are not effective at sweeping liquids through laterals, have multi-phase flow interference issues, have depth limitations, and more importantly, have limited drawdown, which is equivalent to limited gas production and recoverable reserves.

Condensate Banking

Condensate blockage inside the wellbore, near the wellbore and inside the reservoir pore space significantly reduces the productivity of a well and ultimate gas and condensate recovery. This phenomenon is particularly important in unconventional liquid rich gas reservoirs, where the ratio of the pressure drop in the hydraulic fracture to the total drop within the reservoir can be significant. Several methods have been suggested to solve this problem, such as gas injection, CO_2 huff-n-puff, wettability alteration, interfacial tension reduction and hydraulic fracturing. They all have certain limits. For example, hydraulic fracturing increases the effective contact area with the formation and is the most common mitigating technology in shale reservoirs. However, hydraulic fracturing will neither prevent condensate banking nor remove condensate once the pressure at the sand face drops below the dewpoint pressure, and the condensate saturation will continue to increase around the fracture and around the wellbore.

Upwing's SCS has demonstrated that it can lower bottom hole pressures well below current abandonment pressures; this will increase the gas velocity to ensure there is no liquid loading in the horizontals, increase the positive coupling effects within the reservoir and overcome the capillary effects that are causing blockages within the formation. Exploitation of unconventional reservoirs requires access to nano matrix permeabilities. Nelson et al. 2008 presented results of laboratory measurements in siliciclastic rocks with pore throats sizes plotted on the pore throat size spectrum (Figure 2). Figure 3 shows the capillary pressure tube model with an air water interface separating two immiscible fluids with water representing the wetting phase. Figure 4 shows the required in situ pressure ratio to overcome capillary effects and mobilize reservoir fluids from static equilibrium.

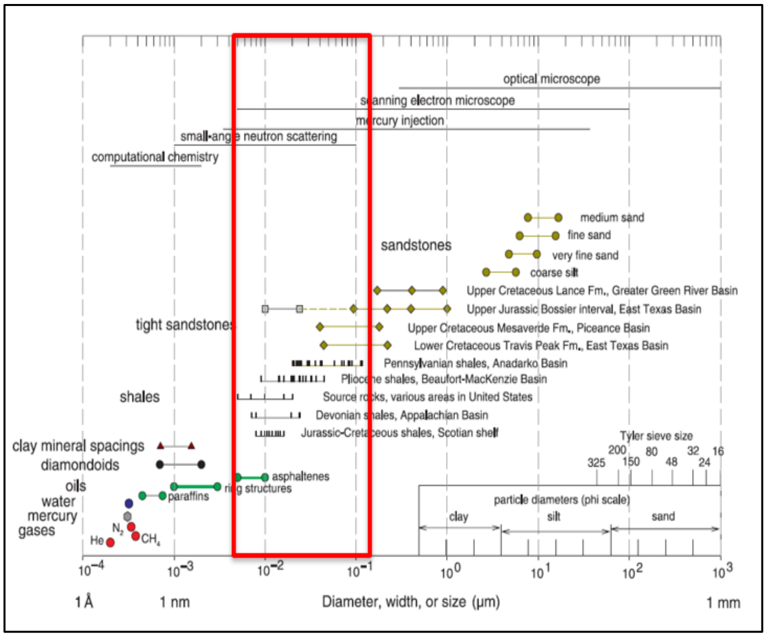

Figure 2. Pore throat and pore size.

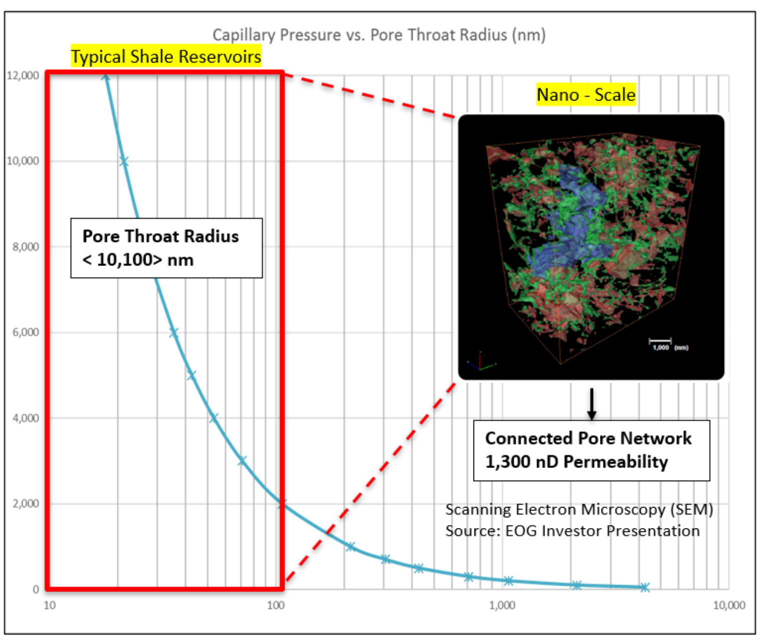

Figure 3. Capillary tube model.

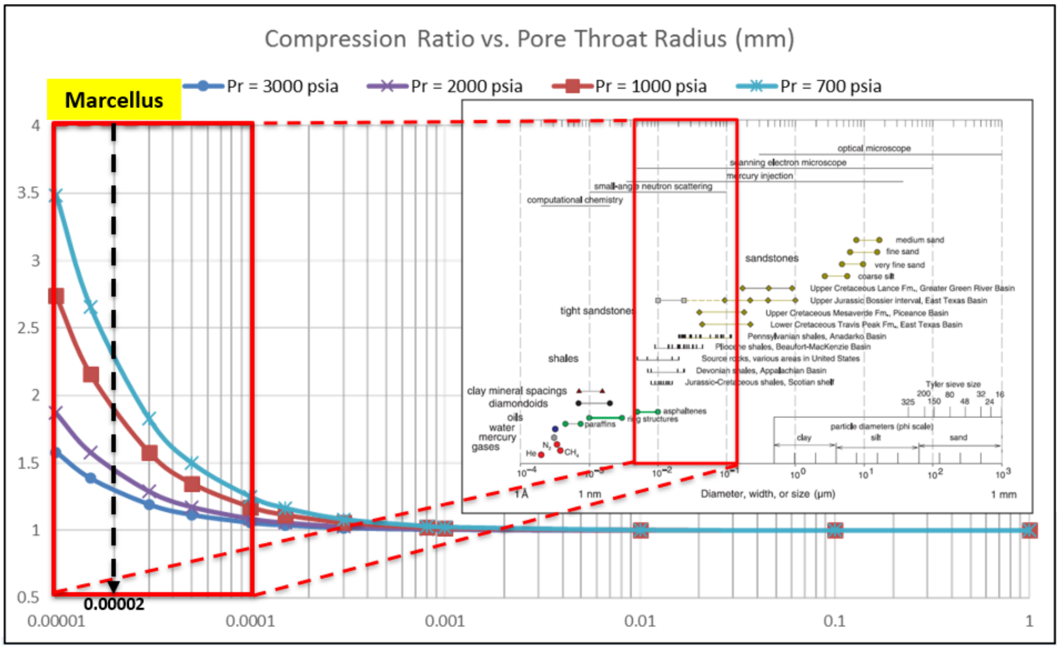

Figure 4. Pressure ratio vs. pore throat radius.

The positive rate effect attributed to the coupling of the flow of the two phases referred to as the "positive coupling effect" can potentially greatly reduce condensate banking in the formation. The effects of positive coupling on gas and condensate relative permeabilities can be seen in Figure 5 (G.D.Henderson et al. Heriot-Watt University).

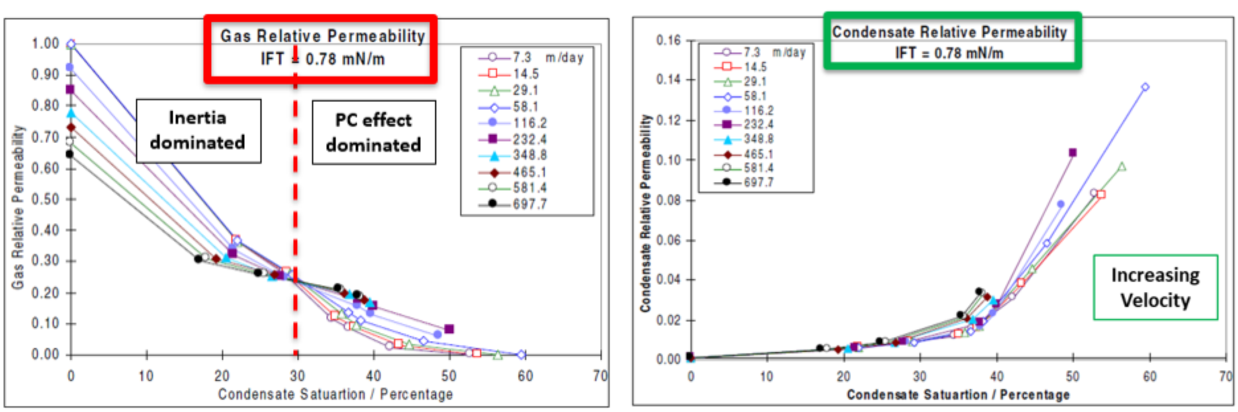

Figure 5. Coupling of the flow of two phases – "Positive coupling effect."

About Upwing Energy

Upwing Energy, Inc. ("Upwing"), headquartered in Cerritos, Calif., provides the most reliable, available and retrievable artificial lift technology that increases the production and recovery of hydrocarbons from conventional and unconventional wells. The company is an innovative offshoot of parent company Calnetix Technologies, which is a recognized leader in high-speed rotating systems for a wide variety of industries. For more information, please visit www.upwingenergy.com.